~~SECURITY-RELATED INFORMATION - WITHHOLD UNDER 10 CFR 2.390~~

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June 18, 2026

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Serial No. 26-144
NRA/CBL: R0
Docket No. 50-395
License No. NPF-12

DOMINION ENERGY SOUTH CAROLINA (DESC)
VIRGIL C. SUMMER NUCLEAR STATION (VCSNS) UNIT 1
UPDATE TO THE FINAL SAFETY ANALYSIS REPORT – REVISION 26

Pursuant to 10 CFR 50.71(e), Dominion Energy South Carolina submits Revision 26 to the Updated Final Safety Analysis Report (UFSAR) for Virgil C. Summer Nuclear Station (VCSNS).

The complete VCSNS UFSAR, Revision 26, is provided in Enclosure 1 and contains Security-Related Information that DESC requests be withheld from public disclosure in accordance with 10 CFR 2.390. A public version of the VCSNS UFSAR, Revision 26, is provided in Enclosure 2.

A list and brief description of changes since the previous annual update is provided in the Revision Summary located in the Frontmatter of each enclosure. Third-party documents included by reference in the VCSNS UFSAR may not be text searchable.

A review in accordance with 10 CFR 54.37(b) has been completed, which identified no new systems, structures, or components subject to aging management or time-limited aging analyses for VCSNS.

If you have any questions or require additional information regarding this submittal, please contact Cailyn Ludwig at (804) 273-5131.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 06/18/26.

Respectfully,

James Holloway (Jun 18, 2026 14:34:00 EDT)

James E. Holloway
Vice President – Nuclear Engineering & Fleet Support

ENCLOSURE 1 TO THIS LETTER CONTAINS SECURITY-RELATED INFORMATION WHICH IS TO BE WITHHELD FROM PUBLIC DISCLOSURE UNDER 10 CFR 2.390. UPON SEPARATION FROM ENCLOSURE 1, THIS LETTER IS DECONTROLLED.

Enclosures:

1. Virgil C. Summer Nuclear Station Unit 1, Updated Final Safety Analysis Report, Revision 26 **[Security-Related Information – Withhold Under 10 CFR 2.390]**
2. Virgil C. Summer Nuclear Station Unit 1, Updated Final Safety Analysis Report, Revision 26 [Redacted]

Commitments made in this letter: None

cc:

U. S. Nuclear Regulatory Commission
Region II

G. Ed Miller
NRC Senior Project Manager
U.S. Nuclear Regulatory Commission

NRC Senior Resident Inspector
Virgil C. Summer Nuclear Station

Bureau of Environmental Health Services
South Carolina Department of Health and Environmental Control

G. J. Lindamood
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ENCLOSURE 2

VIRGIL C. SUMMER NUCLEAR STATION UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REVISION 26

[REDACTED]

DOMINION ENERGY SOUTH CAROLINA (DESC)
VIRGIL C. SUMMER NUCLEAR STATION

V. C. Summer

Updated Final Safety Analysis Report

UFSAR Updated through June 2026

Revision 26

Docket Number 50-395
License Number NPF-12

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Revision Summary

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
26 - Chapter 4	04/08/26	VCS-UCR-2026-001	Sections 4.1, 4.2.1.2, 4.2.1.3.2, 4.2.4, 4.3.2.1, 4.4.1, 4.4.2, 4.4.3, 4.4.6, Tables 4.1-1,4.3-1, Figures 4.2-2 through 4.2-7	Implementation of PRIME Fuel Features at V. C. Summer Unit 1 EVAL-ENG-RSE-V1C30 Rev 0
26 - Chapter 15	04/08/26	VCS-UCR-2026-001	Table 15.4-1a	Implementation of PRIME Fuel Features at V. C. Summer Unit 1 EVAL-ENG-RSE-V1C30 Rev 0
26 - Chapter 0	04/09/26	Chapter 0	N/A	to update REV history
26 - Chapter 4	01/12/26	VCS-UCR-2025-004	Sections 4.2.1.1.1, 4.2.1.3.1.4, 4.2.1.3.1.5, and 4.2.4	ETE-NAF-2025-0040 implements an alternate cladding strain acceptance criterion for Condition II overpower transients, based on behavior of fuel cladding as a function of hydrogen concentration, into the V. C. Summer Unit 1 (VCS) Final Safety Analysis Report (FSAR). ET-NAF-2025-0040, Rev. 0
26 - Chapter 0	01/12/26	Chapter 0	N/A	to update REV history
26 - Chapter 0	11/06/25	Chapter 0	N/A	to update REV history
26 - Chapter 4	11/06/25	VCS-UCR-2025-008	Section 4.2.1.4.3	V. C. Summer UFSAR Update for RCCA Receipt Inspection Procedure Change Revision 15 to NF-AA-FPA-503 (New Fuel Inspection)

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
26 - Chapters 11, 12, 13	7/24/25	VCS-UCR-2025-006	Sections 11.5.6, 12.1.5, 12.3.1.1.1, 12.3.1.1.2, 12.3.1.2, 12.3.2.1.1, 12.3.2.2.2, 12.3.2.3.2, 12.3.2.3.5-12.3.2.3.9, 13.2.4, 13.5, 13.5.1.2, 13.5.1.3, 13.6	VCS Management Position Title Changes in the FSAR Substitution Memo
26 - Chapter 0	7/24/25	Chapter 0	n/a	to update REV history
25 - Chapter 3	6/26/25	RN 19-038	Tables 3.10-1, 3.10-3	ECR 50938 RBCU condensate leak detection ECR50938
25 - Chapter 5	6/26/25	RN 19-038	Section 5.2.7.1.2, Figures 5.2-9, 9.3-5	ECR 50938 RBCU condensate leak detection ECR50938
25 - Chapter 1	1/30/25	VCS-UCR-2024-006	Section 1.2.3.1	V.C. Summer FSAR change (LBDCR-22-VCS1-001) LBDCR-22-VCS1-001, CR1231277, CA12444283
25 - Chapter 3	1/30/25	VCS-UCR-2024-006	Section 3.7.4.4	V.C. Summer FSAR change (LBDCR-22-VCS1-001) LBDCR-22-VCS1-001, CR1231277, CA12444283
25	01/30/25	Chapter 0	n/a	to update REV history
25	12/12/24	Chapter 0	n/a	to update REV history

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
25 - Chapter 5	12/12/24	VCS-UCR-2024-005	Section 5.4.2.1	UFSAR Change Supporting Design Equivalent Change Package VC-24-00010 for Replacement of RVCH Guide Studs VC-24-00010
25 - Chapter 6	12/12/24	VCS-UCR-2024-005	Table 6.2-7	UFSAR Change Supporting Design Equivalent Change Package VC-24-00010 for Replacement of RVCH Guide Studs VC-24-00010
25	10/24/24	Chapter 0	n/a	to update REV history
25 - Chapter 9	10/24/24	VCS-UCR-2023-010	Section 9.4.7.2.4	FSAR Changes per ECR50585X “C Chiller Replacement” ECR50585X
25 - Chapter 9	10/24/24	VCS-UCR-2024-009	Section 9.2.3.2	Revision of FSAR Section 9.2.3 for use of Demineralizer Trailers and Skids ETE-VC-2024-0038
25 - Chapter 6	10/24/24	VCS-UCR-2023-005	Section 6.2.2	Reactor Building Cooling Unit Fan Group Clarification VCS-CR-19-04103
25 - Chapter 8	07/25/24	VCS-UCR-2024-004	Section 8.3.2.1.5.7	Modify FSAR Section 8.3.2.1.5.7 for Correct SR Inverter Channel Configuration CR1260675
25	07/25/24	Chapter 0	n/a	to update REV history
24	05/29/24	Chapter 0	n/a	to update REV history
24	05/24/24	Chapter 0	n/a	to update REV history
24 Chapter 3	05/29/24	VCS-UCR-2024-002	Sections 3.6.1.2.1 and 3.6.1.2.2	Modification to Chapter 3 Typographical Errors CA12237359

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
24 - Chapter 11	05/24/24	VCS-UCR-2023-013	Section 11.4.2.8, Table 11.4-1	RML0008 Replacement VC-22-00009
24 - Chapter 3	02/08/24	VCS-UCR-2023-012	Section 3.8.1.3.1.2	ECR72063 – Dome Tendon Minimum Required Prestress Value Reduction ECR72063
24 - Chapter 9 24 - Chapter 12	02/08/24	VCS-UCR-2024-001	Figures 9.5-6, 9.5-7, 9.5-8, 9.5-9, 9.5-10, 12.1-19, 1.2-27 (IBR file), and 1.2-28 (IBR file)	Correct UFSAR pages sent to NRC in last submittal NRC identification.
24 - Chapter 4	02/08/24	VCS-UCR-2022-006	Section 4.4.5.4	Loose Parts Monitoring Program (Metal Impact Detection System) Training Requirement Change CR1209410
24	02/08/24	Chapter 0	n/a	to update REV history
24 - Chapter 0	11/2/23	Chapter 0	n/a	to update REV history
24 - Chapter 6	11/2/23	VCS-UCR-2023-008	Section 6.3.2.6	ETE-NAF-2022-0115 FSAR 6 Updates ETE-NAF-2022-0115
24 - Chapter 5	7/26/23	VCS-UCR-2023-006	Section 5.2.7.3	Revise Reactor Coolant Leakage Requirements LBDCR 22-VCS1-003
24 - Chapter 6	7/26/23	VCS-UCR-2021-020	Section 6.2.2.4.1.2	Technical Specification Revision for Reactor Building Spray Nozzle Flow Blockage Check LBDCR-21-VCS1-005

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
24 - Chapter 18	7/26/23	VCS-UCR-2023-007	Section 18.2.15.2	Enhancement to VCS FSAR Chapter 18 Aging Management Fire Barrier Scope CR1197972 (CA11108983) Fire Protection Team Inspection (FPTI) Self-Assessment, SA22-DE-01 Enhancement
24 - Chapter 1	7/26/23	VCS-UCR-2023-009	Table 1.7-1	Editorial change to the original RN 09-013 implementation items. RN 09-013]
24 - Chapter 9	7/26/23	VCS-UCR-2021-006	Section 9.2.3.2	OWS to Unit 1 Filtered Water Connection VC-20-00008
24 - Chapters 1 and 9	7/26/23	VCS-UCR-2021-008	Sections 1.2.3.8.4, 9.2.3.2, and 9.2.4	OWS to Unit 1 Sterile Water Connection VC-20-00009
23 - Chapter 4	4/27/23	VCS-UCR-2023-003	Sections 4.1, 4.2, and Figure 4.2-2	Westinghouse Integral Nozzle (WIN) top nozzle fuel component EVAL-ENG-RSE-V1C28
23 - Chapter 18	3/30/23	VCS-UCR-2023-004	Section 18.2.31	FSAR Chapter 18 CA11417519
23 - Chapter 7	3/30/23	VCS-UCR-2022-013	Sections 7.1.2.11.1 and 7.1.3	Bases to Eliminate Pressure Sensor Response Time Testing for Rosemount 3150 Series Transmitters from Technical Specification Requirements ECR72857

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
23 - Chapter 9	2/23/23	VCS-UCR-2022-005	Section 9.1.3.5.3	Spent Fuel Purification Demineralizer Resin Level Probe Removal VC-22-00018
23	2/23/23	CHAPTER 17		N/A -POSTED FRAMEMAKER VERSION
23	2/23/23	CHAPTER 16		N/A -POSTED FRAMEMAKER VERSION
23	1/26/23	VCS-UCR-2022-011	Chapter 00, Revision summary table	Modifying Change to Identify 50.59 Changes in Chapter 00, Revision Summary Table Header PA11333039
23 - Chapter 3 Chapter 5	1/26/23	VCS-UCR-2022-010	Sections 3.1.2.5, 3.8.1.3.1.2, 3.8.1.4.1.2.1, 3.8.1.6.3.3, 3.8.1.7.2, 3A.35, & 3A.35.1 (new), and Section 5.7.1.4	FSAR Chapters 3 and 5 ECR72151, ECR70876
23	1/26/23	CHAPTER 14		N/A -POSTED FRAMEMAKER VERSION
23 - Chapter 13	12/12/22	VCS-UCR-2022-012	Section 13.2.2.3	Remove reference to ANSI 18.1-1971 in Chapter 13.2.2.3 and replace with "as stated in the Quality Assurance Program Description". QAPD Change Request 2022-004
23	12/09/22	CHAPTER 5		N/A -POSTED FRAMEMAKER VERSION (CORRECTED FOR MISSING SYMBOLS)
23 - Chapters 9 and 8	12/07/22	VCS-UCR-2020-020	Section 9.1.3.3, Table 8.3-3	Update of Table 8.3-3 and Chapter 9.1.3.3 for ECR 50940 - Spent Fuel Pool Cooling Alternate Power ECR 50940

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
23 - Chapter 15	12/07/22	VCS-UCR-2022-007	Section 15.4.3.2.2	ERG Revision Level Removal from 15.4.3.2.2 EOP-4.0 Revision
23	12/07/22	CHAPTER 5		N/A -POSTED FRAMEMAKER VERSION
23	12/07/22	CHAPTER 11		N/A -POSTED FRAMEMAKER VERSION
23 - Chapter 3	7/21/22	VCS-UCR-2022-002	Section 3.11, Table 3.11-0	Update Section 3.11 regarding EQDB location. NRC identified. Information Technology retired VAX machine and EQDB (database) is now accessed on site Intranet system.
23 - Chapter 8	8/25/22	VCS-UCR-2021-018	Tables 8.3-3, 8.3-3a, 8.3-3b	FSAR TABLE 8.3-3 Part A1, A2, B1, and B3 Revision. CR-20-03674 Action (6)
22	11/22/21	VCS-UCR-2021-019	Table 8.3-1	Revision of Main Transformer Rating in FSAR Table 8.3-1 for ECR50522A ECR50522A, Main Transformer Contingency Replacement

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
22	9/21/21	VCS-UCR-2021-013	Section 1.6 (pages 1.6-7 through 1.6-12) Table 1.8-1 (page 1.8-4) Section 6.2.1.3.11 (page 6.2-45) Table 6.2-60 (page 6.2-295) Section 6.3.3.13 (page 6.3-41) Section 7.2.1.2.4 (page 7.2-15) Table 8F-1 (page 8F-3) Sections 15.1.8, 15.1.9, 15.1.10 (pages 15.1-8 through 15.1-11, 15.1-13, and 15.1-14) Table 15.1-4 (pages 15.1-19 and 15.1-20) Figure 15.1-6 (no page number) Section 15.3 (page 15.3-1) Section 15.4.1.2.1 (page 15.4-16) Section 15.3.1 – Complete Replacement, except Sections 15.3.1.1, 15.3.1.2.4, and 15.3.1.2.5 Section 15.4.1 – Complete Replacement, except Sections 15.4.1.1.6 and 15.4.1.1.7 and Sections 15.4.1.2-15.4.1.4	V. C. Summer Full Spectrum LOCA FSAR Changes ETE-NAF-2021-0085

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
22	11/2021	VCS-UCR-2021-011	Sections: 1.6, 4.2, 4.3, 4.4, 6.2, 15.1, 15.2, 15.3, 15.4 Tables: 4.1-1, 4.1-2, 4.4-1, 15.1-2, 15.1-4, 15.2-1, 15.3-3, 15.4-34, 15.4-42 Figures: 4.4-3, 15.2-1, 15.2-2, 15.2-12, 15.2-13, 15.2-14, 15.2-19, 15.2-26, 15.2-27, 15.2-31, 15.2-32, 15.3-27, 15.3-28, 15.4-85, 15.4-89, 15.4-96B, 15.4-100, 15.4-101, 15.4-102, 15.4-103	Implementation of PAD5 for V.C. Summer ETE-NAF-2021-0082
22	3/31/22	VCS-UCR-2021-009	FSAR Chapter 18 Table of Contents, Table 18.1-1, Sections 18.1, 2.3, 2.5, 2.10, 2.12, 2.13, 2.15.1, 2.17, 2.18, 2.21, 2.28, 2.30, 2.31, 2.34, 2.36, 2.39, 2.40, 2.42, 2.43, 2.44, 2.45, 2.46 (new) and 18.3.2.2	FSAR Chapter 18 Update of Aging Management Activities and Descriptions VCS License Renewal (LR) Plant Life Extension (PLEX) Program Assessment Report DMNVCS00001-REPT-001 Revision 1 and the associated actions in CR-19-03752
22	06/2021	VCS-UCR-2021-007	Chapter 17, Section 2	Add words "incorporated by reference" into Section 17.2 of the VCS U FSAR to align with Fleet. CR-20-03022
22	6/2021	VCS-UCR-2021-004	Chapter 1/Section 1.6	Correction of RN # associated with Section 1.6 Note CR-20-03020

Revision Summary (continued)

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22	1/14/21	VCS-UCR-2021-002	Section 10.4.7.1.2	Replace the Condensate to DA Flow Control Valves VC-20-00001
22	9/2021	VCS-UCR-2020-026	Sections 6.2.1.3.10.1.2 and 6.2.7	The changes include the following: Reference to PWROG-17034-P-A in the mass and energy release for LOCAs section (6.2.1.3.10.1.2). The addition of Reference 49 (PWROG-17034-P-A) into the references section (6.2.7). ETE-NAF-2020-0113, Rev. 0
22	5/25/21	VCS-UCR-2020-017	Section 9.2	Rated horsepower change for the CCW Booster Pumps in FSAR Table 9.2-12 ECR 72669
22	4/29/21	VCS-UCR-2020-002	Section 1.8 of Appendix 3A	Update VC Summer Commitment Reg 1.8 to a newer revision Section 13.1.3.1.12 LBDCR-21-VCS1-001

Revision Summary (continued)

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22	3/31/21	RN 2020-01	Sections 1.6, TOC, LOF, 15.2.2.2, 15.2.2.2.1,15.2.2.2,2, 15.2.4.2, 15.2.4.3, 15.2.7.2.1, 15.2.7.2.2, 15.2.8.2.1, 15.2.10.1, 15.2.10.2.1, 15.2.10.2.2, 15.2.10.3, 15.2.13, 15.2.16, 15.4.2.2.2.1, 15.4.2.2.2.2.1, 15.4.2.2.2.2.2, 15.4.6.2.2, 15.4.6.2.6, 15.4.6.2.8, 15.4.6.2.11, 15.4.7, Tables 15.1-2, 15.2-1, 15.4-19, 15.4-34, 15.4-42, Figures 15.2-3, 15.2-4, 15.2-5, 15.2-6, 15.2-7, 15.2-8, 15.2-9, 15.2-19, 15.2-20, 15.2-21, 15.2-25, 15.2-26, 15.2-27, 15.2-33, 15.2-34, 15.4-83, 15.4-84, 15.4-85, 15.4-86, 15.4-87, 15.4-88, 15.4-89, 15.4-90, 15.4-95, 25.4-96A, 15.4-96B. 15.4-100, 15.4-101, 15.4-102 (new), 15.4-103 (new)	Chapter 15 Non-LOCA Analyses With Updated RCE Initial Condition Uncertainties ECR-72616
22	11/5/21	RN 19-020	Figures 12.1-19 and 12A.4-7	Update of FSAR Figures Associated with ECR50928, Conduit Installation for Mansell SystemF ECR50928

Revision Summary (continued)

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22	9/29/21	RN 18-037	Section 9.4.7.2.4	FSAR Changes per ECR50585W "Replacement of Chiller B" ECR50585W
22	6/10/21	VCS-UCR-18-032	Table 8.3-3B	Update of Table 8.3-3b per ETBT 72319 ETBT 72319
21	04/2021	VCS-UCR-2021-005	Section 8.2.2	The FSAR is being updated to reflect the most recent Transmission Stability Study done for 2020. Though the conclusions of the study are in the end the same for the previous study and the FSAR, some portions need to be updated. For example, the year studied, the change from SCE&G to DESC, and some of the wording is being modified for readability and understanding.
21	04/2021	RN 09-013	Table 1.7-1, Section 10.4.7.2.3	Table 1.7-1 and Section 10.4.7.2.3 of the FSAR are being updated to address plant changes implemented per MRF 90004. Table 1.7-1 is being updated to remove reference to the elementary wiring drawings associated with the FWIV “B” train solenoids and alternate MCB FWIV switch. References to the “B” train solenoids and alternate MCB FWIV switch are being removed from Section 10.4.7.2.3. CR-08-01410, ECR 71280, MRF 90004

Revision Summary (continued)

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21	03/2021	VCS-UCR-2021-001	Sections 5.2.2.4, 6.3.4.3	Revision of FSAR Sections 5.2.2.4 and 6:3.4.3 to revise the frequency for testing Pressure Isolation Valves from “every refueling outage” to “during refueling outages on a performance-based frequency” 1ST Program Relief Requests RR-4-19 and RR-4-21
21	03/2021	VCS-UCR-2020-027	Section 8.2	Adding a description of the Open Phase Isolation System (OPIS) to Chapter 8 per industry guidance. ECR50884
21	02/28/21	UCR-2020-0021	Chapters 15.4.2 and 15.4.7 Tables 15.4-23 – 15.4-27, 15.4-34d, 15.4-41, 15.4-47, and 15.4-50	ETE-NAF-2020-0062 The FSAR description of the Main Steam Line Break (MSLB) dose analysis has been updated based on ETE-NAF-2020-0062. The changes include the following: • Update tables to reflect new MSLB analysis inputs and results. • Updates to descriptions to correct inconsistencies between sections, add clarification to improve reader understanding. • Update to description of non-design basis events.
	10/06/20	UCR-2020-025	Section 8.3, Section 8B	ECR 72707 – Section B This change updated FSAR Chapter 8 to reference SP-834 for construction guidance on electrical circuit physical separation.
	10/08/20	UCR-2020-022	Section 8.3	CR-20-00060 – Section 8.3 This change administratively corrected the when the Diesel Generator loads are verified from every refueling outage to periodically.

Revision Summary (continued)

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	09/17/20	RN 19-042	Section 3A	LAR-03-01931-20 – APPENDIX 3A This change added Reg Guide 1.196 Revision 0 to the FSAR
	08/24/20	RN 19-030	Section 12.3 Section 13.4 Section 17.2	DOM-QA-1 REVISION 28 This change revised section 13.4.2 and 17.2 to reflect incorporation of VCS into the Dominion Energy nuclear Facility Quality Assurance Program Description. Section 12.3.1.1 was revised to replace PSRC and NSRC with FSRC and MSRC, respectively.
	07/02/20	RN 19-034	Section 9.4	ECR 72587 – Section 9 This change corrected the description of the Penetration Access Areas Ventilation System.
	06/18/20	RN 19-023	Section 7.5 Section 7.7 Section 7.3 Section 14.1	ECR 72535 – Section 7, 9 and 14 These sections are being revised to remove the terminology referring to specific types of recorders.
	01/27/20	RN 19-037	FSAR Drawing removal	FSAR DRAWING REMOVAL This change removed the FSAR drawings in order to obtain alignment with Dominion Fleet.
	01/22/20	RN 14-015	Figure 1.2-5, Figure 1.2-6, Figure 9.3-1	ECR 50790B – Fuel Handling Building Upgrade This change upgraded the Fuel Handling Building for Used Fuel Storage, which includes the addition of dry cask storage equipment.

Revision Summary (continued)

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	01/06/20	RN 19-033	Section 12.3, Section 13.4, Section 17.2	ECR72598 – Repair of Leaking Buried Pipe This change revised Drawing D-302-201 to show a cured-in-place liner was installed under WO 1104685 to repair leaking buried pipe from Steam Generator Blowdown return to circulating water return.
	01/06/20	RN 19-012	Section 2.2, Section 6.4, Table 6.4-3, Section 9.2, Figure 9.2-8, Section 9.4	ECR 72460 – Chlorine No Longer Stored On-Site This change updated the FSAR Figure 9.2-8 to reflect chlorine is no longer stored on-site.
	01/02/20	RN 18-008	Figure 1.2-5, Section 7.7, Figure 8.3-4, Section 9.3, Figure 9.3-16, Sheet 2	ECR 50905 – Elimination of Boron Concentration Monitoring System These changes eliminated the Boron Concentration Monitoring System (BCMS).
	12/18/19	RN 19-026	Section 13.1	QAPD REVISION 7 – Section 13.1 This change revised Sections 13.1.2 and 13.1.3 to address organizational changes made by QAPD Revision 7 to support integration into the Dominion Energy Nuclear Fleet.
	12/12/19	RN 15-013	Figure 1.2-1, Figure 2.4-1, Figure 2.4-6, Figure 8.2-2a, Figure 8.2-2b, Figure 8.3-5a	ECR 50882- installation of new Critical Infrastructure Protection Building in Switchyard This change installed new Critical Infrastructure Protection Building in the Switchyard to meet North America Electric Reliability Corporation version 5 Critical Infrastructure Protection Reliability Standards.
	12/04/19	RN 10-032	Figure 1.2-6	ECR 50765 – Installed FME Equipment at Spent Fuel Pool This change installed portable handrails and nylon FME canvas covers at 463 elevation and on the mezzanine area above the Spent Fuel Pool.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	11/25/19	RN 19-015	Section 18.2.22, Section Appendix 3A	FSAR Appendix 3A and Chapter 18.2.22 Update This change revised FSAR Appendix 3A and Chapter 18.2.22 to update the references to NUMARC 93-01 revision form Revision 2 to Revision 4F and Regulatory Guide 1.160 Rev. 3 to Rev. 4.
	11/20/19	RN 19-005	Figure 9.3-14	ECR 72280 - Section 9 Figure Update This change added 2 new valves and associated piping there were added per NC-13-02056 Disposition #1
	11/05/19	RN 16-021	Figure 1.2-5, Section 2.4, Section 3.4, Section 9.3	ECR 50890 – External Flooding Protection This change revised FSAR drawings to include the modifications generated in TR02060-003 flooding re-evaluations post-Fukushima.
	10/17/19	RN 19-019	Figure 8.2-2, Figure 8.2-3	ECR 72530 This change revised Figure 8.2-2 and Figure 8.2-3 to include a sheet 1 for each drawing
	10/08/19	RN 18-035	Figure 9.3-18	ECR 72432 – Boron Recycle System Drawing, Database, and DBD Corrections This change revised FSAR Section 9.3, Figure 9.3-16. The changes made reflect the as-built and approved configuration of the plant.
	09/30/19	RN 16-022	Section 1.2, Section 9.2	ECR 50891 – Potable Water Connections This change updates section 1.2.3.8.4 with the alternate source of potable water from the Off Site Water Treatment System.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	09/19/19	RN 19-021	Section 7.1, Table 7.1-2 Figure 9.3-18	ECR 72221 This change revised FSAR Table 7.1-2 and Figure 9.3-18 to correct administrative errors. FSAR Section 9.3, Figure 9.3-18 had a valve incorrectly labeled as PVC-251 instead of PCV-251. FSAR Table 7.1-2 had a typographical error where number “13” was listed twice in the number sequence
	08/22/19	RN 15-005	Figure 10.4-17	ECR 50837 – Replacement of LW Piping at Penstock This change revised FSAR Figure 10.4-17 to include a check valve in between XVG6904D and XVG06903D, added a guard pipe around he 3” process pipe, added a level switch, and enlarged the valve box around valves XVC06903 and XVC6903E.
	08/16/19	RN 19-013	Section 9.5	CR-17-04053 This change revised FSAR Section 9.5.7.4 to read “Lube oil is replaced when it no longer satisfies site standards.”
	08/12/19	RN 19-004	Figure 9.4-28	ECR 72464 – Section 9 Figure Update This change revised FSAR Section 9.4 Figure 9.4-28 to correct the sample header (at coordinate E-7) from D-806-001 A-5 to D-806-001 C-5
	07/11/19	RN 19-014	Section 8.3, Table 8.3-3b	MRF 21307 230 KV & 115 KV System Digital VM Installation This change revised the Indicator Type in FSAR Table 8.3-3b to Electro Industries DTVA120, A-C Voltmeter.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	06-24-19	RN 14-010	Figure 8.3-4a	ECR 50737 – Replacement of Alterrex Rectified Diode Assemblies This change revised FSAR Figure 8.3-4a to show spare DPN1HX3 breaker 07 is no longer used to power the Alterrex Rectified alarm circuitry.
	06-13-19	RN 19-009	Figure 10.4-10	ECR 72513 – CR-19-00592 This change revised FSAR Figure 10.4-10 to correct the equipment ID for the Main Feedwater Warm-up Header Isolation Valve.
	06-03-19	RN 19-006	Figure 9.2-2, S1 Figure 9.2-2, S3 Figure 10.4-4a Figure 10.4-4b	ECR 72463 – Drawing and Database Corrections for XVG03105A/B-SW Solenoid Valves This change revised FSAR figures in Section 9.2 and 10.4 to include current information and remove historical references.
	06-03-19	RN 18-056	Figure 9.5-1, S3	ECR 72486 – RB Hose Reel Supply Valve Equipment ID Change This change revised FSAR figures 9.5-1 to reflect the as-built configuration of the plant. Valve 06779-FS which is shown as an angle valve but a gate valve is installed at this location was corrected.
	2019-05	RN 16-008	Figure 5.2-8A	ECR 72141- Revision to Figure 5.2-8A This change revised FSAR section 5.2 to include the as-built configuration of the Nitrogen System.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2019-05	RN 18-040	Figure 9.2-4	ECR 72444 - Corrections to FSAR Figure 9.2-4 This change revised FSAR Figure 9.2-4 to reflect the as-built configuration of the plant. The location of the plugged recirculation line, valve symbol used for XVA09614-CC, added IFX7081, and flanges on either side of the CC Chem Inj Pump Oil Trap were added to the figure.
	2019-05	RN 18-046	Figure 10.4-7A	ECR 71630 – Correction to FSAR Section 10 Figure 10.4-7A, Drawing D-302-165, Revision 30 This change revised FSAR Figure 10.4-7A to include Pressure indicator (IPI16631) and the associated HR valve (IPI16631-HR-WI). These changes were made to reflect the as-built configuration of the plant.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2019-05	RN 18-050	Figures 9.5-1 SH 1, 3, 4 & 5	ECR 50628 – Fire Protection Program Transition to NFPA 805 This change revised FSAR Section 9.5.1 Figure 9.5-1, S1, S3, S4, and S5 to correct errors identified during ECR 50628 implementation. Figure 9.5-1 S1 was revised to add a reducer downstream of XVT06017-FS and to Shift border for AFSPH back to proper location. Figure 9.5-1 S3 & S4 was revised to remove safety classification flags to show fire hose stations that are listed in SAP-131A and Figure 9.5-1 S3 & S4. Since these Hose stations are Quality Related (QR) Note 3 was which states "Valve is QR, Hose Station is Non-Safety Related." Figure 9.5-1 S5 was revised to remove the safety classification flag upstream of XVM041 05-FS.
	2019-05	RN 19-001	Figure 9.3-2	ECR 72491 - Renaming XVA72670 to XVN72670 This change revised FSAR Figure 9.3-2 to correct the valve symbol to show a needle valve for VN72670.
	2019-04	RN 18-039	Figure 9.4-25, SH2	ECR 50874AD - Reactor Building Cooling Upgrade Major Revision This change revised FSAR Figure 9.4-25 to include the installation of oil coolers to XHX0010B and XHX0010C.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2019-03	RN 11-024	Figure 2.4-6, Figure 9.3-15	Engineering Change Request (ECR) 50809 and ECR 50809F - Site Drainage Piping Improvements This change revised FSAR Figure 2.4-6 and 9.3-15 to show the modification of drain lines and relocated drainage outlets to comply with 10CFR73.55 and 10CFR73.58.
	2019-03	RN 16-010	Section 8.1 Section 8.2 Figure 8.2-1, Figure 8.2-2 Figure 8.2-2a, Figure 8.2-2b Figure 8.2-2c	ECR 50855 – Replacement of Fairfield Breakers 8942 and 8912 This changed revised FSAR Figures in Section 8.2 to incorporate the replacement of Fairfield Breakers 8942 and 8912. The previous oil circuit breakers 8942 and 8912 were replaced with SF6 circuit breakers, new coupling capacitors, voltage transformers, and new foundations for each line.
	2019-03	RN 17-008	Figure 9.5-1, SH2 Figure 1.2-1	ECR 50913 – South Protected Area Blast & Ballistic Rates Enclosures (BBRE) Installation This changed revised FSAR Figures 1.2-1 and 9.5-1 to reflect the removal of the ‘C’ Warehouse south overhang sprinkler system and addition of three new security BBREs.
	2019-03	RN 18-047	Figure 5.2-8A	ECR 50931, Incore Detector System Ten Path Vent Removal This change revised FSAR Section 5.2, Figure 5.2-8A to incorporate the incore detector system ten path vent removal. This revision consisted of removing portion of the CO2 Purge System tubing and installing an overflow drain line to ILS50402.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2019-03	RN 18-053	Figure 9.2-9, Figure 9.3-2	ECR 72479 - Airflow/Flow Path Corrections to FSAR Figure 9.2-9 and FSAR Figure 9.3-2 This change revised FSAR Figure 9.2-9 and 9.3-2 to correctly show the instrument air flow requirements for the DW Demineralizers. These changes were made to reflect the approved, as-built configuration of the plant.
	2019-02	RN 14-041	Figure 7.4-1, Figure 7.4-2 Figure 8.3-2aa, Figure 8.3-2ab Figure 8.3-4	ECR 50810 - Hazards Protection for NFPA 805 Transition This FSAR change revised plant drawings to achieve compliance with NFPA 805 requirements. Specifically, FSAR figures 7.4.1 and 7.4.2 were revised to include the addition of the new transfer switches for the EFW valves and charging vale to allow isolation of the control building circuits for control room evacuation panel operations in case of a fire. FSAR Figures 8.3-2aa, 8.3-2aB, and 8.3-4 were revised to show the addition of the new fuses in the shunt circuit for Control Room Battery Charger remote ammeter circuits.
	2019-02	RN 15-010	Figure 1.2-1, Figure 2.4-6	ECR 50888 – Combined Maintenance Shop Utility Tie-Ins and Site Preparation This change revised FSAR Figure 1.2-1 and 2.4 to show the new utility tie-ins for a Combined Maintenance Shop in the yard area.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2019-02	RN 18-004	Section 8.3, Figure 8.3-4b	ECR 50615 - Elimination of XIT5905 for Digital Control Systems (DCS) Cabinets XPN6035 thru XPN6038 This change revised FSAR Figure 8.3-4b to reflect the configuration changes of adding a redundant power supply to the DCS Cabinets. FSAR Section 8.3.2.1.1 and 8.3.2.1.5.5 were also revised to include the Independent Spent Fuel Storage Installation Electrical Building as an uninterruptible power supply to the secondary plant digital control system. 13
	2019-01	RN 17-029	Section 3.2, Section 3.9 Section 6.2, Figure 6.2-52 Figure 7.5-1, SH5, Figure 9.2-9A, Section 9.4 Figure 9.4-32	ECR 50917 – Control Rod Drive Mechanism Cooling System Demolition This change revised the FSAR description of the CRDM Cooling Water System to denote equipment removed during RF-24 and its status of being abandoned in place to ECR 50917. These changes were incorporated to FSAR Sections 3.2, 3.9, 6.2, 7.5, 9.2, and 9.4.
	2019-01	RN 18-028	Figure 5.2-8a	ECR 72404 – Low Pressure Nitrogen Missing Needle Valves Document & Database Changes This change revised FSAR Figure 5.2-SA to include two missing needle valves (XVN06300-NN and XVN06301-NN) in the Low Pressure Nitrogen System.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2019-01	RN 18-030	Figure 9.2-9	ECR 72406 – Addition of XVG15522-DW to FSAR Figure 9.2-9 This change revised FSAR Figure 9.2-9, Demineralizer Water System Flow Diagram to include XVG15522-DW.
	2019-01	RN 18-044	Figure 10.4-17	ECR 72207 NC/CR-11-03747 Accept-As-Is/ Current Penstocks Operation Acceptable This change revised FSAR Figure 10.4-17 to permanently accept the current condition/operation of the Liquid Waste System at the Penstocks, with section of piping removed & valve XVG06904A-LW out of service.
	2019-01	RN 18-045	Figure 9.2-2, SH1 Figure 9.2-2, SH3	ECR 50933 – Repair Service Water (SW) Pipe Leaks Using PM Caps This change revised FSAR Figure 9.2-2 to move the design flags from the outlet of the XVB03121A(B)-SW to the outlet of the orifice XPS0245A(B). These changes were a result of cavitation damage at the outlet of XVB03121A(B)SW, EDG Cooler A and B Service Water Return Valves, the material downstream is changed to stainless and an orifice is installed to lessen the throttling duty of the valves.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2019-01	RN 18-048	Figure 9.2-7	ECR 72474 . Piping and Valve Corrections to FSAR Figure 9.2-7 This change revised FSAR Section 9., Figure 9.2-7 to reconnect ITI07003B to the Charging/SI Pump cooling water return line and redraw valve symbols for XVT09530A/B/CCC and XVT09686A/B/CCC.
	2019-01	RN 18-052	Section 11.3 SH 1	ECR 72478 – Piping Correction to FSAR Figure 11.3-4 This change revised FSAR Section 11.3, Figure 11.3-4 to remove a cross-connection at a coordinate (F-8) that does not exist.
	2019-01	RN 18-054	Section 3A	FSAR Appendix 3A Division 1 NRC Regulatory Guides applicable to the VCSNS. (CR-16-01194) This change revised the specific revisions listed for Regulatory Guides 1.84 and 1.192 in FSAR Appendix 3A. FSAR Appendix 3A was also revised to show that Regulatory Guide 1.85 was withdrawn and eliminated.
	2018-12	RN 17-022	Section 3.10, Section 8.3 Figure 8.3-1	ECR 50883 – Safety Related Inverter Replacement This change revised FSAR Sections 3.10 and 8.3 to include the increased efficiency of the replacement inverters XIT5901, XIT5902, XIT5903, and XIT5904 on the automatic and manual loading and unloading of the Diesel Generator.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-12	RN 18-033	Figure 9.3-2	ECR 72429 – Misaligned Instrument Air Valve This change revised FSAR Section 9.3 Drawing D-302-271 to correct the valve XVA76670-IA to XVA72670-IA.
	2018-12	RN 18-036	Section 6.2	ECR 72425 – Reactor Building Spray Operation Basis Reconciliation This change to the FSAR clarifies the operating time of the Reactor Building Spray System following a design basis Loss of Coolant Accident from 2 hours to 4 hours.
	2018-12	RN 18-017	Figure 1.2-11, Figure 12.1-4 Figure 12.1-13, Figure 12A.4-8	ECR 50920 – Emergency Feedwater Mezzanine Walk Platform This change revised FSAR Figures 1.2-11, 12.1-4, 12.1-13, and 12A.4-8 to include the addition of an emergency feedwater mezzanine walk platform.
	2018-10	RN 18-018	Figure 4.2-6	ECR 50923 – Cycle 25 Core Reload Design This change revised FSAR Section 4.2 Figure 4.2-6 to be consistent with the fuel built for VCSNS Unit 1 Cycle 25. Specifically, this change incorporated the Westinghouse design change of the Fuel Top Grid bulge tool.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-10	RN 18-026	Figure 9.2-1, SH1 Figure 9.2-9A, Figure 10.4-7A Figure 11.3-4, SH3	ECR 72395 – Corrections to FSAR Figure 302 Drawings This change revised FSAR Section 9 Figure 9.2-1, Drawing 302-221 Sheet 1, Revision 32 and Figure 9.2-9A, Drawing 302-162, Revision 14; Section 10 Figure 10.4-7A, Drawing 302-165, Revision 29 and Section 11, Figure 11.3-4, Sheet 3, and Drawing E-302-742, Revision 17. These changes were completed to ensure that the drawings reflected the as-built configuration of the systems.
	2018-10	RN 18-034	Figure 6.2-59	ECR 72431 – Correction to FSAR Section 6.2, Figure 6.2-59 This change corrected Equipment IDs for valves associated with IFI07304, IFI07305, and IFI07313 on the Reactor Containment Leak Rate Test Panel.
	2018-10	RN 18-042	Section 6.2, Section 10.4	CR-14-01490 – Revise Reactor Building Spray System and Feedwater System Design Information This change revised FSAR Sections 6.2 and 10.4 to include a description of relief valves installed to prevent pressure locking of the Reactor Building Spray System and Feedwater System Valves.
	2018-10	RN 18-043	Section 13.2	ACAD 17-001 Training Program This change revised FSAR Section 13.2.1, Item 9 to remove the reference to Mechanical Maintenance Supervisor Training Program as an INPO Accredited Training Program.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-09	RN 18-024	Figure 9.3-3	ECR 72186 – Correction to FSAR Section 9 Figure 9.3-3 This change corrected piping configuration upstream of the Reactor Building (RB) Instrument Air (IA) Compressors to reflect the as-built configuration of plant. Equipment IDs IPI08364 and IPI08374 High Root Valves were corrected. The electrical connection to the 'A' RB IA Compressor Motor will be drawn to show it cross over the 6-inch header to the 'A' Compressor.
	2018-08	RN 17-012	Figure 9.3-14	ECR 50910 – Turbine Building Sump Radiation Monitor RM-L8 Sample Line Suction Strainer This change added a Wye strainer, strainer blow-off isolation valve, and strainer isolation valve to drawing D-302-352. The strainer and associated valves were installed to intercept and remove debris upstream of the Turbine Building Sump Liquid Radiation Monitor (RML0008).
	2018-08	RN 17-028	Section 6.2 Figure 6.2-1-6.2-3 Figure 6.2-7	ECR 72296 – TS 6.8.4.g Containment Leak Rate Testing Program – LAR-14-01541 The change revises the peak loss of cooling accident containment pressure to a value which reflects an updated mass an energy (M&E) analysis. The peak pressure is also used as a criterion for containment leak rate testing. The updated M&E analysis address Westinghouse Nuclear Safety Advisory Letters NSAL-06-06, 11-2, and 14-1.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-08	RN 18-007	Figure 9.5-1, SH1 Figure 9.2-4, Figure 9.2-6	ECR 72366 – Correction to FSAR Figure 302 Drawings This change corrected component symbols in FSAR Section 9.2 and 9.5 302 Drawings.
	2018-08	RN 18-011	Figure 5.2-8 Figure 9.2-2, SH4 Figure 9.3-4, Figure 10.4-6 Figure 10.4-7A	ECR 72367 – Corrections to Drawing Errors Generated During CADD Process This change revises FSAR Drawings – Section 5 Figure 5.2-8, Drawing 302-812, Revision 21; Section 9 Figure 9.3-4, Drawing 302-771, Revision 40 and Figure 9.2-2, Drawing 302-222, Sheet 4, Revision 4; Section 10 Figure 10.4-6, Drawing 302-204, Revision 4, and Figure 10.4-7A, Drawing 302-165, Revision 29.
	2018-08	RN 18-012	Figure 9.5-7	ECR 72375 – FSAR Figure Enhancement This change enhanced FSAR Figure 9.5-7 to make the equipment identifications (IDs) associated with 1MS-32-005-3 legible.
	2018-08	RN 18-021	Figure 9.2-2, SH 2 Figure 9.2-2, SH 4	ECR 71580 – Revision to Drawing D-302-222, S2 and S4 This change corrected FSAR Section 9.2 Drawing 302-222 Sheet 2 and 4 to reflect as-built conditions for their respective systems. 21

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-07	RN 18-003	Section 18.3.2	ECR 72340 – Environmentally Assisted Fatigue Methodology This change revised FSAR Section 18.3.2.1 to include the use of NUREG/CR-6909 as an acceptable NRC approved methodology for computing fatigue cumulative usage factors, which account for the effects of environmentally assisted fatigue for the period of extended operation.
	2018-07	RN 18-015	Figure 9.3-16, SH 3	ECR 72379 – Revision to FSAR Section 9.3, and Figure 9.3-16 Sheet 3. This change revised FSAR Figure 9.3-16 Sheet 3, Drawing E-302-675, Revision 37 to add a missing 'B' match mark flag that was inadvertently removed under ECR 51007.
	2018-07	RN 18-023	Figure 9.2-5	Equal To or Better Than (ETBT)-458 – Replacement Check Valves for XVC09591A/B/C-CC This change removed the Bill of Materials number 'ROI-5' and replaced it with 'ETBT-458' on FSAR Figure 9.2-5 (Drawing D-302-612, R28) to reflect the replacement of Check Valves XVC09591A/B/C-CC.
	2018-07	RN 18-029	Section 3A	CR-17-00717 – Correction to FSAR Section 3A This change revised the VCSNS regulatory position on quality requirements associated with Reg. Guide 1.189

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	2018-06	RN 18-014	Section 2.5.4	CR-12-00400 – Added the use of Controlled Low-Strength Material This FSAR change adds the use of Controlled Low-Strength Material flowable cementitious backfill as an acceptable safety related backfill to FSAR section 2.5.4.5.2.
	2018-06	RN 18-022	Section 6.2	CR-18-01009 – Correction to FSAR Table 6.2-54a This change makes a correction to FSAR Table 6.2-54a. This correction adds a spare electrical penetration, Penetration 807 to the table.
	2018-06	RN 18-025	Figure 9.3-7	ECR 71289 – Correction to FSAR Section 9 Figure 9.3-7 This change corrected two labels (J-6 and J-9) at location F-11 and added a label to location H-12 for FD-23 on E-911-103.
	2018-05	RN 17-021	Figure 5.5-4	ECR 50914 – Revise FSAR Figure 5.5-4 – RHR Vent Quick Connects This change revised an error in a safety-class marker at vent RH-10.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-05	RN 17-030	Section 12.1, Section 12.3 Table 12.3-2, Table 12.3-3 Table 12.3-4	CR-17-02776 and CR-17-04650 – Correct Errors in Chapter 12.1 and Chapter 12.3 This change corrected a typo in FSAR Chapter 12.1 and implemented changes in FSAR Chapter 12.3 as a result of the 2017 Calibration Lab self-assessment. FSAR Chapter 12.3 added additional clarification to contamination monitoring practices and oversight structure
	2018-05	RN 17-033	Section 8.3, Table 8.3-3	ECR 50752 – Project, Security 10 CFR 73.55 Upgraded This change revised FSAR Chapter 8, Table 8.3-3 to incorporate a new redundant Protected Area (PA) Intrusion detection and video surveillance and assessment system called the Integrated Video Management System (IVMS).
	2018-05	RN 18-010	Figure 10.4-9	ECR 50065 – Section 10 Figure 10.4-9, Drawing D-302-102, Revision 28. This change moved design flags on the system flow diagram drawing for the Condensate inlet and outlet of the Blowdown Heat Exchangers back to their correct location.
	2018-05	RN 18-013	Figure 6.2-50, S4	ECR 50897 – Replacement Reactor Service Structure-Integrated Head Assembly (IHA) This change revised FSAR Section 6, Figure 6.2-50, Drawing 922-104, Revision 7 to include the addition of the Integrated Head Assembly (IHA) and instrumentation added by ECR 50897.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-05	RN 18-016	Section 12.2, Section 12.3 Table 12.3-3, Index 13-iv Section 13.1, Figure 13.1-4 Section 13.2, Section 13.4 Section 13.5, Section 13.6	CMP-17-04632 – Organizational Changes required due to the closure of Units 2 and 3. This change was performed due to the closure of the Unit 2/3 project requiring a new organizational structure. Changes to programs owned by department was needed due to the Emergency Response Unit assuming responsibility for non-radiological respiratory program while Radiological Protection retained ownership of radiological respiratory program.
	2018-05	RN 18-019	Section 3A, Section 7.1 Section 7.4, Section 8.3 Section 13.5, Section 18.2 Section 18.4	CR-18-00530 – FPER Removal This change removed references to the Fire Protection Evaluation Report (FPER). FPER is labeled Historical and is no longer a reference source to the FSAR.
	2018-04	RN 18-005	Figure 9.5-1, S1	ECR 72329 – Revised Section 9, Figure 9.5-1, S1, D-302-231, R38 This change revised valve symbols on Section 9 Figure 9.5-1 Sheet 1, Drawing 302-231 Sheet 1, Revision 38 for XVT04115-FS and XVT14000-FS. These valve symbols were changed from gate vales to the standard globe valve symbol.
	2018-04	RN 18-006	Section 2.3	ECR 50518 – Section 2.3.3.2 Page # 2.3-26 This change revised FSAR section 2.3.3.2 to delete “TSC” from the IPCS Control Building location description.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-04	RN 18-009	Section 3A	Section 3A License Amendment 183 Alternate Source Term updated FSAR 3A Section 1.13 This change revised the spent fuel pool ventilation requirements in FSAR 3A Section 1.13 to align with License Amendment Request 183- Alternate Source Term.
	2018-04	RN 12-035	Figure 10.3-2	ECR 71780 – Revision of FSAR Figure 10.3-2, D-302-012 This change revised Figure 10.3-2, D-302-012 to correctly show the design configuration of the sensing lines IPT05673 and IPX05673 including valves XVT22818-MS and IPT05673-HR-TB. The sensing line from steam chest to XVT22818-MS was revised from 3/4" to 1". Valves XVT22818-MS and IPT05673-HR-TB were revised from 3/4" to 1 ". Sensing line IPT05673 was changed from 3/4" to 1". The sensing line to IPX05673 was revised to be 3/4" 902X piping and 3/8" 2505X tubing.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-04	RN 13-012	Section 8.2.1, Figure 8.2-2 Figure 8.2-2a, Figure 8.2-2b Figure 8.2-2c, Figure 8.3-5 Figure 8.3-5a	ECR 50836 and ECR 50867 – Replacement of VCS 230kV Off-site Supply Breaker 8892 This change replaced the existing Oil Circuit Breaker XCB8892 with a new Sulfur Hexafluoride (SF6) gas circuit breaker. This change also included an additional bushing current transformer (CT), installed a capacitance coupled Voltage Transformer (CCVT) and other supporting hardware. Additionally, 63kA circuit breaker XCB8932 was replaced with a new SF6 gas circuit breaker and supporting hardware.
	2018-04	RN 15-006	Figure 1.2-3, Figure 9.5-1, S5	ECR 50810A and ECR 50810I – Hazards Protection for NFPA-805 Transition This change addressed the following scope items related to the Hazards Protection for NFPA 805 Transition: 1) Modification of IB 436'. 2) Modification of AB 400' Fire Detection System. 3) Hydraulic Analysis of IB 436' and 412' Control Complex Fire Protection Sprinkler Systems. 4) Installation of overpressure protection for wet pipe sprinkler systems. 5) Replacement of Sprinkler System Heads in Turbine Driven Emergency Feedwater Pump Room.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-04	RN 16-028	Section 8.2	ECR 71872 – Updated for Review Transmission Stability Study Updated FSAR to reflect 2017 Transmission Stability Study. No design or operational plant parameters were changed. This ECR also developed a calculation to formalize the review of the Stability Study. Refer to CR-15-04773 and CR-13-03074 for additional information regarding why this ECR was needed
	2018-04	RN 17-010	Figure 1.2-28a, Figure 8.2-3 Section 9.4, Figure 9.4-25, S1 Figure 9.4-25, S2	ECR 50874 – Reactor Building Cooling Upgrade This change installed new Chiller Loop to act as a new heat sink for Industrial Cooling Water system. To support this new system, four (4) 400-ton chillers, two (2) chilled water pumps, and frame heat exchangers were installed in parallel with the existing Industrial Cooling Towers.
	2018-04	RN 17-023	Figure 9.3-14	ECR 71365 – Correct error in Figure 9.4-14 This change corrected an administrative error on FSAR Figure 9.3-14 drawing D-302-352. In section E-9, a line appeared to show a connection coming off of a 6" header which implied it goes to drawing 302-207 at location D-4. This error was introduced during a CADD enhancement of the drawing per ECR 50239.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2018-04	RN 18-001	Figure 10.3-2	ECR 72324, CR-17-04302 – Revised Figure 10.3-2, Drawing D-302-012, R36 This change modified Drawing D-302-012 at G3. A section of the reheat steam drain line, was changed from a 1” pipe to a 2” pipe to reflect the as-built configuration.
	2018-03	RN 17-034	Figure 9.2-9b	ECR 72323, CR-17-05919 – Typo Correction for Figure 9.2-9b This change corrected a typographical error on FSAR Figure 9.2-9b, D-302-164, R24. At location H-8 on the figure, XA3-29-DW was corrected to read XAJ-29-DW.

Revision Summary (continued)

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	2018-02	RN 16-003	Figure 1.2-9, Figure 1.2-10, Section 3.2 Table 3.2-1, Table 3.2-3 Section 3.5, Table 3.5-3 Section 3.7, Table 3.7-3 Section 3.8, Section 3.12 Section 3A, Section 4.2 Figure 4.2-22, Figure 4.2-23 Index 5-ix, Section 5.1 Figure 5.1-1, S1 Section 5.2, Table 5.2-8 Table 5.2-11, Table 5.2-13 Section 5.4, Section 5.5 Table 5.5-13, Table 5.5-14 Table 5.5-15, Section 5.6 Section 6.2, Table 6.2-7 Figure 8G-2, Section 9.1 Section 9.4, Figure 9.4-31 Figure 12.1-8, Figure 12.1-9 Figure 12.1-17, Figure 12.1-18 Section 15.4	ECR 50868 and ECR 50897 – Replacement of Reactor Vessel Head This change incorporates the changes made by ECR 50868 and ECR 50897 that replaced the reactor vessel head and service structure.

Revision Summary (continued)

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	2018-02	RN 17-004	Section 6.3	ECR 72012 – RWST Empty Level Alarm Setpoint Change This change revised the Caution prior to Step 1, EOP-2.2 Revision 16, from stopping all pumps taking suction on the RWST on the 6% empty alarm to a 10% control board indication. This was done to provide protection to the critical vortex level of 5% consistent with Tech Report TR09650-001. This change significantly reduced the indicated level available to complete swapover from RWST injection to containment sump recirculation, and the existing operator timeline calculation no longer supports this scenario.
	2017-12	RN 17-025	Section 13.4	CR-16-02179 – FSAR CHAPTER 13, SECTION 13.4.2.1 This change removed the word “audit” based on guidance in ANSI N18.7-1976 Section 4.4 describing the review activities of the Onsite Operating Organization.
	2017-11	RN 17-016	Figure 9.3-16, S4	ECR 72275 – Thermal Regeneration Demineralizer Drawing Correction This change corrected drawing 302-676 for the Chemical Volume Control System piping associated with the Thermal Regeneration Demineralizers. There was an erroneous connection point depicted on the drawing.

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	2017-11	RN 12-030	Section 3.9, Table 3.9-8 Table 3.10-3, Section 3.10 Section 9.2, Figure 9.2-2, S1 Section 10.4, Table 10.4-8 Figure 10.4-8, Figure 10.4-16 Section 15.4	ECR 50695 B/C/E/G – Installation of Cured-In-Place Pipe-Liner This change installed a Cured-In-Place Pipe-liner (CIPP) in the Service Water (SW)-to- Emergency Feedwater (EF) cross connect lines for Train A. This change also installed EF Cavitating Venturis (XPS5040A/B/C), EF Automatic Recirculation Control Valves (XVM01072A/B) on the Motor-Driven EF Pumps, and a new by-pass test line for the Turbine-Driven EF Pump. Note 13 was added to drawing 302-101 regarding TRP-13 for Quality Related EF Recirculation line.
	2017-10	RN 17-015	Section 8.3, Figure 8.3-0 Figure 8.3-0d, Figure 8.3-0e Figure 8.3-0f, Figure 8.3-0g	ECR 50919 and ECR 50919A – Cable Bus Conductor Replacement This change replaced cables in cable duct for the normal feed from XTF31 to XSW1DB U16. During RF23, corona damage was witnessed in several locations on several of the cables for the normal feed from XTF31 to XSW1DB U16. This cable replacement required several drawing changes related to cable run.
	2017-09	RN 16-011	Figure 1.2-6, Figure 1.2-7 Table 6.2-7, Figure 8G-3	ECR 50869 – B Loop Auxiliary Crane This change replaced the existing B Loop Auxiliary Crane (XCR0064) with a new, permanently installed, crane. The new crane was installed on the existing Auxiliary Crane Support Tower (MK-180ST1) in the Reactor Building

Revision Summary (continued)

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	2017-09	RN 17-006	Figure 9.2-2, S1, Figure 9.4-22	ECR 50585U – A-Chiller Replacement This change replaced the A-Chiller with new chiller designed to resolve numerous designed challenges and improve reliability.
	2017-09	RN 17-013	Figure 8.2-4	ECR 50915 – Modification to Allow Emergency Diesel Generator to Parallel with Alternate AC This change allowed the station to transfer the 7.2 kV ESF Buses XSW1DA and XSW1DB from the normal or alternate feed to Alternate AC (AAC) source using XTF5052.
	2017-09	RN 17-014	Section 5.5, Figure 9.3-5 Figure 9.3-16, S1C	ECR 50799H – RCP #3 Seal Leakoff Overflow Piping Installation This change added a description of Reactor Coolant Pump seal leakoff alternate overflow path to section 5.5.1.3.12, and updated the station drainage flow diagram and administrative change to Chemical Volume Control System Flow diagram.

Revision Summary (continued)

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	2017-08	RN 17-019	Figure 1.2-5	ECR 50614 – Reactor Building Safety Modification This change upgraded personnel safety features associated with the Reactor Building. Existing ladders have been modified with the addition of ladder extensions, safety gates, cages and vertical ladder cage bars to the top of adjacent handrail. Existing platforms have been modified with the addition/modification of handrails, toeplate, chains and grab bars. The Loop B platform at elevation 435'-11¼ " has been modified by adding additional walking surfaces to facilitate access around existing piping and supports.
	2017-08	RN 15-001	Figure 10.3-1	ECR 50828 – Revision of Figure 10.3-1 This change revised the control logic for manually operating Main Steam Isolation Valves (MSIV) XVM2801A/B/C by interlocking with the Main Steam Isolation Bypass Valves XVM2869A/B/C to ensure the bypass valves are fully open prior to the MSIV valves opening.
	2017-08	RN 16-027	Figure 9.3-10	CR-16-04716 – Revision of Figure 9.3-10 This Revision corrected FSAR Figure 9.3-10 for the proper location of orifices installed as isolation boundaries for the chillers and chilled water pumps.

Revision Summary (continued)

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	2017-08	RN 17-003	Section 9.2.7.4	CR-16-03524 Revised FSAR Section 9.2.7.4, "Inspection and Testing Requirements" This change revised FSAR Section 9.2.7.4 to remove the statement specifying 10CFR50.55a requires the Reactor Makeup Water System ANSI N18.2 Safety Class 2b/NNS isolation valves be closure tested under 10CFR50.55a. The valves are passive and do not perform a specific safety function that would require testing under 10CFR50.55a. This change removef the statement that Class 2, Category A valves in this system require periodic closure and Type C leakage tests under 10CFR50.55a. This FSAR change also deleted the statement that periodic tests of the XVD01920A/B-MU valves and Control Isolation Valves are required (CIVs are part of RC System).
	2017-07	RN 16-031	Figure 1.2-20	ECR 72202 – Change to FSAR Figure 1.2-20 As-built Configuration of door DRWT/204 This change corrected a drawing discrepancy related to the location of door DRWT/204.
	2017-07	RN 17-011	Section 3.11.1.1 Section 9.3.3.1 Section 9.4.6.1, Figure 9.4-14	ECR 50585 – Adds Steam Propagation Barriers to the FSAR This change corrected the design functions of the steam propagation barrier equipment and floor drain system.

Revision Summary (continued)

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	2017-07	RN 15-020	Figure 1.2-24, Figure 9.2-1	ECR 510038B – FLEX Alternate Emergency Feedwater (EFW) Suction Source This change provided a 4" connection to the Service Water discharge crosstie header ("C" train) at the 24" tee between valves XVB03118D-SW and XVB03118C-SW in the Service Water Pump House above floor elevation 425'-0". This 4" connection will be used as the discharge connection for the FLEX Alternate EFW Suction Pumps (XPP0248A/B) located in the SW pump house.
	2017-06	RN 16-002	Figure 1.2-3, Figure 1.2-5 Figure 1.2-6, Figure 1.2-11 Figure 1.2-12, Figure 1.2-15 Figure 1.2-16, Figure 1.2-18 Figure 1.2-19, Figure 1.2-20	ECR 51013 and ECR 51008C – FLEX In-Plant Equipment Storage This change added permanent storage locations for FLEX and B.5.b equipment to plant layout drawings. The equipment is required to support station FLEX strategies. Locations of FLEX and B.5.b equipment storage is required to be placed onto plant layout drawings.
	2017-04	RN 16-025	Section 9.4 Figure 9.4-25, Sheet 2	ECR 50874 – Increase the heat removal capacity of the Reactor Building Cooling Units. This change installed a new Chiller Loop to act as a new heat sink for Industrial Cooling Water system. An interfacing plate heat exchanger is used to transfer heat to the new chiller loop.

Revision Summary (continued)

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	2017-04	RN 17-002	Figure 5.2-8A	ECR 72212 – Revised FSAR Figure 5.2-8A to Show Correct Valve Lineup This change updated drawing D-302-717 (FSAR Figure 5.2-8A) to correct a discrepancy in the valve lineup. D-302-717 was revised to show XVT16302A-NN as normally open and XVT16304B-NN as normally closed. A note was added to explain that either header may be in service during normal operation while the other is in standby
	2017-04	RN 17-007	Section 13.1	CMP-15-04298 - Organization Change to Merge Unit 1/2/3 OD&P Departments This change merges the Unit 1 and Unit 2/3 OD&P groups under one manager reporting to the existing General Manager Organizational / Development and Effectiveness for Unit 1. The change also provides updates to FSAR Section 13.1.2.2.2.1.
	2017-03	RN 17-001	Section 12.3, Section 13.1 Figure 13.1-4, Section 13.2	CMP-15-04298 – To Align Units 1/2/3 for Commercial Operation This change is a re-organization to change VPNSS title to VPNO 2/3. Additionally, the Director Nuclear Training and new managers of Chemistry and Radiation Protection are now under the VPNO 2/3 position.

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	2017-03	RN 17-009	Section 13.2	CR-16-05895 – Changed Plant Access Training (PAT) and Radiological Worker Training (RWT) Required Frequencies This change revises FSAR Section 13.2.3.1 to require PAT and RWT from annually to biennial.
	2017-03	RN 11-008	Figure 2.4-6	ECR 50753G – Owner Controlled Area (OCA) Perimeter Corridor Grading and Drainage This change revises FSAR Figure 2.4-6 (E-744-052) to show the final as-built location of the OCA perimeter, following installation of ECR-50753G. This major revision provides excavation, backfill and grading for a 20 foot wide monitoring corridor in support of a future security modification inside the rock barrier.
	2017-03	RN 13-019	Section 2.4, Figure 2.4-9	ECR 71793 - VCS Response to Seismic/Flooding Recommendations of March 12, 2012 NRC 50.54(f) Information Request This change modifies the site flooding event descriptions that were revised based upon current data and inputs.
	2017-03	RN 16-029	Appendix 3A, RG 1.147	CR-16-01194 – FSAR Appendix 3A Update Regulatory Guide 1.147 Update This change updates Regulatory Guide 1.147, from Rev. 13 to Rev. 17. Rev. 17 endorses Code Cases that are beneficial to VCSNS for the ASME Section XI Inservice Inspection Program.

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	2017-03	RN 16-030	Figure 9.4-17	ECR72198 - Corrected Mislabeled Fire Damper This change corrected a typographical error on FSAR Figure 9.4-17 IB Ventilation Flow Diagram. Damper labeled XMD-189-AH should be labeled XFD-189-AH.
	2017-01	RN 16-020	Figure 1.2-1, Figure 2.4-6	ECR 51012 – FLEX Diesel Generator Building This change updated FSAR Figures 1.2-1, and 2.4-6 to show the location of the new FLEX Diesel Generator Building.
	2017-01	RN 16-026	Section 13.1, Figure 13.1-4	CR-16-05196 – Changes to the Organizational Chart This change updates FSAR Chapter 13 to include the new manager position for Nuclear Fuels and Analysis. The Nuclear Fuels and Analysis group for Units 1, 2 and 3 includes previous functions of Fuel Management Reactor Engineering and Probabilistic Risk Assessment.
	2017-01	RN 15-018	Figure 9.4-3	ECR 50886 – Control Building Elevator Modernization Project This change updated FSAR Figure 9.4-3 with the new control building elevator machine room fan.
	2017-01	RN 16-014	Section 15.1, Table 15.1-4 Section 15.2, Table 15.2-1 Section 15.3	ECR 72147 – Removal of the term Station Blackout from the FSAR This change replaces “Station Blackout” with the correct language of “Loss of Offsite Power.”

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	2016-10	RN 16-018	Section 3.9, Table 3.9-7 Section 9.3	ECR50780C – Updated Information Related to Alternate Seal Injection (ASI) System This change updated chapters 3 and 9 to describe the ASI a system that is not credited in station analysis.
	2016-10	RN 14-031	Figure 8.2-2, Figure 8.2-2a Figure 8.2-2c, Figure 8.3-5 Figure 8.3-5a	ECR 50864 – Replaced Breaker 8902 (Main Transformer Feed) and Associated Equipment This ECR replaces the existing XCB8902, associated bus control and monitoring equipment, protection equipment, conduits, wiring and grounding.
	2016-10	RN 15-022	Section 1.6, Section 4.1 Table 4.1-2, Section 4.2 Section 4.3, Section 15.3	ECR72020 – Cycle 23 Core Reload Design This change provides technology updates and methods related to the cycle 23 core design.
	2016-10	RN 16-012	Figure 9.3-16 SH 1A Figure 9.3-16 SH 1B Figure 9.3-16 SH 1C	ECR 50799I – Document Updates for Reinstallation of Fuse Pairs FU-CS75/76/77 This change removed notes associated with fuses for XVT08141A/B/C-CS as shown in Figures 9.3-16 Sh 1A, Sh 1B and Sh 1C.
	2016-10	RN 16-015	Section 9.4	ECR 50587B – Replacement of Turbine Building Switchgear Room Chiller XHX0005 This change updates the chiller's instrumentation and control devices described in the FSAR.
	2016-09	RN 16-009	Section 13.1, Figure 13.1-4	Change to Organization Chart This change added the newly created position of the Vice President of Nuclear Support Services (VPNSS). The org chart was also changed to show that Quality Services now reports to the VPNSS.

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	2016-09	RN 16-019	Section 15.4, Figure 15.4-91 Table 15.4-28, Table 15.4-29 Table 15.4-31, Table 15.4-32 Table 15.4-33	ECR 70290 – Steam Generator Tube Rupture (SGTR) Enhancements This change describes an NRC-approved supplementary SGTR analysis License Amendment 205 that demonstrate the effectiveness of Emergency Operating Procedure guidance incorporating realistic operator action times, and demonstrates the prevention of Steam Generator overfill.
	2016-08	RN 13-027	Figure 1.2-1, Figure 1.2-28 Figure 9.3-1	ECR 50790 – Upgrade Fuel Handling Building for Used Fuel Storage This change added plant service connections for 120VAC & 480VAC Non-1E electrical power, service air, helium and cask venting to the Fuel Handling Building. These upgrades support activities required for loading spent fuel in dry casks.
	2016-07	RN 16-004	Figure 9.2-9b, Figure 10.4-16	ECR 51002 – Flex Water Transfer Connections This change implemented water transfer piping connections between Condensate Storage Tank, Filtered Water Tank and Demineralized Storage Tank to support FLEX Strategies.

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	2016-07	RN 14-043	Figure 1.2-27, Table 3.2-1 Index 5.0, Figure 5.1-1, Sh 2 Table 5.2-1, Section 5.3.2 Section 5.5, Table 5.5-1 Figure 5.5-1, Figure 5.5-16 Figure 5.5-17, Figure 5.5-18 Section 9.2, Figure 9.2-24 Section 9.3, Table 9.3-4 Table 9.3-5, Figure 9.3-16, Sh 1A Figure 9.3-16, Sh 1B Figure 9.3-16, Sh 1C Section 11.2.3.1.3.1	ECR50799 Base and ECR50799C – Reactor Coolant Pump Seal Replacement The change replaced the reactor coolant pump seals with Flowserve N-9000 seals.
	2016-07	RN 15-004	Figure 9.4-11, Figure 9.4-34	ECR 50790 – Upgrade Fuel Handling Building Air Handling Unit and Support Platform This change provided additional cooling required for cask loading operations. A permanent air handling unit and supporting systems were installed.
	2016-06	RN 14-044	Section 9.2, Figure 9.2-2, Sh2 Figure 9.2-2, Sh4	ECR50567S – Change Interlock Settings ECR50567S Added a 10+1 second time limit to the Reactor Building Cooling Unit Service Water Valves interlock with the Service Water Pump Start Permissive.

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	2016-06	RN 16-007	Figure 9.3-14	ECR 72140 – Revises Drawings to Correct Valve System Designator Discrepancies This change corrected valve labeling for XVG02422-MD and XVG02436-MD on FSAR FSAR Figure 9.3-14.
	2016-05	RN 12-025	FSAR Figure 1.2-1, FSAR Figure 2.4-6 FPER E-023-001	ECR50794, Constructed ISFSI Haul Path. This change constructed the Haul Path that connects the ISFSI, Fuel Handling Building (FHB) and the HI-STORM cask fabrication pad. The haul path is for transporting empty HI-STORM storage casks from the HI-STORM cask fabrication pad to the FHB, and loaded HI-STORM storage casks from the FHB to the ISFSI.
	2016-05	RN 14-022	FSAR Figure 1.2-3 FSAR Figure 1.2-5 FSAR Figure 6.3-1 FSAR Figure 9.1-3 FSAR Figure 9.3-16, S3 FSAR Figure 9.3-16, S5	ECR51007, Reactor Coolant System (RCS) Make-up and Boration Piping Modifications. This change modified the Refuel Water Storage Tankvcr5 and Boric Acid Tank piping to add new piping with a hose connection for a suction source for a Regional Response Center pump or the FLEX RCS Make-up pump. This arrangement will provide a diverse source of borated water to the Reactor Coolant System for both inventory and reactivity control during an ELAP.

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	2016-05	RN 14-039	FSAR Figure 8.3-2aa FSAR Figure 8.3-2ab	ECR 51006, FLEX Backup Power from Electrical Building. This change implemented the FLEX alternate power scheme strategies which mitigate an ELAP. These include: 1) Alternate Power Source of Alternate Seal Injection; 2) Alternate Battery Charging for 125VDC Class 1 E Batteries XBA1A-ED and XBA1B-ED; 3) Alternate Power for the Backup Technical Support center; and 4) Alternate power to Electrical Building 480 VAC Distribution Panel APN04071.
	2016-05	RN 15-007	FSAR Table 3.9-8 FSAR Figure 9.1-3 FSAR Section 9.1.3.2	ECR 50879B and ECR50879, Modifications to the Refuel Water Storage Tank (RWST). This change added a riser loop seal to isolate any potential break in the non-safety related section of the Spent Fuel Purification loop. The safety-related riser loop seal prevents drainage of the RWST by only allowing drawdown of tank to the low level height equal to the riser height.

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	2016-05	RN 15-015	FSAR Figure 8.2-2 FSAR Figure 8.2-2a	ECR50864B, Replace Main Transformer Feed Breaker 8902 and Associated Equipment. This change modified the transient recovery voltage (TRV) capacitance for the new XCB8902 from the originally specified 30nF (per phase) to 15nF (per phase). The reduced TRV capacitance is to provide an interrupt rating of 63kA. This rating is the same as the existing XCB8902 and is the interim vendor recommended configuration for XCB8902, until an acceptable long term design rated for 90kA. This design change is an interim configuration that de-rates the new breaker from a fault rating of 90kA to 63kA. The final configuration implemented by the overall modification will restore the 90kA interrupt rating of the breaker to support VCS3.
	2016-05	RN 15-021	FSAR Section 3A FSAR Table 5.2-8 FSAR Section 9.1.4.2.2.8 FSAR Section 9.1.4.2.2.11	ECR70905 Rev. 1, Replacement of Reactor Vessel HvdraNuts with Standard Nuts and Washers. This changed replaced the HydraNuts used for the Reactor Vessel Closure Head with conventional nuts and washers. The replacement, conventional nuts and washers, are equal to or better than the original design nuts and washers.
	2016-05	RN 16-005	FSAR Figure 8.2-2	ECR50777, Upgrades to Switchyard Bus 3. This administrative change is to correct a drawing that was not captured as part of a previous revision notice.

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	2016-03	RN 13-029	FSAR Figure 1.2-1 FSAR Figure 2.4-6 FSAR Section 9.4.7 FSAR Figure 9.4-35, Sh1 FSAR Figure 9.4-35, Sh2 FSAR Figure 9.4-36 FPER Figure E-023-001	ECR50793B and ECR50870, ISFSI Electrical Building (EB) and Auxiliary Electrical Equipment Building (AEB). This change added an ISFSI EB, which houses equipment used for monitoring the temperature/ ventilation of the spent fuel storage casks. This change also added an ISFSI AEB, which houses a portable diesel generator to supply backup power to the ISFSI EB.
	2016-03	RN 14-004	FSAR Figure 1.2-12	ECR 51004, Changed Orientation of Two Main Steam Power Operator Valves (MS PORV). This change rotated the actuator assembly for IPV02000-MS and IPV02010-MS to have its hand-wheel ergonomically positioned to improve accessibility for local control at the valve. Additionally, this change installed permanent moveable platforms adjacent to the MS PORVs IPV02010-MS and IPV02020-MS to facilitate accessibility for manual valve control during a FLEX event, if needed.
	2016-03	RN 14-042	FSAR Figure 9.4-25, S1 FSAR Figure 9.4-25, S2	ECR 50874, Reactor Building Cooling Upgrade (RBCU). This change installed new connections to support a new heat sink for the RBCUs. The new Industrial Cooling Water system will increase the heat removal capacity of the RBCUs and will allow for isolation of the existing Industrial Cooling Towers at a later date

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2016-03	RN 12-020	FSAR Figure 1.2-16 FSAR Section 9.5 FPER Whole Document	ECR-50628, Update FSAR and FPER This revision notice updated the FSAR and made the FPER historical in accordance with transition from Appendix R to NFPA 805.
	2016-03	RN 12-024	FSAR Figure 1.2-1 FSAR Figure 2.4-6 FSAR Figure 9.5-1, Sh 2 FPER Figure E-023-001	ECR-50792, Relocation of Underground Utilities to Support ISFSI The change relocated and modified underground utilities to accommodate ISFSI: 1) Fire Service piping and hydrant modifications, and a new B.5.b firewater line to the Monticello Reservoir for a fire pump truck connection; and 2) Storm Water drain piping and catch basin.
	2016-02	RN 12-023	FSAR Section 1.2 FSAR Section 3.5.1.1.3 FPER Section 4.11.3.1 FPER Section 4.11.3.2 FPER Section 4.11.7.1 FPER Section 4.11.7.2 FPER Figure E-023-001 FSAR Figure 1.2-1	ECR-50791, Relocation of Hydrogen System to Support Independent Spent Fuel Storage Installation (ISFSI). This change relocated the Hydrogen Supply systems to mitigate a hazard to Spent Fuel Storage Casks travel path.
	2016-02	RN 12-036	FSAR Figure 1.2-1 FSAR Figure 2.4-6 FPER Figure E-023-001	ECR-50793A and ECR-50793I, Provides Design Instructions for the ISFSI Pad This change provided construction details for the ISFSI Storage Pad, Approach Slab, and Protected Area fences and gates. The FSAR/FPER revision notice revises applicable FSAR/FPER figures that depict the plant layout to show these major ISFSI features.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2016-02	RN 14-020	FSAR Figure 1.2-5 FSAR Figure 1.2-12 FSAR Figure 1.2-28 FSAR Figure 9.1-3 FSAR Figure 9.2-2, S2 FSAR Figure 9.2-2, S4	ECR 51003, FLEX Feed Connections. This change installed a FLEX hose manifold as a diverse means to accomplish several key safety functions (core cooling & heat removal, spent fuel cooling and containment integrity) during an Extend Loss of AC Power (ELAP). Storage containers for hoses were also placed at strategic locations in the Intermediate and Auxiliary Buildings.
	2016-02	RN 15-025	FSAR Table 8.3-3 Part A1 FSAR Table 8.3-3 Part A2 FSAR Table 8.3-3 Part B1 FSAR Table 8.3-3 Part B2 FSAR Section 9.2.1.3	ECR-50899, Service Water (SW) Traveling Screen Operation after an Engineered Safety Feature (ESF) Signal. This changed removed the function of the SW Traveling Screen to rotate after an ESF demand. The rotating function of the SW Traveling Screen is not required for SW System operability could create a failure mode of debris intrusion after the ESF demand.
	2016-02	RN 15-028	FSAR Figure 9.3-16, SH 1C	ECR72120, Reactor Coolant Drain Tank (RCDT) Heat Exchanger (HX) Champs/Q-List Revision. This change corrected the Safety Class of the Shell Side of XHE0009 (Excess Letdown Heat Exchanger) as 2B.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2016-01	RN 14-018	FSAR Section 5.5.7.2.2.4	CR-12-04658, Administrative Correction. This change corrected FSAR Section 5.5.7.2.2.4, which incorrectly states that the Reactor Pressure Vessel Head (RPVH) “is gradually raised as the water level in the refueling cavity increases.” Analysis supports the current VCSNS practice of performing a “dry” lift in which the RPVH is raised in a single movement disregarding water level in the refueling cavity.
	2016-01	RN 14-029	FSAR Table 3.9-8 FSAR Figure 9.2-9b FSAR Figure 10.4-16	ECR51002, FLEX Water Transfer Connections. This change provided multiple connections and piping between the Condensate Storage Tank, Demineralized Water Storage Tank and Filtered Water Storage Tank as part of the NRC Order EA-12-049 Mitigation Strategies for Beyond-Design-Basis External Events.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2016-01	RN 15-024	FSAR Figure 10.4-8 FSAR Figure 10.4-16	ECR-50157A, Upgraded the Emergency Feedwater (EFW) Mini-flow Lines to Condensate Storage Tank (CST) from Non-nuclear Saftey (NNS) to Quality Related (QR). This change upgraded the 2 inch, 3 inch and 4 inch mini-flow/recirculation lines for the Motor Driven Emergency Feedwater, Turbine Driven Emergency Feedwater pumps and 10 inch condensate return line from the EF tie in point to the CST from NNS to QR. The upgrade of the lines also addressed concerns of potential flooding problems of the Diesel Generator Building and the potential crimping of the line during a seismic event.
	2015-12	RN 15-023	FSAR Section 4.2.2.2.2 FSAR Section 4.2.4 FSAR, Section 5.4.2 FSAR Section 5.4.5	ECR-50846D and ECR-72103, Weld Repair Contingency for RV Head Inspection During Refuel 21. This change updated the FSAR to include Relief Request RR-4-05, “Alternative Weld Repair for Reactor Vessel Upper Head Penetrations” (approved April 30, 2014) and the weld repairs performed on the reactor vessel head, during RF-21.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2015-11	RN 13-018	FSAR Section 1.2.3.2, FSAR Section 1.2.3.7, FSAR Section 3.8.4.1.6, FSAR Section 3.8.4.4.10, FSAR Section 9.1.2, FSAR Section 9.1.4.2, FSAR Section 9.1.4.3.5, FSAR Section 9.1.5, FSAR Section 9.1.6, FSAR Section 13.1.2.2.1, FSAR Section 13.4.2.1, FSAR Table 3.2-1	ECR-50797, Upgrades for Used Fuel Storage. This change described the onsite ISFSI system description and updated the design functions of the FHB and the FHB crane.
	2015-10	RN 11-032	FSAR Figure 1.2-13	ECR-50798B, Safety Improvements to the Diesel Generating Building. This change revised FSAR Figure 1.2-13 to remove “air tight” note for hatch DRDB 404/405.
	2015-10	RN 13-006	FSAR Figure 1.2-1, FSAR Figure 9.5-1, S2	ECR-50853, Installation of Utility Tie-ins for Emergency Response Building (ERB). This change provided connections to the existing fire service water line, potable water line and waste water line. A separate Simplex fire control panel was also installed and networked with the Combined Nuclear Operations Building and Nuclear Learning Center panels.
	2015-08	RN 15-016	FSAR Figure 8.3-4	ECR-50811 and ECR-50811A, NFPA 805 Incipient Detection Implementation. This change added the Incipient Detection fire detection equipment to Figure 8.3-4.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2015-08	RN 15-017	FSAR Section 9.3.1.1, FSAR Section 9.3.1.2	ECR-72076, Administrative Correction to Voltages in FSAR. This change corrects the FSAR Section 9.3.1.1 and 9.3.1.2 voltage from 460 to 480 volts for air compressors.
	2015-08	RN 15-012	FSAR Table 3.2-1, FSAR Section 13.1.2.2.4	Correct QAPD title. This change corrects the QAPD title in Section 13 and Table 3.2-1 Notes.
	2015-08	RN 15-014	FSAR Section 9.3, FSAR Figure 9.4-32	ECR-50682C, Control Rod Drive Mechanism (CRDM) Cooling Tower XCI0004 Drawing Change. This change added the vent lines on the spray pumps casings shown in FSAR Figure 9.4-32 (Essential Drawing D-302-852).
	2015-07	RN 15-011	FSAR Table 6.4-1, FSAR Section 6.4.1.2.1 FSAR Section 13.1.2.2.1 FSAR Section 13.1.2.3 FSAR Section 13.1.3.1.5 FSAR Section 13.2.1 FSAR Section 13.5.1.3 FSAR Section 13.5.1.3.1	CR-14-02981, VCS Unit 1 “Shift Supervisor” Position Title Change to “Shift Manager”. This title change was recommended by INPO SOER 96-1, Recommendation 6.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2015-06	RN 06-044	FSAR Figure 1.2-4	ECR-50579, Reactor Building Sump Debris Collection. Modifications were made to meet requirements of NRC Generic Letter 2004-02 and certify that the sump screens can accommodate the debris quantities following a LOCA.
	2015-06	RN 12-006	FSAR Table 8.3-3 Part A1 FSAR Table 8.3-3 Part A2 FSAR Table 8.3-3 Part B1 FSAR Table 8.3-3 Part B2	ECR-50537G, Replace Heat Trace Control Panels. This change added heat tracing circuits to panels XPN2022 and XPN2023. This affects information and loading for XMC1DA2Y and XMC1DB2, which is contained in FSAR Table 8.3-3.
	2015-06	RN 13-022	FSAR Figure 3.8-17 FSAR Section 3A FSAR Section 6.2.1.6 FSAR Section 6.2.2.2.1.1 FSAR Section 6.2.2.3.1.1 FSAR Section 6.3.2.6 FSAR Section 6.3.2.14 FSAR Section 6.3.6 FSAR Figure 6.2-48	ECR-50579A, GL 2004-02, RB Sump Debris Collection (RB Sump Strainers). This change updated Chapters 3 and 6 to include updated text and figures for the new recirculation sump design.

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	2014-04	RN 13-011	FSAR Section 5.2.7.1.1 FSAR Section 12.2.4.2.2 FSAR Section 12.2.4.4 FSAR Figure 12.2-3 FSAR Figure 12.2-4	ECR-71781 - Technical Specification Bases changes (Amendment # 186) made in accordance with TSTF-513 (Rev 3) and allow removal of TSR-1 069. FSAR Sections relating to use of RMA2 for RCS leak detection were revised to (1) state how the alarm setpoints are typically set, (2) to identify recognized limitation (per TSTF-513, Rev. 3, TS Amendment #186) on meeting the 1 hour response time for RC leak detection and (3) to reflect the use of new limits on maximum alarm setpoint(s) to ensure operability.
	2014-03	RN 05-043	FSAR Figure 10.2-5	ECR-70502 Base and Revision A (CR-12-01355) - Corrected a duplicate valve number. Valve number 12227 -HY was changed to XVT12195-HY in FSAR Figure 10.2-5. This purge valve and vent operations are not described in the FSAR.
	2014-03	RN 13-028	FSAR Section 9.1	ECR-71903 (CR-12-01303) - Added clarification to FSAR Section 9.1.1.3. This change included a reference to assumptions necessary for the 10 CFR 70.24 exemption previously received by the NRC.
	2014-03	RN 14-006	FSAR Section 4.3.2.7.1 FSAR Section 9.1.1.1	ECR-71953 - Provided technical background for the removal of the k-infinity from the two sections in the FSAR. Two k-infinity sentences within the FSAR were not removed after TS Amendment 144. This ECR corrects this discrepancy.

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	N/A	RN 14-014	FSAR Section 13.2.1	CR-14-00887 - Removed the accreditation renewal dates from Section 13.2.1. The accreditation renewal dates are information that is anecdotal and excessive detail that is not important to providing an understanding of the plant's design and operation.
	N/A	RN 14-023	FSAR Section 4.4.2.3.4.3	ECR-71888 - Cycle 22 Core Reload Design. Increased Rod Bow DNBR penalty from "<1.3%" to "<2%" per vendor recommendation .
	2014-02	RN 13-032	FSAR Table 3.9-8	ECR-50567, ECR-50567B and ECR-50567F - Service Water Vacuum Relief Valves and Replacement of XVG031 07 AlB-SW. Added service water vacuum relief valves XW13143A and XW13143B to Table 3.9-8 Active Code Class 1, 2, and 3 valves.
	2014-02	RN 06-039	FSAR Figure 1.2-1 FSAR Figure 1.2-16 FSAR Figure 1.2-26 FSAR Figure 2.4-6 FSAR Figure 8.3-2a FSAR Figure 8.3-2d	ECR-50557 - Changed several figures detailing the physical barriers installed outside the protected area. Modifications were made to the Vehicle Barrier System, Delay Fencing, and some roadways. New access provisions inside the Protected Area include stair towers, and access between the Control Building and Auxiliary Building roofs were also developed.

Revision Summary (continued)

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	2014-02	RN 13-013	FSAR Section 13.1.1.2 FSAR Section 13.1.2.2 FSAR Table 13.1-4	CR-13-00603 - Organizational changes. Organizational changes were made that affected FSAR Chapter 13. The changes resulted in an adjustment of the Manager Business and Financial Services duties and the deletion of the Nuclear Strategic Business Unit Projects Coordinator. In addition, other minor discrepancies were corrected .
	2014-01	RN 13-030	FSAR Figure 8.3-8	ECR-50495D - Main Power Transformer Replacement. This ECR replaced existing 1052 MVA Main Power Transformer with a new 1232 MVA Transformer. Extended Isophase Cooling Bus was also reconfigured in conjunction with the Fire Detection and Suppression system.
	2014-01	RN 13-034	FSAR Figure 2.4-6	ECR-50583A - Replaced feedwater control valve positioned and feedwater control valve operator copper tubing. The existing Bailey positioners on IFV00478, IFV00488, and IFV00498 were replaced with redundant digital valve controllers because the positioners do not provide adequate stability in valve operation resulting in wear and tear on the valve. The existing positioners are also prone to malfunctions/ failures due to very small internal contaminates.
	2014-01	RN 08-018	FSAR Figure 2.4-6	ECR-50713 - Improved selected security fences and barriers. Additional security fencing near the Turbine Building, Closed Cycle Cooling Tower, Access Portal and Fitness Center were added to enhance the current configuration.

Revision Summary (continued)

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	2014-01	RN 13-020	FSAR Section 5.2.2.4	ECR-50650 - Added a back pressure regulator around the Accumulator Fill Header Inlet Vent Valve (XVTOO037-SI). Back Pressure Regulator installed around XVT00037 -SI. This ECR was performed to allow controlled leakage to the Pressurizer Relief Tank and to reduce the potential for leakage into and pressurization of interfacing systems.
	2014-01	RN 13-021	FSAR Section 5.2.7.1.3	ECR-50677 - Modified reactor coolant system leak detection. This ECR modified the existing drain piping for XCE0021-AH and installed new CADM Condensate Drain Line Flow Transmitter 11F175025-LDI to provide enhanced ACS leakage detection.
	2013-12	RN 12-010	FSAR Figure 10.2-5	ECR-50823 - Hydrogen Storage Unit Temp Unit Tie-In. The change installed a temporary connection to the existing Hydrogen Storage System in order to repair/replace the existing Hydrogen Storage Unit. This allowed the replacement/repair of the Hydrogen Storage Unit while the turbine/plant is online.

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	2013-11	RN 13-004	FSAR Figure 9.3-2	ECR-50538 - Upgraded the reliability and efficiency of the instrument and service air (lAlSA) systems. The drawing was revised to capture the current plant configuration after the implementation of the ECR. Revisions included the installation of two new IAiSA compressors, two new dryers, and corrected the piping configuration from the condensate drain traps associated with mist eliminator XMS05008 and dryers XDR0004A1B to the Turbine Building 412' elevation floor drains.
	2013-10	RN 13-025	FPER Drawing E-023-011	ECR-50567 - Installed new vacuum relief valves and replaced motor-operated gate valves with fast-closing, air-operated butterfly valves. This ECR alleviated the effects of water hammer within the Service Water System downstream of the Reactor Building Cooling Units imposed by certain scenarios that were not identified as part of Generic Letter 96-06.
	2013-09	RN 11-033	FSAR Figure 5.2-8	ECR-71545 - Essential drawing discrepancies. An administrative document only change revised an essential drawing to match marks next to XVT00016B-RH and corrected a typo in the equipment number drawing for XVM18811-SI.

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	2013-09	RN 12-002	FSAR Figure 9.2-9b	ECR-71655 - Essential drawing discrepancy. An administrative document only change package revised an essential drawing to provide an equipment number for XVB05568B-DW. This drawing did not have the "B" Demin Water Pump discharge Valve labeled. The equipment number was added to the drawing.
	2013-09	RN 13-007	FSAR Figure 10.4-16	ECR-71820 - Essential drawing discrepancy. An administrative document only change package revises an essential drawing to correctly show the 1" pipe cap installed downstream of XVT01 033-EF. This reflects the as-built condition in the field and the configuration shown on the original design drawing.
	2013-06	RN 13-016	FSAR Section 6.2.2.5.2.5 FSAR Section 9.4.8.2.4.3.b FSAR Section 9.4.8.2.5.4.a FSAR Section 9.4.8.2.6.2.a FSAR Section 9.4.8.2.8.5.b FSAR Section 9.5.1.2.2	ECR-71849 - Revised the FSAR for Reactor Building (RB) HVAC Smoke Detectors. This change to the FSAR clarified the fact that the RB HVAC smoke detectors are no longer to be credited as the sole means for determining the existence of a fire in the RB and deployment of the fire brigade. These detectors are for information only to assist the operators in making decisions about the presence of a fire in the RB.

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	2013-05	RN 08-013	FSAR Figure 9.4-32	ECR-50682, Replacement of Control Rod Drive Mechanism Cooling Tower XCI0004. The new cooling tower is manufactured by the same original equipment manufacturer as the existing tower. This ECR also addresses minor changes in configuration of the new tower compared to the old tower. Figure 9.4-32 was revised to add valves and another level switch.
	2013-05	RN 12-015	FSAR Figure 10.4-16	ECR 71718 - Corrected Typographical Error with IFT03561A. When this figure was enhanced per ECR-50239 (Rev. 43), IFT3561A was typed as IFT3531A (coordinate B11). The instrument in the plant is not affected and remains as IFT3561A.
	2013-05	RN 12-018	FSAR Section 9.3.1.2 FSAR Section 9.3.1.5 FSAR Table 9.3-1 FSAR Figure 9.3-2	ECR-50577 - Diesel Air Compressor Auto-Start Addition. This ECR eliminated an Operator Recovery Action by providing the diesel driven air compressor, XAC0014, with an Auto-Start signal. Figure 9.3-2 was updated to reflect the electronic signal from IPS08395 to XAC0014. Section 9.3.1 was revised to include discussion of the diesel air compressor.
	2013-05	RN 12-005	FSAR Figure 1.2-1 FSAR Figure 2.4-6 FSAR Index 11-iii FSAR Section 11.7 (removed)	ECR 71498 - Waste Oil Incinerator Demolition. Removed the Incinerator Building from site drawings and Section 11.7. ECR was written to remove the incinerator from service and any related buildings or materials.

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	2013-05	RN 12-042	FSAR Section 4.2.2.2.2 FSAR Section 5.4.2	ECR-50846, Relief Request RR-III-09, Reactor Vessel Head. The FSAR was updated to reflect the Reactor Vessel Head weld repairs and installation of Flow Restrictor on Upper Internals.
	2013-05	RN 13-001	FSAR Figure 5.1-1, Sh 3A FSAR Figure 5.1-1, Sh 3B FSAR Figure 5.1-1, Sh 3C FSAR Section 5.5.1.2	ECR-50683 - RCP/RB Fan Vibration System Replacement. The existing Reactor Coolant Pump (RCP) Vibration System, a Bentley Nevada (BN) 7000 Series Vibration Monitoring System, (XCP6090) and existing Reactor Building (RB) Fan Vibration System (IYM9295) were removed and replaced with a BN 3500 Series Machinery Protection System.
	2013-05	RN 11-016	FSAR Section 9.4.7.2.3 FSAR Figure 9.4-20 FPER Section 4.11.2.1 FPER Section 4.11.2.3 FPER Section 5.0	ECR-50763A, First Floor SB HVAC Replacement. FSAR Figure 9.4-20 was updated to reflect the current Service Building first floor layout. This figure was also updated to reflect changes made to refrigeration components and piping of XRC0002 and the change in controls from pneumatic to digital for the first floor HVAC system per ECR-50763A. FSAR Section 9.4.7.2.3 and FPER Sections 4.11.2.1, 4.11.2.3 and 5.0 were updated to reflect the as-built configuration and use of the former permanent records vault and the HVAC changes made in ECR-50763A. The current permanent records vault is now housed in the Nuclear Operations Building.

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	2013-05	RN 10-012	FSAR Figure 9.2.2, Sht 1 FSAR Figure 9.2.2, Sht 3 FSAR Figure 10.4-16	ECR-50695, Emergency Feedwater System Flow Control Enhancements. Added three notes to Figure 9.2.2, Sheets 1 and 3 to indicate the installation of Cured-In-Place Piping [B16.5 150# TEE 316 SST to eliminate and resist corrosion and the use of Plastocor to prevent corrosion and microbiologically induced corrosion build up]. Added a note to Figure 10.4-16 to indicate valve inlet nozzle and upstream face of disk is covered with Plastocor.
	2013-05	RN 10-028	FSAR Figure 9.4-21	ECR-50763, Service Building First and Second Floor HVAC Replacement. Figure 9.4-21 was updated to reflect the current Service Building second floor layout. This figure was also updated to reflect changes made to refrigeration components and piping of XRC0003, and the change in control system from pneumatic to digital.

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	2013-05	RN 11-027	FSAR Figure 1.2-1 FSAR Figure 1.2-3 FSAR Figure 1.2-10 FSAR Figure 1.2-27 FSAR Figure 1.2-28A FSAR Table 3.2-1 FSAR Table 3.2-1 Notes FSAR Figure 3.8-73 FSAR Table 3.9-7 FSAR Section 5.5.7 FSAR Section 9.3.4.1.5 FSAR Section 9.3.4.2.1 FSAR Table 9.3-4 FSAR Table 9.3-5 FSAR Figure 9.3-16 SH 3 FSAR Figure 12A.4-	ECR-50780C - Alternate Seal Injection. ECR-50780C installed an Alternate Seal Injection (ASI) system to provide an alternate means for Reactor Coolant Pump (RCP) seal injection to reduce the probability of RCP seal LOCA. The ASI takes suction from the Refueling Water Storage Tank via the 20 inch discharge header and discharge to the 2" seal injection line upstream of the filters. A check valve is provided (under ECR 50780) in the seal injection line to prevent back flow to the charging pump header and normal injection line through FCV-122.
	2013-05	RN 13-009	FSAR 7.7.3.1	CR-12-03645 - Safety Parameter Display System (SPDS). Added language to the SPDS description to illustrate that SPDS provides a continuous indication of plant parameters except in the case that a seismic event results in the loss of IPCS.
	2013-05	RN 13-010	FSAR 6.2.3.2.1	ECR-71830 (MRF-20168; CR-12-05293) - NaOH Tank Recirculation Loop from MRF-20168. Updated Section 6.2.3.2.1 to add description of NaOH tank recirculation loop installed under MRF-20168.

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	2013-04	RN 12-021	FSAR Figure 9.1-3 FSAR Figure 9.5-1, SH 3 FSAR Figure 9.5-1, SH 5	Six different changes were made to Drawing 302-231, Sheet 3, covering Revisions 5 through 10 - ECR-50205 (Kaowool) and ECR-50692 (B5b).
	2013-04	RN 13-002	FSAR Figure 8.2-3	ECR-50851 - Determinated Circuit ESM361X and Recalibrated Overcurrent Relay of XSW1B-12.
	2013-04	RN 13-005	FSAR Section 12.3.1.1.1 FSAR Section 12.3.1.1.2	CR-12-02077 and CR-12-02078 - FSAR Section 12 was revised due to organizational changes identified during a QA Audit - Station Radiation Control Audit.
	2013-02	RN 07-006	FSAR Figure 8G-6 FSAR Figure 8G-7 FSAR Figure 8G-8	ECR-50625 - Rod Control System Blocking Diode Replacement/Removal. Westinghouse identified the Rod Control system blocking diodes as a single failure component. Additionally, Westinghouse identified the blocking diode fuses and all TI-600 trigger indicating fuses as a reliability issue. The blocking diodes were replaced with a jumper wire and the fuses were replaced with more reliable fuses.
	2013-02	RN 12-009	FSAR Figure 5.1-1, SH 2	ECR-71669 - Valve Shown in Wrong Position. Isolation valve XVT00100-WG was changed from “normally open” to “normally closed” on drawing 302-602. Valve was installed by MRF-21256 as normally closed.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2013-01	RN 12-033	FSAR Section 12 FSAR Table 12.3-3	CR-12-02080 - FSAR Table 12.3-3, “Portable Health Physics Instruments”, was revised to change Location Column for all portable survey instruments from “412’ Control Building” to “Refer to Section 12.3.2.1.2”. Also changed location for air samplers to “various”.
	2012-12	RN 12-027	FSAR Section 4.3.4 FSAR Section 7.7.7 FSAR Section 15.3.8	CR-10-03107, Technical Specification Amendment 190, BEACON. TS Amendment 190 adopted the revised BEACON power distribution methodology that incorporated the use of the three-dimensional advance nodal code neutronic model into SPNOVA/BEACON. This revision notice updated references to the WCAP-12472-P-A Addendum 1-A.
	2012-12	RN 11-020	FSAR Section 5.7.1.4 FSAR Section 17.2.1.2.4 FSAR Section 17.2.10.3	Change Management Plan (CMP-10-02766). Revised the FSAR to show change of control for the Inservice Inspection Program from Quality Control to Design Engineering and revised information for the Containment Inservice Inspection Program.
	2012-12	RN 06-024	FSAR Figure 10.4-1 FSAR Figure 10.4-8 FSAR Figure 10.4-9	ECR-50065 – ECR changed the design data upset pressure for various design flag sections of the process piping. Drawings were revised to reflect the boundaries and design conditions.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2012-11	RN 10-024	FSAR Figure 1.2-3 FSAR Figure 1.2-4 FSAR Figure 1.2-5 FSAR Figure 1.2-6 FSAR Figure 1.2-8 FPER Figure E-023-003 FPER Figure E-023-005 FPER Figure E-023-008 FPER Figure E-023-014	ECR-50685 - In the Auxiliary Building, existing hoist (XCR0019) was replaced with a new equipment lift (XCR0075). As part of the ECR, fire extinguishers were added to the FPER drawings. The new lift was added to the FSAR drawings.
	2012-11	RN 11-038	FPER Figure 023-007 FPER Figure 023-008 FPER Figure 023-010 FPER Figure 023-019 FPER Figure 023-022	ECR-71012 - Proper location of portable fire extinguishers. FPER drawings were revised to show the proper locations of portable fire extinguishers.
	2012-11	RN 12-011	FSAR Figure 10.4-14	ECR-71665 (CR-12-00337) - Valves Shown in Wrong Position. Valves XVD06102B and XVD06103B were changed from “normally closed” to “normally open”on drawing 302-782.
	2012-11	RN 12-014	FSAR Figure 9.2-1 FSAR Figure 9.2-4 FSAR Figure 9.3-5 FSAR Figure 9.3-10 FSAR Figure 9.4-22 FSAR Figure 9.4-25 FSAR Figure 9.5-1, SH 3 FSAR Figure 10.4-16	ECR-71215 - Editorial change. Drawing 302-222 was converted from 1 sheet to 4 sheets to make the document easier to read and follow. Match Marks on 8 drawings were revised to show the new 302-222 sheet numbers.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2012-09	RN 11-034	FSAR Table 6.2-53a	TS Amendment 191 deleted five High Head Safety Injection Containment Isolation Valves from the Local Leak Rate Test Program. FSAR Table 6.2-53a was revised to reflect this NRC approved deletion.
	2012-09	RN 12-004	FSAR Table 3.9-8	ECR-50780 - Alternate Seal Injection. Added active code valve XVC18529-CS to FSAR Table 3.9-8. This change was required due to implementation of the ECR-50780 base package. This change was not included in the previous FSAR RN 11-009 approved November 2011.
	2012-08	RN 07-034	FSAR Figure 9.3-15, SH 1	ECR-50474 - Added a match mark on drawing 302-361 sheet 1 which shows a continuation on new drawing 302-361 sheet 2. New drawing 302-361 sheet 2 was created to show the lift stations outside the protected area.
	2012-08	RN 07-035	FPER 5.0.E.2(c)	ECR-70830A - Replaced Electric Fire Pump Controller.
	2012-08	RN 10-021	FSAR Figure 9.2-5	ECR-50239 - Editorial Change - Revised drawing 302-612 to change valve “XVT09363B-CC” to “XVT09563B-CC”.
	2012-08	RN 11-022	FSAR Section 10.4.9.4	CR-11-01651 - Revised FSAR to correctly describe how the Service Water-to-Emergency Feedwater pump suction valves are tested.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2012-07	RN 05-015	FPER Section 2.2.2.3 FPER Section 2.2.2.4 FPER Section 4.4	ETBT-70690, ETBT-71259 - Removed the words “magnesium oxychloride” from three sections of the FPER. The plant’s original structural steel fire coating Albi Duraspray is no longer manufactured or available. Replacement products Albi Clad Thin Film and Pyrocrete 241 do not contain magnesium oxychloride.
	2012-07	RN 06-08	FSAR Figure 10.4-14	ECR-70756 - Revised drawing to clarify piping configuration represented as Detail “A” and Detail “B”. A Corrective Action identified that valves contained in Detail “A” of this drawing could be missed when preparing a tagout boundary due to the method chosen to show these valves on the drawing. The same problem existed for valves shown in Detail “B”.
	2012-07	RN 06-043	FSAR Figure 10.4-8	ECR-70967 - Add component IDs for 3” condensate pump vent valves to Detail A of Drawing D-302-101. This was done to be consistent with the level of details provided in the drawing for other valves associated with the condensate pumps.
	2012-07	RN 07-038	FSAR Figure 2.4-6	ECR-70883 - Yard drainage system was changed to improve legibility and to make minor editorial changes that did not involve design information.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2012-07	RN 10-023	FSAR Figure 1.2-12 FPER Section 4.4.22.1	ECR-50764 - Safety Improvements to DRIB/324 Hatch and Ladder; Health Risk BS-08-01. FSAR Figure 1.2-12 notes the hatch as a 2'6" x 3'0" removable opening. This note is being changed to reflect the dimension of the new hatch opening which is 2'6"x 4'6". The new hatch was installed under ECR-50764.
	2012-07	RN 10-031	FSAR Figure 9.2-8	ECR-50728 - Replaced Clay Feeder Mixing Tank and Associated Equipment. FSAR Figure 9.2-8 is the piping and instrument diagram for the Water Treatment System. The FSAR Figure was updated to capture permanent plant changes resulting from the implementation of ECR-50728. The changes include the replacement of the clay feeder (XTK0068), mixing tank (XTK0071), solution pump (XPP0062), and associated equipment, piping, and valves.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2012-07	RN 11-018	FSAR Table 1.7-1 FSAR Table 3.9-0 FSAR Table 3.10-3 FSAR Figure 9.2 -2, Sh. 1 FSAR Figure 9.3-10 FSAR Section 9.4.7.2.4 FSAR Figure 9.4-22 FPER Section 4.4.20.2 FPER Section 4.4.21.2 FPER Section 4.4.23.1 FPER Section 4.4.23.4 FPER Section 4.4.23.5 FPER Section 4.5.2.2 FPER Figure E-023-007	ECR-50585A - Safety Related Chiller Replacement. Revised FSAR Chapters 1, 3, and 9 and FPER Chapter 4 to reflect the new safety related chiller "A" (XHX0001A), which has recently been replaced with a new, state-of-the-art chiller. Design features of the new chiller and associated piping, valves and electrical circuits have been updated in the FSAR and FPER.
	2012-07	RN 11-025	FSAR Figure 10.4-10	ECR-71598 - Drawing enhancement to aid with work or tagging.
	2012-07	RN 11-028	FSAR Figure 1.2-1	ECR-71558 (CR-10-03242) - Parr Hydro Project Boundary Line (PBL). The PBL was added to a plant layout drawing.
	2012-07	RN 11-030	FPER 3.6	ECR-50556 - 8-Hour Emergency Battery Light Upgrades. ECR installed additional emergency lighting units at various locations in the plant to enhance lighting required for the performance of local manual actions needed to accommodate Appendix R safe shutdown.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2012-07	RN 11-039	FSAR Section 5.5.7.1.1.3.3.i	CR-12-00713 - Wording was be changed to say, "Normal Charging Isolation Valve 8146 - If the normally open valve closes spuriously, alternate charging valve 8147, which fails open, can be used." This will eliminate any confusion caused by the current wording of "…which fails to open…"
	2012-07	RN 12-019	FSAR Section 2.4.12.2	CR-12-02022 - Correct numerical errors on page 2.4-26. Updated Section 2.4.12.2, pg 2.4-26, to provide correct information concerning spatially-averaged Cs-137 peak concentration across the effective width of the contaminated local aquifer (3.7 x 10-3.5). The discharge from the uncontaminated portion of the local ground water system was changed to 0.52 cfs.
	2012-06	RN 03-037	FSAR Figure 9.5-1, SH 2	ECR-50510C - This change converted the cafeteria on the first floor of the Auxiliary Service Building to a central planning area for outage activities. The ECR added Sprinkler System Strainer Flushing Valve XVG34037-FS to drawing D-302-231, Sheet 2. The sprinkler system was also changed from manual to an automatically operated system upon detection of fire.
	2012-06	RN 12-022	FPER Figure 3.2-1	CR-12-02035 - Reassigned the operator actions for emergency feedwater during control room evacuation from the Shift Technical Advisor (STA) to the Fire Emergency Procedure (FEP) Operator.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2012-05	RN 11-040	FSAR Section 3A FSAR Section 13.1 FSAR Section 13.4 FSAR Section 13.5 FSAR Section 13.6 FSAR Section 17.2 FSAR Figure 17.2-1	CR-10-03108 (TS Amendment 188) - License Amendment Request for the new Quality Assurance Program Description (QAPD) to change the program to comply with the requirements of ANSI/ASME NQA-1-1994. Removed the Quality Assurance Program information from Chapter 17, Section 17.2, and identified that the information is found in the QAPD. Revised Regulatory Guide commitments in Chapter 3, Appendix 3A, related to the application of the new QA program. Revised Chapter 13 to reference new requirements in the QAPD.
	2010/6	RN 05-038	FSAR Section 10.2.2.1, Table 8.3-1, Figures 1.2-19 and 8.2-3	The main generator was rewound due to leaks (ECR 50574). Consistent with this work the single point temperature sensors were replaced with dual sensor heads for improved reliability. This RN updates the FSAR to reflect these changes.
	2010/6	RN 06-040	FSAR Sections 6.2.1.3.11, 6.2.7, 15.4.1 and 15,4,7; Tables 6.2-56 thru 60, 15.4-1, -1a, -2, -2a, and -5; Figures 6.2-62 to 64, 15.4-1-67, and 15.4.105-122	This RN updates Chapters 6 and 15 to reflect the new Best-Estimate large Break LOCA analysis approved by the NRC via issuance of Tech Spec Amendment 176. The Best Estimate Large Break LOCA Analysis was performed to regain peak clad temperature margin via application of an improved Evaluation Model.
	2010/6	RN 07-003	FSAR Figures 9.3-16 SH. 1A, 9.3-16 SH. 1B, & 9.3-16 SH. 1C	ECR70818 incorporates the guidance provided in Westinghouse TB-04-22 in order to support the RCP seal leakage rate assumed within the FPER safe shutdown analysis

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2010/6	RN 07-024	FSAR Section 3.9.3.8	Revises the FSAR to reflect the use of Maxi-Bolts as equipment anchors which can be considered an acceptable replacement for Hilti Kwik Bolts, with proper design considerations. Reference Design Guide ST-01, Calculations DC0395E-001 and DC0395E-002.
	2010/6	RN 08-001	FSAR Section 10.4.5.1 Item 3, Table 10.4-3 and Figure 10.4-5	This RN updates the FSAR to reflect the re-routing of a Filtered Water cooling line header for the three Circulating Water pumps and motors, installation of pressure instrumentation for the FI motor cooling water supply lines, installation of throttle valves for flow control through the motor cooling coils, closing valves 8844A, B, C and installation of drains (ECRs 50706, 50706A, and 50706H).
	2010/6	RN 08-011	FSAR Section 7.7.1.7	Added description of the Instrument Air System for each main feedwater control valve and its associated hardware to allow for local and manual control and locking of the main feedwater control valves in position with air pressure (air-gag), while maintaining the trip closed feature of the feedwater control valves (ECR 50708).
	2010/6	RN 08-021	FSAR Figure 9.2-24	ECR 71187 revised drawing 302-791 to show the appropriate ASME Code breaks for valves XVD01928A-MU and XVD01928B-MU.
	2010/6	RN 08-022	FSAR Sections 5.5.3.3.4, 5.5.10.2.2, 5.5.10.4	Updated Chapter 5 to reflect the incorporation of the pressurizer structural weld overlays applied during RF-17 (ECR 50636).

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2010/6	RN 08-028	FSAR Figure 10.3-2	ECR 71003 corrected drawing 302-012 to change the 'gate' valve symbols to 'globe' valve symbols for valves XVT02818A-MS and XVT02818B-MS.
	2010/6	RN 08-029	FSAR Section 5.4.2	Updates Chapter 5 to reflect the installation of Canopy Seal Clamp Assemblies at the lower canopy seal weld on some CRDMs. These clamps prevent and/or arrest any non-pressure boundary RCS leakage.
	2010/6	RN 08-030	FSAR Section 9.1.4.2.2.8 and 9.1.4.2.2.11, Appendix 3A, Table 5.2-8, and Figure 9.1-12	Amends the FSAR to describe the replacement of the reactor vessel stud tensioners with Closure Studs, Inserts and Adaptors, HydraNuts, and Washers (ECR 70905A).
	2010/6	RN 09-001	FSAR Figures 1.2-15 and 10.4-12	ECR 50583 replaced the feedwater control valve positioner with a digital valve controller to provide for stable valve operation. Drawings E-005-001 and 302-083 were updated to reflect this change.
	2010/6	RN 09-002	FSAR Tables 3.9-8, 7.3-7 and 7.4-2 Sections 5.5.7.1.1.3 a. & b., 9.2.1.2 and 9.2.1.5, Figure 9.2-2 Sheets 1 - 4	ECR 71215 converted Service Water system drawing 302-222 into four sheets from 1 sheet for legibility purposes and to replace breaks with direct connections for clarity.
	2010/6	RN 09-004	FSAR Section 9.2.7.1	Deleted the non-safety related flow performance capability from the design function list for the Reactor Makeup System to the Chemical and Volume Control System (ECR 71130).
	2010/6	RN 09-005	FSAR Figure 9.4-32	ECR 50327 revised drawing 302-852 to reflect the revised setpoints for XVR07510A, B, C, & D

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2010/6	RN 09-006	FSAR Figures 5.2-8A, 9.2-5, 9.2-6, and 10.4-16	ECR 50239 converts the 302 series drawings from a Raster file to Vector file system. No design information shown on the drawings has been affected.
	2010/6	RN 09-008	FSAR 18.3.1.1, 18.3.1.2, and 18.3.1.3	CR-08-03647 identified the need to update the FSAR to reflect the information from the most recently removed reactor vessel surveillance capsule.
	2010/6	RN 09-009	FSAR Figures 1.2-15 and 1.2-17 FPER Figures E-023-018 and E-023-020	ECR 50481 modified the Control Building elevation 412 dress-out and RCA access control rooms to provide adequate facilities to address the radiological and facility inadequacies of the previous design layout.
	2010/6	RN 09-010	FSAR Figure 9.2-5	ECR 71263 revised drawing 302-612 to change valve ID 9606-cc to XVG09606-CC
	2010/6	RN 09-011	FSAR Figure 11.3-4, Sheet 3	ECR 71261 revised drawing 302-742 to correct typographical error of pressure transmitter IDs. PT1065A is changed to PT1065 and PT1065A is changed to PT1065B.
	2010/6	RN 09-012	FSAR Figure 10.4-1	ECR 71185 revised drawing 302-131 to reflect the line spec as 151X
	2010/6	RN 09-014	FPER Section 4.11.6.1, FSAR Table 8.3-1, FSAR Figures 1.2-1 1.2-21; 8.2-2a, c & d; 9.2-9b and 9.5-1 SH 5	ECR 50495D replaced the main station transformer and updates the FSAR / FPER to reflect the new ratings and changes in physical configuration.
	2010/6	RN 09-016	FSAR Figure 9.2-7	ECR 71297 revised System Data table Item 3 to reflect actual system conditions and specifies the maximum and minimum flow rates.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2010/6	RN 09-017	FSAR Table 15.4-34 and Figure 15.4-96B	CR-09-01895 / Westinghouse NSAL-09-02 noted a non-conservative assumption in initial pressurizer level required a re-analysis of the Locked Rotor overpressurization accident. As a result, the new peak pressure has been added to Table 15.4-34 and Figure 15.4-96B.
	2010/6	RN 09-018	FSAR Figure 1.2-12	ECR 71277 revised drawing E-001-022 to show the actual field configuration for XPP157A&B.
	2010/6	RN 09-019	FSAR 13.1.2.2.1	SAP-131 Revision 6, Change D: SAP-131 was updated to reflect the Fire Protection Group realignment as recommended by the GMES to QA / GMNPO. This RN updates the FSAR to reflect this change.
	2010/6	RN 09-020	FSAR Section 2.5.4.10.3.2	This RN revised the FSAR to specifically identify that the ground settling inspection is performed in the area of the DG Fuel Oil Storage Tanks. (CR-09-01266)
	2010/6	RN 09-021	FSAR Sections 15.2.2.1, 15.2.2.2, and 15.2.16	This RN updates Chapter 15.2 to include the results of the plant specific Rod Withdrawal at Power event analysis. CR-09-00701 / Westinghouse NSAL-09-01 identified an overpressure concern for the Rod Withdrawal at Power event. Plant specific analysis demonstrated that the RCS overpressure limit would not be exceeded provided the reactivity insertion rate is . 60 pcm/second

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2010/6	RN 09-023	Section 6.2.2.5.2.4, Table 1.7-1, Figures 1.2-15, 6.2-49, 9.4-29, & 9.4-31	ECR 50693 replace the vibration systems on the RBCU fans, CRDM fans, and the Reactor Compartment Cooling Fans. This RN updates the FSAR to reflect these changes.
	2010/6	RN 09-025	FSAR Table 3.2-1	ECR 71329 added clarifying information and new Note 38 to state the isolation valves were purchased as Code Class 3 but are being used as safety related non-code dampers.
	2010/6	RN 09-026	FSAR Figure 1.2-6	ECR revised drawing E-001-031 to reflect the as-built condition showing the correct system and name for the PORV accumulator tanks.
	2010/6	RN 09-031	FSAR Section 6.3.3.2	ECR 71341 eliminated the option to place both trains of RHR in service during Mode 4 when the temperature is less than 250 „aF in order to ensure one train of RHR is able to fulfill the Mode 4 ECCS safety function.
	2010/6	RN 10-002	FSAR Sections 2.4.13.1.2., 2.4.13.2.7, 2.4.13.5	ECR 50560 - Installation of the dewatering system, including well vaults, wells, pumps, and associated control/monitoring equipment. This RN updates the FSAR to incorporate the description of the non-safety dewatering system installed.
	2010/6	RN 10-003	FSAR Section 5.3.2.11.3 & Figure 9.3-16 SHT. 3	ECR 50613A phase 1 installed new valves XVT38100A-CS and XVT38202A and updates the FSAR accordingly.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2010/6	RN 10-004	FSAR Figure 9.3-14	ECR 71250 revised drawing 302-352 to show the correct Equipment ID for IAP07896
	2010/6	RN 10-009	FSAR Figures 1.2-4 and 9.5-1A	ECR 71269 revised drawing E-001-011 to show the correct location of two electrical penetrations XRP0043 and XRP-0044.
	2010/6	RN 10-011	FSAR 7.7.1.3.2, 7.7.1.3.4, and 7.7.1.3.5	ECR 50686 upgraded the existing DRPI system to remove some single point vulnerabilities and provide a more reliable system. This RN updates the portion of the DRPI system located in the Main Control Board.
	2009/09	RN 05-038	FSAR Section 10.2.2.1, Table 8.3-1, Figures 1.2-19 and 8.2-3	The main generator was rewound due to leaks (ECR 50574). Consistent with this work the single point temperature sensors were replaced with dual sensor heads for improved reliability. This RN updates the FSAR to reflect these changes.
	2009/09	RN 06-040	FSAR Sections 6.2.1.3, 6.2.7, 15.4.1 and 15,4,7; Tables 6.2-56 thru 60, 15.4-1, -1a, -2, -2a, and -5; Figures 6.2-62 to 64, 15.4-1 to -67, and 15.4.105 to -122	This RN updates Chapters 6 and 15 to reflect the new Best-Estimate large Break LOCA analysis approved by the NRC via issuance of Tech Spec Amendment 176. The Best Estimate Large Break LOCA Analysis was performed to regain peak clad temperature margin via application of an improved Evaluation Model.
	2009/09	RN 07-024	FSAR Section 3.9.3.8	Revises the FSAR to reflect the use of Maxi-Bolts as equipment anchors which can be considered an acceptable replacement for Hilti Kwik Bolts, with proper design considerations. Reference Design Guide ST-01, Calculations DC0395E-001 and DC0395E-002.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2009/09	RN 08-001	FSAR Section 10.4.5.1 Item 3, Table 10.4-3 and Figure 10.4-5	This RN updates the FSAR to reflect the re-routing of a Filtered Water cooling line header for the three Circulating Water pumps and motors, installation of pressure instrumentation for the FI motor cooling water supply lines, installation of throttle valves for flow control through the motor cooling coils, closing valves 8844A, B, C and installation of drains (ECRs 50706, 50706A, and 50706H).
	2009/09	RN 08-011	FSAR Section 7.7.1.7	Added description of the Instrument Air System for each main feedwater control valve and its associated hardware to allow for local and manual control and locking of the main feedwater control valves in position with air pressure (air-gag), while maintaining the trip closed feature of the feedwater control valves (ECR 50708).
	2009/09	RN 08-022	FSAR Sections 5.5.3.3.4, 5.5.10.2.2, 5.5.10.4	Updated Chapter 5 to reflect the incorporation of the pressurizer structural weld overlays applied during RF-17 (ECR 50636).
	2009/09	RN 08-028	FSAR Figure 10.3-2	ECR 71003 corrected drawing 302-012 to change the 'gate' valve symbols to 'globe' valve symbols for valves XVT02818A-MS and XVT02818B-MS.
	2009/09	RN 08-029	FSAR Section 5.4.2	Updates Chapter 5 to reflect the installation of Canopy Seal Clamp Assemblies at the lower canopy seal weld on some CRDMs. These clamps prevent and/or arrest any non-pressure boundary RCS leakage.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2009/09	RN 08-030	FSAR Section 9.1.4.2.2.8 and 9.1.4.2.2.11, Appendix 3A, Table 5.2-8, and Figure 9.1-12	Amends the FSAR to describe the replacement of the reactor vessel stud tensioners with Closure Studs, Inserts and Adaptors, HydraNuts, and Washers (ECR 70905A).
	2009/09	RN 09-004	FSAR Section 9.2.7.1	Deleted the non-safety related flow performance capability from the design function list for the Reactor Makeup System to the Chemical and Volume Control System (ECR 71130).
	2009/09	RN 09-005	FSAR Figure 9.4-32	ECR 50327 revised drawing 302-852 to reflect the revised setpoints for XVR07510A, B, C, & D
	2009/09	RN 09-006	FSAR Figures 5.2-8A, 9.2-5, 9.2-6, and 10.4-16	ECR 50239 converts the 302 series drawings from a Raster file to Vector file system. No design information shown on the drawings has been affected.
	2009/09	RN 09-008	FSAR 18.3.1.1, 18.3.1.2, and 18.3.1.3	CR-08-03647 identified the need to update the FSAR to reflect the information from the most recently removed reactor vessel surveillance capsule.
	2009/09	RN 09-009	FSAR Figures 1.2-15 and 1.2-17, FPER Figures E-023-018 and E-023-020	ECR 50481 modified the Control Building elevation 412 dress-out and RCA access control rooms to provide adequate facilities to address the radiological and facility inadequacies of the previous design layout.
	2009/09	RN 09-010	FSAR Figure 9.2-5	ECR 71263 revised drawing 302-612 to change valve ID 9606-cc to XVG09606-CC

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2009/09	RN 09-011	FSAR Figure 11.3-4, Sheet 3	ECR 71261 revised drawing 302-742 to correct typographical error of pressure transmitter IDs. PT1065A is changed to PT1065 and PT1065A is changed to PT1065B.
	2009/09	RN 09-016	FSAR Figure 9.2-7	ECR 71297 revised System Data table Item 3 to reflect actual system conditions and specifies the maximum and minimum flow rates.
	2009/09	RN 09-017	FSAR Table 15.4-34 and Figure 15.4-96B	CR-09-01895 / Westinghouse NSAL-09-02 noted a non-conservative assumption in initial pressurizer level required a re-analysis of the Locked Rotor overpressurization accident. As a result, the new peak pressure has been added to Table 15.4-34 and Figure 15.4-96B.
	2009/09	RN 09-019	FSAR 13.1.2.2.1	SAP-131 Revision 6, Change D: SAP-131 was updated to reflect the Fire Protection Group realignment as recommended by the GMES to QA / GMNPO. This RN updates the FSAR to reflect this change.
	2009/09	RN 09-020	FSAR Section 2.5.4.10.3.2	This RN revised the FSAR to specifically identify that the ground settling inspection is performed in the area of the DG Fuel Oil Storage Tanks. (CR-09-01266)

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2009/09	RN 09-021	FSAR Sections 15.2.2.1, 15.2.2.2, and 15.2.16	This RN updates Chapter 15.2 to include the results of the plant specific Rod Withdrawal at Power event analysis. CR-09-00701 / Westinghouse NSAL-09-01 identified an overpressure concern for the Rod Withdrawal at Power event. Plant specific analysis demonstrated that the RCS overpressure limit would not be exceeded provided the reactivity insertion rate is . 60 pcm/second
	2008/12	RN 04-005	FSAR 5.5.7.2.1, 9.3.4.2.5, 9.3.4.2.5.29	ECR 70465 updates design documents and the FSAR to add reference to the zero-leakage design requirement for ECCS recirculation system components.
	2008/12	RN 05-011	FSAR 12A.3.2.1, 12A.4.1, 12A.4.3, 12A.4.7, 12A.4.10, 12A.4.11, 12A.4.13-2, Tables 12.3-2, 12A.4-1 & 12A.4-2	ECR 50328 revised the sump volume documented in calculation DC01380-002, Revision 3, which ultimately changes the post-LOCA sump source terms used in FSAR Chapter 12, Appendix 12A that addresses NUREG-0578 shielding/access review.
	2008/12	RN 005-042	Figure 9.3-3	ECR 50479 upgraded the RB Instrument Air moisture removal system by installing an additional drain valve, moisture traps and a dew point monitor to the system
	2008/12	RN 06-011	FSAR 2.3.3.2 and Figure 8.3-4b	ECR 50518, 'Integrated Plant Computer System (IPCS) Replacement", replaced the existing IPCS with a Windows PC based system. Section 2.3.3.2 and Figure 8.3-4b are revised to reflect these changes.
	2008/12	RN 06-017	FSAR 12.3.3.1 and Table 12.1-1	Deleted reference to quarterly dose and TLD processes to allow processing on a less frequent basis

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2008/12	RN 06-022	FSAR 15.2.9.4 and 15.4, and associated Tables	The reference density, used to convert primary to secondary leakage from volumetric to mass flow rates within the FSAR Chapter 15 dose calculations, is revised to 62.4 lb/ft3 (ECR 70843). The dose calculations for the LOOP, Locked Rotor, and Rod Ejections are also updated to use thyroid dose conversion factors based on ICRP-30. FSAR Chapter 15 is being updated to include the new offsite doses for affected accidents.
	2008/12	RN 07-005	FSAR 17.2.1.2.1.9, 17.2.1.2.4.6, & 17.2.15.2	Revised Chapter 17.2 to remove QC as the group responsible for administrative control and close-out inspection of the nonconformance (NC) program. The VCS Corrective Action Program delineates the requirements and controls of the NC program.
	2008/12	RN 07-012	FSAR 5.5.3.2, 5.5.12.1 and Figure 5.1-1 Sht 2	Westinghouse NSAL-00-006 recommended an upgrade of the Pressurizer Upper level Instrument Lines and Root Valves from ASME Class 2 to Class 1, since the failure of these lines could cause automatic operation of the ECCS systems. ECR 70100 upgrades 22 Pressurizer Upper Level Root Valves and associated piping/tubing from ASME Class 2 to Class 1. This RN revised those portions of the FSAR which stated that these Instrument Lines and Root Valves are Safety Class 2A.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2008/12	RN 07-013	FSAR Figures 9.2-8, 9.2-9A, & 9.2-0c	ECR 50509 upgraded the VCS Water Treatment Plant drinking water instrumentation to provide for continuous on-line turbidity monitoring and recording, and monitoring and recording peak hourly distribution flow rates to meet current SCDHEC requirements under the Long Term 1 Enhanced Surface Water Treatment Rule.
	2008/12	RN 07-014	FSAR 17.2.1.1, 17.2.1.2, 17.2.2.2, 17.2.2.3, 17.2.3.1, 17.2.10.3, 17.2.18.1	Organizational changes to align reporting groups to General Managers of Nuclear Support Services and Organizational Effectiveness. Quality Systems and Security now report to the GMOE not the GMNSS
	2008/12	RN 07-017	FSAR Figure 10.4-12	ECR 50678 installed pressure transducers in the Feedwater System piping at the inlet to each Steam Generator to provide additional monitoring instrumentation.
	2008/12	RN 07-019	FSAR Figure 9.2-9B	ECR 71007 revises drawing 302-164 to show the correct valve number as XVD05579A-DW.
	2008/12	RN 07-022	FSAR 6.2.4.2.2	Revise FSAR section 6.2.4.2.2 &Table 6.2-53 to state that the RB pressure transmitters have a fluid filled transmission system (as opposed to water filled). [CER 07-01796}
	2008/12	RN 07-023	FSAR 13.1.2.2.2 and 13.1.2.2.4	Revise FSAR Sections 13.1.2.2.2 and 13.1.2.2.4, and Figure 13.1-4 which delineate personnel functions, responsibilities, and authorities for the GMNSS and GMOE, to reflect the current operating organization configuration.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2008/12	RN 07-026	FSAR Figures 8.3-2a, -2b, -2c, -2e, and -2f	ECR 70674 - Champs IDs were assigned to all electrical manholes. .FSAR Figures 8.3-2a, 8.3-2b, 8.3-2c, 8.3-2e, and 8.3-2f were revised to show the new IDs.
	2008/12	RN 07-027	FSAR Figures 9.3-5 and 9.4-32	CR-06-00305 identified the discovery of a funnel location that was erroneous on drawing 305-851 Sheet 4. The funnel was shown on the drawing as being located just above the floor elevation at 436'-0" within the Reactor Building. The piping is in fact directly connected to the drain line and the funnel does not exist. Walkdowns were completed that confirmed the correct as-built configuration. Drawings changed per ECR 70975.
	2008/12	RN 07-029	FSAR Figure 9.2-9c	ECR 50509 revised XVA04151-DO "STERILE WATER TANK DRAIN SYS OUTLET VLV", name description for clarity and update drawing E-302167 to reflect the valve position as normally open. (CR-07-02052)
	2008/12	RN 07-021	FSAR Figure 5.2-8	ECR 50650 added a back pressure regulator to the ECCS test header to bypass XVT00037-SI and keep the ECCS header pressure . 400 PSIG.
	2008/12	RN 07-032	FSAR 3.5.1.4, 3.5.3, and Table 3.5-6	ECR 71042 revises FSAR Sections 3.5.1.4 and 3.5.3 and Table 3.5-6 to update the list of safety related components that need to be considered for inclusion in the probability analysis for missiles generated by natural phenomena (tornados).

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2008/12	RN 07-033	FSAR Figure 9.2-4	ECR 50239 revises the 302 series drawing format from a Raster file to a Vector file system. Changing from a Raster file to a Vector File system will allow the long range plan to make the flow drawing available to be viewed on individual computers for design purposes.
	2008/12	RN 07-036	FSAR Figures 1.2-1 and 2.4-6	ECR 50508A removed the existing Turnover structure, located just east of the Turbine Building and installed a non combustible structure onto the existing foundation with electricity and communications. FSAR drawings 036-001 and 744-052 were revised to show the new Security Turnover Station.
	2008/12	RN 08-002	FSAR Figure 9.3-3	ECR 71116 added a Reference Note 6 to link the air compressor skid on 302-273 with the details of the skid on vendor drawing 1MS-20-220 Sheet 2.
	2008/12	RN 08-006	FSAR Figure 10.4-10	ECR 50239 revises the 302 series drawing format from a Raster file to a Vector file system. Changing from a Raster file to a Vector File system will allow the long range plan to make the flow drawing available to be viewed on individual computers for design purposes.
	2008/12	RN 08-007	FSAR Figure 9.5-1 Sheet .5	ECR 71097 revised drawing 302-231 Sheet 5 to show the correct reference for the Main Transformer Deluge System as 1MS-55-143-1. None of the design information shown on the drawing was affected.
	2008/12	RN 08-009	FSAR 6.5.1.6.1	ECR 71092 HEPA Filters are manufactured without separators, use high temperature silicon adhesive, and silicon rubber closed cell sponge

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2008/12	RN 08-010	FSAR Figure 6.2-46	ECR 50239 revises the 302 series drawing format from a Raster file to a Vector file system. Changing from a Raster file to a Vector File system will allow the long range plan to make the flow drawing available to be viewed on individual computers for design purposes.
	2007/5	RN 06-019	FSAR Sections 6.3.2.2, 6.3.3.1, 15.3.1.2 Figures 6.3-1 Sh 1, 15.3-17, 15.3-18a thru 15.3-18f, & 15.3-19a thru 15.2-19c	Updates the FSAR to reflect the changes from replacing the twelve (12) High Head Safety Injection throttle valves and their associated branch line orifices during RF16 to support the RB Sump modification. (ECR 50579)
	2007/5	RN 06-038	FSAR Sections 15.3.1 with Tables, and 15.3.8 Figs 15.3-1a thru 15.3-2 & 15.3-4 thru 15.2-21	ECR 70304 updates the FSAR to reflect the new "analysis of record" for Small Break LOCA. The analysis was provided by Westinghouse using the latest version of the NOTRUMP Evaluation Model and to address NRC questions regarding the adequacy of standard Westinghouse SBLOCA break spectrum (i.e., 1, 2, 3, integer breaks) and the need to consider pre-transient oxidation when demonstrating conformance to 10CFR50.46 acceptance criteria for local oxidation (i.e., 17%).
	2007/5	RN 06-042	FSAR Section 8.2, Table 8.2-2 and Appendix 8D	ECR 70754 documented the effects of the 2005 V. C. Summer Transient Stability Study. Calculation DC08200-001 required a revision to incorporate new values for the allowable range of offsite system voltages.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2007/5	RN 07-001	FSAR Sections 8.1, 8.2.1.1, 8.2.1.2, 8.3.1.1.1 Figures 8.2-4 & 8.3-0c	Incorporation of the details of ECR 50555, Alternate AC Modification, and its impact on the 1DX bus with capability to extend DG AOT to 14 days.
	2007/5	RN 07-010	FSAR Figure 11.3-6	ECR 70644 replaced the pressure gauges for the waste gas compressor moisture separators. The original pressure gauges (0 to 100 PSIG) were indicating in the upper end of their range, and have been replaced with 0 to 160 PSIG gauges to prevent over-ranging and comply with vendor recommendations.
	2006/12	RN 01-119	FSAR 12.1.5 & 12.2, Figure 12.2-2, and Tables 12.2-2 & 12.2-4	ECR 70048 updated various sections within Chapter 12 to correct several identified discrepancies related to the radiation monitoring information presented in the FSAR based on calculation DC00030-050
	2006/12	RN 03-011	FSAR 11.4.2 & 12.2.4.2 and Table 11.4-1	ECR 70064 revised plant drawings and documents to correct radiation monitor sensitivities. These descrepancies were identified in FSAR Assessment 7483.
	2006/12	RN 04-013	FSAR Figures 9.3-16 Sht 2 & 9.3-16 Sht 4	ECR 50506D restored the CVCS and BTRS systems to their original configuration. P&ID D-302-674 and P&ID D-302-676 are revised to reflect the valve positions with normal flow through the Cation Bed.
	2006/12	RN 04-016	FSAR Figure 9.1-3	ECR 50494 installs a new ball valve to provide isolation between the RMUWST and the SFP. XVT06726 remains in service to act as a throttle valve. P&ID D-302-651 is revised to reflect the changes.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2006/12	RN 04-017	FSAR Figure 9.2-1	ECR 50456 replaced copper tubing and unions with flanged fitting and dielectric unions on the Service Water pump lube oil coolers. P&ID D-302-221 is revised to reflect the changes.
	2006/12	RN 04-021	FSAR Figures 1.2-1, 1.2-28, 2.4-6. 9.5-1 Sht 2 & 9.5-1 Sht 2 FPER Figure E--023-001.	FSAR and FPER figures are updated to reflect the addition of the new Nuclear Learning Center (NLC) and tie-in to the Fire Service Yard Loop for supply to the NLC sprinkles. ECR 50474 P&IDs E-036-001, D-302-001, E-744-052, D-302-231 Sht 2, D-302-231 Sht 6, E-023-001
	2006/12	RN 04-029	FSAR Figure 9.4-3	ECR 50437 upgraded the Health Physics Lab to include a briefing room and remote monitoring equipment room. Existing electrical and HVAC equipment was relocated and additional power circuits were installed. P&ID D-912-114 is revised to reflect these changes.
	2006/12	RN 05-007	FSAR Figure 10.2-1	ECR 70670 revised P&ID D-302-011 to correctly identify Turbine Driven EF Pump steam ring drain valves as XVT02804A and XVT02804B.
	2006/12	RN 05-017	FSAR 5.4.3.6 Figure 1.2-1	ECR 50571 installed Ex-Vessel Neutron Dosimetry to be used to measure damage associated with the fast neutron exposure (neutron fluence) of the Reactor Vessel
	2006/12	RN 05-023	FSAR Figure 9.2-9b	ECR 50550 added a suction strainer to the waste neutralization pumps to prevent clogging. P&ID D-302-164 is revised to reflect the changes.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2006/12	RN 05-025	FSAR 9.2, 9.3, & 12A and Tables 5.2-10, 12A.4-2 & 12A.4-4	RN 05-025 updates the FSAR to reflect changes approved by Tech Spec Amendment 152, and corrects grammatical and editorial errors.
	2006/12	RN 05-026	FSAR Figure 10.4-5	ECR 70383 revised P&ID D-302-201 to correctly identify stainless steel components previously shown as carbon steel.
	2006/12	RN 05-029	FSAR Figure 6.3-1	ECR 70514 revised P&ID E-302-693 to show the RHR Heat Exchangers using phantom lines to reflect the actual field configuration.
	2006/12	RN 05-031	FSAR Figure 10.4-8	ECR 50488 changed the design and operational levels of condenser hotwell levels to optimize system thermal performance.
	2006/12	RN 05-032	FSAR Figure 9.2-9	ECR 50586 removed the Caustic Pump Discharge Flow Transmitter IFT06249 and Flow Controlled IFC06249 which were bypassed and no longer used in the flow control loop.
	2006/12	RN 05-040	FSAR Figure 10.4-7A	ECR 50239 changed P&ID D-302-165 from Raster to Vector file format. No technical information has been changed.
	2006/12	RN 06-002	FSAR Figure 10.4-12	ECR 70832 revised P&ID D-302-083 to correct design table Normal and Upset temperature that was changed as a result of MRF 90102
	2006/12	RN 06-003	FSAR Figure 9.4-6	ECR 70777 revised P&ID D-912-115 to correctly identify IPI09637B.

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	2006/12	RN 06-005	FSAR Figure 9.3-1	MRF 22412 (ECR 700601) updates this figure to correctly reflect the additions to the Radiological Maintenance Building.
	2006/12	RN 06-006	FSAR 10.4.7.2 and Figures 10.4-8, 10.4-10, & 10.4-12	ECR 50206 redesigned Feedwater components and flow path to minimize water hammer events during plant startup.
	2006/12	RN 06-007	FSAR Figure 9.3-2	ECR 50601 relocated XVC02698-IA to facilitate installation of a pressure sensing line.
	2006/12	RN 06-010	FSAR Table 3.2-1	ECR 50056 replaced all three "B" Train Diesel Generator heat Exchangers with ASME Section VIII Heat Exchangers.
	2006/12	RN 06-012	FSAR Figure 9.4-25	ECR 70848 revised P&ID D-302-851 to change XVG14236B-CI to XVG14236A-CI on Industrial Chiller "1A".
	2006/12	RN 06-018	FSAR Figure 9.3-4	ECR 70826 revised P&ID D-302-771 to uniquely identify each stage of XPP0162A and XPP0162B as XPP0612A-PP1 & -PP2, XPP0612B-PP1 & -PP2.
	2006/12	RN 06-025	FSAR Figure 10.4-13	ECR 70878 revised P&ID D-302-781 to move the pressure and temperature design flag and the pipe line spec 151X/902X from valve XVT00058-BD to the reducer downstream of relief valve XVR00509-BD.
	2006/12	RN 06-028	FSAR Figure 9.3-2	ECR 70829 added equipment identification number XAC0014 to the equipment database and P&ID D-302-271.

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	2006/12	RN 06-029	FSAR 6.3.2.6, Tables 6.3-3 & 6.3-10	ECR 50316 installed an auto closure of the RWST isolation valves when the sump isolation valves are fully open to the RHR and RB Spray pumps.
	2006/12	RN 06-031	FSAR 15.4.1.4.4	ECR 70892 revised LOCA calculation DC00040-035 to incorporate the limiting ventilation scenario where both trains of the Control Room emergency ventilation start, there is an assumed damper failure, and the operator shuts off the affected train within 30 minutes IAW the EOPs
	2006/12	RN 06-034	FSAR Figure 5.1-1 Sht 2	ECR 70902 revised P&ID D-302-602 to correct the symbol for valves XVD08030-RC and XVD08031-RC.
	2006/12	RN 06-035	FSAR App 3A & 17.2.18.1	These sections are updated to reflect the frequency time intervals and limits for audits preformed by the Quality Assurance group.
	2006/12	RN 06-037	FSAR 2.3.3.2, Tables 2.3-85 & 2.3-85F	ECR 50521 installed the new meteorological tower and replaced the EA system instruments with and updated digital system that provides digital data to the plant for processing and display.
	2006/12	RN 04-029	FSAR Figure 9.4-3	ECR 50437 upgraded the Health Physics briefing and monitoring area by relocating equipment and upgrading HVAC supply to reduce area ambient temperature increases during routine briefing sessions.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2006/12	RN 05-019	FPER 4.71.4, 4.7.5.4 and 4.4.16	ECR 50205C re-routed safe shutdown cabling of 3-TW and 51-TW Kaowool items in Fire Areas IB-16, SWPH-1, and SWPH-5 to assure separation in accordance with 10CFR50 Appendix R, Section III.G.2.
	2006/12	RN 05-040	FSAR Figure 10.4-7A	ECR 50239 converted flow drawing 302-165 from a Raster to a Vector file system. No technical changes were made.
	2006/12	RN 06-025	FSAR Figure 10.4-13	ECR 70878 Changed the location of the pressure and temperature design flag (3/4) boundary and the pipe line spec 151X/920X boundary from valve XVT00508-BD to a reducer downstream of relief valve XVR00509-BD. This corrects the figure to reflect the actual system design and design upset pressure boundaries.
	2006/12	RN 06-031	FSAR 15.4.1.4.4	ECR 70892 revised the LOCA calculation DC00040-035 to allow for higher recirculation leakage and incorporate the more limiting ventilation scenario where both trains of Control Room Emergency ventilation start. This RN updates the radiological consequences presented in the UFSAR.
	2005/10	RN 02-037	17.2	Chapter 17 changes to remove the static QA in-line procedure review requirements and to remove the requirements for QA to issue releases to work to vendors/contractors performing special process activities on site.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2005/10	RN 03-032	Table 12.1-19	Correct typing error in RM-G8 Sensitivity range.
	2005/10	RN 03-036	Figure 10.4-11	Revise Figure 10.4-11 to change socket weld valves to flanged valves. ECR 70367
	2005/10	RN 03-040	Figures 9.3-16 Sht 3, 9.3-16 Sht 5, 9.5-1 Sht 3	ECR 50290: Revise figure to add spectacle flange upstream of XVG06772-FS to eliminate the potential of over pressurizing penetration XRP0404. ECR 50491: Revise figure to add vent valves in the CS system downstream of XVD08331-CS and the RH system downstream of XVG08706A-RH to eliminate air entrapment/void in the piping.
	2005/10	RN 03-047	5.5.7.2.1.1	ECR-50099: Added a high-point vent to RHR Heat Exchanger A Discharge Header upstream of XVC08716A-RH ('B' Train work scheduled for RF-15). ECR-50260 relocated the control of FCV00602A/B to the output of the RHR Heat Exchanger A/B Discharge Header. Update RHR system diagram & RHR pump miniflow control description accordingly.
	2005/10	RN 03-054	Figures 5.1-1 Sht 1, 6.3-1 Sht 1, 3, 9.3-14, 9.3-16 Sht 1A, 1B, 1C	ECR 50239: 302 drawings (P&IDs) conversion from a Raster file to a Vector file system only. No technical changes are being made.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2005/10	RN 03-055	Figures 11.3-4 Sht 2, 11.3-4 Sht 3	ECR 70467, CER 0-C-03-0148: Revise figures to correctly show the ANS safety class information relative to WG components that provide CCW pressure boundary.
	2005/10	RN 04-001	9.5.4.4	Add specific exemptions to ASTM standards used to test Diesel Generator fuel oil, as required to comply with Tech Spec Amendment 164.
	2005/10	RN 04-004	Figures 9.3-2, 9.3-3, 9.3-3A	This change incorporates drawings 302-271 R33, 302-273 R14, and 302-274 R13 as a result of ECR-70483. These are drawing enhancements to clearly show components that are classified as Quality Related.
	2005/10	RN 04-012	5.2.2.4, 5.5.12.4, 5.7.1.3, 6.2.2.4.1, 6.3.4.4, 9.2.7.4, 10.4.4.4	Revise FSAR to conform with Tech Spec Amendment 166. This Amendment was a result of the recent changes to 10CFR50.55a which now references the performance of inservice testing per ASME OM code and inservice inspection activities per ASME B&PV codes.
	2005/10	RN 04-014	Figure 5.2-8A	ECR 50492: Revise figure to show allowed use of 16 PAK Nitrogen kits or an individual nitrogen bottle.
	2005/10	RN 04-018	10.3	Add the flow path "Main Steam to Turbine Stop Valve" to Table 10.3-2. Add an asterisk to 93,272 lb/hr of steam dump drains (Bypass) and remove the asterisk for the 144,300 lb/hr of the MS to FW Pump flow in Table 10.3-2. This flow is not an uncontrolled blowdown.

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	2005/10	RN 04-019	Chapter 18 3.9.3.1.1, 5.2.1.10.3, 6.2.4.5, 6.2.5.1.1	Create and issue new FSAR Chapter 18 "Aging Management programs and Activities". License Renewal requirement. Change wording in existing sections to correspond with new Chapter 18.
	2005/10	RN 04-020	6.2, 9.4, and 11.2	302 drawings conversion from a Raster file to a Vector file system only. No technical being made.
	2005/10	RN 04-022	3.2, 3.3, 4.2, 4.3, 4.4	Appendix R Analyses - Time critical actions. ECR 50371, CER 0-C-02-2707
	2005/10	RN 04-023	12.2.4.2, 12.2.4.2.10	Revise section 9.1.4.2.2.3 of the FSAR for clarity to describe how the New Fuel Elevator is used with irradiated fuel.
	2005/10	RN 04-024	9.1.4.2.2.3	Revise section 9.1.4.2.2.3 of the FSAR for clarity to describe how the New Fuel Elevator is used with irradiated fuel.
	2005/10	RN 04-025	17.2.2.3.2	Revision to FSAR to reclassify certain piping within the Blowdown System as Quality Related Note Piping per TRP-13. RE: RG 87-11 guidance, ECR 70481.
	2005/10	RN 04-026	10.4.8.3 10.4.8.1.6	Revision to FSAR to reclassify certain piping within the Blowdown System as Quality Related Note Piping per TRP-13. RE: RG 87-11 guidance, ECR 70481.
	2005/10	RN 04-027	FPER 4.4.25, Fig E-023-007	Change FPER to indicate the presence smoke only detector(s) in IB-25.1 (4.4-79) should read "Fire detection for this zone consists of a smoke detector system, which . . . " ECR 70273

Revision Summary (continued)

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	2005/10	RN 04-030	10.4	Change IPY03211 designator as an I/P converter to a mixing amp on FSAR figure 10.4-10.
	2005/10	RN 04-031	5.5.3.3.4, 5.5.3.4	Changes associated with the "A" Reactor Vessel Hot Leg Nozzle Repair and Implementation of the Mechanical Stress Improvement Process (MSIP) on the "B" and "C" Reactor Vessel Hot Leg Nozzle Welds.
	2005/10	RN 04-034	17.2	The Nonconformance Conformance Notice (NCN) Program has been integrated into the VCSNS electronic Corrective Action Program. Revised program description to reflect this change.
	2005/10	RN 04-036	17.2.2.3	Add a statement to the Administrative Controls section to state that administrative procedures envelope how an independent safety review is performed IAW NUREG-0373, Item 1.B.1.2.
	2005/10	RN 04-037	11.2	Correct the duplicate Equipment ID of LI4843 on FSAR figure 10.4-15 and Table 11.2-5 by changing LI4843, located on XPN-5436-WD, Solid Waste Disposal Panel, to LI4843A.
	2005/10	RN 04-038	Fig. 9.5-1	Drawing 302-231 sheet 1 references the location of pressure switches XPS04911 and XPS04909 as being in XPN7305B and XPN7305A respectively. The correct equipment numbers should be XPN7075A and XPN7075B.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2005/10	RN 04-040	Fig. 9.3-2	The station instrument air suction and bypass/unload valves are obsolete and require upgrade with replacement valves. Revise FSAR Figure to reflect that the bypass valve has been replaced with an improved ball valve.
	2005/10	RN 04-42	5.2 and 5.4	Pertinent reactor vessel structural integrity parameters are to be revised due to the results of the testing and analysis of surveillance capsule Z recently removed from the reactor vessel. These changes are implemented by ECR-70582.
	2005/10	RN 04-043	Fig. 9.5-11	Valves XVP20981A-DG and XVP20981B-DG require identification on FSAR Figure 9.5-11 (drawing D-302-353).
	2005/10	RN 04-044	Appendix 3A, 13.6 and 17.2	Change the requirements for electronic records storage to comply with the technical aspects of the NIRMA Technical Guidelines. Removes the specific requirement for electronic records to be stored on redundant servers located in remote, separate locations.
	2005/10	RN 04-045	Fig. 9.3-15	Revise FSAR Figure 9.3-15, drawing D-302-361, to add equipment number designation XPP-0203A and XPP-0203B to the sanitary lift pumps.
	2005/10	RN 05-003	Appendix 3A, and 17.2.18.3	Change time constraints and number of audits a prospective Lead Auditor must participate in. Provide clarification to Appendix 3A RG 1.146 position.

Revision Summary (continued)

Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2005/10	RN 05-005	17.2.18.1	Change frequency of external audit, of activities under the control of MQS, by an independent agency from annual to not exceeding 24 months.
	2005/10	RN 05-006	FSAR Fig 1.2-15, FPER Fig E-023-018	The entrance door to the I&C shop needs to be relocated to support the remodeling that is being performed. The double door currently used for entrance will be removed and a sheetrock wall will be installed. A single door will be installed adjacent to the existing entrance door. ECR 50540
	2005/10	RN 05-008	10.4 Tbl 10.4-7	Revise to reflect the correct Nuclear Blowdown Demineralizer Inlet Filter particulate size retention, per BOM RGh-01.
	2005/10	RN 05-010	9.1.3.3	FSAR Section 9.1.3.3 of the FSAR is revised to describe how the design basis scenarios for spent fuel cooling are translated into operating procedures with respect to availability of redundant heat removal paths during full core offloads. This includes discussion on maintenance of multiple reliable sources of electrical power. Reference Tech Spec Amendment 160.
	2005/10	RN 05-013	Fig. 9.2-8	Change the name description of XTK-67-WT from 'Reactivator' to 'Clarifier' on FSAR Figure 9.2-8.

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2005/10	RN 05-014	FPER Tbl 3.2-6	Revise Table 3.2-6 to identify XSW1DA1-ES, U4C as the equipment tag number for the tie-breaker to XW1B1. ECR 70649, CER 04-2013
	2005/10	RN 05-016	5.2.2.5.3	Revise Section 5.2.2.5.3 to allow HCV-142 to be throttled which achieves better RCS pressure control when RCS pumps are started. ECR 70715, CER 0-C-05-0590
	2005/10	RN 05-018	Fig. 10.4-1	ECR-50470 moved suction tap for RMA009 to the condenser side of XVB00104B-AR (Main Condenser Vac Pump B Isolation Valve) to allow RMA009 to stay in service when the Vac Pump is isolated.
	2005/10	RN 05-020	Fig. 9.2-4	Revise FSAR Figure 6.3-1 Sheet 2, drawing D-302-692 Rev. 12, to eliminate the flange and tailpipe at the discharge of XVR08857-SI.
	2005/10	RN 05-021	Fig 6.3-1 Sh 2	Revise FSAR Figure 6.3-1 Sheet 2, drawing D-302-692 Rev. 12, to eliminate the flange and tailpipe at the discharge of XVR08857-SI.
	2005/10	RN 05-022	5.4.3.6	Revision to reactor vessel surveillance capsule removal schedule contained in FSAR section 5.4.3.6.
	2005/10	RN 05-027	17.2.16.2	Revise FSAR 17.2 to clarify the QA department requirements for follow-up to issues identified during audits and surveillances. Self Assessment SA04-QS-02

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Revision	Revision Release Date	Change Activity	Document Elements Affected (Sections, Tables, Figures)	Summary Description of Changes Effective Revision 22.02, changes are made under the provisions of 10 CFR 50.59 except where indicated in brackets.
	2005/10	RN 05-041	6.2, 9.4, and 11.2	ECR 50239: 302 drawings (P&IDs) conversion from a Raster file to a Vector file system only. No technical changes are being made.

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V.C. Summer Nuclear Station
Safety Analysis Report

Introduction And General Description of Plant

Chapter 1

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 1 - INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

NOTE: With the exception of the description of 10CFR50.2 design basis parameters, numerical values throughout this FSAR should be considered nominal in nature. They are intended to provide a sense for the value of the parameter and should NOT be viewed as an actual value observable in the plant. Plant operation at values other than those presented herein is acceptable. The actual values are documented within established Technical Specification, Design Basis Documentation, or other controlled documents.

1.0 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

NOTE: Section 1.1 is being retained for historical purposes only.

1.1 INTRODUCTION

This Final Safety Analysis Report is submitted in support of an application by South Carolina Electric and Gas Company (SCE&G) for a class 103 license to operate a nuclear power station designated as the Virgil C. Summer Nuclear Station. This report presents descriptions and analyses of the final station design.

1.1.1 Station Location

The plant site is located north (2.5 miles) of Parr, South Carolina. Parr is the site of existing fossil and hydro power stations operated by SCE&G and the decommissioned, experimental Carolinas Virginia Tube Reactor (CVTR). The nuclear plant site is adjacent to a manmade reservoir created by placing a series of dams across Frees Creek, a tributary of the Broad River in western Fairfield County, South Carolina. The resulting Monticello Reservoir provides water requirements for the nuclear station and a pumped storage facility. The reservoir is located east of the Broad River and west of South Carolina State Highway 215, about 26 miles north of Columbia, South Carolina. The pumped storage facility raises and lowers the reservoir level approximately 4.5 feet when in operation.

1.1.2 Nuclear Steam Supply System

The station includes a pressurized water reactor nuclear steam supply system (NSSS), designed and furnished by Westinghouse Electric Corporation and a turbine generator, designed and furnished by General Electric Company. This equipment is similar in design to several projects licensed or currently under review by the Nuclear Regulatory Commission (see Section 1.3). The balance of the station is designed and constructed by SCE&G, with the assistance of its agent, Gilbert Associates, Inc.

1.1.3 Containment

Containment is provided by the Reactor Building, a reinforced concrete structure designed by Gilbert Associates, Inc. The Reactor Building is comprised of a flat foundation mat, cylindrical wall and shallow dome roof. The foundation mat and cylindrical wall are reinforced with conventional mild steel reinforcing. The cylindrical wall is prestressed in the vertical and horizontal directions by a post-tensioning system. The shallow dome roof is prestressed by a three-way post-tensioning system. The inside surface of the Reactor Building is lined with a carbon steel liner to ensure a high degree of leak tightness under operating and accident conditions.

1.1.4 Core Thermal Power Levels

The NSSS is designed for a rated power output of 2912 MWt, which is the license application rating, with an equivalent station net electrical output of approximately 950 MWe. Containment and engineered safety features are designed and evaluated for operation based upon an Engineered Safety Design Rating (ESDR) and Licensed Power Level of 2900 MWt in the core. Postulated accidents having offsite dose consequences are evaluated at 2900 MWt. Analyses of all accident consequences, to show conformance to 10CFR50.46, have been performed at 2900 MWt. Conformance to 10CFR50.46 for Large Break LOCA is evaluated at 2900 MWt, the rated core power level following Refueling 9 in the Spring of 1996.

1.1.5 Schedule

The project schedule is based upon plant completion (to fuel loading) in February, 1982 and commencement of commercial operation approximately six months after issuance of the operating license.

NOTE: Section 1.2 is being retained for historical purposes only.

1.2 GENERAL PLANT DESCRIPTION

1.2.1 Site

1.2.1.1 Location

The Virgil C. Summer Nuclear Station site is located in Fairfield County, South Carolina, approximately 15 airline miles west of Winnsboro, the county seat. Newberry, the county seat of Newberry County, is about 17 airline miles away in a westerly direction. Therefore, the site is situated approximately midway between 2 county seats. All other communities within 15 miles of the site are small villages. Columbia, the state capital, is located about 26 miles to the southeast, as shown by the Regional Location Map, Figure 2.1-1. The Site Location Map, Figure 2.1-2 shows the site with respect to nearby roads, highways and villages in the vicinity.

1.2.1.2 Population and Land Use

The station site is located within a sparsely populated rural area in which forestry is the principal land use. In 1967, about 86% of the region within 50 miles of the site was forest or agricultural land. Columbia, the state capital, represents the major concentration of population and industry in the region. The sector south-southeastward from the site probably will continue to be the dominant urban and industrial center in the future. The migration of rural population to urban centers is believed to have maximized and should diminish with the establishment of industry, increased development of forestry and consolidation of small farms.

Within 10 miles of the site, approximately 20% of the land was being used for agriculture in 1967. This usage is decreasing and should diminish during the next decade, to be replaced largely by increases in forest land and, in some areas, by urbanization. In the next 40 years, land use within 10 miles of the site is expected to be predominantly forest land with lesser amounts devoted to urban and agricultural use. These figures are based upon factors and land use trends during the period 1958 to 1967, population growth forecasts and the expected influence of local circumstances, such as available public transportation facilities and utilities, existing soils and topography.

1.2.1.3 Meteorology

The monthly average temperature at the station site varies from about 45°F in winter to 80°F in summer. The annual precipitation averages about 45 inches. Monthly precipitation values vary from about 2-1/2 inches in November to about 5-1/2 inches in July.

The types of severe weather which may affect the site include tornadoes (with a return period of 1389 years), hurricanes (about 1 every 2 years passes within 250 miles of the site) and

thunderstorms (about 54 days per year). The fastest wind speed for a 100-year return period is 100 miles per hour, sustained for about a 30 to 40-second duration.

The prevailing wind direction is from the southwest and the average wind speed is 6.1 miles per hour. This prevailing wind direction is fairly typical for all seasons except in the fall and early winter, during which time northeast to northwest winds prevail.

The occurrence of stable conditions as measured at the plant site is about 51% annually. During these conditions, the average wind speed is 4.9 miles per hour. There is no evidence that unusual topographic influences on wind direction frequencies, such as a valley drainage wind, occur during stable conditions.

The diffusion characteristics at the site are adequate to support the sitting of the Virgil C. Summer Nuclear Station. Development of Monticello Reservoir and the Fairfield Pumped Storage Facility is likely to enhance the diffusion qualities.

1.2.1.4 Hydrology

The site is situated on an irregularly shaped ridge about 1 mile east of the Broad River, the principal stream in the site area. The Broad River watershed originates in North Carolina and traverses South Carolina. Monticello Reservoir occupies approximately 6800 acres just north of the site and was created by constructing dams across Frees Creek, a tributary of the Broad River.

The climate in the area is moderately humid, and rainfall averages about 45 inches per year. Available data indicates that runoff plus small groundwater contributions to streams is approximately 17 inches annually, and evapotranspiration is about 70% (31 inches) of precipitation. Evaporation from water bodies averages 42 inches annually.

Groundwater at the site occurs in fractured crystalline bedrock and overburden soils. Water tables in the area are generally subdued replicas of topography and are deeper at higher elevations. The quality of groundwater is usually acceptable for most purposes, but large yields are seldom attained. Wells in the surrounding area are concentrated in the Jenkinsville community, approximately 3 miles southeast of the site.

At the site, impoundment of Monticello Reservoir to elevation 425’ may cause the direction of groundwater flow to be reversed from the northeast toward the west and south. Seepage will ultimately enter tributaries of the Broad River. Local domestic wells or springs or municipal and industrial wells are not located down gradient from the site and will not be affected by operation of the plant.

1.2.1.5 Geology

The Virgil C. Summer Nuclear Station site lies within the Piedmont Physiographic Province. The surface of the Piedmont Province consists of elevated, gently rolling hills which are separated on the northwest from the intensely folded and faulted Appalachian Mountains by intervening hills of the Blue Ridge Province, and overlapped on the southeast by sediments of the Coastal Plain

Province. The Piedmont Province is essentially a dissected peneplain and is characterized by northeast-southwest trending belts of crystalline metamorphic and plutonic rocks. Piedmont rocks in general were found under many different combinations of geothermal and pressure conditions, and represent a complex succession of geologic events.

The Virgil C. Summer Nuclear Station site overlies complex zones of crystalline rocks, including migmatites in transitional areas between metamorphic rocks and injected igneous bodies. There are numerous joints in the rocks and small displacements have occurred along shears. Detailed geologic studies at the site and radiometric dating of rock samples from site excavations show latest movements along the shears occurred no later than 45 million years ago, and probably occurred 150 to 300 million years ago.

The Piedmont is generally covered by a deep mantle of residual soils derived by the inplace weathering of the underlying rock. The soil profile is typically characterized by an upper silty and clayey horizon overlying saprolite, which grades with depth to decomposed rock and unweathered rock. Soil strengths typically increase with depth. Transported soils are restricted to surficial veneers of alluvium near present day streams and isolated deposits of colluvium on lower slopes of some hills.

Detailed geologic information is provided in Section 2.5.

1.2.1.6 Seismology

Earthquake epicenters are scattered in the Piedmont and no causal faults have been identified.

The historic earthquake closest to the site occurred in 1945 about 5 miles west-southwest of the site. An epicentral intensity of Modified Mercalli (MM) VI has been assigned to this event due to the large area over which the effects were felt. The largest Piedmont earthquake within 200 miles of the site was the Union County shock of January 1913. Its epicenter was approximately 35 miles northwest of the site and its intensity is now regarded as VI-VII MM, recently downgraded from VII MM. The Safe Shutdown Earthquake (SSE) for the Virgil C. Summer Nuclear Station site is based upon this shock.

The largest earthquake in historic time within 250 miles of the site was the 1886 Charleston Earthquake, rated at an intensity of X MM. Its epicenter was about 125 miles southeast of the site in the Coastal Plain, within an area of recurring earthquake activity in the vicinity of Charleston, South Carolina.

Foundation conditions at the site are satisfactory from the standpoint of earthquake resistant design. Seismic Category I structures at the Virgil C. Summer Nuclear Station site are supported upon either rock or compact soils which are not adversely affected by earthquake motions.

Detailed seismic information, including reservoir induced seismicity, is included in Section 2.5.

1.2.1.7 Environmental Radiation Monitoring

Prior to operation of the Virgil C. Summer Nuclear Station, an environmental radiological surveillance will be initiated. Selected biota, air, water, soil and selected foods ingested by man and animals will be monitored. The survey will provide background data on the amount, type and source of radioactivity in the vicinity of the station. The data will be used for the following purposes:

1. Estimation of population exposure.
2. Verification of the adequacy of control of radioactivity sources.
3. Demonstration of the quality of the monitoring program with regard to its capability or providing useful data and the sensitivity and suitability of the detection equipment.
4. As a source of data for public information.

The surveillance program will continue subsequent to commencement of plant operation.

1.2.2 Principle Design Criteria

The criteria followed in the design of Virgil C. Summer Nuclear Station have been developed as performance criteria which define or describe safety objectives and procedures. They provide a guide to the type of design information included in this FSAR. These criteria are addressed in those FSAR sections to which they pertain. Criteria which are generally applicable to the design of Virgil C. Summer Nuclear Station are presented in Section 1.2.2.1 through Section 1.2.2.7.

Virgil C. Summer Nuclear Station is designed to comply with the intent of "General Design Criteria for Nuclear Power Plants," Appendix A to 10 CFR 50. The specific applications of the General Design Criteria to Virgil C. Summer Nuclear Station are discussed in Section 3.1. Appendix 3A addresses NRC Regulatory Guides.

Compliance with NRC Regulations 10 CFR Parts 20, 50 and 100 is documented in a letter to the NRC dated November 14, 1980.

1.2.2.1 Quality Standards

Safety-related features of the plant are essential for the prevention of accidents which could affect the public health and safety and the mitigation of the consequences of such accidents. These features are designed, fabricated and erected to quality standards that reflect the importance of the safety function to be performed.

The Quality Assurance Program, described in Chapter 17, provides a planned program to ensure that safety-related activities are performed and documented to the appropriate degree. The Quality Assurance Program applies to safety-related systems, components and structures. This program continues through initial design, procurement, fabrication, site construction, erection, construction modifications, preoperational and startup testing and operation. Records are kept and audited to ensure proper program functioning.

Safety-related features of the plant essential to accident prevention and mitigation are the fuel cladding, Reactor Coolant System and containment barriers; the controls and emergency cooling systems, whose functions are to maintain the integrity of these barriers; systems which depressurize and reduce the contamination level of the reactor building; emergency power supplies and essential services to the above features; and the components employed to safely convey and store radioactive wastes and spent reactor fuel. Quality standards for material selection, design, fabrication and inspection governing the above features conform to the applicable provisions of recognized codes and standards.

Reviews are performed by other affected design disciplines (Structural, Electrical, Instrumentation and Control) to ensure that interface requirements are satisfied and that the design requirements are consistent with overall plant design.

1.2.2.2 Performance Standards

Certain features of the plant are essential to the prevention of accidents which could affect the public health and safety and the mitigation of the consequences of such accidents. The plant is designed to withstand, without loss of the capability to protect the public, the additional loadings imposed by the most severe earthquakes, flooding conditions, winds, ice or other natural phenomena which could conservatively be estimated to occur in the vicinity of the site.

The Nuclear Steam Supply System (NSSS) and other safety-related systems, including their support structures, are designed to withstand seismic disturbances conservatively predicted for the site, including the dynamic response of the structures to ground acceleration, based upon characteristics of the site foundation and damping of the foundation and structures.

Materials for structures, equipment and piping in Seismic Category I buildings are selected for compatibility with expected normal and accident environments in addition to selection based upon design and operational suitability.

1.2.2.3 Fire Protection

Primary emphasis is directed at minimizing the risk of fire by use of thermal insulation and adhesives which do not support combustion, flame retardant wiring, adequate electrical overload and short circuit protection, separation and elimination of combustible trim and furnishings. The plant is equipped with Fire Protection Systems for controlling and limiting the effects of fires. See Section 9.5.1 for a description of the Fire Protection System. Structures, systems and components important to safety, the loss of which would affect other systems, components or structures, are located to minimize the effects of fires and explosions.

1.2.2.4 Missile Protection

The Virgil C. Summer Nuclear Station is designed so that missiles from external or internal sources do not prevent safe shutdown of the plant or adversely affect the health and safety of the public.

Section 3.5 presents a discussion of missile protection measures.

1.2.2.5 Safety Classification

Classification of structures, systems, and components, in accordance with their importance to safety, is discussed in Section 3.2.

1.2.2.6 Vital Component Separation

To avoid common mode failures of redundant vital components due to occurrences, such as fire or missile impact, such components are physically separated in accordance with the following criteria:

1. Major Mechanical Equipment

   The physical separation criteria are applied to a number of major mechanical systems, including but not limited to the following safety-related systems and components:

   a. Reactor Building Cooling Units.

   b. Emergency Diesel Generators.

   c. Emergency Feedwater System components.

   d. Service Water System components.

   e. Main steam lines and valves to the outermost Main Steam Isolation Valves.

   f. Component Cooling Water System components.

   g. Reactor Building Spray System components.

   h. Post Accident Hydrogen Removal System components.

2. Piping

   Redundant portions of safety-related piping are protected where necessary by concrete barrier walls or by separation as discussed in Section 3.5.

3. Instrument and Controls

Separation of redundant protection channels originates at the process sensors and continues through the wiring route and containment penetrations to the protection racks. Physical separation is used to the maximum practical extent to achieve separation of redundant transmitters. Separation of redundant wiring is achieved using adequately separated wireways, cable trays, conduit runs and containment penetrations for each redundant channel. Redundant equipment is separated by locating modules in different protection rack sets. Each redundant protection channel set is energized from a separate instrument bus.

The possibility of fires is reduced by using fire retardant materials, metal wireways and metal cabinets. Cables within trays are suitably derated. Loading is designed to minimize heat buildup. Trays are physically separated for fire protection. Safety-related cables are clearly identified to provide assurance that replacement, testing or maintenance activities are properly performed.

1.2.2.7 Common Mode Failure Consideration

Consideration is given to reduction of the potential for common mode failures in vital structures, systems and components during design.

Where possible, previously approved designs and designs which have been tested or proven in actual operations are utilized. These designs are updated where practical to include desirable modifications to improve system reliability.

Redundant components, piping, cabling and electrical equipment are protected through physical separation or by barriers. Pipe restraints are used to minimize pipe whip. Missile barriers are installed in areas where missiles from adjacent equipment may cause damage. Means are provided to ensure that temperatures suitable for equipment and personnel are maintained. Adequate instrumentation is provided to monitor system and component operation.

Designs are reviewed to ensure that assumptions, calculations and system layouts satisfy the requirements of the individual system and that the design does not adversely affect a redundant system or component (i.e., design of one system does not void the redundancy of another).

In addition to the normal reviews and tests, formal design reviews are conducted for safety-related designs by engineers not associated with the original design. Quality assurance personnel audit design review activities in accordance with the approved Quality Assurance Program.

Field installations are checked by Quality Control personnel to ensure conformity with installation drawings. Quality assurance personnel perform audit and surveillance functions in accordance with the approved Quality Assurance Program. Nonconformances in the installation of safety-related equipment are documented. The situation is reviewed and an appropriate disposition is made. If the field installation affects several design interfaces, the engineering

disciplines affected review the situation and make a combined decision. Plans (drawings) are updated to show any field modifications.

Modifications to safety-related equipment or systems are reviewed and calculations and/or tests are performed as necessary to ensure that the modification does not prevent the system or equipment from performing its design function. After installation, system checkout in accordance with approved written procedures ensures proper system and component operation.

Design of the NSSS entails the following specific considerations:

1. The primary objective of Westinghouse design and quality assurance activities is to design and procure or manufacture equipment which is safe and reliable. An essential portion of this objective is the combination of policies and procedures which lead to prevention of common mode failures.
2. The cognizant System Engineer has the basic responsibility for translating license application and operational parameters into functional equipment requirements. The work of the Systems Engineer is verified through independent calculations or system testing. Functional requirements are provided to Equipment Design Engineers who develop equipment specifications or drawings. These design documents are reviewed by Licensing, Materials, Quality Assurance and interfacing disciplines as appropriate, to assure that the parts and fabrication processes specified are adequate for the production of equipment which will perform its intended function. Supplier detail designs are also reviewed by the cognizant engineer and other engineering groups to assure the adequacy of parts and processes. In addition, formal and comprehensive design reviews are selectively performed on equipment and system designs. These design reviews bring together experts from many disciplines to critically analyze the safety and reliability of the equipment or system. Design control processes are performed in accordance with written procedures which provide for documented results.
3. The design control measures of items 1 and 2 minimize the potential for common mode failures by:

    a. Assuring the use of previously qualified standard parts and processes. Where nonstandard parts or processes are required, their use is preceded by qualification tests to assure against misapplication.

    b. The multiple reviews by parties not directly involved in the design assure that adequate consideration is given to the effect of any potential malfunctions, including common mode failures. Typically, the effect of a malfunction is controlled by having the equipment fail in a safe mode, providing redundant equipment to assure continuing operation and including sufficient separation to prevent single external events from causing common mode failures of equipment performing parallel functions.

4. The effectiveness of these design techniques is confirmed by both system testing and operation. Component failure data are analyzed to determine the potential or actual effect on system function.

1.2.3 Plant Description

1.2.3.1 General

Virgil C. Summer Nuclear Station incorporates a closed-cycle, pressurized water NSSS, a tandem compound turbine generator and necessary auxiliaries. Additional auxiliary systems, structures and other onsite facilities required for a complete, operational plant are also provided. The general arrangement of Virgil C. Summer Nuclear Station is shown by the plot plan and layout drawings, Figures 1.2-1 through 1.2-26.

As required by NUREG-0737, items I.D.1 and II.D.3, a Preliminary Control Room Design Review was performed by the Essex Corp. to identify significant human factors problems followed by a Human Factors Design Review/Audit conducted by the NRC Staff. A November 10, 1980 letter from R. L. Tedesco to SCE&G transmitted the NRC Audit Report. A copy of the Essex Preliminary Control Room Design Review Report is attached to the program plan for the human factors engineering evaluation and improvement of the Virgil C. Summer Nuclear Station Control Room, transmitted by a November 12, 1980 letter from SCE&G to the NRC.

This plan presents a program for resolving the problems identified in both the NRC Audit and the Essex Preliminary Review for completing a comprehensive evaluation of the control room after the NUREG-0700 Guidelines are issued. The Audit Reports and a draft of this plan were discussed with the NRC Human Factors Engineering Branch in an October 22, 1980 meeting.

Supplemental reports dated January 15, 1981 and November 25, 1981 describe specific methods of correcting each discrepancy identified in the NRC Audit and the Essex Preliminary Evaluation.

As required by NUREG-0578 Section 2.2.2.b, the Onsite Technical Support Center as shown on Figure 1.2-15 is located on the 463’ elevation of the Control Building adjacent to the main control room. The center has the capability to display and transmit plant status to those individuals who are knowledgeable of and responsible for engineering and management support of reactor operations in the event of an accident. The habitability system for the center is the same as the one provided for the main control room. The records that pertain to the as-built conditions and layout of structures, systems and components are located in the center. Communications are provided between the Technical Support Center, and the Control Room, Operational Support Center, Emergency Operations Facility, Nuclear Regulatory Commission, state and local agencies, and key contractor organizations. More detailed information for the Onsite Technical Support Center can be found in Section 7.7.3.

As required by NUREG-0578 Section 2.2.2.c, the Operational Support Center, is located in the Control Building. In the event of an emergency, operations personnel not assigned to the Control Room and designated maintenance personnel will secure the operation in which they are

performing and proceed to the Operational Support Center for emergency instructions and accountability.

The Emergency Operations Facility, required by NUREG-0737 and NUREG-0696, is located offsite within the Corporate Emergency Response Center (CERC), 5000 Dominion Blvd, Glen Allen, VA 23060. In the event of an emergency, the offsite emergency organization personnel will occupy this area in order to provide external support of the onsite emergency organization.

System diagrams are included with the appropriate system descriptions in various chapters of this FSAR. Symbols and abbreviations used on these system diagrams are illustrated by Figures 1.2-27 and 1.2-28. Figure 1.2-28a is an equipment list.

1.2.3.2 Structures

The major structures are the Reactor Building, Auxiliary Building, Fuel Handling Building, Intermediate Building, Control Building, Turbine Building, Diesel Generator Building, Service Water Intake Structure, Circulating Water Intake Structure, Water Treatment Building, Independent Spent Fuel Storage Installation and Service Building. The general arrangement of buildings is shown by Figures 1.2-1 through 1.2-26.

The reinforced concrete Reactor Building consists of a flat foundation mat, cylindrical wall and shallow dome roof. The foundation mat is reinforced with conventional mild steel reinforcing. The cylindrical wall is prestressed in the vertical and horizontal directions by a post tensioning system. The shallow dome roof is prestressed by a three-way post tensioning system. The inside surface of the Reactor Building is lined with a carbon steel liner to ensure a high degree of leak tightness under operating and accident conditions. The Reactor Building is designed to withstand postulated accidents as discussed in Chapter 15, severe environmental phenomena and to satisfy biological shielding requirements.

Seismic criteria used in the design of structures are discussed in Section 3.7.

1.2.3.3 Nuclear Steam Supply System

The NSSS (Figure 1.2-29) consists of a Pressurized Water Reactor, Reactor Coolant System and associated auxiliary fluid systems. The Reactor Coolant System is arranged as 3 closed reactor coolant loops connected in parallel to the reactor vessel. Each loop contains a reactor coolant pump and steam generator. An electrically heated pressurizer is connected to the hot leg of 1 reactor coolant loop.

The initial reactor core is of the three-region cycled type. The core is composed of uranium dioxide pellets enclosed in zircaloy tubes with welded end plugs. The tubes are supported in assemblies by a spring clip grid structure. The mechanical control rods consist of clusters of stainless steel clad silver-indium-cadmium absorber rods and zircaloy guide tubes located within the fuel assembly. The fuel is loaded in 3 core regions. New fuel is introduced into the outer region, moved inward into a checkerboard pattern during successive refuelings and removed from

the inner region to spent fuel storage. The typical reactor core fuel assembly arrangement is discussed in FSAR Section 4.3.2.1.

The Reactor Coolant System is designed so that static and dynamic loads imposed upon reactor coolant pressure boundary components as a result of an inadvertent and sudden pressure change does not cause rupture of the pressure boundary. To continually ensure system integrity, the components containing reactor coolant pressure have provisions for inspection and testing to assess the structural and leaktight integrity of the boundary components during their service lifetime.

The reactor coolant pumps are vertical, single stage, centrifugal pumps, equipped with controlled leakage shaft seals.

The steam generators are vertical, U-tube type heat exchangers with Alloy 690 tubes. Integral moisture separating equipment is designed to reduce the moisture content of the steam to 0.1% or less.

The pressurizer is a vertical, cylindrical, pressure vessel with hemispherical heads, equipped with electric heaters and spray nozzles for system pressure control.

High pressure water circulates through the reactor core to remove the heat generated by the controlled nuclear chain reaction. The heated water exits the reactor vessel and passes through the reactor coolant loops to the steam generators. In the steam generators, heat from the reactor coolant is transferred to the feedwater, generating steam. The cycle is completed when the reactor coolant is pumped from the steam generators to the reactor vessel. The entire Reactor Coolant System is composed of leaktight or controlled leakage components, thus ensuring that reactor coolant is confined within the system or associated auxiliary systems.

Auxiliary system components are provided to charge the Reactor Coolant System and add makeup water, collect leakage, purify reactor coolant water, provide chemicals for corrosion inhibition and reactivity control, cool system components, remove residual heat when the reactor is shut down and for emergency core cooling.

1.2.3.4 Engineered Safety Features

Engineered Safety Features (ESF) are provided to mitigate the consequences of postulated accidents up to and including a design basis accident as discussed in Chapter 15. The ESF systems provided for Virgil C. Summer Nuclear Station have sufficient redundancy and independence of components and power sources that, under postulated accident conditions, the following are accomplished:

1. Core cooling limits the core thermal transient, thereby preventing excessive metal-water reactions and maintaining coolable core geometry.
2. Reactor Building structural integrity is maintained.

3. Radiation dose to the public is maintained within the limits of 10 CFR 100.11 and 10 CFR 50.67.

The ESF systems provided are summarized in Section 1.2.3.4.1 through Section 1.2.3.4.5. Further details of the ESF system are available in Section 7.3.

1.2.3.4.1 Containment System

The steel lined, prestressed, reinforced concrete Reactor Building provides a barrier against the escape of fission products should a Loss of Coolant Accident (LOCA) occur. The general containment design parameters are described in Section 1.2.3.2.

1.2.3.4.2 Emergency Core Cooling System

The Emergency Core Cooling System (ECCS) injects borated water into the Reactor Coolant System under high and low reactor coolant pressure conditions. This limits any potential damage to the core and limits the release of energy and fission products into the reactor building following a LOCA. The ECCS also inserts negative reactivity into the core through injection of borated water following a steam line break accident or after an accidental steam release.

Following a LOCA, the reactor core is cooled by automatic injection of water from the passive accumulators into the reactor coolant loops or by automatically pumping water from the Refueling Water Storage Tank (RWST) using the charging pumps and Residual Heat Removal (RHR) pumps. The charging pumps discharge to the reactor coolant loops. The RHR pumps discharge to the reactor coolant loop cold legs.

Long term emergency core cooling is accomplished by operation of the charging pumps and RHR pumps to circulate spilled coolant and previously injected water from the reactor building recirculation sumps.

1.2.3.4.3 Reactor Building Heat Removal Systems

The Reactor Building heat removal systems cool the Reactor Building atmosphere following a LOCA or steam line break. Thus, Reactor Building pressure and energy content are reduced. The Reactor Building heat removal systems include the Reactor Building cooling units and the Reactor Building Spray System.

The Reactor Building cooling units contain fans and heat exchangers to condense the steam and transfer heat to the Service Water System. These units also provide cooling under normal conditions; however, the cooling fluid is supplied by the Industrial Cooling Water System rather than the Service Water System.

The Reactor Building Spray System reduces the energy content of the Reactor Building by spraying the interior with a relatively cool, alkaline, borated water solution. The spray solution also reduces radioactivity levels since it absorbs radioactive iodine from the Reactor Building

atmosphere. During the injection phase, a mixture of water from the RWST and sodium hydroxide tank is sprayed into the Reactor Building interior.

1.2.3.4.4 Combustible Gas Control

Two (2) hydrogen recombiners of the Post Accident Hydrogen Removal System remove hydrogen from the Reactor Building atmosphere following a LOCA by combining the hydrogen with oxygen to form water. Thus, the Reactor Building hydrogen concentration is maintained within allowable limits. An alternate purge system is provided as a backup to the Post Accident Hydrogen Removal System.

1.2.3.4.5 Containment Isolation System

The Containment Isolation System isolates pipe lines not essential to operation of other ESF systems which penetrate the containment boundary. Thus, under severe accident conditions, radioactivity inside the Reactor Building is not released to the environment.

1.2.3.5 Instrumentation and Control

Plant instrumentation and control systems are provided to monitor significant variables in the reactor core, Reactor Coolant System and Reactor Building over their anticipated ranges. The installed instrumentation provides capability for continuous monitoring, maintenance and initiation of required safety functions. More detailed information is provided in FSAR Section 7.0.

Overall reactivity control is achieved by a combination of chemical shim and Rod Cluster Control Assemblies (RCCA). Long term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short term reactivity control for power level changes is accomplished by moving RCCAs.

The control system allows the plant to accept a step load increase or decrease of 10% and a ramp load increase or decrease of 5% per minute within the load range of 15% to 100%, subject to possible xenon limitations. The steam dump system permits 100% load rejection without turbine or reactor trip.

A control room and technical support center, designed for safe occupancy under both normal and accident conditions, are provided. Adequate shielding is included to maintain reasonable radiation levels. In the unlikely event that the control room is uninhabitable, total controls are provided to effect hot shutdown from outside the control room and to maintain the plant in a hot shutdown condition for an extended period of time. It is also possible to achieve cold shutdown under such conditions (refer to SCE&G letters to the NRC dated October 16, 1981, November 9, 1981 and November 11, 1981). More detailed information is provided in FSAR Sections 7.4.1.3 and 7.4.1.4.

1.2.3.6 Electrical Systems

The main generator is an 1800 rpm, 24 kV, 3 phase, 60 hertz, conductor cooled unit. The main step-up transformer delivers power to the substation at 230 kV. Transmission lines interconnect with the SCE&G and SCPSA transmission systems from this substation at 230 kV.

The station service system consists of auxiliary transformers; 7200 volt and 480 volt switchgear and buses; 480 volt motor control centers; 115 volt A-C, vital instrument buses; 125 volt D-C batteries, chargers, inverters and equipment.

The normal source of Balance Of Plant (BOP) station service power is the unit auxiliary transformer which is connected to the generator isolated phase bus duct. The preferred power supplies for the engineered safety features buses are from a 115 kV line which is part of the SCE&G transmission system and a second power supply from the local 230 kV substation.

Two (2) independent diesel generators are provided in the event of complete loss of system power. Each diesel generator has sufficient capacity for operation of engineered safety features equipment which must be operated in the event of a LOCA or other emergency conditions.

1.2.3.7 Fuel Handling and Storage Systems

The reactor is refueled by equipment designed to handle spent fuel underwater from the time the spent fuel is removed from the reactor vessel until it is placed in a cask for removal from the Fuel Handling Building. Underwater transfer of spent fuel provides an effective, economic and transparent radiation shield and a reliable cooling medium for removal of decay heat.

The Fuel Handling System includes 2 areas: the refueling cavity and refueling canal which are flooded only during plant shutdown for refueling; and the spent fuel pool and transfer canal which are kept full of water and are accessible to operating personnel. The refueling canal and transfer canal are connected by the fuel Transfer System.

Spent Fuel is removed from the reactor vessel by a refueling machine and is placed in the fuel Transfer System carriage. The Fuel Transfer System moves the spent fuel from the refueling canal to the transfer canal. The spent fuel is removed from the Fuel Transfer System carriage in the transfer canal and placed in the spent fuel storage racks in the spent fuel pool. After a decay period the spent fuel is removed from the spent fuel racks and loaded into a cask for removal from the Fuel Handling Building.

Handling and storage of both new and spent fuel is performed using equipment and procedures which ensure that the fuel remains subcritical.

1.2.3.8 Auxiliary Systems

1.2.3.8.1 Service Water System

The Service Water System is vital to plant safety and is therefore equipped with redundant pumps, heat exchangers, flow circuits, etc. System design is such that no single failure will result in loss of cooling to necessary equipment. The service water pumps take suction from the service water pond and supply cooling water to the component cooling heat exchangers, diesel generators, HVAC (Heating, Ventilating and Air Conditioning) mechanical water chiller condensers, service water pump house ventilation cooling coils and, under emergency conditions, to the reactor building cooling units. The normal supply of cooling to the reactor building cooling units is from the industrial cooling water system.

1.2.3.8.2 Cooling Systems

The cooling systems include the Component Cooling Water System, Spent Fuel Cooling System, Residual Heat Removal System, and Chilled Water System. These systems are closed loop systems which can receive makeup water from primary grade water sources or the Demineralized Water System. For a more detailed description of the make-up sources, consult the 302 drawings in the pertinent FSAR section for these systems.

1.2.3.8.3 Ultimate Heat Sink

The ultimate heat sink, the safety class service water pond, provides sufficient cooling water for normal and postulated accident conditions.

1.2.3.8.4 Other Water Systems

The Demineralized Water Makeup System pretreats and demineralizes water from Monticello Reservoir and provides for storage of demineralized water for primary and secondary plant makeup. Potable water is obtained from the system following pretreatment but prior to demineralization.

The Potable Water System serves sanitary plumbing fixtures, showers, laundry and emergency eye wash units. Sanitary drainage from plumbing fixtures served by the Potable Water System and toilet room floor drains is collected by a drainage system which terminates at an onsite sanitary disposal facility.

The modified source of potable water is obtained from the Off-Site Water Treatment System (OWS). The main purpose of the OWS is to provide forced flow distribution of Filtered Water and Potable Water to support operational water needs for VC Summer Unit 1. The OWS treats water from the adjacent Monticello Reservoir. Wastewater generated in the production of filtered and potable water is discharged from the OWS Retention Basins by either gravity drain and/or pump back to the Monticello Reservoir. A local Emergency Diesel Generator (EDG) located at the OWS Water Treatment Plant Site is available to provide backup power to the OWS distribution

pumps in the event of loss of off-site power. The EDG is sized to provide power to two (2) filtered water pumps and two (2) potable water pumps for 24 hours without refueling.

The OWS does not perform or support any safety-related function and is not credited for mitigation of design basis accidents or low probability events such as seismic, fire, sabotage, passive failures, multiple active failures, etc. Failure of components within the OWS will not preclude essential function of safety related systems.

The OWS does not perform licensing-related functions, such as those associated with the Anticipated Transient Without Scram (ATWS) or fire protection event per 10 CFR 50, Appendix A and Appendix R, or with mitigation of severe accidents and is not modeled in the Probabilistic Risk Assessment (PRA) mitigation sequence. Therefore, the OWS does not perform or support any licensing-related functions.

1.2.3.8.5 Condensate Storage Facilities

Condensate storage is provided in the form of a 500,000 gallon tank, of which approximately 160,000 gallons is reserved for the Emergency Feedwater System.

1.2.3.8.6 Compressed Air Systems

Two (2) nonsafety-related compressed air systems are provided. One system supplies Reactor Building instrument air; the other supplies instrument and service air to the balance of the plant. These systems provide compressed air of suitable quality and at the pressures required for use by various components. Certain air operated devices are required to operate after an accident. These devices utilize air volume tanks to perform these functions. The devices and justification for their uses are provided in the appropriate section which discusses associated fluid system operation.

1.2.3.8.7 Process Sampling System

The sampling systems collect primary and secondary plant gaseous and liquid samples as required for radiochemical and chemical analyses.

1.2.3.8.8 Chemical and Volume Control System

The Chemical and Volume Control System (CVCS) adjusts boron concentration in the reactor coolant, maintains proper Reactor Coolant System water inventory, provides required seal water flow to the reactor coolant pump shaft seals, provides high pressure flow to the ECCS, maintains proper concentrations of corrosion inhibiting chemicals in the reactor coolant and reduces the inventory of corrosion and fission products in the reactor coolant.

The Boron Thermal Regeneration System (BTRS) accepts borated water letdown from the Reactor Coolant System and returns it with boron removed as necessary based upon operating requirements.

1.2.3.8.9 Boron Recycle System

The Boron Recycle System processes reactor coolant effluent to obtain reusable boron and purified water.

1.2.3.8.10 Air Conditioning, Heating, Cooling, and Ventilation Systems

The following ventilation systems are provided:

1. Control Building, including control room, relay room, cable spreading areas, computer room and controlled access area.
2. Fuel Handling Building, including spent fuel pool area.
3. Auxiliary Building.
4. Turbine Building.
5. Intermediate Building.
6. Reactor Building.
7. Diesel Generator Building.
8. Service Water Intake Structure.
9. Circulating Water Intake Structure.
10. Service Building.

Each ventilation system is provided to maintain a suitable environment for equipment and personnel and to filter effluents as necessary.

1.2.3.8.11 Fire Protection System

The Fire Protection System is designed to detect, extinguish and mitigate the effects of fires. Details are presented in Section 9.5.1.

1.2.3.8.12 Communication Systems

1.2.3.8.13 Reliable systems are provided for both onsite and offsite communications. Details are presented in Section 9.5.2.

1.2.3.8.14 Lighting Systems

The lighting system provides adequate lighting under normal operating and postulated accident conditions. Details are presented in Section 9.5.3.

1.2.3.8.15 Diesel Generator Auxiliaries

The diesel generator auxiliaries consist of the following:

1. Bulk Fuel Oil Storage and Transfer System.
2. Fuel oil day tank.
3. Jacket Water and Air Intercooler Cooling System.
4. Starting System.
5. Lubricating Oil System.
6. Combustion air intake and exhaust equipment.
7. Generator exciter/regulator.
8. Engine-generator control panel.

The auxiliaries for each diesel generator are designed to ensure independence from the other diesel generator.

1.2.3.9 Steam and Power Conversion System

1.2.3.9.1 Turbine Generator

The turbine is a General Electric tandem compound, 4 flow exhaust, 1800 rpm unit. The overspeed protection system operates through the turbine electrohydraulic control system. The overspeed protection system is designed so that no single failure can lead to destructive turbine overspeed. Provision is made for inservice testing of the turbine protection system.

1.2.3.9.2 Main Steam System

The Main Steam System delivers steam from the steam generators to the turbine generator, main feedwater pump turbines, steam driven emergency feedwater pump turbine, reheaters and auxiliary steam system.

Connections from the Main Steam System to the Main Steam Dump System are provided. Overpressure protection is provided by a total of 15 safety valves, 5 in each steam header, outside the Reactor Building upstream of the main steam isolation valves. One (1) power operated relief valve is also provided for each steam header. One (1) quick closing main steam isolation valve, capable of closing tightly regardless of steam flow direction, is provided in each steam header, just outside of the Reactor Building.

1.2.3.9.3 Main Condenser

The main condenser is a twin shell, dual pressure unit with circulating water arranged to pass through the two (2) sections in series. Condensate is collected in the hotwell section of each shell, which are interconnected. The hotwell storage level is controlled to provide sufficient condensate retention to accommodate sudden increases in load demand with makeup provided by the Condensate Storage Tank. A duplex, closed feedwater heater is horizontally mounted in each condenser neck.

1.2.3.9.4 Condenser Air Removal System

Evacuation of each main condenser shell is accomplished by a mechanical vacuum pump. The auxiliary condenser shells are piped and normally aligned to vent to the low pressure shell of the main condenser. Mechanical vacuum pumps are provided for backup air removal of the auxiliary condensers. Non-condensible gases removed from the condensate are monitored to detect radioactivity. Normally such gases are discharged through the Auxiliary Building charcoal filters. Provision is made for discharge of noncondensibles to the environment if no radioactivity is present.

1.2.3.9.5 Turbine Gland Seal System

The Turbine Gland Seal System prevents steam leakage from the high pressure turbine shaft seals and air leakage into the condenser through the low pressure turbine shaft seals.

1.2.3.9.6 Turbine Bypass System (Main Steam Dump System)

Connections to the Main Steam System are provided for the Turbine Bypass System. The Turbine Bypass System contains 8 bypass control valves for steam dump to the main condenser, 3 bypass control valves for steam dump to atmosphere and 3 power relief valves. The maximum flow capacity of each individual valve is limited to prevent uncontrolled plant cooldown should a single valve fail in the open position.

1.2.3.9.7 Circulating Water System

The Circulating Water System provides cooling water to the main and auxiliary condensers. Cooling water is supplied from Monticello Reservoir through an intake structure. Circulating water pumps, traveling water screens and associated screen wash pumps, a vacuum priming system and a condenser tube cleaning system are provided.

1.2.3.9.8 Condensate and Feedwater System

Condensate is withdrawn from the high pressure condenser hotwell by 3 motor driven condensate pumps. The pumps discharge into a common header which carries condensate to the steam packing condenser. Downstream of the steam packing condenser, the common header divides into 2 lines which carry condensate through 3 stages of low pressure feedwater heaters. Effluent from each of these 2 lines enters the deaerator.

Feedwater booster pumps take suction from the deaerator storage tank and discharge to the suction of the feedwater pumps which discharge through 2 stages of half capacity, high pressure feedwater heaters, arranged in parallel, to a discharge header. Feedwater from the discharge header is distributed to each steam generator through individual feedwater flow control valves.

During startup and shutdown and as required during condenser leaks, the condensate cleanup system will be used. The cleanup system is located between the condensate pump discharge and steam packing condenser.

1.2.3.9.9 Steam Generator Blowdown

The Steam Generator Blowdown and Nuclear Blowdown Processing Systems control the chemistry of the secondary side by continuous blowdown of the steam generator.

Normally, blowdown from each steam generator is cooled and directed to the Nuclear Blowdown Processing System or, alternatively, discharged into the circulating water discharge.

An abnormally high level of blowdown radioactivity activates an alarm and automatically diverts the fluid to the Nuclear Blowdown Processing System. Effluent from the Nuclear Blowdown Processing System is normally returned to the Condensate System via the main condenser. Effluent can also be discharged to the penstocks.

1.2.3.9.10 Emergency Feedwater System

One (1) full capacity, steam turbine driven and 2 100% capacity, motor driven emergency feedwater pumps are provided to supply feedwater to the steam generators during loss of offsite power, under postulated accident conditions or during plant startup and shutdown. Steam is supplied to the steam turbine driven emergency feedwater pump from the Main Steam System; electric power is supplied to the motor driven emergency feedwater pumps from the Class 1E power system. Feedwater flow to individual steam generators is controlled by a remotely operated control valve in each supply line.

1.2.3.10 Radioactive Waste Management

Radioactive waste management is accomplished through use of 3 interrelated systems:

1. Liquid Waste Processing System.
2. Gaseous Waste Processing System.
3. Solid Waste Disposal System.

The Liquid Waste Processing System collects and processes potentially radioactive waste liquids generated during plant operation and refueling, for either recycling within the plant or for discharge. Radioactive constituents are removed or concentrated and processed until suitable for discharge or shipment offsite.

The Gaseous Waste Processing System removes fission product gases from the reactor coolant and allows for retention or controlled release.

The Solid Waste Disposal System provides the capability to process and package solid waste in Department of Transportation approved containers for shipment offsite or for storage onsite (refer to Chapter 11).

1.2.3.11 Radiation Monitoring System

The Radiation Monitoring System detects, indicates, annunciates and records radiation levels at selected locations throughout the plant. Three (3) subsystems are provided: area gamma monitoring, atmospheric monitoring, and liquid monitoring. Fixed monitors display their measured variable and any alarm condition in the control room except for monitors associated with the radwaste solidification equipment (refer to Chapter 11).

Figure 1.2-1
DRAWING E-036-001
FSAR Figure Reference

Figure 1.2-2
DRAWING E-001-001
Also Associated with Figures 12A.4-1, 12.1-1, and 12.1-10
FSAR Figure Reference

Figure 1.2-3
DRAWING E-001-002
Also Associated with Figures 12.1-2, 12.1-11, and 12A.4-2
FSAR Figure Reference

Figure 1.2-4
DRAWING E-001-011
Also Associated with Figures
9.5-1A, 12.1-3, 12.1-12, AND 12A.4-3
FSAR Figure Reference

Figure 1.2-5
DRAWING E-001-021
Also Associated with Figures 9.5-1B, 12A.4-5, 12.1-5, Sht. 1, And 12.1-14
FSAR Figure Reference

Figure 1.2-6
DRAWING E-001-031
Also Associated with Figures 9.5-1C, 12.1-7, 12.1-16, and 12A.4-6
FSAR Figure Reference

Figure 1.2-7
DRAWING E-001-034
FSAR Figure Reference

Figure 1.2-8
DRAWING E-001-035
FSAR Figure Reference

Figure 1.2-9
DRAWING E-002-001
Also Associated with Figures 12.1-8, and 12.1-17
FSAR Figure Reference

Figure 1.2-10
DRAWING E-002-002
Also Associated with Figures 12.1-9, and 12.1-18
FSAR Figure Reference

Figure 1.2-11
DRAWING E-001-012
Also Associated with Figures 12.1-4, 12.1-13, and 12A.4-8
FSAR Figure Reference

Figure 1.2-12
DRAWING E-001-022
Also Associated with Figures 9.5-1D, 12.1-6, and 12.1-15
FSAR Figure Reference

Figure 1.2-13
DRAWING E-001-032
Also Associated with Figure 9.5-1E
FSAR Figure Reference

Figure 1.2-14
DRAWING E-002-004
FSAR Figure Reference

Figure 1.2-15
DRAWING E-005-001
Also Associated with Figures 12.1-19, 12A.4-7, 9.5-1F, and 13.5-1
FSAR Figure Reference

Figure 1.2-16
DRAWING E-005-002
Also Associated with Figures 12.1-19a, and 9.5-1g
FSAR Figure Reference

Figure 1.2-17
DRAWING E-005-003
Also Associated with Figure 12.1-20
FSAR Figure Reference

Figure 1.2-18
DRAWING E-001-013
Also Associated with Figure 9.5-1H
FSAR Figure Reference

Figure 1.2-19
DRAWING E-001-023
FSAR Figure Reference

Figure 1.2-20
DRAWING E-001-033
FSAR Figure Reference

Figure 1.2-21
DRAWING E-002-003
FSAR Figure Reference

Figure 1.2-22
DRAWING E-002-005
FSAR Figure Reference

Figure 1.2-23
DRAWING E-026-101
FSAR Figure Reference

Figure 1.2-24
DRAWING E-026-102
FSAR Figure Reference

Figure 1.2-25
DRAWING E-015-001
12.1-5 Sheet 2 of 2
FSAR Figure Reference

Figure 1.2-26
DRAWING E-001-062
FSAR Figure Reference

Figure 1.2-27
DRAWING E-302-002
FSAR Figure Reference

Figure 1.2-28
DRAWING D-302-001
FSAR Figure Reference

Figure 1.2-28a
DRAWING E-013-001
FSAR Figure Reference

NOTE: Section 1.2 is being retained for historical purposes only.

1.3 COMPARISON TABLES

1.3.1 Comparison With Similar Facility Designs

Table 1.3-1 provides significant similarities and differences between the Virgil C. Summer Nuclear Station and other designs.

1.3.2 Comparison of Final and Preliminary Information

Table 1.3-2 provides significant design changes since submittal of the Preliminary Safety Analysis Report.

Table 1.3-1
Design Comparison With Similar Facilities(1)

Chapter Number	Chapter Title System Component	Virgil C. Summer Nuclear Station FSAR References	Significant Similarities	Significant Differences
4.0	Reactor	Section 4.0	Similar to North Anna Units 1 and 2 total 1 NSSS heat output of 2785 MWt	Beaver Valley Unit 1 has a total NSSS heat output of 2660 MWt.
	Fuel	Section 4.2.1	Similar to Beaver Valley Unit 1 and North Anna Units 1 and 2.	Small variations in design parameters based on nuclear and thermal-hydraulic design.
	Reactor Vessel Internals	Section 4.2.2	Similar to Beaver Valley Unit 1 and North Anna Units 1 and 2.	Beaver Valley Unit 1 and North Anna Units 1 and 2 have thermal shields; Virgil C. Summer Nuclear Station has neutron pads.
	Reactivity Control Systems	Section 4.2.3	Similar to Beaver Valley Unit 1 and North Anna Units 1 and 2.	None.
	Nuclear Design	Section 4.3	Similar to Beaver Valley Unit 1 and North Anna Units 1 and 2	Small variations in nuclear parameters.
	Thermal-Hydraulic Design	Section 4.4	Similar to Beaver Valley Unit 1 and North Anna Unit 1 and 2	Small variations in thermal-hydraulic and heat transfer parameters.

1. Comparisons identified relative to thermal power are compared to the pre-uprate power level of 2775 MWt RTP

Table 1.3-1
Design Comparison With Similar Facilities(1) (continued)

Chapter Number	Chapter Title System Component	Virgil C. Summer Nuclear Station FSAR References	Significant Similarities	Significant Differences
5.0	Reactor Coolant System	Sections 5.1, 5,2	Similar to Beaver Valley Unit 1 and North Anna Units 1 and 2.	Virgil C. Summer Nuclear Station does not have loop stop valves.
	Reactor Vessel	Section 5.4	Similar to Beaver Valley Unit 1 and North Anna Units 1 and 2.	No significant differences.
	Reactor Coolant Pumps	Section 5.5.1	The hydraulics are similar to Beaver Valley Unit 1 and North Anna Units 1 and 2	Virgil C. Summer Nuclear Station motors are of modular construction.
	Steam Generators	Section 5.5.2	Similar to Wolfe Creek & Millstone Unit 3.	Alloy 690 tube material, triangular tube pitch, larger heat transfer area.
	Piping	Section 5.5.3	Similar to Surry Units 1 and 2	Virgil C. Summer Nuclear Station has no electroslag welding.
	Residual Heat Removal System	Section 5.5.7	The piping and fittings are similar to Joseph M. Farley Units 1 and 2	No significant differences.
	Pressurizer	Section 5.5.10	Similar to North Anna Units 1 and 2	No significant differences.

1. Comparisons identified relative to thermal power are compared to the pre-uprate power level of 2775 MWt RTP

Table 1.3-1
Design Comparison With Similar Facilities(1) (continued)

Chapter Number	Chapter Title System Component	Virgil C. Summer Nuclear Station FSAR References	Significant Similarities	Significant Differences
	Emergency Core Cooling System	Section 6.3	Similar to Joseph M. Farley Units 1 and 2	Automatic sump valve opening logic is different.
6.0	Engineered Safety Features Electric Hydrogen Recombiner	Section 6.2.5	Similar to Surry Units 1 and 2	No significant differences.
7.0	Instrumentation and Controls Reactor Trip System	Section 7.2	Similar to Joseph M. Farley, Unit 1	No significant differences.
	Engineered Safety Features Actuation System	Section 7.3	Similar to Joseph M. Farley, Unit 1	No significant differences.
	System Required for Safe Shutdown	Section 7.4	Similar to Joseph M. Farley, Unit 1	No significant differences.
	Safety-Related Display Instrumentation	Section 7.5	Similar to Joseph M. Farley, Unit 1	No significant differences but physical display may differ.
	Other Safety System	Section 7.8	Similar to Joseph M. Farley, Unit 1	No significant differences.

1. Comparisons identified relative to thermal power are compared to the pre-uprate power level of 2775 MWt RTP

Table 1.3-1
Design Comparison With Similar Facilities(1) (continued)

Chapter Number	Chapter Title System Component	Virgil C. Summer Nuclear Station FSAR References	Significant Similarities	Significant Differences
	Control Systems	Section 7.7	Similar to Joseph M. Farley, Unit 1	Joseph H. Farley, Unit 1 has a 50% load rejection capability. Virgil C. Summer Nuclear Station has an 85% load rejection capability.
8.0	Electric Power			
	Offsite Power	Section 8.2		Three Mile Island Nuclear Station Unit 1 has two offsite sources, 230 kV/6.9 kV. Virgil C. Summer Nuclear Station has one 115 kV/7.2 kV and one 230 kV/7.2 kV offsite source.
	Offsite Power	Section 8.3	Joseph M. Farley Units 1 and 2 have Colt Industries 12PC2V diesel engines	Three Mile Island Nuclear Station Unit 1 has four 125 volt batteries for supply of vital d-c power. Virgil C. Summer has two 125 volt batteries for supply of vital d-c power.

(1) Comparisons identified relative to thermal power are compared to the pre-uprate power level of 2775 MWt RTP

Table 1.3-1
Design Comparison With Similar Facilities(1) (continued)

Chapter Number	Chapter Title System Component	Virgil C. Summer Nuclear Station FSAR References	Significant Similarities	Significant Differences
	120 Volt Vital a-c Bus System		Three Mile Island Nuclear Station Unit 1 normal source of power is 480 volt a-c ESF bus; alternate source is 125 volt d-c system.	Three Mile Island Nuclear Station Unit 1 has four 15kVA single phase inverters. Virgil C. Summer Nuclear Station has six 7.5kVA single phase inverters, arranged in four independent channels.
9.0	Auxiliary System Fuel Handling System	Section 9.1.4	Similar to Beaver Valley Unit 1 and North Anna Units 1 and 2	Each project has difference capacities for spent fuel storage.
	Chemical and Volume Control System	Section 9.3.4	Similar to Joseph M. Farley Units 1 and 2	No significant differences.
10.0	Radioactive Waste Management Source Terms	Section 11.1	Similar to Joseph M. Farley Units 1 and 2	Differences in source term analysis.
	Liquid Waste Processing	Section 11.2	Performance characteristics similar to Joseph M. Farley Units 1 and 2	Differences in source term analysis.
	Gaseous Waste Processing	Section 11.3	Similar to Joseph M. Farley Units 1 and 2	Differences in source term analysis.
14.0	Initial Tests and Inspections	Chapter 14	Similar to Beaver Valley Unit 1 and North Anna Units 1 and 2.	No significant differences.

1. Comparisons identified relative to thermal power are compared to the pre-uprate power level of 2775 MWt RTP

Table 1.3-1
Design Comparison With Similar Facilities[1] (continued)

Chapter Number	Chapter Title System Component	Virgil C. Summer Nuclear Station FSAR References	Significant Similarities	Significant Differences
15.0	Accident Analysis	Chapter 15	Similar to Beaver Valley Unit 1 and North Anna Units 1 and 2	The accident analysis sections have been updated. New sections have been added, e.g., single RCCA withdrawal, accidental depressurization of the RCS, code descriptions, etc.

1. Comparisons identified relative to thermal power are compared to the pre-uprate power level of 2775 MWt RTP

Table 1.3-2
Comparison of Final and Preliminary Designs

Item	FSAR Reference	Change
Service Water Pond Bottom and North Dam Foundation	2.5.6	The following changes were made to the service water pond as conservative measures to reduce the potential for seepage losses from the pond during a postulated loss of the Monticello Reservoir: a. Installation of a grout curtain along the centerline of the North Dam foundation. b. Placement of a clay blanket on the portion of the pond bottom adjacent to the South Dam.
Auxiliary Building Charcoal Exhaust System	Table 3.2-1 and 9.4.2.2.3	The auxiliary building charcoal exhaust system was declassified from SC-3 to non-nuclear safety class. Release calculations indicated that this system was not necessary to maintain offsite dose rates within acceptable limits. However, areas exhausted were increased and HEPA filters were added.
Change in Seismic Instrumentation	3.7.4	Seismic instrumentation program was changed to meet the required sensitivity of instrumentation to measure the seismic response of nuclear power plant features important to safety.

Table 1.3-2
Comparison of Final and Preliminary Designs (continued)

Item	FSAR Reference	Change
Increase of Reactor Building Internal Design Pressure	3.8.1.3.1.2 and 6.2.1	The reactor building internal design pressure was increased from 55 psig to 57 psig to maintain the required margin above the calculated pressure.
Compressive Strength of 5000 psi Concrete was Changed from 28 day Test to 90 day Test	3.8.1.6.1.2.1	The heat generated during the curing period of mass concrete calculated from results obtained from actual field tests, utilizing the actual dimensions of the reactor building mat, was higher than acceptable. The reduction in concrete mix cement content and consequent lower temperature in the concrete was acceptable by using the 90 day strength as a design requirement.
Control Building Foundation	3.8.5.1.4	The control building foundation was changed from caissons to mat on fill concrete.
Fuel	4.2.1	The reactor will be fueled with 17 x 17 fuel assemblies in lieu of 15 x 15 fuel assemblies.
Reactor Internals	4.2.2	The reactor internals have been modified to accept 17 x 17 fuel assemblies.

Table 1.3-2
Comparison of Final and Preliminary Designs (continued)

Item	FSAR Reference	Change
Fuel Pellet Enrichments and Density	4.3	The fuel pellet enrichments as well as other core parameters change between the PSAR and FSAR to reflect the evolution of the design as core performance and safety requirements are met. Fuel density has been increased from 94, 92, and 91 percent of theoretical to 95 percent of theoretical.
Burnable Poison Loading Pattern	4.3	The burnable poison pattern shown in the FSAR reflects more detailed calculations than that of the PSAR.
Reactor Top Head Penetrations	5.4	Reactor vessel top head penetrations and CRDM were redesigned to meet requirements for inservice inspection.
Reactor Vessel Nozzle Insulation	5.4	Non crushable insulation is used.
Reactor Building Ventilation System	6.2.2 and 9.4.8	HEPA filters and bypass dampers were added to the reactor building ventilation system to reduce offsite releases following a LOCA.
Post Accident Hydrogen Recombiner	6.2.5	Change of post accident hydrogen recombiners from externally mounted to internally mounted units.

Table 1.3-2
Comparison of Final and Preliminary Designs (continued)

Item	FSAR Reference	Change
Semi-Automatic Emergency Core Cooling System (ECCS) Switchover	6.3	System was revised to automatically change residual heat removal (RHR) pump suction from the refueling water storage tank (RWST) to the recirculation sump of the reactor building during changeover from the injection phase to the recirculation phase during post accident core cooling. This revision ensures continual water supply to the suction of the RHR pump.
Automatic Reactor Building Spray Switchover	6.3.2	System was revised to automatically change spray pump suction from the RWST to the recirculation sump of the Reactor Building on lo-lo level in the RWST. This revision ensures continuous water supply to the suction of the pumps.
Elimination of Redundancy of Instrument Air Supply for Ventilation Control in the Control Room	6.4 and 9.4.1	Since the control air system is not nuclear safety related and all dampers/valves fail to the post accident mode, redundancy is not required.
Steam Dump	7.2	Power operated steam relief valves were automated to increase dump capacity.
Undervoltage Reactor Trip	7.2	The undervoltage sensors and underfrequency sensors were moved to the motor side of the reactor coolant pump breaker. Trip on pump breaker open was removed.

Table 1.3-2
Comparison of Final and Preliminary Designs (continued)

Item	FSAR Reference	Change
Safety Injection	7.2	Injection signal on pressurizer low pressure in lieu of coincident low level and low pressure.
Feedwater Control	7.2	The programmed setpoint for the feedwater control valve uses steam flow/feed flow mismatch and S/G level. The bypass valves use S/G level and neutron flux to control valve position. Also, the feedwater pump speed is programmed using line pressures and steam flow.
Main Steam Isolation Signal	7.2	Changed the main steam isolation from activating on high steam line flow coincident with low steam line pressure or lo-lo T_{avg} to low steam line pressure or high steam line flow coincident with lo-lo T_{avg}.
Blowdown and Sample Line Isolation	7.2	Automatic initiation of emergency feedwater causes isolation. Manual isolation was removed.
Changes to Manual Actuation of the following Three Systems: Main Steam Isolation, Containment Isolation Reactor Building Spray and Automatic Initiation of Reactor Building Spray	7.2, Figure 7.2-1 and Table 7.3-2	Changes have been made to these systems to provide the required redundancy for system initiation.
Post Accident Monitoring	7.5	A post accident monitoring system has been added.

Table 1.3-2
Comparison of Final and Preliminary Designs (continued)

Item	FSAR Reference	Change
Analog to Digital	7.7	Analog rod position indication has been replaced by digital rod position indication to improve reactor protection instrumentation.
Incorporation of a Circuit Breaker between the Generator Terminals and the Unit Auxiliary Transformer	8.2.1.1	The addition of this circuit breaker improves operational flexibility by permitting the use of the unit auxiliary transformer during startup and eliminating the need of station service transfer during turbine trip.
Physical Arrangement and Separation Criteria Requirements of Installed Electrical Systems and Equipment	8.3.1.1 and 8.3.2.1	Electrical equipment such as motor control centers, batteries, battery chargers, distribution panels, diesel generators, etc., have been located to provide protection and/or separation from postulated accidents (i.e. missiles, seismic event, fire hazards, etc.).
Removal of Bus Tie Breaker between Class 1E d-c Buses 1A and 1B	8.3.2.1.2 and 8.3.2.2.1	The manually operated bus tie breaker between Class 1E d-c buses 1A and 1B was removed to improve system reliability and safety.

Table 1.3-2
Comparison of Final and Preliminary Designs (continued)

Item	FSAR Reference	Change
Diesel Generator Fuel Oil System	8.3.1.1.2.1 and 9.5.4	The following changes have been made to the diesel generator fuel oil system: a. Incorporation of two independent fuel oil storage systems, including independent buried storage tanks, in lieu of a common storage system. b. Incorporation of two a-c motor driven transfer pumps per system in lieu of one a-c and one d-c motor driven pump. c. Reduction in operating time for fuel available in day tanks to a nominal 1.5 hours to be consistent with the maximum size of day tank permitted by National Fire Protection Association Standard (NFPA) 37.
Spent Fuel Racks	9.1	The storage lattice spacing has been reduced to 14 inches from 21 inches on center to increase storage from approximately 1-1/3 core to 4-1/3 core.
Reactor Building Instrument Air System	9.3.1	The reactor building instrument air system was revised to: a. Delete one air compressor. b. Relocate remaining two compressors outside the reactor building.

Table 1.3-2
Comparison of Final and Preliminary Designs (continued)

Item	FSAR Reference	Change
Nuclear Sampling System	9.3.2	Recent regulatory guidelines permit declassification of nuclear sampling system piping outside reactor building without reduction in system reliability or performance.
Fuel Handling Building Charcoal Exhaust System	9.4.3.2.1	Additional areas were added to the exhaust system to reduce normal plant releases. Redundant plenums and additional HEPA filters were added.
Steam Generator Blowdown System	10.4.8	The steam generator blowdown system was redesigned to accommodate the changes in the secondary cycle chemistry control from phosphate to all volatile treatment (AVT).
Redesign of Radiation Monitoring	11.4, 12.1.4 and 12.2.4	Various changes to the radiation monitoring system to increase surveillance and detection capabilities of plant effluents.
Automatic Emergency Feedwater Switchover from Condensate Tank to Service Water	10.4.9	System was revised to automatically change emergency feedwater pump suction from the condensate storage tank to the service water system on lo suction pressure to the EFW pumps. This revision ensures continuous water supply to the suction of the pumps.
ATWS Mitigation System Actuation Circuitry (AMSAC)	7.8	Added instrumentation and controls necessary to respond to 10CFR50.62 for mitigation of ATWS events.

NOTE: Section 1.4 is being retained for historical purposes only.

1.4 IDENTIFICATION OF AGENTS AND CONTRACTORS

South Carolina Electric and Gas Company (SCE&G) is the sole applicant for the construction permit and operating license for the Virgil C. Summer Nuclear Station. SCE&G is two-thirds owner of the Virgil C. Summer Nuclear Station. The remaining one-third is owned by the South Carolina Public Service Authority (SCPSA) which together with SCE&G owns the Virgil C. Summer Nuclear Station as tenants in common. It is specifically noted that SCE&G is the agent for the SCPSA with regard to the Virgil C. Summer Nuclear Station, and that SCE&G retains sole responsibility for the overall technical direction in the licensing, design, construction, operation, management, maintenance and decommissioning. Likewise, it is specifically noted that the ownership change reflected in the amended application does not effect a transfer of control from SCE&G to the SCPSA, nor does the ownership change involve a physical or design change in the facility or site.

Gilbert Associates, Inc. (Gilbert), has been retained by SCE&G as architect engineer for the entire project, including plant layouts and system arrangements, and design of balance of plant equipment. A brief summary of Gilbert technical qualifications is included in Section 1.4.2.

SCE&G has contracted with the Westinghouse Electric Corporation (Westinghouse) for the design and manufacture of the complete Nuclear Steam Supply System. In addition, Westinghouse supplies competent technical consultation in areas such as initial fuel loading, testing, and initial startup. Westinghouse is involved in the training of SCE&G personnel. A brief summary of Westinghouse technical qualifications is included in Section 1.4.3.

Dames and Moore, Inc. (D&M), is retained as environmental consultant and has assisted SCE&G in the preparation of the environmental portions of this report. In addition, D&M has assisted SCE&G in the preparation of the required Environmental Report-Operating License Stage. A brief summary of D&M technical qualifications is included in Section 1.4.4.

1.4.1 South Carolina electric and gas company qualifications and experience

SCE&G owns and operates an integrated electric generation, transmission, and distribution system which serves approximately 484,000 customers in a 15,000 square mile service area. This area, stretching from the central region to the coastal plains, includes Columbia, the state capital, and Charleston, South Carolina’s principal seaport. SCE&G’s transmission system is part of the interconnected grid extending over a large part of the central and eastern portion of the nation.

SCE&G, acting as its own general contractor, has constructed generating facilities which provide most of SCE&G’s present generating capacity. For the construction of the Virgil C. Summer Nuclear Station, SCE&G has engaged Daniel Construction Company (Daniel) of Greenville, S.C.

to act as the general contractor. A summary of the qualifications of Daniel is given in Section 1.4.5.

SCE&G is a partner with Carolina Power and Light Company, Duke Power Company and Virginia Electric and Power Company in Carolinas Virginia Nuclear Power Associates, Inc. (CVNPA). CVNPA was formed in 1956 to build and operate a 17,000 kWe nuclear steam generating plant at Parr, S.C., for research, operating and engineering experience. This plant, the Carolinas Virginia Tube Reactor (CVTR), was constructed and operated under license granted by the Atomic Energy Commission. The CVTR was decommissioned in 1967 after completion of a successful operating and research program. SCE&G actively participated in the CVTR project in the planning, management, training, research, technical and operational levels.

SCE&G has maintained active participation in the fast breeder programs of both Westinghouse and Atomics International as well as participating in the Savannah River Nuclear Study Group which examined the feasibility of developing power from a production reactor.

Organization charts for SCE&G relevant to this project, are Figures 13.1-1 through 13.1-5. The engineering and construction of this project is the responsibility of the Vice-President, Group Executive, Engineering and Construction.

1.4.2 Gilbert Associates, Inc. Qualifications and Experience

Gilbert Associates, Inc. (Gilbert) engineers and consultants, is the architect engineer for the Virgil C. Summer Nuclear Station. The company, with its main office in Reading, Pennsylvania, was originally known as W. S. Barstow and Company which was organized in 1906. The corporate name was changed to E. M. Gilbert Engineering Corporation in 1933. In 1942, the corporate structure was revised to provide for complete employee ownership and the name became Gilbert Associates, Inc. In 1973, Gilbert Associates acquired Commonwealth Associates, Inc., a large engineering and consulting firm of similar capabilities.

Throughout the past 70 years, Gilbert has progressively grown in size and in scope of activity. The collective experience and capabilities of the firm offer complete consulting and engineering services to both investor-owner utilities and general industry in such diverse fields as: nuclear and conventional power generation; transmission, substation, and distribution systems; economic engineering and management consulting service; steel making and processing; cement and minerals processing; chemical and general industrial facilities; water desalination plants; institutional and commercial installations; environmental and solid waste treatment; and water production projects. Projects undertaken have ranged from large electric power generating plants and production facilities to small industrial boiler plants and allied service facilities.

Since 1942, Gilbert has been responsible for the design of well over 100 thermal generating units, both fossil and nuclear power, representing approximately 30,000,000 kW of new generating capacity. The company’s experience includes one of the first reheat units, one of the first once through boiler units and one of the first supercritical steam pressure units. Individual unit designs have ranged in ratings up to 1,200,000 kW and stations have varied complexity - nuclear, mine-

mouth, closed cycle cooling tower, base-load, peaking and others. At present, Gilbert has over 17,000,000 kW of generation under design, of which 10,600,000 kW is nuclear.

Since 1950, Gilbert has played an active and important role in the development of nuclear energy for private utilities, industry and governmental agencies. Gilbert projects include complete programs of nuclear power development involving analysis of sites, complete evaluations of proposals, contract and fuel program assistance, preparation of license applications, containment vessel design concepts, complete plant design and procurement. More than a score of studies, cost estimates, evaluations, concept developments and preliminary plant designs have been prepared since 1953 for various utility customers and other clients such as the Nuclear Regulatory Commission (formerly the Atomic Energy Commission), Westinghouse Electric Corporation, Atomics International and the Air Force. Development of reactor containment design concepts for plants near large population centers was accomplished in 1963. The first complete station design was the Saxton Experimental Power Reactor (20 MWe) in 1959. Other completed designs include the 490 MWe Robert Emmett Ginna Station for the Rochester Gas and Electric Corporation; the 320 MWe Mihama plant for the Kansai Electric Power Company, Inc.; the 781 MWe Takahama Station for the Kansai Electric Power Company, Inc. as subcontractor to Westinghouse Electric International Company; and the 870 MWe Three Mile Island Nuclear Station, Unit 1 for the Metropolitan Edison Company. Stations for which Gilbert now has overall plant design and engineering responsibility are the 855 MWe Crystal River Plant, Unit 3, for Florida Power Corporation; the 2 unit, 1200 MWe each, Perry Nuclear Power Plant for the Cleveland Electric Illuminating Company; the 2 unit, 1122 MWe each, Ohi Station (ice condenser), as subcontractor to Westinghouse for the Kansai Electric Power Company, Inc.; the 564 MWe Ko-Ri Station, Unit 1, as subcontractor to Westinghouse for the Korea Electric Power Company; and the 615 MWe Nuclear Power Plant Krsko for Savske Elektrarne, Ljubljana, Slovenia; Elektroprivreda, Zagreb, Croatia, as subcontractor to Westinghouse.

The Gilbert organization includes nearly 3700 employees with a complete staff of engineers, draftsmen and many technical specialists. Included in the total staff are over 2200 engineers, technical specialists and draftsmen. This includes members of management, professional personnel and individuals in other specialized fields.

Responsibility for engineering and design of nuclear power plants is centered in the Utilities Division of the Company. Every nuclear project is assigned to a Project Manager, selected from a staff of engineers having an average of about 15 years with Gilbert. Through this divisional control, the production function of the project is carried through to completion.

The engineering disciplines, such as nuclear, mechanical, electrical, civil, structural, architectural, environmental engineering, etc., are grouped into departments and provide technical resources to the project. Each department is managed by a chief engineer who assumes technical and administrative responsibility for the personnel assigned to the various projects. Figures 1.4-1 and 1.4-2 depict the Gilbert organization.

Additional support necessary to the project is provided from other service departments, including drafting, estimating, specifications, legal, accounting, purchasing, expediting, etc.

1.4.3 Westinghouse Electric Corporation Qualifications and Experience

Westinghouse Electric Corporation's (Westinghouse) experience in nuclear plants for the electric utility industry is demonstrated by the Pressurized Water Reactor (PWR) plants that Westinghouse has designed, developed, and manufactured. Table 1.4-1Table 1.4-1 lists all Westinghouse PWR plants to date, including those plants currently under construction or on order.

Westinghouse has long held a position of leadership in the electrical manufacturing industry. Traditionally this leadership has been based on technological development of both standard and new products, reliability and product quality. Nowhere is this traditional leadership displayed more vividly than in nuclear power. Through early participation in basic research and basic engineering development, Westinghouse has established a broad technological foundation in nuclear power application. This has been followed by a continuing program of sound technological development which enables Westinghouse to offer to the electric utility industry a reliable and safe source of power.

The experience of Westinghouse in nuclear activity is evident in numerous nuclear power projects completed, soon to go into operation, or under construction. The following paragraphs describe Westinghouse designed PWR plants which are presently in operation.

1.4.3.1 Plants in Operation

Westinghouse PWR plants in operation are as follows:

1. Shippingport

   Shippingport was the world's first large central station nuclear power plant. The reactor plant was designed by the Bettis Atomic Power Laboratory, which is operated by Westinghouse under a Nuclear Regulatory Commission (NRC) contract. Shippingport's PWR has produced power for Duquesne Light Company since December 1957.

2. Yankee-Rowe

   Singled out by the NRC as a "Nuclear Success Story," Yankee-Rowe went online in November 1960. Owned and operated by the Yankee Atomic Electric Company, Yankee-Rowe has progressed from an initial rating of 120 Mwe to its present 175 MWe rating. Westinghouse supplied the NSSS and the turbine generator.

3. Trino Vercellese (Enrico Fermi)

   The Trino Vercellese nuclear plant was one of the first Westinghouse designed plants to incorporate chemical shim control of reactivity. Chemical shim has since become a standard feature of Westinghouse PWR control. Trino Vercellese achieved initial criticality in June 1964 and began power operation in October 1964. The plant is rated at 261 MWe.

4. Chooz (Ardennes)

   The Chooz plant is unique in that the Westinghouse PWR and its auxiliaries are housed in man-made caverns. Ardennes, a joint Franco-Belgian undertaking, owned and operated by the Societe d'Energie Nucleaire Franco-Belge des Ardennes (SENA), is located in France near the French-Belgian border. Chooz achieved initial criticality in October 1966 and began power operation in 1967.

5. San Onofre No. 1

   San Onofre No. 1 employs the Westinghouse developed rod cluster control concept which has since become a standard feature on the Westinghouse PWR. Owned by the Southern California Edison Company and the San Diego Gas and Electric Company, the 430 MWe plant is located near San Clemente, California. Westinghouse supplied the NSSS and the turbine generator. Initial criticality was achieved in June 1967, and power operation began in January 1968.

6. Haddam Neck (Connecticut Yankee)

   Owned and operated by the Connecticut Yankee Atomic Power Company, this plant went critical in July 1967 and attained full power operation in December 1967. Like San Onofre No. 1, the plant employs rod cluster control in conjunction with chemical shim control. Westinghouse supplied the NSSS and the turbine generator. The plant has been uprated to 575 MWe.

7. Jose Cabrera-Zorita

   The Jose Cabrera-Zorita station is located near Zorita, Spain. The 153 MWe plant employs rod cluster control, chemical shim control and a Zircaloy clad core. Construction began in mid-1965, and power operation began in 1968. Jose Cabrera-Zorita is owned and operated by the Union Electrica, S.A., a Spanish utility.

8. Beznau No. 1 and No. 2

   Beznau No. 1, Switzerland's first commercial nuclear power plant, achieved initial criticality in June 1969 and supplied power to the system in July 1969. The 350 MWe plant was designed and constructed by the Westinghouse-Brown Boveri Consortium for the owner/operator utility, Nordostschweizerische Kraftwerke A. G. The plant started producing power less than four years after award of the plant contract. Beznau No. 2 achieved criticality in October 1971 and began commercial operation in early 1972.

9. Robert Emmett Ginna

   The Robert Emmett Ginna Plant, owned and operated by the Rochester Gas and Electric Corporation, is located in New York on the south shore of Lake Ontario. Westinghouse supplied the 490 MWe plant on a turnkey basis. Construction began in April 1966 with initial criticality being achieved in November 1969 (just 42 months after start of construction). Power was supplied to the system in December 1969.

10. Mihama No. 1 and Takahama No. 1

    These plants are owned by the Kansai Electric Power Company, Inc. Mihama No. 1 is a two-loop, 320-MWe unit and marks the beginning of a line of Westinghouse PWR's supplying the generation needs of the Far East. Westinghouse International Company was the prime contractor for the Mihama project, supplying the NSSS engineering, nuclear fuel, and some major system components. Mihama No. 1 required only 44 months from the start of site construction to first power production in August 1970. Takahama No. 1 is a three-loop, 781 MWe unit. Initial criticality was achieved in March 1974.

11. H. B. Robinson No. 2

    This plant is a three-loop, 700 MWe unit which was built on a turnkey basis for the Carolina Power and Light Company. The plant is located at a site near Hartsville, South Carolina on a man-made cooling lake. The construction permit was granted in April 1967. The plant achieved criticality in September 1970 and first power to the system in October 1970.

12. Point Beach No. 1 and No. 2

    The Point Beach Project consists of two 497 MWe units, which were built on a turnkey basis for the Wisconsin Michigan Power Company and the Wisconsin Electric Power Company. The plants are located near Two Creeks, Wisconsin, 90 miles north of Milwaukee on Lake Michigan. This was the first two-unit station to utilize many common facilities and shared auxiliary systems. The construction permit for Point Beach No. 1 was granted in July 1967 with initial criticality and first power to the system in November 1970. Point Beach No. 2 went critical in May 1972 and was available for commercial operation in October 1972.

13. Surry No. 1 and No. 2

    The Surry Power Station, two three-loop 788 MWe units, is owned by the Virginia Electric and Power Company. (The James River Station is about 30 miles from Norfolk, Virginia). First criticality on Surry No. 1 was achieved July 1972. Commercial operation began in September 1972. Initial criticality on Surry No. 2 was achieved in March 1973.

14. Turkey Point No. 3 and No. 4

Florida Power and Light Company is the owner of a four-unit station on Biscayne Bay, Florida. Turkey Point Nos. 3 and 4 of the station are three-loop, 666 MWe plants. Commercial status for Turkey Point No. 3 was achieved in December 1972. Initial criticality for Turkey Point No. 4 was achieved in June 1973.

15. Indian Point No. 2 and 3

    Consolidated Edison Company of New York operates three nuclear units located in Buchanan, New York; two are (units 1 and 2) owned by the company and one (unit No. 3) is owned by the Power Authority of the State of New York. Units 2 and 3 are Westinghouse PWRs rated at 873 and 965 MWe respectively. Indian Point No. 2 achieved initial criticality in May 1973 and Indian Point No. 3 achieved initial criticality in April 1976.

16. Prairie Island No. 1 and No. 2

    Northern States Power Company is the owner of these two-loop, 530 MWe units located in Welch, Minnesota. Initial criticality was achieved in December 1973 for Prairie Island No. 1 and in December 1974 for Prairie Island No. 2.

17. Zion No. 1 and No. 2

    Commonwealth Edison Company is the owner of these four-loop, 1050 MWe units located on Lake Michigan near Zion, Illinois. Initial criticality was achieved in June 1973 for Zion No. 1 and in December 1973 for Zion No. 2.

18. Kewaunee

    Wisconsin Public Service Corporation, Wisconsin Power and Light Company, and Madison Gas and Electric Company are the owners of this two-loop, 541 MWe plant located in Kewaunee, Wisconsin. Initial criticality was achieved in March 1974.

19. Ringhals No. 2

    Statens Vattenfallsverk (SSPB) is the owner of this three-loop, 822 MWe unit located in Sweden. Initial criticality was achieved in June 1974.

20. Donald C. Cook No. 1 and No. 2

    Indiana and Michigan Electric Company is the owner of these four-loop, 1060 MWe plants located in Bridgman, Michigan. These plants are the first to use the Westinghouse ice condenser containment design. Unit 1 initial criticality was achieved in January 1975, and Unit 2 initial criticality was achieved in 1978.

21. Trojan

    This four loop, 1130 MWe plant is jointly owned by Portland General Electric Company, Eugene Water and Electric Board, and Pacific Power and Light Company. In addition to being the first commercial nuclear plant to operate in the Pacific Northwest (located on the Oregon shore of the Columbia River near Rainier, Oregon), Trojan is the first 17 x 17 fuel-rod-per-assembly plant to achieve criticality. Initial criticality was achieved in December 1975.

22. Beaver Valley No. 1

    This three-loop, 852 MWe plant is jointly owned by Duquesne Light Company, Ohio Edison Company, and Pennsylvania Power Company. Beaver Valley No 1 is located on the Ohio River, 22 miles northwest of Pittsburgh, Pennsylvania. Commercial operation began in April 1977.

23. Salem No. 1

    Salem No. 1, owned jointly by the Public Service Electric and Gas Company, Philadelphia Electric Company, Atlantic Electric Company, and Delmarva Power and Light Company, is located on Artificial Island, a man-made peninsula in Salem County, New Jersey. The 1090 MWe, four-loop plant achieved initial criticality in late 1976.

1.4.3.2 Westinghouse Facilities

Westinghouse Electric Corporation was contracted to design, fabricate, and deliver the Nuclear Steam Supply System and Nuclear Fuel for the Virgil C. Summer Nuclear Station. Westinghouse provided technical assistance for the installation and startup of their supplied equipment.

1.4.4 Dames and Moore, Inc. Qualifications and Experience

The partnership of Dames and Moore, Inc. (D&M) was founded in 1938 in Los Angeles, California. Since then the firm has grown to more than 1400 employees in 25 offices in the United States and 17 offices in foreign countries.

The professional staff of D&M has a diversified background in the fields of land use planning, socioeconomics, demography, meteorology, air and water quality, biology, ecology, geology, soil and rock mechanics and dynamics, foundation engineering, geophysics, seismology, hydrology, marine engineering and systems management.

D&M has served more than 8500 clients in over 100 countries. The firm has performed more than 30,000 investigations of various types. D&M has been involved in site and environmental studies for close to half of the nuclear power plants under construction or planned in the United States. Within the Southeast, these projects include:

Arkansas Power & Light Company	Arkansas Nuclear One
Alabama Power Company	Joseph M. Farley
Carolina Power & Light Company	H. B. Robinson
Carolina Power & Light Company	Shearon Harris
Duke Power Company	Oconee
Florida Power & Light Company	Turkey Point
Florida Power & Light Company	South Dade
Florida Power & Light Company	St. Lucie
Georgia Power Company	Edwin I. Hatch
Virginia Electric & Power Company	North Anna
Virginia Electric & Power Company	Surry

1.4.5 Daniel Construction Company Qualifications and Experience

Daniel Construction Company (Daniel), a division of Daniel International Corporation, Greenville, S.C., has a wide variety of engineering and construction assignments. The parent company, Daniel International Corporation has in excess of $10,000,000 worth of projects currently in engineering or construction in many parts of the world. A recent survey of the nation's 400 largest contractor rates Daniel 3rd in contract awards, and 32nd in design/construction awards. Daniel has acquired extensive construction and project management experience in major industrial complexes for the chemical, paper, rubber, textile, aluminum and power generation industries. These construction services involve the ability to meet precise tolerances and specifications on erection, fabrication and equipment installation and have required a thorough knowledge of heavy construction, mechanical, electrical and instrumentation techniques and methods. This experience and the developed capabilities are applicable to the construction of nuclear power facilities.

The Daniel quality assurance program for ASME nuclear code construction has been evaluated and accepted by an ASME survey team and an interim certificate of authorization issued.

The certificate of authorization to perform code construction ("N" Stamp) will be obtained following the successful completion of an ASME survey team field implementation and enforcement audit at the Virgil C. Summer Nuclear Station.

Daniel's experience, past and present, include construction of nuclear and fossil fueled power plants. First project of this nature was construction of the nuclear power CVTR at Parr, S.C. This

facility operated several years as a prototype plant. Power plants completed or currently under construction are specified below:

1. Alabama Power Co. J. M. Farley Project Unit 1 & 2 847 MW (each)
2. Carolina Power & Light Co. Shearon Harris Unit 1, 2, 3, & 4 900 MW (each) Darlington Elec. Plant (Turbines) 660 MW
3. Detroit Edison Company Fermi II Unit 2 1150 MW
4. Duke Power Company Spencer Facility 170 MW Cliffside Facility 575 MW
5. Georgia Power Company Vogtle Plant (Turbines) 300 MW McManus Plant (Turbines) 360 MW Plant Wansley Unit 1 & 2 880 MW (each)
6. Kansas City Power & Light Company Kansas Gas & Electric La Cygne Unit 2 600 MW Wolf Creek Unit 1 1150 MW
7. Kansas City Power & Light Company St. Joseph Light & Power Iatan Station 630 MW
8. South Carolina Electric & Gas Company Arthur M. Williams (Turbines) 60 MW Arthur M. Williams Unit 1 600 MW Virgil C. Summer Unit 1 918 MW Fairfield Pumped Storage (8 Units) 480 MW
9. Union Electric Company Callaway Generating Plant Unit 1 & 2 1150 (each)
10. Virginia Electric & Power Company Bath County Pumped Storage (6 units) 2100 MW

In addition to constructing numerous gas turbine power stations, Daniel is currently building a nuclear fuel reprocessing plant for Allied Gulf Nuclear Services.

Table 1.4-1
Westinghouse Pressurized Water Reactor Nuclear Power Plants

Plant	Owner Utility	Location	Scheduled Commercial Operation	Mwe Net	Number of Loops
Shippingport	Duquesne Light Company; Research & Development Administration	Pennsylvania	1957	90	4
Yankee-Rowe	Yankee Atomic Electric Company	Massachusetts	1961	175	4
Trino Vercellese (Enrico Fermi)	Ente Nazionale per L'Energia Elettrica (ENEL)	Italy	1965	261	4
Chooz (Ardennes)	Societe d'Energie Nucleaire Franco-Belge des Ardennes (SENA)	France	1967	309	4
San Onofre No. 1	Southern California Edison Co.; San Diego Gas and Electric Co.	California	1968	430	3
Haddam Neck (Connecticut Yankee)	Connecticut Yankee Atomic Power Company	Connecticut	1968	575	4
Jose' Cabrera-Zorita	Union Electrica, S. A.	Spain	1969	153	1
Beznau No. 1	Nordostschweizerische Kraftwerke AG (NOK)	Switzerland	1969	350	2
Robert Emmett Ginna	Rochester Gas and Electric Corporation	New York	1970	490	2
Mihama No. 1	The Kansai Electric Power Company, Inc.	Japan	1970	320	2

Table 1.4-1
Westinghouse Pressurized Water Reactor Nuclear Power Plants (continued)

Plant	Owner Utility	Location	Scheduled Commercial Operation	Mwe Net	Number of Loops
Point Beach No. 1	Wisconsin Electric Power Co.; Wisconsin Michigan Power Co.	Wisconsin	1970	497	2
H. B. Robinson No. 2	Carolina Power and Light Co.	South Carolina	1971	700	3
Beznau No. 2	Nordostschweizerische Kraftwerke AG (NOK)	Switzerland	1972	350	2
Point Beach No. 2	Wisconsin Electric Power Co.; Wisconsin Michigan Power Co.	Wisconsin	1973	497	2
Surry No. 1	Virginia Electric and Power Co.	Virginia	1972	788	3
Turkey Point No. 3	Florida Power and Light Co.	Florida	1972	666	3
Indian Point No. 2	Consolidated Edison Company of New York, Inc.	New York	1973	873	4
Prairie Island No. 1	Northern States Power Company	Minnesota	1973	530	2
Turkey Point No. 4	Florida Power and Light Co.	Florida	1973	666	3
Surry No. 2	Virginia Electric and Power Co.	Virginia	1973	788	3
Zion No. 1	Commonwealth Edison Company	Illinois	1973	1050	4
Kewaunee	Wisconsin Public Service Corp.; Wisconsin Power and Light Co.; Madison Gas and Electric Co.	Wisconsin	1974	541	2
Prairie Island No. 2	Northern States Power Company	Minnesota	1974	530	2

Table 1.4-1
Westinghouse Pressurized Water Reactor Nuclear Power Plants (continued)

Plant	Owner Utility	Location	Scheduled Commercial Operation	Mwe Net	Number of Loops
Takahama No. 1	The Kansai Electric Power Company, Inc.	Japan	1974	781	3
Zion No. 2	Commomwealth Edison Company	Illinois	1974	1050	4
Doel No. 1	Indivision Doel	Belgium	1975	390	2
Doel No. 2	Indivision Doel	Belgium	1975	390	2
Donald C. Cook No. 1	Indiana and Michigan Electric Company (AEP)	Michigan	1975	1060	4
Ringhals No. 2	Statens Vattenfallsverk (SSPB)	Sweden	1975	822	3
Almaraz No. 1	Union Electrica, S. A.,; Compania Sevillana de Electricidad, S. A.; Hidroelectrica Espanola, S. A.	Spain	1981	902	3
Beaver Valley No. 1	Duquesne Light Company; Ohio Edison Company; Pennsylvania Power Company	Pennsylvania	1976	852	3
Diablo Canyon No. 1	Pacific Gas and Electric Co.	California	1980	1084	4
Indian Point No. 3	Consolidated Edison Company of New York, Inc.	New York	1976	965	4
Lemoniz No. 1	Iberduero, S. A.	Spain	1982	902	3

Table 1.4-1
Westinghouse Pressurized Water Reactor Nuclear Power Plants (continued)

Plant	Owner Utility	Location	Scheduled Commercial Operation	Mwe Net	Number of Loops
Salem No. 1	Public Service Electric and Gas Company; Philadelphia Electric Co.; Atlantic City Electric Co.; Delmarva Power and Light Co.	New Jersey	1977	1090	4
Trojan	Portland General Electric Co.; Eugene Water and Electric Board; Pacific Power and Light Company	Oregon	1976	1130	4
Almaraz No. 2	Union Electrica, S. A.; Compania Sevillana de Electricidad, S. A.; Hidroelectrica Espanola, S. A.	Spain	1984	902	3
Asco No. 1	Fuerzas Electricas de Cataluna, S. A. (FESCA)	Spain	1982	902	3
Diablo Canyon No. 2	Pacific Gas and Electric Co.	California	1981	1106	4
Joseph M. Farley No. 1	Alabama Power Company	Alabama	1977	829	3
Ko-Ri No. 1	Korea Electric Power Co., Ltd.	Korea	1978	564	2
North Anna No. 1	Virginia Electric and Power Co.	Virginia	1978	898	3
North Anna No. 2	Virginia Electric and Power Co.	Virginia	1980	898	3
Ohi No. 1	The Kansai Electric Power Co., Inc.	Japan	1979	1122	4

Table 1.4-1
Westinghouse Pressurized Water Reactor Nuclear Power Plants (continued)

Plant	Owner Utility	Location	Scheduled Commercial Operation	Mwe Net	Number of Loops
Ohi No. 2	The Kansai Electric Power Co., Inc.	Japan	1979	1122	4
Ringhals No. 3	Statens Vattenfallsvert (SSPB)	Sweden	1981	900	3
Sequoyah No. 1	Tennessee Valley Authority	Tennessee	1980	1148	4
Angra dos Reis No. 1	Furnas-Centrais Electricas, S.A.	Brazil	1981	626	2
Asco No. 2	Fuerzas Electricas de Cataluna, S. A. (FESCA); Empresa Nacional Hidroelectrica del Ribagorzana, S. A. (ENHER); Fuerzas Hidroelectricas	Spain	1983	902	3
Donald C. Cook No. 2	Indiana and Michigan Electric Company (AEP)	Michigan	1978	1060	4
Lemoniz No. 2	Iberduero, S. A.	Spain	1984	902	3
Sequoyah No. 2	Tennessee Valley Authority	Tennessee	1981	1148	4
Watts Bar No. 1	Tennessee Valley Authority	Tennessee	1981	1177	4
William B. McGuire No. 1	Duke Power Company	North Carolina	1981	1180	4
Joseph M. Farley No. 2	Alabama Power Company	Alabama	1980	829	3
Krsko	Savske Elektrarne, Ljubljana, Slovenia, Elektroprivreda Zagreb, Croatia	Yugoslavia	1981	615	2

Table 1.4-1
Westinghouse Pressurized Water Reactor Nuclear Power Plants (continued)

Plant	Owner Utility	Location	Scheduled Commercial Operation	Mwe Net	Number of Loops
Ringhals No. 4	Statens Vattenfallsvert (SSPB)	Sweden	1982	900	3
Salem No. 2	Public Service Electric and Gas Company; Philadelphia Electric Co.; Atlantic City Electric Co.; Delmarva Power and Light Co.	New Jersey	1980	1115	4
Virgil C. Summer	South Carolina Electric and Gas Company.	South Carolina	1981	900	3
Watts Bar No. 2	Tennessee Valley Authority	Tennessee	1982	1177	4
William B. McGuire No. 2	Duke Power Company	North Carolina	1982	1180	4
Comanche Peak No. 1	Texas Utilities Generating	Texas	1983	1150	4
Bryon No. 1	Commonwealth Edison Co.	Illinois	1984	1120	4
Seabrook No. 1	Public Service Company of New Hampshire; United Illuminating Company	New Hampshire	1984	1200	4
South Texas Project Unit No. 1	Houston Lighting and Power Co.; Central Power and Light Co.; City Public Service of San Antonio; City of Austin, Texas	Texas	1983	1250	4

Table 1.4-1
Westinghouse Pressurized Water Reactor Nuclear Power Plants (continued)

Plant	Owner Utility	Location	Scheduled Commercial Operation	Mwe Net	Number of Loops
Beaver Valley No. 2	Duquesne Light Company; Ohio Edison Company; Pennsylvania Power Co.; Cleveland Electric Illuminating Company; Toledo Edison Company	Pennsylvania	1986	852	3
Braidwood No. 1	Commonwealth Edison Company	Illinois	1985	1120	4
Callaway No. 1	SNUPPS - Union Electric Co.	Missouri	1983	1150	4
Catawba No. 1	Duke Power Company	South Carolina	1985	1153	4
Ko-Ri No. 2	Korea Electric Power Co., Ltd.	Korea	1983	605	2
Braidwood No. 2	Commonwealth Edison Company	Illinois	1986	1120	4
Byron No. 2	Commonwealth Edison Company	Illinois	1985	1120	4
Comanche Peak No. 2	Texas Utilities Generating Co.	Texas	1985	1150	4
Marble Hill No. 1	Public Service Company of Indiana, Inc.; Northern Indiana Public Service Company	Indiana	1984	1150	4
Millstone No. 3	Northeast Nuclear Energy Co.	Connecticut	1987	1156	4
Seabrook No. 2	Public Service Company of New Hampshire; United Illuminating Company	New Hampshire	1989	1200	4

Table 1.4-1
Westinghouse Pressurized Water Reactor Nuclear Power Plants (continued)

Plant	Owner Utility	Location	Scheduled Commercial Operation	Mwe Net	Number of Loops
South Texas Project Unit No. 2	Houston Lighting and Power Co.; Central Power and Light Co.; City Public Service of San Antonio; City of Austin, Texas	Texas	1986	1250	4
Taiwan Unit No. 5	Taiwan Power Company	Taiwan	1984	950	3
Wolf Creek Unit No. 1	SNUPPS - Kansas Gas and Electric Company; Kansas City Power and Light Company	Kansas	1983	1150	4
Alvin W. Vogtle No. 1	Georgia Power Company	Georgia	1986	1113	4
Taiwan Unit No. 6	Taiwan Power Company	Taiwan	1985	950	3
Alvin W. Vogtle No. 2	Georgia Power Company	Georgia	1991	1113	4
Marble Hill No. 2	Public Service Company of Indiana, Inc.; Northern Indiana Public Service Company	Indiana	1985	1150	4
Shearon Harris No. 1	Carolina Power and Light Co.	North Carolina	1987	900	3
Shearon Harris No. 2	Carolina Power and Light Co.	North Carolina	1988	900	3
Atlantic No. (O.P.S.)	Public Service Electric and Gas Company; Atlantic City Electric Co.; Jersey Central Power and Light Company	New Jersey	1987	1150	4
Shearon Harris No. 4	Carolina Power and Light Co.	North Carolina	1988	900	3
Sundesert No. 2	San Diego Gas and Electric Co.	California	1988	950	3

Table 1.4-1
Westinghouse Pressurized Water Reactor Nuclear Power Plants (continued)

Plant	Owner Utility	Location	Scheduled Commercial Operation	Mwe Net	Number of Loops
Sayago No. 1	Iberduero, S. A.	Spain	1980’s	1000	3
Unit No. 4	Iberduero, S. A.	Spain	1980’s	1000	3
Shearon Harris No. 3	Carolina Power and Light Co.	North Carolina	1990	900	3
Unassigned No. 1 (O.P.S.)	Public Service Electric and Gas Company; Atlantic City Electric Company	New Jersey	1990	1150	4
Unassigned No. 2 (O.P.S.)	Public Service Electric and Gas Company; Atlantic City Electric Company	New Jersey	1992	1150	4

Figure 1.4-1
Gilbert Commonwealth Corporate Organization

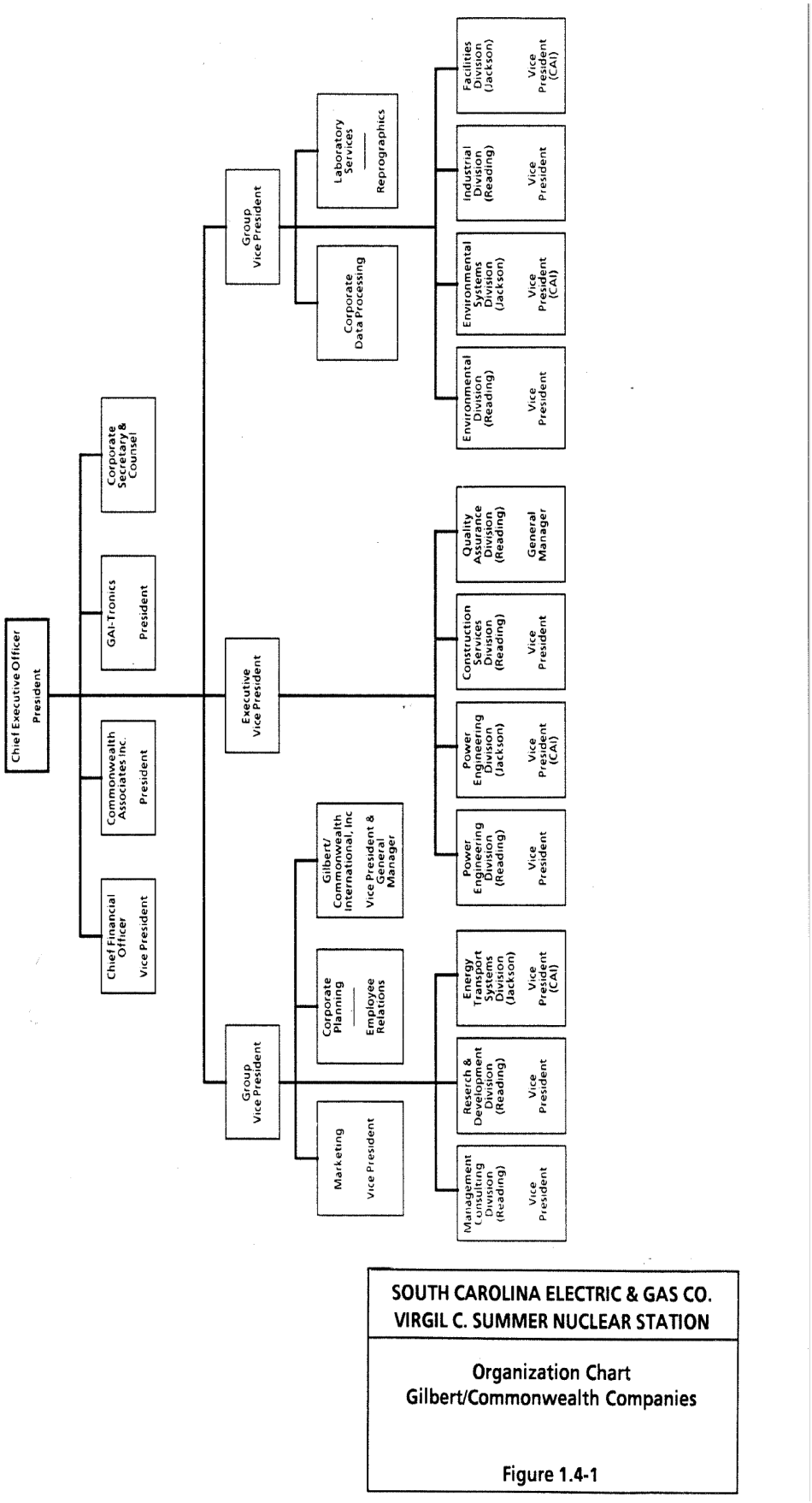
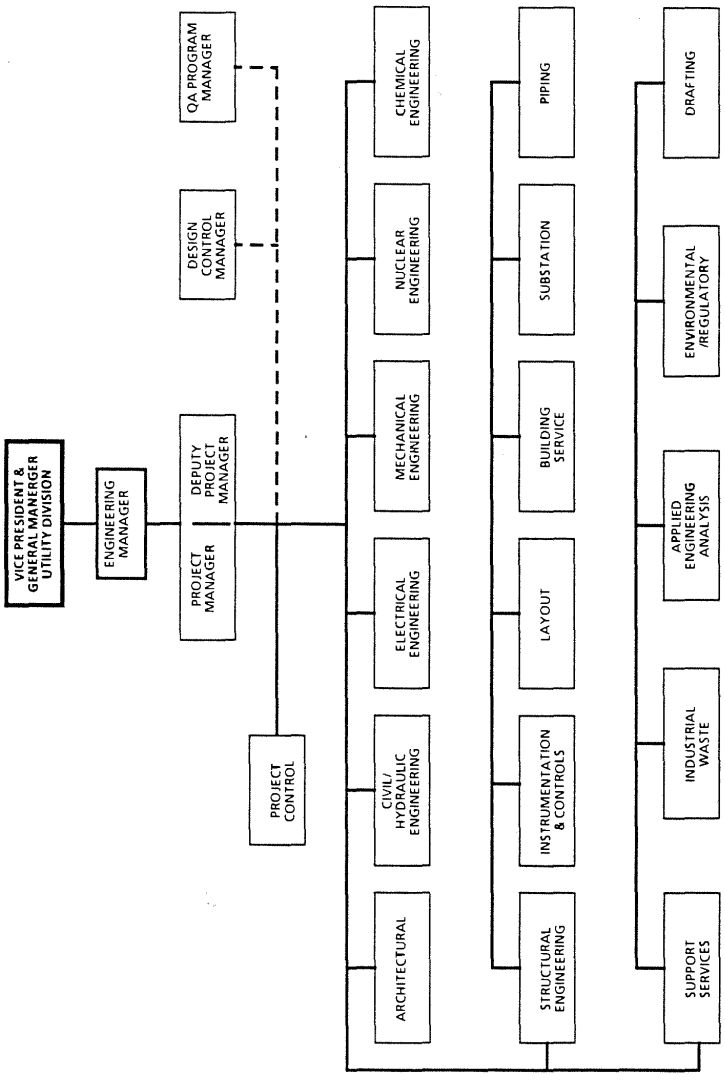


Figure 1.4-2
Organization Chart Gilbert Project Engineering



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Organization Chart
Gilbert Project Engineering

Figure 1.4-2

NOTE: Section 1.5 is being retained for historical purposes only.

1.5 REQUIREMENTS FOR FURTHER TECHNICAL INFORMATION

Reference 1 presents descriptions of the safety-related research and development programs which are being carried out for, or by, or in conjunction with, Westinghouse Nuclear Energy Systems, and which are applicable to Westinghouse Pressurized Water Reactors.

For each program described in this section and still in progress, the safety-related program is first introduced, followed, where appropriate, by background information. There is, then, a description of the program which relates the program objectives to the problem and presents pertinent recent results. Finally, an alternate position may be given for programs (generally experimental rather than analytical) which have not yet reached a stage where it is reasonably certain that the results confirm the expectation. The alternate position is one that might be used if the results are unfavorable; it is not necessarily the only course that might be taken.

The term “research and development”, as used in this section, is the same as that used by the Commission in Section 50.2 of its regulations, that is:

> (n)“Rearch and development” means (1) theoretical analysis, exploration, or experimentation; or (2) the extension of investigative findings and theories of a scientific nature into practical application for experimental and demonstration purposes, including the experimental production and testing of models, devices, equipment, materials, and processes.

The technical information generated by these research and development programs will be used either to demonstrate the safety of the design and more sharply define margins of conservatism, or will lead to design improvements.

Progress in these development programs will be reported on a timely basis. New safety-related research and development programs, which include existing programs which become safety-related, will also be described.

Included in the overall research and development effort are the programs below which are applicable to the 17 x 17 fuel assembly. The test programs were completed during 1975 in order to support the initial loading of the first 17 x 17 fuel in late 1975.

1.5.1 Verification Tests (17 x 17)

The design of the reactor uses a 17 x 17 square array of fuel rods and thimbles in a fuel assembly and is conceptually similar to, but geometrically different from, the 15 x 15 array used in previous designs. The 17 x 17 design is considered to be a relatively small extrapolation of the 15 x 15

design. Comprehensive testing has been performed to verify that the extrapolation is sufficiently conservative.

Westinghouse maintains that no plant need be designated a prototype and instrumented to verify the 17 x 17 fuel design. The change in flow induced vibration response of the internals from a 15 x 15 to a 17 x 17 fuel design will be minimal for the following reasons:

1. The only structural changes in the internals, other than the fuel assemblies, resulting from the design change from the 15 x 15 to the 17 x 17 fuel assembly are the guide tube and control rod drive line.
2. The guide tube is rigidly attached at the upper core support plate only. The upper core plate serves only to align the guide tubes. Because of this type of support arrangement, the guide tube has a minimal contribution to the vibrational response of the core barrel and other internal components.
3. The effective flow area of the 17 x 17 guide tube is essentially the same as that of the 15 x 15 guide tube and therefore, there are no significant differences in the flow distribution in the upper plenum.
4. The fuel assembly lateral spring rate was found by applying loads at various grid locations with both nozzles restrained. This test assures that the effects of the fuel on the vibrational response of the reactor internals will remain essentially unchanged between the 15 x 15 and the 17 x 17 fuel assembly design because of the small variance of mass and spring rate between the tow designs. The preoperational hot functional flow testing presented in Chapter 14 is considered the most conservative test condition since higher flowrates exist.

Some of the verification work described herein was conducted using 17 x 17 assemblies of seven grid design whereas, the selected 17 x 17 assembly design has eight grids. Tabulated below are those 17 x 17 tests which utilized a seven grid geometry and the effect of adding an eighth grid.

Test	Parameter	Effect
Fuel Assembly Structural Test	Axial Stiffness	Negligible effect at blowdown impact forces[2].
	Lateral Impact	Additional grid shares impact load[2].
Prototype Assembly Test	Pressure Drop	The margin between 7 grid design P and D-Loop results[3] is adequate to cover the additional P resulting from the additional grid (< 5% increase in P).
	Lift Force	The margin between 7 grid design lift force and D-Loop results[3] is adequate to cover the additional lift force resulting from the additional grid
	Rod Vibration	Decreased span length results in improved vibration characteristics and reduced rod wear.
Departure from Nucleate Boiling (DNB)	DNB Correlation	Addition of a grid increases mixing which increases DNB margin. The effect of additional grid testing is presented in Reference (4).
Incore Flow Mixing	Thermal Diffusion Coefficient (TDC)	TDC increases as grid spacing decreases[5].

The above tabulation shows that:

1. Additional design changes are not required (e.g., number of new fuel assembly holddown springs) due to the addition of a grid, and
2. Seven grid test information can be used to assess the adequacy of the eight grid design.

Additional testing to specifically investigate the eight grid assembly is not required.

1.5.1.1 Rod Cluster Control Spider Tests

1.5.1.1.1 Test Purposes and Parameters

The 17 x 17 rod cluster control spider is conceptually similar to, but geometrically different from, the 15 x 15 spider. The 17 x 17 spider supports 24 rodlets (the 15 x 15 design supports 20) with no vane supporting more than two rodlets (same as the 15 x 15 design).

The rod cluster control spider tests verified the structural adequacy of the design. The spider vane to hub joint was tested for structural adequacy by:

1. Vertical static load test to failure, and
2. Vertical fatigue test to approximately 3.0 x 10^6 steps.

The static load test was performed by applying tensile and compressive loads to the spider. The load was applied parallel to the spider hub and reacted between the spider hub and fingers. The spider fingers shared the load equally. The number of cycles for the fatigue test was determined from the expected number of steps a control rod drive mechanism would experience during 20 years in a load follow reactor (1.5 x 10^6 steps). The test met the recommended cyclic test requirements of the ASME Code, Section III, Appendix II, paragraph 1520.

The spring pack within the spider hub was tested to determine the spring load deflection characteristic as a function of the loading cycles seen by the spring. The test was terminated after 1000 cycles compared to a 400 cycle (rod drop) design value. The test loads were equal to or greater than that predicted to result in spring material yielding. These loads were in excess of the design values. The test acceptance criterion was for the spring to retain adequate preload after the repeated cycling.

1.5.1.1.2 Facility

The 17 x 17 spider tests were performed at the Westinghouse Engineering Mechanics Laboratory (see Section 1.5.3.2.15)

1.5.1.1.3 Status

Spider tests have been completed. A vertical static load test approximately seven times the design dynamic load did not result in spider vane to hub joint failure. A spider was tested to 2.8 x 10^6 steps without failure. The spider loading was 110 percent of the design value for 1.8 x 10^6 cycles and 220 percent of the design loading for 1 x 10^6 cycles. Design load is 3600 pounds compression and 1800 pounds tension. The spring test resulted in negligible preload loss.

1.5.1.2 Grid Tests

1.5.1.2.1 Test Purpose and Parameters

The 17 x 17 grid is conceptually similar to, but geometrically different from the 15 x 15 "R" grid. The purpose of the grid tests is to verify the structural adequacy of the grid design.

Load deflection tests have been made on the grid spring and dimple. Grid spring radial (normal) stiffness and the grid dimple radial and tangential stiffness were obtained. This information was used to verify that the fuel rod clad wear evaluation has been based on conservative values of these parameters. The fuel rod wear evaluation is conservative as shown by the flow test results presented in Reference 3.

The grid buckling strength has been determined from tests using both static and dynamic loads. The loads were applied uniformly to the face of the outside strap, transmitted directly through the grid and reacted at the grid face opposite the input. A description of the grid impact test along with a description of the analytical use of the test parameters is given in Reference 2. These tests are used to verify that grid buckling during a postulated seismic occurrence does not interfere with control rod insertion.

1.5.1.2.2 Facility

The grid tests were conducted at the Westinghouse Engineering Mechanics Laboratory (see Section 1.5.3.2.15.

1.5.1.2.3 Status

The grid tests have been completed. Test results are in agreement with pretest design values. The test results, along with fuel assembly structural test results, were factored into the seismic analysis (Reference 2).

1.5.1.3 Fuel Assembly Structural Tests

1.5.1.3.1 Test Purpose and Parameters

The 17 x 17 fuel assembly tests were performed to determine mechanical strength and properties. The fuel assembly parameters obtained were as follows:

1. Lateral and axial stiffness.
2. Impact and internal structural damping coefficients.
3. Vibrational characteristics.
4. Lateral and axial impact response for postulated accident loads.

The parameters obtained from the lateral dynamic tests are used for seismic analysis, while those obtained from the axial tests are incorporated in the loss of coolant (blowdown) accident analysis. The remaining tests are primarily to demonstrate that the assembly has sufficient mechanical strength to preclude damage during shipment, normal handling, and normal operation.

The fuel assembly is subjected to both lateral and axial loads to obtain the respective static axial and lateral stiffnesses. The information obtained from these tests is used to establish parameters primarily for accident analysis since these conditions appear limiting. The axially applied loads, which were well in excess of shipment, normal handling and normal operational design loads, did not result in any fuel assembly permanent deformation or damage.

Static loads were incrementally applied to the fuel assembly to determine its lateral stiffness. The tests were accomplished with both nozzles fixed in place and forces applied to various grids.

The fuel assembly was dynamically tested in a vertical position using core pins to simulate reactor support conditions. An electrodynamic shaker was attached to the center (4th) grid to provide excitation. The fuel assembly mode shapes and corresponding natural frequencies were obtained from displacement transducers. A comparison of analytical and experimental results is given in Reference 2. Experimental vibrational studies of individual fuel rods were also performed. The rods were tested under simulated fuel assembly support conditions and as assembled in a prototype fuel assembly. The information obtained from these tests included the fundamental frequencies and mode shapes. A general test description and a summary of the results is presented in Reference 3.

The fuel assembly axial stiffness was found by incrementally increasing the static load (compressive) and then incrementally decreasing the static load.

Lateral impact tests were performed by displacing the center of the assembly with the nozzles fixed in place. The assembly was released and allowed to impact on lateral restraints at each of the five center grid locations.

The axial impact response and damping were found by dropping the fuel assembly from various heights. The axial impact test was performed with the fuel assembly in the upright position.

The relevant parameters measured during the lateral and axial impact tests are as follows:

1. Impact duration versus impact load.
2. Impact force versus drop height or initial displacement.
3. Impact damping or restitution as a function of impact force.

A general description of the test procedure, including a description of use of the parameters as related to accident analysis is presented in Reference 2.

There is a general axial test buckling criterion which does not allow local buckling of components which could preclude control rod insertion during an accident. The fuel assembly overall buckling and component local buckling is checked during the axial static and dynamic tests. The lateral displacement associated with the fuel assembly overall (beam type) buckling is limited by the reactor internals clearances and therefore buckling does not reduce the fuel assembly ultimate strength. Local component buckling was not experienced during either the static or dynamic tests for loads well in excess of the design values. The general acceptance criteria was not violated.

1.5.1.3.2 Facility

These tests were conducted at the Westinghouse Engineering Mechanics Laboratory (see Section 1.5.3.2.15) .

1.5.1.3.3 Status

The fuel assembly structural tests have been completed. The fuel assembly structural test results are factored into the seismic and blowdown analyses (Reference 2).

Guide Tube Tests

A new guide tube was designed to accommodate the 24 rodlet pattern adopted for 17 x 17 cores. This guide tube is sufficiently strong to provide increased margins of safety over present guide tubes. The main features of the new design are full length enclosures and cylindrical upper enclosures. The 17 x 17 (24 rodlet) pattern reduced the central area available for driveline passage significantly, thus necessitating a generally tighter design of the rod guidance elements.

The following guide tube tests are considered as engineering tests.

These tests are used as design tools and are not specifically required for demonstration of plant safety.

1. Engineering Prototype Assembly Tests.
2. Guide Tube Drop and Deflection Test.

1.5.1.4 Engineering Prototype Assembly Tests

1.5.1.4.1 Test Purpose and Parameters

The purpose of these tests was to demonstrate that the 17 x 17 fuel assembly and driveline hardware designs perform as predicted. These tests were run prior to the required plant functional tests and are used as an engineering information test to obtain experimental data. A single set of driveline hardware, including control rods, was used in the tests. The fuel assemblies and driveline were subjected to flow and system conditions covering those most likely to occur in a plant during normal operation as well as during a pump overspeed transient.

These tests are used to verify, from an engineering confidence standpoint, the integrated fuel assembly and rod cluster control performance in several areas. Data obtained included pressures and pressure drops throughout the system, hydraulic loadings on the fuel assembly and driveline, control rod drop time and stall velocity, fuel rod vibration and control rod, driveline, guide tube, and guide thimble wear during a lifetime of operation. None of this information is considered to be safety-related.

Specifically, two full size 17 x 17 fuel assemblies (one for Phase I and one for Phase II and III testing), one control rod, drive shaft and control rod drive mechanism were installed and tested in the 24 inch inside diameter x 40 foot high D-Loop at the Westinghouse Test Engineering Laboratory Facility.

1.5.1.4.1.1 Fuel Assembly Life Test (Phase 1)

The first fuel assembly was subjected to the maximum expected control rod travel during one fuel assembly lifetime. The nominal test conditions were a flow velocity based on the design flowrate, a temperature of 585°F and a pressure of 2000 psig. These conditions represent an extreme set of conditions.

Using an instrumented 17 x 17 prototype fuel assembly, guide tube and rod cluster control drive assembly, the tests conducted in the D-Loop obtained information on the following:

1. Mechanical integrity and performance
2. Drop time
3. Fuel rod vibration
4. Control rod velocity
5. Hydraulic lift force
6. Guide thimble dashpot pressure

Following this, the prototype fuel assembly underwent a complete post test evaluation and the guide tubes and driveline were inspected for any abnormal wear conditions. The purpose of this test was basically to determine the effect of the 17 x 17 fuel assembly and control rod configuration of Items 1 through 6 in Phase I and Items 1 and 2 in Phases II and III. The effect on control rod drop due to a seismic disturbance is evaluated analytically.

1.5.1.4.1.2 Guide Tube and Rod Cluster Control Life Test (Phase II and Phase III)

The second fuel assembly was then installed to continue the test at the same flow and temperature until 3,000,000 total steps of the driveline were accumulated. For Phases II and III, testing was run at temperatures between 100°F and 585°F and at flowrates from 50 percent to 140 percent of the design flowrate.

The test included a program of control rod drops and mechanism stepping that approximates the driveline duty for the design lifetime of an operating plant (Phase II). Specifically, approximately 1,275,000 mechanism steps and approximately 270 control rod drops were accumulated. The components were then inspected. Following inspections, testing was continued until a total of 3,000,000 mechanism steps and approximately 500 control rod drops were accumulated (Phase III testing).

These tests were directed toward:

1. Life wear evaluation
2. Drop time
3. Rod stall characteristics

These tests are not safety-related tests; they are used as engineering tools. Final verification is demonstrated during the precritical rod drop tests.

At the completion of Phase II tests, the test assembly was inspected to determine guide tube and driveline wear characteristics. This inspection was repeated at the end of the test (Phase III).

1.5.1.4.2 Facility

The above testing is conducted in the Westinghouse Test Engineering Laboratory Facility (see Section 1.5.3).

1.5.1.4.3 Status

The D-Loop testing has been completed. The results of the testing are given in References 3 and 6.

1.5.2 Loca Heat Transfer Tests (17 x 17)

1.5.2.1 17 X 17 Reflood Heat Transfer Tests

Extensive experimental programs have recently been performed with a simulated 17 x 17 assembly to determine its behavior under Loss of Coolant Accident (LOCA) conditions. The 17 x 17 tests were conducted in the G-Loop facility at the Westinghouse Forest Hills Laboratory.

Results from the 17 x 17 programs were compared with data from the 15 x 15 assembly test programs and were used to confirm predictions made by correlations and codes based on the 15 x 15 test results (see Reference 7).

1.5.2.2 Facility Description

The 17 x 17 test facility provides experimental measurements on the reflooding behavior of a 17 x 17 rod array following a LOCA. The test assembly consists of an array of 336 electrically heated rods and 25 guide tube thimbles arranged in a 17 x 17 array. The heater rod diameter, the active heated length, and pitch spacing is identical to that used in the 17 x 17 fuel. There were eight Westinghouse production mixing vane grids in the bundle.

1.5.2.3 Delayed Departure From Nucleate Boiling Testing

1.5.2.3.1 Introduction

The NRC Acceptance Criteria for Emergency Core Cooling Systems (ECCS) for Light-Water Power Reactors was issued in Section 50.46 of 10 CFR 50 on December 28, 1973. It defines the basis and conservative assumptions to be used in the evaluation of the performance of the ECCS. Westinghouse believes that some of the conservatism of the criteria is associated with the manner in which transient DNB phenomena are treated in the evaluation models. Transient critical heat flux data presented at the 1972 specialist’s meeting of the Committee on Reactor Safety

Technology (CREST) indicated that the time to DNB can be delayed under transient conditions. To demonstrate the conservatism of the ECCS evaluation models, Westinghouse has initiated a program to experimentally simulate the blowdown phase of a LOCA. This testing is scheduled for the middle of 1976 as part of an Electric Power Research Institute (EPRI) sponsored Blowdown Heat Transfer Program. This program is scheduled for completion at the end of 1976. Development of a transient DNB correlation for use in the Westinghouse ECCS analysis is planned for completion in 1977.

1.5.2.3.2 Objective

The objective of the delayed departure from nucleate boiling (DDNB) test is to determine the time that DNB occurs under LOCA conditions. This information will be used to confirm the existing, or develop a new, Westinghouse transient DNB correlation. The steady-state DNB data obtained from 15 x 15 and 17 x 17 test programs can be used to assure that the minimal geometric differences between the two fuel arrays can be correctly treated in the transient correlations.

1.5.2.3.3 Program

The program is divided into two phases. Phase I simulates PWR behavior during a LOCA to permit definition of the time delay associated with onset of DNB. Tests in this phase will cover the large double ended guillotine cold leg break. All tests in Phase I are started after establishment of typical steady-state operating conditions. The fluid transient is then initiated, and the rod power decay is programmed in such a manner as to simulate the actual heat input of fuel rods. The test is terminated when the heater rod temperatures reach a predetermined limit (dependent on power level).

Typical parameters which can be studied under Phase I testing are shown in Table 1.5-1.

Phase II will provide separate effects data to permit heat transfer correlation development.

The Phase II tests will also start from steady-state conditions, with sufficient power to maintain nucleate boiling throughout the bundle. Controlled ramps of decreasing test section pressure or flow will initiate DNB. By applying a series of controlled conditions, investigation of the DNB will be studied over a range of qualities and flows and at pressures relevant to a PWR blowdown.

Typical parameters which can be studied under Phase II testing are shown in Table 1.5-2.

1.5.2.3.4 Test Description

The experimental program is being conducted in the J-Loop at the Westinghouse Forest Hills Facility with a full length 5 x 5 rod bundle simulating a section of a 15 x 15 assembly to determine DNB occurrence under LOCA conditions.

The heater rod bundles to be used in this program will be assembled using internally heated rods and Westinghouse grids. The heater rods are designed for high reliability, long life, and high power density. The maximum power is 18.8 kW/ft, and the total power is 135 kW for extended

periods over the 12 foot heated length of the rod. Heat is generated internally by means of a varying cross-section, rugged, tubular resistor which approximates a U^2 cos U power distribution, skewed to the bottom. Each rod is adequately instrumented with a total of 20 thermocouples (8 resistors and 12 sheath thermocouples).

1.5.2.3.5 Results

The experiments in the DDNB facility will result in cladding temperature and fluid properties measured as a function of time throughout the blowdown range from 0 to 20 seconds.

Facility modifications and installation of the initial test bundle have been completed. A series of shakedown tests in the J-Loop have been performed. These tests provided data for instrumentation calibration and check-out, and provided information regarding facility control and performance. Initial program tests were performed during the first half of 1975.

1.5.2.4 Single Rod Burst Test

The single rod burst test results are used to quantify the maximum assembly flow blockage which is assumed in LOCA analyses.

Previously, single rod and multi-rod burst tests have been completed on the 15 x 15 fuel assembly rods under conditions which exist during the LOCA. The conclusion of these tests was that fuel rods burst in a staggered manner so that maximum average flow area blockage for the assembly is 55 percent during blowdown and 65 percent during reflood, based on the characteristics of the PWR fuel rod and the conservative peak clad temperature predicted during the LOCA transient.

The single rod burst test program for the 17 x 17 fuel assembly rods consisted of bursting specimens at the various internal pressures and heating rates in a steam atmosphere.

In addition, tests were run on 15 x 15 fuel assembly rods to assure reproducibility of the 1972 single rod burst test results. Results from the program are documented in References 8 and (9).

The single rod burst tests and evaluation have been completed and are reported in References (8) and (9). Results of the tests showed that the LOCA behavior of the 17 x 17 clad in comparison to that of the 15 x 15 clad exhibited no significant differences in failure ductility. Because of the results and the geometric scaling, the flow blockage (%) as determined by 15 x 15 multi-rod burst test simulation can be used for the 17 x 17 geometry.

1.5.2.5 Power-Flow Mismatch

Design emphasis has been placed on reliable and effective control and protection systems for the reactor core and engineered safety features to ensure adequate margins within incidents can be terminated before the onset of fuel failure. For this reason, investigations into the mechanisms of fuel failure and its propagation, and phenomena of molten fuel-coolant interaction have been limited.

Obtaining complete answers to the question related to fuel rod failure will require extensive testing because of the multiplicity of parameters involved. Such an extensive inpile test program has been proposed by the Aerojet Nuclear Company under NRC (AEC) sponsorship for the Power Burst Facility (PBF).

The proposed PBF program is expected to simulate conditions appropriate to major accidents postulated for reactor systems, i.e., loss of flow, loss of coolant, and reactivity initiated accidents. Phase I of the proposed PBF program is expected to be completed approximately two years after facility checkout or by mid 1977. Phase I is expected to concentrate upon establishing the thresholds for and the consequences of fuel failure and utilizes fuel rod clusters of various sizes to determine the extent of failure propagation. This program would broaden the experimental basis for evaluating reactor safety, but should not be considered essential for the design and safe operation.

Westinghouse will closely follow any such experimental program or analytical studies that may become available. Until such information is available, clearly demonstrating that local fuel melting is an acceptable condition, the emphasis in design will continue to be placed on providing adequate margins to minimize the probability of fuel melting. The margins incorporated in the design within which incidents can be terminated, before the onset of fuel failure, provide a sound basis for safe operation.

1.5.3 Westinghouse Test Engineering Laboratory Facility

1.5.3.1 Introduction

The Test Engineering Laboratory at Forest Hills, Pennsylvania, has long been the major Westinghouse center for nuclear research and development. The Test Engineering Laboratory is totally involved with the design and implementation of facilities and programs to prove the reliability of Westinghouse PWR concepts and components.

The Test Engineering Laboratory has full in-house capabilities to design and construct PWR loops for both hydraulic and heat transfer testing programs.

Historically the Test Engineering Laboratory has been in a state of transition, depending upon the current need for its services. Today’s great need is for ECCS data and the verification of many new PWR system components. Past needs and accomplishments have included the development of supercritical heat transfer once through loops; rod cluster control drive mechanisms; fuel assemblies; underwater handling tools; and fuel assembly grid design, among many other earlier projects. Testing has included air filter tests; water chemistry tests; inpile testing for fuel rods; single fuel rod burst tests; hydraulic studies on fuel assemblies; and corrosion testing of Zircaloy and other PWR components and materials, with and without heat transfer.

The Test Engineering Laboratory is a very flexible installation, one which will continue to expand and develop as future needs for its services arise. Its staff, too, varies according to requirements.

There are currently more than 100 persons involved in laboratory projects, including 12 electrical and mechanical engineers, more than 75 highly skilled technicians, and some 30 specialists from other divisions of Westinghouse. The Test Engineering Laboratory has the option of obtaining personnel from the entire Corporation, depending upon the need for specific skills, knowledge and experience.

Ongoing research performed at the Test Engineering Laboratory continues to demonstrate the reliability of Westinghouse PWR plant components and greatly facilitates the development of improved reactor system components. As the test center for Westinghouse Nuclear Energy Systems, the Test Engineering Laboratory is totally committed to the advancement of the nuclear energy industry.

1.5.3.2 Tests, Test Loops, and Equipment

This section contains a brief description of the major tests, test loops and test equipment at the Westinghouse Test Engineering Laboratory Facility.

1.5.3.2.1 A and B-Loops, Low Flow/High Pressure Hydraulic Facilities

These loops are small, high pressure, stainless steel facilities, used for testing small components and individual parts of larger components under normal working conditions. A canned motor pump circulates water in both the A-Loop and the B-Loop at 150 gpm. Operating temperatures are obtained from the conversion of the pumping power into heat, as well as from external heaters. Typical tests run in these loops are:

1. Full scale gate and check valves;
2. Material corrosion-erosion, with variable water chemistry; and
3. Corrosion product release and transport properties of crud.

Characteristics of A and B Loops

Maximum Flowrate	150 gpm at 300 feet
Maximum Pump Head	335 feet at 60 gpm
Maximum Allowable Temperature	650°F
Normal Working Pressure	2000 psi
Normal Working Temperature	600°F

1.5.3.2.2 D-Loop, Medium Flow/High Pressure Hydraulic Facility

The D-Loop is a flexible test facility used for demonstrating the interplay of reactor subsystems and evaluating component design concepts. It contains a canned motor pump, which produces a 290 foot head at 3000 gpm. All piping (10 inch Schedule 160) in contact with the primary water is stainless steel. Loop pressure is established and maintained by an air driven charging pump operating in conjunction with a gas loaded back pressure valve. Most of the power required to

establish and maintain loop temperature is derived from the circulating pump operation, and 75 kW of heat is available from electric strip heaters.

The D-Loop services a 24 inch inside diameter x 40 foot long test vessel, which accommodates full scale models of large PWR core components for operational studies.

Characteristics of D Loop

Maximum Flowrate	4400 gpm
Maximum Allowable Pressure	2400 psi
Maximum Allowable Temperature	650°F
Normal Working Pressure	2000 psi
Normal Working Temperature	600°F
Pump Head at 3000 gpm	290 feet
Maximum Pump Head	340 feet (at 1500 gpm
Main Loop Flow Measurement	10 inch venturi
Auxiliary Flow Measurement	6 inch venturis (2 inch branch lines)

1.5.3.2.3 E-Loop, Low Flow/Low Pressure Hydraulic Facility

The E-Loop is a low pressure, six inch, stainless steel loop, with 2 circulating pumps. These pumps may be connected in parallel, giving 2000 gpm at a 130 foot head, or in series, giving 1000 gpm at a 260 foot head. Flow and vibration studies are conducted with this loop, and, because of its low pressure, plastic models for visual observation or photography may be used. In addition, a four inch Rockwell water meter in a branch line permits the calibration of flow meters up to 800 gpm.

Characteristics of E Loop

Maximum Flowrate	2000 gpm at 130 feet 1000 gpm at 260 fee
Maximum Working Pressure	Pump Head

1.5.3.2.4 G-Loop, Emergency Core Cooling System Facility

The G-Loop is a high pressure, ECCS test facility designed and fabricated to ASME Section I for 2000 psi and 650°F. It consists of a main test section and vessel, exhaust system, piping, separators and muffler, flash chamber steam supply system, and high pressure/low pressure cooling systems.

This loop is basically designed to obtain test data for analysis of LOCAs, for breaks up to and including double ended pipe breaks for PWRs. Tests are initiated at simulated conditions existing

8 seconds after the start of a LOCA. A typical run consists of constant power and pressure, followed by pressure blowdown, power decay and emergency core cooling. The G-Loop is capable of performing the following methods of emergency core cooling: Current, Upper Head Injection (UHI), UHI w/Current and other Core Spray Systems. It may also be used for constant temperature/pressure small leg break tests (core uncovering tests). These consist of boiling off water at a constant bundle power input until the rods can no longer be cooled.

The G-Loop test bundle consists of 480 electrically heated rods, 16 grid support thimbles, and 33 spray thimbles bounded by an octagonal stainless steel baffle and arranged as per a four-loop 15 x 15 rod bundle configuration. The loop is controlled (fully automated during transients) through a PDP-II-DEC-16K computer with a 600 point Computer Products A-D Converter operating at a sweep rate of 40,000 points per second for data acquisition. Figure 1.5-1 is a schematic of the G-Loop test facility.

G-Loop System Components and Characteristics

		Rated		Typical Operating	
Component	Material	Pressure (psi)	Temperature (°F)	Pressure (psi)	Temperature (°F)
Test Vessel	Carbon Steel	2000	650	1000	545
Downcomer Side Tank	Carbon Steel	2000	650	1000	545
In-Line Mixer	Carbon Steel	2000	650	1000	545
Mixer Accumulator	Stainless Steel	2500	650	1800	100
Flash Chamber	Carbon Steel	3000	700	2800	660
Separators Nos. 1&2	Carbon Steel	2000	650	1000	545
Spray Accumulators Nos. 1&2	Carbon Steel	2000	650	1800	150
Spray Accumulator No. 3	Stainless Steel	2500	650	1800	150
Reflood Tank	Stainless Steel	Atmosphere	212	Atmosphere	150
Primary Piping	Carbon Steel	2000	650	1000	545

1.5.3.2.5 H-Loop, High Flow Hydraulic Facility

The H-Loop constitutes a versatile hydraulic facility, capable of supplying 14,000 gpm of water at a developed head of 600 feet and at temperatures as high as 200°F. This four-loop system can simultaneously handle either full scale prototype test assemblies, or one large scale reactor model. The major purpose of the H-Loop is to permit the use of 1/7 scale reactor models and full scale fuel assemblies for conducting mixing studies, flow distribution studies, and similar low temperature/low pressure hydraulic tests.

Characteristics of H Loop

Maximum Flowrate	14,000 gpm
Pressure Drop Across Vessel Model	120 psi
Minimum Vessel Outlet Pressure	10 psig
Flow Accuracy	1/2%
Water Temperature Range	7-200°F
Maximum Loop-to-Loop Temperature Variation	2°F
Maximum Loop-to-Loop Flowrate Variation	3%

1.5.3.2.6 J-Loop, Delayed Departure from Nucleate Boiling Heat Transfer Facility

The J-Loop is a completely instrumented pressurized water test facility for verifying DDNB phenomena during a LOCA, and for conducting steady-state heat transfer studies. This test loop is a full size, single-loop simulation of a typical four-loop reactor system; it will accept a full length 5 x 5 bundle of internally heated fuel rods. The J-Loop is designed to operate at 2500 psia at 650°F, and at variable flowrates of up to 450 gpm. During LOCA tests, fluid input to the reactor vessel is closely controlled by 2 servo-controlled mixers, which inject a two-phase water/steam mixture into the test vessel, to simulate flow from the unbroken loops. Figure 1.5-2 is a schematic of the J-Loop test facility.

Characteristics of J Loop

Test Fluid	Demineralized Water
Design Pressure	2500 psia
Design Temperature	650°F
Maximum Flowrate (hot)	450 gpm
Power Input to Test Vessel	3,500,000 watts (maximum)
Primary Test Heat Exchanger Rating	11,400,000 BTU/hour

1.5.3.2.7 K-Loop, Boron Thermal Regeneration Test

The K-Loop, Boron Thermal Regeneration System (BTRS) test facility is used to study the performance and to verify the component sizing of both the currently available THERM I and the improved THERM II BTRS. The function of this system is to process boron-containing effluents from the Reactor Coolant System (RCS) to yield a high boron concentration fraction, which can be used to borate the RCS. A relatively boron free fraction is also processed, which can be used to dilute the RCS, such as that required in load follow operations.

Characteristics of K-Loop

Total Tank Capacity	30,000 gallons
Chiller Capacity	48 ice-tons
Maximum Ion Exchange Resin Test Volume	75 ft^3
Maximum Test Process Rate Capability	10 gpm/ft^2 bed area
Maximum Flow Test Capability	200 gpm
Minimum Boron Storage Mode Fluid Temperature	50°F
Maximum Boron Release Mode Fluid Temperature	160°F

1.5.3.2.8 FLECHT-SET, Emergency Core Cooling System Facility

The FLECHT-SET is a low pressure facility, designed to provide experimental data on the influence of system effects on ECCS during the reflood phase of a LOCA.

The facility consists of a once through system, including an electrically heated test section (fuel rods and housing), accumulator, steam generator simulators, pressurizer, catch vessels, instrumentation, and the necessary piping to simulate the reactor primary coolant loop. Data acquisition is accomplished through a PDP-II-DEC-16K Computer with a 256 point Computer Products A-D Converter, operating at a sweep rate of 1200 points per second.

Characteristics of FLECHT-SET

100 Rod Bundle Maximum Power	100 KW
Maximum Bundle Flooding Rate	86 gpm
Water Temperature Range	100-200°F
System Pressure	0-60 psia

1.5.3.2.9 Single Rod Loop, Heater Rod Development Facility

The Single Rod Loop is used to evaluate prototype heater rods and for in-depth study of existing rods in pressurized water systems. The test section of the loop is easily replaced to facilitate the

installation of various length and diameter heater rods. The Single Rod Loop is electrically controlled and operated by one person. Steady-state and blowdown at various conditions can be simulated in the loop. The main test section can be replaced with a quartz tube, and DNB phenomenon can be observed on a single rod with a remotely operated camera.

Characteristics of Single Rod Loop

Maximum Operating Pressure	2250 psia
Maximum Operating Temperature	650°F
Maximum Flowrate	10 gpm
System Capacity	5 gallons
Maximum Power Available	200 kW
Piping Size	1 and 3 inch

1.5.3.2.10 Hydraulic Model Testing

Miscellaneous hydraulic tests on mock-ups of reactor system parts and components are routinely performed at the Test Engineering Laboratory. Typical of this type of testing are the two discussed below, which were recently completed:

1. Emergency Core Cooling Flow Distribution

   A 10 x 10 rod bundle was installed in a plastic housing with a water supply at the top. A grid collection unit at the bottom of the bundle collected the water as it flowed through the model and diverted it to the measuring tubes at the base. Knowledge of the flow distribution in the bundle was obtained in this manner.

2. Sample System Mixing Test

   This test used one thermocouple to measure the temperature of water from four locations in a reactor. The purpose of the procedure was to determine whether the indication from the single thermocouple was representative of the average temperature of the four water supplies. A mock-up of the mixing chamber was constructed so that hot or cold water (at closely controlled pressure) could be supplied to any of the four inlets. By running combinations of hot and cold inlets and making simultaneous recordings of the various temperatures, highly useful information was obtained.

1.5.3.2.11 Autoclave Testing

The Test Engineering Laboratory is equipped with autoclaves ranging in size from 1/2 gallon to 100 gallons. These devices are in constant use to determine the effect of various water chemistries on core components, as well as to perform corrosion tests. The units have also been used as boilers to provide steam for miscellaneous development tests, including acoustic leak detection.

1.5.3.2.12 Mechanical Component and Vibration Test

Full scale mechanical and vibration tests are performed at the Test Engineering Laboratory on plant and reactor components to prove the reliability of equipment design. Vibration testing of reactor components is also performed in the laboratory, using electronically excited shaker heads. Three sizes are available (2 lbs, 50 lbs, and 150 lbs) for regular scale model testing for frequencies from 5 Hz to 50 Hz.

1.5.3.2.13 Electrical Component Assembly

Highly skilled technicians are available at the Test Engineering Laboratory for constructing complex control and instrumentation systems. Work is initiated with engineering ideas and sketches, and includes mounting of process controllers, recorders, meters, relay logic, protection circuits, switches and indicators.

Point-to-point wiring is used, as required. Final as-built drawings are prepared, inspection and thorough electrical checkout is performed before installation in a facility.

1.5.3.2.14 Surveillance System Development

Surveillance systems provide on-line monitoring of pressure vessels for flaws. Electronic components are being developed at the Test Engineering Laboratory for an acoustic emission monitoring system for inservice inspection of operating plant vessels and piping. This system is designed to detect and locate initiation and propagation of cracks at various locations, such as welds and stress risers. Vessel flaw growth and rupture data have been obtained through joint programs at the Idaho National Engineering Laboratories and at the Oak Ridge National Laboratories. Pipe rupture data has been obtained from NRC (AEC) sponsored tests, and hydrostatic test data, operational noise and attenuation characteristics have been measured at various Westinghouse operating plants.

1.5.3.2.15 Engineering Mechanics Laboratory

Bench tests are performed in fixtures designed for the particular test using standard test equipment and techniques.

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Table 1.5-0
Delayed Departure From Nucleate Boiling Phase I Test Parameters

PARAMETERS	NOMINAL VALUE
INITIAL STEADY-STATE CONDITIONS	
Pressure	2250 psia
Test section mass velocity	2.5 x 10^6 lb/hr-ft^2
Inlet coolant temperature	560°F
Maximum heat flux	531,000 BTU/hr-ft^2
TRANSIENT CONDITIONS	
Simulated break	Double ended cold leg guillotine breaks

Table 1.5-1
Delayed Departure From Nucleate Boiling Phase II Test Parameters

PARAMETERS	NOMINAL VALUE
INITIAL STEADY-STATE CONDITIONS	
Pressure	1750 to 1900 psia
Test section mass velocity	2.0 to 3.0 x 10^6 lb/hr-ft^2
Inlet coolant temperature	530 to 560°F
Maximum heat flux	440,000 to 560,000 BTU/hr-ft^2
TRANSIENT RAMP CONDITIONS	
Pressure decrease	0 to 350 psi/sec (subcooled depressurization)
Flow decrease	0 to 100% sec
Inlet enthalpy	Constant

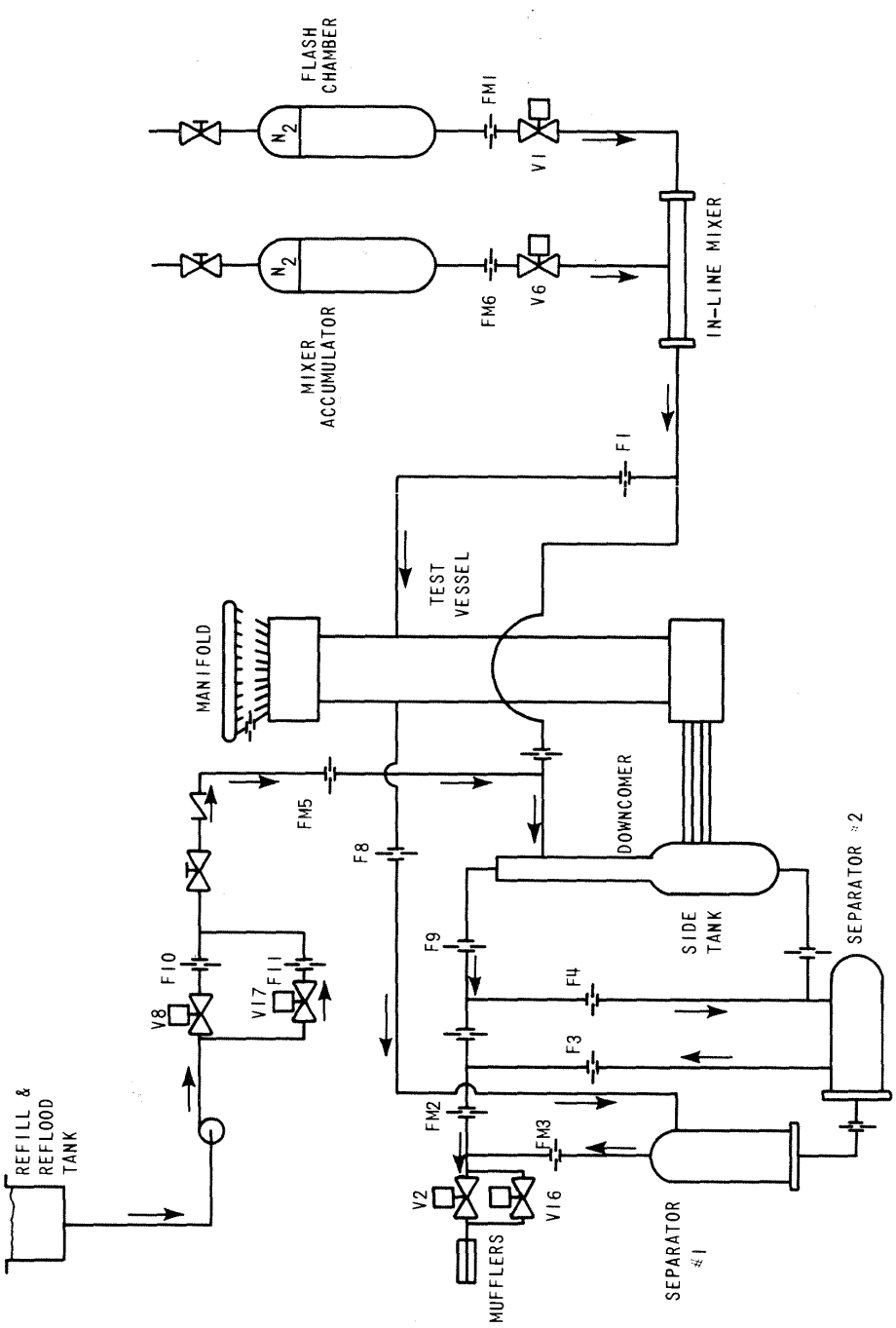
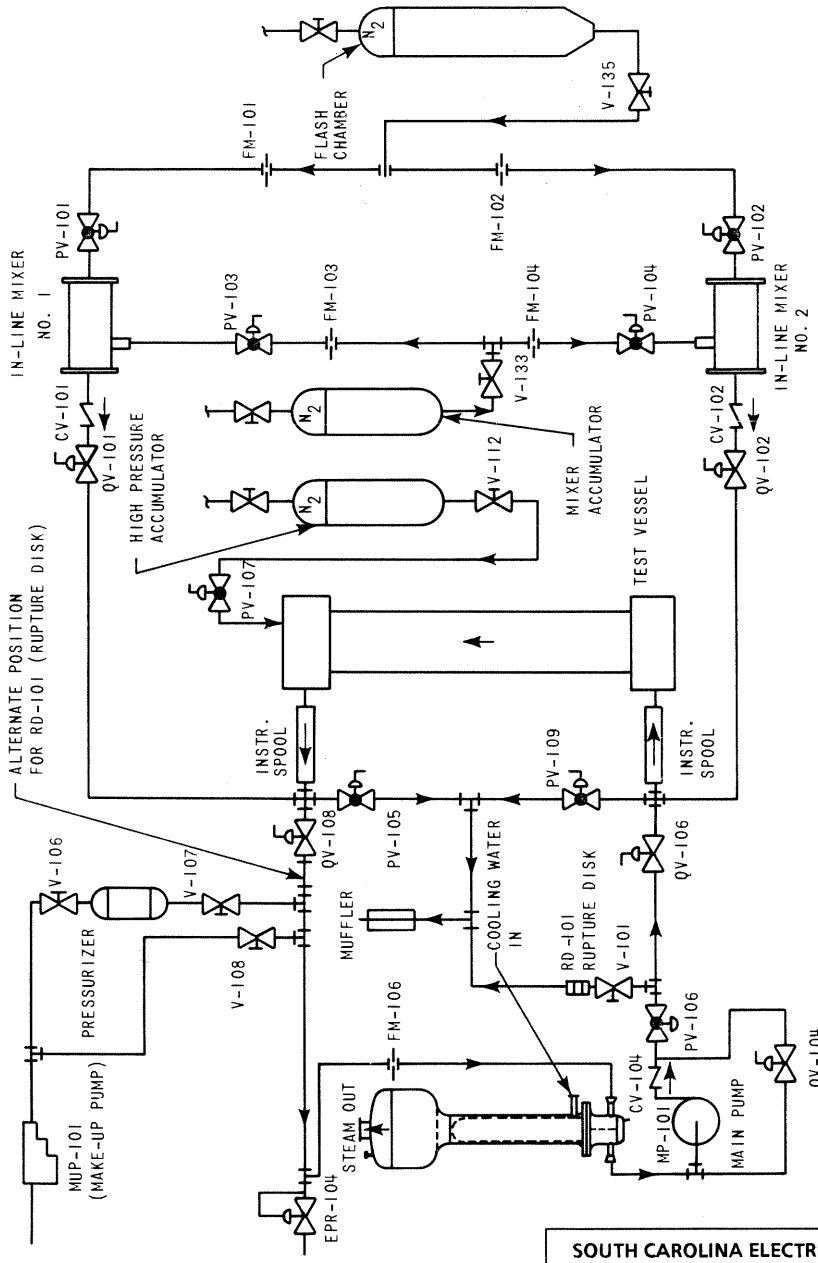


Figure 1.5-1
Schematic of G-Loop Test Facility

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Schematic of G - Loop Test Facility
Figure 1.5-1



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Schematic of J - Loop Test Facility
Figure 1.5-2

Figure 1.5-2
Schematic of J-Loop Test Facility

NOTE: Section 1.6 is being retained for historical purposes only.

1.6 Material Incorporated by Reference

This section lists topical reports, referenced throughout this FSAR, which provide information additional to that provided in this FSAR, and have been filed separately with the NRC in support of this and similar applications.

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"Methodology for the Analysis of the Dropped Rod Event," WCAP-11394-P-A, January 1990	15.2
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"Addendum to Final (Summary) Stress Report 157" PWR Vessel Virgil C. Summer Nuclear Station Revision 2 (Uprating/Steam Generator Replacement Evaluation)," WCAP-13777, June 1993	5.2
"Westinghouse LOCA Mass and Energy Release Model for Containment Design," WCAP-10325-P-A March 1979 (Proprietary), WCAP-10326-A, May 1983(Non-Proprietary)	6.2

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"Evaluation of Pressurizer Thermal Shock for V.C. Summer Unit 1," WCAP-15103, Revision 0, September 1998	5.2
"Beacon Core Monitoring and Operations Support System," WCAP-12472-P-A, August 1994	4.3, 4.4, 7.7, 15.3
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NOTE: Section 1.7 is being retained for historical purposes only.

1.7 ELECTRICAL, INSTRUMENTATION, AND CONTROL DRAWINGS

Electrical, instrumentation and control drawings have been provided under separate cover in the Wiring Schematic Package. Included in this package is a listing of drawings with drawing number, title, and system sheet number. This list is presented herein as Table 1.7-1.

Table 1.7-1
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-004	AH024	HVAC Control Board Graphic Display Annun Alarm and Status Light Inputs
B-208-004	AH025	HVAC Control Board Graphic Display Annun Alarm and Status Light Inputs
B-208-004	AH102	Control Room Emer Filt Sys Fan A (XFN30A) & Dmprs (XDP23A & XDP24A)
B-208-004	AH103	Control Room Emer Filt Sys Fan A (XFN30A) & Dmprs (XDP23B & XDP24B)
B-208-004	AH104	Control Room Normal Supply Fan A (XFN32A) & Dmpr (XDP105A)
B-208-004	AH105	Control Room Normal Supply Fan B (XFN32B) & Dmpr (XDP105B)
B-208-004	AH107	Relay Room Cooling System Fan A (XFN36A) (Unit 1)
B-208-004	AH108	Relay Room Cooling System Fan B (XFN36B) (Unit 1)
B-208-004	AH112	Computer Room Supply Fan B (XFN41B)
B-208-004	AH121	Control Room Supp Inlet DPRS “A” (XDP22A, 239A) & Butterfly Isol Valves “A” (XVB0003A, 0004A)
B-208-004	AH122	Control Room Supp Inlet DPRS “B” (XDP22B, 239B) & Butterfly Isol Valves “B” (XVB0003B, 0004B)
B-208-004	AH123	HVAC Control Board Status Light Inputs
B-208-004	AH124	HVAC Control Board Status Light Inputs
B-208-004	AH125	HVAC Control Board Status Light Inputs
B-208-004	AH126	HVAC Control Board Status Light Inputs

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-004	AH129	HVAC Control Board Graphic Display Annun Alarm Inputs
B-208-004	AH130	HVAC Control Board Graphic Display Annun Alarm Inputs
B-208-004	AH131	HVAC Control Board Graphic Display Annun Alarm Inputs
B-208-004	AH132	HVAC Control Board Graphic Display Annun Alarm Inputs
B-208-004	AH141	Relay, Computer Room & Instrument Repair Room Cooling System
B-208-004	AH142	Relay, Computer Room & Instrument Repair Room Cooling System
B-208-004	AH143	MCR Ventilation Isolation Normal and Emerg. Loop A
B-208-004	AH144	MCR Ventilation Isolation Normal and Emerg. Loop B
B-208-004	AH145	MCR Ventilation Isolation Normal and Emerg. Loop B
B-208-004	AH146	MCR Ventilation Isolation Normal and Emerg. Loop B
B-208-004	AH147	Controlled Access Damper Control XDP-45
B-208-004	AH148	Controlled Access Damper Control XDP-106
B-208-004	AH149	MCR Toilet Exhaust Relief Dampers XDP245A&B
B-208-004	AH164	Diesel Generator Room B Supply Fan A (XFN45A)
B-208-004	AH165	Diesel Generator Room B Supply Fan B (XFN45B)
B-208-004	AH166	Diesel Generator Room A Supply Fan A (XFN75A)
B-208-004	AH167	Diesel Generator Room A Supply Fan B (XFN75B)
B-208-004	AH170	HVAC Control Board Graphic Display Annun Alarm Inputs

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-004	AH174	Fuel Handling Building Exhaust Fan A (XFN23A) & Dmprs (XDP12A & XDP13A)
B-208-004	AH175	Fuel Handling Building Exhaust Fan B (XFN23B) & Dmprs (XDP12B & XDP13B)
B-208-004	AH177	HVAC Control Board Graphic Display Annun Alarm and Status Light Inputs
B-208-004	AH178	HVAC Control Board Graphic Display Annun Alarm and Status Light Inputs
B-208-004	AH179	Vibration Switches YS9652, YS9684A, YS9684B
B-208-004	AH182	Battery Room ‘A’ Dampers (XDP152) & (XDP155)
B-208-004	AH183	Battery Room ‘B’ Dampers (XDP153) & (XDP156)
B-208-004	AH194	Battery Room Supply Fan A (XFN38A) & Damper (XDP89A)
B-208-004	AH195	Battery Room Supply Fan B (XFN38B) & Damper (XDP89B)
B-208-004	AH196	Battery Room Exhaust Fan A (XFN39A) & Damper (XDP88A)
B-208-004	AH197	Battery Room Exhaust Fan B (XFN39B) & Damper (XDP88B)
B-208-004	AH202	Vibration Switch YS9886A Battery Room IB
B-208-004	AH204	HVAC Control Board Graphic Display Annun Alarm and Status Light Inputs
B-208-004	AH205	HVAC Control Board Graphic Display Annun Alarm and Status Light Inputs
B-208-004	AH206	Vibration Switch YS9886B Battery Room IB
B-208-004	AH208	HVAC Control Board Graphic Display Annun Alarm and Status Light Inputs
B-208-004	AH209	HVAC Control Board Graphic Display Annun Alarm and Status Light Inputs
B-208-004	AH236	Reactor Building Vibration Switch Reset Pushbutton

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-004	AH245	Reactor Building Purge Sup Isol XVB-1A
B-208-004	AH246	Reactor Building Purge Sup Isol XVB-1B
B-208-004	AH247	Reactor Building Purge Exh Isol XVB-2A
B-208-004	AH248	Reactor Building Purge Exh Isol XVB-2B
B-208-004	AH249	Misc. Alarms - Reactor Building Air Handling System
B-208-004	AH250	Misc. Alarms - Reactor Building Air Handling System
B-208-004	AH251	Misc. Alarms - Reactor Building Air Handling System
B-208-004	AH252	Misc. Alarms - Reactor Building Air Handling System
B-208-004	AH273	Reactor Building Cooling Unit Fan A (XFN64A) Motor (MFN97A)
B-208-004	AH275	Reactor Building Cooling Unit Fan B (XFN64B) Motor (MFN97B)
B-208-004	AH277	Reactor Building Cooling Unit Fan A (XFN65A) Motor (MFN97C)
B-208-004	AH279	Reactor Building Cooling Unit Fan B (XFN65B) Motor (MFN97D)
B-208-004	AH281	RBCU HEPA Filter Bypass Damper XDP110A
B-208-004	AH282	RBCU HEPA Filter Bypass Damper XDP110B
B-208-004	AH283	RBCU HEPA Filter Bypass Damper XDP111A
B-208-004	AH284	RBCU HEPA Filter Bypass Damper XDP111B
B-208-004	AH285	Reactor Building - Smoke Detectors XA9299A & XA9299B
B-208-004	AH286	Reactor Building - Smoke Detectors XA9299C & XA9299D

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-004	AH287	Reactor Building - Vibration Switches IYE40000, IYE40001, IYE40002, & IYE40003
B-208-004	AH326	Service Water Pumphouse Supply Fan 'A' (XFN80A) & Damper (XDPR74A)
B-208-004	AH327	Service Water Pumphouse Supply Fan 'B' (XFN80B) & Damper (XDPR74B)
B-208-004	AH328	Dampers XDP-71A, 72A, 73A Mode Control
B-208-004	AH329	Dampers XDP-71B, 72B, 73B Mode Control
B-208-004	AH330	HVAC Control Board Graphic Display Annun Alarm & Status Light Inputs
B-208-004	AH331	HVAC Control Board Graphic Display Annun Alarm & Status Light Inputs
B-208-004	AH334	Vibration Switches for XFN - 80A, 80B
B-208-004	AH399	HVAC Control Board Graphic Display Annun Alarm & Status Light Inputs
B-208-004	AH400	HVAC Control Board Graphic Display Annun Alarm & Status Light Inputs
B-208-008	AS50	Aux Steam to Aux Bldg Isolation XVG-265
B-208-008	AS51	Aux Steam to Aux Bldg Isolation XVG-273
B-208-009	BD07	S/G A Blowdown Isolation Valve XVG-503A
B-208-009	BD08	S/G B Blowdown Isolation Valve XVG-503B
B-208-009	BD09	S/G C Blowdown Isolation Valve XVG-503C
B-208-009	BD10	Steam Gen. Blowdown Isolation
B-208-009	BD12	Miscellaneous Alarms - Blowdown System
B-208-011	CC01	Component Cooling A Pump (XPP1A)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-011	CC02	Component Cooling B Pump (XPP1B)
B-208-011	CC03	Component Cooling C Pump (XPP1C) (Channel A)
B-208-011	CC04	Component Cooling C Pump (XPP1C) (Channel B)
B-208-011	CC10	RHR Heat Exchanger Inlet Valve XVB9503A
B-208-011	CC11	RHR Heat Exchanger Inlet Valve XVB9503B
B-208-011	CC12	Non-Essential Equip. Isolation Valve XVB9524A
B-208-011	CC13	Non Essential Equip. Isolation Valve XVB9524B
B-208-011	CC14	Non-Essential Equip. Isolation Valve XVB9525A
B-208-011	CC15	Non-Essential Equip. Isolation Valve XVB9525B
B-208-011	CC16	Non-Essential Equip. Isolation Valve XVB9526A
B-208-011	CC17	Non-Essential Equip. Isolation Valve XVB9526B
B-208-011	CC18	Reactor Coolant & Containment Isolation Valve XVG9568
B-208-011	CC24	R.C. Pump Thermal Barrier Isolation Valve XVG9600
B-208-011	CC25	R.C. Pump Thermal Barrier Isolation Valve XVG9605
B-208-011	CC26	R.C. Pump Thermal Barrier Isolation Valve XVB9606
B-208-011	CC27	Non-Essential Equip. Isolation Valve XVB9687A
B-208-011	CC28	Non-Essential Equip. Isolation Valve XVB9687B
B-208-011	CC29	Non-Essential Loop to Comp. Clg. Bstr. Pp. Isol. Valve XVG9625

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-011	CC30	Non-Essential Loop to Comp. Clg. Bstr. Pp. Isol. Valve XVG9626
B-208-011	CC31	Component Cooling Pump 1A Speed Switch XES2001A
B-208-011	CC32	Component Cooling Pump 1A Speed Switch XES2001B
B-208-011	CC33A	Component Cooling Pump 1C Speed Switch XES2001C
B-208-011	CC33B	Component Cooling Pump 1C Speed Switch XES2001C
B-208-011	CC52	S.W. Supply to Component Cooling XVG9627A
B-208-011	CC53	S.W. Supply to Component Cooling XVG9627B
B-208-011	CC60	Component Cooling System Alarms
B-208-011	CC61	Component Cooling System Alarms
B-208-011	CC62	Miscellaneous Alarms - Component Cooling System
B-208-011	CC63	Miscellaneous Alarms - Component Cooling System
B-208-020	CR01	Reactor Trip Switchgear XSW0001A
B-208-011	CR01A	Reactor Trip Switchgear XSW0001A
B-208-020	CR02	Reactor Trip Switchgear XSW0001B
B-208-011	CR02A	Reactor Trip Switchgear XSW0001B
B-208-020	CR55	Full Length Bank Selector Switch
B-208-021	CS01	Boric Acid Transfer Pump A (XPP13A)
B-208-021	CS02	Boric Acid Transfer Pump B (XPP13B)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-021	CS04	Charging/Safety Injection Pump C Transfer SW XET21002C Elec. Connections
B-208-021	CS05	Charging/Safety Injection Pump A (XPP43A)
B-208-021	CS06	Charging/Safety Injection Pump B (XPP43B)
B-208-021	CS07	Charging/Safety Injection Pump C (XPP43C) (Channel A)
B-208-021	CS08	Charging/Safety Injection Pump C (XPP43C) (Channel B)
B-208-021	CS09	Bat to Charging Injection Pump Suction Valve 8104 (XVT8104)
B-208-021	CS10	Seal Water Injection Filter Isol. Valve 8102A (XVT8102A)
B-208-021	CS11	Seal Water Injection Filter Isol. Valve 8102B (XVT8102B)
B-208-021	CS12	Seal Water Injection Filter Isol. Valve 8102C (XVT8102C)
B-208-021	CS13	Charging Pump 1A Miniflow Valve 8109A (XVT8109A)
B-208-021	CS14	Charging Pump 1B Miniflow Valve 8109B (XVT8109B)
B-208-021	CS15	Charging Pump 1C Miniflow Valve 8109C (XVT8109C)
B-208-021	CS16	Charging Pump Miniflow Valve 8106 (XVG8106)
B-208-021	CS17	Seal Water Return Isol. Valve 8100 (XVT8100)
B-208-021	CS18	Seal Water Return Isol. Valve 8112 (XVT8112)
B-208-021	CS19	RCS Charging Line Valve 8107 (XVG8107)
B-208-021	CS20	RCS Charging Line Valve 8108 (XVG8108)
B-208-021	CS21	Seal Water Injection Valve 8105 (XVT8105)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-021	CS22	Charging Pump Suction Header Isol. Valve 8130A (XVG8130A)
B-208-021	CS23	Charging Pump Suction Header Isol. Valve 8130B (XVG8130B)
B-208-021	CS24	Charging Pump Suction Header Isol. Valve 8131A (XVG8131A)
B-208-021	CS25	Charging Pump Suction Header Isol. Valve 8131B (XVG8131B)
B-208-021	CS26	Charging Pump Discharge Header Isol. Valve 8132A (XVG8132A)
B-208-021	CS27	Charging Pump Discharge Header Isol. Valve 8132B (XVG8132B)
B-208-021	CS28	Charging Pump Discharge Header Isol. Valve 8133A (XVG8133A)
B-208-021	CS29	Charging Pump Discharge Header Isol. Valve 8133B (XVG8133B)
B-208-021	CS30	Charging Pump A Aux. Lube Oil Pump
B-208-021	CS31	Charging Pump B Aux. Lube Oil Pump
B-208-021	CS32	Charging Pump C Aux. Lube Oil Pump
B-208-021	CS33	Refueling Water Supply Line Stop Valve LCV-115B (XVG0115B)
B-208-021	CS34	Volume Control Tank Outlet Line Stop Valve LCV-115C (XVG0115C)
B-208-021	CS35	Refueling Water Supply Line Stop Valve LCV-115D (XVG115D)
B-208-021	CS36	Volume Control Tank Outlet Line Stop Valve LCV-115E (XVG0115E)
B-208-021	CS40	XET2002C Transfer Scheme Channel “A”
B-208-021	CS41	XET2002C Transfer Scheme Channel “B”
B-208-021	CS54	Boric Acid Injection to Blender FCV-113A

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-021	CS55	Boric Acid Injection to Charging Pump Header FCV-113B
B-208-021	CS56	Boric Acid Dilution Injection to VCT FCV-168A
B-208-021	CS57	Reactor Makeup Water Injection to Boric Acid Blender FCV-168B(CS)
B-208-021	CS58	Letdown to VCT or Holdup Tank LCV-115A
B-208-021	CS59A	Letdown Line Isolation Valve LCV-459
B-208-021	CS59B	Letdown Line Isolation Valve LCV-459
B-208-021	CS60A	Letdown Line Isolation Valve LCV-460
B-208-021	CS60B	Letdown Line Isolation Valve LCV-460
B-208-021	CS79	Excess Letdown to VCT XVM-8143
B-208-021	CS81	Norm. Charging to Reactor Cooling System Isolation XVT-8146
B-208-021	CS82	Aux. Charging to Reactor Cooling System Isolation XVT-8147
B-208-021	CS83A	Letdown Orifice Isolation XVT-8149A
B-208-021	CS83B	Letdown Orifice Isolation XVT-8149A
B-208-021	CS83C	Letdown Orifice Isolation XVT-8149A
B-208-021	CS84A	Letdown Orifice Isolation XVT-8149B
B-208-021	CS84B	Letdown Orifice Isolation XVT-8149B
B-208-021	CS84C	Letdown Orifice Isolation XVT-8149B
B-208-021	CS85A	Letdown Orifice Isolation XVT-8149C

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-021	CS85B	Letdown Orifice Isolation XVT-8149C
B-208-021	CS85C	Letdown Orifice Isolation XVT-8149C
B-208-021	CS86	Letdown Line Isolation XVT-8152
B-208-021	CS87	Excess Letdown Line XVT-8153
B-208-021	CS88	Excess Letdown Line XVT-8154
B-208-021	CS92	VCT to Vent Hdr. Isolation XVG-8101
B-208-021	CS94	Boron Meter Isolation Valve 8455
B-208-021	CS95	Boron Meter Isolation Valve 8461
B-208-021	CS100	Miscellaneous Alarms - Chemical & Volume Control System
B-208-021	CS101	Miscellaneous Alarms - Chemical & Volume Control System
B-208-024	DG01	Diesel Generator 1A Breaker
B-208-024	DG01A	Diesel Generator 1A Breaker
B-208-024	DG02	Diesel Generator 1B Breaker
B-208-024	DG02A	Diesel Generator 1B Breaker
B-208-024	DG03	Diesel Generator Fuel Transfer “A” Pump (XPP0004A)
B-208-024	DG04	Diesel Generator Fuel Transfer “B” Pump (XPP0004B)
B-208-024	DG05	Diesel Generator Fuel Oil Transfer “A” Pump (XPP141A)
B-208-024	DG06	Diesel Generator Fuel Oil Transfer “B” Pump (XPP141B)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-024	DG10	Diesel Generator System Misc. Alarms
B-208-024	DG11	Diesel Generator System Misc. Alarms
B-208-024	DG12	Diesel Generator System Misc. Alarms
B-208-024	DG13	Diesel Generator System Misc. Alarms
B-208-024	DG14	Diesel Generator Status Lights
B-208-024	DG15	Diesel Generator A Exciter XEX4201
B-208-024	DG16	Diesel Generator B Exciter XEX4202
B-208-028	EI01	Earthquake Instrumentation System Alarms
B-208-032	EF01	Motor Driven Emergency Feedwater Pump A (XPP21A)
B-208-032	EF02	Motor Driven Emergency Feedwater Pump B (XPP21B)
B-208-032	EF03	Motor Driven Emerg. F.W. Pump A Suct. Isol. Valve XVG1001A
B-208-032	EF04	Motor Driven Emerg. F.W. Pump B Suct. Isol. Valve XVG1001B
B-208-032	EF05	Turb. Driven Emerg. F.W. Pump S.W. Loop B Isol. Valve XVG1002
B-208-032	EF06	Turb. Driven Emerg. F.W. Pump S.W. Loop A Isol. Valve XVG1008
B-208-032	EF07	Service Water Loop A Isol. Valve XVG1037A
B-208-032	EF08	Service Water Loop B Isol. Valve XVG1037B
B-208-032	EF30A	Diesel Buses Undervoltage Signal
B-208-032	EF31	Steam Generator A Isolation Valve XVC-1009A

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-032	EF32	Steam Generator B Isolation Valve XVC-1009B
B-208-032	EF33	Steam Generator C Isolation Valve XVC-1009C
B-208-032	EF34A	EF Isol. From Motor Driven Pumps to Steam Gen “A” IFV-3531
B-208-032	EF34B	EF Isol. From Motor Driven Pumps to Steam Gen “A” IFV-3531
B-208-032	EF35A	EF Isol. From Motor Driven Pumps to Steam Gen “B” IFV-3541
B-208-032	EF35B	EF Isol. From Motor Driven Pumps to Steam Gen “B” IFV-3541
B-208-032	EF36A	EF Isol. From Motor Driven Pumps to Steam Gen “C” IFV-3551
B-208-032	EF36B	EF Isol. From Motor Driven Pumps to Steam Gen “C” IFV-3551
B-208-032	EF37A	EF Isol. From Turb. Driven Pumps to Steam Gen “A” IFV-3536
B-208-032	EF37B	EF Isol. From Turb. Driven Pumps to Steam Gen “A” IFV-3536
B-208-032	EF38A	EF Isol. From Turb. Driven Pumps to Steam Gen “B” IFV-3546
B-208-032	EF38B	EF Isol. From Turb. Driven Pumps to Steam Gen “B” IFV-3546
B-208-032	EF39A	EF Isol. From Turb. Driven Pumps to Steam Gen “C” IFV-3556
B-208-032	EF39B	EF Isol. From Turb. Driven Pumps to Steam Gen “C” IFV-3556
B-208-032	EF50	Miscellaneous Alarms Emergency Feedwater System
B-208-032	EF51	Miscellaneous Alarms Emergency Feedwater System
B-208-032	EF52	Miscellaneous Alarms Emergency Feedwater System
B-208-037	ES07	7.2 kv Bus 1DB Normal Incoming Breaker

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-037	ES08	7.2 kv Bus 1DB Emergency Incoming Breaker
B-208-037	ES09	7.2 kv Bus 1DA Normal Incoming Breaker
B-208-037	ES10	7.2 kv Bus 1DA Emergency Incoming Breaker
B-208-037	ES19	Transformer 1DB1 & 1DB2 Feeder Breaker
B-208-037	ES20	Transformer 1DA1 & 1DA2 Feeder Breaker
B-208-037	ES21	Transformer 1EB1 Feeder Breaker 1EB1
B-208-037	ES22	Transformer 1EA1 Feeder Breaker 1EA1
B-208-037	ES23	Service Water Pump House Bus 1EB Feeder Breaker
B-208-037	ES24	Service Water Pump House Bus 1EA Feeder Breaker
B-208-037	ES36	480V Bus 1DB1 Feeder Breaker
B-208-037	ES37	480V Bus 1DB2 Feeder Breaker
B-208-037	ES38	480V Bus 1DA1 Feeder Breaker
B-208-037	ES39	480V Bus 1DA2 Feeder Breaker
B-208-037	ES40	480V Bus 1EB1 Feeder Breaker
B-208-037	ES41	480V Bus 1EA1 Feeder Breaker
B-208-037	ES47	480V Bus 1B1-1DA1 Tie Breaker
B-208-037	ES48	480V Bus 1B3-1DB1 Tie Breaker
B-208-037	ES53	7.2 kv Switchgear Bus 1DA Control Circuits

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-037	ES54	7.2 kv Switchgear Bus 1DB Control Circuits
B-208-037	ES65	Reactor Protection Under Freq. and Under Voltage Relays 7.2 kv Bus 1A, 1B, & 1C
B-208-037	ES66A	7.2 kv Bus 1DA Undervoltage Relaying
B-208-037	ES66B	7.2 kv Bus 1DA Undervoltage Relaying
B-208-037	ES67A	7.2 kv Bus 1DB Undervoltage Relaying
B-208-037	ES67B	7.2 kv Bus 1DB Undervoltage Relaying
B-208-037	ES80	480 V Switchgear Bus 1DA1 & 1DA2 Control Circuits
B-208-037	ES81	480 V Switchgear Bus 1DB1 & 1DB2 Control Circuits
B-208-037	ES82	480 V Switchgear Bus 1EA1 & 1EB2 Control Circuits
B-208-037	ES100	Miscellaneous Alarms Electrical System
B-208-037	ES102	Miscellaneous Alarms Electrical System
B-208-037	ES107	7 kv Motor Overcurrent Indication Light
B-208-039	EV01	Misc. Alarms Vital Bus 120V Distribution
B-208-039	EV02	Misc. Alarms Vital Bus 120V Distribution
B-208-044	FS01	Fire Service Containment Isolation
B-208-045	FW41	Chemical Feed Containment Isolation Valve XVK1633A
B-208-045	FW42	Chemical Feed Containment Isolation Valve XVK1633B
B-208-045	FW43	Chemical Feed Containment Isolation Valve XVK1633C

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-045	FW50	FW Pumps A, B & C Turbines Tripped
B-208-045	FW51	W ESF-FW Isolation Trip
B-208-045	FW61A	FW Isolation Loop A XVG1611A
B-208-045	FW61B	FW Isolation Loop A XVG1611A
B-208-045	FW62A	FW Isolation Loop B XVG1611B
B-208-045	FW62B	FW Isolation Loop B XVG1611B
B-208-045	FW63A	FW Isolation Loop C XVG1611C
B-208-045	FW63B	FW Isolation Loop C XVG1611C
B-208-045	FW65	Stm. Gen. A FW Control FCV478
B-208-045	FW66	Stm. Gen. B FW Control FCV488
B-208-045	FW67	Stm. Gen. C FW Control FCV498
B-208-045	FW68	Stm. Gen. FW. Control
B-208-045	FW70	Loop #1 Feedwater Flow Select FS/478Y
B-208-045	FW71	Loop #2 Feedwater Flow Select FS/488Y
B-208-045	FW72	Loop #3 Feedwater Flow Select FS/498Y
B-208-045	FW73	Loop #1 Steam Line Flow Select FS/478Z
B-208-045	FW74	Loop #2 Steam Line Flow Select FS/488Z
B-208-045	FW75	Loop #3 Steam Line Flow Select FS/498Z

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-045	FW81A	FW Bypass Control Valves IFV-3321, 3331, 3341
B-208-045	FW81B	FW Bypass Control Valves IFV-3321, 3331, 3341
B-208-045	FW88	FW Isol. Reset Switch (Low T_{avg} Coincid with Reactor Trip)
B-208-045	FW89	FW Isol. Reset Switch (Low T_{avg} Coincid with Reactor Trip)
B-208-045	FW90	Miscellaneous Relays - Feedwater System
B-208-045	FW94	S/G Level - RX Trip Setpoint Indicator LI-474A Input Signal Select SW LS-4742
B-208-045	FW100	FW Reverse Flush Valve XVG-1678A
B-208-045	FW101	FW Reverse Flush Valve XVG-1678B
B-208-045	FW102	FW Reverse Flush Valve XVG-1678C
B-208-045	FW103	FW Reverse Flush Valve XVG-1678A, B, C
B-208-054	HR01	Post Accident H2 Removal Exh Sys Contain Isol Valve (XVG6056)
B-208-054	HR02	Post Accident H2 Removal Exh Sys Contain Isol Valve (XVG6057)
B-208-054	HR21	Post Accident H2 Analyzer A
B-208-054	HR22	Post Accident H2 Analyzer B
B-208-054	HR23	6” Continuous Purge Line to HR Sys. Isol. Valve XVG-6067
B-208-054	HR24	6” Continuous Purge Line to HR Sys. Isol. Valve XVG-6066
B-208-054	HR25	Post Accident H2 Removal Loop A (IRB) XVX6050A
B-208-054	HR26	Post Accident H2 Removal Loop B (IRB) XVX6050B & 6051B

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-054	HR27	Post Accident H2 Removal Loop A Suction A Suction Valve XVX6051A
B-208-054	HR28	Post Accident H2 Removal Loop A Dom Suct. Valve XVX6051C
B-208-054	HR29	Post Accident H2 Removal Loop A (ORB) XVX6052A & 6053A
B-208-054	HR30	Post Accident H2 Removal Loop B (ORB) XVX6052B & 6054B
B-208-054	HR31	Containment Isolation for PT8254 XVX6054
B-208-054	HR32	HVAC Annunciator and Status Light Inputs - H2 Removal System
B-208-057	IA50	R.B. Air Service Isolation Valve XVT2662A
B-208-057	IA51	R.B. Air Service Isolation Valve XVT2662B
B-208-057	IA52	R.B. Air Service Isolation Valve XVT2660
B-208-057	IA55	Instrument Air System Alarms
B-208-057	IA56	Instrument Air System Alarms
B-208-060	LD01	Leak Detection System Miscellaneous Alarms
B-208-060	LD02	Leak Detection System Miscellaneous Alarms
B-208-060	LD03	Leak Detection System Miscellaneous Alarms
B-208-060	LD04	Leak Detection System Miscellaneous Alarms
B-208-060	LD05	Leak Detection System Miscellaneous Alarms
B-208-060	LD06	Leak Detection System Miscellaneous Alarms
B-208-063	MB02	Steam Dump Interlock Select

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-063	MB03	Steam Dump Interlock Select
B-208-063	MB05A	Cooldown Condenser Steam Dump Valve IFV2116
B-208-063	MB06A	Cooldown Condenser Steam Dump Valve IFV2096
B-208-063	MB07A	Condenser Steam Dump Valve IFV2097
B-208-063	MB08A	Condenser Steam Dump Valve IFV2106
B-208-063	MB09A	Condenser Steam Dump Valve IFV2107
B-208-063	MB10A	Condenser Steam Dump Valve IFV2117
B-208-063	MB11A	Condenser Steam Dump Valve IFV2126
B-208-063	MB12A	Condenser Steam Dump Valve IFV2127
B-208-063	MB13A	Atmospheric Steam Dump Valve IFV2006
B-208-063	MB14A	Atmospheric Steam Dump Valve IFV2016
B-208-063	MB15A	Atmospheric Steam Dump Valve IFV2026
B-208-064	MD30	Intermediate Bldg. Flood Protection
B-208-064	MD31	Intermediate Bldg. Flood Protection
B-208-066	MI01	Containment Isolation A and Safety Injection ESF Monitor Lights
B-208-066	MI02	Containment Isolation A and Safety Injection ESF Monitor Lights
B-208-066	MI03	Containment Isolation A and Safety Injection ESF Monitor Lights
B-208-066	MI04	Containment Isolation A and Safety Injection ESF Monitor Lights

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-066	MI05	Containment Isolation A and Safety Injection ESF Monitor Lights
B-208-066	MI06	Containment Isolation A and Safety Injection ESF Monitor Lights
B-208-066	MI07	Containment Isolation A and Safety Injection ESF Monitor Lights
B-208-066	MI08	Containment Isolation A and Safety Injection ESF Monitor Lights
B-208-066	MI09	Cold Leg - Hot Leg Recirculation ESF Monitor Lights
B-208-066	MI10	Cold Leg - Hot Leg Recirculation ESF Monitor Lights
B-208-066	MI11	Cold Leg - Hot Leg Recirculation ESF Monitor Lights
B-208-066	MI12	Safety Injection ESF Monitor Lights
B-208-066	MI13	Safety Injection ESF Monitor Lights
B-208-066	MI14	Safety Injection (BOP) ESF Monitor Lights
B-208-066	MI15	Safety Injection (BOP) ESF Monitor Lights
B-208-066	MI16	Safety Injection (BOP) ESF Monitor Lights
B-208-066	MI17	Safety Injection (BOP) ESF Monitor Lights
B-208-066	MI18	Safety Injection (BOP) ESF Monitor Lights
B-208-066	MI19	Containment Isolation Phase B and Reactor Building Spray ESF Monitor Lights
B-208-066	MI20	Containment Isolation Phase B and Reactor Building Spray ESF Monitor Lights
B-208-066	MI21	Safety Inj. West. Group 1 ESF Monitor Lights (Channel XA)
B-208-066	MI22	Safety Inj. West. Group 1 & 2 ESF Monitor Lights (Channel XA)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-066	MI28	Safety Inj. West. Group 1 & 3 ESF Monitor Lights (Channel XB)
B-208-066	MI29	Safety Inj. West. Group 1 & 3 ESF Monitor Lights (Channel XB)
B-208-067	MS01	Main Stm. Loop 2 to Turb. Drvn. Emerg. Feed Pump XVG2802A
B-208-067	MS02	Main Stm. Loop 3 to Turb. Drvn. Emerg. Feed Pump XVG2802B
B-208-067	MS04	Emerg. Feedwater Turbine Steam Line Drain Valve XVT2813
B-208-067	MS20A	Power Relief Valve IPV2000
B-208-067	MS20B	Power Relief Valve IPV2000
B-208-067	MS21A	Power Relief Valve IPV2010
B-208-067	MS21B	Power Relief Valve IPV2010
B-208-067	MS22A	Power Relief Valve IPV2020
B-208-067	MS22B	Power Relief Valve IPV2020
B-208-067	MS29	Main Steam Line A Drain Valve XVT2843A
B-208-067	MS30	Main Steam Line A Drain Valve XVT2877A
B-208-067	MS31	Main Steam Line B Drain Valve XVT2843B
B-208-067	MS32	Main Steam Line C Drain Valve XVT2843C
B-208-067	MS33	Main Steam Line C Drain Valve XVT2877B
B-208-067	MS34	Main Steam Lines Drain Valves (Train B)
B-208-067	MS35	Main Steam Isolation Valve XVM2801A

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-067	MS36	Main Steam Isolation Valve XVM2801B
B-208-067	MS37	Main Steam Isolation Valve XVM2801C
B-208-067	MS38A	Main Steam Isolation Valves XVM2801A, 2801B & 2801C - Train B
B-208-067	MS38B	Main Steam Isolation Valves XVM2801A, 2801B & 2801C - Train B
B-208-067	MS40	Main Steam Line A Bypass Isolation XVM2869A
B-208-067	MS41	Main Steam Line B Bypass Isolation XVM2869B
B-208-067	MS42	Main Steam Line C Bypass Isolation XVM2869C
B-208-067	MS43	Main Steam Lines Bypass Isolation (MS)
B-208-067	MS46	Main Steam to EF Turbine Isolation IFV2030
B-208-067	MS47A	Main Steam to EF Turbine Isolation IFV2030
B-208-067	MS47B	Main Steam to EF Turbine Isolation IFV2030
B-208-067	MS48	Miscellaneous Alarms - Main Steam System
B-208-067	MS51	Miscellaneous Alarms - Main Steam System
B-208-068	MU01	Reactor Makeup Water Pump A (XPP40A)
B-208-068	MU02	Reactor Makeup Water Pump B (XPP40B)
B-208-068	MU04	Reactor Coolant Makeup Control
B-208-068	MU60	Reactor Makeup Discharge Valves Auto Close
B-208-068	MU61	Reactor Makeup Flow to Non-Essential Comp. Isol. XVD1920A

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-068	MU62	Reactor Makeup Flow to Non-Essential Comp. Isol. XVD1920B
B-208-068	MU63	Reactor Makeup Demineralized Water Supply XVD1921
B-208-068	MU64	Reactor Makeup System Alarms
B-208-068	MU65	Reactor Makeup System Alarms
B-208-072	ND50	Reactor Building Sump Isolation XVD-6242A
B-208-072	ND51	Reactor Building Sump Isolation XVD-6242B
B-208-074	NI01A	Source Range Reset Block Logic
B-208-074	NI01B	Source Range Reset Block Logic
B-208-074	NI02A	Intermediate Range Block Logic
B-208-074	NI02B	Intermediate Range Block Logic
B-208-074	NI03A	Power Range Block Logic
B-208-074	NI03B	Power Range Block Logic
B-208-074	NI04	Nuclear Flux Recorder Select Pen 1
B-208-074	NI05	Nuclear Flux Recorder Select Pen 2
B-208-076	NN01	PORV (PCV-445A) N2 Supply Isolation Valve XVX-6309A
B-208-076	NN02	PORV (PCV-445B) N2 Supply Isolation Valve XVX-6309B
B-208-082	RC01	Reactor Coolant Pump “A” (XPP30A)
B-208-082	RC02	Reactor Coolant Pump “B” (XPP30B)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-082	RC03	Reactor Coolant Pump “C” (XPP30C)
B-208-082	RC10	Pressurizer Relief Isol. Valve 8000A (XVG8000A)
B-208-082	RC11	Pressurizer Relief Isol. Valve 8000B (XVG8000B)
B-208-082	RC12	Pressurizer Relief Isol. Valve 8000C (XVG8000C)
B-208-082	RC14	Reactor Head Vent VV to Press. Relief Tank (XVG8095A)
B-208-082	RC15	Reactor Head Vent VV to Press. Relief Tank (XVG8095B)
B-208-082	RC16	Reactor Head Vent VV to Press. Relief Tank (XVG8096B)
B-208-082	RC17	Reactor Head Vent VV to Press. Relief Tank (XVG8096A)
B-208-082	RC50	Pressurizer Power Relief Valve PCV444B
B-208-082	RC51	Pressurizer Power Relief Valve PCV445A
B-208-082	RC52	Pressurizer Power Relief Valve PCV445B
B-208-082	RC53	Pressurizer Relief Tank Primary Water Valve XVD8028
B-208-082	RC57	Pressurizer Relief Tank to Gas Decay XVD8033
B-208-082	RC58	Pressurizer Relief Tank to Gas Decay XVD8047
B-208-082	RC60	Pressurizer SI Block Reset Channel A
B-208-082	RC61	Pressurizer SI Block Reset Channel B
B-208-082	RC62	Pressurizer Level Control Switch LS/459Z
B-208-082	RC63	Pressurizer Level Record Switch LS/459Y

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-082	RC64	DT-T_{avg} Protect Switch TS/412Z
B-208-082	RC65	HI-T_{avg} Control Select Switch TS/408
B-208-082	RC66	HI-DT Control Select Switch TS/409
B-208-082	RC67	Turbine 1st stage Pressure Select Switch PS/446Z
B-208-082	RC68	Pressurizer Pressure and Level
B-208-082	RC69	Pressurizer Pressure and Level
B-208-082	RC70	Pressurizer Pressure and Level
B-208-082	RC72	RCS Cold Overpressurization Relays
B-208-082	RC74	Pressurizer Safety Valve Indication
B-208-082	RC77	Pressurizer Steam to Pressurizer Relief Tank PCV-444C
B-208-082	RC78	Pressurizer Steam to Pressurizer Relief Tank PCV-444D
B-208-084	RH01	Residual Heat Removal Pump A (XPP31A)
B-208-084	RH02	Residual Heat Removal Pump B (XPP31B)
B-208-084	RH03	RHR Loop 1 Inlet Isol. Valve 8701A (XVG8701A)
B-208-084	RH04	RHR Loop 3 Inlet Isol. Valve 8701B (XVG8701B)
B-208-084	RH05	RHR Loop 1 Inlet Isol. Valve 8702A (XVG8702A)
B-208-084	RH06	RHR Loop 3 Inlet Isol. Valve 8702B (XVG8702B)
B-208-084	RH07	RHR Pump Miniflow Valve FCV-602A (XVT602A)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-084	RH08	RHR Pump Miniflow Valve FVC-602B (XVT602B)
B-208-084	RH09	RHRS to Charging Pump Valve 8706A (XVG8706A)
B-208-084	RH10	RHRS to Charging Pump Valve 8706B (XVG8706B)
B-208-084	RH20	Miscellaneous Alarms - Residual Heat Removal
B-208-093	SF01	Spent Fuel Pool Cooling “A” Pump XPP32A
B-208-093	SF02	Spent Fuel Pool Cool & Trnsf Pump B XPP32B
B-208-094	SG01A	R.B. Spray Actuation, Containment Isolation A & B & Containment Ventilation Isolation
B-208-094	SG01B	R.B. Spray Actuation, Containment Isolation A & B & Containment Ventilation Isolation
B-208-094	SG02	Containment Isolation A, Containment Ventilation Isolation
B-208-094	SG03	R.B. Spray Reset, Containment Isolation A & B Reset & Containment Ventilation Isolation Reset
B-208-094	SG04	ESF Load Sequence Train A Status Lights
B-208-094	SG05	ESF Load Sequence Train B Status Lights
B-208-094	SG06	Miscellaneous Alarms System SG
B-208-094	SG07	ESF Loading Sequence A Reset Control & Safety Injection Test Circuit
B-208-094	SG08	ESF Loading Sequence B Reset Control & Safety Injection Test Circuit
B-208-095	SI09	High Head to Cold Leg Injection Valve 8801A (XVG8801A)
B-208-095	SI10	High Head to Cold Leg Injection Valve 8801B (XVG8801B)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-095	SI13	High Head to Hot Leg Injection Valve 8884 (XVG8884)
B-208-095	SI14	High Head to Cold Leg Injection Valve 8885 (XVG8885)
B-208-095	SI15	High Head to Hot Leg Injection Valve 8886 (XVG8886)
B-208-095	SI16	Accumulator Isolation Valve 8808A (XVG8808A)
B-208-095	SI17	Accumulator Isolation Valve 8808B (XVG8808B)
B-208-095	SI18	Accumulator Isolation Valve 8808C (XVG8808C)
B-208-095	SI19	RWST to RHR Pump A Isolation Valve 8809A (XVG8809A)
B-208-095	SI20	RWST to RHR Pump B Isolation Valve 8809B (XVG8809B)
B-208-095	SI21	Recirc. Sump to RHR Pump A Isol. Valve 8811A (XVG8811A)
B-208-095	SI22	Recirc. Sump to RHR Pump B Isol. Valve 8811B (XVG8811B)
B-208-095	SI23	Containment Sump Isolation Valve 8812A (XVG8812A)
B-208-095	SI24	Containment Sump Isolation Valve 8812B (XVG8812B)
B-208-095	SI25	Low Head to Hot Leg Cross Tie Valve 8887A (XVG8887A)
B-208-095	SI26	Low Head to Hot Leg Cross Tie Valve 8887B (XVG8887B)
B-208-095	SI27	Low Head to Cold Leg Cross Tie Valve 8888A (XVG8888A)
B-208-095	SI28	Low Head to Cold Leg Cross Tie Valve 8888B (XVG8888B)
B-208-095	SI29	Low Head to Hot Leg Cross Tie Valve 8889 (XVG8889)
B-208-095	SI30	Valve 8889, 8888A & 8884 Power Lockout

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-095	SI31	Valve 8886 & 8888B Power Lockout
B-208-095	SI52	Safety Injection Reset Switches
B-208-095	SI54	Safety Injection Reset Switches
B-208-095	SI58	Accumulator Fill Line 8860
B-208-095	SI59	Accumulator Holding Tank Isolation Valve 8871
B-208-095	SI72	Accumulator N2 Supply Isolation Valve 8870
B-208-095	SI76	Accumulator Holding Tank Isolation Valve 8961
B-208-095	SI77A	Critical Function Valve Alarm
B-208-095	SI77B	Critical Function Valve Alarm
B-208-095	SI86	Latched Safety Injection Reset Switch
B-208-095	SI87	Latched Safety Injection Reset Switch
B-208-095	SI88	Redundant Position Indication for XVG-8884, 8888A, 8889
B-208-095	SI89	Redundant Position Indication for XVG-8886, 8888B
B-208-095	SI90	P11-Isolation Relay
B-208-097	SP01	Reactor Bldg. Spray Pump A (XPP38A)
B-208-097	SP02	Reactor Bldg. Spray Pump B (XPP38B)
B-208-097	SP03	RWST to R.B. Spray Pump “A” Suction Valve XVG3001A
B-208-097	SP04	RWST to R.B. Spray Pump “B” Suction Valve XVG3001B

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-097	SP05	NaOH Tank to R.B. Spray Pump “A” Suction Valve XVG3002A
B-208-097	SP06	NaOH Tank to R.B. Spray Pump “B” Suction Valve XVG3002B
B-208-097	SP07	Spray Header Isolation Valve “A” XVG3003A
B-208-097	SP08	Spray Header Isolation Valve “C” XVG3003B
B-208-097	SP09	Reactor Bldg. Sump Isolation Valve “A” XVG3004A
B-208-097	SP10	Reactor Bldg. Sump Isolation Valve “B” XVG3004B
B-208-097	SP11	Reactor Bldg. Sump Isolation Valve “A” XVG3005A
B-208-097	SP12	Reactor Bldg. Sump Isolation Valve “B” XVG3005B
B-208-097	SP20	Reactor Building Spray System Alarms
B-208-097	SP21	Reactor Building Spray System Alarms
B-208-099	SS01	Reactor Bldg. Air Sample XVA9311A
B-208-099	SS02	Reactor Bldg. Air Sample XVA9311B
B-208-099	SS03	Reactor Bldg. Air Sample XVA9312A
B-208-099	SS04	Reactor Bldg. Air Sample XVA9312B
B-208-099	SS07	Pressurizer Steam Sample XVX9356A
B-208-099	SS08	Pressurizer Liquid Sample XVX9356B
B-208-099	SS09	Pressurizer Sample XVX9357
B-208-099	SS10	Reactor Coolant Hot Leg Sample XVX9364B

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-099	SS11	Reactor Coolant Hot Leg (Loop 3) XVX9364C
B-208-099	SS12	Reactor Coolant Hot Leg (Loop 2) XVX9365B
B-208-099	SS13	Reactor Coolant Hot Leg (Loop 3) XVX9365C
B-208-099	SS23	Accumulator Sample XVX9387
B-208-099	SS24	Steam Generator A Blowdown Sample XVX9398A
B-208-099	SS25	Steam Generator B Blowdown Sample XVX9398B
B-208-099	SS26	Steam Generator C Blowdown Sample XVX9398C
B-208-099	SS27	EF Pump Start Signal
B-208-099	SS44	Post Accident Sample Part Isolation XVX9339
B-208-099	SS45	Post Accident Sample Part Isolation XVX9341
B-208-101	SW01	Service Water Pump A (XPP39A)
B-208-101	SW02	Service Water Pump B (XPP39B)
B-208-101	SW03	Service Water Pump C (XPP39C) (Channel A)
B-208-101	SW04	Service Water Pump C (XPP39C) (Channel B)
B-208-101	SW05	Service Water Screens Isolating Relays
B-208-101	SW06	Service Water Booster “A” Pump (XPP45A)
B-208-101	SW07	Service Water Booster “B” Pump (XPP45B)
B-208-101	SW08	Screen Wash “A” Pump (XPP44A)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-101	SW09	Screen Wash “B” Pump (XPP44B)
B-208-101	SW10	Screen Wash “C” Pump (XPP44C)
B-208-101	SW11	(XMC1EC1X) Transfer Scheme Channel A
B-208-101	SW14A	Service Water Pump C Speed Switch (XES2003C)
B-208-101	SW14B	Service Water Pump C Speed Switch (XES2003C)
B-208-101	SW15	(XMC1EC1X) Transfer Scheme Channel B
B-208-101	SW16	Traveling Screen A (XRS0002A)
B-208-101	SW17	Traveling Screen B (XRS0002B)
B-208-101	SW18	Traveling Screen C (XRS0002C)
B-208-101	SW20	Service Water Pump A Discharge Valve (XVB3116A)
B-208-101	SW21	Service Water Pump B Discharge Valve (XVB3116B)
B-208-101	SW22	Service Water Pump C Discharge Valve (XVB3116C) (Channel C)
B-208-101	SW23	Recirc. Unit A Containment Isolation Valve (XVG3103A)
B-208-101	SW24	Recirc. Unit B Containment Isolation Valve (XVG3103B)
B-208-101	SW25	Reactor Building Inlet A Isolation Valve (XVB3106A)
B-208-101	SW26	Reactor Building Inlet B Isolation Valve (XVB3106B)
B-208-101	SW27	Reactor Building Outlet A Isolation Valve (XVB3107A)
B-208-101	SW28	Reactor Building Outlet B Isolation Valve (XVB3107B)

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-101	SW29	Reactor Building Recirc. Unit A Isolation Valve (XVG3108A)
B-208-101	SW30	Reactor Building Recirc. Unit B Isolation Valve (XVG3108B)
B-208-101	SW31	Reactor Building Recirc. Unit C Isolation Valve (XVG3108C)
B-208-101	SW32	Reactor Building Recirc. Unit D Isolation Valve (XVG3108D)
B-208-101	SW33	Reactor Building Recirc. Unit A Isolation Valve (XVG3109A)
B-208-101	SW34	Reactor Building Recirc. Unit B Isolation Valve (XVG3109B)
B-208-101	SW35	Reactor Building Recirc. Unit C Isolation Valve (XVG3109C)
B-208-101	SW36	Reactor Building Recirc. Unit D Isolation Valve (XVG3109D)
B-208-101	SW37	Building Service Inlet A Isolation Valve (XVB3110A)
B-208-101	SW38	Building Service Inlet B Isolation Valve (XVB3110B)
B-208-101	SW39	Building Service Outlet A Isolation Valve (XVG3111A)
B-208-101	SW40	Building Service Outlet B Isolation Valve (XVG3111B)
B-208-101	SW41	Building Service Outlet A Isolation Valve (XVK3112A)
B-208-101	SW42	Building Service Outlet B Isolation Valve (XVK3112B)
B-208-101	SW43	Screen Wash Pump Discharge Valve (XVG3113A)
B-208-101	SW44	Screen Wash Pump Discharge Valve (XVG3113B)
B-208-101	SW45	Screen Wash Pump Discharge Valve (XVG3113C)
B-208-101	SW50	Emergency Water Supply to DG “A” Cooler XVT3105A

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-101	SW51	Emergency Water Supply to DG “B” Cooler XVT3105B
B-208-101	SW52	DG Cooler A Isolation XVB3104A & 3121A
B-208-101	SW53	DG Cooler B Isolation XVB3104B & 3121B
B-208-101	SW54	SW Pumps A & C Cross Connect XVB3118A & 3118C
B-208-101	SW55	SW Pumps B & C Cross Connect XVB3118B & 3118D
B-208-101	SW57	CC Heat Exchanger A Isolation XVB3122A & 3123A
B-208-101	SW58	CC Heat Exchanger B Isolation XVB3122B & 3123B
B-208-101	SW59	HVAC Chiller Cond. A Isolation XVB3126A & 3127A
B-208-101	SW60	HVAC Chiller Cond. B Isolation XVB3126B & 3127B
B-208-101	SW65	SW Booster Pump A Suction XVB3134A
B-208-101	SW66	SW Booster Pump B Suction XVB3134B
B-208-101	SW70	Service Water System Alarms
B-208-101	SW71	Service Water System Alarms
B-208-101	SW72	Service Water System Alarms
B-208-101	SW73	Service Water System Alarms
B-208-101	SW74	Service Water System Alarms
B-208-101	SW75	Service Water System Alarms
B-208-101	SW78	DRPI Cooling Unit Coil Isolation Valve XVT-3164

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-101	SW79	DRPI Cooling Unit Coil Isolation Valve XVT-3165 & 3169
B-208-101	SW86	SW Inlet to HVAC Chiller “A” (XVB3126A)
B-208-101	SW87	SW Inlet to HVAC Chiller “B” (XVB3126B)
B-208-101	SW88	“A” Train SW Inlet to HVAC Chiller “C” (XVB3128A)
B-208-101	SW89	“B” Train SW Inlet to HVAC Chiller “C” (XVB3128C)
B-208-103	TB02	Redundant Turbine Trips - Train A
B-208-103	TB03	Redundant Turbine Trips - Train B
B-208-103	TB04	Turbine Tripped Relaying
B-208-103	TB07	Turbine Stop Valves and Control Valves Limit Switches
B-208-108	VL01	Aux. Bldg. MCC - Switchgear AHU Fan (XFN132)
B-208-108	VL02	Aux. Bldg. MCC - Switchgear AHU Fan (XFN133)
B-208-108	VL05	Charging/SI Pump Room 1 Cooling Unit Fan A (XFN46A)
B-208-108	VL06	Charging/SI Pump Room 3 Cooling Unit Fan B (XFN46B)
B-208-108	VL07	Charging/SI Pump Room 2 Cooling Unit Fan (XFN47)
B-208-108	VL08	RHR/Spray Pump Room 1 Cooling Unit Fan A (XFN49A)
B-208-108	VL09	RHR/Spray Pump Room 2 Cooling Unit Fan B (XFN49B)
B-208-108	VL10	Ventilation System Annunciator & Alarm Inputs - Aux Bldg
B-208-108	VL11	Ventilation System Annunciator & Alarm Inputs - Aux Bldg

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-108	VL12	Ventilation System Annunciator & Alarm Inputs - Aux Bldg
B-208-108	VL18	Speed Switch Room Air Handling Fan (XFN-106A-VL)
B-208-108	VL19	Speed Switch Room Air Handling Fan (XFN-106B-VL)
B-208-108	VL22	ESF Switchgear Room 1DA Cooling Unit Fan (XFN50)
B-208-108	VL24	ESF Switchgear Room 1DB Cooling Unit Fan (XFN76)
B-208-108	VL26	Service Water Booster Pump Area Cooling Unit Fan A (XFN81A)
B-208-108	VL27	Service Water Booster Pump Area Cooling Unit Fan B (XFN81B)
B-208-108	VL30	Emergency Feedwater Pump Area Cooling Unit Fan A (XFN83A)
B-208-108	VL31	Emergency Feedwater Pump Area Cooling Unit Fan B (XFN83B)
B-208-108	VL34	Ventilation System Annunciator & Alarm Inputs - Int. Bldg
B-208-108	VL35	Ventilation System Annunciator & Alarm Inputs - Int. Bldg
B-208-108	VL36	Ventilation System Annunciator & Alarm Inputs - Int. Bldg
B-208-108	VL37	Ventilation System Annunciator & Alarm Inputs - Int. Bldg
B-208-109	VU01	HVAC Mechanical Water Chiller XHX0001A
B-208-109	VU02	HVAC Mechanical Water Chiller XHX0001B
B-208-109	VU03	HVAC Mechanical Water Chiller XHX0001C (“A” Channel)
B-208-109	VU04	HVAC Mechanical Water Chiller XHX0001C (“B” Channel)
B-208-109	VU05	HVAC System Chilled Water Pump XPP0048A

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-109	VU06	HVAC System Chilled Water Pump XPP0048B
B-208-109	VU07	HVAC System Chilled Water Pump XPP0048C (“A” Channel)
B-208-109	VU08	HVAC System Chilled Water Pump XPP0048C (“B” Channel)
B-208-109	VU09	HVAC System Water Chiller “A” Control Scheme
B-208-109	VU10	HVAC System Water Chiller “B” Control Scheme
B-208-109	VU11	HVAC System Water Chiller “C” Control Scheme
B-208-109	VU16	Comp Cooling Pump Motor Isol Valve XVG6516
B-208-109	VU17	Comp Cooling Pump Motor Isol Valve XVG6519
B-208-109	VU18	Comp Cooling Pump Motor Isol Valve XVG6517
B-208-109	VU19	Comp Cooling Pump Motor Isol Valve XVG6518
B-208-109	VU25	Chilled Water Nonessential Load Isolation Valve XVT-6412A
B-208-109	VU26	Chilled Water Nonessential Load Isolation Valve XVT-6412B
B-208-109	VU27	Chilled Water Nonessential Load Isolation Valve XVT-6384A
B-208-109	VU28	Chilled Water Nonessential Load Isolation Valve XVT-6384B
B-208-109	VU29	Chilled Water Nonessential Load Isolation Valve XVT-6385A
B-208-109	VU30	Chilled Water Nonessential Load Isolation Valve XVT-6385B
B-208-109	VU31	Chilled Water Nonessential Load Isolation Valve XVT-6490A
B-208-109	VU32	Chilled Water Nonessential Load Isolation Valve XVT-6490B

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station
Wiring Schematic Package
Safety Related Elementaries of Safety Related Systems

Drawing No.	System Sheet	Title
B-208-109	VU34	HVAC Control Graphic Display Annunciator Alarm Inputs
B-208-109	VU35	HVAC Control Graphic Display Annunciator Alarm Inputs
B-208-109	VU36	HVAC Control Graphic Display Annunciator Alarm Inputs
B-208-120	WP50	Reactor Coolant Drain Tank Vent XVD-7126
B-208-120	WP51	Reactor Coolant Drain Tank Pump XVD-7136
B-208-120	WP52	Reactor Coolant Drain Tank Vent XVD-7150
B-208-120	WP53	Reactor Coolant Drain Tank Pump XVD-7170

Table 1.7-1
Virgil C. Summer Nuclear Station Wiring Schematic Package
One-line and Relay Diagrams

DRAWING NO.	TITLE
E-206-001	Notes, Legend & References
E-206-011	Balance of Plant Power System
E-206-012	Engineered Safety Features Power System
E-206-021	7200 V Swgr. Busses 1A, 1B, 1C & 1DX
E-206-022	7200 V Swgr. Busses 1DA, 1DB, 1EA & 1EB
E-206-031	480/277 V Swgr. Busses 1A1, 1A3, 1B1, 1B3, 1C1 & 1C3
E-206-032	480/277 V Swgr. Busses 1A2, 1A4, 1B2, 1B4, 1C2 & 1C4
E-206-033	480/277 V Switchgear 1A5
E-206-034	480/277 V Swgr. Busses 1DA1, 1DA2, 1DB2, 1EA1 & 1EB1
E-206-042 Sheet 1	240/120 V Miscellaneous AC Distribution
E-206-042 Sheet 2	240/120 V Miscellaneous AC Distribution
E-206-043	480/277 V Miscellaneous AC Distribution
E-206-047	480 V Engineered Safeguard MCC Power Feeds
E-206-061 Sheet 1	Balance of Plant - Vital A.C. - D.C. System
E-206-061 Sheet 2	Balance of Plant - Vital A.C. - D.C. System
E-206-062 Sheet 1	Engineered Safety Features Vital A.C. - D.C. System
E-206-062 Sheet 2	Engineered Safety Features Vital A.C. - D.C. System
E-206-062 Sheet 3	Engineered Safety Features Vital A.C. - D.C. System

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station Wiring Schematic Package
One-line and Relay Diagrams

DRAWING NO.	TITLE
E-206-071	480 V Switchgear - Pressurizer Heaters

Table 1.7-1
Virgil C. Summer Nuclear Station Wiring
Schematic Package Schematic Diagrams

Drawing No.	GAI MFRS. DWG. NO.	TITLE
D-2544-1013 Sheet 1	IMS-28-096-1-2	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 2	IMS-28-096-2-3	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 3	IMS-28-096-3-4	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 4	IMS-28-096-4-3	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 5	IMS-28-096-5-3	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 6	IMS-28-096-6-5	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 7	IMS-28-096-7-2	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 8	IMS-28-096-8-6	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 9	IMS-28-096-9-2	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 10	IMS-28-096-10-4	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 11	IMS-28-096-11-4	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 12	IMS-28-096-12-4	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 13	IMS-28-096-13-4	(AII/VLD) ESF Loading Sequence Electrical Schematics

Table 1.7-1 (continued)
Virgil C. Summer Nuclear Station Wiring
Schematic Package Schematic Diagrams

Drawing No.	GAI MFRS. DWG. NO.	TITLE
D-2544-1013 Sheet 14	IMS-28-096-14-4	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 15	IMS-28-096-15-6	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 16	IMS-28-096-16-1	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 17	IMS-28-096-17-2	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 18	IMS-28-096-18-2	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 19	IMS-28-096-19-2	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 20	IMS-28-096-20-4	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 21	IMS-28-096-21-3	(AII/VLD) ESF Loading Sequence Electrical Schematics
D-2544-1013 Sheet 22	IMS-28-096-22-2	(AII/VLD) ESF Loading Sequence Electrical Schematics

NOTE: Section 1.8 is being retained for historical purposes only.

1.8 TMI ACTION PLAN REQUIREMENTS

A cross reference between various TMI Action Plan Requirements (NUREG-0737, November 1980) addressed in the FSAR and the appropriate FSAR sections is presented by Table 1.8-1.

Table 1.8-1
Cross Reference
TMI Action Plan Requirements to FSAR Sections

Action Plan Requirements	FSAR Section/SCE&G Letters
I.A.1.1	13.1.2.1, 13.1.2.2.2, 13.1.3.1.12, 13.2.1, SCE&G letter to NRC dated 1/2/81
I.A.1.2	13.1.2.2, 13.5.1.3.1
I.A.1.3	13.1.2.3, 13.5.1.3, SCE&G Letter to NRC dated 1/22/82
I.A.2.1	13.2.1, SCE&G letters to NRC dated 10/28/80, 10/31/80, 5/22/84, 7/19/84, 11/28/84
I.A.2.3	13.2, SCE&G letter to NRC dated 10/28/80
I.A.3.1	13.2.1, 13.2.2, SCE&G letter to NRC dated 10/28/80
I.B.1.2	13.1.1.4, SCE&G letter to NRC dated 1/2/81
I.C.1	6.3.3.3.1, 13.5.2, SCE&G letters to NRC dated 11/14/80, 12/2/80, 3/17/82, and Westinghouse Owners Group Letter OG-47 dated 12/15/80
I.C.2	13.5.1.3
I.C.3	13.5.1.3.1, Tech Spec (6.1.2)
I.C.4	13.5.1.3
I.C.5	13.5.1.13
I.C.6	13.5.1.6, SCE&G letter to NRC dated 12/11/80
I.C.7	13.5.1.3.2, SCE&G letter to NRC dated 12/2/80 and 12/22/80
I.C.8	13.5.1.3.3, SCE&G letter to NRC dated 11/14/80

Table 1.8-1 (continued)
Cross Reference
TMI Action Plan Requirements to FSAR Sections

Action Plan Requirements	FSAR Section/SCE&G Letters
I.D.1	1.2.3.1, SCE&G letters to NRC dated 11/12/80, 1/15/81, 11/25/81, 2/23/82, 3/26/82, 6/11/82, 4/15/83, 7/21/83, 10/28/83, 4/4/84, 4/15/85
I.D.2	7.7.3, SCE&G letters to NRC dated 3/31/83, 4/15/83, 12/28/83, 4/18/85, 12/23/85
I.G.1	14.1.4.4, SCE&G letters to NRC dated 10/31/80, 12/2/80, 12/22/80, 3/31/82 and 7/29/82
II.B.1	5.5.15, SCE&G letters to NRC dated 2/19/81, 12/30/81, 1/18/84
II.B.2	12.1.2.3, App. 12A, SCE&G letters to NRC dated 8/27/80 and 11/21/80
II.B.3	9.3.2, App. 12A, SCE&G letter to NRC dated 3/30/82
II.B.4	13.2.1, 13.2.2, SCE&G letter to NRC dated 10/28/80
II.D.1	5.5.13.4, SCE&G letters to NRC dated 3/25/81, 7/29/81, 3/26/82, 4/1/82, 6/29/82 and 7/30/82
II.D.3	1.2.3.1, 1.7, 5.5.10.2.2.4, 5.6, 7.7.4, SCE&G letters to NRC dated 1/13/81, 2/26/82, 3/12/82 and 8/26/82
II.E.1.1	SCE&G letters to NRC dated 8/15/80, 11/5/80 and 12/2/80
II.E.1.2	7.3.1.1.1, 7.3.2.2, 7.3.2.3, 7.5.1, 10.4.9.1, 10.4.9.2, 10.4.9.3, 10.4.9.5.3
II.E.3.1	8.3.1.1.1.a, 8.3.1.1.3, SCE&G letter to NRC dated 2/23/82
II.E.4.1	6.2.5.2.1
II.E.4.2	6.2.4.3; 9.4.8.2.2, Items 8.l and 8.m; 9.4.8.2.3, Items 8.h and 8.i
II.F.1	6.2.5.1.3, 6.2.5.2.3, 6.2.5.3.3, 6.2.5.4.3, 6.2.5.5.3, 6.2.5.5.4, 7.7.3.1, 11.4, 11.4.2, Figure 11.4-2, 12.2.5, Figure 12.2-2, 12.3.2.2, SCE&G letters to NRC dated 8/28/80, 12/22/80, 6/30/82, 1/18/84, 3/22/84
II.F.2	1.2.3.1, 5.6, SCE&G letters to NRC dated 12/4/80, 12/15/80, 12/30/80, 2/19/81, 6/8/81, 7/30/81, 1/18/82, 3/16/82, 4/30/82, 7/20/82, 3/8/83, 3/10/83, 4/22/83, 8/26/83, 2/17/84, 4/13/84, 4/16/84, 4/30/84 and 6/6/84

Table 1.8-1 (continued)
Cross Reference
TMI Action Plan Requirements to FSAR Sections

Action Plan Requirements	FSAR Section/SCE&G Letters
II.G.1	7.4.1.2.1, 8.3.1.1.3
II.K.1	7.3.1.1, 13.5.1.6, and Technical Specifications
II.K.2	SCE&G letters to NRC dated 12/11/80, 1/6/81, and 12/31/81
II.K.3	5.2.2.3; 7.2.1.1.2, Item 6; Figure 7.7-4; Technical Specifications, SCE&G letters to NRC dated 9/9/80, 1/6/81, 1/12/81, 2/19/81, 3/10/81, 3/23/81, 12/31/81, and 4/22/83, 5.5.1.3.13, 13.5.1.3.4, 13.5.1.14, 15.3.1.2, Westinghouse letters to NRC (NS-EPR-2581) dated 3/26/82 and (NS-EPR-2581) dated 6/28/82
III.A.1.1	Radiation Emergency Plan, SCE&G letters to NRC dated 5/12/81 and 6/16/81
III.A.1.2	1.2.3.1, 6.4, 7.7.3, Appendix 12A, SCE&G letters to NRC dated 3/16/82, 7/23/82, 8/6/82, 11/24/82, 12/3/82, 3/31/83, 4/15/83, 5/16/83, 9/14/84
III.A.2	2.3.3.2, Radiation Emergency Plan, SCE&G letters to NRC dated 5/12/81, 6/16/81, 3/31/83
III.D.1.1	6.3.2.11.2, Technical Specifications, SCE&G letter to NRC dated 2/23/82
III.D.3.3	6.2.5.1.3, 6.2.5.2.3, 6.2.5.3.3, 6.2.5.4.3, 6.2.5.5.4, 12.1.4.2, 12.3.2.2.4
III.D.3.4	2.2.1, 2.2.2, 2.2.3, 6.4, 15.4, SCE&G letters to NRC dated 11/15/80, 12/15/80, 1/18/84

V.C. Summer Nuclear Station
Safety Analysis Report

Site Characteristics

Chapter 2

Revision 26--06/25/2026

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

Site Characteristics
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CHAPTER 2 - SITE CHARACTERISTICS

2.0 SITE CHARACTERISTICS

NOTE: Section 2.1 is being retained for historical purposes only (per RN 00-081).

2.1 GEOGRAPHY AND DEMOGRAPHY

2.1.1 Site Location

The Virgil C. Summer Nuclear Station site is located in Fairfield County, South Carolina, approximately 15 miles Southwest of the county seat of Winnsboro and 26 miles Northwest of Columbia, the state capital. The site is in a sparsely populated rural area. The nearest community is Jenkinsville, located approximately 3 miles Southeast of the site. The Broad River is located approximately 1 mile West of the site and flows in a southerly direction. Lake Murray is a 50,000 acre reservoir utilized for hydroelectric power generation and recreation, located 12 miles South of the site. Figure 2.1-1, Regional Location Map, and Figure 2.1-2, Site Location Map, indicate the plant location with respect to local and regional cultural features.

The reactor building is located at latitude N34°17’54.1" and longitude W81°18’54.6". Universal Transverse Mercator (UTM) grid coordinates, Zone 17, for the reactor building are N3,795,086 and E470,996.

2.1.2 Site Description

The Site Area Map presented on Figure 2.1-3 indicates the site boundary, plant property line and the location of principal plant structures in relation to existing cultural features in the area. The exclusion area consists of a zone within approximately 1 mile of the reactor building. This area encompasses parts of the Monticello Reservoir and the Fairfield Pumped Storage Facility. SCE&G has acquired, by purchase, all land within the site boundary. For purposes related to the operation of the nuclear facilities the plant property line is considered to coincide with the site boundary. The plant property, as defined herein, covers approximately 2,200 acres.

The representation of the reservoir and its boundaries on Figure 2.1-3 is an approximation of the final configuration of the area. The increase in surface level of the existing Parr Reservoir is also depicted on Figure 2.1-3.

2.1.2.1 Exclusion Area Control

Licensees will maintain absolute ownership of all land contained within the site boundary for the Virgil C. Summer Nuclear Station. The site boundary also serves as the site exclusion area and is identified in Figure 2.1-3. SCE&G, as an owner and the manager of the nuclear station, retains the right to maintain control of both station and non-station related activities within the exclusion

area. Mineral rights within this area are jointly owned by SCE&G and SCPSA, and are under the control of SCE&G as manager of the plant.

The exclusion area for the nuclear station is not and will not be traversed by other than wholly owned land accesses. The closest primary public road, South Carolina State Highway 215, lies approximately 6,800 feet East of the Reactor Building centerline and is outside the exclusion area.

The Broad River is approximately 6,050 feet West of the Reactor Building and is outside the exclusion area. The southern portion of the Monticello Reservoir lies within the exclusion area. The closest railroad not owned by SCE&G and SCPSA lies approximately 5,850 feet to the Southwest on the outside edge of the site boundary. Figure 2.1-3 shows river, reservoir and railroad locations.

Licensees own and maintain some railroad facilities within the exclusion area. These facilities are used for receipt and shipment of carload freight to and from the Virgil C. Summer Nuclear Station in accordance with an agreement between Southern Railway Company and the licensees. The licensees are the sole authority for control and operation of these rail facilities.

A 68’ right-of-way has been granted through the exclusion area for a 115 KV transmission line owned by Duke Power Company. Terms of this agreement provide for the licensees to retain authority to determine all activities within the exclusion area.

The only other non-station related activities conducted within the exclusion area are those related to the Fairfield Pumped Storage Facility.

The location of the Fairfield Pump Storage Facility is shown on Figure 2.1-3. Personnel of this facility are limited to employees of SCE&G and therefore are subject to administrative controls of the company. The pumped storage facility is staffed by approximately 10 people during the day shift and one operator for each night shift. The estimated time to evacuate all personnel from this facility is 10 minutes if the plant is not running and 20 minutes if the units must be shut down.

Licensees own all property within the exclusion area and has the authority to determine all activities, including exclusion or removal of personnel and property from the area.

Licensees maintain the right to limit access to and control evacuation from the exclusion area. Normal evacuation of persons within the exclusions area is estimated to take no more than 20 minutes.

The term “transportable property” as used in the Amended ROW agreement is self-explanatory and includes all properties of the Grantee which are not part of its permanent transmission line facilities. These facilities are fixtures which are attached to the land and are steel frame transmission towers and high voltage conductors. The Amended ROW agreement dated April 5, 1978, clearly states in paragraph 4, that SCE&G (Grantor) has the right to either exclude or require the immediate removal of all personnel and transportable (nonfixed) property from the exclusion area. SCE&G does not anticipate conditions which would require the removal of fixed

facilities as being “hazardous to the public health and safety” of 10 CFR 100. The requirements of Section 100.3 (a) are satisfied by the Amended ROW agreement.

“Nontransportable” property within the ROW corridor consists of fixed steel frame transmission towers and high voltage conductors. Personnel and/or public use and access to properties within the exclusion zone is defined in Section 2.1.2.1.

The Amended ROW agreement fully meets the requirements of Section 100.3 (a). The document does not state or imply that “prior” notification to Grantee is required, but that he will immediately remove all personnel and transportable property from the exclusion zone upon notification from Grantor to do so.

The original ROW agreement was specifically amended to define the limits of the exclusion zone and to incorporate the requirements of Section 100.3 (a). Further amendment would be superfluous.

Figure 1.2-1 clearly shows the ROW corridor with respect to plant structures. Incorporated plats within and made a part of the Amended ROW agreement read in conjunction with supportive text within the agreement itself clearly define the location of the ROW within the exclusion zone. The plat identified as “Duke Power Company Relocation of Great-Falls Newberry Transmission Line Crossing Property of South Carolina Electric and Gas Company” defines the corridor width as 68’.

2.1.2.2 Boundaries for Establishing Effluent Release Limits

Control of personnel and access to the Virgil C. Summer Nuclear Station exclusion area are discussed in Sections 13.3 and 13.7. The site exclusion area, identified as the “site boundary” on Figure 2.1-3, is the selected boundary for establishing effluent release limits. The release points for both liquid and gaseous effluents are described in Sections 11.2.7 and 11.3.7; these sections also provide the minimum distances between the various release points and the exclusion area boundary.

The site boundary is located approximately 5,350 feet South, East, and North from the Reactor Building, and is at least 5,850 feet from the Reactor Building in a westerly direction. Routine operational radiological effluent concentrations at and beyond this area boundary are within the limits prescribed by 10 CFR 20 and 10 CFR 50 Appendix I.

2.1.3 Population and Population Distribution

The location of the site in relation to the surrounding cities and towns within a 50 mile radius is shown on Table 2.1-1. Those communities for which Census population data are available are listed, together with their 1970 populations, in Table 2.1-1 (all incorporated cities, towns, villages, and unincorporated places of 1,000 or more persons).

The base (1970) population distribution has been developed for the Virgil C. Summer Nuclear Station. Projections are based on estimates produced in December 1975, by the Bureau of

Economic Analysis (BEA) for the U. S. Army Corps of Engineers, South Atlantic Division. (Reference 1)

Within the 10 mile radius, population distribution was based on a house count using county highway maps prepared from aerial photographs. A household population size of 3.5 was used in converting the house count into population. This factor is an average of the household size for Fairfield and Newberry Counties, taken from the 1970 Census of Population.

Beyond the 10 mile radius, the 1970 population distribution utilized the smallest geographic unit for which Census data were available: city, town, unincorporated place, or Census county division. The population wheel, composed of 10 annular rings and 16 segments, was superimposed upon a map of these Census geographic units. The Census units within each cell of the wheel were identified, and the population associated with each unit was proportioned into the appropriate cell, assuming uniform population distribution.

Two population projections thus derived are presented in Section 2.1.3.1 and Section 2.1.3.2 below. The low projection is based upon the rates of change for counties in South Carolina recently projected by the BEA.(Reference 1) These local area projections are an extension of the OBERS* water resources program which produced projections for the nation and its subareas. Both studies utilized the Bureau of Census Series E projections which assumed a complete cohort fertility rate of 2.11 children per woman. The high projection utilized alternate rates presented in Appendix B of the 1975 Corps of Engineers/BEA study. This alternate projection reflects the future growth estimates of the South Carolina Division of Research and Statistics. The higher growth rates are based upon the fact that South Carolina appears atypical of the nation as a whole. Between 1970 and July, 1974, South Carolina experienced a considerably higher growth rate than the Series E projections anticipated. This rapid population growth has resulted from increased economic development and gains in employment opportunities which induced a high net in-migration, reversing the historical net out-migration which had been experienced by the state for decades.(Reference 2) Historical and projected populations for counties all or partially within the 50 mile radius are presented in Table 2.1-2.

Projections for 1980, 1990, 2000, 2010, and 2020 were prepared by the following method: 1970 values for each cell were broken down into the component parts related to each county within a cell. This was done on an areal basis, assuming population homogeneity. Each component value was increased or decreased according to the county’s rate of change, and then the components were summed to reach the new cell total.

Differences between population projections for 2010 in this report and those presented in the PSAR for the Virgil C. Summer Nuclear Station result from the fact that the PSAR reflected more heavily local area projections prepared at the county level, while this report utilizes more recently available county projections made by agencies at the State and Federal level (though representatives of local agencies participated in the preparation of the projections made by the higher level agencies).

(*)Office of Business, Economic and Economic Research Services

The high estimate, based on BEA's alternate projections, is only 1.6 percent lower for the 50 mile area than the PSAR projection. Counties which are generally lower include Greenwood, Saluda, and portions of Richland. New estimates for Lexington, Kershaw, Chester, Spartanburg and the counties bordering Spartanburg (Cherokee, Union and Laurens Counties) are higher. The new estimates for the Rock Hill portion of York County are slightly lower, but higher for the balance of the county.

Growth in the Camden area is now projected to be higher, while estimates for Columbia, Newberry and Greenwood have dropped.

The population projected within the 0-10 mile area is 21 percent higher than the earlier projection (8,552 persons versus 7,072 persons). This is more likely to be a function of the projection methodology used for this report which assumed even population distribution when applying the county growth projections.

Population distributions for the area within 10 miles (discussed in Section 2.1.2.1) and between 10 and 50 miles (discussed in Section 2.1.3.2) appear on Figures 2.1-4 through Figure 2.1-9.

2.1.3.1 Population Within 10 Miles

Within 10 miles of the plant the 1970 estimated population was 6,370 (a density of 20.3 persons per square mile). The following communities included in the 1970 Census of Population are within the 10 mile radius:.

	1970 Population	Distance (in miles) and Direction from Site
Peak	87	4S
Pomaria	264	6 WSW
Little Mountain	240	9 SW
Chapin	342	9 SSW

Other communities within the 10 mile radius, not included in the 1970 Census published data are Parr, Jenkinsville, Monticello, and Blair.

Within 5 miles the 1970 estimated population was 1,203 (a density of 15.3 persons per square mile). The communities within 5 miles are Peak, Parr, Jenkinsville, and Monticello.

The highest population densities out to 10 miles are in the three sectors between South-southwest and West-southwest and are partly related to the presence of the communities of Pomaria, Chapin, Little Mountain, and a generally better developed local road system than exists in the remaining portions of the 10 mile area.

The 1980 projected population within 5 miles ranges from 1,214 (15.5 persons per square mile) to 1,275 (16.2 persons per square mile). Within 10 miles, the 1980 projections range from 6,543 (20.8 persons per square mile) to 6,934 (22.1 persons per square mile). No major population

increase is projected by the two alternate methods utilized, nor any major redistribution of population.

Research undertaken at the time of the PSAR revealed that some population decreases may occur in some of the subareas within a 5 mile radius of the plant due to the abandonment of some small, marginal farms. These changes are too small, however, to be reflected in the population wheels which were produced from the BEA Series E and BEA Alternate projections described above.

The 2020 low and high projections for the 10 mile radius are 7,122 and 8,871 with an average density of 22.7 and 28.3 persons per square mile, compared with a 1970 density of 20.3. Thus, the changes are not anticipated to be great. The high projection results in a large percentage change but increases density by only eight persons per square mile.

By the year 2020, the projected end of plant life, the low and high projections for the 5 mile radius are 1,261 and 1,584, respectively, an absolute increase from 58 to 381 persons. These increases would result in an average density ranging from 16.1 to 20.2 persons per square mile compared with 15.3 in 1970.

As noted above, future projections were made by applying uniformly the County growth rates. This may have the effect of increasing population estimates of the rural inner 10 miles too rapidly. This method of population estimation is, however, as accurate a method as the application of subjective judgment on changes within small geographic areas over a span of 40 years.

2.1.3.2 Population Between 10 and 50 Miles

The largest accumulated population in the site region in 1970 was within the 20 to 30 miles circles, with the highest concentration of people being in the southeast and south-southeast segments. This area includes Columbia [(*)], West Columbia, Cayce, and Forest Acres. Seventy percent of the total for this annulus occurs in the cell in which Columbia and its suburbs are located. The second highest population is found between the 40 and 50 mile area with concentrations in the north-northeast, northeast, west and west-northwest segments. Centers of population within the 40 to 50 mile northern segments include York, Rock Hill, and Lancaster; Greenwood, Laurens and Clinton account for most of the population in the westerly segments.

The highest population density (2,138 persons per square mile) occurred in the cell formed by the southeast sector and 20 to 30 mile annulus, and was accounted for by the city of Columbia. The second highest density (288 persons per square mile) was in the area of Rock Hill, 40 to 50 miles north-northeast. No other cell exceeded a density of 250 persons per square mile.

Projections for 1980, the first year of plant life, for 2020, the projected last year of plant life, and for each decennial year from 1980 to 2020 are presented on Figures 2.1-11, 2.1-13, 2.1-15, and 2.1-19.

Not included in these projections are some qualitative predictions of probable growth for two portions of the 10 to 50 mile area which are based upon information received from the South Carolina Division of Research and Statistical Services (Reference 3). These estimates are not

reliably quantifiable either as to magnitude or point of time. They have not been included by the State in their official projections for countries. Consequently, they are treated here descriptively rather than quantitatively. The first area is Fairfield County, especially the east and east-northeast sectors between 10 and 30 miles. It is anticipated that growth will be accelerated in this area by the future construction of Interstate 77. This major route will provide vastly improved access south to Columbia and north to Charlotte, North Carolina, opening the area into the industrial heart of Ohio. This new access, together with the new county tax revenues which will be generated by the Virgil C. Summer Nuclear Station, is expected to cause some in-migration into Fairfield County, probably centering in the Winnsboro and Ridgeway areas. More growth there may also result from an overflow of population north from Columbia.

Another growth area is anticipated to be that portion of Lexington County west and northwest of Columbia (the southeast sector between 10 and 30 miles). The area is served by Interstate 26, providing access to Columbia, and this advantage, together with the attraction of Lake Murray, is already generating rapid suburban development as well as industrial growth. Much of this growth, including a planned new community of 25,000 (Harbison) will occur in the area between 10 and 20 miles southeast of the site.

Figure 2.1-20 graphically presents the estimated cumulative population for the entire 50 mile radius for the year 1980, the year of initial plant operation, compared with a hypothetical cumulative population which would result from a uniform density of 500 persons per square mile. Figure 2.1-21 presents the projected population for the year 2020 compared with a hypothetical population of 1,000 persons per square mile. Only the high projections have been plotted, since they are well below the hypothetical values.

* Including Fort Jackson

2.1.3.3 Low Population Zone

In accordance with criteria specified in 10 CFR 100, the outer boundary of the low population zone (LPZ) is at a distance of 3 miles from the reactor building. These criteria include the low population within the area; the small number of institutions, recreation facilities, and places of employment; and the presence of public surface routes for evacuation purposes.

Figure 2.1-21 illustrates significant cultural features within the low population zone (LPZ). Table 2.1-3 indicated weighted transient and projected residential populations within the LPZ. In 1970, approximately 365 persons lived within the zone. It is expected by 2020 that the total residential population will be 470, excluding transient population.

The community of Jenkinsville lies within the LPZ, as do portions of Parr Reservoir and Monticello Reservoir. The only school within the low population zone is Whitehall Elementary, located north of Jenkinsville off S. C. 215, on County Road 209. The school had a 1976 enrollment of 111 pupils with approximately nine staff members (Reference 4). Whitehall School has been closed, but the building still remains. Two industries located within the LPZ, the Nylene Corporation, in Jenkinsville (Reference 5), and Interstate Materials, Inc., a quarry operation located near Monticello (Reference 6), are now closed. The Fairfield Pumped Storage Facility, the Parr Hydroelectric Facility and the Virgil C. Summer Nuclear Plant have expected staff levels of approximately 900 employees during normal operational shifts (Reference 7).

Transient populations also include highway traffic along major thoroughfares within the LPZ. Average daily traffic along S. C. 215 in the plant vicinity was 1,600 in 1975. S. C. 213, connecting S. C. 215 to Winnsboro, average 950 vehicles per day. Other roads in the LPZ averaged less than 200 vehicles per day (Reference 8). Highway traffic is not included in Table 2.1-3.

Future transient population within the LPZ associated with recreational use of the Monticello Reservoir is expected to be minor. Most of the developed recreational facilities will be located at the northernmost end of the reservoir, outside the LPZ (Reference 9). In addition, routes to and from the recreation areas are not limited to highways passing through the LPZ.

Seasonal population movements in the LPZ are also expected to be minor, although recreational users of the reservoir will probably increase during the summer months. Also, the Carlisle Game Management Area, which surrounds the site and is partially located within the LPZ, attracts hunters during game seasons. Highest visitation rates occur during deer season. Estimated visitation figures within the LPZ are included in Table 2.1-3.

2.1.3.4 Transient Population

Three types of transient population generators are discussed in this section: recreation attractions, industrial facilities, and communities. The purpose is to determine where population concentrations may occur on a daily or seasonal basis in excess of that indicated by residential distributions. In the study region, manufacturing has tended to locate in rural areas along major

highways, introducing patterns of cross-commuting between rural areas and urban centers which tend to offset any significant in-migration into the areas associated with worker commuting.

Population concentrations on the periphery of the 50 mile radius, along with recreational areas, are the more significant transient population generators with respect to the daily or seasonal spatial redistribution of population into the 50 mile area from outside.

Six categories of communities, based on size, have been identified within the 50 mile radius. These indicate the relative ability of the communities to provide economic, cultural, institutional and administrative functions for surrounding areas, thereby generating population concentrations on a temporary basis. The communities, their 1970 populations and their size category are shown in Table 2.1-1. It is expected that these communities will continue to dominate the spatial organization of population in the region.

Recreation facilities tend to generate seasonal, temporary population peaks, especially if the facilities are associated with outdoor activities such as hunting, camping, water sports, etc. During these times of seasonal activity the facilities will not only concentrate populations from the general vicinity but may also attract persons outside the study region, thereby increasing overall population levels within the area. Within 50 miles of the site are seven state parks, three administrative units of the Sumter National Forest, and several areas used for public hunting and fishing. Users of these recreational facilities, excluding Lake Murray, totaled approximately 1.7 million during 1975. Of these, it is estimated that approximately 2 to 10 percent were campers using the facilities on an overnight basis.Table 2.1-4 indicates where these facilities are in relation to the site and the total usage of each area during 1975. Figure 2.1-22 is an areal representation of the areas in relation to the site.

The most significant recreation attraction within 20 miles of the site is Lake Murray, a 50,000 acre reservoir 10 miles northwest of Columbia. Due to its proximity to Columbia and to two interstate highways in the area, the lake is becoming a major recreational attraction. A shoreline survey of the lake in 1973 identified 4,910 homes of which 1,651 were year-round residences. Private homes and condominiums for full-time residence near the eastern end of the lake were a significant part of the development. Total annual visitor days on the lake in 1973 for non-residential users were estimated at 1.8 million (Reference 10).

Figure 2.1-24 is a graphic illustration of cumulative residential and weighted transient populations for the years 1980 and 2020 compared with hypothetical populations at a density of 500 and 1,000 persons per square mile, respectively. The results of these graphs may be misleading, since some of the population is being double-counted. Many users of the recreation facilities reside within the radii locating the facility and thus are tabulated twice. However, determination of user origins is precluded by lack of data. Most of the recreational areas around the Monticello Reservoir are expected to be located outside the low population zone, approximately 4 to 6 miles from the reactor building (Reference 9).

2.1.3.5 Population Center

The nearest population center as defined by 10 CFR 100 is the city of Columbia, the capital of the state of South Carolina. The nearest corporate limits are 23 miles southeast of the site, 7.7 times the radius of the low population zone. Transient population has not been considered in establishing the population center because it is estimated that cross-commuting between the city and outlying industrial developments results in no significant in-migration of working population. Other institutional population (notably that related to the University of South Carolina and Fort Jackson) was included in resident population since it was included in the 1970 Census of Population which formed the basis for distribution of base population.

If the present suburban development now occurring along Interstate 26 northwest of Columbia continues (especially with the development of Harbison), it is estimated there will be a contiguous population grouping of over 25,000 (not necessarily an incorporated city) within 15 miles south-southeast of the plant within the lifetime of the facility. Official projections do not include this possible growth.

Additionally, it is possible that the Winnsboro/Winnsboro Mills area, 15 miles east-northeast of the facility, may grow to a population of 25,000 if the economic development of that area is sufficiently stimulated by the construction of Interstate 77 and through potential tax advantages to Fairfield County resulting from the operation of the plant.

2.1.3.6 Public Facilities and Institutions

Table 2.1-5 indicates schools, hospitals, nursing care facilities, prisons and jails within 10 miles of the site, their location in respect to the reactor and present populations of these facilities. There are no state parks within 10 miles of the nuclear plant. A discussion of recreation attractions within 50 miles of the site is found in Section 2.1.3.4.

2.1.4 Land Use

2.1.4.1 General

The general classes of land use in the 50 mile region (see Table 2.1-6 and Figure 2.1-24) are derived from county statistics obtained from the publication, “South Carolina Soil and Water Conservation Needs Inventory,” dated May, 1970 (Reference 11). These land-use categories are further described below:

1. Federal Land - Federally owned land except cropland operated under lease or permit, and Indian lands under trusteeship but owned by individuals or tribes.
2. Urban and Built-up Areas - Areas that include
   a. cities, villages, and built-up areas of more than 10 acres;
   b. industrial sites (except strip mines, borrow and gravel pits), railroad yards, cemeteries, airports, golf courses, and so forth;

c. institutional and public administrative sites and similar types of areas.

3. Cropland - Land in tillage rotation, orchards, vineyards, bush fruits, and open land recently cropped.
4. Pasture - Land in grass or other long-term forage growth that is used primarily for grazing.
5. Forest - Lands which are at least 10 percent stocked by forest trees, including commercial forest land, farm woodlots, and afforested (planted) areas; and also, land of less than 10 percent stocking that has not been developed for other uses.
6. Other - Includes non-productive farm land occupied by buildings, road, ditches, etc., and other non-farm land such as built-up areas less than 10 acres in size, gravel pits, and borrow pits.

Land use and general topography within 10 miles of the site are illustrated on Figure 2.1-26, utilizing information presented in general soil maps of Newberry, Fairfield and Richland Counties. Soils at the site in general consist of a surficial zone of silty, clayey materials, underlain by sandy silt and silty sand. These materials, in general, are typical of soil conditions in the vicinity. Topography and soil conditions have an effect on future land use and their consideration provides an aid in predictions of future land use.

Forestry is the most extensive land use within the region. Data from 1967 (Table 2.1-6) indicate forests occupied approximately 53 percent of the land in Richland County and 80 percent in Fairfield County. The average for the site region was about 64 percent forest land, representing a 2.9 percent increase over 1958. Within 10 miles of the site, 69 percent of the land was in forest in 1967 which represented an increase of 3.8 percent occurring between 1958 and 1967.

The Enoree/Tyger division of the Sumter National Forest lies within a 50 mile distance. The southern boundary is 5 miles northwest of the site. Harbison State Forest lies 16 miles southeast of the site. Agricultural land use is second in importance to forestry with 22 percent of the land within 50 miles of the site and 17 percent within 10 miles devoted to this use (Table 2.1-6).

The chief crops grown in the region are cotton, soybeans, small grains, and vegetables. Livestock enterprises, mainly beef and dairy cattle operations, are increasing at the expense of land devoted to field crops, resulting in a gradual shift from cropland to more pastureland in the region (Table 2.1-6).

The area within 10 miles of the site lies principally in Fairfield County and Newberry County. Data for these two counties indicate that agriculture is relatively unimportant in the site vicinity, particularly in the Fairfield County portion. Farming activity is devoted to small grains, pasture, feed crops, and beef cattle. Most farms are owned and operated by part-time farmers whose main livelihood comes from employment in industries or other commercial activities within neighboring communities.

2.1.4.2 Urban Development

2.1.4.2.1 Fairfield County

The western half of Fairfield County, in which the Virgil C. Summer Nuclear Station is located, is sparsely developed area characterized by small rural communities which have developed at the crossroads of major highways. Future growth in the area is expected to be minor with some residential development occurring along those sections of S. C. 215 in the vicinity of the nuclear plant site. Since much of the northwestern part of the county is in National Forest holdings, the amount of land available for urban development is quite limited, ensuring the continued rural nature of the area (Reference 12).

By comparison, the eastern half of the county, including the Winnsboro area, is more developed and is likely to experience greater development than the western half. Most of the present urban development is within the vicinity of Winnsboro or along U. S. 21. The completion of Interstate 77, which passes through the area, is expected to be a growth factor. When completed, this interstate will connect the area with the cities of Cleveland and Akron in Ohio. The state has also planned to construct a small reservoir in the vicinity of Winnsboro for recreation, residential and employment center (industrial and commercial) use (Reference 12).

2.1.4.2.2 Newberry County

The city of Newberry is the geographic and economic center of Newberry County. Interstate 26 has influenced moderate development around Newberry and is expected to remain a growth factor. Predictions are for the eventual linking of Newberry, Prosperity, and Little Mountain by development associated with the interstate highway. Other parts of the county are not expected to grow at the levels associated with the Newberry area. Much of the northern portions of the county are in National Forest land holdings and therefore unavailable for urban development (Reference 12).

2.1.4.2.3 Richland-Lexington Counties

Major development in these two counties is expected to occur in the suburbs of Columbia and northwestward along Interstate 26 and the north shore of Lake Murray. Growth radiating outward along major highways from the central urban area is already evident. Future growth along Interstate 77, U.S. 176, and U.S. 76 northward from Columbia is also expected (Reference 12).

2.1.5 References

1. U. S. Army Corps of Engineers, South Atlantic Division and U. S. Department of Commerce, Bureau of Economic Analysis, *Projections of Economic Activity in South Carolina (Series E Population)*, December, 1975.
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21. Teagle, Marimac, Statistician, and Strickland Jessie, Director of Regional Operations, South Carolina Department of Corrections, May, 1976.

2.1.6 Map References

1. South Carolina State Highway Department, General Highway Maps: Lexington County 1958, Revised 1970; Newberry County 1961, Revised 1970; Fairfield County 1962, Revised 1970; Richland County 1963, Revised 1969.
2. South Carolina State Highway Department, Primary Highway System Map, 1975.
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4. U. S. Department of Agriculture, U. S. Forest Service, Map of Sumter National Forest, 1964.
5. U. S. Department of Agriculture, Soil Conservation Service, General Soil Maps of Newberry County 1967; Fairfield County 1966; Richland County 1968.
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7. U. S. Department of the Interior, Geological Survey, Map of South Carolina, 1:500,000, 1970
8. U. S. Department of the Interior, Geological Survey, 7-1/2 Topographic Quadrangle Maps: Blair (1969), Chapin (1971), Irmo (1971), Irmo NE (1971), Jenkinsville (1969), Lake Murray East (1971), Lake Murray West (1971), Lebanon (1969), Little Mountain (1971), Newberry East (1968), Pomaria (1969), Prosperity (1970), Rion (1969), Richtex (1971), Salem Crossroads (1969), Winnsboro (1969), Winnsboro Mills (1969).

2.1.7 Aerial Photography References

1. U. S. Department of Agriculture, Agricultural Stabilization and Conservation Service, Panchromatic, Original scale 1:20,000, Mosaic, November 25, 1970.
2. Dames & Moore, False Color, Infrared, Scale: 1:24,000, April 10, 1976.

Table 2.1-1
Communities Within 50 Miles of the
Virgil C. Summer Nuclear Station, 1970

1970 Population Category	Place	Distance From Site (Miles)	Direction	1970 Population
Over 100,000	Columbia[(a)]	26	SE	113,542
35,000 - 99,999	None	-	--	--
10,000 - 34,999	Greenwood	48	W	21,069
	Laurens	43	W	10,298
	Rock Hill	46	NNE	33,846
	Union	34	NNW	10,775

Table 2.1-1 (CONTINUED)
Communities Within 50 Miles of the
Virgil C. Summer Nuclear Station, 1970

1970 Population Category	Place	Distance From Site (Miles)	Direction	1970 Population
5,000 - 9,999	Camden	40	E	8,532
	Cayce	27	SE	9,967
	Chester	29	N	7,045
	Clinton	35	W	8,138
	Forest Acres	27	SE	6,808
	Lancaster	44	NE	9,186
	Newberry	17	W	9,218
	West Columbia	26	SE	7,838
	York	47	N	5,081
1,000 - 4,999	Baldwin-Argon Mills	29	N	1,042
	Batesburg	30	SSW	4,036
	Buffalo	37	NW	1,461
	Edgefield	49	SW	2,750
	Eureka	29	SSW	1,524
	Great Falls	30	NE	2,727
	Irwin	38	NE	1,424
	Joanna	30	WNW	1,631
	Johnston	42	SW	2,552
	Jonesville	43	NNW	1,447
	Kershaw	47	ENE	1,818
	Lancaster Mills	44	NE	2,558
	Leesville	28	SSW	1,907

a) Includes population at Fort Jackson, South Carolina

1,000 - 4,999 (continued)	Monarch	33	NNW	1726
	Ninety-Six	40	W	2166
	Pacolet	50	NNW	1418
	Pacolet Mills	49	NNW	1666
	Saluda	33	SW	2442
	Sandy Run	40	SSE	2169

Table 2.1-1 (CONTINUED)
Communities Within 50 Miles of the
Virgil C. Summer Nuclear Station, 1970

1970 Population Category	Place	Distance From Site (Miles)	Direction	1970 Population
	South Congaree	29	SSE	1434
	Springdale	27	SSE	2638
	Springdale	39	NE	3193
	Watts Mills	39	WNW	1181
	Whitmire	22	NW	2226
	Winnsboro	15	ENE	3411
	Winnsboro Mills	15	ENE	2312
0 - 999	Arcadia Lakes	28	SE	741
	Ardincaple	28	SE	726
	Boyden Arbor	27	SE	416
	Carlisle	22	NNW	670
	Chapin	9	SSW	342
	Forest Lake	27	SE	39
	Gilbert	26	S	186
	Irmo	16	SSE	517
	Lexington	22	SSE	969
	Little Mountain	9	SW	240
	Peak	4	S	87
	Pineridge	29	SSE	633
	Pomaria	6	WSW	264
	Prosperity	14	WSW	762
	Ridgeway	22	E	437
	Silverstreet	22	W	156
	Summit	26	SSW	130

Source: U. S. Department of Commerce, Bureau of the Census, 1970 Census of Population: Number of Inhabitants, South Carolina, PC(1)-A42, S. C., June, 1971 (Reference 13)

Table 2.1-2
Population For Selected South Carolina Counties, 1930 to 2020
(In Thousands)

County	1930	1940	1950	1960	1970	1974	1980	1990	2000	2010	2020	1960-1970% Change	1970-1974% Change (Est.)
Aitken	47.4	49.9	53.1	81.0	91.0	93.7	92.4	94.0	93.8	94.6	95.0	12.3	2.9
Calhoun	16.7	16.2	16.2	14.8	10.8	10.6	10.5	12.0	12.5	13.2	13.5	-12.0	-1.5
Cherokee	32.2	33.3	34.9	35.2	36.8	39.7	40.8	43.2	44.2	45.4	46.4	4.5	8.0
Chester	31.8	32.6	32.6	30.9	29.8	30.7	31.9	33.3	33.8	34.1	34.4	-3.5	3.1
Edgefield	19.3	17.9	16.6	15.7	15.7	16.4	14.9	14.7	14.5	14.4	14.3	-0.3	4.5
Fairfield	23.3	24.2	21.8	20.7	20.0	19.8	20.2	21.1	21.1	21.1	21.1	-3.4	-0.8
Greenwood	36.1	40.1	41.6	44.3	49.7	51.8	54.6	59.9	63.0	65.7	67.9	12.2	4.3
Kershaw	32.1	32.9	32.3	33.6	34.7	35.8	37.8	44.9	49.5	53.3	55.8	3.4	3.1
Lancaster	28.0	33.5	37.1	39.4	43.3	45.3	45.8	48.1	49.0	49.7	50.2	10.1	4.5
Laurens	42.1	44.2	47.0	47.6	49.7	49.7	50.0	53.0	55.9	57.0	NA	4.4	---
Lexington	36.5	36.0	44.3	60.7	89.0	111.5	129.1	174.1	204.4	227.5	251.4	46.6	25.2
McCormick	11.5	10.4	9.6	8.6	8.0	8.2	7.3	7.1	6.6	6.2	NA	-7.8	2.6
Newberry	34.7	33.6	31.8	29.4	29.3	30.2	30.0	31.0	31.2	31.3	31.3	-0.5	3.1
Orangeburg	63.9	63.7	68.7	68.6	69.8	76.0	76.8	83.1	86.7	89.1	91.1	1.8	8.9
Richland	87.7	104.8	142.6	200.1	233.9	249.3	245.0	271.2	289.1	318.0	340.1	16.9	6.6
Saluda	18.1	17.2	15.9	14.5	14.5	14.6	15.5	16.0	16.2	16.5	16.9	-0.2	0.2

Table 2.1-2 (CONTINUED)
Population For Selected South Carolina Counties, 1930 to 2020
(In Thousands)

County	1930	1940	1950	1960	1970	1974	1980	1990	2000	2010	2020	1960-1970% Change	1970-1974% Change (Est.)
Spartanburg	116.3	127.7	150.3	156.8	173.7	189.0	205.6	239.1	260.9	281.6	297.5	10.8	9.3
Sumter	45.9	52.5	57.6	74.9	79.4	82.6	85.0	89.7	94.2	97.9	101.6	6.0	4.0
Union	30.9	31.4	31.3	30.0	29.2	30.2	31.8	33.4	34.1	34.9	33.7	-2.9	3.4
York	53.4	56.7	71.6	78.8	85.2	92.5	92.2	101.5	106.7	111.2	114.7	8.2	8.6

References

a) Years 1930-1960: Petty, Julian J., Twentieth Century Changes in South Carolina Population, Bureau of Business and Economic Statistics, University of South Carolina, 1962 (Reference 14)

b) Years 1970 and 1974: South Carolina Division of Research and Statistical Services, State Budget and Control Board, News Release Regarding Estimates of the Population of South Carolina Counties 1970-1974, February 13, 1975 (Reference 15).

c) Years 1930-2020: U.S. Army Corps of Engineers and BEA, Projections of Economic Activity in South Carolina (Series E Population), December, 1975 (Reference 16).

Note: - Figures for 1980-2020 represent the low estimate (BEA, Series E). The high estimate added the following percentage rate to the low estimate: 1980 - +6.5%; 1990 - +5.6%; 2000 - +4.6%; 2010 - +3.6%; 2020 - +2.8%.

Table 2.1-3
Estimated Populations in the Low Population Zone, 1975
(Residential and Transient) [a,g]

Sector	Distance (Miles) 0-1	1-2	2-3	0-3 (Total)
N	0+(83)[b]	23	23	129
NNE	0	23	27	50
NE	0	41	58[d]	99
ENE	0	109[c]	74	183
E	0	41	25	66
ESE	0	55	0	55
SE	0	41	39[h]	80
SSE	0	23	18	41
S	0	23	0	23
SSW	0	23	51[e]	74
SW		23	23	46
WSW	0	23	23	46
W	0	23	34	57
WNW	0	38f	23	61
NW	0	23	23	46
NNW	0	23	30	53
	83	555	471	1109

a) Transient population numbers are weighted to reflect the proportion of a 24-hour day during which people are present at the facility. Resident and transient population may be double-counted within the low population zone. Resident populations come from 1970 Census figures. Transient populations for 1975.

b) Includes Virgil C. Summer Nuclear Station employees (Reference 7).

c) Includes weighted population associated with Whitehall Elementary School (Reference 4).

d) Includes weighted population associated with Interstate Materials, Inc.(Reference 6).

e) Includes weighted population associated with Parr Steam and Hydroelectric Plants (Reference 7).

f) Includes weighted population associated with Fairfield Pump Storage Facility (Reference 7).

g) Weighted population of Central Piedmont Hunt Unit included (Reference 17).

h) Includes weighted transient population associated with Nylene Corporation (Reference 5).

Table 2.1-4
Recreational Use Within 50 Miles of the Virgil C. Summer Nuclear Station, 1975

Recreation	Distance From Site (Miles)	Direction	Visitor Annual Overnight	Visitor Annual Daytime	Peak Monthly	Low Monthly	Total Annual Visitor Days	Weighted Annual Transient Population
Sumter National Forest[a]								
Enoree Adm. Unit	5-30	N, NNW, NW, WNW, W	1,700	83,700	N.A.	N.A.	85,400	29,597
Tyger Adm. unit	10-40	N, NNW, NW, WNW, W	11,500	146,500	N.A.	N.A.	158,000	60,328
Edgefield Admin Unit, Including Par-son's Mtn. & Forks-Key Bridge Game Mgmt. Areas	40-50	WSW	2,500	127,400	N.A.	N.A.	129,000	44,924
Chester State Park[b]	27	N	4,475	127,069	20,728	3,288	131,544	46,789
Dreher Island State Park	16	SSW	5,985	12,008	2,449	388	17,993	9,984

Table 2.1-4 (CONTINUED)
Recreational Use Within 50 Miles of the Virgil C. Summer Nuclear Station, 1975

Recreation	Distance From Site (Miles)	Direction	Visitor Annual Overnight	Visitor Annual Daytime	Peak Monthly	Low Monthly	Total Annual Visitor Days	Weighted Annual Transient Population
Greenwood State Park	37	WSW	34,704	439,492	99,896	6,448	474,196	181,055
Sesquicentennial	29	NW	None	53,708	7,772	2,396	53,708	17,885
Rose Hill State Park	29	NW	None	53,708	7,772	2,396	52,708	17,885
N. R. Goodall State Park	45	E	None	101,059	23,528	1,420	101,059	33,683
Landsford Canal State Park	40	NE	--	--	--	--	Under Construction	--
Lake Murray[c]	12-20	SSE, S, SSW, SW	N.A.	N.A.	N.A.	N.A.	1,791,442	596,550
Central Piedmont[d] Hunt Unit, Including Broad River, Fair Forest, Enoree, and Carlisle Game Management Areas	1-50	N, NNW, NW, WNW, W	N.A.	50,000	N.A.	N.A.	50,000	16,665
Wateree Lake and Adjacent Game Management Areas of Dutchman Creek and Wateree	20-40	NE, ENE, E	N.A.	75,000	N.A.	N.A.	75,000	24,998

Table 2.1-4 (CONTINUED)
Recreational Use Within 50 Miles of the Virgil C. Summer Nuclear Station, 1975

Recreation	Distance From Site (Miles)	Direction	Visitor Annual Overnight	Visitor Annual Daytime	Peak Monthly	Low Monthly	Total Annual Visitor Days	Weighted Annual Transient Population
Lake Greenwood (at Greenwood State Park)	35-40	W	N.A.	60,000	N.A.	N.A.	60,000	19,998
Congaree Region	30-50	SE	N.A.	20,000	N.A.	N.A.	20,000	6,666

(N.A. - Not Available)

Source:

a) Sumter National Forest: Personal Communication, John Connell, U.S. Forest Service [18].
b) State Parks: Personal Cummical, Frances B. Coleman, South Carolina Department of Parks, Recreation and Tourism [19].
c) Lake Murray: Saluda River Hydroelectric Development Relicensing Application South Carolina Electric & Gas, 1974 Appendix R [10].
d) Hunting & Fishing Recreation Areas: Personal Communication, John Davis, South Carolina Wildlife & Marine Resources Dept. 1975 Estimates[17].

Table 2.1-5
Schools, Hospitals, and Prisons Within 10 Miles
of the Virgil C. Summer Nuclear Station, 1996

Schools[a]	Distance from Site (Miles)	Direction	Populationa (Pupils/Staff)
Pomaria-Garmany Middle	7.0	WSW	260/22
McCrorey-Liston	7.0	N	300/40
Chapin Elementary	11.0	S	893/87
Chapin Middle	11.0	S	475/65
Chapin High	9.0	S	700/85
Little Mountain Elementary	9.0	SW	252/22
Kelley-Miller	11.0	E	200/35
Mid-Carolina High	10.5	WSW	550/43
Mid-Carolina Middle	10.5	WSW	460/45
Hospitals[b] - None			
Rest Homes[c]- None			
Prisons/Jails[d]- None			

Source:

a) County Civil Defense Directors, March 11, 1996
b) Riley, Henry M., Jr., Director of Licensing, April 15, 1976, Department of Health and Environmental Control, Personal Communication (Reference 19)
c) Booknight, Sara, Staff Member, May 7, 1976, Lowman Home Institutional Care Facility, Personal Communication (Reference 20)
d) Teagle, Marimac, Statistician, and Strickland, Jessie, Director of Regional Operations, May 1976, South Carolina Department of Corrections, Personal Communications (Reference 21).

Table 2.1-6
Land Use in Site Region [a,b], 1958-1067

Total County Land (Acres)		Chester 374,000	Fairfield 447,000	Greenwood 286,000	Kershaw 503,000	Average 12 County Area
Federal Land (%)						3.9
	1958	3.2	2.7	3.5	0	3.9
	1967	3.2	2.7	3.5	0	0% Change
Urban & Built Up (%)						4.2
	1958	4.3	1.3	5.2	2.1	6.4
	1967	4.2	2.8	6.3	2.9	+2.2% Change
Cropland (%)						18.4
	1958	15.2	11.2	17.9	19.1	13.1
	1967	12.4	6.0	11.2	13.0	-5.3% Change
Pasture (%)						7.2
	1958	12.1	7.5	10.8	2.0	8.9
	1967	11.4	7.1	14.1	3.2	+1.7% Change
Agricultural (Cropland plus Pasture) (%)						24.2
	1958	17.6	18.7	28.7	21.1	22.0
	1967	24.2	13.1	25.3	16.2	-2.2% Change
Forest (%)						61.3
	1958	61.7	75.5	60.0	72.8	64.2
	1967	66.6	80.0	63.1	77.7	+2.9% Change
Other Land (%)						3.6
	1958	3.5	1.7	2.1	3.9	2.2
	1967	1.8	0.9	1.4	2.9	-1.4% Change

Table 2.1-6 (CONTINUED)
Land Use in Site Region [a,b], 1958-1067

		Lancaster	Laurens	Lexington	Newberry	Average 12
Total County Land (Acres)		323,000	449,000	445,040	405,120	County Area
Federal Land (%)						3.9
	1958	0	4.5	0	13.6	3.9
	1967	0	4.5	0	13.6	0% Change
Urban & Built Up (%)						4.2
	1958	4.3	1.3	5.2	2.1	6.4
	1967	4.2	2.8	6.3	2.9	+2.2% Change
Cropland (%)						18.4
	1958	15.2	11.2	17.9	19.1	13.1
	1967	12.4	6.0	11.2	13.0	-5.3% Change
Pasture (%)						7.2
	1958	12.1	7.5	10.8	2.0	8.9
	1967	11.4	7.1	14.1	3.2	+1.7% Change
Agricultural (Cropland plus						24.2
Pasture) (%)	1958	17.6	18.7	28.7	21.1	22.0
	1967	24.2	13.1	25.3	16.2	-2.2% Change
Forest (%)						61.3
	1958	61.7	75.5	60.0	72.8	64.2
	1967	66.6	80.0	63.1	77.7	+2.9% Change
Other Land (%)						3.6
	1958	7.4	3.1	2.8	2.5	2.2
	1967	3.7	2.4	2.4	2.1	-1.4% Change

Table 2.1-6 (CONTINUED)
Land Use in Site Region [a,b], 1958-1067

Total County Land (Acres)		Richland 479,000	Saluda 283,000	Union 330,000	York 438,000	Average 12 County Area
Federal Land (%)						3.9
	1958	11.5	1.4	17.0	0.7	3.9
	1967	11.5	1.7	17.0	0.7	0% Change
Urban & Built Up (%)						4.2
	1958	10.2	0.8	2.7	6.0	6.2
	1967	17.6	1.2	3.2	9.2	+2.2% Change
Cropland (%)						18.4
	1958	15.6	25.2	12.0	21.2	13.1
	1967	13.1	19.5	7.6	15.3	-5.3% Change
Pasture (%)						7.2
	1958	3.5	11.8	6.5	10.4	8.9
	1967	2.9	17.3	9.4	11.8	+1.7% Change
Agricultural (Cropland plus Pasture) (%)						24.2
	1958	19.1	37.0	18.5	31.6	22.0
	1967	16.0	36.8	17.0	27.1	-2.2% Change
Forest (%)						61.3
	1958	56.1	57.6	55.6	55.7	64.2
	1967	52.7	57.0	61.2	58.0	+2.9% Change
Other Land (%)						3.6
	1958	2.7	2.8	6.1	4.8	2.2
	1967	0.7	2.8	1.5	3.5	-1.4% Change

a) The area within 50 miles of the site takes in all or parts of the 12 counties listed in this table
b) Reference: South Carolina Soil and Water Conservation Needs Inventory, May, 1970 (Reference 11)

Figure 2.1-1

REGIONAL LOCATION MAP

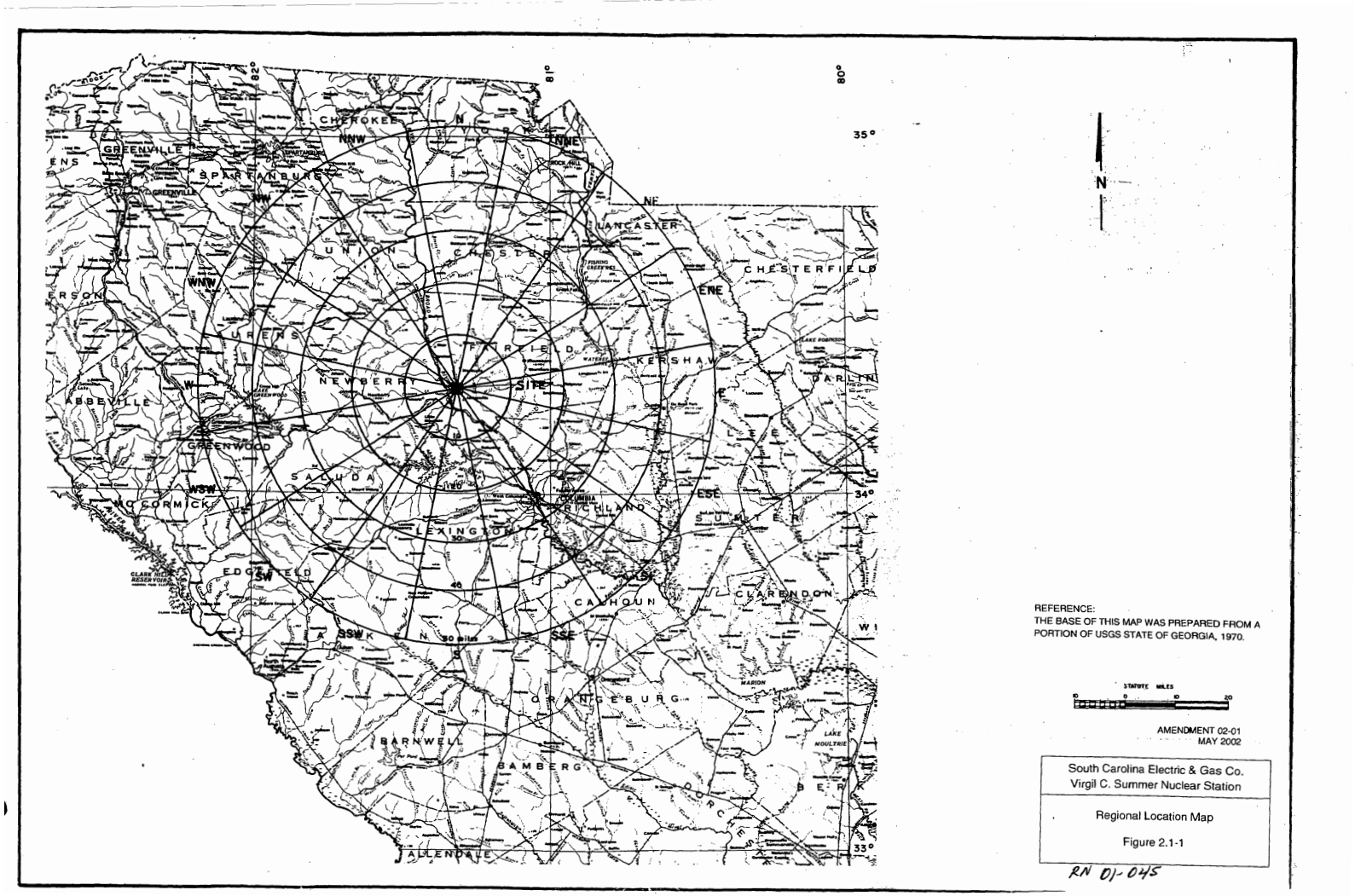


Figure 2.1-2

SITE LOCATION MAP

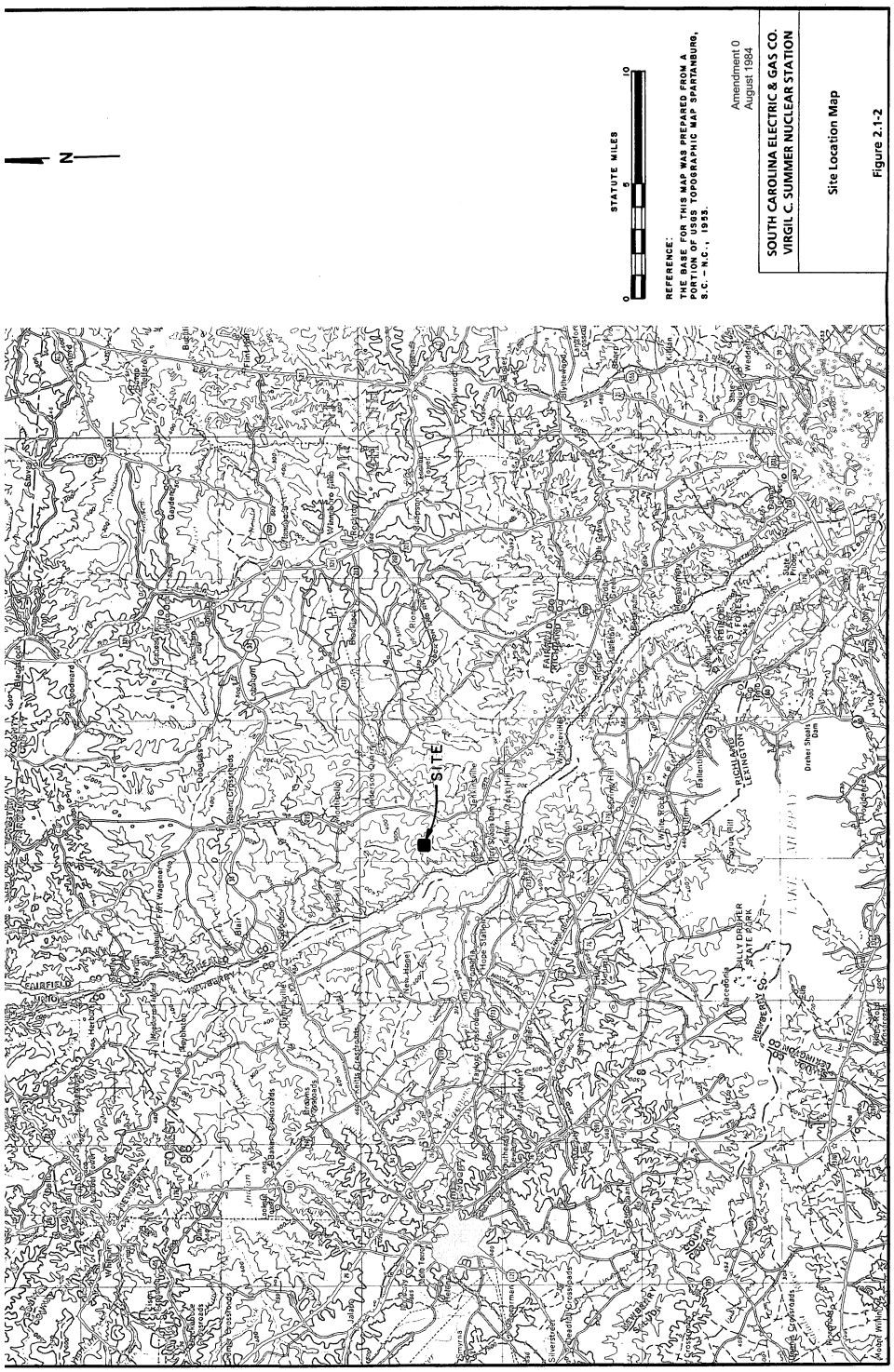


Figure 2.1-3
SITE AREA MAP

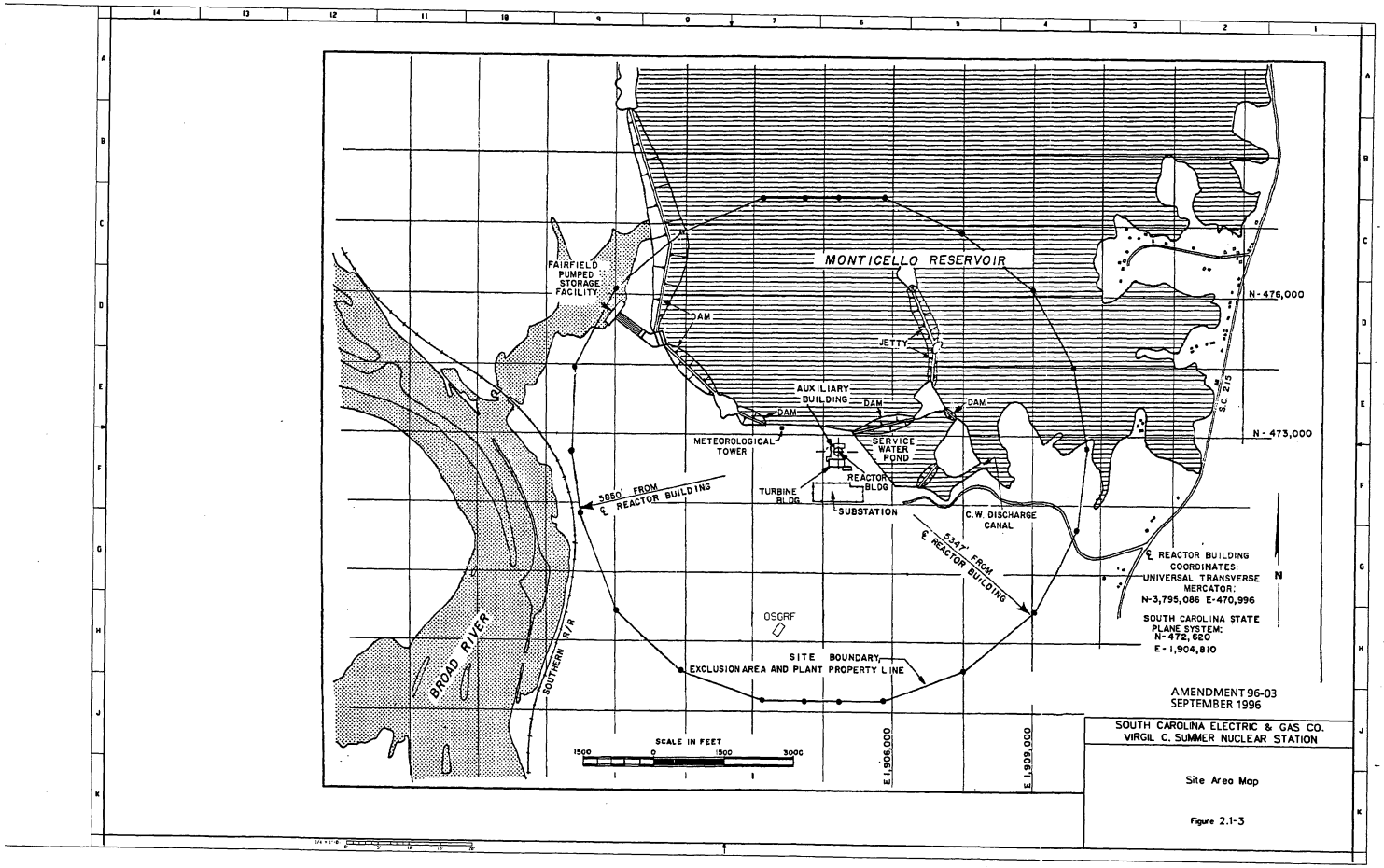


Figure 2.1-4

RESIDENT POPULATION DISTRIBUTION
UP TO 10 MILES, 1970

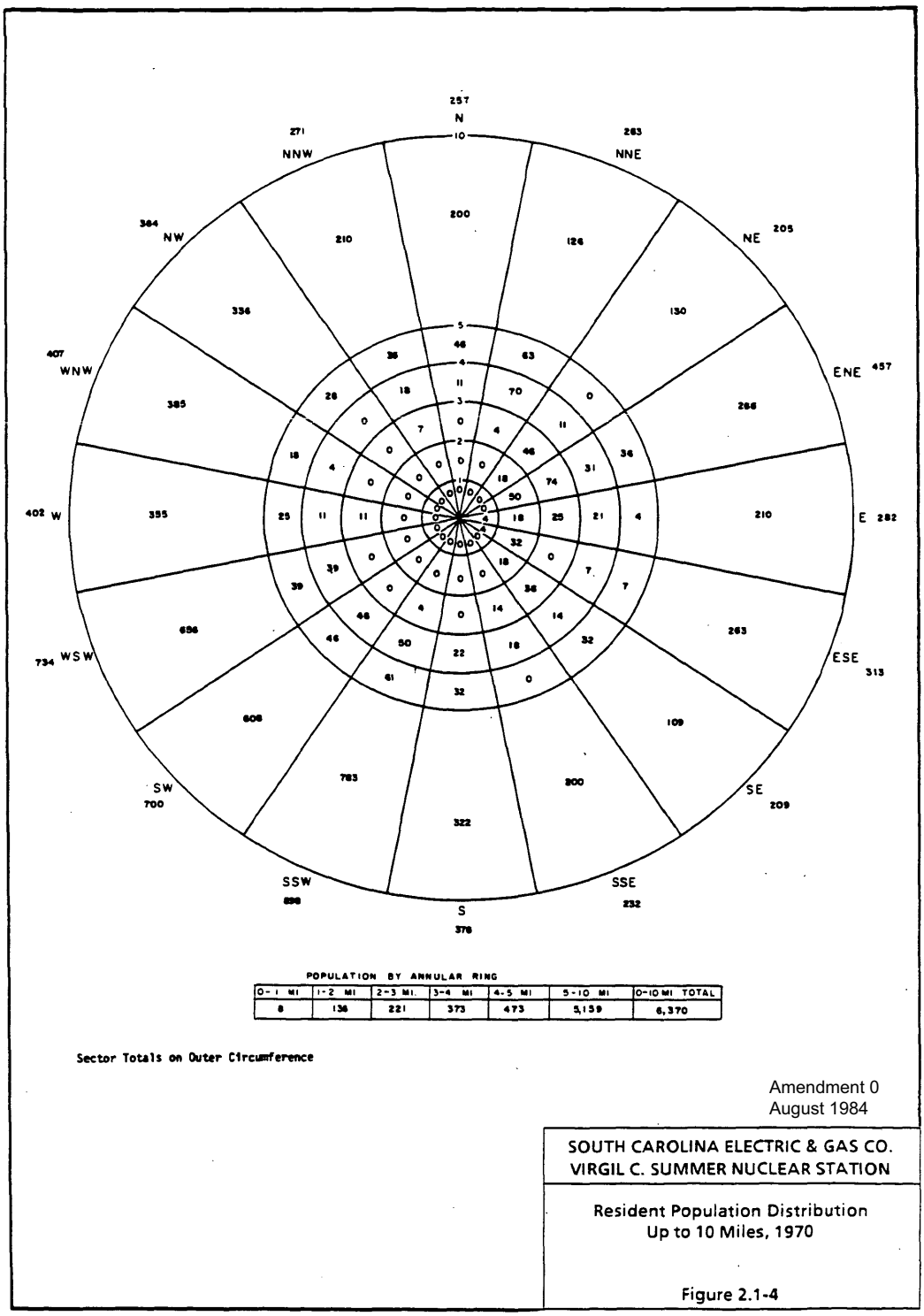
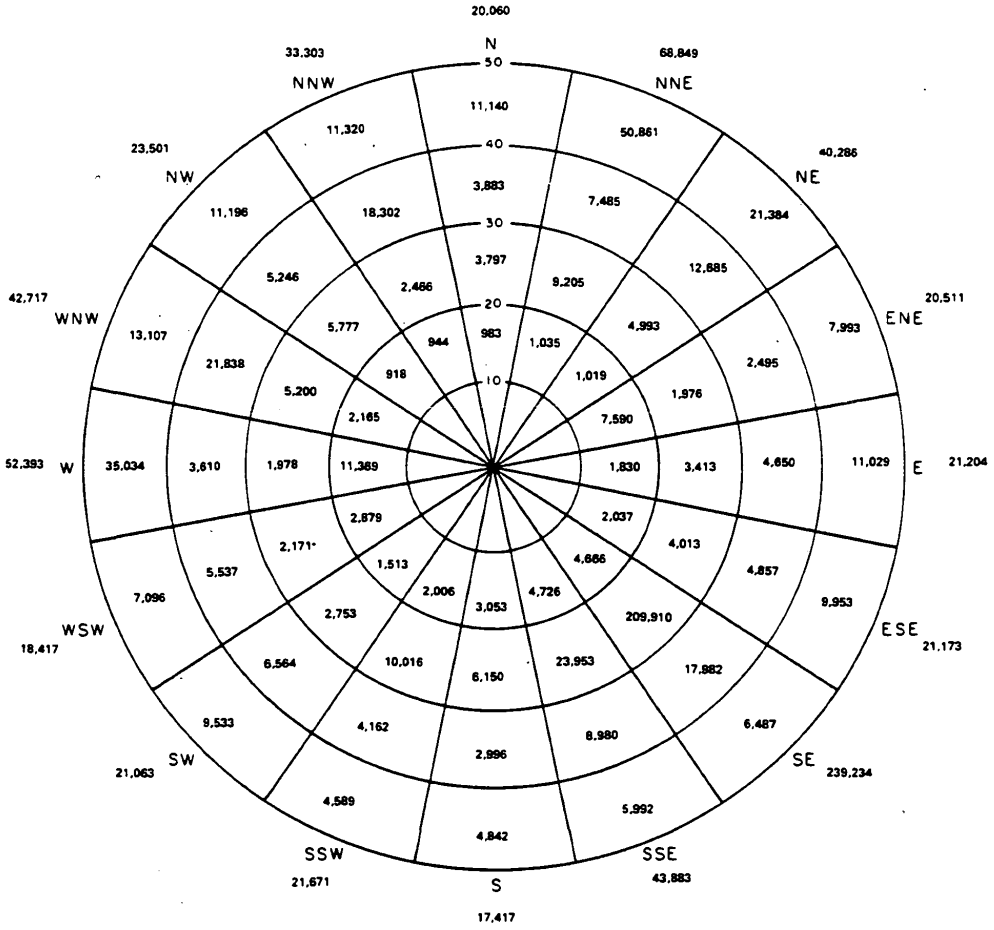


Figure 2.1-5

RESIDENT POPULATION DISTRIBUTION BETWEEN 10 AND 50 MILES, 1970



POPULATION BY ANNULAR RING

0-10 MI	10-20 MI	20-30 MI	30-40 MI	40-50 MI	10-50 MI	0-50 MI TOTAL
6,370	48,733	297,771	131,272	221,536	699,312	705,682

Sector Totals on Outer Circumference
0 to 10 mile populations are found on
0 to 10 mile rose

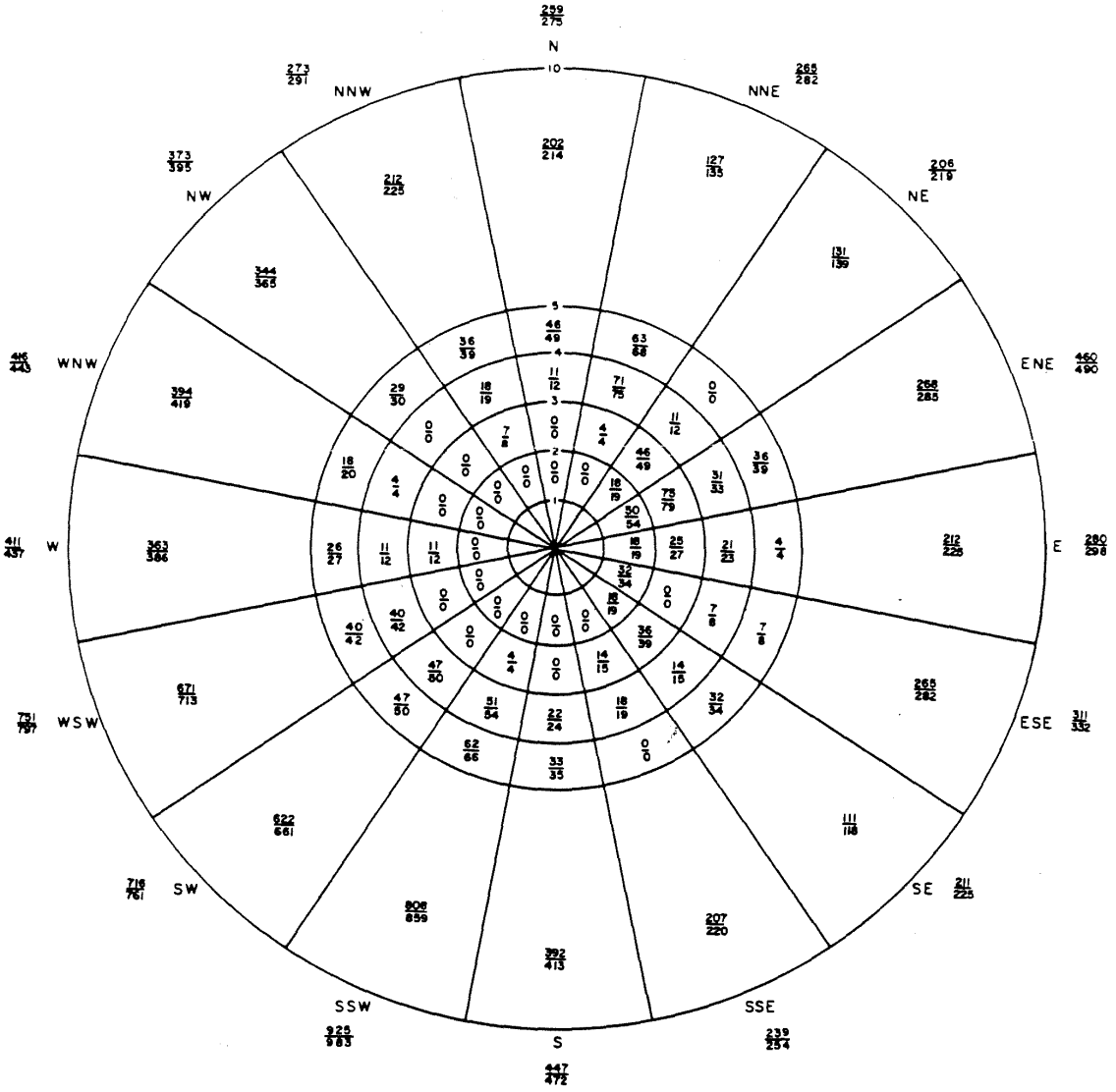
Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Resident Population Distribution
Between 10 and 50 Miles, 1970

Figure 2.1-8

PROJECTED RESIDENT POPULATION DISTRIBUTION UP TO 10 MILES, 1980



POPULATION BY ANNULAR RING

PROJECTION	0-1 MI	1-2 MI	2-3 MI	3-4 MI	4-5 MI	5-10 MI	0-10 MI TOTAL
LOW	0	136	222	377	479	5,329	6,543
HIGH	0	145	237	402	511	5,659	6,954

Key:
805 = Low Projections (BEA Series E)
851 = High Projections (BEA Alternate Method)
Sector Totals on Outer Circumference
All 0-1 Mile Sectors Have Zero Population

Amendment 0
August 1984

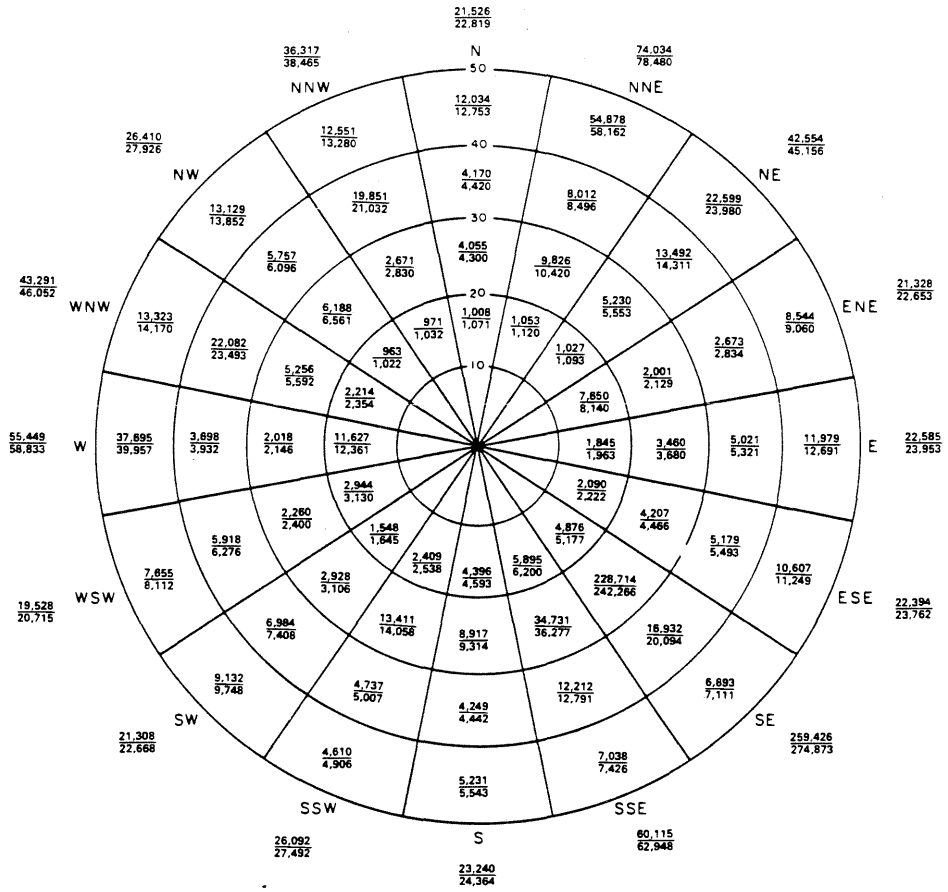
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Up to 10 Miles, 1980

Figure 2.1-8

Figure 2.1-9

PROJECTED RESIDENT POPULATION
DISTRIBUTION BETWEEN 10 AND 50 MILES, 1980



POPULATION BY ANNULAR RING

PROJECTION	0-10 MI	10-20 MI	20-30 MI	30-40 MI	40-50 MI	10-50 MI	0-50 MI TOTAL
LOW	6,543	52,516	335,873	142,967	237,698	769,054	775,597
HIGH	6,954	55,861	355,098	151,446	252,000	814,205	821,139

Key:
805 = Low Projections (BEA Series E)
851 = High Projections (BEA Alternate Method)
Sector Totals on Outer Circumference
0 to 10 Mile Populations are found on
0 to 10 Mile Rose

Amendment 0
August 1984

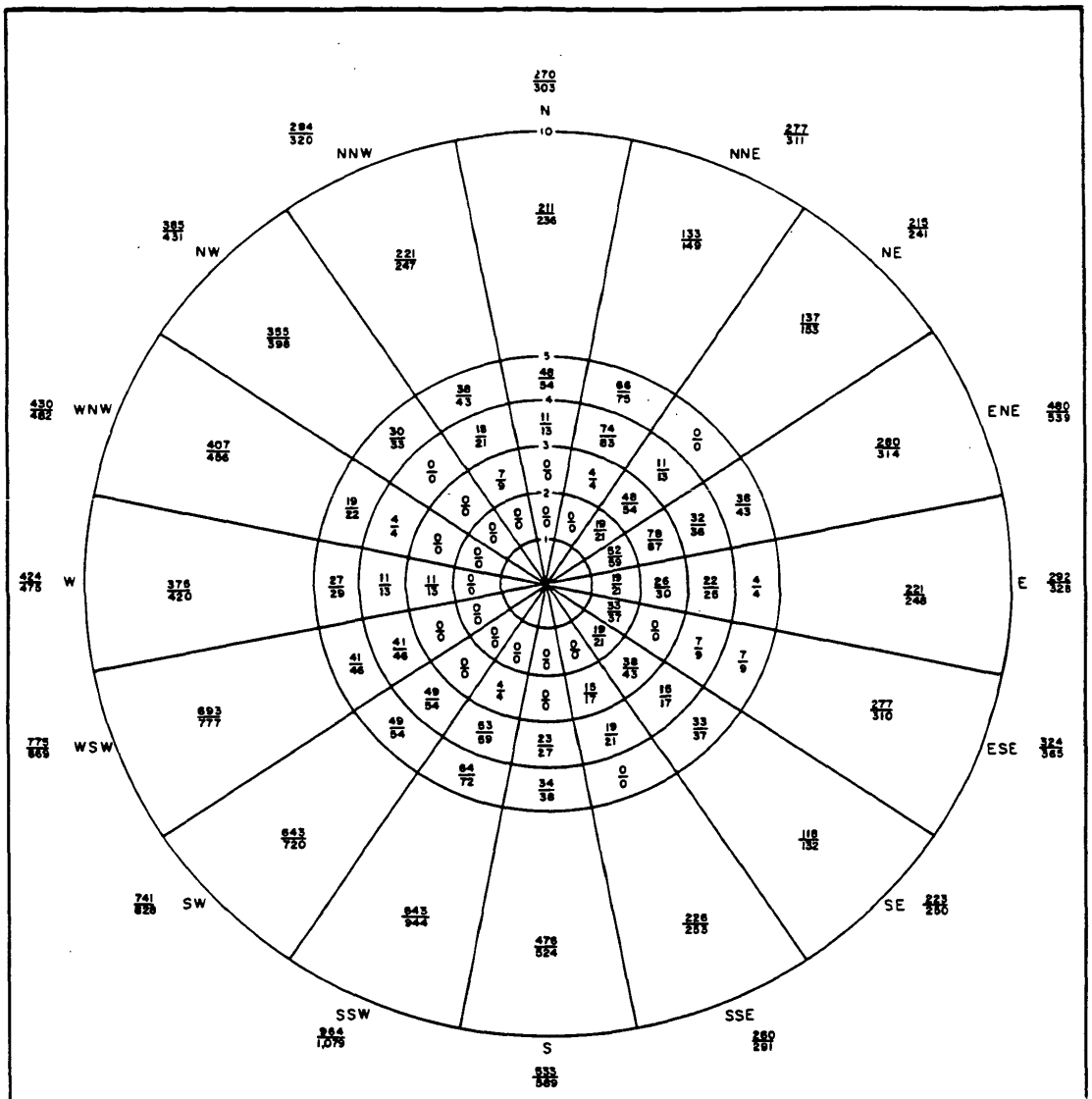
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Between 10 and 50
Miles, 1980

Figure2.1-9

Figure 2.1-10

PROJECTED RESIDENT POPULATION DISTRIBUTION UP TO 10 MILES, 1990



POPULATION BY ANNULAR RING

PROJECTION	0-1 MI	1-2 MI	2-3 MI	3-4 MI	4-5 MI	5-10 MI	0-10 MI TOTAL
LOW	0	142	231	390	498	5616	6,877
HIGH	0	159	261	441	559	6281	7,701

Key:
805 = Low Projections (BEA Series E)
851 = High Projections (BEA Alternate Method)
Sector Totals on Outer Circumference
All 0-1 Mile Sectors Have Zero Population

Amendment 0
August 1984

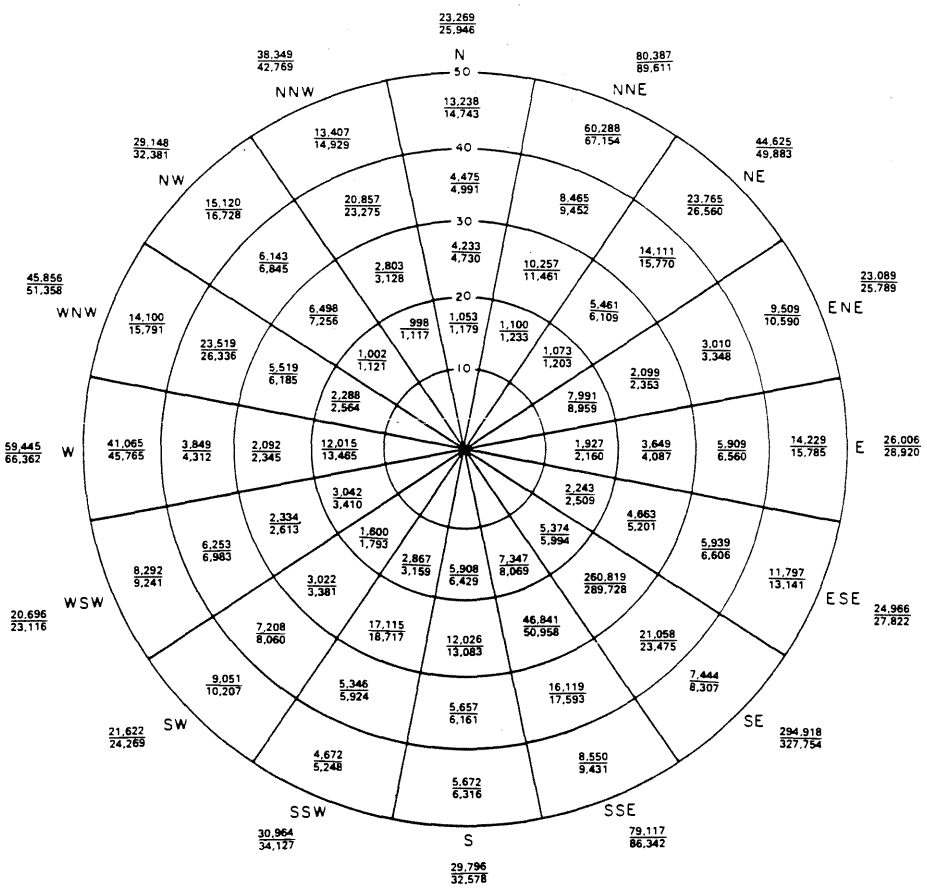
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Up to 10 Miles, 1990

Figure 2.1-10

Figure 2.1-11

PROJECTED RESIDENT POPULATION
DISTRIBUTION BETWEEN 10 AND 50 MILES, 1990



POPULATION BY ANNULAR RING

PROJECTION	0-10 MI	10-20 MI	20-30 MI	30-40 MI	40-50 MI	10-50 MI	0-50 MI TOTAL
LOW	6,877	57,828	389,431	157,918	260,199	865,376	872,253
HIGH	7,701	64,364	431,335	175,691	289,936	961,326	969,027

Key:
805 = Low Projections (BEA Series E)
851 = High Projections (BEA Alternate Method)

Sector Totals on Outer Circumference

0 to 10 Mile Populations are found on
0 to 10 Mile Rose

Amendment 0
August 1984

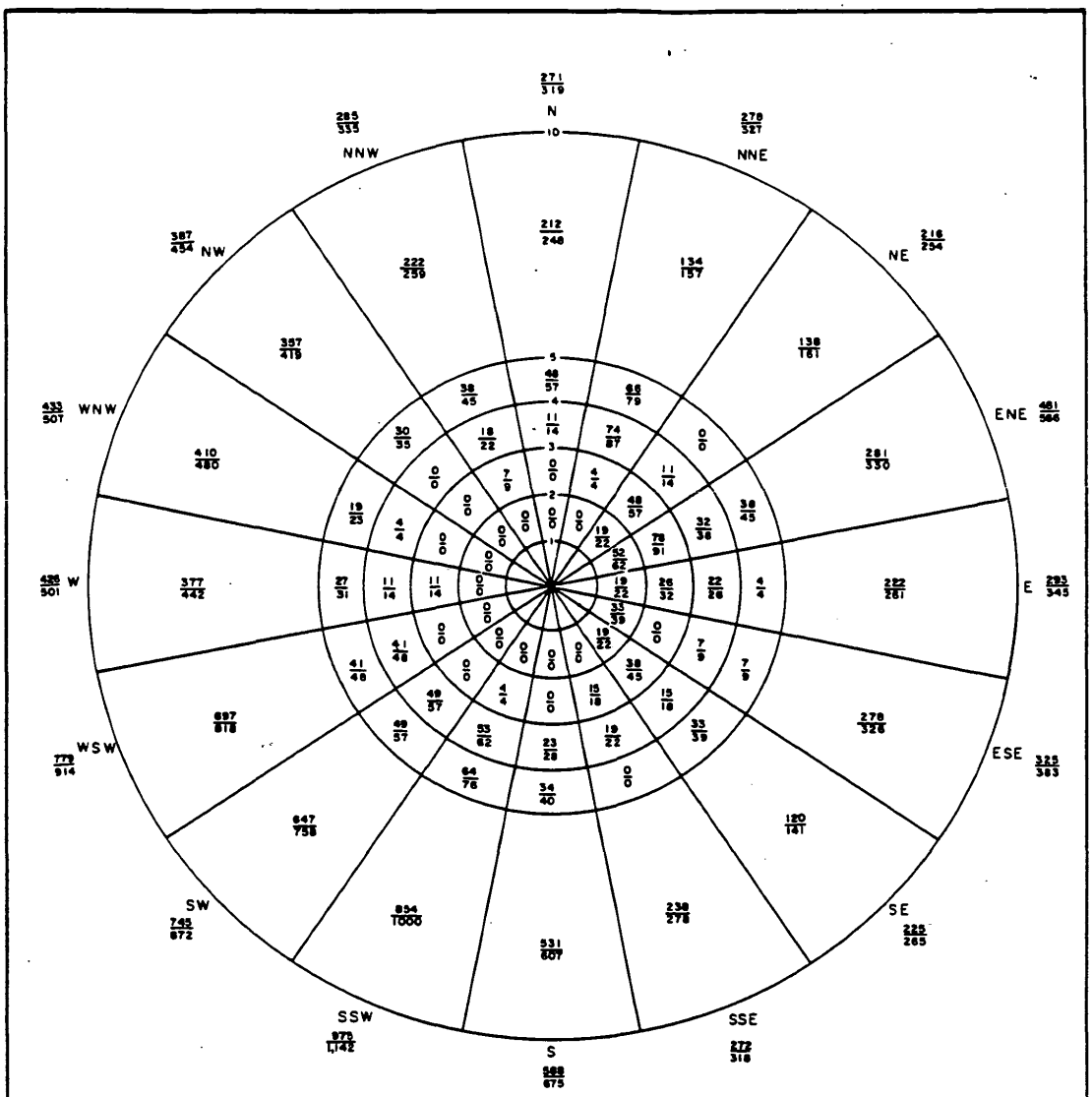
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Between 10 and 50
Miles, 1990

Figure 2.1-11

Figure 2.1-12

PROJECTED RESIDENT POPULATION
DISTRIBUTION UP TO 10 MILES, 2000



POPULATION BY ANNULAR RING

PROJECTION	0-1 MI	1-2 MI.	2-3 MI.	3-4 MI.	4-5 MI	5-10 MI	0-10 MI TOTAL
LOW	0	142	231	390	498	5,718	6,979
HIGH	0	167	274	463	588	6,685	8,177

Key:
805 = Low Projections (BEA Series E)
851 = High Projections (BEA Alternate Method)
Sector Totals on Outer Circumference
All 0-1 Mile Sectors Have Zero Population

Amendment 0
August 1984

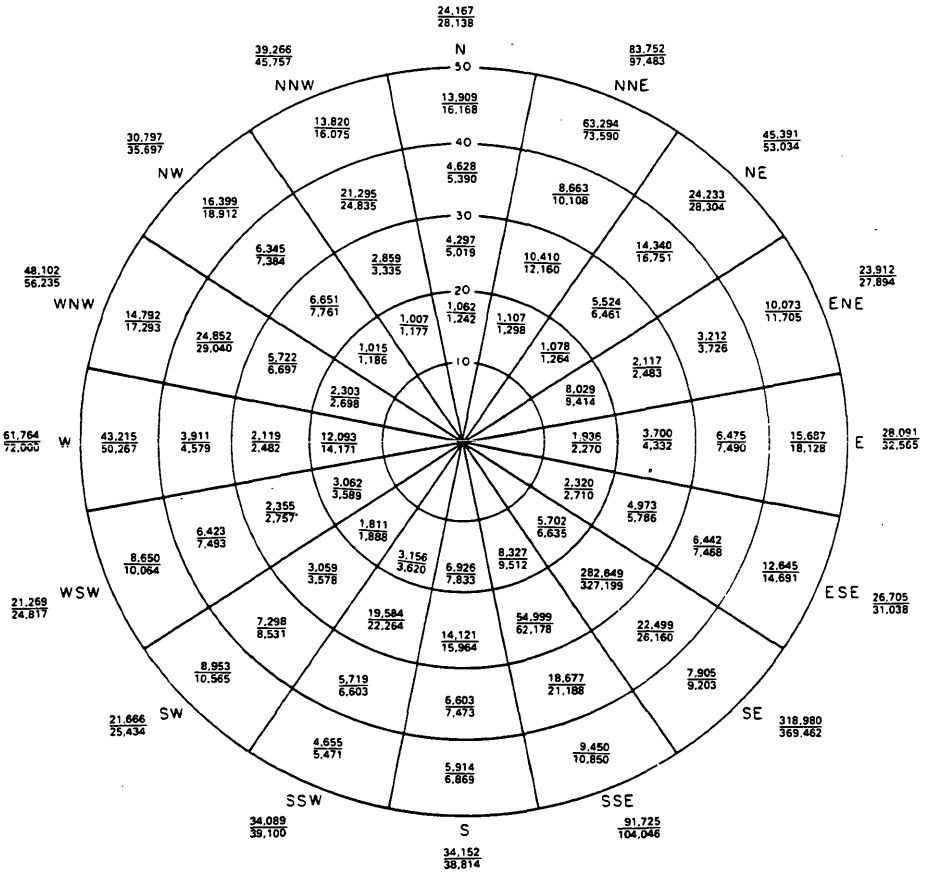
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Up to 10 Miles, 2000

Figure 2.1-12

Figure 2.1-13

PROJECTED RESIDENT POPULATION
DISTRIBUTION BETWEEN 10 AND 50 MILES, 2000



POPULATION BY ANNULAR RING

PROJECTION	0-10 MI	10-20 MI	20-30 MI	30-40 MI	40-50 MI	10-50 MI	0-50 MI TOTAL
LOW	6,979	60,734	425,139	167,382	273,594	926,849	933,828
HIGH	8,177	70,507	490,456	194,219	318,155	1,073,337	1,081,514

Key:
805 = Low Projections (BEA Series E)
851 = High Projections (BEA Alternate Method)

Sector Totals on Outer Circumference

0 to 10 Mile Populations are found on
0 to 10 Mile Rose

Amendment 0
August 1984

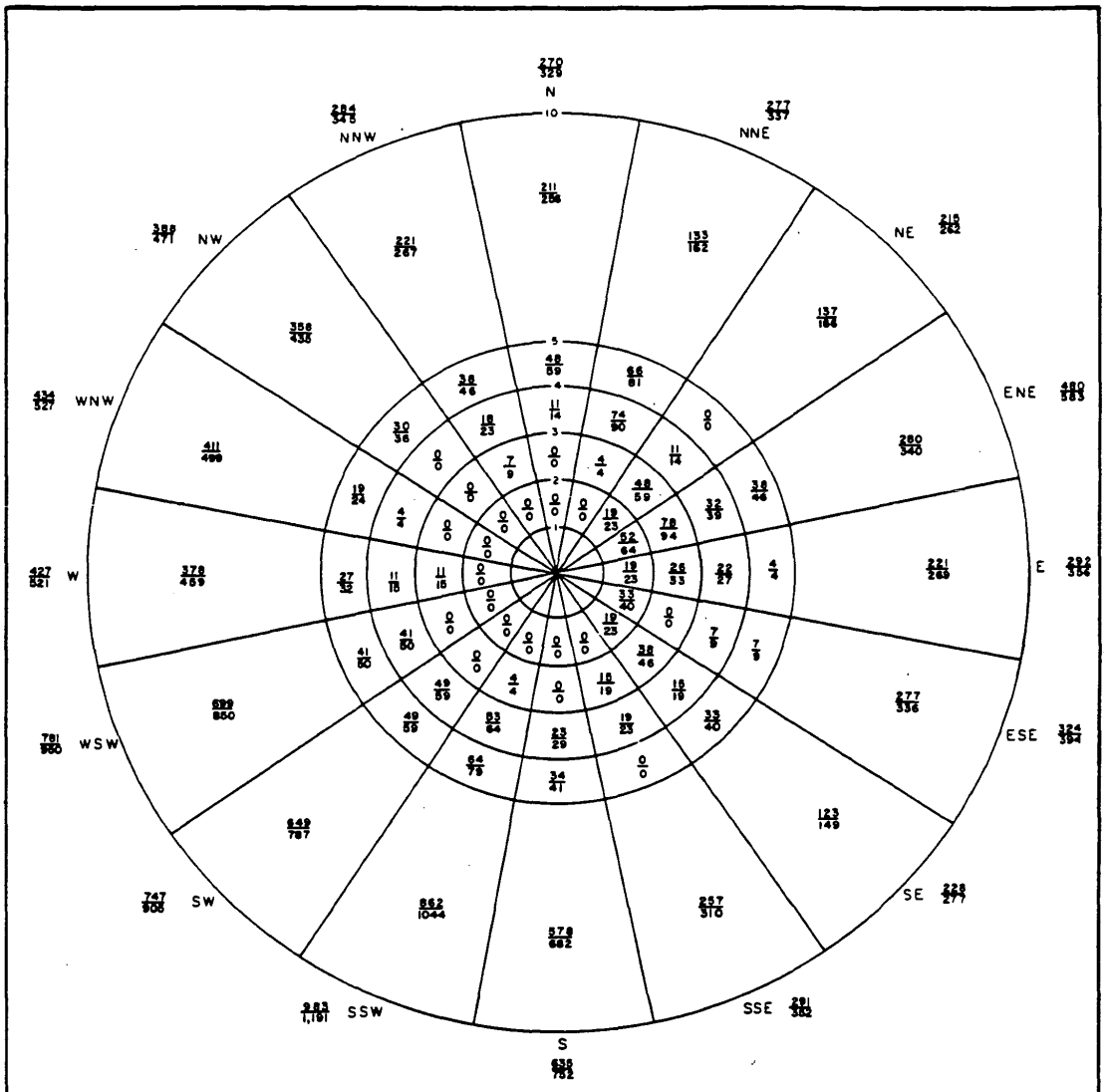
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Between 10 and 50
Miles, 2000

Figure 2.1-13

Figure 2.1-14

PROJECTED RESIDENT POPULATION DISTRIBUTION UP TO 10 MILES, 2010



POPULATION BY ANNULAR RING

PROJECTION	0-1 MI	1-2 MI	2-3 MI	3-4 MI	4-5 MI	5-10 MI	0-10 MI TOTAL
LOW	0	142	231	390	498	5,795	7,056
HIGH	0	173	283	479	606	7,011	8,552

Key:
805 = Low Projections (BEA Series E)
851 = High Projections (BEA Alternate Method)
Sector Totals on Outer Circumference
All 0-1 Mile Sectors Have Zero Population

Amendment 0
August 1984

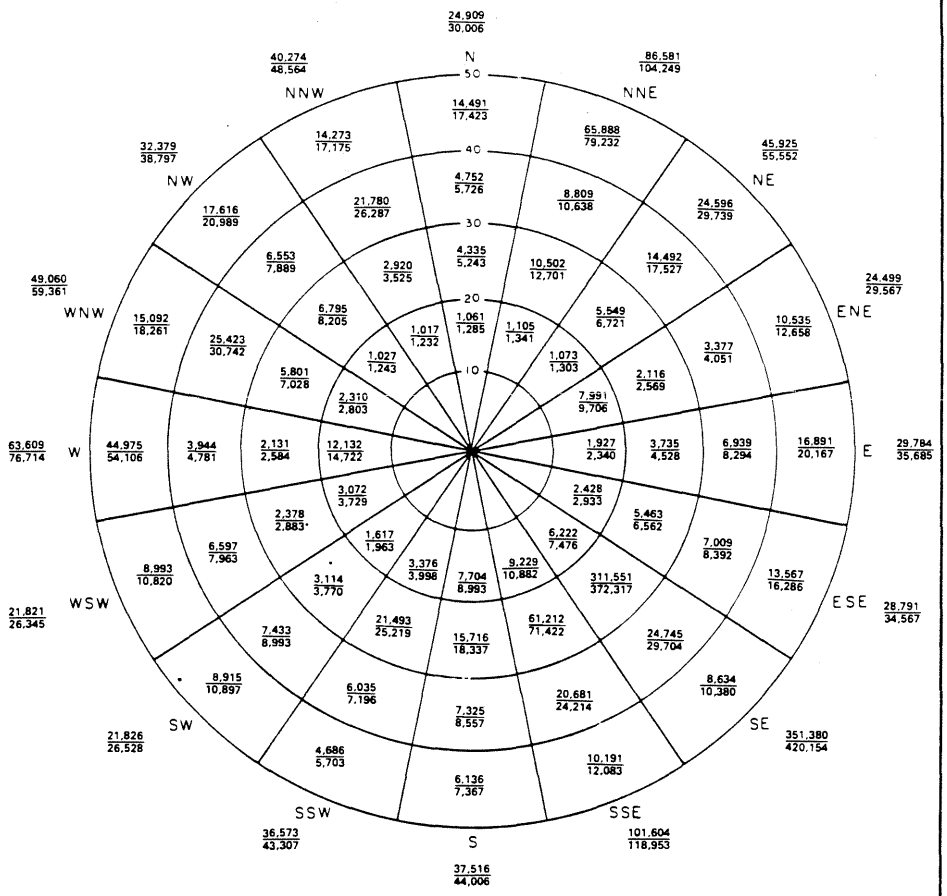
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Up to 10 Miles, 2010

Figure 2.1-14

Figure 2.1-15

PROJECTED RESIDENT POPULATION
DISTRIBUTION BETWEEN 10 AND 50 MILES, 2010



POPULATION BY ANNULAR RING

PROJECTION	0-10 MI	10-20 MI	20-30 MI	30-40 MI	40-50 MI	10-50 MI	0-50 MI TOTAL
LOW	7,056	63,291	464,811	175,894	285,479	989,475	996,531
HIGH	8,552	75,949	553,614	210,954	343,286	1,183,803	1,192,355

Key:
805 = Low Projections (BEA Series E)
851 = High Projections (BEA Alternate Method)

Sector Totals on Outer Circumference

0 to 10 Mile Populations are found on
0 to 10 Mile Rose

Amendment 0
August 1984

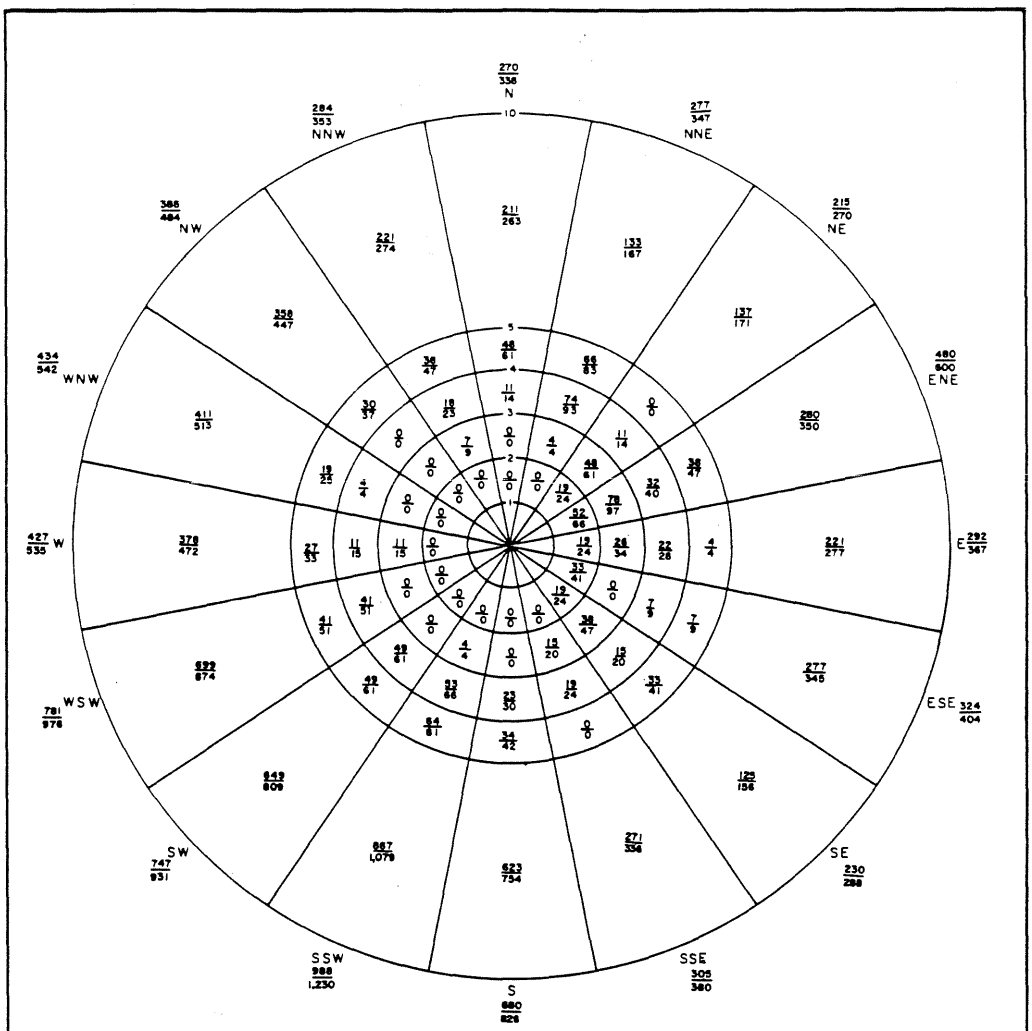
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Between 10 and 50
Miles, 2010

Figure 2.1-15

Figure 2.1-18

PROJECTED RESIDENT POPULATION DISTRIBUTION UP TO 10 MILES, 2020



POPULATION BY ANNULAR RING

PROJECTION	0-1 MI	1-2 MI	2-3 MI	3-4 MI	4-5 MI	5-10 MI	0-10 MI TOTAL
LOW	0	142	231	390	498	5,861	7,122
HIGH	0	179	291	492	622	7,287	8,871

Key:

805 = Low Projections (BEA Series)

851 = High Projections (BEA Alternate Method)

Sector Totals on Outer Circumference

All 0-1 Mile Sectors Have Zero Population

Amendment 0
August 1984

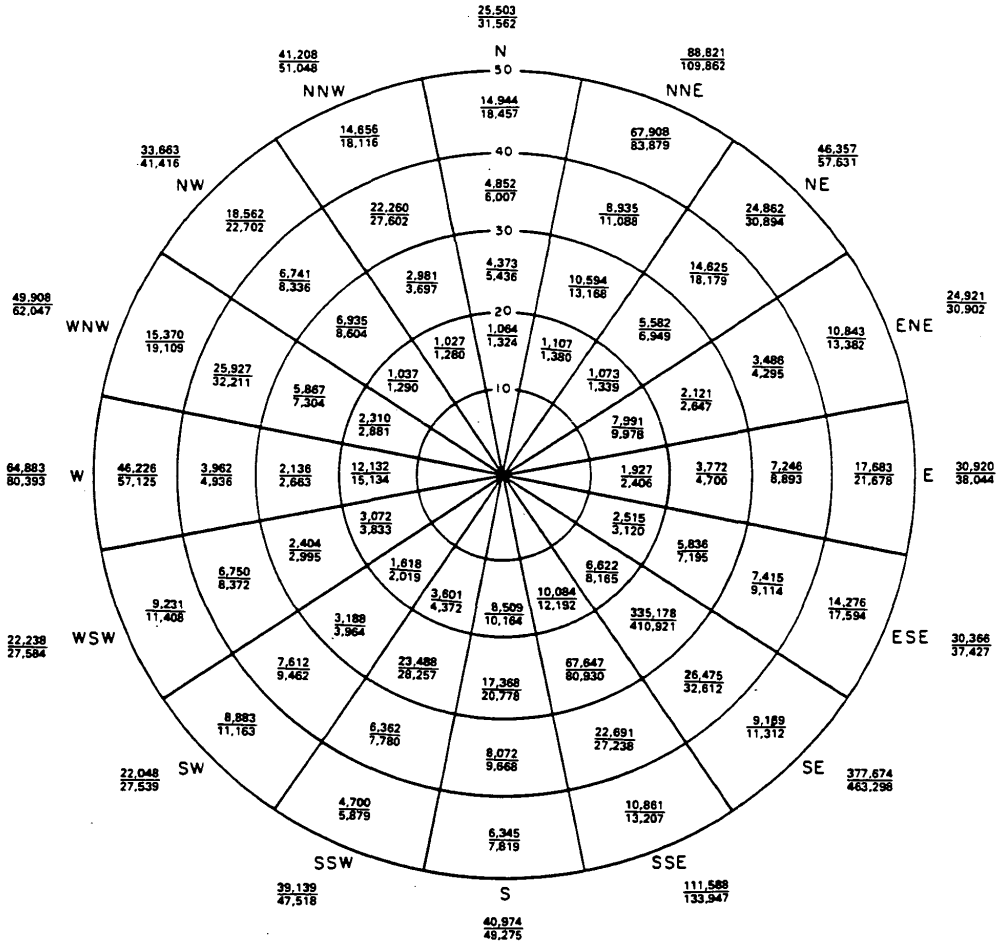
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Up to 10 Miles, 2020

Figure 2.1-18

Figure 2.1-19

PROJECTED RESIDENT POPULATION
DISTRIBUTION BETWEEN 10 AND 50 MILES, 1020



POPULATION BY ANNULAR RING

PROJECTION	0-10 MI	10-20 MI.	20-30 MI	30-40 MI	40-50 MI	10-50 MI	0-50 MI TOTAL
LOW	7,122	65,689	499,470	183,411	294,519	1,043,089	1,050,211
HIGH	8,871	80,897	610,208	225,793	363,724	1,280,622	1,289,493

Key:
805 = Low Projections (BEA Series E)
851 = High Projections (BEA Alternate Method)
Sector Totals on Outer Circumference
0 to 10 Mile Populations are found on 0 to 10 Mile Rose

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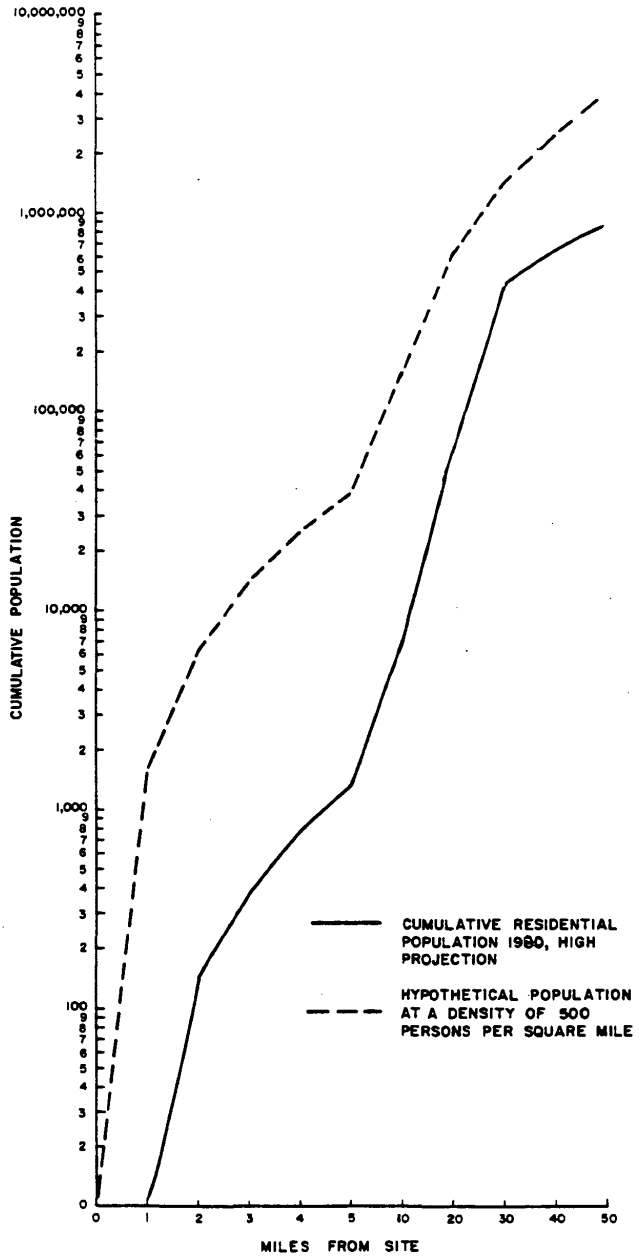
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Resident Population
Distribution Between
10 and 50 Miles, 2020

Figure 2.1-19

Figure 2.1-20

PROJECTED CUMULATIVE RESIDENTIAL POPULATION - 1980



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SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Cumulative Residential Population - 1980

Figure 2.1-20

Figure 2.1-21

PROJECTED CUMULATIVE RESIDENTIAL POPULATION - 2020

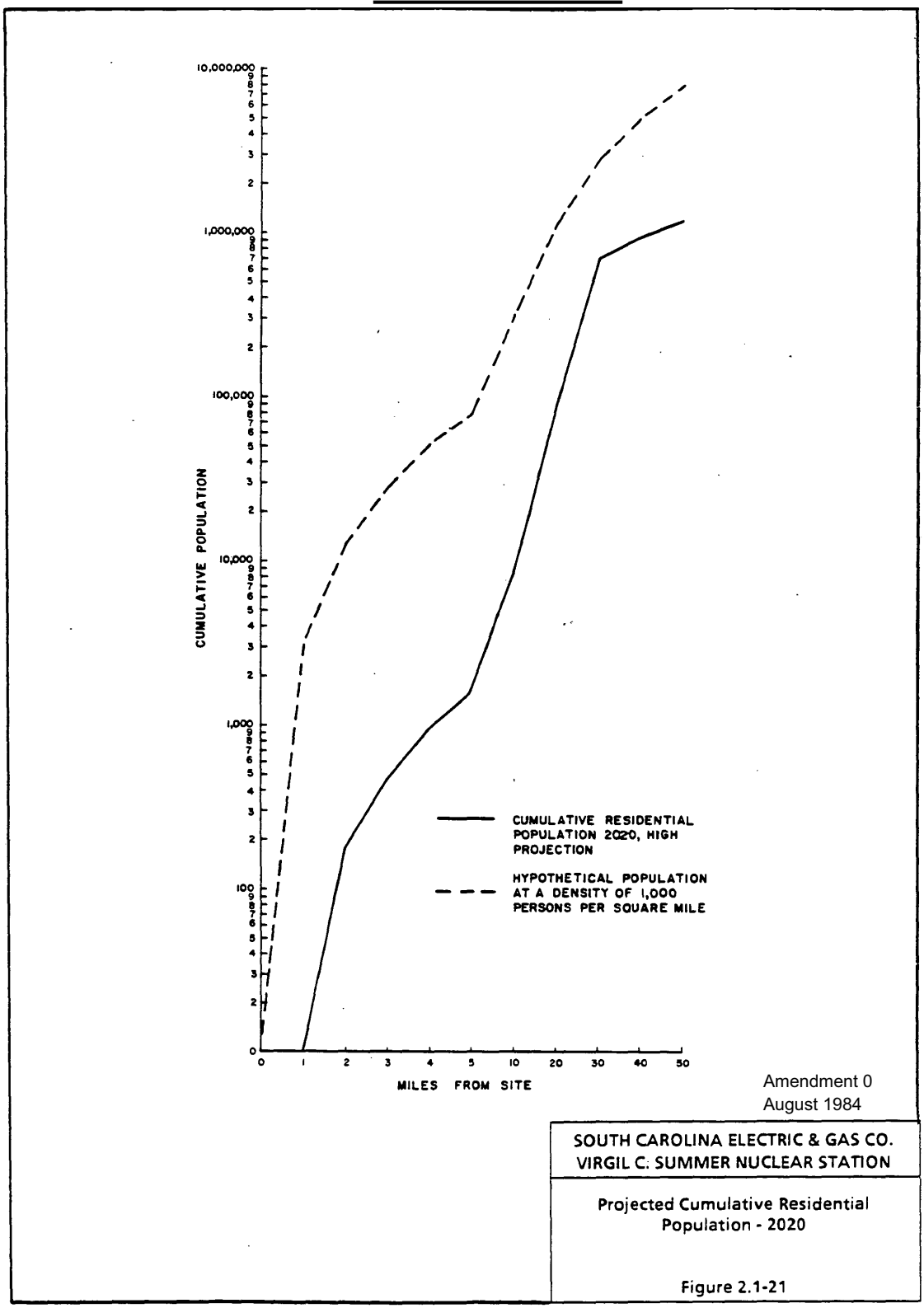


Figure 2.1-22

PLAN OF THE VIRGIL C. SUMMER NUCLEAR STATION

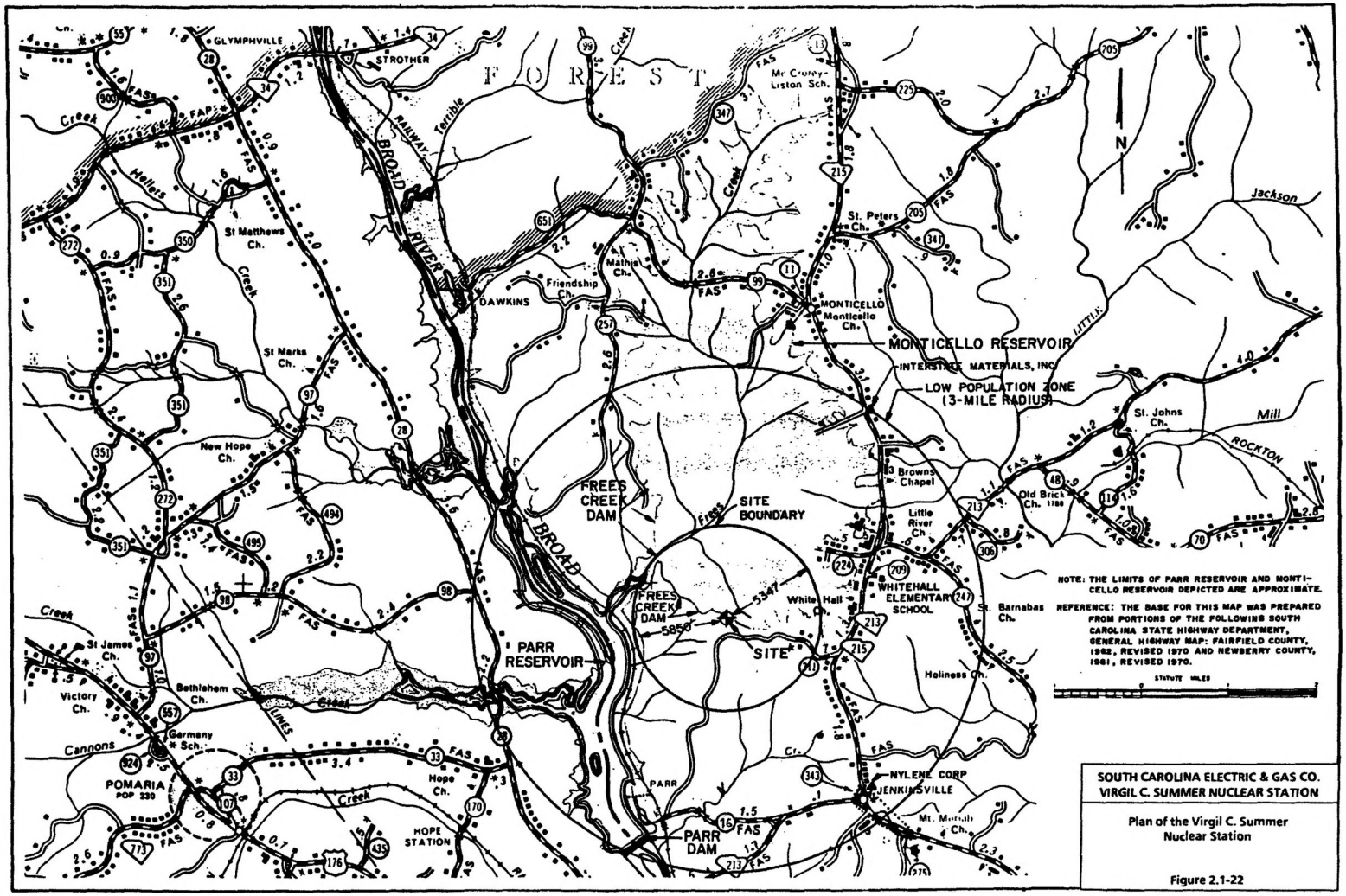
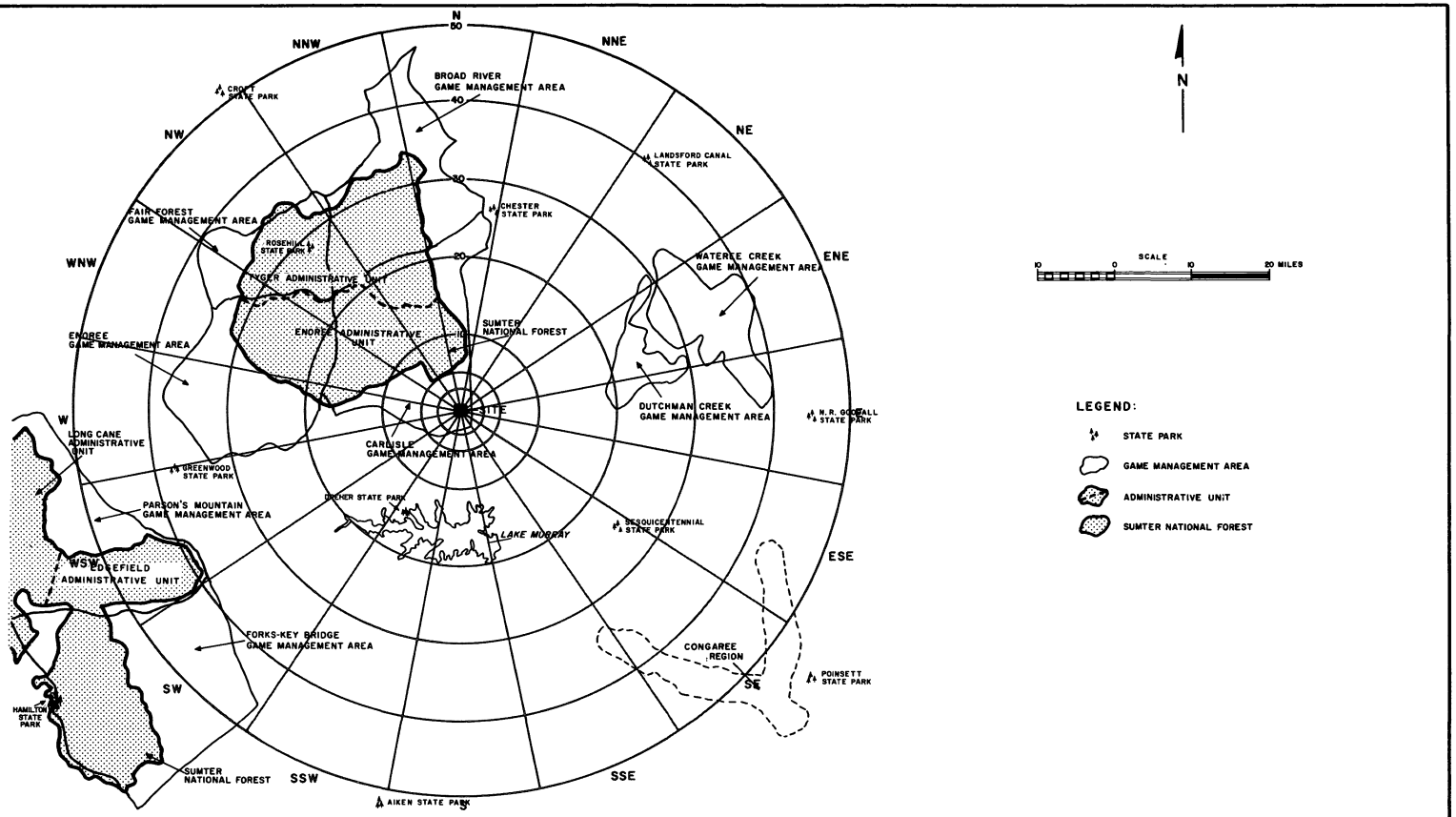


Figure 2.1-23

NATIONAL FORESTS, STATE PARKS AND SELECTED RECREATION AREAS WITHIN 50 MILES OF THE SITE



REFERENCE: BASE MAP FROM U.S.G.S. MAP, SOUTH CAROLINA, 1:500,000 1970. PARK FEATURES FROM SOUTH CAROLINA 1975 PRIMARY HIGHWAY SYSTEM MAP. NATIONAL FOREST FEATURES FROM U.S. DEPARTMENT OF AGRICULTURE, FOREST SERVICE, SUMTER NATIONAL FOREST MAP, 1964. GAME MANAGEMENT AREAS FROM U.S. ARMY CORP OF ENGINEERS, ENVIRONMENTAL RECONNAISSANCE INVENTORY OF THE CHARLESTON DISTRICT, 1973.

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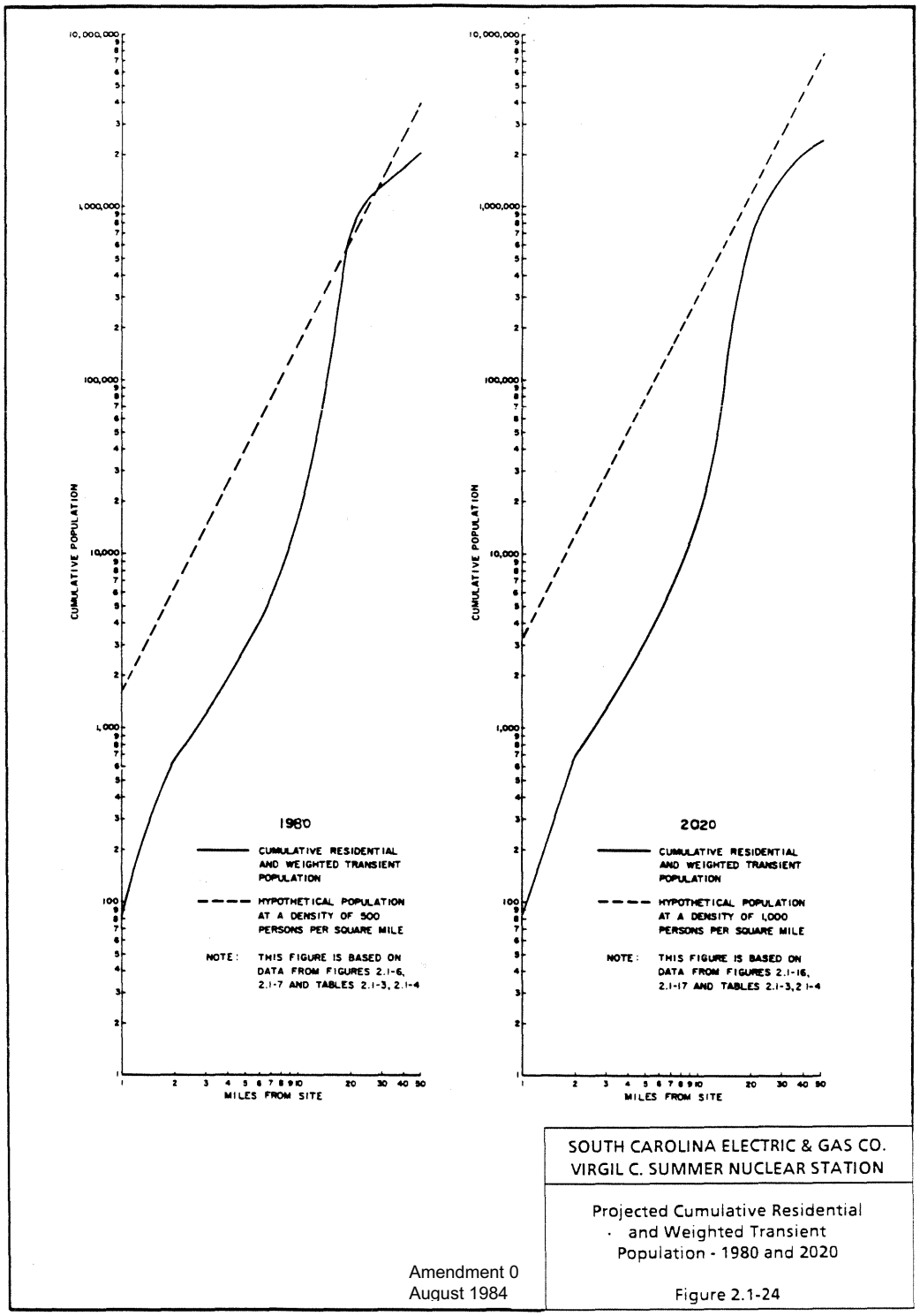
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

National Forests, State Parks and Selected Recreation Areas Within 50 Miles Of The Site

Figure 2.1-23

Figure 2.1-24
PROJECTED CUMULATIVE RESIDENTIAL AND WEIGHTED TRANSIENT POPULATION - 1980 AND 2020



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Projected Cumulative Residential and Weighted Transient Population - 1980 and 2020

Figure 2.1-24

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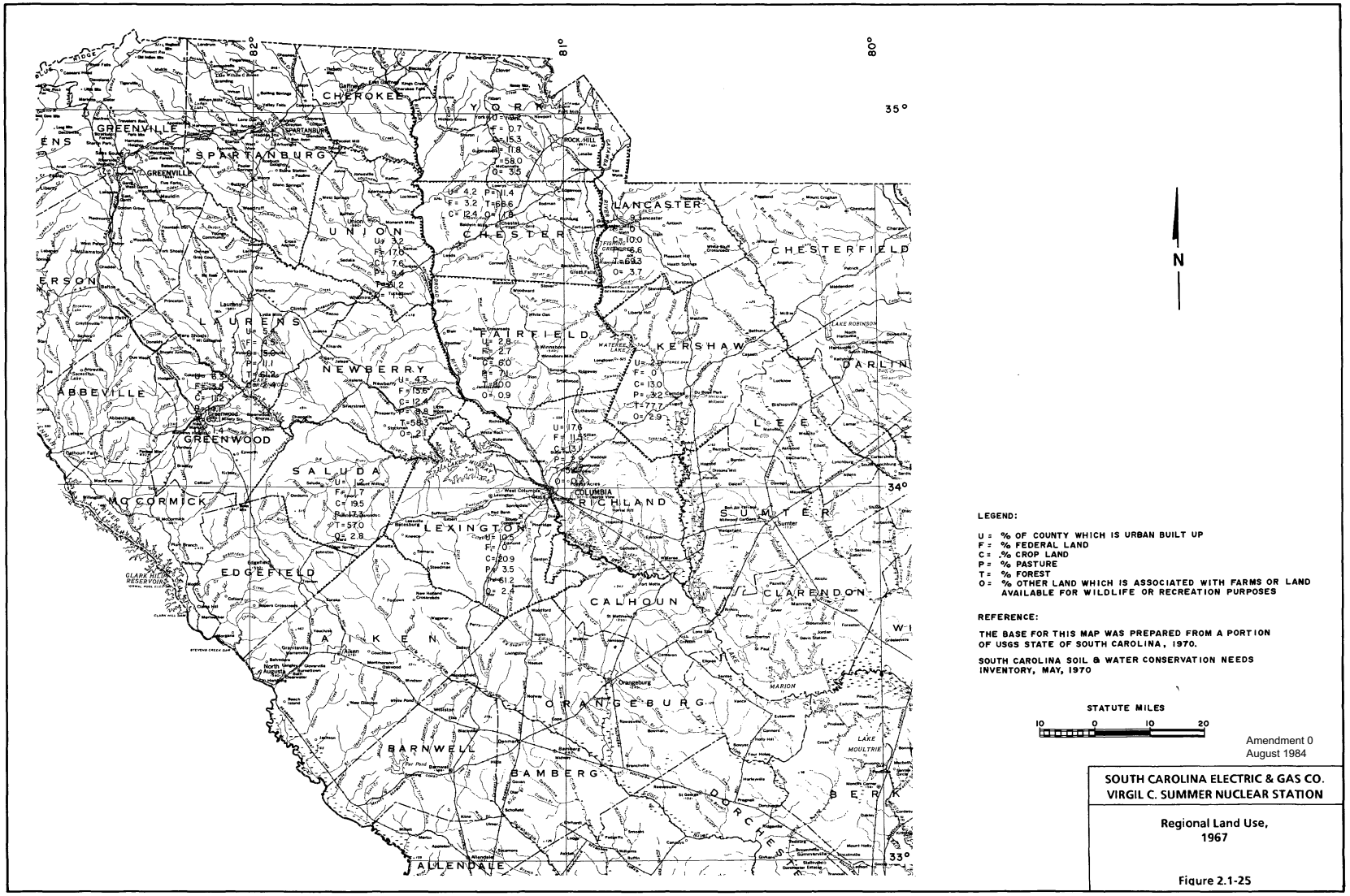
August 1984

Figure 2.1-25

REGIONAL LAND USE, 1967



2.2 NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES

NOTE: Section 2.2 is being retained for historical purposes only (per RN 00-081).

2.2.1 Locations and Routes

2.2.1.1 Industrial Facilities

The only industrial facilities within 5 miles of the Virgil C. Summer Nuclear Station site not associated with the proposed project are those in or near Jenkinsville and Monticello, located 2.5 miles southeast and 4.5 miles north-northeast of the plant site, respectively. Both towns are located in Fairfield County. The industrial (and commercial) facilities are shown on the Site Vicinity Map, Figure 2.2-1, and are described in Table 2.2-1. Industrial facilities located at distances greater than 5 miles of the plant site are shown on Figure 2.2-3. Facilities within 20 miles are described in Table 2.2-3.

The nuclear station is located within Fairfield County, as are several other South Carolina Electric & Gas Company facilities: the Fairfield Pumped Storage Facility, and the Parr Hydro Station. The Parr Hydro Station is located on the Broad River approximately 2.5 miles southwest of the nuclear station. The decommissioned Carolinas-Virginia Tube Reactor (CVTR) lies within a short distance of the east end of Parr Dam. The Fairfield Pumped Storage Facility is located at Frees Creek, about 1/2 mile east of the Broad River and about 1 mile west of the nuclear plant. Pipeline information is included in Section 2.2.2.3 and shown on Figure 2.2-1.

2.2.1.2 Transportation Facilities

Highway access to the plant is via S. C. 215 from Columbia, or by Interstate 26 to S. C. 176 and then to S. C. 213, as shown on Figure 2.2-1. Routes 215 and 213 merge at the center of Jenkinsville and continue north together for 3.2 miles. Route 215 continues on in a northerly direction; Route 213 veers off to the northeast. S. C. 215/213 transects the eastern sector of the 5 mile zone from north to south at an approximate distance of 6,800 feet due east from the Reactor Building; this is the nearest approach of a primary state highway to the plant. County road 311 (secondary road system) is 0.7 miles in length, generally oriented east-west connecting Route 215/213 to the site area. Its primary use is as an access road for the Virgil C. Summer Nuclear Station.

Two railroad lines, one of the Norfolk-Southern Railway and one of the CSX Railroad are located within 10 miles of the plant site, as shown on Figure 2.2-1. Alston, S.C., located 2 rail miles southeast of Parr, functions as an active junction for freight operations of the Norfolk-Southern Railway. The line running northerly from Alston through Parr and Strother passes west of the site along the east bank of the Broad River, approximately 1 mile from the Reactor Building. This line provides rail access to the Virgil C. Summer Nuclear Station with a spur track leading off the main line from a switch southwest of the site. This spur branches into several sidings within the plant

area. Two freight trains per day utilize the main line of the Southern Railway with a 1970 traffic of about 150 cars each. No passenger traffic utilizes this line.

The other line belongs to the CSX Railroad, running between Columbia and Laurens. This line connects with the Norfolk-Southern Railway line just east of Prosperity. This railway's closest approach to the site occurs near Little Mountain, at a distance of over 7.5 miles.

The locations of airports and significant flight paths occurring within the general area of the site are shown on the Airport Facilities Map, Figure 2.2-2. Airports within 30 miles of the plant site are listed in Table 2.2-2. The closest major airport is Columbia Metropolitan Airport, located approximately 24 miles southeast of the site. The Columbia Metropolitan Airport serves Delta, Eastern, Southern and Piedmont Airlines. The remaining ten airports within 30 miles of the site serve general aviation, including the closest to the site, Fairfield County Airport, located approximately 10 miles east-northeast of the plant. This 106.5 acre airport has one asphalt runway 3,200 feet in length, oriented approximately northeast-southwest.

There is one Low Altitude Federal Airway (18,000' MSL and lower) which is within 5 miles of the plant. Airway V53 passes approximately 3 miles southwest of the plant on a heading of 331° from the Columbia VORTAC. Jet Airway J47 is also located on this heading.

The Virgil C. Summer Nuclear Station is located approximately 1 mile east of the Broad River. In 1965, the Army Corps of Engineers compiled a listing of navigable rivers in relation to bridge construction planning. This study indicated that there was no commercial navigation on the Broad River; there is presently no commercial navigation on the river. In the vicinity of the nuclear plant, the Broad River is about 2,000 feet wide and quite shallow, ranging from a few feet to about 15 feet in depth.

2.2.1.3 Military Facilities

There are no military facilities within 10 miles of the site, but four military bases are located within a 50 mile radius. These are Fort Jackson Army Base, approximately 25 miles southeast of the site; McEntire Air National Guard Base, approximately 37 miles southeast of the site; Shaw Air Force Base, approximately 50 miles southeast of the site; and North Air Field, approximately 47 miles south-southeast of the site. North Air Field is designated as a "bare base" and is listed as closed on aeronautical charts. It is utilized for limited military training functions.

Shaw Air Force Base maintains Military Training Route 157, but this route is located approximately 20 to 35 miles southwest of the site.

2.2.2 Descriptions

2.2.2.1 Industrial Facilities

Industrial facilities located within 5 miles of the plant are listed in Table 2.2-1. Significant industries located within 20 miles of the plant are listed in Table 2.2-3; these industries have been considered because of their use and/or storage of hazardous materials.

2.2.2.2 Products and Materials

A description of the products and materials utilized by industrial facilities within 5 miles of the plant, including the number of employees, hazardous materials, and distances from the plant site, is presented in Table 2.2-1. Listed in Table 2.2-3 are other products and materials used by industrial facilities located out to a radius of approximately 20 miles which may present a possible hazard to the plant due to the products they manufacture and/or the amounts of hazardous materials they utilize or store. Table 2.2-3 also presents the tonnage of plastic materials and petrochemicals used by each industry, the amounts of explosives stored, or the gallons of bulk propane storage at each facility.

2.2.2.3 Pipelines

A buried natural gas pipeline extends from the southeast to the Parr Steam Plant as shown on Figure 2.2-1. The closest approach of the pipeline to the Virgil C. Summer Nuclear Station occurs at the steam plant, a distance of approximately 2.5 miles to the southwest. The pipeline does not lie within the Monticello Reservoir watershed. The line was installed approximately 6 years ago to utilize natural gas which may be available to SCE&G for fuel at the steam plant. The pipeline is 12 inches in diameter, buried at a depth of 3 feet, and has a maximum operating pressure of 700 psi. Isolation of the line is obtained with a 12 inch Cameron ASA 600 ball valve located approximately 13,800 feet south of the nuclear plant. There is no gas storage at the Parr Steam Plant other than that in the pipeline. The consumption of natural gas through this line is intermittent, occurring only at those times when this fuel is available. There are no plans to utilize the pipeline for the propagation of materials other than natural gas.

2.2.2.4 Waterways

The Broad River is the most prominent hydrologic feature in the vicinity of the Virgil C. Summer Nuclear Station. The plant is located approximately 1 mile east of the Broad River. Monticello Reservoir provides the cooling water for the nuclear plant. There is no commercial navigation on the Broad River, but it is used for recreational purposes.

2.2.2.5 Airports

There are no airports within 5 miles of the nuclear plant. The locations of airports within the general area of the site are shown on Figure 2.2-2. Fairfield County Airport lies approximately 10 miles east of the site and is the closest airport facility. This airport has three single-engine planes permanently based at the facility. The asphalt runway is 3,200 feet in length; its orientation is 40° and 220°. The airport is unattended, but yearly operations have been estimated at 3,000 to 5,000 (an operation consists of a take-off or a landing). Between the 20 mile and the 10 mile radius, there are four active general aviation airports. These are Gilbert Shealy’s Airport, 14 miles southwest; Newberry Municipal Airport, 18 miles west; Oxner’s Airport, 19 miles northwest; and Sabie Cathcart Airport, 13 miles northeast. The Winnsboro Airport, 14.5 miles northeast, has been closed and is replaced by the Fairfield County Airport facility. The 20 to 30 mile annulus encompasses four general aviation airports: Owens Field, J. Sexton, Connelly Field and Clemson (Pontiac) Experimental Station Airstrip, all private facilities. Columbia Metropolitan Airport, 24

miles southeast of the site, is the largest facility in the area and provides FAA services. Delta, Eastern, Piedmont and Southern Airlines operate at Columbia, as well as general aviation aircraft. The Columbia airport has two asphalt runways: one is 7,550 feet in length, oriented 110° and 290°; the other is 5,000 feet in length, oriented 50° and 230°. No approach patterns to Columbia lie within 5 miles of the nuclear plant. Two companies, Eagle Aviation and Miller Aviation, have a combined total of 91 single-engine and twin-engine planes and one small jet permanently based at Columbia. Yearly operations for 1975 reported by Columbia Metropolitan Airport totaled 118,182, of which about 68 percent were in general aviation. Information pertaining to airports within 30 miles of the site, with exception of military facilities, is presented in tabular form in Table 2.2-2. This table includes distance and direction from the site, number and type of aircraft based at the airport, largest type of aircraft likely to land at the airport facility, runway orientation and length, runway composition, hours attended, and yearly operations.

2.2.2.5.1 General Aviation Traffic

Available data for general aviation do not permit a direct evaluation of the number of flights over the site area. An indirect estimate of the traffic flux was made by assuming an isotropic flux of traffic from every general aviation airport within a 30 mile radius of the plant. This estimate counts very short flights, such as crop dusting and training exercises, but excludes long distance overflights not originating in the 30 mile radius. Since the 30 mile radius includes the general aviation activities near Columbia, a major hub of South Carolina air traffic, it is unlikely that any substantial number of general aviation overflights are omitted.

The isotropic model assumes that flights in all directions are equally likely, such that the number of flights passing through a 1 mile zone at the site is inversely proportional to the distance from the originating airport. Airport operations statistics include each landing and each take-off as separate operations; hence, both inbound and out bound flights are counted. Air traffic flux estimates based upon the isotropic model are:

Airport	General Activation Operations (Annually)	Distance From Site (Miles)	Traffic Flux Per Perimeter Mile
Columbia Metropolitan	79,700	24	529
Owens Field	76,000	27	448
Newberry Municipal	10,800	18	95
Oxner’s	9,000 (est.)	19	75
Fairfield County	5,000	10	80
Gilbert Shealy’s	400 (est.)	14	5
Sabie Cathcart	1,000	13	12
J. Sexton	400	27	2
Connelly Field	700	25	4
Clemson Experimental Station	200 (est.)	28	1
		Total	1,251

Since there are no approach or takeoff patterns near the site, the isotropic flux assumption is a conservative one.

An analysis of the probability of an aircraft collision at the site and the effects of the collision on the safety related components of the plant are provided in Section 3.5.

2.2.2.5.2 Scheduled Air Carriers

The maximum flux of scheduled carriers near the plant utilizing Low Altitude Federal Airway V53 (3 miles southwest of the site) is estimated to be four flights daily, or 1,460 annually. It is unlikely that this traffic level is achieved, due to reduced schedules, etc. Aircraft in these corridors in the vicinity of the site fly at very high altitudes. Jet Airway J47 passes over the site area at a minimum altitude of 18,000 feet; this corridor is located above Low Altitude Federal Airway V53.

2.2.2.5.3 Military Airport Facilities and Air Activities

Fort Jackson Army Base is located approximately 25 miles southeast of the site. The total acreage of the installation is 52,727 acres. Restricted Area R-6001, artillery range operations, is located

within the installation, approximately 27 miles southeast of the plant site at the nearest approach. Projectiles fired from the base reach altitudes of 10,000 to 12,000 feet. Impact is absorbed by the base. Fort Jackson has an aviation detachment located at Columbia Metropolitan Airport, approximately 24 miles southeast of the site. Activities of the aviation section include transporting personnel, flying support missions, and training missions. Contact (take-off and landing) training is conducted within the immediate vicinity of the airport (approximately 1 mile), usually on the east side. Instrument training is conducted under air traffic control clearances. Standard procedures of air traffic control operate the aircraft within a 10 nautical mile radius of the airport. Approaches to the airport are along the same paths utilized by civilian aircraft, and are made by instrument procedures. There are two types of aircraft, U8 Delta twin-engine and T42 Alpha twin-engine; both are fixed wing, propeller aircraft. A total of 13 aircraft are based at the Fort Jackson Army Aviation Section, seven of which belong to the Army Reserve. Fort Jackson Army Aviation Section also has MAST (Military Assistance to Traffic Safety) Unit 4th Platoon, 498th Medical Company. The MAST Unit is on call at all times to aid in cases of emergency within the state of South Carolina. MAST aircraft consist of six helicopters, type UH1H, operating out of Columbia Metropolitan Airport.

McEntire Air National Guard Base is located approximately 37 miles southeast of the site. The total acreage of the base is 2,397 acres. Air National Guard aircraft fly daily training missions. McEntire air traffic has no flight patterns within 30 miles of the plant site. The operations and training zones utilized by McEntire military aircraft lie primarily to the east of the base, and therefore are located more than 37 miles from the site.

The South Carolina Army National Guard is also stationed at McEntire Air National Guard Base. The Guard’s Aviation Section has 57 helicopters and two light aircraft. Helicopters fly to Spartanburg and Greenville for assigned military training missions, which may bring them into the vicinity of the plant.

North Air Field, located approximately 47 miles south-southeast of the plant, is listed as closed on aeronautical charts. However, this field is still utilized, on a limited basis, by military organizations. The field is designated as a “bare base” and has no permanently based aircraft, no regular flight training programs, no tower control, no refueling facilities, and no assigned personnel with the exception of a single grounds keeper. The runway is 10,000 feet in length, 500 feet wide, and is oriented along coordinates of 33°37’N and 81°05’W. The primary user, Charleston Air Force Base, S. C., flies approximately 15 C-141 cargo training missions per week. Limited paratroop drops occur, and some Reserve Officer Training Corps detachments use the area for weekend encampment and training on an as-requested basis. Expansion of the present facilities or activities conducted at North Air Field is not expected.

Shaw Air Force Base is located approximately 50 miles southeast of the site. The total acreage of the installation is 3,257 acres for the base, plus an additional 8,038 acres for Poinsett Gunnery Range (R-6002), located approximately 52 miles southeast of the plant site at its nearest point. Military aircraft at Shaw Air Force Base are used primarily for tactical reconnaissance training (aerial photography). Shaw has 83 RF-4C Phantom II reconnaissance jet aircraft and three T-39 aircraft assigned to the 363rd Tactical Reconnaissance Wing. The 507th Tactical Air Control Group has seven OV-10 and seventeen 0-2 aircraft and four CH-3 helicopters assigned. Officials

at Shaw Air Force Base do not foresee increased flight operations or larger aircraft at Shaw in the near future. Shaw's air operations utilize two parallel runways running north and south. One runway is 10,000 feet long; the other is 8,000 feet long. Shaw controls Poinsett Gunnery Range (restricted area R-6002 shown on Figure 2.2-2), which is used currently by RF-4C, 0-2, and OV-10 aircraft from Shaw Air Force Base; F-4C aircraft from Seymour-Johnson Air Force Base, North Carolina; Navy A-7 aircraft from Atlanta, Georgia; Air National Guard/Reserve units flying A-7 aircraft from Santurce, Puerto Rico and McEntire Air National Guard Base, South Carolina; A-37 aircraft out of bases in Youngstown, Ohio, Baltimore, Maryland, Hartford, Connecticut, Sergeant Bluff, Iowa, and Terre Haute, Indiana; F-100 aircraft from Dobbins Air National Guard Base, Georgia; and F-105 aircraft from Sandston, Virginia (Reference 1).

Training Route 157 is also controlled by Shaw Air Force Base, utilizing the same aircraft and altitude restrictions as those applied to Training Route 47. Training Route 157 is located approximately 20 to 35 miles southwest of the site, and is therefore not considered a hazard.

Three Military Operating Areas (MOA) for aircraft are located east of the site, as shown on Figure 2.2-2. Air operations within these MOA are under the control of Shaw Air Force Base. These areas are utilized for general military aviation training and exercises. The nearest approach to the plant site of any of the three MOA is approximately 27 miles.

2.2.2.5.4 Future Aircraft Expansion

The only general aviation airport expansion cited in the South Carolina Statewide Aviation Plan (1970) within the 30 mile radius of the site is the now completed Fairfield County Airport. Communications with the South Carolina Aeronautical Commission revealed the following tentative plans:

1. Newberry Municipal Airport - Plan possible extension of the existing runway to 6,000 feet, or the construction of a new airport.
2. Columbia Metropolitan Airport - The addition of a parallel east-west runway is under construction. Improvements on the current facility are under way.
3. A "master plan study" shall be conducted at Columbia Metropolitan Airport to possible examine Columbia Metropolitan air facilities with respect to expandability for privately owned aircraft, and to investigate possible joint use of McEntire Air Force Base.
4. Owens Field is under investigation by Richland County for future plans not yet disclosed.

2.2.2.6 Projections of Industrial Growth

The Virgil C. Summer Nuclear Station is located in a sparsely populated rural area, with little existing or projected urban or industrial development within a 10 mile radius. Most future industrial development within 10 to 20 miles of the site is expected to be in the vicinity of Winnsboro in Fairfield County, and in the Irmo area in Lexington and Richland Counties (Reference 2 and Reference 3). Industrial growth in the Winnsboro area, located approximately 15 miles east-northeast of the site, is expected as the result of the completion of Interstate 77 between Columbia and Charlotte, North Carolina, and because of increased tax revenues to

Fairfield County from the Virgil C. Summer Nuclear Station. This increase in tax base may be used by the county to lower tax rates and/or to increase the level of public services. Such actions could be a strong inducement for the location of new industry in the county. This is most likely to occur in the Winnsboro area because the urban infrastructure is more developed there than in most parts of the county. Good access (via Interstate 77) to major market areas will be an additional inducement.

The Irmo area, located about 16 miles south-southeast of the site, has already experienced rapid industrial growth during the past 5 to 7 years because of its proximity to Columbia, its location on Interstate 26, and the growing labor force in Lexington County. These factors are expected to continue to attract industry to the area, although there are no known plans for major developments at this time. The community of Harbison, with an anticipated 1995 population of 25,000, is located just to the southeast of Irmo, and new industry is part of the projected development.

2.2.3 Evaluations

2.2.3.1 Determination of Design Basis Events

2.2.3.1.1 Toxic Gases

Potential sources of toxic gases which might reach the facility from accidental releases due to transportation accidents are limited to rail tank cars and tank trucks. The capacity of tank trucks is typically 16 tons, and the capacity of present-day rail tank cars is approximately 90 tons. The transport of ammonia, chlorine, or other toxic chemicals considered in Regulatory Guide 1.78 by tank truck on Routes 213-215 in the site vicinity is unlikely. No regular use of these commodities is indicated in the industries within a 30 mile radius of the plant, and the adjacent highways do not attract through traffic due to their limited access. Rail transport of these commodities is more likely; however, due to the lesser elevation of the railroad bed in the vicinity of the site, only volatile chemicals are considered as a potential hazard. Chlorine-producing plants operate in southeastern Georgia, and there is a chlorine repackager in northwest South Carolina.

The dispersion of toxic gases from transportation spills has been studied by Simmons et al (Reference 4). The 1,000 ppm-minute dosage isopleth may be used as a criterion to determine whether a downwind plume will affect a particular area. This isopleth constitutes a lethal (LD-50) zone, but most persons would have time to leave the affected area and avoid lethal exposure. The centerline downwind plume lengths can be determined from a standard dosage formula* for a spectrum of meteorological conditions:

	Land Spill	Water Spill
wind 2.2 m/sec, D stability	0.93 miles	2.4 miles
wind 1.0 m/sec, E-F stability	2.55 miles	6.6 miles
wind 0.57 m/sec, F stability (5 percentile condition)	3.92 miles	10.1 miles

These distances are determined assuming initial flashoff of 16 tons of chlorine due to a spill from a 90 ton tank car onto land, and full flashoff of a spill into water. The horizontal dispersion parameters are of the form $AX^{0.91}$, where A has the values 0.13, 0.077, and 0.069 for the above conditions, respectively (values in meters). The dispersion parameters are further augmented 25 percent, following Simmons, to account for the dispersion time interval. Vertical dispersion is conservatively estimated at 1/5 that of the horizontal for chlorine dispersion. The average effective distance of the plume would be about 3 miles, based upon statistical weights of the above values of 30 percent, 15 percent and 5 percent for the respective stabilities, and equal weight between land and water spills.

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* Dosage $\frac{Q}{\pi\sigma_y\sigma_z U}\exp(-y^2/2\sigma^2 y)$ where Q is the mass of vapor released nearly instantaneously, y is the distance normal to the downwind centerline, U is the wind speed, and σ_y, and σ_z are the Pasquill-Gifford atmospheric dispersion parameters, or equivalents.

The cargo loss rate estimated by the Association of American Railroads for 90 ton tank cars is about 2.3×10^{-5} per trip. If the average trip per car is conservatively estimated at about 500 miles, the change of accidental cargo spillage would be about 5×10^{-8} per mile per car. The chance that a car would have an accident within 3 miles of the site is about 2.8×10^{-7} (5.6 miles track length x 5×10^{-8}). The probability that such an accidental release on the rail line would cover the plant is estimated to be approximately 2 percent because of the narrowness of the zone of severe effects under the plume, assuming that wind direction preferences are negligible. Therefore, the chance that a toxic chlorine gas plume would reach the plant in a given year will be less than 1.0×10^{-7} if fewer than 17 tank cars per year pass through Alston. The result will be the same if a larger radius is considered because the chances of affecting the plant from more distant releases decreases at about the same rate that the release probability would increase.

However, Simmons et al note that chlorine shipments, as a subset of all 90-ton tank car shipments, have a loss rate which is 10 times better than that for an average tank car. On this basis, the traffic of chlorine shipments would be as high as 170 per year before the chance of affecting the plant reaches 1.0×10^{-7}.

The lethal dosage for anhydrous ammonia was estimated to be 90,000 ppm-minutes. The length of a lethal plume comparable to the example for chlorine would be reduced to about one-tenth that for the chlorine. If the accidental release rate for ammonia is taken to be ten times that of chlorine, then the hazard from ammonia is roughly equivalent to that for chlorine. Thus, the toxic gas hazard from rail shipments will be less than 1.0×10^{-7} per year if fewer than 170 tank cars of both chlorine and ammonia are shipped through Alston. Assessment of Southern Railway traffic records indicates that far fewer than 170 tank cars of chlorine or ammonia are shipped annually on the near-site rail lines (11 such shipments were counted for 1975). Railway traffic records also indicate that the only other volatile chemical considered hazardous in Regulatory Guide 1.78 and which occurs as annual traffic through the general area in significant quantity is methanol. Rail traffic in the market area which contains the site included 30 carloads of methanol during 1976. Methanol is shipped non-pressurized and has an evaporation rate sufficiently low to prevent exceeding guideline levels of concentration at the site in the event of a railroad accident.

Other offsite sources which might accidentally release toxic gases, such as smoke from plastics containing sulfur or halogenated compounds, were considered out to the 20 mile radius (see Table 2.2-3). Since none of the smoke is as toxic as raw chlorine and ammonia, it is concluded that such sources are too small or too distant to constitute a toxic gas hazard at the plant.

While note permanently stored on-site, V. C. Summer maintains the ability to use chlorine for water treatment purposes. If used, Two 150 pound capacity bottles of liquid chlorine would be installed at the east side of the water treatment building, approximately 300 feet southeast of the Control Building. There are not reliable data for determining the chance of chlorine bottle ruptures. As a rough approximation, the total number of chlorine bottles that would be in use is on the order of 10^4 to 10^6. The lower number is recorded in interstate shipments; the higher can be estimated from chlorine consumption. The number of ruptures can be estimated at 1 to 10 annually. The number of chlorine exposures is of order 10^2 annually, but a large portion of these

are from defective fittings and leaks which do not create concentrated flash puffs. Thus the annual chance of bottle rupture, assuming chlorine use is re-implemented, can be estimated to be of order 10^{-5}. The chance of a fatal release is lower, with only 4 incidents recorded (bottle ruptures) over a 50 year span. An annual probability of a fatal bottle rupture can be estimated from this at 10^{-6} to 10^{-7}. The worst case situation for an accidental release of gas from the chlorine bottles would be the rupture of both bottles outside of the storage shed during a time of wind drift directly toward a Control Building air intake. The concentration at ground level of a puff of gas resulting from flashoff of the chlorine is given by:

$$C = \frac{2Q}{(2\pi)^{3/2}\sigma_x\sigma_y\sigma_z}$$

where C is the plume centerline peak concentration by weight at ground level, Q is the mass of vapor released, $\sigma_x = \sigma_y = 0.069\ x^{0.91}$, $\sigma_z = 0.2\sigma_y$, and x is the downwind distance in meters. The dispersion coefficients are for worst case (F stability) meteorology, and are in meters. The amount of chlorine flashing at rupture would be approximately 27 kilograms, or 20 percent of the volume. The puff concentration by volume at a distance of 300 feet would be approximately 7.6 percent. Should Pasquill C dispersion conditions prevail instead of the F stability assumed, then the concentration at 300 feet would be reduced to 0.3 percent.

Plume and puff dispersion models are not suitable for near-field travel of fumes because of local effects such as exhaust fan currents, breeze fluctuations, etc., which can completely change the local trajectory of a puff. However, chlorine vapors have negative buoyancy in air, and the upward dispersion of a lethal puff would be between 4 and 12 meters after travel of 300 feet. An air intake located well above ground level might avoid any intake of a flash puff, dependent upon the upwash/downwash local currents of the air flow about the facility buildings.

Outside of the chance of drawing in a concentrated puff of vapors during a rupture, the chlorine does not represent a severe hazard. The reach of the 1,000 ppm-minute isopleth along the plume centerline for undisturbed dispersion under F stability conditions and 0.57 meter/second wind (5 percentile meteorology) would be approximately 1,310 meters, or 0.8 mile, for release of the entire 300 lbs. of gas. Persons not trapped or stunned by the initial exposure could escape from the affected area, but this lethal exposure is a good measure of the affected area.

The annual probabilities previously established at 10^{-6} to 10^{-7} for fatal chlorine bottle rupture, assuming chlorine is stored year-round, are considered conservative. Furthermore, unique meteorological conditions would be required for a plume of chlorine to reach the Control Room air intake, including relatively continuous direction and altitude parameters with little variance. These requirements would significantly decrease the already conservative probabilities. Control Room habitability is also discussed in Section 6.4.

2.2.3.1.2 Delay Vapor Explosions

The worst case condition for buildup of an explosive concentration of flammable gases would be from a large accidental release of vapor in a railway accident. As an example, a source of 10 tons per hour of propane vapor, 1 mile downwind of the plant, is examined. This corresponds to a rail accident of a severity realized in less than 1 percent of all accidents, excluding loading and unloading of the tank cars. The ground level plume centerline concentrations (by weight) downwind can be described for the 5 percentile condition (F stability, 0.57 meter/second wind speed) by a standard equation:

$$\text{Concentration Fraction} = \frac{Q}{\pi\sigma_y\sigma_z UR}$$

Where Q is release rate,

$\sigma_y = 0.069 \times {}^{0.91}$downwind distance in meters
$\sigma_z = 0.2\sigma_y$.
U is wind speed.
R is the air density

The flammability limits of propane in air are given as 2 to 10 percent by volume, with the theoretical concentration for complete combustion estimated at 4 percent. These correspond to weight percents of 3.0, 6.3 and 14.4. For the conditions assumed, the combustive zone downwind of a 10-ton-per-hour source will lie between 230 and 540 meters from the release point. The point of complete propane combustion would be at approximately 340 meters. This can be assumed as the most likely point for detonation of a pocket of the propane-air mixture.

The explosive power of a propane-air mixture is about 430 calories per gram, or about 40 percent of the TNT weight equivalent. This estimate is based upon a typical Chapman-Jouget type of detonation, achieving a stagnation pressure of 25 atmospheres and a stagnation temperature of 3,500 degrees Rankine. The explosion of a pocket of 80,000 cubic meters of gas (100 x 20 x 40 meters) mixture 340 meters downwind of the source (4,000 feet from the plant) can be estimated from TM 5-1300, Figure 4-11 (Reference 5), by determining the scaled distance.

Scaled distance = 4,000 feet/3 $\sqrt{(40\ \%)(216\ ,000\ )}$ = 90 feet.

The peak incident overpressure at the Reactor Building location from such a blast would be of the order 1.0 psi, which would have little or no effect upon the plant’s structures.

The probability of such an accident occurring can be estimated at about 8×10^{-10} per year per rail car, assuming that at most 1 percent of the accidents would create the postulated conditions. This estimate is conservative because of the implicit assumption of delayed ignition. Most accidents of

this severity generally ignite flammable vapors readily. The accident probability will be less than 10^{-7} if fewer than 125 rail cars of liquefied propane (or equivalent) are shipped between Alston and Strother each year. Information from Southern Railway indicates that approximately 70 carloads per year of flammable compressed gases are shipped into the general area extending 100 miles from Columbia, S. C. It is conservatively estimated that no more than 35 carloads per year are shipped via the nearby rail line west of the site.

Propane storage facilities were inventoried to determine whether they constituted any hazard at the facility. From the considerations above, it is evident that the fuel storage amounts listed in Table 2.2-3 are too distant from the facility to create a blast or explosive vapor hazard.

The buried natural gas pipeline that serves the Parr Steam Plant is located, at its closest point, approximately 13,000 feet to the south of the nuclear plant site. The pipeline is used intermittently, dependent upon the availability of natural gas. The line is 12 inches in diameter and is operated at a maximum pressure of 700 psi. The escape rate in the event of total rupture would be approximately 70,000 standard cubic feet (scf) per minute, or 40 kg per second of methane. The flammability limits of methane in air are 5 percent to 15 percent by volume, corresponding to weight percentages of 3 percent to 9 percent. The centerline weight concentration is given by:

$$\frac{Q}{\pi\sigma_y\sigma_z UR}$$

where Q is release rate, U is wind speed, R is air density, X is downwind distance, $\sigma_y = 0.069 \times ^{0.91}$, and $\sigma_z = 0.5\sigma_y$.

The dispersion coefficients are given for stable (adverse) conditions, with the relation between horizontal and vertical appropriate for 300-500 meters. The plume distances corresponding to 3 and 9 percent at 0.57 meter/second wind speed (5 percentile condition) are approximately 135 to 245 meters (400 to 800 feet). Unconfined methane will not detonate, but ignites readily. The flammability zone is more than 2 miles from the site, and the amount of material ignitable is too small to create a radiant flux hazard. There would be no blast wave hazard. Because the pipeline is buried, it must also be considered that a cratering explosion of gases in soil could be generated, but the affected distance from rupture would be no more than 500 feet.

2.2.3.1.3 Explosives and Projectiles

Two companies within the 5 mile radius of the site carry substantial inventories of explosive materials. Interstate Materials, Inc., located near the intersection of Routes 215 and 213, stocks up to 40 tons of high explosive Torpex (ammonium nitrate-gelignite) for rock quarrying. Farm Milling Service, at Monticello, carries up to 200 tons of ammonium nitrate as fertilizer. Trucks transporting materials to and from these companies carry lesser amounts of explosives than those stockpiled, and the effect of a truck exploding at its closest approach to the plant, on Route 215,

would be far less than that due to an accident at Interstate Materials, Inc., or Farm Milling Services.

Operations at the Interstate Materials quarry site, about 2-1/2 miles from the site, are 90 percent related (by volume of crushed stone produced) to construction of the Virgil C. Summer Nuclear Station and Fairfield Pumped Storage Facility projects, and may be discontinued upon completion of these projects.

Ammonium nitrate and ammonium nitrate slurries (5-10 percent concentration in fluids, which may be water or other solvents) have an explosive strength of about 60 percent TNT weight equivalent. The theoretical detonation velocities range from 11,350 feet/second, dry, and up to 15,750 feet/second at the 5 percent slurry concentration. High temperature and/or pressure are required to achieve detonation, and the theoretical detonation velocities are seldom attained. Representative detonation velocities for material samples greater than 9 inches in diameter are 3,940 to 4,900 feet/second. The blasting material used at Interstate Materials is Torpex, in which a more easily detonable material is mixed into the ammonium nitrate as a propagator of the detonation. The explosive is tightly packed to achieve full brisance (shock power). In contrast, fertilizer is loosely packed and can be detonated only with great difficulty.

Incident peak overpressures which would be felt at the site if all of the materials at either of these companies were fully detonated can be estimated from TM 5-1300, Figure 4-11 (Reference 5), for a ground wave resulting from a surface burst. For Interstate Materials, the scaled distance would be equal to 15,840 feet/3) $\sqrt{(60\ \%)(80{,}000)}$ = 435 feet. For Farm Milling Service, about 3.6 miles distant, scaled distance equals 19,000 feet/3 $\sqrt{(60\ \%)(400{,}000)}$ = 305 feet. The limiting peak incident overpressure for a scaled distance of 305 feet would be about 0.1 psi*, and less for 435 feet. It is unlikely that a full detonation in a single blast could ever be achieved accidentally with fertilizer materials.

* extrapolated

Since Torpex may be encased, primary fragments could be generated. From TM 5 1300 (page 4 66 ff), the maximum primary fragment velocity realizable from a cylindrical casing is about $\sqrt{2}$ times the Gurney Energy constant, which is 7,450 feet per second for Torpex. The velocity decay in air is given by:

$V_r/V_o = \exp(-0.004\ r/W_f^{1/3})$

where V_o is the initial velocity, V_r is the velocity at distance r (feet), and W_f is the fragment weight in ounces. For a final velocity of 0.1 feet/second (a velocity that would not result in damage to either facilities or personnel), the maximum range of fragments from the Torpex casing would be:

$r = 250\ W_f^{1/3}\ \text{Ln}\ 105{,}000$

= 2,900 feet for a 1 ounce fragment,
5,250 feet for a 6 ounce fragment.

Primary fragments are improbable with fertilizer, since metals are unlikely to be directly in contact with the explosive. By hypothesizing that a sheet of steel falls into a fertilizer container or pile before a blast, then a maximum primary fragment velocity of $\sqrt{3}$ times the Gurney Energy constant might be realizable. A Gurney constant of 5,000 - 5,500 feet/ second would probably apply for the loosely packed material, but the Torpex value can be used to estimate the range. For a 1-ounce fragment, the range would be about 2,940 feet and for a 6-ounce fragment, about 5,340 feet. Secondary blast wave fragments from disintegration of the surrounding structure would not approach the range of the primary fragments.

The recommended standard distance (Armed Services Explosives Safety Board, December 1, 1955) for inhabited buildings from an unbarricaded magazine is about 2,800 feet for 50,000 pounds of TNT (the quarry equivalent), and 4,310 feet for 250,000 pounds of TNT (the fertilizer equivalent). The distance to the site is nearly five times the recommended standard in the first case, and over four times the standard in the second.

It can be concluded from these basic calculations that the plant site would be beyond the zone of penetrating primary fragment scatter and strong blast wave effects from postulated explosions at Farm Milling Service or the Interstate Materials quarry. Minor effects associated with the arrival of a blast wave of incident overpressure 0.1 psi could be experienced at the site, one of which would be a startling noise. Mitigating factors to the postulated hazards are (1) the quarry explosive inventory will be eliminated or substantially reduced when construction of the power projects is completed, and (2) detonation of ammonium nitrate fertilizer is very difficult to achieve, making the likelihood extremely remote of an accidental detonation in a single blast of all of the material inventory.

Munitions shipped on the railroad are another potential source of projectiles. The rail accident rate for other than grade crossing accidents has been estimated at 0.08 per million railcar miles

(Reference 6), and about 1 percent of the accidents would be severe enough to damage a munitions cargo. The annual probability that a munitions explosion might occur within 10 miles of the site will be less than 10^{-7} if fewer than three carloads per year are shipped on the Alston-Strother section of line, five carloads per year on the Alston-Pomaria section of the Southern Railway lines, or eight carloads for the Columbia-Newberry-Laurens section of line. Southern Railway shipments of hazardous cargo within approximately 100 miles of Columbia, S. C., were reviewed. Not a single carload of code 41 049 (explosives) was included during 1975, indicating that shipments approaching or exceeding the aforementioned numbers designated for the pertinent near-site rail lines would only possibly occur in case of escalation to wartime levels. The chance that a projectile would strike the site if there were a munitions detonation on the railroad would not be large (on the order of 1 percent), providing an additional margin of safety (Reference 6).

2.2.3.1.4 Forest Fire Smoke and Heat Fluxes

Newberry and Fairfield Counties maintain active forest products industries, with 79 and 86 percent, respectively, of the land classed as commercial forest, most of which is in private individual ownership. A 1975 directory of timber buyers lists 10 dealers, 10 loggers and yards in Fairfield County; and 9 mills, 5 dealers, and 7 loggers and yards in Newberry County. Pulpwood is the primary forest product for the two counties.

The average annual loss of acreage due to fire in South Carolina over the 5 year period 1970 to 1975 has been 22,700 acres in 4,240 fires, for a 5.3 acre average per burn. In 1974-75, only 0.1 percent of the fires were larger than 100 acres in extent, and all of these were Class D (199-299 acres). However, rainfall over the past 5 years has been 11 percent above the long-term average, which has helped in producing such favorable fire statistics.

The smoke hazard from forest fires in the Southern Region (which includes the Southeast) is rated by the Environmental Protection Agency as the lowest for any section of the United States except for the Great Basin forests. This is due primarily to the low average available fuel loading per acre for wildfires -- 9 tons/acre, compared to up to 60 tons/acre for the Pacific Northwest. The available fuel loading per acre is the average amount of material actually burned in wildfires and is not the total combustible material per acre. Emission per ton burned for Southern fires is the same as for U. S. averages: 8.5 kg. of particulates, 70 kg. of carbon monoxide, 12 kg. of hydrocarbons, and 2 kg. of nitrogen oxides per metric ton burned (Reference 7).

Because of the low smoke emission characteristics which would be expected for the region, fires outside the exclusion area should not create smoke hazards or high radiant energy fluxes at the plant site. Additional mitigating factors for the site are the open, moist areas created by the Broad River, Monticello Reservoir, and Parr Reservoir.

Less than 35 percent of the exclusion area consists of woodland, and the heavily wooded area closest to the reactor building lies approximately 1/2 mile southeast to southwest. Woodland fires inside the exclusion area of the plant could create smoke nuisance, but there would be no problem of high thermal heat exposure to the reactor building.

2.2.3.1.5 Collisions and Spills at Intake Structure

The intake structure at Monticello Reservoir is not located on a navigable waterway. The structure is located within the exclusion area. Control of the exclusion area is discussed in Section 2.1.2.1.

The possibility of liquid spills into the reservoir is extremely remote. No interstate petroleum or gas lines are located in the Frees Creek watershed. The only potential source of liquid spills would be from tanker trucks which might enter the upper watershed. The dilutive effects of the reservoir would mitigate any effects of a tank truck spill. For example, a spill of 100 barrels of fuel oil into the upper reservoir area, a typical size spill for a tank carrier, would spread out to a film of about.003 inches thickness on the surface of the reservoir within about 6 hours after entering the waters. The design of the intake structure precludes the introduction of such a spill into the intake structure. Spills from rail tank cars near the site would not enter the Frees Creek watershed but would drain toward the Broad River.

2.2.3.1.6 Release of One Rail Car Load of Methanol

The shortest distance from the control room air intakes to a postulated accidental release of one rail car load of methanol is approximately one mile (see Figure 2.2-1). The estimated wetted area following an accident along the railroad tracks opposite the site, assuming blockage of the railroad bed drainage, would be 2000 ft^2. For analytical purposes, a wetted area of 4000 ft^2 is assumed.

The estimate of evaporation rates for methanol is extrapolated from climatological data for water vapor. Evaporation is controlled by the difference in vapor pressure between the evaporating fluid and the overlying vapor. The emission of molecules from the surface of the liquid would be proportional to the vapor pressure and inversely proportional to the square root of the molecular weight. The vapor pressure buildup in the overlying gas is influenced by the diffusivity of the vapor molecules. This diffusivity is lower for methanol than for water vapor because of the greater molecular weight. The extrapolation does not consider the latter difference and, thus, is conservative. To obtain a conservative estimate of water vapor evaporation, wind speeds are assumed to be higher than would be applicable under the F-stability conditions at the Virgil C. Summer Nuclear Station site. Lower ambient relative humidity is also assumed for analytical purposes. Evaporation rates of 55 inches over the warmest 6 months of the year have been measured at Yuma, Arizona (Reference 8). This rate (0.3 in/day) is extrapolated to 1.1 in/day of methanol. Evaporation of 1.1 in/day of methanol over a 4000 ft^2 area would result in a release rate of about 0.09 kg/sec from the railcar spill.

The dispersion equation (see (Reference 4) is as follows:

$$X = \frac{Q/Mm}{\pi \sigma_y \sigma_z UR/Ma}$$

Where:

X = Maximum concentration along plume centerline.

Q = Release rate, 0.09 kg/sec.

Mm = Molecular weight of methanol, 32.

σ_y = Lateral dispersion coefficient, $0.69d^{0.91}$

σ_z = Vertical dispersion coefficient, 0.2 σ_y, for heavier than air vapors.

U = Wind speed, 0.57 m/sec.

R = Density of air, 1.25 kg/m^3.

Ma = Molecular weight of air, 29.

d = Distance, 1 mile (1610 m).

The methanol concentration at the control room air intakes, calculated using the above equation and estimated parameters, is 53 ppm. This concentration is substantially less than the 400 ppm toxicity limit recommended by Regulatory Guide 1.78.

The methanol vapor concentration inside the control room is dependent upon operation of the air conditioning system. In the normal mode of operation, outside air is supplied to the Control room (design flow rate is 3700 cfm). In the emergency mode of operation, dampers isolate the outside air intakes.

The odor of methanol would be readily detected by the operator in the control room and would result in a rapid operator response to switch from the normal to emergency mode.

If it is assumed that the air conditioning system is operated in the normal mode for an extended period of time following the methanol spill, concentration of vapor inside the control room is calculated using the follow equation:

$$r = 1 + C - \frac{1 + C}{(1+C)^n}$$

Where:

r = Ratio of vapor concentration inside control room to vapor concentration at the control room air intakes.

c = Ratio of outside supply air, 3700 cfm, to control room free volume, 224,940 ft^3.

n = Elapsed time from initial arrival of the methanol plume at the air intakes.

The period of time calculated for methanol vapor concentration inside the control room to increase to the concentration outside (i.e., 53 ppm) is 253 minutes. This period of time is more than adequate for appropriate corrective action.

2.2.4 References

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7. U. S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Second Edition, Research Triangle Park, North Carolina, March, 1975.
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Begy, Mr., Midlands Aviation, Owens Field Downtown Airport, Columbia, South Carolina, April 27, 1976.

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Westbrook, R. A., Farm Milling Services, Monticello, South Carolina, May 3, 1976.

Willson, Marge, Martin Marietta Aggregates, Cayce, South Carolina, May 11, 1976.

Table 2.2-1
Industrial Facilities Within 5 Miles of the Site

Company	Distance from Plant Site (Miles)	Products	Hazardous Material	Current Employment
Nylene Corp.	2.6 SE	Nylon pellets Brush bristle Monofilament fish line	42,000 lbs. caprolactan	10
Farm Milling Service	3.8 NE	Animal Feed Fertilizer	150-200 tons Ammonium nitrate (Solid & liquid)	7
Interstate Materials, Inc. Division of Clement Bros. Co.	3.0 NE	Crushed stone (granite)	25,000 lbs. Ammonium nitrate & Torpex (water gel) 50,000 lbs. Ammonium nitrate & fuel oil (ANFOPrill)	35
Interstate Materials, Inc. Division of Clement Bros. Co.	4.8 NW	Sand	None	6
Winnsboro Granite Corp.	4.8 NE	Dimension stone	100 lbs. black powder 200 blasting caps	20

Table 2.2-2
Airports Within 30 Miles of the Site

Airport	Distance (mi) And Direction Site	No. and Type of Aircraft Based at the Airport	Largest Type of Aircraft Likely to Land at the Airport	Runway Direction and Length (Feet)	Runway Composition	Hours Attended	Yearly Operations
Gilbert Shealy's Airport	≈≈14 SW	2 Single Engines	182 Cessna	120°+300° 1200'	Turf	Unattended	Private - Not Available
Owens Field	≈≈27 SE	99 Single & Twin Engines	DC-3	70°+250° 3456' 150°+330° 3607'	Asphalt Asphalt	7:00 AM - 10:00 PM	75,696
Newberry Municipal	≈≈18 W	11 Single Engines	Citation Cessna	40°+220° 3500'	Asphalt	8:00 AM - 7:00 PM	10,800
Airport		2 Twin Engines		100°+280° 2400'	Turf		
Oxner's Airport	≈≈19 NW	2 Single Engines	310 Cessna	90°+270° 2950'	Turf	8:00 AM - 5:00 PM	Private -Not Available
J. Sexton	≈≈27 W	1 Single Engine	182 Cessna	90°+270° 1700'	Turf	Unattended	≈≈400
Connelly Field	≈≈25 W	3 Single Engines	182 Cessna	50°+230° 2000'	Turf	Unattended	≈≈600-700
Fairfield Co. Airport	≈≈10 E	3 Single Engines	C-47 Twin Engine	40°+220° 3200'	Asphalt	Unattended	≈≈3,000-5,000
Sabie Cathcart	≈≈13 NE	1 Single Engine	Light Twin	150°+330° 2000'	Turf	Unattended	1000
Winnsboro Airport	≈≈14 1/2 NE	CLOSED		CLOSED			CLOSED
Clemson (Pontiac) Experimental Station Airstrip	≈≈28 SE	Information not available					
Columbia Metropolitan Airport	≈≈24 SE	91 Single + Twin Engines 1 Small Jet	C-5 Transport Plane	110°+290° 7550' 50°+230° 5000'	Asphalt Asphalt	24 Hours	118,182

Table 2.2-3
Industrial Facilities With Hazardous
Materials Within 20 Miles of the Site

Company	Location	Petrochemical & Plastics	Bulk Propane Storage (A.G.W.G)	Maximum Amount of Explosives Stored	Product
Allied Chemical Corp.	Irmo	4,500 tons	(2) - 30,000[1]		Nylon staple, Nylon & polyester fil yarn
Chrysler Corp. (Airtemp S.C., Inc.)	Winnsboro		(1) - 18,000 (1) - 12,000		Air Conditioning & heating products
Corena Mfg. Company	Winnsboro		(1) - 30,000		Lawn & casual furniture
Uniroyal Fibers Textiles	Winnsboro		(2) - 30,000		Tire Cord-rayon Nylon polyester steel
United States Rubber Company*	Winnsboro		(1) 18,000		
General Electric Company	Irmo	Urea-Formaldehyde [Genol] 2 tons 100,000 gals, Fuel			Capacitors
Lone Star Industries (Quarry)	Blair			Atlas Powder 12,300 lbs. Ammonium Nitrate 700 bags	Crushed stone
Martin Marietta Aggregates (Quarry)	Rion			Ammonium Nitrate 14,600 lbs. Dynamite [Hydrive] 5,500 lbs.	Crushed stone

[ ] Indicates trade name of explosive
* Not listed in 1975 South Carolina Industrial Directory
A.G.W.G. denotes Above Ground Water Gallons Capacity Storage
L.P.G.D. denotes Liquefied Petroleum Gas Dealer

1. Number of tanks - Capacity in gallons

Table 2.2-3 (CONTINUED)
Industrial Facilities With Hazardous
Materials Within 20 Miles of the Site

Company	Location	Petrochemical & Plastics	Bulk Propane Storage (A.G.W.G)	Maximum Amount of Explosives Stored	Product
Nylene Corporation **	Jenkinsville	42,000 lbs caprolactam			Nylon Pellets, Brush bristles, monofilament fish line
Farm Milling Service **	Monticello			Ammonium Nitrate 150-200 tons	Animal feed & fertilizer
Interstate Materials, Inc. ** (Quarry)	Jenkinsville			Ammonium Nitrate 25,000 lbs. Ammonium Nitrate & Fuel Oil [ANFO Prill] 50,000 lbs.	Crushed Stone
Winnsboro Granite Corporation **	Jenkinsville			Black Powder 100 lbs. 200 blasting caps	Dimension stone
Clinton-Newberry Gas Authority (Utility)	Newberry		(5) - 30,000[1]		
Farmers Ice & Fuel Company (L.P.G.D.)	Newberry		(1) - 18,000		Liquefied Petroleum Gas
Pargas of Newberry (L.P.G.D.)	Newberry		(1) - 30,000 (4) - 4,000		Liquefied Petroleum Gas
Porter Gas Service (L.P.G.D.)	Winnsboro		(1) - 18,000		Liquefied Petroleum Gas
Superior Gas Company (L.P.G.D.)	Winnsboro		(1) - 30,000 (1) - 18,000		Liquefied Petroleum Gas

Table 2.2-3 (CONTINUED)
Industrial Facilities With Hazardous
Materials Within 20 Miles of the Site

Company	Location	Petrochemical & Plastics	Bulk Propane Storage (A.G.W.G)	Maximum Amount of Explosives Stored	Product

1. [ ] Indicates trade name of explosive
* * Located on Fig. 2.2.1
A.G.W.G. denotes Above Ground Water Gallons Capacity Storage
L.P.G.D. denotes Liquefied Petroleum Gas Dealer
1 Number of tanks - Capacity in gallons

Figure 2.2-1
SITE VICINITY MAP

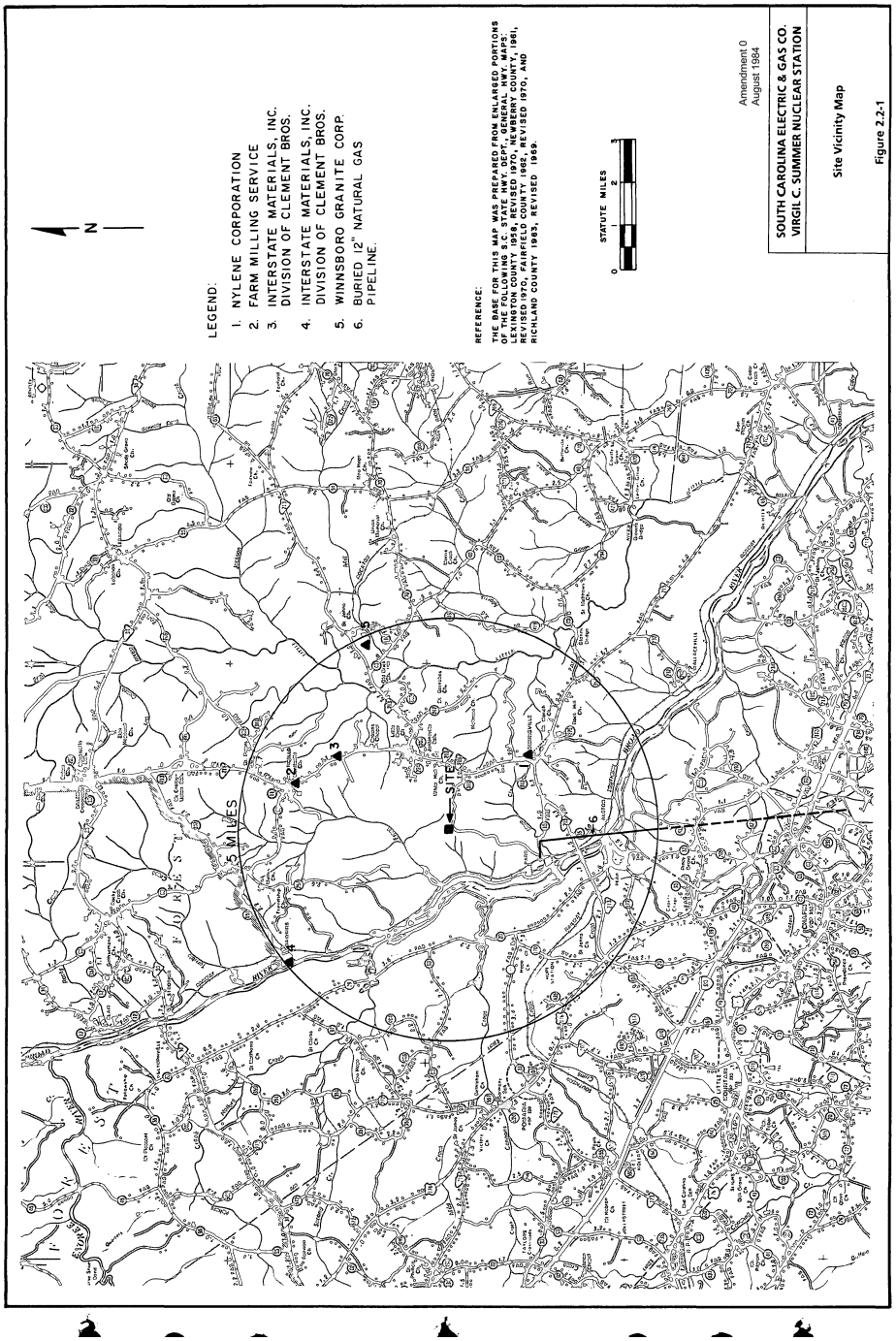


Figure 2.2-2

AIRPORT FACILITIES MAP

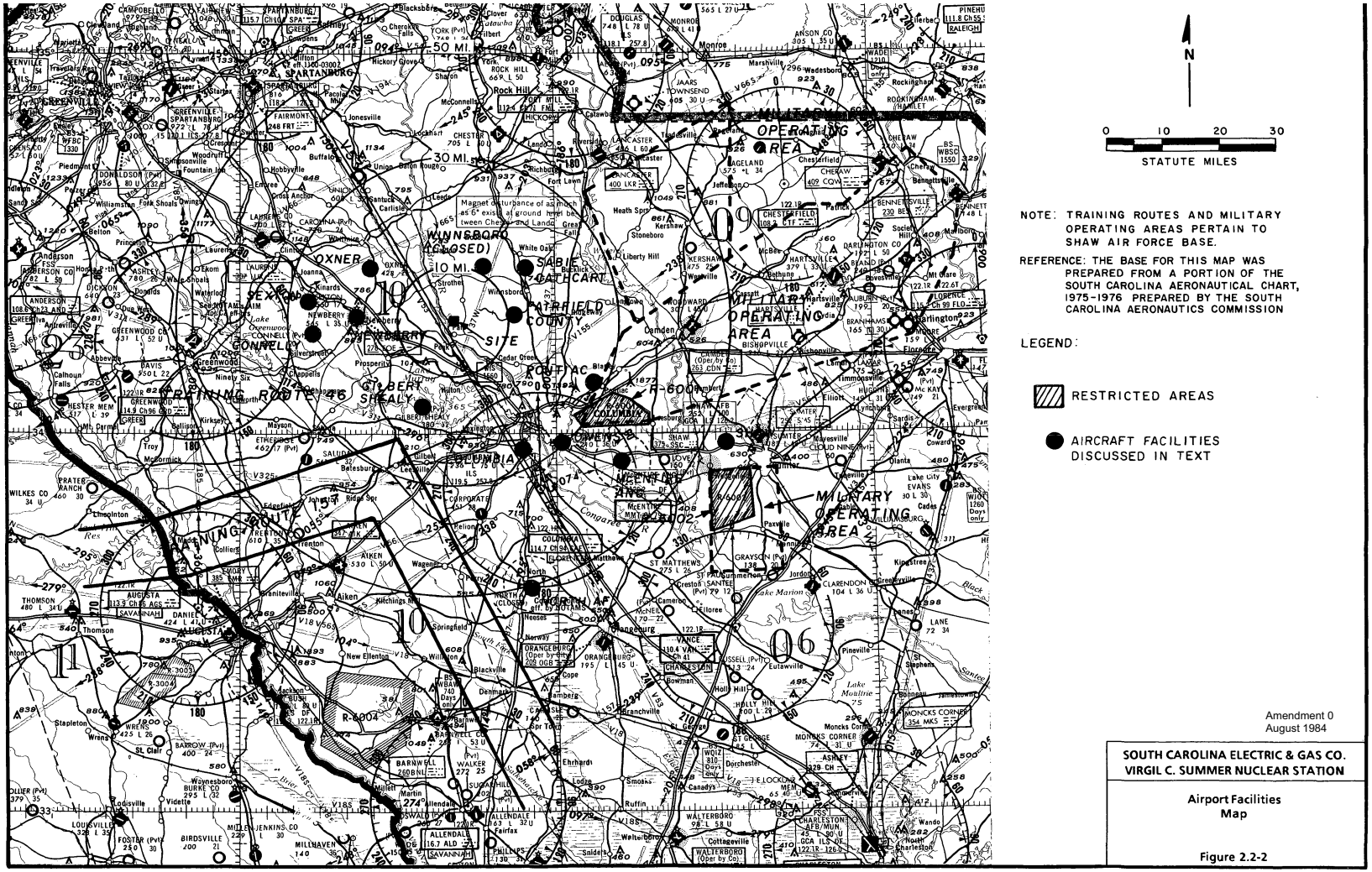
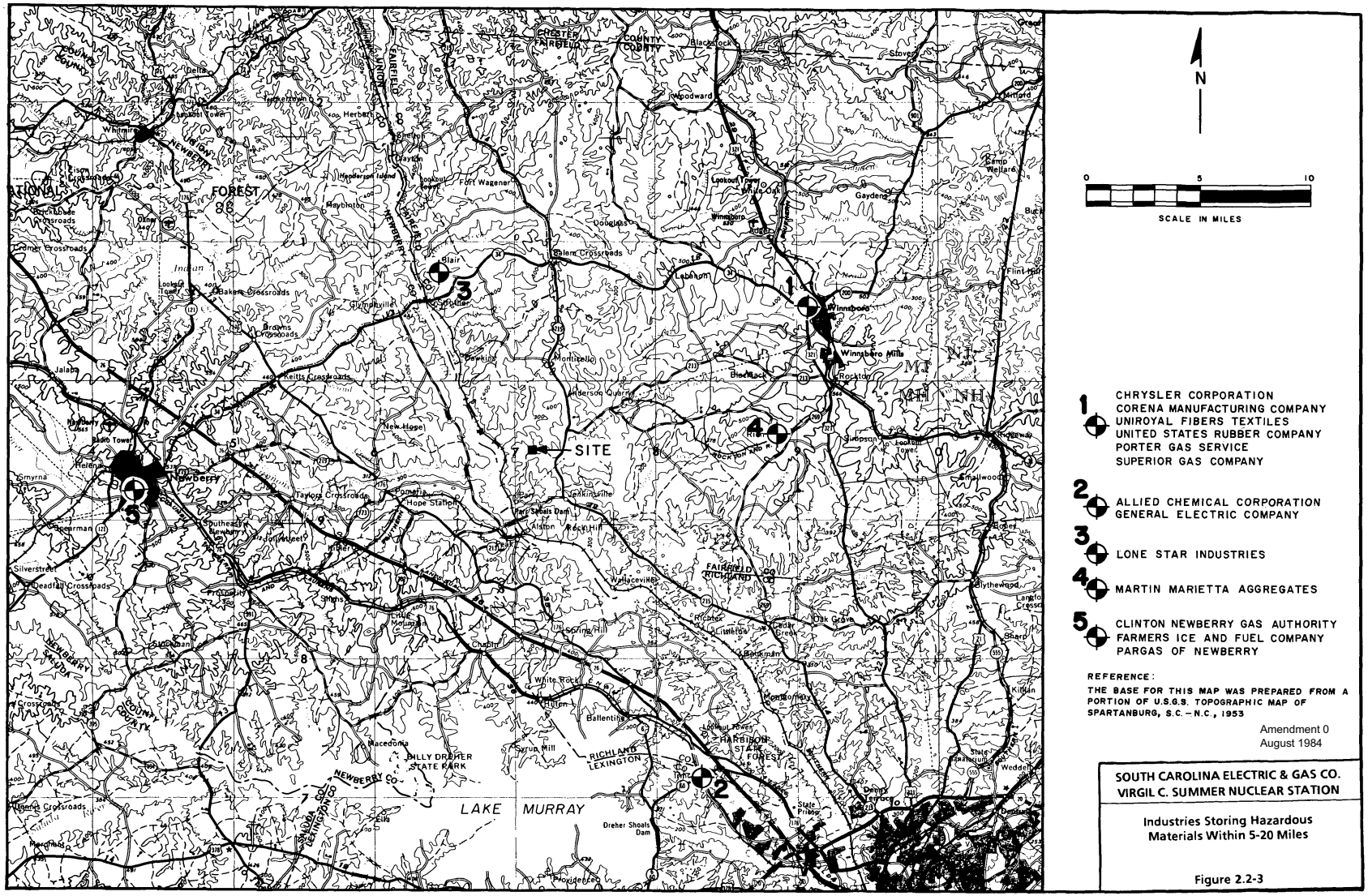


Figure 2.2-3

INDUSTRIES STORING HAZARDOUS MATERIALS WITHIN 5-20 MILES



2.3 METEOROLOGY

NOTE: Section 2.3 is being retained for historical purposes only (per RN 00-081).

2.3.1 Regional Climatology

Figure 2.3-1 shows the relative locations of the site and available climatological stations for use in the evaluation of the climatology of the region.

2.3.1.1 Data Sources

Sources used in the preparation of the regional climatology include:

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2.3.1-N. Pautz, M.E. - *Severe Local Storm Occurrences, 1955-1967*. ESSA Technical Memorandum WBTM FCST 12. U.S. Department of Commerce, September 1969.

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2.3.1-Q. Thom, H.C.S. - *Tornado Probabilities*. Monthly Weather Review, October - December 1963.

2.3.1-R. *Design Basis Tornado for Nuclear Power Plants*. U.S. Atomic Energy Commission, Regulatory Guide 1.76, April 1974.

2.3.1-S. Cry, George W. - *Effects of Tropical Cyclone Rainfall on the Distribution of Precipitation Over the Eastern and Southern United States*. ESSA Professional Paper 1, U.S. Department of Commerce, Washington, D.C., June 1967.

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2.3.1.2 General Climate

The Virgil C. Summer Nuclear Station site is located in the Piedmont Physiographic Province. The site is 26 miles northwest of Columbia, South Carolina (Figure 2.3-1). The terrain consists of rolling hills; elevations range from 200’ near Columbia to over 600’ near Little Mountain. The Broad River lies approximately 1 mile to the west, and Parr Dam is located approximately 2-1/2 miles southwest. The site is located near the center of the state, approximately 140 miles northwest of the Atlantic Ocean and 100 miles southeast of the Appalachian Mountains. Plant elevation is approximately 435’ above mean sea level.

The climate in this region is temperate, having long hot summers and cool winters. The Appalachian Mountain chain frequently retards the approach of cold fronts during the winter months.

In summer, the Bermuda High is the greatest single weather factor influencing the area. This semi-permanent high pressure system blocks the entry of cold fronts so that many stall before reaching central South Carolina. Also, the southwesterly flow around this system supplies moisture from the Gulf of Mexico for the many summer thunderstorms. Typically, summer has approximately 50 days with temperatures of 90° F or above and 6 days with temperatures of 100° F or above. Summer is the rainiest season of the year, contributing about 33 percent of the annual total rainfall. The summer rains are largely in the form of local thundershowers, occurring on an average of 11 days per month during this season. About once or twice a year, effects of passing tropical storms are felt by way of strong winds and heavy rains. The incidence of these storms is greatest in September, although they represent a possible threat from summer to late fall. Rainfall during the late fall (October and November) is at an annual minimum.

Winter weather in this region is largely made up of polar outbreaks that reach the area in a much modified form. On rare occasions, arctic air masses push through this region and cause some of the coldest temperatures. On the average, the minimum temperature can be expected to drop to 32° F or lower on 45 to 50 days, and at or below 20° F on 5 days during this season. A day or more with snowfall is probable during 9 out of 11 winters. A day with more than 1 inch of snowfall is likely to occur in 1 out of 5 winters. Winter rainfall accounts for 22 percent of the annual total.

Spring is the most changeable season of the year in this area due to the alternating effects of polar and maritime tropical air masses. Spring rainfall accounts for 25 percent of the annual total. While tornadoes are infrequent, they occur most frequently during this season. Hailstorms are not frequent, with the annual incidence at a maximum in spring and early summer (Data Source 2.3.1-A.)

The prevailing surface winds tend to be either from the northeast or southwest due to the presence and orientation of the Appalachian Mountains. The prevailing wind direction during the winter, spring and summer seasons is southwest; northeast or north-northeast winds prevail during the fall (Data Source 2.3.1-B.)(Data Source 2.3.1-C.). The wind direction frequencies observed at the nuclear plant onsite meteorological tower show the same prevailing directions as those cited from

other sources, providing evidence that the site climate is controlled by regional synoptic processes rather than by local influences such as the Broad River valley terrain features.

Annually, values of relative humidity of 90 percent or greater are recorded 25 percent of the time. Values of relative humidity in this range occur most frequently during the hours from 0000 to 0700 local time (Data Source 2.3.1-C.).

The mean percentage of possible sunshine in the state varies from a low of 59 percent in January to a high of 68 percent in April and October (Data Source 2.3.1-A., Data Source 2.3.1-B., Data Source 2.3.1-D., and Data Source 2.3.1-E.).

2.3.1.3 Severe Weather

2.3.1.3.1 General

Severe weather conditions (significant departures from the general climate) include heavy precipitation, ice storms, thunderstorms, hail, lightning, tornadoes, hurricanes, and high air-pollution potential.

2.3.1.3.2 Precipitation

Maximum rainfall, estimated by statistical analysis of regional precipitation data, is given on Table 2.3-1 for return periods of 1 to 100 years and for rainfall durations of 30 minutes to 24 hours (Data Source 2.3.1-F.).

The maximum recorded point rainfall for durations of 5 minutes to 24 hours at Greenville, Spartanburg, and Columbia, are presented in Table 2.3-2. For plant design criteria, the “probable maximum precipitation” estimates of extreme rainfall are used to provide complete assurance of plant operability. The probable maximum precipitation is defined as the critical depth- duration-area dependent rainfall for a particular area that would result if conditions during an actual storm in the region were increased to represent the most critical meteorological conditions that are considered probable. The critical meteorological conditions are determined for each season through the analyses of the historical synoptic conditions during past storms, air-mass properties associated with these storms (temperature, winds, etc.), topography, and particular location of the area of interest.

Estimates of probable maximum precipitation for a 10 square mile area in the vicinity of the site are as follows (Data Source 2.3.1-H.).

Duration	Inches
6 Hr.	31.4
12 Hr.	34.2
24 Hr.	36.7
48 Hr.	39.5

Extreme snowfalls for representative stations in the area are given in Table 2.3-3 (Data Source 2.3.1-A, I and J). The 100 year return period, antecedent snow and ice pack for the area in which the plant is located, in terms of snow load on the ground and water equivalent is listed below (Data Source 2.3.1-K.):

Snow Load 13 lbs/ft^2
Water Equivalent = 2.5 inches

Using the 100 year return period snow load above, the weight of snow and ice on the roof of each Seismic Category 1 structure is presented in Table 2.3-4. Buildings are designed to the Southern Standard Building Code which includes snow loadings of 20 lbs/ft^2.

2.3.1.3.3 Ice Storms

Ice storms, attributed to precipitation in the form of freezing rain, generally occur from one to three times per winter in the northern half of South Carolina. Moderate to heavy ice storms can be quite damaging to utility lines and trees, as well as being a serious traffic hazard. One of the most severe ice storms occurred in February 1969 in several north-central and northeastern counties. Power and telephone services were seriously disrupted over a large area and timber losses were tremendous (Data Source 2.3.1-B.).

The extreme thickness of glaze ice observed on utility wires during a 9 year period (1928-1937) in central South Carolina was approximately 1.0 inch (Data Source 2.3.1-L.). The estimated probability of this occurring in any one year is 0.05 Data Source 2.3.1-M.). Buildings are designed to the Southern Standard Building code which includes ice loadings of 20 lbs/ft^2.

Table 2.3-4 in the FSAR presents the maximum values of the Seismic Category 1 roof loading due to extreme winter precipitation. This table is based on the 100-year return period information presented in ANSI A58.1 (1972). To illustrate the conservative nature of this number, the maximum recorded depth of snow recorded in Columbia, South Carolina for the period of 1887-1975 has been 15 inches (February 1973). (Local Climatological Data, U. S. Department of Commerce, National Oceanic and Atmospheric Administration, February 1973, and Ludlum, David M., Weather Record Book United States and Canada, Weatherwise Press, Princeton N. J. 1971). The depth associated with the 13 lbs/ft^2 is 26 inches.

The maximum ground level depths at this site are associated with a single snow storm of short duration (less than 48 hours). The maximum ground depth of 15.0 inches remained for less than one day; no snow remained on the ground four days after this snowfall. Due to the fact that the maximum snowfalls cause the maximum depth of snow and since the period of retention of the snow in this region is limited, new storms adding additional snows to these maximum snowfall depths are a very unlikely occurrence.

The design loading for buildings in this region is 20 lbs/ft^2, representing the weight of 40 inches of snow. This value permits using the maximum recorded snowfall for a given month during the 89 year period, 15.7 inches for February 1973 and the application of a drift factor of 2.55. This coefficient is based on no snow present prior to the storm, as indicated in the previous paragraph. The coefficient is also near the maximum value of the adjustment coefficients, based on roof shapes and building configurations, as given in ANSI A58.1 (1972). Thus the design snow loadings as given in Section 2.3.1.3 are adequate for winter precipitation loads in this region of South Carolina.

The normal range of snow density, the ratio of the volume of melted snow to the volume of snow, is from 0.07 to 0.15 for freshly fallen snow to 0.91 for compacted snow. Snow accumulation in Columbia, South Carolina is an unusual event as more than 3 days of sustained snow cover is rare. A day with more than 1 inch of snowfall is likely to occur in only one out of five winters. This, plus the fact that only one third of the days in winter have minimum temperatures below freezing indicates the lack of sufficient time needed to have accumulated snow exist long enough to pack. Therefore, to represent the snow density at the site, a value of 0.1 was used as a representative value of new fallen snow.

As indicated in footnote 1 of Table 2.3-4, the weight of snow and ice given in this table was based on the 100-year return period ground snow load of 13 lbs/ft^2 without considering roof shapes and building configuration adjustments given by ANSI A58.1 (1972). However, seismic Category 1 buildings at the Summer site are actually designed for snow loadings of 20 lbs/ft^2, representing the weight of 40 inches of snow, in accordance with the Southern Standard Building Code.

The snow loads which would be exerted if the 48-hour probable maximum winter precipitation (PMWP) was in the form of snow are not appropriate as a component of the design basis snow load in southern locations. The 48- hour PMWP value is based on “a critical depth-duration-area rainfall relations for a particular area during various seasons of the year that would result if conditions during an actual storm in the region were increased to represent the most critical meteorological conditions that are considered probable of occurrence.” One of the critical meteorological conditions which contributes to the PMWP is the requirement that the atmosphere over the site be warm and near saturation. The atmosphere at temperatures approaching or below freezing cannot contain sufficient moisture at the Summer site to cause the PMWP.

Design basis events which are uncontrollable by the plant operator, such as tornadoes and floods, should have an extremely low probability of occurrence. However, the accumulation of snow loads on building roofs does not fall in the category for two reasons:

a. The maximum accumulated loads can only build up over an extended period of time measured in hours and days, and

b. The plant operational procedures include requirements for the removal of snow from roofs to prevent the buildup of excessive loads.

An appropriate criteria to ensure structured integrity of safety related structures due to snow load conditions at Summer would be to select, as the design basis of the structures, load conditions with return interval representative of the plant life, no more than 50 years, combined with operational procedures to ensure that snow is removed from roofs to prevent the buildup of excessive loads.

Seismic Category 1 buildings at the Virgil C. Summer Nuclear Station site are actually designed for snow loadings of 20 pounds per square foot, representing the weight of 40 inches of snow. This load does include consideration of roof shapes and building configuration.

During periods of inclement weather, the Operations group will monitor the building roofs for accumulation of snow or ice. This will be accomplished by operations logs. Accumulations of snow exceeding 30 inches in depth or of ice exceeding 3 inches in depth will then be removed.

2.3.1.3.4 Hail

The most commonly reported hailstones are 1/2 to 3/4 inch in diameter and cause little or no property damage. During the 13 year period from 1955-1967, hail 3/4 inch in diameter or greater occurred on 14 occasions within the 1° latitude-longitude square containing the site (Data Source 2.3.1-N). This gives a mean annual frequency of 1.1 potentially damaging hailstorms for the region as a whole.

The monthly and seasonal breakdown of hail 3/4 inch or greater in diameter for the state of South Carolina for the 13 year period, 1955-1967, is listed in Table 2.3-5 (Data Source 2.3.1-N.). Damaging hailstorms occur most frequently between March and July, with May having by far the greatest number of occurrences.

2.3.1.3.5 Thunderstorms

The largest number of thunderstorms occur in late spring and summer with a minimum during the winter months. The most severe thunderstorms accompany the squall lines and active cold fronts of spring. There is an average of 50-60 thunderstorms per year in this area of South Carolina. The monthly and seasonal distributions at several cities around the site are displayed in Table 2.3-6 (Data Source 2.3.1-A., Data Source 2.3.1-I., and Data Source 2.3.1-0.).

2.3.1.3.6 Lightning

A typical thunderstorm is believed to produce one to three cloud-to-ground flashes each minute. The number of lightning strikes per square mile has been determined from photographs, records of strikes to power lines, and from electrical lightning counters. The combined results of several studies indicate that the number of flashes to ground per square mile per year is equal to between 0.05 and 0.8 times the number of thunderstorm-days per year (Data Source 2.3.1-P.).

Applying these results to the thunderstorm data for Columbia in Table 2.3-6, the seasonal and annual estimates of lightning strikes are:

Winter	0.1 - 1.6	Summer	1.6 - 25.6
Spring	0.7 - 10.4	Fall	0.3 - 4.8
		Annual	2.7 - 43.2

(Sum of seasonal values do not equal annual due to round-off errors.)

These data indicate that the annual expectancy of lightning strikes for a square mile area in the site vicinity is between 3 and 43.

The expected lightning strikes to the safety-related structures at the site, based on the attractive area of each building, are presented in Table 2.3-6A. The number of thunderstorm days, seasonally and annually, are presented in Table 2.3-6. (Data Source 2.3.1-A., Data Source 2.3.1-I., and Data Source 2.3.1-0.)

2.3.1.3.7 Tornadoes

From 1955 through 1967 a total of 12 tornadoes occurred within the 1°-square containing the site (Data Source 2.3.1-N). This gives a mean annual frequency of 0.92. The probability of a tornado hitting a point in a given year is:

$$P = \left(2.8209\bar{t}/A\right)$$

where A is the area in square miles of a one-degree square centered on the point, the t is the mean annual frequency of tornadoes in the area (Data Source 2.3.1-Q.). The return period is the reciprocal of P. For the nuclear plant site, $\bar{t}$ is 0.92 and A is approximately 3,930 square miles. Therefore, the probability of a tornado hitting the site in any given year is 0.00066 with a return frequency of once every 1,514 years.

Based on the 13 year period of record from 1955-1967, the mean seasonal and annual number of occurrences of tornadoes for the entire state are (Data Source 2.3.1-N.):

Winter	1.1	Summer	4.5
Spring	5.2	Fall	2.2
		Annual	12.9

(Sum of seasonal values do not equal due to round-off errors.)

Storm Data publications[(c)] were examined for the period of 1 January 1950 to 30 November 1976. Tornado data were extracted for a 16 county area encompassing the site. The selection of counties was biased to the west and southwest in order to correlate with normal paths of tornadoes. A listing of the counties included in this study is given in Table 2.3-6B. Table 2.3-6C consists of a chronological listing of all tornadoes in the study area, their path lengths (if known), and corresponding intensity and damage area information.

Areal analysis and classification was based upon the system developed by Fujita [(d)]. The four area classes used are as follows: 1-Micro, less than 0.1 square miles of damage area; 2-Meso, 0.1 to 1.0 square miles of damage; 3-Regular, 1.0 to 10 square miles of damage; 4-Giant, greater than ten square miles of damage. Intensity classes are based on damage descriptions. The categories used in this study are given in Table 2.3-6D. It must be realized that the data are very dependent on public observations and, therefore, both sightings and damage reports are more frequent in the more densely populated areas.

The following additional parameters pertinent to the design and operation of a nuclear plant in this region are listed below (Data Source 2.3.1-R.):

Translational Speed	70 mph
Rotational Speed	290 mph
Maximum Wind Speed	360 mph (sum of translational and rotational speed)
Maximum Pressure Drop	3.0 psi
Rate of Pressure Drop	2.0 psi/sec

c. (2.3.1-N1) [1]Storm Data is a monthly publication by the National Climatic Center in Ashville, North Carolina.

d. (2.3.1-N2) [1]Theodore Fujita, “Estimate of Areal Probability of Tornadoes from Inflationary Reporting of Their Frequencies.” SMRP Research Paper #89, October 1970.

2.3.1.3.8 Hurricanes

Tropical cyclones, including hurricanes, lose strength rapidly as they move inland. Of concern during these storms are potential effects from both wind and excessive rainfall. The precipitation concern has been addressed in Section 2.3.1.3.2. The probability of excessive winds due to tropical storms is discussed below.

The tropical cyclone season for South Carolina extends from June to October; occurrences outside this period are extremely rare. The peak months are August through October. Two separate studies have been reviewed to determine expected frequency of occurrences of tropical storms and to present the wind speeds measured at Columbia during these storms.

From a study[(a)] published by the South Carolina Disaster Preparedness Agency, 1973, at least 169 tropical storms have affected South Carolina for the period of 1686-1972. This number may not represent all storms as currently defined since earlier records may have been lost or incomplete. During a more recent period, 1900-1972, the number of tropical storms affecting South Carolina was 89, representing a frequency of 1.2 per year.

A second study covering the period 1931-1960 reports that a total of 60 tropical storms affected South Carolina during the period (Data Source 2.3.1-S.). This study reports more storms than the previous study due, most likely, to different definitions of when a storm affected the state. Of the 60 tropical storms recorded during this period, only 9 of these are reported as having hurricane intensity winds of 74 mph or greater in South Carolina and are expected only within the coastal regions of the state.

Because the Summer Station is about 25 miles more distant from the coast than Columbia, the winds recorded at the Columbia National Weather Service Station, during tropical storms and hurricanes provide a conservative indication of the winds to be expected at the Summer Station from such storm phenomena. Inspection of the Columbia, South Carolina National Weather Service monthly weather records for the tropical storms and hurricanes reported by Purvis and Landers from 1900 through 1964 shows that the maximum (5 minute average) wind speed achieved at Columbia was 42 mph during this 64 year period of record [(b)]. Six tropical storms affecting South Carolina during 1964 to 1972 were also evaluated [(c),] none of which produced significant wind speeds.

For further confirmation of the lack of hurricane winds at Columbia, the nine reported storms of hurricane intensity affecting South Carolina during the period of 1931 through 1960 were investigated (Data Source 2.3.1-S.).

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a. Purvis, John C., and H. Landers, “South Carolina Hurricanes or a Descriptive Listing of Tropical Cyclones That Have Affected South Carolina.” The South Carolina Disaster Preparedness Agency, 1973.

b. Monthly records of the Columbia, South Carolina, National Weather Service. Reviewed by SCE&G.

c. Purvis, John C., and H. Landers, op. cit.

From investigations of hourly meteorological observations it was found that the highest wind speed recorded at Columbia, South Carolina during these hurricanes was a gust of 58 miles per hour. Based on the above records, it is seen that hurricane force winds associated with tropical storms have never been recorded in the Columbia area.

2.3.1.3.9 Extreme Winds

Estimated extreme winds (fastest mile) for the general area based on the Frechet distribution are (Data Source 2.3.1-T.):

Return Periods (Years)	Fastest Mile (Miles/Hr.)
2	50
10	70
50	81
100	101

Fastest mile winds are sustained winds, normalized to 30 feet above ground and include all meteorological phenomena except tornadoes.

From 1955 through 1967, a total of 22 windstorms with wind speed of 58 miles/ hour or greater occurred within the 1° latitude-longitude square containing the site (Data Source 2.3.1-N.). The diurnal distribution of windstorms (of 58 miles/hour or greater) for the entire state of South Carolina over the 13 year period of record is presented in Table 2.3-7. A definite peak occurs at 1600 hours with a total of 29 occurrences.

2.3.1.3.10 Air Pollution Potential

In January 1972, Holzworth (Data Source 2.3.1-U.) published a study on mixing heights, wind speeds, and potential for urban air pollution throughout the continuous United States. Surface and upper air data from the National Weather Service Station at Charleston, S.C., and Athens, Georgia were included in the analyses made for this study. The data covered the 5 year period from 1960 through 1964.

The mixing height (or depth) as used in the study is defined as the height above the surface through which relatively vigorous vertical mixing occurs. The morning mixing height was calculated as that existing around the morning commuter rush hours. The afternoon mixing height may be considered to coincide approximately with the usual mid-afternoon minimum concentration of slow-reacting urban pollutants.

Wind speeds for both morning and afternoon were computed as arithmetic averages of speeds observed at the surface and aloft within the mixing layer. Mean mixing heights and corresponding wind speeds are presented for the site area in Table 2.3-8. These data show that, on the average,

the greatest air pollution potential (lowest mixing height and lowest wind speed) occurs on autumn mornings.

The persistence of high meteorological potential for air pollution is indicated by parameters called episodes and episode days by Holzworth. An episode occurs if a mixing depth of 2,000 meters or less, combined with a wind speed of 6 meters per second or less, persists without precipitation for 2 or more days (five consecutive computations at morning and afternoon). Holzworth determined the frequency of 2 day and 5 day (11 consecutive computations) episodes at several intensities, where intensity is greater at slower winds and shallower mixing depths. Episode days are the total number of days included in the episodes.

The number of episodes in 5 years at Columbia, S.C., lasting 2 or more days and 5 or more days are presented in Table 2.3-8 (Data Source 2.3.1-U.).

During this period, there were no episodes with a mixing height below 500 meters.

Based on a 30 year period of record (1936-1965), Korshover tabulated the number of time stagnating anticyclones persisted for 4 or more and 7 or more days (Data Source 2.3.1-V.). Occurrences of stagnation were determined primarily on the basis of a surface pressure-gradient analysis.

In the general area of the site, there were 82 stagnation cases which persisted for at least 4 days during the 30 year period. The total number of stagnation days was 395. There were seven stagnation cases which persisted for 7 or more days during this same period. Approximately 40 percent of the stagnation cases which persisted for at least 4 days occurred during the fall.

The above data for the air pollution potential indicates very few stagnations are expected at the site persisting for 4 or more days. Less than 3 percent of the days, based on 30 years of record, are involved with stagnation of this magnitude. This, combined with the relatively low pollution potential (presented in Table 2.3-8), should enable operation without significant effects on the diffusion climatology due to these conditions.

2.3.1.3.11 Ultimate Heat Sink

The meteorological parameters used for the evaluation of the performance of the ultimate heat sink, with respect to maximum evaporation and minimum water cooling, are presented in Section 9.2.5.3. That section describes the basis and procedures used for the selection of the critical meteorological data.

2.3.1.3.12 Extreme Temperatures

General climatic temperature variations, including extremes, are discussed in Section 2.3.1.2. The design basis air temperatures considered in the design of systems and components are as follows:

1. Minimum Air Temperatures
   a. Outdoor air temperature for heating, ventilating and air conditioning (HVAC) system design, 19° F.
   b. Outdoor air temperature for safety related components located outdoors, - 2° F.
2. Maximum Air Temperatures:
   a. Outdoor air temperatures for HVAC system design, 95° F dry bulb, 77° F wet bulb.
   b. Outdoor air temperature for safety related components, 107° F.

The bases for the selection of the design of systems and components are as follows:

1. HVAC design air temperatures are based upon data presented in the American Society of Heating, Refrigerating and Air Conditioning Engineers, ASHRAE Handbook for weather stations in the general vicinity of the site. The temperatures used represent values that are equaled or exceeded less than one percent of the time. Dry bulb and coincident wet bulb temperatures are presented for summer or maximum temperature conditions. Only dry bulb values are presented for winter or minimum temperature conditions.
2. Minimum and maximum air temperatures for safety related components are the extreme minimum and maximum temperatures presented in the Preliminary Safety Analysis Report, Table 2.3-1. Although Table 2.3-49 indicates that these design basis temperatures have been exceeded (the minimum temperature is -4° F versus a design basis of -2° F; maximum temperature is 108° F versus a design basis of 107° F), the differences are very small and are insignificant for engineering design purposes. A significant difference between the design basis temperatures and the observed extreme temperatures is considered to be a temperature variance that could materially affect the operation and integrity of safety related components.
3. Persistent low outside air temperature would have negligible effect upon safety related equipment since heating systems are designed to maintain ambient temperatures substantially above freezing. Safety related equipment susceptible to sustained high temperature is located in areas served by mechanical cooling systems. Mechanical cooling systems are designed with sufficient safety margin to preclude operating problems. Moisture buildup in buildings housing safety related equipment would generally not be a problem for the following reasons:
   a. Relative humidity of outside air supplied to the buildings is usually low in winter.
   b. Cold outside air is heated prior to being supplied to the buildings.
   c. Ventilation systems are designed for frequent air changes.

d. Due to the “flywheel” effect of large masses of concrete in the buildings, average inside ambient temperatures will not vary rapidly.

Main steam isolation valves are located inside the intermediate building which has adequate heating to prevent freezing (see Section 9.4).

The diesel generator building and service water pumphouse have large labyrinth type air intakes that are not susceptible to ice blockage (see Sections 9.4 and 9.5). Also, there are no dampers in the diesel generator building air intakes.

Service water system valves and instrument lines are located indoors in adequately heated spaces (see Section 9.4).

Persistence of extreme outdoor air temperature has been thoroughly considered in the environmental design of safety related components. Most safety related components are located in indoor spaces which have heating and cooling equipment of sufficient capacity to moderate even the most extreme outdoor temperatures. The reactor makeup storage tank, refueling water storage tank, and sodium hydroxide storage tank, safety related piping, instrument lines and level transmitters located outdoors are protected from extremely low temperatures by heat tracing designed for an ambient temperature of -7° F.

Recirculation of condensate between the condensate storage tank and condenser hotwell will maintain the temperature of condensate storage tank contents well above freezing.

These measures ensure that the safety related components will continue to operate without impairment.

Most building spaces housing safety related components that require cooling are equipped with air recirculation systems that will function with a minimum or no outside air during the winter. The remaining spaces, equipped with other than air recirculation systems, are the diesel generator building (air intakes addressed above) and the battery rooms (see Section 9.4).

The battery room cooling system will operate with a minimum amount of outside air. The outside air is introduced through a roof ventilator designed for weather protection.

Freeze protection is provided, as required, for portions of systems and components located outdoors. Such protection is discussed in Sections 6.2.2, 6.3.2, 9.1.3, 9.2.6 and 9.2.7.

2.3.2 Local Meteorology

2.3.2.1 Data Sources

2.3.1-A. *Climatography of the United States No. 82-38, Summary of Hourly Observations - Columbia, South Carolina, 1941-1960*, U.S. Department of Commerce, Weather Bureau, Washington, D.C., 1963.

2.3.2-B.*On-Site Local Meteorological Data,* Virgil C. Summer Nuclear Site, South Carolina Electric & Gas Co., Dames and Moore Job #5182-070, Atlanta, Georgia, 1975.

2.3.2-C.*Local Climatological Data*, *Columbia, South Carolina*; U.S. Department of Commerce, NOAA, Environmental Data Service, 1973.

2.3.2-D.*Local Climatological Data,* Greenville-Spartanburg, South Carolina; U.S. Department of Commerce, NOAA, Environmental Data Service, 1973.

2.3.2-E.*Climatography of the United States No. 86-33, Climatic Summary of the United States - Supplement for 1951-1960, South Carolina.* U.S. Department of Commerce, Weather Bureau, Washington, D.C., 1965.

2.3.2-F.*Local Climatological Data, Columbia, South Carolina- Observations at 3-Hour Internals*. U.S. Department of Commerce, NOAA, Environmental Data Service, 1971-1975.

2.3.2-G.*Climatic Summary of the United States, Section 93, Western South Carolina.* U.S. Department of Agriculture, Weather Bureau, Washington, D.C., 1933.

2.3.2-H.*Wind Distribution by Pasquill Stability Classes, 1965-1969, Columbia, S.C.*, U.S. Department of Commerce, NOAA, Environmental Data Service, 1971.

2.3.2-I.*Turner, D.B., A Diffusion Model For An Urban Area*, Journal of Applied Meteorology, February, 1964.

2.3.2-J.*Wind Distribution by Pasquill Stability Classes, 1975, Columbia, S.C.*, U.S. Department of Commerce, NOAA, Environmental Data Service, 1976.

2.3.2-K.*Persistence of Surface Wind Direction by Wind Speed, 1965-1969, Columbia, S.C.*, U.S. Department of Commerce, NOAA, Environmental Data Service, 1971.

2.3.2-L.Allen, R.G., and Courtney, F.E., *The Meteorological Program at Parr, South Carolina*. CVNA-172, for Carolinas Virginia Nuclear Associates, Inc., by Lockheed Nuclear Products, Lockheed-Georgia Company, April 1963.

2.3.2-M.Appendix D, Meteorological and Diffusion Study, *Preliminary Safety Analysis Report for Atlantic Richfield Reprocessing Center, Atlantic Richfield Company*, date unknown.

2.3.2-N.*Wind Distribution by Pasquill Stability Classes, 1956-1975, Columbia, S.C.*, U.S. Department of Commerce, NOAA, Environmental Data Service.

2.3.2-O.Van der Hoven, *Atmospheric Transport and Diffusion at Coastal Sites*, Nuclear Safety, Vol. 8 No. 5 (Sept. - Oct., 1967).

2.3.2.2 Normal and Extreme Values of Meteorological Parameters

2.3.2.2.1 General

In this section, the normal and extreme statistics of wind, temperature, water vapor, precipitation, fog, and atmospheric stability are described. Long-term data from proximal weather stations (see Figure 2.3-1) have been used to supplement the shorter term onsite data.

2.3.2.2.2 Surface Winds

The percent frequency distribution of surface wind at Columbia, for the years 1951-1960 are shown on an annual and monthly basis in Table 2.3-9 through Table 2.3-21 (Data Source 2.3.2-A.). According to Table 2.3-9, the maximum frequency of surface wind on an annual basis, 10.1 percent, is from the southwest. The annual average wind speed is 7.0 miles per hour, including 14.4 percent calms. Onsite wind frequency distributions at the 10.5 and 61.5 meter levels are included in Table 2.3-6A through 2.3-111B, discussed in Section 2.3.3 (Data Source 2.3.2-B.). Similar to the offsite distribution, the maximum frequency of surface wind on an annual basis, 9.4 percent, is from the southwest, while the annual average wind speed is slightly lower, averaging 6.1 miles per hour (see Table 2.3-98B).

The “fastest mile” wind of record at Columbia and Greenville-Spartanburg for each month is presented in Table 2.3-22 (Data Source 2.3.2-C. and Data Source 2.3.2-D.).

Frequency distributions of wind direction persistence, determined from observations at 3 hourly intervals over a 5 year period (1965-1969) from Columbia, S.C. (Data Source 2.3.2-K.) are presented in Figure 2.3-2 and Figure 2.3-3. Persistence values illustrated are for one sector and for three sectors and within four wind speed classes. Persistence was maintained through calm or missing observations if it was maintained subsequent to them. Because of these criteria, the persistence intervals defined by the consecutive observations tend to have a bias toward long duration. Monthly and annual wind direction persistence, determined from hourly onsite observations at both the 10.5 and the 61.5 meter levels in 1975 (Data Source 2.3.2-B.) are presented in Tables 2.3-23 through 2.3-48. These tabulated distributions, which have not considered stability class, indicate that most cases of persistence are less than 10 hours in duration. The maximum duration, 21 hours, occurred in the NNE sector.

2.3.2.2.3 Temperatures

Monthly and annual values of daily mean temperature, and average and extreme daily maximum and minimum temperatures are shown in Table 2.3-49 based on data records at Parr and Little Mountain (Data Source 2.3.2-E.). Parr is located 3 miles southwest of the site at an elevation of 258’ and Little Mountain is located 9 miles southwest of the site at an elevation of 710’. Based on these data, the annual mean temperature in the site area is approximately 63° F. The monthly averages indicate that July is the hottest month and December the coldest month.

The monthly and annual diurnal distribution of temperature at the site during 1975 are shown in Tables 2.3-50 through 2.3-62 (Data Source 2.3.2-B.). Values of the mean, absolute maximum and minimum, and average daily maximum and minimum temperatures for each month are also presented. The annual mean temperature from Table 2.3-62 is 17.2°C which is equivalent to the long-term mean of 63° F for the site area.

2.3.2.2.4 Water Vapor

Monthly and annual values of relative humidity for four different times of day, based on 7 years of record (1967-1973) at Columbia, are given in Table 2.3-63 (Data Source 2.3.2-C.). Based on these data the annual average relative humidity is estimated to be about 73 percent.

Monthly and annual average dewpoint temperatures and extreme maximum and minimum dewpoint temperatures are shown in Figure 2.3-64. These values are based on 1971-1975 data from Columbia, S.C. (Data Source 2.3.2-F.). The monthly and annual diurnal distribution of dewpoint temperature, and relative humidity at the site during 1975 are shown in Tables 2.3-50 through 2.3-62 (Data Source 2.3.2-B.). Values of the mean, absolute maximum and minimum, and average daily maximum and minimum for both parameters are also presented. The annual average relative humidity from Table 2.3-62 is 69 percent or slightly lower than the estimated long-term average of 73 percent.

2.3.2.2.5 Precipitation

Estimated monthly precipitation normals and mean number of days with precipitation equal to or greater than 0.5 inches at the site are presented in Table 2.3-65, based on data from Little Mountain, Santuck, and Winnsboro (Data Source 2.3.2-E.). These data indicate that the rainfall is fairly well distributed throughout the year with an annual average of 45 inches. Monthly maximum precipitation as recorded at Columbia and Greenville- Spartanburg are also presented in Table 2.3-65, Data Source 2.3.2-C. and Data Source 2.3.2-D.). The maximum value, 16.72 inches, occurred during August 1949 at Columbia.

Monthly and annual average snowfall expected at the site is given in Table 2.3-66, based on data from Little Mountain, Santuck, and Winnsboro (Data Source 2.3.2-E.). These data give an annual expectancy of 2.4 inches of snow in the site area. Monthly maximum snowfall amounts at selected stations in the region are also presented in Table 2.3-66, (Data Source 2.3.2-C., Data Source 2.3.2-D., Data Source 2.3.2-E., and Data Source 2.3.2-G.).

2.3.2.2.6 Fog

Heavy fog is defined as that fog which reduces visibility to one-fourth mile or less. The average number of days with heavy fog at Columbia and Greenville-Spartanburg are listed in Table 2.3-67 (Data Source 2.3.2-C. and Data Source 2.3.2-D.). These data indicate that there is a slight predominance of heavy fog days in winter with a minimum in late spring.

2.3.2.2.7 Atmospheric Stability

Based on data for the period 1965-1969 at Columbia, S.C., the monthly and annual frequency distributions of stability classes are shown in Table 2.3-68, (Data Source 2.3.2-H.). The stability classes are based on the Pasquill classification (Data Source 2.3.2-H-I) and are summarized in Table 2.3-68. These data indicate that the frequency of stable classes reach a peak during the fall season.

Monthly summaries of the diurnal distribution of stability and stability persistence are presented in Tables 2.3-69 through 2.3-81 based on onsite data for the year 1975 (Data Source 2.3.2-B.). Stability is determined from the 10-61 meter delta temperature measurements onsite and the class intervals specified in NRC Regulatory Guide 1.23.

The annual percentages by stability class are as follows:

A	B	C	D	E	F	G
3.6	2.0	5.4	35.0	31.6	12.9	9.5

These frequencies are not directly comparable to the long-term frequencies at Columbia, S.C., since the distributions are based on a different criteria for determining Pasquill stability classes.

The frequencies of seasonal and annual mixing heights are included and discussed in Section 2.3.1.3.

2.3.2.2.8 Representativeness of the Onsite Data

To demonstrate that the onsite data sample is representative of a long-term climatological average, concurrent data from Columbia S.C. (January through December, 1975) were compared to a longer data record for Columbia (January through December, 1956-1975). Comparisons of the wind frequency distributions and the stability class frequency distributions are presented in Table 2.3-82, (Data Source 2.3.2-J. and Data Source 2.3.2-N.).

The wind frequencies are in good agreement with the exception of calm occurrences. Calms occur about 58 percent more frequently during the 1 year period as compared to the 20 year period of record. Telephone discussions with Columbia National Weather Service Station personnel indicate that there has been no change in wind sensor location or type during the period of comparison. The stability distributions are in excellent agreement. The major difference within any stability class was no more than about 2 percent. In conclusion, the comparison implies that the onsite data used in the Section 2.3 analyses are generally representative of longer term climatological conditions. The large percentage of calms during 1975 indicates that the diffusion meteorology for this year is probably below normal; yielding larger values of relative concentration than would occur over a longer period of record.

2.3.2.3 Potential Influence of the Plant and Its' Facilities on Local Meteorology

2.3.2.3.1 Impact of Physical Buildings

Potential modifications of the local meteorology at the site, resulting from the construction and operation of the Virgil C. Summer Nuclear Station, are believed to be small. The containment building and associated facilities are expected to have some small influence on local air flow; specifically, mechanical turbulence is expected downwind of the plant due to building wake effects.

2.3.2.3.2 Impact of Monticello Reservoir

The Monticello Reservoir can influence the micro-climate of the site. An evaluation of the influence is presented herein from two viewpoints: the influence of the reservoir on the diffusion climate and its relation to dispersion of accidental or routine releases of radionuclides, and the influence of the reservoir on other aspects of the local climate. The results of this evaluation have been found to be relatively insensitive to reservoir heat loading; effects of the reservoir are similar under equilibrium and heat loading conditions. The influence of this reservoir on the diffusion climate of the site has been investigated, and the findings are summarized as follows:

1. Table 2.8-83 presents the changes in the diffusion parameters (wind speed, sigma theta, and horizontal diffusion coefficient) measured as air moves offshore over the Chesapeake Bay. These data show the effect of water 2° F warmer than the air to water 7° F or more colder than the air. In general, the wind speeds increase, the wind range decreases, and the horizontal dispersion will tend to decrease as air moves over low-friction water surface, independent of temperature differences. The combination of these changes are generally offsetting, thereby having negligible effects on the diffusion climatology of the site.
2. Temperature differences between the reservoir and the ambient air boundary layer do have a significant influence on the site diffusion climate. Further, such temperature differences will operate to modify the climate for all receptors downwind of the reactor whether the over-water portion of the trajectory occurs before or after it passes the reactor. The effects are adverse when the water is colder than the air and favorable when the water is warmer than the air; these effects were numerically evaluated using the annual set of onsite air temperatures, and the achievement of projectional reservoir surface water temperatures.
3. The reservoir influence on the site diffusion characteristics was found to be ameliorative and significant, as most of the ambient air temperatures were below the water temperatures, especially during stable atmospheric conditions. Specifically, the 5 percentile hourly accident relative concentrations, which was calculated from σ_z values derived from T measurements and σ_y values from wind range measurements, was predicted to drop from 3.3×10^{-4} to 2.15×10^{-4} seconds per cubic meter, as a result of reservoir modifications to the ΔT defined Pasquill Class.
4. It is recognized that neither surface roughness nor surface temperature changes are immediately effective in modifying atmospheric stability conditions. Our initial investigation used results obtained by Craig, Prophet and Van der Hoven and assumed that water warmer or colder than the air required 20 minutes of over water trajectory to significantly modify the air boundary layer stability. The simulation modeling evaluation, therefore, did not permit reservoir air temperature differences to be effected unless a 20 minute or more over water trajectory had occurred. It should also be noted that this study addresses the surface roughness changes on both low level turbulence and on wind speeds and found that although each was significant, considered by itself, the effect of both on dispersion at the reservoir were largely offsetting.
5. The impact of the Monticello Reservoir on the relative concentrations (C/Q) considering the applicability of modifications in the meteorological parameters and temperature differences

between air and water surfaces are presented in Appendix B of the Virgil C. Summer Nuclear Station Environmental Report - Construction Stage.

6. The impact of the reservoir on the vertical plume spread is given in detail in Appendix B of the Virgil C. Summer Nuclear Station Environmental Report - Construction Stage.
7. The C/Q values determined without “reservoir modifications” were developed, as indicated, on the Appendix B, using Parr meteorological tower data; about 3 miles from the Virgil C. Summer Nuclear Station site. Although these meteorological data are different from that used in the FSAR, the effects of the simulation modeling, applied to either data set, must be quite similar.

The evaluation of the potential impact of Monticello Reservoir upon atmospheric conditions other than the diffusion climate was presented in Appendix B of the Virgil C. Summer Nuclear Station Environmental Report - Construction Permit Stage. The results of these evaluations, based on the achievement of the projected reservoir temperatures, remain valid and are summarized below:

1. The existence of Monticello Reservoir will alter the frictional coefficients of the land surface; however, the impact of this upon the wind speed and direction will be limited to the immediate vicinity of the reservoir.
2. No significant changes in the amount of precipitation are anticipated in the area.
3. Monticello Reservoir could warm the air as much as 5° F in periods of calm winds. This warming should only last for several hundred yards from the reservoir’s shore before the warmed air mixes with the ambient air and approaches its original temperature.
4. The possible increase in the frequency of fogs was evaluated for two types of fog, advection and steam fog. For the more significant advection-type fog, the frequency increase was estimated to be greatest during the colder months; 3.6 percent was the greatest increase for those months considered. The summer months were estimated to have no change. Most of the increased fog frequency for advection fog was due to an earlier onset or a later dissipation (i.e., a longer duration) of an observed fog situation. Increases of up to 16 percent were estimated for the less significant, steam-type fog. The nature of this type of fog, however, would limit its effects to the air immediately over Monticello Reservoir and only a short distance inland. From this analysis, it is estimated that there will be an increase in the frequency of fog; however, it will not constitute a significant impact upon the atmospheric environment, except in the immediate vicinity of the reservoir.

2.3.2.4 Topographical Description

A detailed description of the topography within 5 miles of the site is shown in Figure 2.3-4. The radial lines shown in the figure bisect each of the 16 wind direction sectors. The maximum elevation along each of these radials and the corresponding distance from the plant are listed in Figure 2.3-84. For comparison, the site elevation is approximately 435’.

General topographic features for a radius of 50 miles from the plant are shown in Figure 2.3-5.

Variable terrain has a potential to influence local diffusion characteristics. One possible influence, drainage wind conditions in the Broad River Valley, has been investigated using the CVNPA tower data. This valley is oriented north-northwest to south-southeast, and the tower stands on a bluff next to the river, but its base is lower than the nearby valley ridge lines.

When measured over three sectors (67.5°), the 23 foot level winds on the CVNPA tower show a primary directional frequency in those sectors centered on west (Data Source 2.3.2-L.). The secondary frequency maximum is in the three sectors centered on east-northeast. These wind directions cross rather than parallel, the Broad River Valley. Similar wind distributions are observed at Charlotte, Columbia, and Greenville, with bimodel maxima near the west and east-northeast sectors (Data Source 2.3.2-M.). It is evident that these frequency maxima are not local conditions caused by terrain influences.

The three wind sectors centered on north- northwest include all down-valley winds, and the three sectors centered on south- southeast include all up-valley winds. A comparison of the 23 foot level with the 195 foot level tower winds falling within these six sectors shows that the up-valley and down- valley winds are almost twice as frequent at the higher tower elevation than at the lower (Data Source 2.3.2-L.). Drainage winds are, therefore, quite infrequent or non-existent in the portion of the Broad River Valley occupied by the Parr Reservoir.

An examination of the terrain near the plant, see Figure 2.3-4, shows that if valley drainage winds do occur occasionally over the Parr Reservoir, or in the Little River Valley tributary to the east of the plant, the plant and condenser-warmed Monticello Reservoir would be above and to the side of cool air circulation fields. It is concluded that valley drainage winds will not influence the diffusion climate of the Virgil C. Summer Nuclear Station.

2.3.3 Onsite Meteorological Programs

2.3.3.1 Pre-Operational Program

The pre-operational onsite meteorological program was designed to measure the parameters needed to evaluate the dispersive characteristics of the site for both the routine operational and the hypothetical accidental releases of radionuclides to the atmosphere.

The onsite preoperational meteorological monitoring program at Virgil C. Summer Station began with the initial delivery and set up of the system in June, 1973. System refinement for optimum availability, data recovery, and minimization of susceptibility to lightning damage continued through October, 1974. During this period corrective measures were undertaken (including re-wiring and regrounding of the system) along with the development of detailed maintenance procedures in order to obtain the one year of Site Meteorological data required pursuant to Regulatory Guide 1.23 (Sept. 72) and license requirements (CPPR 550-3, 4-2-73) applicable to the Virgil C. Summer Nuclear Station. The date of initiation of the current measurements program was November, 1974. The required year of record for the onsite Meteorological Monitoring program ended on January, 1976 though the equipment has continued to be maintained and calibrated as explained in Section 2.3.3.1.2. In 1976 the instrumentation housing for the large

tower site was relocated due to construction activities and a more accurate dew point measurement system installed.

2.3.3.2 Operational Program

The operational meteorological monitoring program for the Virgil C. Summer Nuclear Station is basically a continuation of selected parameters of the preoperational program. The purposes of the operational program are to provide:

1. Meteorological data useful in the estimation of short term diffusion characteristics to plant personnel on a timely basis.
2. A data base of certain meteorological information for the assessment of plant operational impacts.

The meteorological instrumentation accuracies for primary measurements meet the recommendations stated in Regulatory Guide 1.23, Revision 0 (September 1972). (Reference DC09690-001)

The onsite meteorological tower is located at approximately the same elevation as the Reactor Building and far enough away from plant structures such that their influence on observed conditions is small. Both of these conditions contribute to the representativeness of the observed data for describing atmospheric dispersion conditions from the Reactor Building to the site boundary and the LPZ.

Section 2.3.2.3.2 discusses the influence of the reservoir on the diffusion climate. During winds from north-northwest through northeast, some modifications of atmospheric conditions may occur: first as the trajectory moves over the reservoir surface; and subsequently as it returns to land, passes the tower and the Reactor Building, and onto the site boundary and the LPZ. At all times with these wind directions the tower is likely to record higher wind speeds than prevail through the balance of a trajectory to the site boundary and the LPZ. However, the reduction in wind speed because of the friction of land surfaces will be accompanied by increased turbulence; the wind energy is converted to turbulent energy. The resultant dispersion values are not significantly altered by this conversion process.

On clear nights during light onshore wind conditions, the thermal stability of the air column may increase while the air column moves from the tower toward the site boundary and the LPZ. The evaluation mentioned above shows that with winds more than 3 mph, the over water trajectory is not likely to have modified the thermal stability significantly. In these cases the tower will observe the air column stability near its overland equilibrium value and its readings will be representative of the thermal stability which will prevail throughout the site boundary and LPZ trajectory. With winds in these directions at 3 mph or less, departures from overland stability values will be sensed at night by the tower, and the air column will move toward its more stable overland values during the trajectory from the reservoir shore to the site boundary and the LPZ. Conditions when the tower observed data may be somewhat unrepresentative and more favorable than the actual dispersion conditions downwind of the Reactor Building include the following:

1. When the wind direction is from the north-northwest through northeast, and
2. The wind speed is 3 mph or less, and
3. Overland thermal stabilities have equilibrium values of Pasquill E, F, or G, and
4. During night-time hours.

Onsite meteorological tower data for 1975 indicates the first three of these conditions occur about 5 percent of the time. If daytime conditions were eliminated, this percentage may be somewhat smaller. By comparison, winds from these four directions occur about 22 percent of the time.

In conclusion only about 5 percent or less of the time, tower stability observations may be somewhat nonconservative when used to represent dispersion conditions at the Summer Station. Wind speed may be higher than the representative overland values for about 22 percent of the time, but downwind modification to overland speeds are likely to be offset by compensatory increases in mechanically induced turbulence. The tower location is about as representative of the overall dispersion meteorology as any other available site location.

To account for the possible unconservative meteorological measurements at the tower when the reservoir is in operation, specific operating instructions have been developed. These operating instructions will only affect the night-time hours when the wind speeds are less than 3 mph and for wind directions from the north-northwest through northeast, stabilities of D, E, and F, with associated wind speeds of 3 mph or less, multiply the relative concentration calculated based on observed measurements by:

Time Periods of Concern	Factor
0-8 hours	2.35
> 8 hours	1.72
Annual average	1.60

These factors are applicable to distances from release to the LPZ.

Parameters to be measured on a continuing basis for the operational estimation of diffusion characteristics on site include differential temperature, wind speed, wind direction, and precipitation. Primary meteorological system wind speed, wind direction, and differential (10-61M) temperature observations are stored on the Integrated Plant Computer System (IPCS).

The Integrated Plant Computer System (IPCS) located in the Control Building Computer Room (CB-436) is used to acquire the meteorological data from the Weather Station located at the meteorological tower. This computer will perform data acquisition, averaging, display, and trending (short term). Permanent historical storage of data is performed on the General Data Processing Computers located in the Auxiliary Service Building Computer Room, to which the IPCS is linked.

The IPCS performs engineering unit conversion and calculates 15 minute averages using a minimum of 90 ten second samples.

2.3.3.2.1 Data Output and Recording System

Each parameter required by Technical Specification Section 3.3.3.4 is available for observation in the control room on a dedicated information display screen (TOC Meteorological and Rad Monitoring System) accessed from the VC Summer IPCS. All meteorological data is available for observation, trending, and historical data extraction using network workstations with the VC Summer IPCS. Meteorological data is recorded (stored) on the IPCS.

2.3.3.2.2 Data Processing

Data analysis for both wind distribution and diffusion characteristics of the site requires three basic atmospheric variables. These three variables together with the primary and secondary (backup) measurements for each are as follows:

Horizontal wind speed:	primary measurement - 10 meter wind speed secondary measurement - 61 meter wind speed
Horizontal wind direction:	primary measurement - 10 meter wind direction secondary measurement - 61 meter wind direction
Delta temperature:	primary measurement - 10 to 61 meters secondary measurement - 10 to 40 meters

The secondary measurements are needed only during periods of outage of the primary system. It should be noted that the entire wind measurement (wind speed and direction both) is replaced with secondary sensor data when either the primary wind speed or wind direction is invalid. Since the 1975 data period had almost 100 percent recovery of the primary variables, no substitution of the secondary variables was used in the data analyses.

The final step in the data reduction program is the listing, in sequential order, of the concurrent, hourly averaged values of the meteorological variables observed at the site. A sequential listing of the hourly data for a full year constitutes the annual meteorological record of the site. The annual record provides the input data for all types of meteorological analyses needed to define the site atmospheric dispersive qualities.

2.3.3.2.3 Instrumentation

Wind and temperature sensors are installed on a 62 meter self-supporting tower. A dewpoint sensor is installed separately next to the base of the tower. A precipitation sensor is installed on a 4 foot pedestal near the tower. A barometric sensor is installed in a data processor at the base of the tower. Two instrument elevators (primary and backup), with 8 foot instrument booms are installed on the tower, each providing a full set of wind and temperature measurements. The environmentally capable digital weather system processor is located at the base of the tower. The

tower is located about 1500 feet west of the reactor complex at elevation 438'. The tower mounted sensors are as follows:

1. At 61 meters above ground level, the upper wind sensor and upper temperature sensor for the 10-61 meter differential temperature measurement are mounted on an 8 foot boom attached to the instrument elevator.
2. At 40 meters above ground level, the upper temperature sensor for the 10-40 meter differential temperature measurement is mounted on an 8 foot boom attached to the instrument elevator.
3. At 10 meters above ground level, the lower wind sensor and lower temperature sensor for the 10-61 meter and the 10-40 meter differential temperature measurements are mounted on an 8 foot boom attached to the instrument elevator.

Descriptions and accuracies of the instruments employed on the tower are given in Table 2.3-85F. Design Calculation # DC09690-001.

The major hardware of the totally digital meteorological system consists of the following major components for measurement, data processing, transmission, storage, and display.

a. Wind Speed/Direction sensors (10 and 61 meters) - The sensors are state of the art integrated speed and direction ultrasonic digital sensors.

b. Temperature Elements (10 and 61 meters) - The sensors are high quality RTDs connected directly to the main processor. Each RTD is installed in a powered aspirator.

c. Dewpoint Measurement (1.5 meters) - The dewpoint is calculated by the processor using a dedicated humidity probe with an integrated temperature measurement.

d. Precipitation (1.2 meters) - A tipping bucket type sensor is stationed locally.

e. Barometric Pressure - An integrated pressure sensor is built within the weather station cabinet.

f. Weather Station - The integrated digital weather station is a dedicated digital processor capable of receiving and processing all installed sensor inputs. It then processes all measurements for transmission via an RS-485 communications link to a fiber optic modem. The processor can be accessed locally for direct reading of data and retrieval of stored historical data. The weather station is battery backed for continued monitoring and data storage operation for up to 48 hours given a loss of the normal reliable power source.

g. Data Transmission - The digital data from the meteorological tower is communicated from the weather station to the plant computer via fiber optic cable.

h. Data Storage - The primary storage location is the plant computer data storage files. All measured meteorological data is stored in dedicated files on the plant computer. The data is then processed for user applications and made available on any network workstation.

i. Data Display - The primary (technical specifications required) meteorological information is provided for plant operations access on a dedicated display. This includes two levels of wind speed and direction (61 and 10 meters), ambient temperature (10 meters), two differential temperatures (61-10 and 40-10 meters), and precipitation. All current and historical meteorological data is available for access by any user on a plant network workstation.

2.3.3.2.4 Calibration and Maintenance

To assure data quality and accuracy, the weather instruments are calibrated in accordance with approved plant procedures. Manual field calibrations will be conducted in accordance with Technical Specification requirements. The procedures include the inspection of tower hardware, electronic component calibration when required, and verification of data communications.

Normal service includes various operational checks to reasonably assure 90 percent data recovery. A preventive maintenance schedule has been established for the purpose of performing routine instrument servicing and calibration.

The calibration of the meteorological system is performed when required according to accepted Nuclear Industry practices. The instrumentation used to calibrate the meteorological system (where applicable) has been maintained such that their recordings can be traced to the National Bureau of Standards. These procedures and the test instrument qualities ensure the quality of the meteorological measurements obtained from the Virgil C. Summer Nuclear Station.

In addition to the above calibration of the meteorological system, the following operational procedures are enforced:

- Daily Checks — To identify any abnormal functions (at least two per week)
- Biweekly Calibration Review — To identify need for maintenance or calibration

During the daily checks the verification is made that at least one data channel is functioning.

The calibration review is made every two weeks or any time a channel is suspected to be malfunctioning.

The calibration review is performed by dedicated software analysis of the instrument performance.

These On-line Calibration Verification Programs, periodic calibrations, biweekly calibration checks, and daily checks, ensure that the measurements of the meteorological variables at Virgil C. Summer Nuclear Station are valid. Further verification that the procedures for the maintenance, data collection, and data reduction are in accordance with the recommendations of Regulatory Guide 1.23 (September 1972) is demonstrated by the greater than 90% data recovery for primary variables. System calibration techniques have been upgraded beyond the

requirements of Regulatory Guide 1.23 to reflect the current Nuclear Industry accepted practices of on-line monitoring and performance based directed calibration intervals. These techniques also reflect the modernization of sensors that are digital based with different associated calibration techniques.

2.3.3.3 Wind Roses by Pasquill Stability Classes

Annual monthly wind roses for each Pasquill stability class (and all classes combined) for the 1975 period of record at the Virgil C. Summer Nuclear Station are shown in Tables 2.3-86A through 2.3-111B. The first 13 tables are based on wind distributions at the 10.5 meter level while the last 13 tables are based on wind distributions at the 61.5 meter level. The stability classifications for all tables are based on the 10-61 meter delta temperature measurements.

A discussion of the representativeness of the onsite data is provided in Section 2.3.2.2.8.

2.3.4 Short-Term (Accident) Diffusion Estimates

2.3.4.1 Objective

To evaluate potential health effects for the design basis accidents, hypothetical accidents are postulated to predict upper-limit activity concentrations and doses that might occur in the event of release to the atmosphere. Site-specific meteorological data was used to estimate atmospheric dispersion factors at the site boundary/exclusion area boundary (EAB), low population zone (LPZ) and control room.

According to 10 CFR Part 100, it is necessary to consider the doses for various time periods immediately following the onset of a postulated containment release at the EAB and for the duration of exposure for the LPZ. The relative air concentrations (χ/Qs) are estimated for various time periods ranging from 2 hours to 30 days.

Onsite meteorological data has been used to determine various postulated accident conditions as specified in Regulatory Guide 1.145 (Reference 1). Compared to an elevated release, a ground-level release usually results in higher ground-level concentrations at downwind receptors because of less dilution from shorter traveling distances. Since the ground-level release scenario provides a bounding case, all of the releases were conservatively assumed to occur at the ground level.

2.3.4.2 Diffusion Calculations for EAB and LPZ

The NRC-sponsored PAVAN computer code, as described in NUREG/CR-2858 (Reference 2) has been used to estimate ground-level χ/Qs for potential accidental releases of radioactive material to the atmosphere. The term χ/Q (sec/m^3) is an expression of the relative dispersion occurring between a source (release) location and a receptor location. This relative dispersion can then be used to determine the expected atmospheric concentration at some defined distance away from the source for a known quantity of effluent released. The receptor locations in this analysis are defined as the VC Summer Unit 1 (EAB) and (LPZ) distances of 1 mile (1609 meters) and 3 miles (4828 meters used), respectively.

The PAVAN program implements the guidance provided in Regulatory Guide 1.145. Primarily, the code computes χ/Qs at the EAB and the LPZ boundary for each combination of wind speed and atmospheric stability class for each of 16 downwind direction sectors (i.e., north, north-northeast, northeast, etc.). The χ/Q values calculated for each direction sector are then ranked in descending order, and an associated cumulative frequency distribution is derived based on the frequency distribution of wind speeds and stabilities for the complementary upwind direction sector. The χ/Q value that is equaled or exceeded 0.5% of the total time becomes the maximum sector-dependent χ/Q value.

The χ/Q values calculated above are also ranked independently of wind direction into a cumulative frequency distribution for the entire site. The PAVAN program then selects the χ/Qs that are equaled to or exceeded 5% of the total time.

The larger of the two values (i.e., the maximum sector-dependent 0.5% χ/Q or the overall site 5% χ/Q) is used to represent the χ/Q value for a 0–2 hour time period. To determine χ/Qs for longer time periods, the program calculates an annual average χ/Q value using the procedure described in Regulatory Guide 1.111 (Reference 3). The program then uses logarithmic interpolation between the 0 – 2 hour χ/Qs for each sector and the corresponding annual average χ/Qs to calculate the values for intermediate time periods (i.e., 0 - 8 hours, 8 - 24 hours, 24 - 96 hours, and 96 - 720 hours). As suggested in NUREG/CR-2858, each of the sector-specific 0 – 2 hour χ/Qs provided in the PAVAN output file are examined for “reasonability” by comparing them with the ordered χ/Qs also presented in the model output.

The PAVAN model has been configured to calculate offsite χ/Q values, assuming both wake-credit allowed and wake-credit not allowed.

The PAVAN model input data is presented below:

- Met data: joint frequency distributions of hourly averages of wind speed for each of the 16 standard azimuthal sectors for the 36 month period from 7/1/2003 to 6/30/2006
- Type of release: ground-level (a default height of 10 meters is used)
- Wind sensor height: 10 meters
- Vertical temperature difference: (60 meters – 10 meters)
- Number of wind speed categories: 12 (including calm)
- Building cross sectional area: 1740 meters^2

The minimum distance to the EAB as a function of direction from the plant is shown in Table 2.3-112. The resulting calculated χ/Qs are shown on Table 2.3-117 for the EAB and Table 2.3-118 for the LPZ.

2.3.4.3 Control Room Diffusion Estimates

Conservative estimates of the site specific control room diffusion factors (χ/Qs) for the control room were made using an atmospheric dispersion model and onsite meteorological data. The meteorological data consists of hourly data, covering the period from January 1, 2002, through December 31, 2006. Each record of the hourly data contains a location identifier, Julian day, hour,

lower level (10 m) direction, lower level speed, stability class, upper level (60 m) direction, and upper level speed.

NRC's ARCON96 computer code (Reference 4.) was used to calculate short term accident χ/Q values for the control room. The maximum predicted χ/Q values were determined in accordance with NRC Regulatory Guide 1.194 (Reference 5).

Input to the ARCON96 model other than the site specific meteorological data consisted of the data provided in Table 2.3-121. Table 2.3-122 provides the release and receptor elevations and the horizontal distance between the release and receptor points.

The resultant control room χ/Qs are provided in Table 2.3-123.

2.3.5 Long-Term (Routine) Diffusion Estimates

2.3.5.1 Objective

The 1975 onsite meteorological data record is used to provide realistic estimates of annual average atmospheric dilution factors to a distance of 50 miles (80.5 km) from the plant for use in calibrating the dispersion through air pathways of radionuclides released during routine plant operations.

2.3.5.2 Calculations

The average annual dilution factors which are applicable to routine venting or other routine gaseous effluent releases, have been evaluated from the data record using the technique presented in Regulatory Guide 1.111.

The equation used, for ground level release, is:

$$\chi/Q\,(i, n) = \frac{2.032T}{nD} \sum_{j=1}^{n} \frac{K}{\bar{\mu}(j)\left[\sigma_z^2(j) + \frac{cV^2}{\pi}\right]^{1/2}}$$

(Equation 2.3-3)

Where:

χ/Q (i, n) = average dilution factor (seconds/meter^3) over n hours in sector i at distance D.

σ_z (j) = vertical dispersion coefficient for hour j (dependent on Pasquill class) at distance D.

$\bar{\mu}(j)$= average wind speed (meter/second) for hour j.

D = distance from reactor containment building to various distances up to 80 kilometers.

V = height of highest adjacent building (50.9 meters).

c = building wake shape factor (0.5).

K = wind direction dependent variable:
1 if wind blowing to sector I.
0 if wind not blowing to sector i.

T = terrain correction factor; open terrain, valley flow, or other factor for χ/Q adjustment (distance dependent).

n = number of hourly observations in data period.

The wake factor (cV^2 $\wp$) influence is limited such that the resultant χ/Q may not be reduced greater than a factor of $\sqrt{3}$; i.e., [χ/Q] wake $\geq (1/\sqrt{3})(\chi/Q)$ no wake]. Calm conditions are included in the calculations by setting the wind speed to one half the threshold value of the speed or direction sensor and distributing them among the 16 direction sectors in proportion to the directional frequencies of the 1 and 2 mph speed class intervals in the appropriate stability class.

Equation 2.3-3 is the straight-line trajectory model defined in NRC Regulatory Guide 1.111 assuming a ground level release mode; that is, the release occurs at an elevation less than or equal to the adjacent building height. Since the site is basically in open terrain with gently rolling hills, the T factor in Equation 2.2-3 is the open terrain correction factors given in Regulatory Guide 1.111.

Annual average dilution factors to a distance of 50 miles from the plant are shown in Table 2.3-119. The maximum value at the minimum EZB distance of 1 mile, 5.3×10^{-6} seconds/meter^3 occurs southeast of the plant. There are no higher values beyond the site boundary since for ground level releases, concentrations monotonically decrease from the release point to all locations downwind.

Long term dilution factor estimates for distances out to 5 miles are displayed on Figure 2.3-7. Estimates out of 50 miles are illustrated on Figure 2.3-8.

The annual average dilution factors given in Table 2.3-119 and Figures Figure and Figure 2.3-8 are quite conservative for the reasons given in the last paragraph of Section 2.3.4.2.4. It is expected that over a long period of operation after the Monticello Reservoir is functioning as a heat sink the actual dilution factors will average significantly less than these values at all distances from the site.

The annual average dilution factors are based upon the total meteorological data available for the year of record. These data are representative and applicable to releases of a continuous nature or intermittent (batch) release occurring randomly throughout the year.

Section 11.3 states that planned discharges for gases stored by the GWPS will be made during periods of favorable meteorological conditions. Since the releases will occur throughout the year, the annual average dispersion conditions during these releases will be greater than those depicted by the annual average χ/Q values using all meteorological observations during the year. That is, the resultant annual average χ/Q values using meteorological conditions during releases will be less than the annual average χ/Q values, given in the FSAR, using the full year of data. Therefore, the annual average χ/Q values presented in the FSAR are conservative when used to estimate the diffusion from these intermittent controlled releases.

The actual methodology for determining the conditions for gaseous releases from the GWPS are based on the averaged values of the annual average relative concentrations, normalized by the frequency of occurrence, at the exclusion area boundary (EAB) and the low population zone (LPZ). Using these average relative concentrations for the two distances, the wind speeds associated with each Pasquill stability class that would yield this annual average concentration can be determined. These wind speeds for the two locations were compared and the maximum value used in establishing criteria for releases. These criteria are presented in Table 2.3-120. For a given observation of differential temperature (ΔT) or Pasquill stability class, the wind speeds must be equal to or greater than the value indicated in Table 2.3-120 in order to have conditions permitting the initiation of GWPS gaseous effluent releases.

2.3.6 References

1. U.S. NRC, *Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants*, Regulatory Guide 1.145, Revision 1, November 1982.
2. U.S. NRC, NUREG/CR-2858, PAVAN: *An Atmospheric-Dispersion Program for Evaluating Design-Basis Accidental Releases of Radioactive Materials from Nuclear Power Stations*, PNL-4413, November 1982.
3. U.S. NRC, *Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors*, Regulatory Guide 1.111, Revision 1, July 1977.
4. U.S. NRC, NUREG/CR-6331, *Atmospheric Relative Concentrations in Building Wakes*, PNNL-10521, Revision 1, May 1997.
5. U.S. NRC, *Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants*, Regulatory Guide 1.194, June 2003.

Table 2.3-1
Estimated Point of Rainfall Maxima (Inches) for the Site Area

	Return Period (Years)						
Duration	1	2	5	10	25	50	100
30 Min.	1.10	1.35	1.70	2.00	2.20	2.45	2.80
1 Hr.	1.40	1.65	2.15	2.40	2.80	3.15	3.40
2 Hr.	1.75	2.00	2.60	2.90	3.40	3.80	4.25
3 Hr.	1.80	2.25	2.80	3.35	3.80	4.15	4.65
6 Hr.	2.25	2.65	3.40	3.90	4.60	5.00	5.75
12 Hr.	2.60	3.10	4.00	4.60	5.15	6.00	6.55
24 Hr.	3.00	3.50	4.50	5.40	6.00	6.90	7.60

Data Source 2.3.2-F.

Table 2.3-2
Maximum Recorded Point Rainfall (Inches)
for Selected Stations in the Region

	Greenville (1918-1932; 1938-1961)[1]		Spartanburg (1941-1961)		Columbia (1897-1973)	
Duration	Amount	Date	Amount	Date	Amount	Date
5 Min.	0.80	7/4/56	0.50 [3]	9/22/51	0.74	8/20/11
10 Min.	1.27	7/4/56	0.95[3]	9/22/51	1.05	7/26/22
15 Min.	1.52	7/4/56	1.24[3]	9/22/51	1.39	7/26/22
30 Min.	2.30	7/9/28	1.85[3]	9/22/51	2.40	1965
60 Min.	3.63	9/6/51	3.20	9/22/51	3.90	1965
2 Hr.	4.49	9/6/51	3.53	9/22/51	5.03	1965
3 Hr.	5.29	9/6/51	4.42	10/6/49	5.03	1965
6 Hr.	5.78	9/6/51	6.19	10/6/49	5.03	1965
12 Hr.	6.20	9/6/51	6.67	10/6/49	6.77	8/16/49
24 Hr.	8.20	5/7/10[2]	7.00[4]	8/15/28[5]	7.66[5]	8/16/49

(1) Period of record is in parentheses on this and succeeding tables except as otherwise indicated.
(2) Period of record is 1893 through 1961.
(3) Period of record is 1951 through 1961.
(4) Period of record is 1897 through 1961.
(5) Period of record is 1887 through 1973.
Data Source 2.3.1-A. and Data Source 2.3.1-G.

Table 2.3-3
Extreme Snowfall (Inches)
At Selected Stations in the Region

	Greenvile		Spartanburg (1899-1970)		Columbia (1897-1973)	
Period	Amount	Date	Amount	Date	Amount	Date
24 Hr.	14.4	12/16-17/30	15.0	2/14-15/02	15.7	2/73
Calendar Month	15.3	3/60	15.0	2/02	16.0	2/73
Season	20.4	1935-36	17.5	1901-02	18.2	1972-73

Month	Greenville - Spartanburg Airport (1963-1973)		Columbia (1947-1973)	
	Amount	Year	Amount	Year
January	9.1	1966	2.2	1973
February	6.9	1969	16.0	1973
March	6.6	1971	3.2	1960
April	0.0		0.0	
May	0.0		0.0	
June	0.0		0.0	
July	0.0		0.0	
August	0.0		0.0	
September	0.0		0.0	
October	0.0		0.0	
November	1.9	1968	T (1)	1968(2)
December	11.4	1971	9.1	1958

(1) Trace, an amount too small to measure.
(2) Amount also occurred on earlier date(s).
Data Source 2.3.1-A., Reference 2.3.1-I., and Data Source 2.3.1-J.

Table 2.3-4
Weight of Snow and Ice on Roof of Each Seismic Category Structure

Name of Safety-Related Structure	Estimated Horizontal Roof Area (ft^2)	Weight of Snow And Ice (total lbs)[1]
Auxiliary Building	15,240	198,210
Reactor Building	14,070	182,910
Control Room	12,030	156,390
Intermediate Building	21,500	279,500
Diesel Generating Building	4,730	61,490
Condensate Storage Tank	1,300	16,900
Fuel Handling Building	6,410	83,330
Service Water Intake Structure	3,170	41,210

(1) Based on the 100 year return period ground snow load of 13 lbs/ft^2 without applying snow load coefficients given in Data Source 2.3.1-K.

Table 2.3-5
Average Monthly and Seasonal Number of Occurrences of
Hail 3/4 Inch in Diameter or Greater in South Carolina (1955-1967)

January	0.0	July	0.6
February	0.0	August	0.2
March	0.9	September	0.0
April	1.0	October	0.1
May	1.9	November	0.1
June	0.8	December	0.1
Winter	0.1	Summer	1.5
Spring	3.8	Autumn	0.2

Annual 5.6

Data Source 2.3.1-N.

Table 2.3-6
Mean Number of Thunderstorm Days at Selected Stations in the Region

Period	Columbia (1948-1973)	Greenville (1884-1930)	Greenville-Spartanburg Airport (1963-1973)
January	1	*[2]	*
February	1	1	*
March	3	3	3
April	4	4	3
May	6	8	6
June	9	9	6
July	13	13	12
August	10	9	7
September	4	6	3
October	1	1	1
November	1	1	1
December	*	1	1
Winter	2	2	1
Spring	13	15	12
Summer	32	31	25
Autumn	6	8	5
Annual	54	56	43

(1) Defined as a day on which thunder is heard at the station.
(2) Less than one half.
Data Source 2.3.1-A., Data Source 2.3.1-I., Data Source 2.3.1-0.

Table 2.3-6A
Seasonal/Annual Estimates of Lightning Strikes to
Safety-Related Structures

Safety-Related Structure	Winter (DJF)	Spring (MAM)	Summer (JJA)	Fall (SON)	Annual
Auxiliary Building	0.006	0.024	0.059	0.011	0.099
Reactor Building	0.026	0.115	0.282	0.053	0.476
Control Room	0.007	0.029	0.071	0.013	0.120
Intermediate Building	0.008	0.034	0.085	0.016	0.143
Diesel Generating Building	0.002	0.010	0.025	0.005	0.043
Fuel Handling Building	0.007	0.029	0.072	0.014	0.122
Service Water Intake Building	0.001	0.004	0.011	0.002	0.018

* Reference: Marshall, J. L., Lightning Protection, 1973. (2.3.1-P1)

Table 2.3-6B
South Carolina Counties in the Tornado Study Area

Chester	Union
Fairfield	Laurens
Saluda	Lexington
Richland	Calhoun
Kershaw	Orangeburg
Aiken	Barnwell
Edgefield	McCormick
Greenwood	Newberry

Table 2.3-6C
Chronological Listing of Tornadoes
In Virgil C. Summer Study Area (1950-1976)

Number	Date	Initial County	Length Miles	Area Class[1]	Intensity Class[2]
1	3/3/52	Orangeburg	U*	MI	4
2	5/11/52	Barnwell	45	GI	2
3	6/12/52	Barnwell	U	MI	3
4	6/1/53	Orangeburg	10	MI	3
5	2/28/54	Richland	U	MI	1
6	3/14/54	Orangeburg	U	MI	2
7	3/14/54	Aiken	1	ME	4
8	3/31/54	Kershaw	U	MI	3
9	3/31/54	Lexington	U	MI	1
10	3/31/54	Orangeburg	U	MI	1
11	5/23/54	Chester	U	MI	1
12	3/13/55	Saluda	10	MA	5
13	4/6/55	Chester	1.5	ME	4
14	5/24/55	Aiken	U	ME	2
15	6/11/55	Richland	U	MI	3
16	4/5/57	Lexington	25	ME	4
17	4/5/57	Newberry	3	ME	2
18	4/8/57	Union	14.5	MA	5
19	4/22/58	Greenwood	U	MI	2
20	4/22/58	Calhoun	16	MA	3
21	4/29/59	Orangeburg	< 0.1	MI	1
22	3/30/60	Laurens	10	ME	4
23	3/30/60	Newberry	6	ME	4

*U = unknown by Weather Bureau

Table 2.3-6C (continued)
Chronological Listing of Tornadoes
In Virgil C. Summer Study Area (1950-1976)

Number	Date	Initial County	Length Miles	Area Class[1]	Intensity Class[2]
24	2/24/61	Aiken	0.5	MI	2
25	2/24/61	Aiken	0.5	MI	2
26	2/24/61	Orangeburg	0.5	MI	2
27	11/23/61	Orangeburg	0.1	MI	2
28	1/6/62	McCormick	1	MI	4
29	7/24/62	Orangeburg	1	MI	2
30	4/30/63	Barnwell	1	ME	1
31	8/20/63	Orangeburg	0.3	MI	3
32	9/28/63	Orangeburg	0.5	MI	2
33	9/28/63	Lexington	2	ME	1
34	4/8/64	Barnwell	U	MI	1
35	4/8/64	Orangeburg	< 0.1	MI	1
36	7/3/64	Richland	< 0.1	MI	2
37	8/29/64	Richland	1	MI	3
38	8/29/64	Kershaw	0.1	MI	2
39	3/26/65	Richland	< 0.1	MI	1
40	5/24/65	Orangeburg	< 0.1	MI	1
41	7/23/65	Orangeburg	< 0.1	MI	2
42	8/16/65	Kershaw	3	MI	3
43	8/25/65	Aiken	< 0.1	MI	1
44	4/7/67	Kershaw	2	MA	2
45	5/29/67	Richland	0.5	MI	4
46	11/24/67	Richland	1	MI	4
47	4/18/69	Newberry	4	ME	2
48	4/18/69	Kershaw	0.5	ME	4

Table 2.3-6C (continued)
Chronological Listing of Tornadoes
In Virgil C. Summer Study Area (1950-1976)

Number	Date	Initial County	Length Miles	Area Class[1]	Intensity Class[2]
49	4/18/69	Kershaw	0.8	MI	3
50	4/18/69	Newberry	2	ME	3
51	2/22/71	Calhoun	10	ME	3
52	3/3/71	Orangeburg	6	ME	2
53	5/12/71	Richland	0.3	MI	1
54	1/10/72	McCormick	2	ME	1
55	1/10/72	Lexington	6	ME	4
56	1/13/72	Barnwell	10	ME	5
57	5/24/73	Barnwell	40	ME	1
58	2/22/74	Lexington	1	MI	2
59	3/21/74	McCormick	< 0.1	ME	5
60	3/21/74	Edgefield	1	MI	5
61	3/21/74	Calhoun	0.5	MI	3
62	2/18/75	Barnwell	3	ME	4
63	5/15/75	Chester	0.1	MI	4
64	5/15/75	Newberry	0.1	MI	3
65	9/17/75	Aiken	1	MI	2
66	11/12/75	Edgefield	0.5	MI	5
67	3/16/76	Orangeburg	< 0.1	MI	2
68	5/15/76	Orangeburg	3	MI	2
69	5/15/76	Richland	4	MI	3
70	5/28/76	Barnwell	3.5	MI	3
71	5/28/76	Barnwell	0.5	MI	1

(1) MI = Micro
ME = Meso, MA = Regular, GI = Giant

(2) Intensity Classes are defined in Table 2.3-6D

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Table 2.3-6D
Categories for Damaging Winds

Category	Wind Speed (mph)	Expected Damage
1	50 - 90	Trees uprooted, blown down
2	80 - 120	Partial roof damage, house trailers moved or rolled
3	100 - 150	Total roof removal, minor home damage
4	120 - 180	Small buildings damaged, partial to extensive home damage, weak structures demolished
5	150 - 250	Homes destroyed, substantial buildings damaged
6	225 - 300+	Catastrophic destruction, substantial buildings destroyed

Table 2.3-7
Diurnal Distribution of Wind Storms
For South Carolina (1955-1967)

Time	Number of Occurrences[1]	Time	Number of Occurrences
0100	3	1300	7
0200	2	1400	8
0300	0	1500	18
0400	0	1600	29
0500	2	1700	15
0600	1	1800	10
0700	0	1900	18
0800	3	2000	8
0900	2	2100	6
1000	4	2200	3
1100	2	2300	0
1200	2	2400	1

(1) During the one-hour period ending at the indicated time.
Data Source 2.3.1-N.

Table 2.3-8
Estimated Mixing Heights and Wind Speeds
For the General Site Area

	Morning		Afternoon	
Season	Mixing Height (Meters)	Wind Speed (Meters/Second)	Mixing Height (Meters)	Wind Speed (Meters/Second)
Winter	380	6.0	1000	7.0
Spring	380	5.3	1640	7.4
Summer	400	4.5	1600	5.6
Fall	300	4.5	1350	6.0
Annual	370	5.4	1400	6.6

Episodes of High Air Pollution Potential Lasting
Two or More Days at Columbia, South Carolina

Mixing Height (Meters)	Wind Speed (Meters/Second)		
	≤ 2	≤ 4	≤ 6
≤ 500	0	0	0
≤ 1000	0	2	13
≤ 1500	0	15	60
≤ 2000	0	30	100

Episodes of High Air Pollution Potential Lasting
Five or More Days at Columbia, South Carolina

Mixing Height (Meters)	Wind Speed (Meters/Second)	
	≤ 4	≤ 6
≤ 500	0	0
≤ 1000	0	0
≤ 1500	1	3
≤ 2000	2	13

Data Source 2.3.1-U

Table 2.3-9
Annual Percent Frequency Distribution of Wind
at Columbia, South Carolina (1951-1960)

Wind Direction	Wind Speed (Miles/Hour)							Mean Speed
	0-3	4-7	8-12	13-18	19-24	≥ 25	Total	
N	0.5	2.2	1.6	0.5	+	+	4.9	7.7
NNE	0.6	2.6	2.4	0.9	0.1	+	6.5	8.3
NE	0.9	3.4	2.8	0.9	+	+	8.1	7.7
ENE	0.7	2.6	1.6	0.5	+	+	5.3	7.1
E	0.6	2.1	0.9	0.2	+	+	3.7	6.4
ESE	0.3	1.5	1.1	0.2	+	+	3.1	7.3
SE	0.4	1.6	0.9	0.2	+	+	3.1	7.1
SSE	0.4	1.3	0.8	0.4	0.1	+	3.0	8.0
S	0.6	1.8	1.3	0.7	0.1	+	4.5	8.1
SSW	1.0	2.7	2.3	1.3	0.2	+	7.4	8.6
SW	1.3	3.9	3.0	1.6	0.3	+	10.1	8.4
WSW	0.9	2.7	1.9	1.5	0.4	0.1	7.4	9.1
W	0.9	1.9	1.3	1.0	0.3	+	5.4	8.8
WNW	0.5	1.5	1.3	1.1	0.2	+	4.7	9.5
NW	0.5	1.8	1.3	0.6	0.1	+	4.3	8.4
NNW	0.4	1.6	1.4	0.6	0.1	+	4.1	8.3
Calm	14.4						14.4	
Total	24.8	35.0	25.9	12.1	1.8	0.3	100.0	7.0

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-10
January Percent Frequency Distribution of Wind
at Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.5	1.8	1.1	0.7	.1		4,1	8.9
NNE	0.4	1.6	1.5	0.5	.1	+	4.1	8.2
NE	0.9	2.9	2.2	0.6	+		6.6	7.3
ENE	0.7	1.9	1.2	0.4			4.2	7.0
E	0.6	1.7	0.6	0.1	+		3.0	5.7
ESE	0.4	0.9	0.3	0.1	+		1.6	6.3
SE	0.5	1.0	0.3	+			1.8	5.6
SSE	0.4	0.8	0.4	0.3	0.1	+	2.1	8.5
S	0.7	1.5	0.8	0.6	0.1		3.6	7.7
SSW	1.0	2.0	1.9	1.5	0.3	0.1	6.9	9.3
SW	1.4	4.0	2.7	2.4	0.4	+	10.9	9.0
WSW	1.3	3.3	2.3	2.3	0.5	+	9.7	9.4
W	1.3	2.4	1.7	1.9	0.6	0.1	7.9	9.6
WNW	0.7	1.8	1.6	1.6	0.3	+	6.1	9.7
NW	0.8	2.1	2.0	1.4	0.1		6.4	8.8
NNW	0.5	1.8	2.0	1.1	0.1		5.5	9.1
Calm	15.6						15.6	
Total	27.6	31.2	22.7	15.5	2.8	0.3	100.0	7.2

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-11
February Percent Frequency Distribution of Wind
at Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.5	2.0	1.4	0.4	+		4.4	7.6
NNE	0.6	2.4	2.5	0.8	+		6.3	8.0
NE	0.7	3.0	2.8	1.3	+		7.7	8.3
ENE	0.8	2.7	1.4	0.4			5.3	6.9
E	0.6	2.5	1.0	0.2			4.3	6.4
ESE	0.3	1.1	0.6	0.1			2.1	6.5
SE	0.4	1.0	0.5	0.2		+	2.1	7.0
SSE	0.3	1.1	0.6	0.5	0.2	+	2.7	9.3
S	0.4	1.2	1.0	1.0	0.3	+	3.9	9.9
SSW	0.8	1.8	2.1	1.8	0.4	0.1	7.1	10.1
SW	1.1	2.9	3.0	2.4	0.5	0.1	10.0	9.8
WSW	0.9	2.3	2.0	2.0	0.5	0.2	7.8	10.2
W	1.0	2.1	2.1	1.9	0.4	+	7.5	9.8
WNW	0.6	2.0	2.1	1.8	0.4	0.1	7.0	10.1
NW	0.4	1.8	1.4	0.7	+	0.1	4.4	8.6
NNW	0.4	1.7	1.8	0.6	+		4.5	8.2
12.6								
Total	22.4	31.7	26.3	16.2	2.8	0.7	100.0	7.8

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-12
March Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.4	2.1	1.6	0.6	0.1		4.7	8.1
NNE	0.5	1.9	2.1	0.7	0.1		5.3	8.3
NE	0.5	3.1	2.6	0.8	+		6.9	7.9
ENE	0.3	2.2	2.1	0.8	+		5.5	8.2
E	0.6	1.8	1.2	0.2	+		3.8	6.8
ESE	0.3	1.3	0.7	0.3			2.4	7.4
SE	0.2	1.1	0.8	0.3	+		2.4	8.2
SSE	0.2	1.0	0.6	0.7	0.1	+	2.7	9.7
S	0.2	1.0	1.1	1.0	0.2	+	3.5	10.5
SSW	0.6	1.7	2.3	1.9	0.4	0.1	6.9	10.5
SW	0.9	3.2	2.9	2.5	0.7	0.1	10.3	10.2
WSW	0.7	2.3	2.0	2.3	0.9	0.3	85	11.4
W	0.8	2.4	1.9	2.0	0.7	0.1	7.9	10.6
WNW	0.6	1.8	2.0	2.4	0.8	0.1	7.5	11.4
NW	0.3	1.9	1.7	1.4	0.2	+	5.4	9.7
NNW	0.3	2.1	2.3	1.0	0.1		5.9	9.0
Calm	10.3							
Total	17.5	30.8	27.8	18.8	4.3	0.8	100.0	8.6

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-13
April Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.2	1.2	1.7	0.7	0.1		3.9	9.4
NNE	0.2	1.0	1.3	0.7	0.2	+	3.5	10.3
NE	0.7	1.7	1.8	0.6	0.1		4.8	8.0
ENE	0.5	1.7	1.6	0.6	+		4.4	8.0
E	0.4	2.2	1.0	0.3			4.0	6.8
ESE	0.2	1.6	1.5	0.3			3.7	8.2
SE	0.3	1.7	1.3	0.6	0.1	+	3.9	8.3
SSE	0.3	1.4	1.6	1.3	0.3	0.1	4.9	10.4
S	0.5	1.8	2.6	1.6	0.3		6.9	10.0
SSW	0.6	2.9	3.8	2.9	0.6	0.2	11.1	10.8
SW	0.7	3.5	3.2	2.7	0.7	0.1	10.9	10.2
WSW	0.7	2.2	2.0	2.2	1.0	0.2	8.4	11.4
W	0.6	1.8	1.1	1.4	0.7	0.1	5.6	10.7
WNW	0.2	1.1	1.8	1.6	0.5	0.1	5.3	11.8
NW	0.3	1.4	1.4	0.7	0.1	+	4.0	9.0
NNW	0.2	1.3	1.4	0.9	0.1	+	3.8	9.7
Calm	10.9						10.9	
Total	17.5	28.5	29.1	19.2	4.8	1.0	100.0	8.8

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-14
May Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.3	2.1	1.3	0.3	+		4.2	7.5
NNE	0.2	2.2	1.6	0.7	0.1		4.8	8.4
NE	0.3	2.3	2.3	1.2	0.1		6.2	8.8
ENE	0.5	2.7	2.2	0.5			5.9	7.6
E	0.5	2.1	1.5	0.3			4.4	7.2
ESE	0.3	1.4	1.9	0.3			3.8	7.8
SE	0.5	1.8	1.4	0.3	+		4.0	7.3
SSE	0.5	1.2	1.2	0.4			3.2	7.6
S	0.6	2.1	1.3	0.6	+		4.5	7.5
SSW	1.0	2.8	2.9	1.1	0.1	+	8.1	8.3
SW	1.3	4.5	3.6	1.5	0.2	+	11.1	8.1
WSW	0.9	3.7	2.8	1.5	0.3		9.3	8.5
W	0.7	2.4	1.4	1.0	0.2	0.1	5.8	8.5
WNW	0.3	1.5	1.6	1.3	0.1	+	4.8	9.8
NW	0.4	2.1	1.9	0.8	+		5.2	8.2
NNW	0.2	1.7	1.3	0.3	+		3.6	7.7
Calm	11.2						11.2	
Total	19.9	36.5	30.2	12.1	1.2	0.1	100.0	7.2

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-15
June Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.3	1.9	1.0	0.3	+		3.6	7.3
NNE	0.7	2.1	1.8	0.5	+	+	5.1	7.7
NE	1.0	3.1	2.5	0.7	+		7.3	7.4
ENE	0.9	3.2	1.6	0.3	+		6.1	6.6
E	0.6	2.0	1.1	0.1			3.8	6.6
ESE	0.3	2.1	1.8	0.4			4.6	7.6
SE	0.6	2.4	1.4	0.4	+	+	4.9	7.3
SSE	0.7	2.2	1.2	0.4	+		4.6	7.1
S	1.0	2.4	1.6	0.6	0.1		5.7	7.2
SSW	0.9	4.0	2.5	1.2	0.1	+	8.7	7.7
SW	1.2	4.4	3.9	1.4	0.2		11.0	8.1
WSW	0.5	2.9	2.0	1.5	0.1		7.1	8.7
W	0.6	2.0	1.2	0.6	0.1		4.4	7.7
WNW	0.4	1.7	1.5	0.7	+		4.4	8.3
NW	0.5	2.0	1.3	0.4			4.2	7.2
NNW	0.3	1.3	0.9	0.4			2.8	7.7
Calm	11.8						11.8	
Total	22.2	39.7	27.6	9.9	0.6	+	100.0	6.7

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-16
July Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.4	1.5	0.9	0.2	+		3.0	7.1
NNE	0.5	2.3	1.6	0.4	0.1	+	4.9	7.5
NE	1.1	2.8	2.1	0.6	+		6.8	7.3
ENE	0.7	3.0	1.9	0.7			6.3	7.3
E	0.4	2.4	1.2	0.3			4.4	6.8
ESE	0.4	2.3	1.7	0.4			4.7	7.4
SE	0.3	2.4	1.7	0.3	+		4.8	7.4
SSE	0.5	2.1	1.5	0.4	0.1		4.5	7.4
S	0.8	3.1	2.2	0.8	+		6.8	7.5
SSW	1.1	4.7	3.5	1.2	0.1		10.4	7.7
SW	1.0	6.0	4.4	1.8	0.1		13.2	7.9
WSW	0.6	2.8	2.2	1.0	+		6.6	8.1
W	0.6	1.5	1.1	0.5	+		3.7	7.6
WNW	0.3	1.5	1.0	0.4	0.1		3.4	8.0
NW	0.5	1.5	0.7	0.2	0.1		3.0	6.5
NNW	0.2	0.9	0.6	0.1	+	0.1	2.0	8.1
Calm	11.6						11.6	
Total	21.0	40.7	28.3	9.3	0.6	0.1	100.0	6.7

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-17
August Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.7	2.5	1.6	0.7	0.1	+	5.5	7.8
NNE	0.7	3.0	2.5	0.9	0.1	+	7.3	8.1
NE	1.3	4.0	2.5	0.4	+	+	8.2	6.8
ENE	0.6	2.9	1.5	0.3			5.3	6.9
E	0.5	2.5	1.0	0.1		+	4.1	6.3
ESE	0.3	1.8	1.5	0.3			3.9	7.5
SE	0.7	2.0	1.1	0.2	+		4.1	6.7
SSE	0.6	1.8	0.7	0.2	+		3.3	6.6
S	1.0	2.7	1.6	0.5	+		5.7	6.8
SSW	1.2	4.5	2.8	0.6			9.1	6.9
SW	1.2	6.0	3.5	0.6	+	+	11.4	7.0
WSW	0.6	3.1	1.4	0.4	0.1		5.5	6.9
W	0.6	1.8	0.8	0.2			3.4	6.6
WNW	0.6	1.2	0.7	0.3	+		2.7	6.9
NW	0.6	1.8	0.8	0.3	0.1		3.6	7.0
NNW	0.5	1.3	1.0	0.4	0.1	+	3.3	8.2
Calm	13.6							
Total	25.1	42.9	24.9	6.5	0.5	0.1	100.0	6.1

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-18
September Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.7	3.2	2.0	0.4	0.1	0.1	6.5	7.5
NNE	0.9	5.0	4.4	1.3	0.1	+	11.7	8.0
NE	1.3	5.8	5.1	2.2	0.1	+	14.5	8.2
ENE	1.1	3.8	2.8	0.8		+	8.5	7.4
E	0.8	2.7	1.2	0.3			4.9	6.3
ESE	0.3	1.6	1.5	0.3		+	3.7	7.9
SE	0.4	1.8	1.0	0.2	+		3.5	6.9
SSE	0.4	1.5	0.7	0.2		+	2.8	6.6
S	0.6	2.2	1.1	0.3	+	+	4.2	6.9
SSW	0.9	2.0	1.3	0.5	0.1		4.8	7.3
SW	1.3	2.6	1.5	0.4	+		5.8	6.7
WSW	0.7	1.3	0.9	0.2	+		3.1	6.8
W	0.5	0.7	0.4	0.2			1.9	6.3
WNW	0.4	0.8	0.4	0.1			1.7	6.2
NW	0.4	1.5	0.6	0.3	+		2.8	6.6
NNW	0.6	1.5	0.9	0.6	0.1	+	3.7	8.1
Calm	15.8						15.8	
Total	27.1	37.9	25.9	8.4	0.5	0.2	100.0	6.2

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-19
October Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.6	3.8	3.5	1.1	+		9.0	8.2
NNE	0.6	4.3	4.9	2.3	0.1		12.2	9.0
NE	1.4	4.5	4.5	1.7	0.1		12.1	8.1
ENE	0.9	2.6	1.3	0.3			5.1	6.5
E	0.4	1.7	0.5	0.1			2.7	6.1
ESE	0.3	1.4	0.7				2.4	6.2
SE	0.3	1.3	0.4	0.1			2.0	5.9
SSE	0.4	0.7	0.5	0.1			1.7	6.5
S	0.5	1.1	0.7	0.3			2.5	7.1
SSW	0.9	1.7	0.9	0.2			3.8	6.2
SW	1.7	2.4	1.5	0.6	+		6.2	6.8
WSW	1.1	1.9	1.1	0.7	0.1		5.0	7.6
W	1.1	1.4	0.6	0.5	0.1		3.6	6.7
WNW	0.7	1.3	0.6	0.4	+		3.1	7.3
NW	0.6	1.6	1.1	0.2	+		3.5	6.9
NNW	0.6	2.3	2.1	0.4	+		5.3	7.6
Calm	19.8						19.8	
Total	31.7	33.9	24.9	8.9	0.6	0.0	100.0	6.0

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-20
November Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.7	2.3	1.3	0.4	+		4.7	7.1
NNE	0.7	2.7	2.7	1.0	+		7.2	8.2
NE	0.9	3.7	2.4	0.6			7.6	7.1
ENE	0.6	2.0	1.0	0.2			3.7	6.5
E	0.4	1.2	0.4	+			2.1	5.8
ESE	0.3	1.2	0.4	+			1.9	6.1
SE	0.3	1.1	0.3	0.1			1.8	6.0
SSE	0.4	0.7	0.4	0.3	+		1.9	7.8
S	0.7	1.2	0.7	0.5	0.1	+	3.2	7.9
SSW	1.3	1.7	1.8	1.1	0.1	+	6.1	8.2
SW	2.2	3.2	2.4	1.4	0.1		9.3	7.6
WSW	1.7	2.9	1.6	1.8	0.3	+	8.3	8.4
W	1.4	2.1	1.5	1.1	0.2	+	6.3	8.1
WNW	0.7	1.6	1.3	1.0	0.2	+	4.9	9.0
NW	0.7	2.2	1.4	0.6	+		4.9	7.4
NNW	0.5	2.2	1.9	0.7			5.3	7.9
Calm	20.8						20.8	
Total	34.3	31.9	21.6	10.9	1.2	0.1	100.0	6.1

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-21
December Percent Frequency Distribution of Wind at
Columbia, S.C. (1951-1960)

Wind Direction	Wind Speed (Miles/Hour) 0-3	4-7	8-12	13-18	19-24	≥ 25	Total	Mean Speed
N	0.7	2.4	1.3	0.3	+		4.7	6.9
NNE	0.8	2.4	1.7	0.8	0.2	+	6.0	8.2
NE	1.1	4.0	2.9	0.4			8.4	7.0
ENE	0.8	2.3	0.9	0.1			4.1	6.0
E	0.8	2.0	0.3				3.2	5.1
ESE	0.4	1.2	0.3				1.9	5.4
SE	0.4	1.1	0.4	+	+		1.9	5.8
SSE	0.3	0.8	0.5	0.3			1.9	7.3
S	0.5	1.4	0.9	0.7	0.1		3.6	8.2
SSW	1.1	2.1	1.3	1.0	0.3	0.1	6.0	8.6
SW	1.8	4.0	3.6	1.5	0.2		11.2	8.0
WSW	1.2	3.2	2.2	2.0	0.5	0.1	9.2	9.3
W	1.1	2.3	1.5	1.3	0.3	+	6.5	8.7
WNW	0.8	1.7	1.2	1.0	0.5	+	5.2	9.4
NW	0.5	1.7	1.2	0.6	0.1		4.0	12.6
NNW	0.3	1.6	1.4	0.4	+		3.9	7.7
Calm	18.3						18.3	
Total	31.2	34.3	21.6	10.5	2.2	0.2	100.0	6.6

"+" indicates percentages less than.05 but greater than zero
Data Source 2.3.2-A.

Table 2.3-22
Monthly Variation of Extreme "Fastest Mile" Winds at
Columbia and Greenville-Spartanburg

	Columbia (1954-1973)			Greenville-Spartanburg (1963-1973)		
Month	Speed (mph)	Direction	Year	Speed (mph)	Direction*	Year
January	46	W	1964	44	SW	1967
February	40	SSW	1966+	44	SW	1966
March	60	W	1954	38	W	1963
April	40	W	1961	44	SW	1970
May	48	SW	1958	36	SW	1967
June	40	SW	1957	35	NW	1969
July	40	N	1965	52	NE	1966
August	44	SSE	1961	34	N	1973+
September	38	ESE	1959	31	NE	1964
October	27	SSW	1968+	31	NE	1964+
November	35	N	1967	32	S	1968
December	30	WNW	1954	47	NE	1963
			March			July
Year	60	W	1954	52	NE	1966

*Direction recorded to 8 compass points only.
+ Record also occurred in earlier year (s)
Data Source 2.3.2-C., Data Source 2.3.2-D.

INSERT TABLES 2.3-23 THROUGH 2.3-48 HERE

Table 2.3-23 to Table 2.3-48
Wind Direction Persistence South Carolina Electric and Gas Co.
Virgil C. Summer Nuclear Station
January - December 1975

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TABLE 2.3-23

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: JANUARY, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	6	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	9	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	4	4	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	3	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	3	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	3	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	6	4	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	5	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	6	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	9	1	2	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	10	1	1	0	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	6	3	1	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	5	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	6	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	5	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2.06	3.53	0.	0.	0.	0.	0.	4.80	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	2.41	1.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	2.16	2.51	2.83	3.42	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	3.08	3.05	2.05	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	2.74	0.	2.15	0.	3.74	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	2.42	0.	0.	5.95	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	3.01	2.37	0.	8.59	0.	3.83	3.70	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	3.30	4.87	4.27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	3.69	2.56	5.13	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.15	2.91	3.43	0.	6.09	0.	4.35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	3.64	3.32	4.24	0.	5.49	4.74	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	3.43	3.93	2.39	2.92	7.65	0.	0.	0.	6.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	2.39	3.01	2.85	1.35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	2.35	2.26	1.68	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	2.57	7.87	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	2.15	2.31	4.28	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 1

Data Source: 2.3.2-B

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TABLE 2.3-24

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: FEBRUARY, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
[illegible]	2	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	1	2	2	1	1	1	0	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	2	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	2	1	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	2	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	6	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	4	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
[illegible]	2	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	5	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	1	2	5	1	1	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
[illegible]	12	2	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	6	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
[illegible]	2.08	99.99	3.10	2.34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	1.69	2.98	2.55	2.59	3.76	4.50	0.	4.30	0.	3.98	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	2.15	3.17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	2.47	2.53	0.	2.40	0.	0.	0.	3.51	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	2.07	3.81	3.63	0.	2.54	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	2.88	2.88	0.	0.	0.	0.	3.87	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	2.36	3.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	6.08	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	2.84	0.	4.68	0.	2.88	4.21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	2.50	0.	4.24	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.41	2.32	3.84	5.11	3.77	0.	3.92	0.	0.	0.	0.	0.	4.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.15	4.72	0.	0.	0.	0.	0.	6.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.61	3.10	5.21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	4.27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	2.45	3.59	1.55	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.16	0.	2.34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	2.41	2.70	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 672
TOTAL NO. OF INVALID OBSERVATIONS = 0

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-25

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: MARCH, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	5	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	7	4	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	5	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	4	1	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	6	5	1	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
SSW	8	7	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	6	1	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	0	4	0	0	1	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0
WNW	2	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	6	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	5	2	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	6	2	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	1.93	1.53	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	2.78	2.81	3.58	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	3.22	2.94	3.86	3.43	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	2.80	2.53	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	3.56	3.26	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	4.15	4.84	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	4.50	2.83	0.	0.	0.	3.56	0.	4.75	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	2.67	4.28	4.48	0.	5.74	0.	0.	0.	0.	0.	0.	4.69	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	4.28	3.97	4.57	5.80	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.89	5.79	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	4.92	5.92	7.10	4.54	3.03	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	3.35	4.46	0.	0.	3.09	0.	0.	0.	0.	0.	0.	0.	0.	0.	5.64	7.62	0.	0.	0.	0.	0.	0.	0.	0.
WNW	3.84	4.18	4.74	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	3.88	4.07	4.20	5.77	5.65	3.82	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	3.33	4.28	0.	0.	0.	5.02	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	3.98	2.37	0.	2.94	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 2

BEST COPY AVAILABLE

TABLE 2.3-26

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: APRIL, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	2	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	6	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	8	4	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	11	0	4	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	9	3	0	3	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	4	6	5	0	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	7	2	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	6	2	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	6	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	14	4	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	5	7	0	1	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	4	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2.02	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	1.96	.60	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	2.35	3.87	2.97	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	3.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	3.73	2.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	2.50	0.	2.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	2.75	4.12	5.69	3.79	0.	3.98	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	4.79	0.	2.94	6.09	0.	0.	0.	5.71	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	3.07	4.13	0.	4.64	4.64	5.94	0.	5.91	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.08	3.91	3.49	0.	3.70	5.72	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	2.63	2.44	5.50	0.	0.	0.	3.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	2.60	3.20	9.34	0.	0.	0.	0.	0.	3.17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	2.60	5.95	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	3.88	6.00	4.75	7.77	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	3.70	3.81	0.	4.53	0.	0.	4.44	3.65	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	2.04	2.86	.59	3.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 720
TOTAL NO. OF INVALID OBSERVATIONS = 0

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-27

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: MAY, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	7	3	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	7	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	5	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	4	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	4	3	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	10	2	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	9	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	6	4	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	7	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	5	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	6	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	4	2	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	1.83	2.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	1.87	1.29	3.10	3.12	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	2.44	2.92	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	1.84	2.58	3.17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	2.73	.67	0.	3.85	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	3.03	2.68	2.82	0.	4.48	3.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	3.29	2.48	0.	5.48	0.	0.	0.	4.17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	2.82	1.50	2.79	4.18	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	3.08	2.44	3.69	0.	3.55	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	2.65	2.42	3.26	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	2.06	3.24	3.00	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	2.76	3.02	0.	5.01	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	3.04	3.19	2.94	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	3.13	2.34	0.	0.	1.25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	1.42	0.	2.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	1.90	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 0

BEST COPY AVAILABLE

TABLE 2.3-28

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: JUNE, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	6	3	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	4	7	3	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	6	4	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	3	2	1	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	4	3	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	5	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	6	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	5	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	7	4	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	9	3	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	10	5	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	4	2	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	5	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2.82	3.22	0.	0.	4.92	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	2.87	2.91	3.81	2.31	2.46	5.45	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	3.39	3.35	3.54	3.25	3.00	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	3.04	2.55	3.93	0.	4.72	0.	4.77	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	3.24	3.43	0.	3.06	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	3.96	0.	3.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	3.13	3.35	2.99	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	3.94	2.70	3.29	3.00	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	2.64	3.41	2.53	2.27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	2.40	3.56	3.68	1.79	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	2.44	3.23	1.73	2.71	5.75	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	2.58	2.68	3.17	3.13	0.	4.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	2.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	2.54	1.86	3.06	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	2.62	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	2.94	2.59	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 720
TOTAL NO. OF INVALID OBSERVATIONS = 0

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-29

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: JULY, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	4	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	5	1	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	4	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	8	3	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	15	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	14	1	4	2	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	13	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	9	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	5	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	2	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	1.13	1.08	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	2.78	3.23	1.10	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	1.75	2.29	0.	2.01	0.	0.	0.	0.	3.99	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	2.78	2.17	2.62	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	3.20	2.18	3.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	2.05	3.31	0.	0.	0.	3.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	2.66	2.87	3.84	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	2.50	3.01	2.93	3.98	3.76	1.37	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	2.76	2.86	3.25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	2.72	3.14	3.11	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	2.48	0.	3.27	2.49	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	3.29	1.86	0.	3.03	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	2.49	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	2.28	1.12	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	1.79	0.	.67	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	1.10	1.55	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 3

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-30

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: AUGUST, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	3	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	4	4	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	4	1	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	2	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	5	1	0	3	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	11	8	3	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	20	8	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	8	4	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	6	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	1.07	2.73	0.	0.	1.02	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	1.46	1.95	0.	1.33	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	1.80	2.67	2.32	0.	2.82	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	1.24	1.85	2.25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	1.34	2.44	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	1.49	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	1.72	2.38	2.26	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	1.57	2.10	0.	2.02	.94	1.67	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	2.30	1.98	2.48	2.79	2.24	0.	2.21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	2.20	1.91	2.97	3.34	.77	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	1.94	1.83	2.41	3.31	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	2.01	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	1.27	2.22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	1.42	1.45	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	.69	1.62	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	1.41	.96	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 0

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-31

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: SEPTEMBER, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
	7	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
	5	4	3	1	1	1	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
	7	4	1	3	0	1	0	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2	2	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
	2	1	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	2	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	6	2	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
	2.64	1.34	0.	3.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	3.68	0.	0.	0.	0.
	2.00	2.97	2.51	4.79	5.44	7.06	0.	2.62	0.	0.	0.	0.	3.84	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	1.44	2.31	2.80	3.42	0.	6.38	0.	0.	4.34	0.	0.	0.	0.	3.95	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	.74	0.	0.	2.45	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	2.53	3.74	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	4.48	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	2.49	2.53	0.	0.	3.55	3.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	4.73	3.57	2.44	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	2.67	1.51	0.	6.90	3.56	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	2.54	3.17	0.	4.64	0.	0.	3.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	1.74	0.	0.	0.	5.29	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	2.15	2.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	1.84	.70	2.33	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	2.11	0.	0.	2.06	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	1.84	0.	0.	1.54	0.	2.27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	1.84	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	2.35	2.69	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 720
TOTAL NO. OF INVALID OBSERVATIONS = 3

BEST COPY AVAILABLE

TABLE 2.3-32

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: OCTOBER, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	7	3	1	0	1	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	5	4	2	1	1	0	1	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0
ENE	8	3	2	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	3	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	4	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	5	2	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	3	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	11	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	4	3	1	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	4	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	17	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	7	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	6	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2.55	2.28	5.59	0.	3.37	0.	3.78	0.	0.	7.38	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	3.40	2.65	2.41	2.47	4.45	0.	5.13	0.	0.	2.87	0.	3.25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	2.72	3.30	2.05	0.	0.	0.	3.44	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	1.91	0.	0.	2.80	2.56	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	2.05	3.17	2.69	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	2.22	3.39	0.	6.61	0.	0.	0.	3.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	4.34	0.	0.	0.	0.	4.28	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	4.95	2.91	2.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	2.33	1.37	2.06	3.36	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	1.67	3.53	4.69	3.67	0.	2.85	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	1.74	0.	0.	3.70	0.	0.	3.19	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	2.34	1.01	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	1.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	1.74	3.05	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	2.16	2.16	3.45	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	1.87	2.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 1

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-33

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: NOVEMBER, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	6	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	3	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	5	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	3	3	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	10	0	0	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	2	2	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	6	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	5	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	6	4	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	5	0	1	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	6	1	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	11	1	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	6	1	1	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2.25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	2.23	2.09	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	2.54	2.70	1.41	3.37	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	1.67	1.77	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	2.47	3.13	0.	3.53	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	2.51	3.34	0.	3.61	3.43	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	3.62	0.	0.	3.46	4.10	2.06	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	1.55	4.49	6.91	5.07	0.	0.	0.	0.	3.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	2.46	0.	1.21	5.15	3.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	1.70	1.98	3.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	1.62	2.98	2.46	0.	0.	6.25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	2.27	0.	2.56	0.	3.28	0.	0.	0.	2.52	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	1.33	.54	1.16	0.	0.	3.96	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	1.66	.91	0.	0.	0.	6.60	0.	5.71	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	1.36	.83	3.87	0.	3.08	0.	2.41	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	1.05	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 720
TOTAL NO. OF INVALID OBSERVATIONS = 0

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-34

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: DECEMBER, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	7	0	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	11	5	2	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	3	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	3	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	5	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	2	2	0	2	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
SSW	7	3	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	9	2	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	6	0	1	0	1	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	8	2	0	0	2	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	6	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	3	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2.08	0.	2.61	2.62	3.21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	1.81	2.27	4.12	0.	0.	0.	2.74	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	2.36	2.76	2.92	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	2.61	2.63	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	2.42	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	1.71	3.32	0.	0.	3.09	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	2.71	0.	5.22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	1.94	2.85	0.	3.71	0.	0.	0.	0.	0.	0.	0.	1.63	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	2.76	2.93	2.49	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	2.06	3.24	3.95	3.92	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	2.23	0.	7.93	0.	.69	0.	0.	4.08	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	1.75	1.53	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	1.74	1.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	2.17	1.62	0.	0.	2.37	0.	3.63	1.53	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	3.19	1.39	0.	0.	0.	0.	0.	0.	4.09	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	1.63	0.	5.13	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 0

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-35

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: ANNUAL, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	50	14	5	4	4	0	1	1	0	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0
NE	67	41	15	7	4	3	2	2	0	3	0	1	1	0	0	0	0	0	0	0	0	0	0	0
ENE	68	37	15	9	2	1	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	33	18	6	3	2	0	1	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
ESE	36	17	4	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	61	17	3	4	5	3	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
SSE	76	21	9	4	2	5	1	2	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
S	65	28	16	12	5	5	0	1	1	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0
SSW	97	42	21	10	4	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	95	46	28	9	5	4	2	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
WSW	84	25	13	7	4	3	2	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	85	22	7	4	3	1	0	0	3	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0
WNW	43	13	5	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	91	21	8	3	4	3	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	44	15	5	1	1	1	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
C	47	16	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2.29	2.30	3.40	2.04	3.13	0.	3.76	4.80	0.	7.38	0.	0.	0.	0.	0.	0.	0.	0.	0.	3.68	0.	0.	0.	0.
NE	2.29	2.51	2.94	2.82	4.03	5.67	3.93	3.46	0.	3.56	0.	3.25	3.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	2.36	2.95	2.82	3.40	2.91	6.38	3.44	0.	4.17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	2.45	2.65	2.77	2.55	3.04	0.	4.77	3.51	0.	0.	0.	0.	0.	3.95	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	2.72	2.93	3.04	3.37	3.14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	2.51	3.27	3.01	4.44	3.57	3.46	3.87	3.07	0.	0.	0.	0.	0.	4.48	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	3.20	3.12	3.45	5.33	4.10	3.54	3.70	4.46	0.	0.	0.	0.	6.08	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	3.07	3.32	3.46	3.89	3.37	2.06	0.	5.71	3.30	0.	0.	3.18	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	2.84	2.96	3.09	4.36	3.52	5.94	2.75	5.91	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	2.59	3.04	3.60	3.43	3.62	4.26	4.11	0.	0.	0.	0.	0.	0.	4.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	2.73	3.12	3.64	3.43	3.79	5.25	3.34	5.02	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	2.86	2.94	3.98	3.52	4.67	4.81	0.	0.	4.17	0.	0.	0.	0.	0.	5.64	7.62	0.	0.	0.	0.	0.	0.	0.	0.
WNW	2.40	3.12	3.30	1.95	0.	3.96	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	2.43	2.93	2.91	5.66	2.91	4.23	3.63	3.62	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	2.55	3.42	2.44	4.53	3.08	5.02	3.42	3.85	4.09	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
C	2.27	2.34	3.32	3.26	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 8760
TOTAL NO. OF INVALID OBSERVATIONS = 10

BEST COPY AVAILABLE

TABLE 2.3-36

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: JANUARY, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	6	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	4	4	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	5	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	4	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	2	2	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	3	3	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	3	3	1	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	4	5	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	7	7	2	4	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	10	5	2	2	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	4	5	0	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	3	3	2	2	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	4	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	6.33	0.	0.	0.	0.	0.	0.	6.49	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	4.15	4.08	5.14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	3.17	4.32	5.50	5.02	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	4.09	3.32	2.75	4.38	5.85	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	4.01	4.32	7.22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	2.60	3.64	5.68	0.	0.	0.	0.	6.93	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	3.46	5.43	0.	6.75	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	4.46	4.71	2.86	0.	0.	6.08	0.	6.26	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	5.76	5.89	6.02	6.34	7.06	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	4.14	4.28	4.03	6.17	5.31	0.	9.17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	4.05	6.15	5.87	6.52	7.38	6.04	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	4.71	4.40	0.	0.	10.78	0.	0.	0.	9.47	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	3.34	3.34	4.13	2.62	4.92	0.	0.	4.77	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	3.03	2.54	2.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	5.62	0.	10.09	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	4.25	4.51	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 11

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-37

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: FEBRUARY, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	4	1	2	0	2	2	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	6	4	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	3	1	2	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	7	2	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	2	3	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	3	1	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
S	5	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	6	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	8	4	4	1	1	0	3	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
WSW	10	4	2	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	4	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	5	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	1	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	4	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	5.36	99.99	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	4.00	99.99	4.70	0.	5.49	5.6[illegible]	0.	0.	5.25	5.91	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	3.45	4.51	0.	0.	3.47	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	4.19	4.08	5.19	0.	0.	0.	0.	4.55	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	4.67	6.02	0.	0.	0.	0.	7.3[illegible]	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	5.42	5.47	0.	1.90	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	4.61	3.81	0.	0.	7.14	0.	0.	0.	0.	0.	0.	0.	8.15	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	6.14	0.	5.65	0.	3.35	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	3.56	6.40	6.55	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	5.63	6.46	5.33	8.41	5.45	0.	5.19	0.	0.	0.	0.	0.	7.19	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	5.77	5.36	5.00	7.56	0.	0.	9.14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	6.91	5.68	7.17	3.39	5.14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	4.20	5.51	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	1.77	4.44	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	3.81	0.	4.87	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	4.76	5.59	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 672
TOTAL NO. OF INVALID OBSERVATIONS = 1

Data Source: 2.3.2-B

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TABLE 2.3-38

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: MARCH, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	7	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	5	2	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	4	1	0	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	5	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	4	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	5	2	0	2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	8	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	7	3	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	6	3	2	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	4	2	3	1	1	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
WNW	3	4	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	5	1	0	0	1	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	4	4	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	4	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	4.10	4.54	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	3.95	0.	0.	4.54	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	4.32	4.59	5.55	5.36	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	3.86	6.49	0.	0.	5.19	0.	0.	0.	6.04	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	4.40	4.12	3.96	4.00	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	6.73	7.84	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	5.47	7.03	0.	0.	0.	7.74	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	4.92	6.58	0.	7.19	0.	0.	0.	0.	7.62	6.73	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	3.77	4.16	6.56	6.66	9.36	4.46	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	6.67	7.80	0.	0.	5.53	0.	0.	5.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	7.61	6.01	6.72	0.	0.	5.24	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	6.25	7.02	5.46	5.52	5.21	9.98	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	10.62	0.	0.	0.	0.	0.	0.
WNW	5.37	5.74	6.30	6.02	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	5.90	4.46	0.	0.	6.35	0.	5.91	5.72	6.62	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	3.44	5.02	3.61	0.	0.	4.46	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	3.25	4.19	5.00	3.42	4.15	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 6

Data Source: 2.3.2-B

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TABLE 2.3-39

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: APRIL, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
[illegible]	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	1	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	2	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	4	3	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	10	1	2	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	12	3	0	0	1	0	2	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	6	1	4	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	2	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	2	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	6	5	1	3	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	7	3	1	1	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	1	2	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
[illegible]	0.	5.87	0.	0.	5.75	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	4.79	6.16	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	5.12	4.61	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	4.33	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	2.56	5.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	4.05	2.42	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	3.63	6.50	5.45	5.34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	5.98	2.44	5.28	0.	0.	0.	5.46	6.76	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	3.90	5.97	0.	0.	7.77	0.	7.28	6.43	0.	0.	7.38	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.49	4.59	6.59	6.27	7.09	5.84	0.	11.06	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	6.66	5.45	0.	0.	7.36	0.	0.	5.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	6.47	4.75	0.	0.	0.	0.	4.26	6.11	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.64	11.49	6.26	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	5.59	4.45	6.94	7.40	0.	0.	0.	0.	0.	0.	4.41	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	6.19	5.77	6.54	7.77	0.	0.	0.	5.72	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	1.61	5.83	0.	5.19	4.70	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 720
TOTAL NO. OF INVALID OBSERVATIONS = 10

Data Source: 2.3.2-B

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TABLE 2.3-40

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: MAY, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	9	6	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	5	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	7	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	4	3	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	7	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	6	5	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	5	5	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	5	5	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	6	5	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	9	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	4	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	4	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	4	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2.56	2.44	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	3.67	0.	2.99	3.67	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	4.26	5.68	4.26	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	3.79	3.48	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	4.76	2.24	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	4.91	4.15	5.04	5.57	5.71	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	4.13	4.60	6.15	4.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	3.21	4.88	0.	4.55	0.	6.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	4.07	3.47	6.39	0.	5.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.99	3.28	5.57	4.58	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	3.36	4.08	3.66	4.91	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	3.65	2.69	4.74	7.02	4.46	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	2.88	4.01	4.29	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	2.64	0.	5.06	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	2.71	0.	4.14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	2.44	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 2

Data Source: 2.3.2-B

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TABLE 2.3-41

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: JUNE, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
[illegible]	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	8	6	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	7	6	4	0	2	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	8	5	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	6	2	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	4	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	7	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	1	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	6	3	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	7	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	8	4	2	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	7	2	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	4	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
[illegible]	4.11	3.90	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.89	4.34	0.	0.	0.	5.70	0.	0.	4.77	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	4.32	4.09	6.26	0.	3.35	6.86	0.	3.66	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.97	1.62	4.90	4.91	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	6.08	5.06	0.	5.48	0.	0.	0.	0.	5.46	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	5.11	5.70	2.96	0.	4.28	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	4.94	4.55	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	6.44	5.08	4.65	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	4.68	4.95	4.40	5.19	6.70	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.16	4.47	5.35	6.34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	4.36	4.17	4.08	0.	6.96	3.47	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	4.16	4.40	0.	3.41	4.09	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	4.27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.00	3.25	3.97	3.67	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
[illegible]	3.48	4.43	1.73	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	3.18	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 720
TOTAL NO. OF INVALID OBSERVATIONS = 1

BEST COPY AVAILABLE

TABLE 2.3-42

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: JULY, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	3	1	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	3	2	1	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	7	2	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	2	1	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	6	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	10	1	2	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	14	1	2	2	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	14	1	1	1	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	10	3	2	1	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	9	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	2	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	2.35	2.04	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	1.74	2.74	3.44	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	4.07	2.32	3.70	2.45	2.82	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	3.25	4.96	49.99	0.	49.99	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	3.85	4.35	3.82	3.77	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	3.21	0.	0.	0.	0.	0.	0.	0.	4.60	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	4.14	99.99	4.84	0.	5.97	0.	5.30	4.44	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	3.07	2.99	2.80	4.02	4.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	3.54	3.70	5.36	4.67	5.07	0.	3.76	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.77	1.46	5.70	4.46	5.33	4.67	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	3.52	4.22	3.86	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	4.58	3.62	0.	3.33	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	3.40	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	5.50	1.74	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	2.73	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	1.12	0.	3.34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 7

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-43

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: AUGUST, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	3	3	1	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	7	1	0	1	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	4	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	2	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	4	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	11	5	4	1	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	17	4	6	7	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	5	1	3	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	6	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	4.41	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	3.69	4.88	4.24	3.64	4.13	0.	4.41	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	3.53	4.69	0.	3.44	4.84	0.	3.	4.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	3.20	3.25	3.41	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	2.99	4.51	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	2.97	1.70	5.16	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	3.51	2.46	6.87	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	3.31	3.22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	4.46	4.23	4.76	3.42	0.	0.	0.	0.	0.	5.53	5.12	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.36	4.26	4.82	4.14	4.42	0.	3.07	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	3.45	4.58	3.77	0.	4.28	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	3.43	2.21	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	2.88	2.39	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	2.37	1.43	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	2.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	2.10	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 0

BEST COPY AVAILABLE

TABLE 2.3-44

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: SEPTEMBER, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	4	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
NE	4	4	5	1	1	0	1	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
ENE	8	6	2	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	4	2	0	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
ESE	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	4	4	0	1	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
SSE	2	4	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	6	2	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	5	6	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	5	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	4	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	5	1	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	4	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	6	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	4.70	3.99	5.42	4.28	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	4.69	0.	0.	0.	0.
NE	3.20	3.58	4.93	5.55	7.91	0.	8.21	0.	6.62	0.	0.	4.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	3.75	5.24	3.51	4.77	0.	0.	0.	0.	0.	5.14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	2.75	2.42	0.	0.	5.27	0.	0.	0.	0.	0.	0.	0.	0.	5.26	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	3.62	3.78	6.26	0.	0.	0.	0.	0.	0.	0.	0.	0.	6.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	3.05	2.99	0.	5.91	0.	5.28	0.	0.	0.	0.	0.	0.	0.	0.	5.57	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	5.04	5.27	0.	3.46	5.66	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	4.17	4.85	0.	8.54	4.60	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	3.34	3.95	0.	6.15	0.	0.	0.	4.78	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.39	3.47	2.14	0.	6.82	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	2.81	4.25	2.30	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	3.28	1.18	3.49	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	2.99	1.92	0.	3.28	0.	0.	0.	0.	3.94	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	2.41	3.64	0.	2.66	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	0.	1.34	0.	0.	4.13	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	3.43	4.34	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 726
TOTAL NO. OF INVALID OBSERVATIONS = 5

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-45

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: OCTOBER, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	6	2	1	1	1	1	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
NE	4	3	2	1	2	0	1	0	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0
ENE	4	2	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	3	1	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	5	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	3	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	5	2	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	4	5	1	2	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
WSW	5	3	1	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	7	1	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	6	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	5	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	7	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	7	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	3.85	4.23	7.69	2.66	5.23	5.88	0.	4.54	0.	0.	0.	0.	6.59	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	2.21	4.43	4.89	5.59	4.70	0.	4.51	0.	0.	7.32	0.	0.	0.	0.	0.	5.67	0.	0.	0.	0.	0.	0.	0.	0.
ENE	3.88	5.48	3.65	3.45	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	2.02	2.76	0.	0.	0.	0.	4.41	5.29	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	4.02	5.04	0.	5.78	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	4.12	6.55	5.84	7.68	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	5.92	6.65	0.	0.	4.76	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	3.49	11.88	4.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	3.83	2.23	5.40	5.01	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.87	4.94	5.61	4.64	0.	0.	0.	0.	5.23	0.	0.	0.	0.	0.	0.	0.	0.	5.00	0.	0.	0.	0.	0.	0.
WSW	4.11	4.29	6.41	4.90	0.	0.	5.53	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	4.80	1.48	0.	0.	0.	2.23	0.	5.82	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	0.	3.04	2.59	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	2.95	3.15	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	2.44	0.	3.42	0.	0.	0.	0.	4.14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	3.19	3.55	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 8

BEST COPY AVAILABLE

TABLE 2.3-46

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: NOVEMBER, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	4	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	6	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ENE	2	2	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	4	2	2	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	4	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	4	2	2	1	2	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	4	7	1	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	4	2	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	4	2	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	5	3	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	7	5	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	4	2	2	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	3	5	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	5	4	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	4	3	2	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	4	1	1	0.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNE	3.28	2.89	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	4.53	4.61	0.	1.54	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ENE	2.64	4.25	0.	4.32	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	3.65	4.55	4.55	0.	0.	0.	4.50	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	4.39	4.88	4.04	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	2.90	3.91	6.21	3.66	6.67	0.	0.	6.54	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	4.10	4.52	4.13	7.61	0.	0.	5.64	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	4.32	5.21	0.	0.	6.71	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	4.72	4.28	6.20	3.83	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.88	4.24	5.60	0.	5.17	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	3.18	5.27	1.13	6.42	6.36	8.72	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	5.07	5.94	3.22	0.	0.	0.	5.43	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	2.72	3.21	0.	0.	0.	6.22	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	4.44	4.65	1.52	0.	0.	0.	7.60	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	2.08	4.48	4.70	0.	0.	0.	0.	4.23	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	2.55	2.79	3.88	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 720
TOTAL NO. OF INVALID OBSERVATIONS = 1

Data Source: 2.3.2-B

BEST COPY AVAILABLE

TABLE 2.3-47

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: DECEMBER, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTION PERSISTENCE

CONSECUTIVE HOURS

SECTION	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
	3	1	1	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	2	3	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	5	2	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ESE	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	0	2	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	1	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S	2	2	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSW	5	5	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	7	2	3	2	2	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WSW	4	1	2	1	0	2	0	2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	6	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNW	2	0	2	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NW	4	0	3	1	1	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
NNW	4	2	0	1	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTION	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
	4.05	4.22	2.84	3.97	4.51	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	2.98	2.97	5.20	0.	0.	4.40	0.	0.	5.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	3.74	3.72	4.34	6.27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
	3.37	5.03	4.56	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
ESE	4.49	1.48	4.03	6.11	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	0.	3.98	0.	0.	0.	0.	4.77	2.56	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	3.64	6.40	0.	6.11	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	1.63	5.75	6.23	.70	5.47	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	4.47	4.09	5.97	4.24	5.71	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	3.40	5.09	6.02	5.44	5.33	0.	0.	6.27	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WSW	3.97	4.83	3.12	3.31	0.	5.74	0.	6.58	5.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	2.60	3.58	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
WNW	3.12	0.	2.95	0.	0.	0.	4.11	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NW	4.02	0.	4.64	5.34	5.23	5.26	6.15	0.	0.	0.	2.52	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNW	3.84	7.67	0.	4.57	6.97	1.46	0.	0.	0.	0.	.51	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	2.52	0.	5.73	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 744
TOTAL NO. OF INVALID OBSERVATIONS = 2

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TABLE 2.3-48

WIND DIRECTION PERSISTENCE
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: ANNUAL, 1975

WIND DIRECTION PERSISTENCE - PASQUILL ALL
1 SECTOR PERSISTENCE

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNW	30	17	3	3	4	1	0	2	0	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0
NW	74	28	20	7	6	4	3	0	4	2	0	1	0	0	0	1	0	0	0	0	0	0	0	0
WNW	72	18	14	15	5	1	0	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
W	60	26	11	3	4	0	2	1	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0
WSW	44	18	7	5	1	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SW	43	25	9	5	4	1	1	3	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0
SSW	51	14	10	6	4	1	2	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
S	53	23	10	7	10	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SSE	55	45	18	13	4	1	4	2	0	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0
SE	56	52	29	23	11	3	5	4	1	0	0	0	1	0	0	0	0	1	0	0	0	0	0	0
ESE	52	38	19	8	6	7	2	3	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
E	66	22	8	5	5	3	3	1	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0
ENE	46	21	3	4	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	44	23	10	6	2	1	3	1	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0
NNE	42	14	10	2	2	2	0	4	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
N	34	12	4	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

AVERAGE WIND SPEED (M/SEC)

CONSECUTIVE HOURS

SECTOR	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	>24
NNW	3.67	3.66	5.33	3.70	5.00	5.48	0.	5.52	0.	0.	0.	0.	6.59	0.	0.	0.	0.	0.	0.	4.69	0.	0.	0.	0.
NW	3.59	4.35	4.65	4.02	5.40	5.16	5.71	0.	5.61	6.88	0.	4.64	0.	0.	0.	5.67	0.	0.	0.	0.	0.	0.	0.	0.
WNW	3.88	4.46	4.74	4.64	4.56	6.40	0.	3.96	0.	5.14	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
W	3.65	4.07	4.45	4.73	5.50	0.	4.75	4.55	6.04	0.	0.	0.	0.	5.26	0.	4.64	0.	0.	0.	0.	0.	0.	0.	0.
WSW	4.37	4.60	4.68	5.34	4.10	0.	7.36	0.	5.46	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SW	4.00	4.49	5.15	5.65	5.78	5.28	4.77	5.34	4.60	0.	0.	0.	0.	0.	5.57	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSW	4.56	4.99	5.63	5.76	5.88	7.74	5.50	4.44	0.	0.	0.	0.	8.15	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
S	4.39	5.16	4.72	5.36	5.13	6.08	5.46	6.51	7.82	6.73	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SSE	4.13	4.42	5.83	5.15	6.52	4.96	6.11	5.61	0.	5.53	6.25	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SE	4.07	4.71	5.35	5.33	5.55	5.06	5.55	7.34	5.23	0.	0.	0.	7.19	0.	0.	0.	0.	5.00	0.	0.	0.	0.	0.	0.
ESE	4.62	5.02	5.05	5.03	6.55	6.42	7.33	6.22	5.81	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
E	4.34	4.08	4.79	4.63	5.94	5.49	5.65	5.83	4.47	0.	0.	0.	0.	0.	0.	0.	0.	10.62	0.	0.	0.	0.	0.	0.
ENE	3.60	4.21	4.20	3.64	4.42	5.22	4.11	4.77	3.94	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NE	3.94	3.79	4.25	5.40	5.79	5.26	6.56	5.72	6.62	0.	4.47	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
NNE	3.66	5.14	4.61	6.17	5.55	4.96	0.	4.95	0.	.51	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
N	3.06	4.44	4.75	4.55	4.44	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

TOTAL NO. OF OBSERVATIONS = 8760
TOTAL NO. OF INVALID OBSERVATIONS = 54

Data Source: 2.3.2-B

Table 2.3-49
Values of Mean, Average, and Extreme Daily Maximum, and Average and Extreme Daily Minimum Surface Temperatures (°F) in the Site Area

Month	Mean[1]	Average Daily Maximum[1]	Extreme Maximum[2]	Average Daily Minimum[1]	Extreme Minimum[3]
January	46.5	59.4	84	33.5	5
February	48.1	61.3	82	35.0	-4
March	52.5	65.6	92	39.3	9
April	63.2	77.1	97	49.2	23
May	70.7	84.0	102	57.4	35
June	77.4	90.5	107	64.3	43
July	79.9	92.0	108	67.8	52
August	79.1	91.3	107	67.0	50
September	73.3	85.4	106	61.1	39
October	63.5	76.8	103	50.1	21
November	52.8	66.8	89	38.7	13
December	45.5	58.9	81	32.1	4
Annual	62.7	75.8	108	49.6	-4

(1) Based on 13-14 years of record (1947-1960) at Parr.
(2) Based on 68 years of data (1893-1960) at Little Mountain, but no higher values were recorded at Parr from 1947-1960.
(3) Based on 1893-1960 period of record at Little Mountain and the 1947-1960 period of record at Parr. Value in table is lowest monthly temperature using both records.

Data Source 2.3.2-E.

ADD TABLES 2.3-50 TO 2.3-62

Table 2.3-50 to Table 2.3-62
Statistics and Diurnal Variation of Meteorological Parameters
January 1, 1975 - January 31, 1975

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TABLE 2.3-50

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: JANUARY 1, 1975 TO JANUARY 31, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: JANUARY 1, 1975 TO JANUARY 31, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 9182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00 61.00 DEG C	STAB CLASS 10.00 61.00
1	8.3	2.9	70.8	2.8	216	5.2	228	.7	E
2	7.8	2.8	72.9	2.7	232	5.0	234	.7	E
3	7.[illegible]	2.9	74.8	2.5	212	4.7	233	.7	E
4	7.1	2.9	76.1	2.5	212	4.9	222	.7	E
5	6.9	3.0	77.8	2.4	221	4.8	237	.7	E
6	6.6	3.0	79.3	2.3	226	4.6	228	.9	E
7	6.4	3.0	80.8	2.4	236	4.6	231	.9	E
8	6.2	3.2	81.4	2.4	256	4.5	251	.8	E
9	6.2	3.3	82.0	2.5	246	4.6	246	.7	E
10	6.9	3.8	81.7	2.5	249	4.6	234	.4	E
11	7.8	3.6	77.2	2.8	253	4.8	238	-.2	E
12	9.2	3.4	70.1	3.3	265	4.3	252	-.5	D
13	10.5	3.6	64.2	3.5	270	4.5	253	-.6	D
14	11.7	3.7	60.6	3.6	269	4.5	260	-.6	D
15	12.5	3.9	58.0	3.9	267	4.8	261	-.6	D
16	13.1	4.3	59.1	3.9	244	4.9	241	-.6	D
17	13.4	4.2	56.6	3.9	242	4.9	244	-.5	D
18	13.2	4.2	58.1	3.6	237	4.7	240	-.4	D
19	12.5	4.1	59.4	2.9	215	4.3	224	-.1	E
20	11.7	4.0	62.0	2.6	193	4.6	208	.2	E
21	10.9	4.0	64.4	2.8	204	5.1	212	.6	E
22	10.2	3.7	65.4	2.9	183	5.1	195	.7	E
23	9.6	3.5	66.9	2.9	211	5.1	207	.8	E
24	9.0	3.4	69.4	3.2	217	5.6	227	.8	E
ABSOLUTE MAX	25.8	17.8	98.6	9.1		11.7			
AVG DAILY MAX	14.4	7.7	86.8	5.2		7.5			
MEAN	9.4	3.5	69.3	3.0	236	4.7	234	.3	E
CLIMATIC MEAN	9.6	3.5	68.3	3.0		4.8			
AVG DAILY MIN	4.9	-.6	49.9	.9		2.2			
ABSOLUTE MIN	-3.7	-10.5	16.2	0.0		.4			
STANDARD DEV	5.2	6.6	20.8	1.7		2.3			
VALID OBS	743	707	707	743	743	735	733	742	742
INVALID OBS	1	37	37	1	1	9	11	2	2
TOTAL OBS	744	744	744	744	744	744	744	744	744
DATA RECOVERY	99.9	95.0	95.0	99.9	99.9	98.8	98.5	99.7	99.7

AMENDMENT 97-01
AUGUST 1997

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TABLE 2.3-51

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: FEBRUARY 1, 1975 TO FEBRUARY 28, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: FEBRUARY 1, 1975 TO FEBRUARY 28, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	9.4	3.8	69.1	3.0	165	5.6	187	.7	E
2	8.9	3.8	71.0	2.8	159	5.5	173	.8	F
3	8.4	3.6	72.2	3.0	148	5.5	170	.8	F
4	8.0	3.6	73.8	2.8	154	5.3	166	.7	E
5	7.5	3.4	75.5	2.9	142	5.4	166	.8	F
6	7.0	3.5	78.3	2.9	132	5.3	146	.9	F
7	6.5	3.3	79.4	2.6	207	5.1	180	.9	F
8	6.2	3.0	79.8	2.5	217	5.1	181	.8	F
9	6.0	2.9	80.5	2.4	181	5.0	186	.8	F
10	6.6	3.2	79.0	2.7	189	4.6	201	.5	F
11	8.3	3.3	72.2	3.0	185	4.1	189	-.3	D
12	10.3	3.6	65.6	3.4	228	4.2	214	-.5	D
13	11.3	3.6	62.5	3.4	228	4.2	222	-.6	D
14	12.4	3.5	58.1	3.5	246	4.4	237	-.6	D
15	13.3	3.7	56.0	3.7	250	4.6	243	-.6	D
16	13.7	3.6	54.3	3.5	245	4.4	236	-.5	D
17	14.2	3.7	53.3	3.6	234	4.5	228	-.5	D
18	14.2	3.6	52.9	3.6	230	4.7	226	-.4	D
19	13.	3.9	55.3	3.4	209	4.8	210	-.2	E
20	12.7	3.9	57.9	3.1	206	5.0	206	.0	E
21	11.7	3.9	60.9	3.2	186	5.5	189	.3	E
22	11.0	3.9	63.3	3.2	200	5.6	186	.5	E
23	10.2	3.7	65.4	3.2	186	5.6	184	.7	E
24	9.7	3.8	67.9	3.1	185	5.7	191	.7	E
ABSOLUTE MAX	24.1	18.7	96.8	7.2		9.7			
AVG DAILY MAX	15.3	7.0	84.1	5.0		7.7			
MEAN	10.0	3.6	66.9	3.1	207	5.0	201	.2	E
CLIMATIC MEAN	10.1	3.5	66.3	3.2		5.2			
AVG DAILY MIN	4.9	-.1	48.6	1.4		2.6			
ABSOLUTE MIN	-2.7	-9.1	18.3	0.0		0.0			
STANDARD DEV	4.0	3.8	21.1	1.4		1.9			
VALID OBS	671	671	671	665	665	641	641	672	672
INVALID OBS	1	1	1	7	7	31	31	0	0
TOTAL OBS	672	672	672	672	672	672	672	672	672
DATA RECOVERY	99.9	99.9	99.9	99.0	99.0	95.4	95.4	100.0	100.0

AMENDMENT 97-01
AUGUST 1997

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TABLE 2.3-52

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: MARCH 1, 1975 TO MARCH 31, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: MARCH 1, 1975 TO MARCH MARCH 31, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	10.2	3.4	64.5	3.7	218	6.2	218	.4	E
2	9.6	3.6	67.2	3.4	221	5.8	220	.4	E
3	9.1	3.5	68.6	3.3	233	5.7	232	.5	E
4	8.5	3.2	69.3	3.2	225	5.4	228	.5	E
5	8.1	3.0	70.1	3.0	256	5.1	254	.7	E
6	7.8	2.9	70.8	2.9	241	5.1	260	.7	E
7	7.5	2.8	71.6	3.0	229	5.2	250	.8	F
8	7.1	2.7	73.4	2.9	224	4.9	250	.9	F
9	7.3	2.8	72.9	3.0	239	4.9	261	.5	F
10	8.9	3.4	69.2	3.4	234	4.7	234	-.2	E
11	10.2	2.6	60.6	3.9	260	5.0	244	-.5	D
12	12.0	2.7	55.3	4.3	239	5.3	237	-.6	D
13	13.2	2.6	51.8	4.6	243	5.6	240	-.6	D
14	14.0	2.7	50.6	4.5	249	5.6	247	-.6	D
15	14.8	3.0	49.8	4.6	261	5.7	256	-.6	D
16	15.3	3.1	48.6	4.5	251	5.5	250	-.6	D
17	15.6	3.2	48.6	4.4	244	5.6	242	-.6	D
18	15.5	2.7	47.2	4.4	254	5.5	246	-.5	D
19	14.9	2.7	48.1	4.1	256	5.3	250	-.3	D
20	13.8	3.1	52.9	3.7	270	5.4	253	-.0	E
21	12.7	3.0	55.7	3.8	254	5.9	236	.3	F
22	11.8	2.8	57.5	3.7	203	6.3	204	.5	F
23	11.2	3.1	60.2	3.6	186	6.2	192	.5	E
24	10.6	3.3	62.7	3.5	187	6.1	191	.4	E
ABSOLUTE MAX	24.5	18.3	96.2	11.1		15.2			
AVG DAILY MAX	18.7	7.8	82.3	6.2		8.7			
MEAN	11.2	3.0	60.3	3.7	241	5.5	239	.1	F
CLIMATIC MEAN	11.2	3.3	61.0	4.0		5.8			
AVG DAILY MIN	5.8	-1.0	40.9	1.8		2.9			
ABSOLUTE MIN	-3.2	-12.6	13.5	.5		.4			
STANDARD DEV	6.7	8.3	23.8	1.9		2.4			
VALID OBS	741	738	738	742	742	738	738	742	742
INVALID OBS	3	6	6	2	2	6	6	2	2
TOTAL OBS	744	744	744	744	744	744	744	744	744
DATA RECOVERY	99.6	99.2	99.2	99.7	99.7	99.2	99.2	99.7	99.7

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TABLE 2.3-53

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: APRIL 1, 1975 TO APRIL 30, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: APRIL 1,1975 TO APRIL 30, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR,SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	14.8	6.9	60.8	3.2	193	5.6	204	.9	F
2	14.3	7.0	63.1	3.1	201	5.8	208	1.0	F
3	13.6	7.0	65.8	3.0	205	5.5	214	1.0	F
4	13.0	7.1	68.9	2.8	203	5.3	226	1.0	F
5	12.4	7.1	71.0	2.6	227	5.1	265	1.1	F
6	11.9	7.3	74.5	2.4	245	4.7	275	1.2	F
7	11.6	7.0	74.2	2.4	261	4.8	283	1.1	F
8	11.3	7.0	75.3	2.5	251	4.9	277	1.2	F
9	12.2	7.4	72.8	2.9	259	4.7	263	.4	E
10	14.3	7.0	63.0	3.6	269	4.6	265	-.5	D
11	16.1	6.5	55.7	4.2	276	5.1	271	-.7	D
12	17.6	6.4	51.0	4.1	257	4.8	252	-.7	D
13	18.8	6.5	47.6	4.1	261	4.8	249	-.8	D
14	19.8	6.2	44.3	4.1	256	4.8	249	-.8	D
15	20.6	6.1	42.3	4.2	254	5.1	252	-.7	D
16	21.1	6.0	41.1	4.4	257	5.2	252	-.7	D
17	21.4	5.9	40.3	4.4	258	5.2	249	-.7	D
18	21.4	5.3	40.0	4.3	251	5.2	242	-.6	D
19	21.0	6.0	41.2	4.0	244	5.1	242	-.4	D
20	20.0	6.3	44.4	3.6	227	5.2	230	-.1	E
21	18.7	6.6	48.4	3.4	196	5.5	205	.3	E
22	17.6	6.8	52.1	3.5	190	6.0	197	.7	E
23	16.6	7.0	55.6	3.3	190	5.8	199	.7	E
24	15.9	7.2	58.4	3.3	189	5.9	202	.8	F
ABSOLUTE MAX	30.5	19.2	95.6	10.2		13.6			
AVG DAILY MAX	22.0	10.1	80.3	5.7		8.1			
MEAN	16.5	6.7	56.4	3.5	239	5.2	237	.2	E
CLIMATIC MEAN	16.3	6.7	57.9	3.6		5.4			
AVG DAILY MIN	10.7	3.2	35.5	1.6		2.7			
ABSOLUTE MIN	1.4	-10.6	11.3	0.0		.5			
STANDARD DEV	4.1	8.2	23.2	1.9		2.3			
VALID OBS	719	714	714	720	720	709	708	720	720
INVALID OBS	1	6	6	0	0	11	12	0	0
TOTAL OBS	720	720	720	720	720	720	720	720	720
DATA RECOVERY	99.9	99.2	99.2	100.0	100.0	98.5	98.3	100.0	100.0

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TABLE 2.3-54

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: MAY 1, 1975 TO MAY 31, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: MAY 1,1975 TO MAY 31,1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR,SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-04

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00 61.00 DEG C	STAB CLASS 10.00 61.00
1	20.1	16.6	80.5	2.3	142	4.7	168	1.1	F
2	19.6	16.3	81.5	2.2	124	4.7	165	1.1	F
3	19.1	16.1	83.1	2.1	143	4.5	170	1.0	F
4	18.8	15.9	83.3	2.1	145	4.2	182	1.0	F
5	18.5	15.7	84.4	2.1	137	4.1	172	.9	F
6	18.1	15.7	86.3	1.8	137	3.6	173	.9	F
7	17.8	15.7	87.7	1.7	140	3.4	175	.9	F
8	17.9	16.0	88.2	1.7	97	3.3	104	.6	E
9	19.1	16.5	84.5	2.1	88	3.1	95	-.1	E
10	20.9	16.9	78.3	2.3	317	2.6	24	-.5	D
11	22.6	17.2	72.3	2.4	223	2.7	203	-.7	D
12	24.1	17.3	66.7	2.5	261	2.9	249	-.8	C
13	25.2	17.0	61.7	2.7	278	3.1	208	-.8	C
14	26.0	16.6	57.5	2.8	229	3.0	219	-.8	C
15	26.7	16.3	54.2	2.9	212	3.3	207	-.8	C
16	26.9	16.3	52.7	3.2	213	3.6	211	-.7	D
17	26.9	16.4	53.7	3.5	207	4.0	206	-.7	D
18	26.2	16.4	56.5	3.3	203	3.9	204	-.6	D
19	25.6	16.7	59.6	3.0	172	3.8	181	-.4	D
20	24.3	17.0	65.3	2.8	147	4.2	162	-.2	F
21	23.0	17.0	70.1	2.6	140	4.5	157	.2	E
22	22.1	17.1	73.9	2.5	143	4.7	155	.6	E
23	21.4	17.0	76.8	2.6	155	5.0	163	1.0	F
24	20.7	16.9	79.3	2.5	155	5.0	171	1.1	F
ABSOLUTE MAX	33.7	23.1	97.4	8.2		11.7			
AVG DAILY MAX	27.5	18.6	90.7	4.7		6.9			
MEAN	22.1	16.5	72.5	2.5	168	3.8	178	.1	E
CLIMATIC MEAN	22.5	16.5	70.2	2.8		4.2			
AVG DAILY MIN	17.5	14.5	49.8	.9		1.6			
ABSOLUTE MIN	11.7	6.5	33.1	0.0		0.0			
STANDARD DEV	4.6	3.1	17.7	1.2		1.7			
VALID OBS	742	742	741	744	744	742	742	744	744
INVALID OBS	2	2	3	0	0	2	2	0	0
TOTAL OBS	744	744	744	744	744	744	744	744	744
DATA RECOVERY	99.7	99.7	99.6	100.0	100.0	99.7	99.7	100.0	100.0

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TABLE 2.3-55

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: JUNE 1, 1975 TO JUNE 30, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: JUNE 1,1975 TO JUNE 30, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR,SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	22.4	18.1	77.2	2.5	156	5.1	174	.9	F
2	21.8	18.2	79.9	2.2	161	4.6	179	.9	F
3	21.4	18.0	81.5	2.2	165	4.4	185	.9	F
4	20.9	17.9	82.9	2.1	212	4.3	210	.8	F
5	20.4	17.6	84.2	2.1	246	4.0	272	.9	F
6	20.1	17.4	84.7	2.1	289	4.2	11	.9	F
7	19.8	17.2	85.3	2.0	321	4.0	20	.9	F
8	20.3	17.4	83.8	2.2	356	3.7	31	.4	E
9	21.9	17.8	77.7	2.6	14	3.2	43	-.4	D
10	23.9	18.1	70.0	3.0	28	3.4	50	-.7	D
11	25.7	17.8	62.2	3.3	17	3.6	38	-.8	C
12	27.0	17.3	55.6	3.5	20	4.0	43	-.8	C
13	28.0	16.9	51.6	3.7	46	4.3	102	-.9	C
14	28.8	16.6	48.1	3.6	335	4.1	144	-.9	B
15	29.4	16.6	46.4	3.9	325	4.4	135	-.9	C
16	29.6	16.8	46.6	3.9	273	4.5	231	-.8	C
17	29.6	16.9	46.5	4.1	221	4.6	185	-.8	C
18	29.2	16.9	48.1	4.0	193	4.8	186	-.7	D
19	28.5	17.0	50.7	3.7	142	4.5	146	-.6	D
20	27.5	17.5	55.5	3.2	117	4.3	132	-.4	D
21	26..	17.8	61.2	3.1	121	4.8	142	.0	E
22	24.8	18.0	66.2	2.8	136	4.8	147	.5	E
23	24.0	17.9	69.4	2.5	142	4.7	152	.7	E
24	23.2	18.0	72.7	2.3	172	4.8	179	1.0	F
ABSOLUTE MAX	34.2	23.0	95.0	9.7		12.3			
AVG DAILY MAX	30.1	19.8	88.4	5.1		6.9			
MEAN	24.8	17.5	66.2	2.9	133	4.3	148	.0	E
CLIMATIC MEAN	24.8	17.5	65.8	3.1		4.5			
AVG DAILY MIN	19.6	15.3	43.1	1.1		2.1			
ABSOLUTE MIN	16.3	9.2	31.6	0.0		0.0			
STANDARD DEV	3.9	2.5	18.5	1.3		1.6			
VALID OBS	719	719	719	720	720	719	719	720	720
INVALID OBS	1	1	1	0	0	1	1	0	0
TOTAL OBS	720	720	720	720	720	720	720	720	720
DATA RECOVERY	99.9	99.9	99.9	100.0	100.0	99.9	99.9	100.0	100.0

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TABLE 2.3-56

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: JULY 1, 1975 TO JULY 31, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: JULY 1, 1975 TO JULY 31, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	23.0	20.5	86.4	2.3	181	4.4	189	.5	F
2	22.6	20.4	87.5	2.3	184	4.4	195	.5	E
3	22.3	20.3	88.7	1.9	183	3.8	198	.6	F
4	22.0	20.2	89.4	1.9	176	3.7	191	.5	E
5	21.7	20.1	90.2	1.9	175	3.6	191	.5	E
6	21.4	20.0	91.2	1.6	176	3.4	189	.6	E
7	21.2	20.0	92.4	1.6	176	3.4	194	.6	E
8	21.5	20.2	92.4	1.7	181	3.1	197	.4	E
9	22.4	20.4	88.3	1.9	197	2.7	209	.1	E
10	23.9	19.7	83.5	2.3	192	2.6	199	-.0	F
11	25.2	21.1	77.8	2.4	185	2.6	168	-.0	E
12	26.4	20.9	71.8	2.6	195	3.0	181	-.0	F
13	27.4	20.7	67.6	2.8	202	3.2	193	.1	F
14	27.9	20.7	65.6	2.9	200	3.4	199	-.0	E
15	28.4	20.2	62.1	3.1	199	3.6	205	-.2	E
16	28.4	20.0	61.6	3.4	199	4.0	194	.0	E
17	28.3	19.9	61.7	3.7	199	4.3	207	-.1	F
18	28.0	19.8	62.4	3.6	161	4.2	170	-.1	E
19	27.1	20.0	66.9	3.4	156	4.5	165	-.2	F
20	26.3	20.3	71.2	2.9	169	3.9	172	-.1	E
21	25.6	20.5	75.3	2.4	162	4.0	173	.1	F
22	24.7	20.5	78.6	2.3	153	4.1	170	.4	E
23	24.1	20.6	81.5	2.4	155	4.3	171	.6	F
24	23.5	20.6	84.0	2.4	163	4.7	178	.6	E
ABSOLUTE MAX	33.5	25.2	100.0	9.9		12.5			
AVG DAILY MAX	29.4	21.8	93.7	4.9		6.7			
MEAN	24.7	20.3	78.3	2.5	177	3.7	186	.2	F
CLIMATIC MEAN	25.2	19.8	75.3	2.8		4.2			
AVG DAILY MIN	21.1	17.8	56.8	.8		1.7			
ABSOLUTE MIN	18.4	-17.3	35.3	0.0		0.0			
STANDARD DEV	3.4	2.3	16.3	1.2		1.5			
VALID OBS	736	733	732	741	741	643	643	741	741
INVALID OBS	8	11	12	3	3	101	101	3	3
TOTAL OBS	744	744	744	744	744	744	744	744	744
DATA RECOVERY	98.9	98.5	98.4	99.6	99.6	86.4	86.4	99.6	99.6

AMENDMENT 97-01
AUGUST 1997

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TABLE 2.3-57

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: AUGUST 1, 1975 TO AUGUST 31, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: AUGUST 1, 1975 TO AUGUST 31, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	24.4	21.1	81.8	1.4	183	4.0	192	.8	F
2	23.8	21.1	84.5	1.2	194	3.8	207	.7	F
3	23.5	21.0	85.7	1.3	204	3.8	216	.7	F
4	23.1	20.9	87.2	1.2	207	3.7	221	.7	F
5	22.6	20.8	89.1	1.2	223	3.7	235	.8	F
6	22.4	20.6	89.8	1.1	228	3.7	244	.8	F
7	22.0	20.5	90.8	1.1	238	3.6	242	.8	F
8	22.0	20.5	91.0	1.0	236	3.4	261	.6	E
9	23.1	21.0	87.6	1.4	246	2.7	245	-.1	E
10	25.2	21.5	79.4	1.7	264	2.5	243	-.7	D
11	27.3	21.5	70.4	2.0	276	2.9	242	-.8	C
12	28.8	21.3	63.5	2.2	266	3.1	235	-.8	C
13	29.9	20.6	57.2	2.5	243	3.5	219	-.9	B
14	30.7	20.1	53.0	2.5	239	3.4	215	-.9	B
15	31.3	19.7	49.9	2.6	226	3.4	201	-.9	B
16	31.2	19.4	49.1	2.8	212	3.9	196	-.8	C
17	31.0	19.5	50.2	2.7	202	3.9	191	-.7	D
18	30.8	19.5	51.0	2.5	203	3.5	195	-.6	D
19	30.2	19.8	54.1	2.3	189	3.6	182	-.6	D
20	28.9	20.5	60.8	1.9	164	3.7	171	-.2	E
21	27.5	20.9	67.3	1.8	157	4.1	165	.3	E
22	26.4	21.1	72.4	1.6	162	4.4	171	.6	E
23	25.6	21.0	76.0	1.5	170	4.1	180	.7	E
24	24.9	21.1	79.2	1.4	184	3.9	189	.7	E
ABSOLUTE MAX	36.5	23.9	96.3	5.5		10.3			
AVG DAILY MAX	31.8	22.2	91.8	3.2		5.9			
MEAN	26.5	20.6	71.7	1.8	207	3.6	204	.0	E
CLIMATIC MEAN	26.8	20.5	69.3	1.9		3.8			
AVG DAILY MIN	21.9	18.9	46.7	.7		1.6			
ABSOLUTE MIN	18.9	14.6	31.1	0.0		0.0			
STANDARD DEV	3.9	1.5	17.0	.8		1.5			
VALID OBS	744	744	744	744	744	744	744	744	744
INVALID OBS	0	0	0	0	0	0	0	0	0
TOTAL OBS	744	744	744	744	744	744	744	744	744
DATA RECOVERY	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

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TABLE 2.3-58

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: SEPTEMBER 1, 1975 TO SEPTEMBER 30, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: SEPTEMBER 1, 1975 TO SEPTEMBER 30, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	20.9	18.2	84.7	2.3	136	4.6	133	.5	F
2	20.6	18.0	85.4	2.2	96	4.3	131	.5	E
3	20.2	17.9	86.3	2.2	74	4.1	100	.3	E
4	19.9	17.5	86.5	2.3	56	4.3	67	.3	E
5	19.5	17.3	86.9	2.3	54	4.2	56	.3	E
6	19.3	17.2	87.4	2.2	51	3.9	35	.3	E
7	19.1	17.1	87.8	2.2	50	3.8	23	.3	E
8	19.0	17.0	88.1	2.3	58	4.0	49	.2	F
9	19.3	17.1	86.8	2.4	45	3.6	45	-.2	E
10	20.5	17.4	82.5	2.9	51	3.7	56	-.5	D
11	22.0	17.7	76.7	3.2	61	3.8	67	-.6	D
12	23.5	17.9	71.6	3.0	74	3.6	79	-.8	D
13	24.8	18.1	67.2	3.1	67	3.7	73	-.8	C
14	25.6	17.9	63.3	3.3	81	3.8	92	-.8	C
15	26.3	17.9	60.7	3.3	98	4.0	117	-.8	C
16	26.6	17.7	59.2	3.4	81	4.1	118	-.7	D
17	26.7	17.6	58.7	3.2	101	4.0	120	-.7	D
18	26.1	17.6	60.5	3.2	86	4.0	107	-.6	D
19	25.1	17.8	65.1	2.8	88	4.0	97	-.3	D
20	23.-	18.1	70.5	2.7	85	4.3	80	-.0	E
21	23.0	18.2	75.0	2.7	111	4.8	108	.3	E
22	22.2	18.2	78.4	2.5	121	4.9	115	.7	E
23	21.7	18.1	80.5	2.3	111	4.8	112	.7	E
24	21.1	18.1	83.0	2.4	121	4.8	117	.6	E
ABSOLUTE MAX	35.7	24.1	98.1	10.1		12.4			
AVG DAILY MAX	27.1	19.9	91.4	4.6		6.8			
MEAN	22.4	17.7	76.4	2.7	81	4.1	92	-.1	E
CLIMATIC MEAN	22.8	17.9	74.1	2.9		4.5			
AVG DAILY MIN	18.4	15.9	56.8	1.2		2.2			
ABSOLUTE MIN	10.4	5.1	34.4	0.0		0.0			
STANDARD DEV	4.7	4.3	15.6	1.5		1.8			
VALID OBS	719	719	719	717	717	717	714	715	715
INVALID OBS	1	1	1	3	3	3	6	5	5
TOTAL OBS	720	720	720	720	720	720	720	720	720
DATA RECOVERY	99.9	99.9	99.9	99.6	99.6	99.6	99.2	99.3	99.3

AMENDMENT 97-01
AUGUST 1997

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TABLE 2.3-59

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: OCTOBER 1, 1975 TO OCTOBER 31, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: OCTOBER 1, 1975 TO OCTOBER 31, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5162-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	16.2	12.9	81.0	2.1	38	4.7	113	2.0	F
2	15.8	12.7	82.2	2.2	36	4.5	124	1.7	F
3	15.4	12.5	83.0	2.1	43	4.4	120	1.6	F
4	14.9	12.4	84.9	2.1	6	4.3	49	1.5	F
5	14.4	12.1	86.4	2.0	349	4.2	9	1.5	F
6	14.0	11.9	87.4	2.0	1	4.3	358	1.4	F
7	13.8	11.7	87.2	2.0	351	4.3	356	1.4	F
8	13.6	11.5	87.3	2.1	10	4.3	10	1.3	F
9	14.0	11.8	86.6	2.2	18	4.0	24	.9	F
10	15.6	12.2	80.8	2.7	40	3.7	40	.0	F
11	17.7	12.9	74.2	3.1	42	3.7	45	-.4	D
12	19.7	13.0	66.7	3.1	45	3.6	49	-.6	D
13	21.4	12.8	59.5	3.2	44	3.5	50	-.7	D
14	22.7	12.6	53.5	3.4	3	3.7	18	-.8	D
15	23.4	12.4	50.6	3.5	71	4.0	142	-.7	D
16	23.8	12.4	49.7	3.5	31	4.0	294	-.7	D
17	23.8	12.3	49.7	3.5	72	4.0	74	-.6	D
18	23.1	12.4	52.0	3.0	91	3.8	99	-.4	D
19	21.9	12.9	57.7	2.6	113	4.1	121	.0	E
20	20.6	13.0	62.3	2.5	100	4.6	79	.6	E
21	19.3	13.0	67.8	2.5	100	4.9	91	1.3	F
22	18.1	12.9	72.0	2.4	120	5.0	122	1.8	F
23	17.2	12.7	75.3	2.2	66	4.8	115	1.9	F
24	16.4	12.5	77.9	2.1	77	4.8	120	2.0	F
ABSOLUTE MAX	29.8	22.0	99.3	10.4		13.1			
AVG DAILY MAX	24.0	15.1	90.0	4.4		6.7			
MEAN	18.2	12.5	71.7	2.6	44	4.2	56	.7	E
CLIMATIC MEAN	14.5	12.5	68.9	2.8		4.4			
AVG DAILY MIN	13.0	9.9	47.9	1.1		2.1			
ABSOLUTE MIN	3.3	-4.8	19.8	.4		0.0			
STANDARD DEV	5.3	5.9	18.6	1.5		2.1			
VALID OBS	738	732	732	743	743	737	736	744	744
INVALID OBS	6	12	12	1	1	7	8	0	0
TOTAL OBS	744	744	744	744	744	744	744	744	744
DATA RECOVERY	99.2	98.4	98.4	99.9	99.9	99.1	98.9	100.0	100.0

AMENDMENT 97-01
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TABLE 2.3-60

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: NOVEMBER 1, 1975 TO NOVEMBER 30, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: NOVEMBER 1,1975 TO NOVEMBER 30, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR,SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

	DRY BULB	DEW POINT	REL HUMID	WIND SPEED	WIND DIR	WIND SPEED	WIND DIR	DELTA TEMP 10.00	STAB CLASS 10.00
	10.00	10.00	10.00	10.50	10.50	61.50	61.50	61.00	61.00
HOUR	DEG C	DEG C	PCT	M/SEC	DEG	M/SEC	DEG	DEG C	
1	10.9	6.6	75.0	2.1	189	4.7	184	2.3	G
2	10.3	6.6	77.7	1.9	187	4.4	191	2.4	G
3	9.8	6.5	80.0	1.9	196	4.3	195	2.4	G
4	9.5	6.5	81.4	1.9	189	4.2	195	2.4	G
5	9.0	6.2	81.9	2.0	208	4.0	208	2.4	G
6	8.9	6.0	82.0	1.9	208	4.0	235	2.2	G
7	8.4	5.9	83.9	1.7	234	3.9	271	2.2	G
8	8.1	5.9	85.6	1.7	206	3.9	305	2.2	G
9	9.2	6.2	87.2	2.0	218	4.1	352	2.2	G
10	9.2	6.8	84.5	2.2	292	3.6	328	1.3	F
11	11.5	7.4	76.1	2.4	296	3.2	304	.1	F
12	14.1	7.6	66.0	2.6	280	3.1	254	-.5	D
13	16.0	7.5	58.2	2.8	261	3.2	253	-.7	D
14	17.0	7.3	54.9	2.9	260	3.4	254	-.7	D
15	17.9	7.0	50.9	3.2	239	3.7	238	-.7	D
16	18.3	6.9	49.3	3.3	247	3.8	240	-.6	D
17	18.2	6.8	49.2	3.0	224	3.6	225	-.5	D
18	17.7	6.9	50.9	2.5	222	3.3	220	-.3	D
19	16.7	6.9	53.8	2.3	169	3.5	196	.1	E
20	15.6	7.2	58.5	2.4	162	4.1	186	.8	F
21	14.4	7.3	63.0	2.4	173	4.7	187	1.6	F
22	13.3	7.4	67.6	2.4	179	4.9	186	2.1	G
23	12.4	7.3	71.5	2.3	167	4.9	182	2.2	G
24	11.9	7.2	73.2	2.2	172	4.9	181	2.1	G
ABSOLUTE MAX	26.1	20.4	100.0	7.7		9.8			
AVG DAILY MAX	18.8	10.3	89.9	4.1		6.8			
MEAN	12.8	6.8	69.3	2.3	217	4.0	211	1.1	F
CLIMATIC MEAN	13.0	6.8	67.9	2.6		4.2			
AVG DAILY MIN	7.1	3.4	45.8	1.0		1.6			
ABSOLUTE MIN	-1.4	-7.5	23.4	.4		0.0			
STANDARD DEV	7.1	7.7	19.6	1.5		2.2			
VALID OBS	719	719	719	720	720	719	719	720	720
INVALID OBS	1	1	1	0	0	1	1	0	0
TOTAL OBS	720	720	720	720	720	720	720	720	720
DATA RECOVERY	99.9	99.9	99.9	100.0	100.0	99.9	99.9	100.0	100.0

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TABLE 2.3-61

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: DECEMBER 1, 1975 TO DECEMBER 31, 1975

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: DECEMBER 1, 1975 TO DECEMBER 31, 1975

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 21.30.47.

VIRGIL C SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	5.1	.9	69.0	2.2	186	5.3	211	1.5	F
2	5.5	.7	71.2	2.0	226	4.9	221	1.5	F
3	5.0	.5	72.1	2.0	243	4.6	224	1.5	F
4	4.7	.4	73.4	2.0	141	4.5	232	1.5	F
5	4.3	.5	75.6	1.8	25	4.2	249	1.5	F
6	3.9	.4	77.3	1.8	307	4.0	268	1.7	F
7	3.5	.4	79.1	1.9	232	4.1	253	1.8	F
8	3.3	.5	80.5	1.8	218	4.1	243	1.9	F
9	3.2	.5	80.9	1.9	260	3.9	268	1.8	F
10	3.7	.8	79.7	2.0	278	3.9	277	1.5	F
11	5.3	1.4	75.1	2.2	279	3.5	272	.4	E
12	7.5	1.9	68.1	2.6	270	3.3	242	-.3	D
13	9.2	2.0	61.8	2.8	276	3.4	266	-.5	D
14	10.1	1.1	56.1	3.0	285	3.4	277	-.6	D
15	11.2	1.4	54.4	3.2	275	3.8	269	-.6	D
16	11.5	1.4	53.5	3.3	277	3.9	278	-.6	D
17	11.7	1.2	52.1	3.1	277	3.8	274	-.5	D
18	11.2	1.0	52.9	2.8	281	3.7	276	-.3	D
19	10.3	1.0	55.2	2.6	242	4.0	255	.1	E
20	9.3	.8	57.4	2.8	232	4.7	252	.5	E
21	8.2	.9	61.2	2.5	221	4.8	244	1.0	F
22	7.4	.9	63.9	2.4	203	5.0	219	1.4	F
23	6.8	.7	65.6	2.4	154	5.0	202	1.5	F
24	6.4	.7	67.3	2.4	176	5.3	204	1.4	F
ABSOLUTE MAX	21.9	16.9	96.6	9.1		12.7			
AVG DAILY MAX	12.7	4.5	84.3	4.3		7.2			
MEAN	7.1	.9	66.8	2.4	264	4.2	251	.8	F
CLIMATIC MEAN	7.1	.8	65.3	2.7		4.4			
AVG DAILY MIN	1.5	-2.9	46.3	1.0		1.6			
ABSOLUTE MIN	-9.4	-15.8	14.6	.4		0.0			
STANDARD DEV	6.3	7.5	21.3	1.5		2.3			
VALID OBS	742	742	742	744	744	742	742	744	744
INVALID OBS	2	2	2	0	0	2	2	0	0
TOTAL OBS	744	744	744	744	744	744	744	744	744
DATA RECOVERY	99.7	99.7	99.7	100.0	100.0	99.7	99.7	100.0	100.0

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TABLE 2.3-62

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: JANUARY 1, 1975 0100 EST TO DECEMBER 31, 1975 2400

STATISTICS AND DIURNAL VARIATION OF METEOROLOGICAL PARAMETERS
DATA PERIOD: JANUARY 1, 1975 0100 EST TO DECEMBER 31, 1975 2400

DATA SOURCE: ON-SITE
TABLE GENERATED: 08/05/76. 18.49.58.

VIRGIL C SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO: 5182-070-09

METEOROLOGICAL PARAMETERS (HEIGHTS IN METERS)

HOUR	DRY BULB 10.00 DEG C	DEW POINT 10.00 DEG C	REL HUMID 10.00 PCT	WIND SPEED 10.50 M/SEC	WIND DIR 10.50 DEG	WIND SPEED 61.50 M/SEC	WIND DIR 61.50 DEG	DELTA TEMP 10.00-61.00 DEG C	STAB CLASS 10.00-61.00
1	15.6	11.1	75.1	2.5	178	5.0	188	1.0	F
2	15.1	11.0	77.1	2.4	179	4.8	195	1.0	F
3	14.6	10.9	78.6	2.3	180	4.6	200	1.0	F
4	14.2	10.8	79.8	2.2	185	4.5	205	1.0	F
5	13.8	10.7	81.1	2.2	203	4.4	224	1.0	F
6	13.5	10.6	82.5	2.1	222	4.2	244	1.0	F
7	13.2	10.5	83.4	2.0	242	4.2	257	1.1	F
8	13.1	10.5	83.9	2.1	236	4.1	263	.9	F
9	13.6	10.7	82.3	2.3	252	3.9	263	.6	E
10	15.0	11.0	77.6	2.6	243	3.7	263	.1	E
11	16.7	11.2	70.8	2.9	302	3.7	252	-.4	D
12	18.4	11.2	64.3	3.1	258	3.8	234	-.6	D
13	19.7	11.1	59.3	3.3	253	3.9	234	-.6	D
14	20.6	10.8	55.4	3.3	251	4.0	237	-.7	D
15	21.3	10.8	53.0	3.5	247	4.2	238	-.7	D
16	21.7	10.7	52.1	3.6	243	4.3	234	-.6	D
17	21.7	10.7	51.7	3.6	230	4.4	227	-.6	D
18	21.4	10.6	52.7	3.4	220	4.3	219	-.5	D
19	20.7	10.8	55.6	3.1	198	4.3	207	-.3	D
20	19.6	11.0	59.9	2.9	173	4.5	189	.1	E
21	18.4	11.2	64.2	2.8	160	4.9	176	.5	F
22	17.5	11.2	67.7	2.7	159	5.1	171	.9	F
23	16.8	11.1	70.4	2.6	161	5.0	173	1.0	F
24	16.1	11.1	73.0	2.6	170	5.1	181	1.0	F
ABSOLUTE MAX	36.5	25.2	100.0	11.1		15.2			
AVG DAILY MAX	29.5	13.8	87.9	4.8		7.2			
MEAN	17.2	10.9	68.8	2.7	209	4.4	207	.3	E
CLIMATIC MEAN	17.4	10.8	67.6	3.0		4.6			
AVG DAILY MIN	12.2	7.9	47.3	1.1		2.1			
ABSOLUTE MIN	-4.4	-17.3	11.3	0.0		0.0			
STANDARD DEV	5.6	9.3	20.5	1.6		2.1			
VALID OBS	8733	8680	8678	8743	8743	8586	8579	8748	8748
INVALID OBS	27	80	82	17	17	174	181	12	12
TOTAL OBS	8760	8760	8760	8760	8760	8760	8760	8760	8760
DATA RECOVERY	99.7	99.1	99.1	99.8	99.8	98.0	97.9	99.9	99.9

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Table 2.3-63
Monthly and Annual Average Relative
Humidity (%) at Columbia (1967-1973)

	Hour (Local Standard Time)			
Month	0100	0700	1300	1900
January	80	83	55	66
February	74	80	48	57
March	74	83	48	54
April	77	84	45	50
May	84	88	49	61
June	88	90	54	64
July	89	91	57	72
August	91	93	59	74
September	92	94	56	75
October	89	92	54	78
November	84	88	49	71
December	80	85	55	71
Annual	84	88	53	66

Data Source 2.3.2-C.

Table 2.3-64
Monthly and Annual Mean, and Extreme Maximum and Minimum
Dewpoint Temperatures (°F) at Columbia, S.C. (1971-1975)

Month	Mean	Extreme Maximum	Extreme Minimum
January	41	68	-06
February	36	69	01
March	43	68	09
April	48	72	17
May	60	74	28
June	66	76	39
July	71	79	52
August	71	77	57
September	67	78	41
October	54	75	17
November	44	72	09
December	41	71	02
Annual	53	79	-06

Data Source 2.3.2-F.

Table 2.3-65
Monthly and Annual Precipitation Means
and Extremes in the Site Area (Inches)

Month	Mean[1]	Mean No. of Days >0.5 Inches[2]	Maximum Precipitation[3]	
			Columbia (1948-1973)	Greenville-Spartanburg (1963-1973)
January	3.79	3	7.62 (1972)	6.14 (1972)
February	3.78	3	8.68 (1961)	7.43 (1971)
March	4.45	4	10.89 (1973)	9.66 (1963)
April	3.81	2	5.89 (1958)	11.30 (1964)
May	3.29	2	8.85 (1967)	8.89 (1972)
June	3.29	2	14.81 (1973)	9.59 (1969)
July	5.35	3	13.87 (1959)	7.44 (1964)
August	4.91	3	16.72 (1949)	7.51 (1967)
September	3.63	3	8.78 (1953)	7.98 (1966)
October	2.61	2	12.09 (1959)	10.24 (1964)
November	2.54	1	7.20 (1957)	5.31 (1972)
December	3.59	2	7.43 (1953)	7.55 (1973)
Annual	45.04	30	16.72 (Aug. 1949)	11.30 (Apr. 1964)

(1) Based on 30 years of record (1931-1960) at Little Mountain, Santuck, and Winnsboro.
(2) Based on 10 years of record (1951-1960) at Little Mountain, Santuck, and Winnsboro.
(3) Year of occurrence is given in parentheses
Data Source 2.3.2-C., Data Source 2.3.2-D., Data Source 2.3.2-E.

Table 2.3-66
Monthly and Average Snowfall for the Site Area
and Extremes for Selected Stations (Inches)

		Maximum Snowfalls [2]		
Month	Mean[1]	Columbia (1884-1930; 1948-1973) [3]	Greenville (1884-1930) [3]	Greenville-Spartanburg (1963-1973)
January	0.6	5.9 (1912)	12.9 (1893)	9.1 (1966)
February	0.9	16.0 (1973)	15.0 (1902)	6.9 (1969)
March	0.4	3.2 (1960)	9.7 (1927)	6.6 (1971)
April	T[4]	T	T	0.0
May	T	0.0	0.0	0.0
June	0.0	0.0	0.0	0.0
July	0.0	0.0	0.0	0.0
August	0.0	0.0	0.0	0.0
September	0.0	0.0	0.0	0.0
October	T	0.0	T	0.0
November	0.1	3.3 (1901)	0.3 (1918)	1.9 (1968)
December	0.4	9.3 (1958)	14.4 (1930)	11.4 (1971)
Annual	2.4	16.0 (Feb. 1973)	15.0 (Feb. 1902)	11.4 (Dec 1971)

(1) Based on 68 years of record (1893-1960) at Little Mountain, 65 years of record (1896-1960) at Santuck and 64 years of record (1897-1960) at Winnsboro.
(2) Year of occurrence is given in parentheses.
(3) Monthly extremes that occurred in 1930 or before are based on greatest amount in 24 hours and greatest snow depth of record.
(4) T = trace, an amount too small to measure.
Data Source 2.3.2-C., Data Source 2.3.2-D., Data Source 2.3.2-E., Data Source 2.3.2-G.

Table 2.3-67
Monthly and Annual Average Number of Days With Heavy Fog

Month	Columbia (1948-1973)	Greenville-Spartanburg (1963-1973)
January	2	4
February	2	3
March	2	4
April	1	3
May	1	1
June	2	1
July	2	2
August	2	3
September	3	2
October	3	2
November	3	3
December	3	6
Annual	27	34

Data Source 2.3.2-C., Data Source 2.3.2-D.

Table 2.3-68
Monthly and Annual Stability Class Percent Frequency
Distributions at Columbia, S.C. (1965-1969)

	Stability Class *						
Month	A	B	C	D	E	F	G
January	0.0	3.2	10.7	47.4	11.3	14.5	12.9
February	0.0	3.2	9.7	51.8	11.3	15.0	9.1
March	0.4	6.3	10.4	40.9	13.4	19.0	9.6
April	1.8	7.0	14.8	44.5	13.6	11.8	6.5
May	1.7	13.4	17.1	32.7	14.0	13.4	7.7
June	1.4	14.7	16.3	31.1	12.7	15.9	7.9
July	2.2	16.1	16.8	29.0	15.3	13.9	6.8
August	2.2	16.1	16.8	29.0	15.3	13.9	6.8
September	0.3	6.9	13.9	31.4	12.0	18.7	16.8
October	0.4	8.5	12.4	32.0	10.0	19.8	16.9
November	0.0	5.8	9.1	40.2	10.0	18.5	16.5
December	0.0	2.4	8.9	47.1	11.9	17.3	12.5
Annual	0.9	8.4	13.1	38.1	12.3	16.1	11.1

*Definition of Pasquill Stability Classes

Stability Class	Definition
A	Extremely stable
B	Unstable
C	Slightly unstable
D	Neutral
E	Slightly stable
F	Stable
G	Extremely stable

Data Source 2.3.2-I.

INSERT TABLES 2.3-69 TO 2.3-81 HERE

Table 2.3-69 to Table 2.3-81
Stability-Persistence and Diurnal Distribution
(Based on 10-61 Meter ΔT) January 1975

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TABLE 2.3-69

STABILITY-PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
JANUARY 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 1/ 1/75 TO 1/31/75
DATE AND TIME OF RUN 08/09/76. 10.23.44.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-
2	3	2	7	228	201	78	39
3	1	0	1	186	155	52	28
4	0	0	0	152	129	34	22
5	0	0	0	124	106	22	17
6	0	0	0	99	84	14	14
7	0	0	0	75	68	10	11
8	0	0	0	52	54	6	8
9	0	0	0	35	43	3	6
10	0	0	0	23	34	1	4
11	0	0	0	17	26	0	3
12	0	0	0	11	20	0	2
13	0	0	0	6	15	0	1
14	0	0	0	2	11	0	0
15	0	0	0	0	7	0	0
16	0	0	0	0	3	0	0
17	0	0	0	0	1	0	0
18	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0
>24	0	0	0	0	0	0	0

2 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 1/ 1/75 TO 1/31/75
DATE AND TIME OF RUN 08/09/76. 10.23.44.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	4	14	10	3	31
1	0	0	0	2	15	10	4	31
2	0	0	0	3	18	6	4	31
3	0	0	0	3	16	8	4	31
4	0	0	0	4	16	8	3	31
5	0	0	0	4	17	6	4	31
6	0	0	0	4	14	8	5	31
7	0	0	0	4	14	7	6	31
8	0	0	0	6	13	9	3	31
9	0	0	0	11	14	3	3	31
10	0	0	0	21	7	2	0	30
11	0	0	3	26	2	0	0	31
12	2	1	4	24	0	0	0	31
13	2	3	3	22	1	0	0	31
14	2	1	5	23	0	0	0	31
15	0	0	3	27	0	0	0	30
16	0	0	0	31	0	0	0	31
17	0	0	0	29	2	0	0	31
18	0	0	0	7	24	0	0	31
19	0	0	0	5	22	4	0	31
20	0	0	0	4	14	12	1	31
21	0	0	0	5	11	10	5	31
22	0	0	0	4	14	8	5	31
23	0	0	0	3	15	8	5	31
ALL	6	5	18	276	263	119	55	742

2 INVALID HOUR(S).

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TABLE 2.3-70

STABILITY-PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
FEBRUARY 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 2/ 1/75 TO 2/28/75
DATE AND TIME OF RUN 08/09/76. 10.26.25.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS						
	-A-	-B-	-C-	-D-	-E-	-F-	-G-
2	0	2	4	245	163	71	38
3	0	0	0	209	136	53	28
4	0	0	0	183	116	39	20
5	0	0	0	163	97	27	13
6	0	0	0	147	81	19	7
7	0	0	0	132	69	12	5
8	0	0	0	118	58	8	4
9	0	0	0	107	47	6	3
10	0	0	0	99	37	4	2
11	0	0	0	94	28	2	1
12	0	0	0	90	22	1	0
13	0	0	0	88	16	0	0
14	0	0	0	86	11	0	0
15	0	0	0	85	8	0	0
16	0	0	0	84	5	0	0
17	0	0	0	83	4	0	0
18	0	0	0	82	3	0	0
19	0	0	0	81	2	0	0
20	0	0	0	80	1	0	0
21	0	0	0	79	0	0	0
22	0	0	0	78	0	0	0
23	0	0	0	77	0	0	0
24	0	0	0	76	0	0	0
>24	0	0	0	75	0	0	0

0 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 2/ 1/75 TO 2/28/75
DATE AND TIME OF RUN 08/09/76. 10.26.25.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS							
	-A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	5	11	9	3	28
1	0	0	0	5	11	9	3	28
2	0	0	0	5	11	9	3	28
3	0	0	0	5	11	10	2	28
4	0	0	0	5	11	8	4	28
5	0	0	0	4	12	6	6	28
6	0	0	0	6	11	6	5	28
7	0	0	0	6	11	6	5	28
8	0	0	0	6	11	6	5	28
9	0	0	0	12	8	4	4	28
10	0	0	0	19	9	0	0	28
11	0	1	1	22	4	0	0	28
12	0	1	5	21	1	0	0	28
13	2	3	1	21	1	0	0	28
14	0	2	5	20	0	0	0	28
15	1	1	4	21	0	1	0	28
16	0	0	2	25	1	0	0	28
17	0	0	0	26	2	0	0	28
18	0	0	0	16	12	0	0	28
19	0	0	0	7	20	1	0	28
20	0	0	0	8	14	6	0	28
21	0	0	0	7	13	5	3	28
22	0	0	0	7	10	7	4	28
23	0	0	0	7	11	6	4	28
ALL	3	8	19	286	206	99	51	672

0 INVALID HOUR(S).

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TABLE 2.3-71

STABILITY-PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
MARCH 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 3/ 1/75 TO 3/31/75
DATE AND TIME OF RUN 08/09/76. 10.28.11.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-
2	0	0	15	260	203	42	29
3	0	0	5	219	158	21	22
4	0	0	2	185	130	10	17
5	0	0	0	154	108	5	13
6	0	0	0	137	89	3	10
7	0	0	0	117	72	1	7
8	0	0	0	97	59	0	4
9	0	0	0	79	46	0	1
10	0	0	0	63	34	0	0
11	0	0	0	52	23	0	0
12	0	0	0	41	15	0	0
13	0	0	0	33	10	0	0
14	0	0	0	26	6	0	0
15	0	0	0	21	3	0	0
16	0	0	0	16	1	0	0
17	0	0	0	12	0	0	0
18	0	0	0	9	0	0	0
19	0	0	0	8	0	0	0
20	0	0	0	7	0	0	0
21	0	0	0	6	0	0	0
22	0	0	0	5	0	0	0
23	0	0	0	4	0	0	0
24	0	0	0	3	0	0	0
>24	0	0	0	2	0	0	0

2 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 3/ 1/75 TO 3/31/75
DATE AND TIME OF RUN 08/09/76. 10.28.11.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	3	20	6	2	31
1	0	0	0	5	20	2	4	31
2	0	0	0	4	21	2	4	31
3	0	0	0	3	21	3	4	31
4	0	0	0	4	18	6	3	31
5	0	0	0	5	17	5	4	31
6	0	0	0	4	19	4	4	31
7	0	0	0	3	18	5	5	31
8	0	0	0	11	13	2	5	31
9	0	0	0	19	7	3	0	29
10	0	0	3	27	1	0	0	31
11	2	0	6	22	1	0	0	31
12	0	3	7	21	0	0	0	31
13	0	1	8	22	0	0	0	31
14	1	2	5	23	0	0	0	31
15	0	0	6	25	0	0	0	31
16	0	0	4	26	1	0	0	31
17	0	0	0	29	2	0	0	31
18	0	0	0	25	6	0	0	31
19	0	0	0	12	19	0	0	31
20	0	0	0	9	14	8	0	31
21	0	0	0	7	12	11	1	31
22	0	0	0	4	18	9	0	31
23	0	0	0	4	17	9	1	31
ALL	3	6	39	317	265	75	37	742

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TABLE 2.3-72

STABILITY-PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
APRIL 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 4/ 1/75 TO 4/30/75
DATE AND TIME OF RUN 08/09/76. 10.29.53.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS						
	-A-	-B-	-C-	-D-	-E-	-F-	-G-
2	6	2	28	192	178	46	52
3	3	0	10	147	146	28	43
4	1	0	4	114	123	18	35
5	0	0	3	91	100	8	28
6	0	0	2	75	80	3	22
7	0	0	1	63	65	1	16
8	0	0	0	55	51	0	11
9	0	0	0	47	39	0	7
10	0	0	0	40	29	0	4
11	0	0	0	33	21	0	2
12	0	0	0	28	13	0	0
13	0	0	0	24	6	0	0
14	0	0	0	22	1	0	0
15	0	0	0	20	0	0	0
16	0	0	0	18	0	0	0
17	0	0	0	16	0	0	0
18	0	0	0	14	0	0	0
19	0	0	0	12	0	0	0
20	0	0	0	10	0	0	0
21	0	0	0	8	0	0	0
22	0	0	0	6	0	0	0
23	0	0	0	4	0	0	0
24	0	0	0	3	0	0	0
>24	0	0	0	2	0	0	0

0 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 4/ 1/75 TO 4/30/75
DATE AND TIME OF RUN 08/09/76. 10.29.53.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS							
	-A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	3	17	5	5	30
1	0	0	0	3	15	8	4	30
2	0	0	0	2	16	7	5	30
3	0	0	0	2	16	5	7	30
4	0	0	0	3	13	7	7	30
5	0	0	0	2	15	3	10	30
6	0	0	0	4	13	5	8	30
7	0	0	0	7	10	5	8	30
8	0	0	0	14	9	4	3	30
9	0	0	1	26	3	0	0	30
10	1	2	6	21	0	0	0	30
11	3	1	10	16	0	0	0	30
12	5	3	7	15	0	0	0	30
13	2	7	8	13	0	0	0	30
14	2	2	10	15	1	0	0	30
15	1	3	10	16	0	0	0	30
16	0	2	8	20	0	0	0	30
17	0	0	2	27	1	0	0	30
18	0	0	0	26	4	0	0	30
19	0	0	0	10	20	0	0	30
20	0	0	0	3	23	4	0	30
21	0	0	0	2	17	9	2	30
22	0	0	0	3	18	6	3	30
23	0	0	0	3	18	5	4	30
ALL	14	20	62	256	229	73	66	720

0 INVALID HOUR(S).

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TABLE 2.3-73

STABILITY-PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
MAY 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 5/ 1/75 TO 5/31/75
DATE AND TIME OF RUN 08/09/76. 10.34.10.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-
2	29	3	21	191	125	68	36
3	19	0	8	145	80	47	26
4	11	0	4	110	51	30	19
5	6	0	2	84	31	18	14
6	2	0	1	69	22	9	10
7	0	0	0	57	15	4	6
8	0	0	0	48	10	1	4
9	0	0	0	42	6	0	2
10	0	0	0	36	2	0	1
11	0	0	0	30	0	0	0
12	0	0	0	24	0	0	0
13	0	0	0	20	0	0	0
14	0	0	0	18	0	0	0
15	0	0	0	16	0	0	0
16	0	0	0	14	0	0	0
17	0	0	0	13	0	0	0
18	0	0	0	12	0	0	0
19	0	0	0	11	0	0	0
20	0	0	0	10	0	0	0
21	0	0	0	9	0	0	0
22	0	0	0	8	0	0	0
23	0	0	0	7	0	0	0
24	0	0	0	6	0	0	0
>24	0	0	0	5	0	0	0

0 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 5/ 1/75 TO 5/31/75
DATE AND TIME OF RUN 08/09/76. 10.34.10.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	3	9	13	6	31
1	0	0	0	4	11	12	4	31
2	0	0	0	1	14	10	6	31
3	0	0	0	4	14	9	4	31
4	0	0	0	2	18	6	5	31
5	0	0	0	3	14	9	5	31
6	0	0	0	4	16	6	5	31
7	0	0	0	7	16	4	4	31
8	0	0	0	22	7	2	0	31
9	0	1	3	25	2	0	0	31
10	3	3	6	19	0	0	0	31
11	6	4	9	12	0	0	0	31
12	12	0	4	15	0	0	0	31
13	10	1	7	13	0	0	0	31
14	7	6	9	8	1	0	0	31
15	5	3	8	15	0	0	0	31
16	1	3	6	21	0	0	0	31
17	0	0	5	23	3	0	0	31
18	0	0	0	29	2	0	0	31
19	0	0	0	16	15	0	0	31
20	0	0	0	10	16	5	0	31
21	0	0	0	5	13	12	1	31
22	0	0	0	2	12	10	7	31
23	0	0	0	2	11	12	6	31
ALL	44	21	57	265	194	110	53	744

0 INVALID HOUR(S).

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TABLE 2.3-74

STABILITY-PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
JUNE 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 6/ 1/75 TO 6/30/75
DATE AND TIME OF RUN 08/09/76. 10.37.35.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS						
	-A-	-B-	-C-	-D-	-E-	-F-	-G-
2	31	3	31	176	127	46	34
3	14	1	14	127	92	28	23
4	7	0	5	94	69	19	13
5	4	0	2	75	53	11	6
6	1	0	1	65	40	5	2
7	0	0	0	58	28	2	0
8	0	0	0	52	19	0	0
9	0	0	0	47	13	0	0
10	0	0	0	42	9	0	0
11	0	0	0	38	6	0	0
12	0	0	0	34	3	0	0
13	0	0	0	30	1	0	0
14	0	0	0	27	0	0	0
15	0	0	0	24	0	0	0
16	0	0	0	21	0	0	0
17	0	0	0	18	0	0	0
18	0	0	0	15	0	0	0
19	0	0	0	13	0	0	0
20	0	0	0	11	0	0	0
21	0	0	0	9	0	0	0
22	0	0	0	8	0	0	0
23	0	0	0	7	0	0	0
24	0	0	0	6	0	0	0
>24	0	0	0	5	0	0	0

0 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 6/ 1/75 TO 6/30/75
DATE AND TIME OF RUN 08/09/76. 10.37.35.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS							
	-A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	3	14	8	5	30
1	0	0	0	3	14	7	6	30
2	0	0	0	5	13	6	6	30
3	0	0	0	6	11	10	3	30
4	0	0	0	5	13	7	5	30
5	0	0	0	4	14	7	5	30
6	0	0	0	5	14	3	8	30
7	0	0	0	11	8	10	1	30
8	0	0	0	24	6	0	0	30
9	1	0	5	24	0	0	0	30
10	2	6	8	14	0	0	0	30
11	9	3	9	9	0	0	0	30
12	10	7	8	5	0	0	0	30
13	11	5	7	7	0	0	0	30
14	13	4	7	6	0	0	0	30
15	11	2	8	9	0	0	0	30
16	7	2	9	12	0	0	0	30
17	1	1	9	19	0	0	0	30
18	0	0	2	26	2	0	0	30
19	0	0	0	25	5	0	0	30
20	0	0	0	9	21	0	0	30
21	0	0	0	7	13	9	1	30
22	0	0	0	3	15	8	4	30
23	0	0	0	1	16	6	7	30
ALL	65	30	72	242	179	81	51	720

0 INVALID HOUR(S).

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TABLE 2.3-75

STABILITY-PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER AT)
JULY 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 7/ 1/75 TO 7/31/75
DATE AND TIME OF RUN 08/09/76. 10.39.24.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-
2	13	8	6	100	260	63	17
3	3	1	2	59	207	33	11
4	0	0	0	34	169	22	10
5	0	0	0	20	133	14	9
6	0	0	0	13	107	9	8
7	0	0	0	10	87	6	7
8	0	0	0	8	70	4	6
9	0	0	0	6	55	3	5
10	0	0	0	4	41	2	4
11	0	0	0	2	29	1	3
12	0	0	0	1	18	0	2
13	0	0	0	0	12	0	1
14	0	0	0	0	9	0	0
15	0	0	0	0	6	0	0
16	0	0	0	0	4	0	0
17	0	0	0	0	2	0	0
18	0	0	0	0	1	0	0
19	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0
>24	0	0	0	0	0	0	0

3 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 7/ 1/75 TO 7/31/75
DATE AND TIME OF RUN 08/09/76. 10.39.24.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	1	22	7	1	31
1	0	0	0	1	25	2	3	31
2	0	0	0	2	22	4	3	31
3	0	0	0	4	18	8	1	31
4	0	0	0	3	21	5	2	31
5	0	0	0	1	21	7	2	31
6	0	0	0	2	19	9	1	31
7	0	0	0	4	18	7	1	30
8	0	0	0	14	13	2	1	30
9	1	1	1	13	9	4	1	30
10	1	2	6	8	9	4	1	31
11	1	4	5	6	9	5	1	31
12	4	3	4	7	5	7	1	31
13	6	1	1	11	5	6	1	31
14	7	2	2	8	9	2	1	31
15	2	4	4	8	6	6	1	31
16	3	4	2	11	7	4	0	31
17	2	1	2	12	12	2	0	31
18	0	0	1	18	10	2	0	31
19	0	0	0	16	13	2	0	31
20	0	0	0	9	18	3	1	31
21	0	0	0	2	23	5	1	31
22	0	0	0	4	16	9	2	31
23	0	0	0	3	20	4	4	31
ALL	27	22	28	168	350	116	30	741

3 INVALID HOUR(S).

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TABLE 2.3-76

STABILITY-PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
AUGUST 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 8/ 1/75 TO 8/31/75
DATE AND TIME OF RUN 08/09/76. 10.41.33.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-
2	64	3	11	148	140	78	25
3	40	0	5	107	104	52	16
4	22	0	3	66	75	34	9
5	11	0	1	70	53	21	6
6	4	0	0	61	38	14	5
7	1	0	0	53	26	8	4
8	0	0	0	46	15	3	3
9	0	0	0	39	8	1	2
10	0	0	0	34	4	0	1
11	0	0	0	30	2	0	0
12	0	0	0	26	1	0	0
13	0	0	0	23	0	0	0
14	0	0	0	20	0	0	0
15	0	0	0	18	0	0	0
16	0	0	0	16	0	0	0
17	0	0	0	14	0	0	0
18	0	0	0	12	0	0	0
19	0	0	0	11	0	0	0
20	0	0	0	10	0	0	0
21	0	0	0	9	0	0	0
22	0	0	0	8	0	0	0
23	0	0	0	7	0	0	0
24	0	0	0	6	0	0	0
>24	0	0	0	5	0	0	0

0 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 8/ 1/75 TO 8/31/75
DATE AND TIME OF RUN 08/09/76. 10.41.33.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	4	13	10	4	31
1	0	0	0	4	14	11	2	31
2	0	0	0	3	17	9	2	31
3	0	0	0	4	15	10	2	31
4	0	0	0	4	12	12	3	31
5	0	0	0	4	15	7	5	31
6	0	0	0	4	16	5	6	31
7	0	0	0	6	15	6	4	31
8	0	0	0	18	9	4	0	31
9	0	1	4	26	0	0	0	31
10	7	4	8	12	0	0	0	31
11	13	2	6	10	0	0	0	31
12	16	2	5	8	0	0	0	31
13	18	2	3	8	0	0	0	31
14	19	2	5	5	0	0	0	31
15	16	2	5	7	1	0	0	31
16	7	8	5	9	1	0	1	31
17	0	3	13	12	2	1	0	31
18	0	0	1	29	1	0	0	31
19	0	0	0	20	11	0	0	31
20	0	0	0	7	19	5	0	31
21	0	0	0	5	13	13	0	31
22	0	0	0	5	12	12	2	31
23	0	0	0	3	14	10	4	31
ALL	96	26	55	217	200	115	35	744

0 INVALID HOUR(S).

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TABLE 2.3-77

STABILITY - PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
SEPTEMBER 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 9/ 1/75 TO 9/30/75
DATE AND TIME OF RUN 08/09/76. 10.43.37.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-
2	30	2	11	237	182	32	16
3	21	0	5	198	140	13	9
4	15	0	3	171	110	5	6
5	9	0	1	152	84	2	4
6	4	0	0	136	63	1	3
7	1	0	0	121	47	0	2
8	0	0	0	109	34	0	1
9	0	0	0	97	25	0	0
10	0	0	0	86	19	0	0
11	0	0	0	76	14	0	0
12	0	0	0	67	10	0	0
13	0	0	0	59	6	0	0
14	0	0	0	53	2	0	0
15	0	0	0	47	0	0	0
16	0	0	0	42	0	0	0
17	0	0	0	37	0	0	0
18	0	0	0	33	0	0	0
19	0	0	0	29	0	0	0
20	0	0	0	25	0	0	0
21	0	0	0	22	0	0	0
22	0	0	0	20	0	0	0
23	0	0	0	18	0	0	0
24	0	0	0	16	0	0	0
>24	0	0	0	14	0	0	0

5 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 9/ 1/75 TO 9/30/75
DATE AND TIME OF RUN 08/09/76. 10.43.37.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	4	16	7	3	30
1	0	0	0	6	17	6	1	30
2	0	0	0	5	20	4	1	30
3	0	0	0	7	20	2	1	30
4	0	0	0	7	19	2	2	30
5	0	0	0	9	16	2	3	30
6	0	0	0	10	14	3	3	30
7	0	0	0	10	15	3	2	30
8	0	0	0	17	11	2	0	30
9	0	0	2	25	3	0	0	30
10	1	1	6	21	1	0	0	30
11	9	2	2	17	0	0	0	30
12	7	5	3	14	0	0	0	29
13	7	2	6	14	0	0	0	29
14	8	0	5	16	0	0	0	29
15	6	0	6	16	0	0	0	28
16	4	4	3	19	0	0	0	30
17	1	0	3	25	1	0	0	30
18	0	0	0	23	7	0	0	30
19	0	0	0	9	21	0	0	30
20	0	0	0	5	19	6	0	30
21	0	0	0	4	14	10	2	30
22	0	0	0	5	14	7	4	30
23	0	0	0	4	14	10	2	30
ALL	43	14	36	292	242	64	24	715

5 INVALID HOUR(S).

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TABLE 2.3-38

STABILITY - PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
OCTOBER 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 10/ 1/75 TO 10/31/75
DATE AND TIME OF RUN 08/09/76. 10.45.18.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS						
	-A-	-B-	-C-	-D-	-E-	-F-	-G-
2	1	3	16	159	146	72	104
3	0	0	6	105	111	47	91
4	0	0	1	68	91	29	79
5	0	0	0	49	75	21	68
6	0	0	0	36	61	15	58
7	0	0	0	27	50	10	49
8	0	0	0	20	39	6	40
9	0	0	0	14	29	3	31
10	0	0	0	9	22	0	22
11	0	0	0	6	15	0	14
12	0	0	0	5	11	0	8
13	0	0	0	4	8	0	4
14	0	0	0	3	5	0	1
15	0	0	0	2	2	0	0
16	0	0	0	1	1	0	0
17	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0
>24	0	0	0	0	0	0	0

0 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 10/ 1/75 TO 10/31/75
DATE AND TIME OF RUN 08/09/76. 10.45.18.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS							
	-A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	1	9	10	11	31
1	0	0	0	1	12	9	9	31
2	0	0	0	1	14	7	9	31
3	0	0	0	2	14	5	10	31
4	0	0	0	2	14	6	9	31
5	0	0	0	3	16	3	9	31
6	0	0	0	3	15	4	9	31
7	0	0	0	4	12	8	7	31
8	0	0	0	5	16	4	6	31
9	0	0	0	22	5	3	1	31
10	1	0	2	23	3	2	0	31
11	0	1	7	20	2	1	0	31
12	2	3	9	15	2	0	0	31
13	2	4	12	12	1	0	0	31
14	6	1	8	15	1	0	0	31
15	0	1	9	21	0	0	0	31
16	0	0	0	31	0	0	0	31
17	0	0	0	30	1	0	0	31
18	0	0	0	2	29	0	0	31
19	0	0	0	1	16	14	0	31
20	0	0	0	1	7	17	6	31
21	0	0	0	2	6	12	11	31
22	0	0	0	2	6	9	14	31
23	0	0	0	2	8	8	13	31
ALL	11	10	47	221	209	122	124	744

0 INVALID HOUR(S).

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TABLE 2.3-79

STABILITY - PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
NOVEMBER 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 11/ 1/75 TO 11/30/75
DATE AND TIME OF RUN 08/09/76. 10.47.31.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-
2	0	3	11	124	112	56	141
3	0	0	5	137	73	37	129
4	0	0	1	102	53	23	115
5	0	0	0	74	38	16	102
6	0	0	0	51	26	11	89
7	0	0	0	32	19	7	77
8	0	0	0	20	14	4	65
9	0	0	0	11	10	2	54
10	0	0	0	5	5	1	43
11	0	0	0	2	3	0	34
12	0	0	0	0	1	0	25
13	0	0	0	0	0	0	16
14	0	0	0	0	0	0	8
15	0	0	0	0	0	0	2
16	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0
>24	0	0	0	0	0	0	0

0 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 11/ 1/75 TO 11/30/75
DATE AND TIME OF RUN 08/09/76. 10.47.31.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	4	10	3	13	30
1	0	0	0	4	11	3	12	30
2	0	0	0	4	8	6	12	30
3	0	0	0	6	7	5	12	30
4	0	0	0	3	8	7	12	30
5	0	0	0	3	10	5	12	30
6	0	0	0	3	10	6	11	30
7	0	0	0	2	13	3	12	30
8	0	0	0	5	10	3	12	30
9	0	0	0	10	9	3	8	30
10	0	0	0	18	6	4	2	30
11	1	1	3	21	4	0	0	30
12	1	3	6	20	0	0	0	30
13	0	4	7	19	0	0	0	30
14	0	0	8	22	0	0	0	30
15	0	0	5	25	0	0	0	30
16	0	0	0	28	2	0	0	30
17	0	0	0	20	10	0	0	30
18	0	0	0	3	26	1	0	30
19	0	0	0	2	10	18	0	30
20	0	0	0	4	5	11	10	30
21	0	0	0	5	4	9	12	30
22	0	0	0	5	7	6	12	30
23	0	0	0	5	8	5	12	30
ALL	2	8	29	241	178	98	164	720

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TABLE 2.3-80

STABILITY - PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
DECEMBER 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 12/ 1/75 TO 12/31/75
DATE AND TIME OF RUN 08/09/76. 10.49.24.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-
2	0	0	5	235	190	23	128
3	0	0	1	196	148	14	114
4	0	0	0	164	125	9	101
5	0	0	0	138	104	5	88
6	0	0	0	117	85	2	77
7	0	0	0	101	68	1	66
8	0	0	0	90	52	0	55
9	0	0	0	84	40	0	45
10	0	0	0	79	31	0	36
11	0	0	0	74	23	0	28
12	0	0	0	70	16	0	22
13	0	0	0	67	11	0	16
14	0	0	0	64	8	0	10
15	0	0	0	61	5	0	5
16	0	0	0	58	4	0	0
17	0	0	0	55	2	0	0
18	0	0	0	52	1	0	0
19	0	0	0	50	0	0	0
20	0	0	0	48	0	0	0
21	0	0	0	46	0	0	0
22	0	0	0	44	0	0	0
23	0	0	0	42	0	0	0
24	0	0	0	40	0	0	0
>24	0	0	0	35	0	0	0

0 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 12/ 1/75 TO 12/31/75
DATE AND TIME OF RUN 08/09/76. 10.49.24.

NUMBER OF HOURS

TIME OF DAY (LST)	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	5	13	3	10	31
1	0	0	0	6	12	2	11	31
2	0	0	0	5	13	2	11	31
3	0	0	0	6	13	2	10	31
4	0	0	0	6	14	2	9	31
5	0	0	0	5	15	2	9	31
6	0	0	0	5	11	4	11	31
7	0	0	0	5	12	3	11	31
8	0	0	0	6	10	4	11	31
9	0	0	0	7	12	2	10	31
10	0	0	1	14	10	1	5	31
11	0	1	0	19	10	1	0	31
12	1	1	1	24	4	0	0	31
13	0	1	3	25	2	0	0	31
14	0	0	5	24	2	0	0	31
15	0	0	3	27	1	0	0	31
16	0	0	0	31	0	0	0	31
17	0	0	0	22	9	0	0	31
18	0	0	0	6	25	0	0	31
19	0	0	0	7	15	9	0	31
20	0	0	0	8	9	5	9	31
21	0	0	0	5	12	5	9	31
22	0	0	0	5	13	3	10	31
23	0	0	0	5	12	5	9	31
ALL	1	3	13	278	249	55	145	744

0 INVALID HOUR(S).

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TABLE 2.3-81

STABILITY - PERSISTENCE AND DIURNAL DISTRIBUTION
(BASED ON 10-61 METER ΔT)
JANUARY TO DECEMBER 1975

STABILITY PERSISTENCE SUMMARY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 1/ 1/75 TO 12/31/75
DATE AND TIME OF RUN 08/09/76. 10.51.15.

NUMBER OF HOURS

NUMBER OF CONSECUTIVE HOURS	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-
2	177	41	166	2355	2033	678	665
3	101	2	62	1835	1560	429	542
4	56	0	23	1463	1252	278	449
5	30	0	9	1198	994	177	372
6	11	0	4	1006	788	113	309
7	2	0	1	846	623	69	254
8	0	0	0	715	483	38	205
9	0	0	0	608	368	23	160
10	0	0	0	519	273	11	121
11	0	0	0	454	193	4	88
12	0	0	0	397	132	1	61
13	0	0	0	354	86	0	39
14	0	0	0	321	53	0	19
15	0	0	0	294	31	0	7
16	0	0	0	270	17	0	0
17	0	0	0	248	9	0	0
18	0	0	0	229	5	0	0
19	0	0	0	215	2	0	0
20	0	0	0	201	1	0	0
21	0	0	0	188	0	0	0
22	0	0	0	177	0	0	0
23	0	0	0	166	0	0	0
24	0	0	0	156	0	0	0
>24	0	0	0	146	0	0	0

12 INVALID HOUR(S).

DIURNAL DISTRIBUTION OF STABILITY

VIRGIL C. SUMMER NUCLEAR STATION
PARR, SOUTH CAROLINA
SOUTH CAROLINA ELECTRIC AND GAS COMPANY
DAMES AND MOORE JOB NO 5182-070-09
DATA PERIOD FROM 1/ 1/75 TO 12/31/75
DATE AND TIME OF RUN 08/09/76. 10.51.15.

NUMBER OF HOURS

TIME OF DAY (EST)	PASQUILL STABILITY CLASS -A-	-B-	-C-	-D-	-E-	-F-	-G-	ALL
0	0	0	0	40	168	91	66	365
1	0	0	0	44	177	81	63	365
2	0	0	0	40	187	72	66	365
3	0	0	0	52	176	77	60	365
4	0	0	0	48	177	76	64	365
5	0	0	0	47	182	62	74	365
6	0	0	0	54	172	63	76	365
7	0	0	0	69	162	67	66	364
8	0	0	0	148	128	42	46	364
9	2	3	16	226	72	22	27	362
10	16	18	46	217	46	13	8	364
11	44	20	61	200	32	7	1	365
12	60	32	53	199	12	7	1	364
13	60	34	66	187	10	6	1	364
14	65	22	75	185	14	2	1	364
15	42	16	71	217	8	7	1	362
16	22	23	39	264	12	4	1	365
17	4	5	34	274	45	3	0	365
18	0	0	4	210	148	3	0	365
19	0	0	0	130	187	48	0	365
20	0	0	0	77	179	82	27	365
21	0	0	0	56	151	110	48	365
22	0	0	0	49	155	94	67	365
23	0	0	0	42	164	88	71	365
ALL	315	173	475	3059	2764	1127	835	[illegible]

Table 2.3-82
Comparison of 1 and 20 Year Wind and Stability
Conditions for Columbia, S.C.

Wind Frequency Distribution (%)

Wind Direction	1 Year[1]	20 Year [2]
N	5.48	6.84
NNE	3.73	6.47
NE	4.86	7.88
ENE	5.41	7.00
E	6.20	6.25
ESE	4.62	4.42
SE	3.36	3.29
SSE	2.23	2.62
S	5.55	6.30
SSW	4.59	6.40
SW	7.98	10.67
WSW	6.68	9.83
W	6.51	8.38
WNW	3.73	5.45
NW	3.77	4.19
NNW	3.42	4.01
CALM	21.88	13.83

Stability Class Frequency Distribution and Mean Speed

	1 Year[1]		20 Year[2]	
Pasquill-Turner Classification	Frequency (%)	Mean Speed (mps)	Frequency (%)	Mean Speed (mps)
A	1.23	1.70	0.91	1.65
B	9.90	2.22	8.05	2.42
C	11.34	3.51	13.11	3.76
D	38.46	3.79	38.81	4.43

Comparison of 1 and 20 Year Wind and Stability
Conditions for Columbia, S.C. (continued)

E	10.92	3.04	11.70	3.14
F & G	28.15	0.88	27.42	2.39
All Classes	100.0	2.68	100.00	3.14

(1) January 1, 1975, through December 13, 1975; concurrent with onsite meteorological record used in this report.
(2) January, 1956, through December, 1975.

Table 2.3-83
Average Changes in Certain Diffusion Parameters
as Air Moves Offshore Over Water Surfaces

	Relationship of Water to Air Temperatures		
	> 7°F Colder	Between -7 and +2	> 2°F Warmer
$\overline{U}$, mph			
Day	15.6 to 18.1	11.6 to 16.8	12.9 to 18.7
Night	11.0 to 13.2	11.4 to 16.6	7.9 to 15.9
σ^{1}_{θ}, deg			
Day	11.5 to 5.0	10.3 to 5.3	10.4 to 5.8
Night	10.1 to 4.3	10.1 to 5.1	9.5 to 5.2
$\sigma^{2}_{y,}$ meters @ 500m			
Day	42 to 27	38 to 27	39 to 29
Night	39 to 25	39 to 27	37 to 27

(1) Wind Direction Variability
(2) Horizontal Diffusion Coefficient

Data Source 2.3.2-O.

Table 2.3-84
Maximum Elevation Versus Distance Within
A 5 Mile Radius of the Plant

Sector	Maximum Elevation (Feet, MSL)	Distance From Plant (Hundreds of Feet)
N	436	plant site
NNE	490	247
NE	480	158
ENE	510	137
E	470	41
ESE	490	65
SE	470	43;103
SSE	450	135
S	460	36
SSW	460	50
SW	450	24
WSW	436	plant site
W	436	plant site
WNW	436	plant site
NW	436	plant site
NNW	510	165
ALL	510	137;165

Table 2.3-85
Meteorological Instrumentation Virgil C. Summer Nuclear Station

Measurement	Level (meters)	Instrument	Instantaneous Accuracy	Nominal Threshold	Nominal Operating Conditions	Nominal Calibrated Range
Wind Speed	10 & 61	Ultrasonic	± 0.3mph (0-10mph) ± 3% of Reading (10-100 mph) ± 5% of Reading (110-125 mph)	0 mph	-50° to +125°F	0 - 125 mph
Wind Direction	10 & 61	Ultrasonic	±.5%	0 mph	-50° to +125°F	0 - 359°
Temperature	10	Platinum RTD Probe	±.16°F	N/A[1]	-58 to 122°F	-20 to +120°F
Dewpoint	1.5	Computed	±.4°F	N/A	-50 to +150°F	-15 to + 85°F
Delta Temperature	10-61 10-40	Platinum RTD Probe	±.16°F	N/A	-58 to +122°F	-7 to + 18°F
Precipitation	1.5	Tipping Bucket Rain Gage	± 10%	.01 inch	Above 32°F	N/A

(1) NA - Not applicable

Table 2.3-85A
Table 2.3-85D
Table 2.3-85C
Table 2.3-85D
Table 2.3-85E
Table 2.3-85D
Deleted Per RN 01-030

Table 2.3-85F
Meteorological Monitoring System Accuracies

	Parameter	Reg. Guide 1.23, Revision 0 System Accuracy Design, Basis	Minimum Digital Systems Accuracy (for 15 minute period)	Minimum Digital System Accuracy (for 5 minute period)
A.	Wind Speed	± 0.50 mph[2]	± 0.125 mph	± 0.200 mph
B.	Wind Direction	± 5 degrees	± 0.250 degrees	± 0.500 degrees
C.	Dew Point	± 0.90°F	± 0.20°F	± 0.30°F
D.	Ambient Temperature	± 0.90°F	± 0.100°F	± 0.100 mph
E.	Differential Temperature	± 0.18°F	± 0.040°F	± 0.075°F
F.	Total Precipitation	± 10%[3]	± 10%	± 10%

(1) Reference DC09690-001
(2) Time Averaged Value
(3) Total Precipitation accuracy is given in proposed Revision 1 to Reg. Guide 1.23.

INSERT TABLES 2.3-86A - 2.3-111B

Table 2.3-86A to 2.3-111B
Wind Frequency Distributions
South Carolina Electric & Gas Co.
Virgil C. Summer Nuclear Station
January-December 1975

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TABLE 2.3-86A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: JANUARY, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	0	0	0	0	1	0	2	6.35
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	1	0	0	0	0	0	0	0	0	0	1	2.10
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	2	0	0	0	0	0	0	0	0	0	2	2.10
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													1	.60
TOTAL	0	0	4	0	0	0	0	0	0	0	1	0	6	3.47

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.60
NE	0	0	0	0	0	0	0	0	0	1	0	0	1	9.50
ENE	0	0	0	1	1	0	0	0	0	0	0	0	2	3.45
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	1	0	0	0	0	0	0	0	0	1	2.40
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	1	2	0	0	0	0	1	0	0	5	4.84

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	1	0	0	0	0	0	1	6.80
ENE	0	0	0	0	0	1	0	1	2	2	0	0	7	8.71
E	0	0	0	0	0	0	0	0	0	1	0	0	1	10.50
ESE	0	0	0	0	0	0	1	0	0	0	0	0	1	6.30
SE	0	0	0	1	0	0	0	0	0	0	0	0	1	3.60
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	1	0	0	0	0	0	0	0	0	0	1	2.80
SW	0	0	0	0	0	0	0	0	0	0	0	1	1	13.20
WSW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.30
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	1	0	1	10.10
NW	0	0	0	0	0	1	1	0	0	0	0	0	2	8.05
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	1	0	1	9.40
CALM													0	0.
TOTAL	0	0	1	1	1	2	1	1	1	1	4	1	18	7.84

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	1	1	0	2	0	3	0	1	4	13	8.73
NE	1	0	3	3	2	1	1	0	0	1	0	0	12	4.09
ENE	0	0	1	1	3	3	2	1	3	2	0	0	16	6.20
E	0	0	1	1	0	4	1	2	3	1	0	1	14	6.88
ESE	0	0	0	2	3	0	2	3	2	2	0	0	14	6.85
SE	0	0	0	0	1	1	1	0	0	0	0	4	8	9.40
SSE	0	0	0	0	2	2	0	0	0	0	0	0	4	5.10
S	0	0	0	0	0	2	0	0	0	2	1	2	5	12.10
SSW	0	0	0	0	1	0	0	0	0	1	0	2	4	11.70
SW	0	0	0	2	3	1	1	1	0	1	0	0	9	11.10
WSW	0	0	0	1	2	1	1	0	1	4	0	2	12	7.08
W	0	0	0	2	3	2	5	3	3	3	1	1	23	10.28
WNW	0	0	1	1	4	1	3	5	4	1	0	2	22	10.14
NW	0	0	1	1	5	10	2	1	2	1	0	0	24	5.17
NNW	0	0	0	1	3	1	3	3	0	1	2	0	14	6.57
N	0	2	0	0	5	0	1	1	2	0	0	0	11	5.25
CALM													0	0.
TOTAL	1	4	10	30	35	26	21	20	29	21	10	52	275	7.29

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-86B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: JANUARY, 1975

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	3	3	2	2	1	2	0	0	0	14	5.24
NE	0	0	0	1	4	1	4	2	2	0	0	0	14	5.86
ENE	0	1	0	3	3	7	1	0	0	0	0	0	15	4.70
E	0	0	3	3	0	3	5	1	0	0	0	0	15	5.07
ESE	0	0	0	2	1	3	0	0	0	0	0	0	6	4.67
SE	0	0	0	1	1	0	1	0	1	0	0	1	5	7.64
SSE	0	0	1	0	1	2	7	4	2	0	1	6	24	9.60
S	0	0	2	1	2	1	3	2	0	5	2	3	21	7.80
SSW	0	1	3	3	2	3	2	0	2	5	1	3	25	7.02
SW	0	1	2	3	1	2	2	3	1	9	1	8	33	8.48
WSW	0	0	2	5	1	1	2	2	1	2	4	4	24	7.70
W	0	0	0	1	4	2	3	2	0	1	2	2	17	7.27
WNW	0	0	1	3	1	2	3	1	1	0	0	0	13	5.15
NW	0	1	1	2	1	2	1	0	0	0	0	1	9	5.56
NNW	0	0	2	3	1	0	0	0	0	0	0	3	11	7.91
N	1	0	2	5	1	0	2	0	1	2	0	1	15	5.52
CALM													2	.89
TOTAL	1	5	20	39	29	31	38	18	13	24	11	32	263	6.98

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	1	0	1	2	0	0	0	0	0	0	5	3.84
NE	0	1	0	1	4	0	0	0	0	0	0	0	6	3.83
ENE	1	0	1	2	1	1	2	0	0	0	0	0	8	4.26
E	0	1	0	0	2	1	0	0	0	0	0	0	4	3.85
ESE	0	2	0	0	0	1	0	1	1	0	0	0	5	4.16
SE	0	2	0	0	0	0	1	1	1	0	0	0	4	7.25
SSE	0	0	1	1	1	1	2	1	5	2	1	0	16	6.54
S	0	0	1	0	0	1	1	1	0	0	0	0	4	4.75
SSW	0	0	1	1	2	3	3	5	0	0	0	0	15	5.61
SW	0	1	1	0	0	5	4	5	2	0	0	0	18	5.31
WSW	0	0	0	0	3	4	5	0	0	0	0	0	12	4.74
W	0	0	0	1	0	0	2	0	0	0	0	0	3	4.57
WNW	0	1	1	0	0	1	0	0	0	0	0	0	3	2.78
NW	0	0	0	2	0	1	1	0	1	0	0	0	5	5.54
NNW	0	2	1	1	0	0	0	0	0	0	0	0	5	2.22
N	0	2	1	0	1	0	0	0	0	0	0	0	4	2.45
CALM													1	.48
TOTAL	2	14	8	11	24	23	15	15	4	1	1	0	119	4.58

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	3	0	1	0	0	0	0	0	0	0	4	3.07
NE	1	0	0	0	0	0	0	0	0	0	0	0	1	.90
ENE	0	1	1	0	1	1	0	0	0	0	0	0	4	3.77
E	0	1	2	0	0	0	1	1	0	0	0	0	5	4.02
ESE	1	1	0	0	0	1	2	0	0	0	0	0	5	4.06
SE	0	0	0	1	0	1	0	0	0	0	0	0	2	4.65
SSE	0	0	0	2	1	0	1	1	1	0	0	0	6	5.77
S	0	1	2	0	0	0	0	0	0	0	0	0	3	2.23
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	1	0	0	0	0	0	0	0	0	0	0	1	1.70
WSW	0	0	1	0	1	0	0	0	0	0	0	0	2	3.10
W	0	0	0	1	0	0	0	0	0	0	0	0	1	2.40
WNW	0	0	1	1	0	0	0	0	0	0	0	0	4	3.17
NW	0	1	1	1	0	1	0	0	0	0	0	0	4	2.82
NNW	0	1	1	0	0	0	0	0	0	0	0	0	2	2.05
N	0	1	2	1	2	0	0	0	0	0	0	0	6	3.03
CALM													5	.42
TOTAL	3	8	14	8	6	4	4	2	1	0	0	0	54	3.28

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	7	4	7	4	4	1	5	0	2	4	39	5.05
NE	2	1	3	5	10	2	6	2	2	2	0	0	35	4.09
ENE	1	2	4	7	9	13	5	2	4	4	2	0	53	5.48
E	0	2	6	4	2	6	7	4	3	1	1	1	39	5.40
ESE	1	3	0	4	5	4	6	4	2	2	1	0	33	5.44
SE	1	0	0	4	2	3	3	2	2	0	0	0	31	5.44
SSE	0	0	2	3	5	6	9	10	5	1	2	4	21	7.76
S	0	0	2	5	1	3	2	4	2	0	2	5	50	7.80
SSW	0	1	1	5	5	4	6	5	5	2	4	1	45	7.62
SW	0	1	1	4	6	7	7	8	7	5	2	1	54	7.72
WSW	0	0	0	5	10	4	7	2	5	7	7	12	77	8.25
W	0	0	1	4	4	5	4	6	7	5	2	11	71	7.26
WNW	0	1	1	4	10	5	5	8	5	2	3	11	65	7.11
NW	0	1	1	4	10	11	7	4	2	2	2	5	49	6.96
NNW	0	1	4	7	7	4	1	1	0	1	2	1	29	5.24
N	1	5	5	6	4	0	1	1	1	1	0	1	27	4.65
CALM													9	.41
TOTAL	7	21	47	80	97	86	83	67	48	36	32	73	743	6.21

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-87A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: FEBRUARY, 1975

PASQUILL *A* (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	1	1	0	0	0	0	0	0	0	2	3.50
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.50
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	2	1	0	0	0	0	0	0	0	3	3.33

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL *B* (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	1	0	1	0	0	0	0	0	2	5.50
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	1	0	0	0	0	0	0	0	0	1	3.50
SE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.50
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	1	0	1	11.00
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.50
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.50
NNW	0	0	1	0	0	0	0	0	0	0	0	0	1	2.50
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	2	2	1	1	0	0	0	1	0	8	5.13

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL *C* (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.50
ENE	0	0	0	0	0	0	2	0	0	0	0	0	2	7.25
E	0	0	0	0	0	0	1	0	0	0	0	0	1	5.10
ESE	0	0	0	0	0	0	1	0	0	0	0	0	1	5.10
SE	0	0	0	1	0	0	1	0	0	0	0	0	2	5.60
SSE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.20
S	0	0	0	0	0	1	0	2	0	0	0	0	3	5.63
SSW	0	0	0	0	0	0	1	0	0	0	0	0	1	5.50
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	1	0	0	0	0	0	0	1	4.10
WNW	0	0	0	0	2	1	0	0	1	0	0	0	5	5.40
NW	0	0	0	0	1	0	0	0	1	0	0	0	1	3.50
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	4	4	4	1	2	2	0	0	0	19	5.57

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL *D* (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	2	1	2	4	0	1	0	0	11	5.45
NE	0	0	2	1	3	4	4	0	4	11	6	0	51	8.25
ENE	0	0	0	1	1	2	4	2	7	2	0	1	20	6.62
E	0	0	0	0	1	1	1	2	4	5	1	0	15	6.06
ESE	0	0	0	0	1	1	0	1	0	0	0	0	4	5.03
SE	0	0	0	0	1	0	2	1	1	0	0	0	5	5.20
SSE	0	0	0	0	1	1	0	1	1	1	1	1	7	7.51
S	0	0	1	2	0	1	2	2	1	1	0	1	11	6.79
SSW	0	0	0	1	0	1	1	3	3	1	2	2	14	8.71
SW	0	0	0	0	1	0	2	2	2	5	4	3	19	8.21
WSW	0	1	0	0	0	1	0	2	3	1	4	3	15	9.10
W	1	0	0	0	0	1	1	2	3	1	4	3	16	10.03
WNW	0	0	0	0	1	0	1	1	3	2	4	4	21	8.98
NW	0	1	0	0	1	1	0	2	3	2	2	2	17	8.47
NNW	0	0	1	0	0	1	0	1	2	0	1	1	8	6.81
N	0	0	0	0	1	2	4	1	2	2	0	0	12	6.50
CALM													1	0.0
TOTAL	1	1	5	12	17	21	35	44	46	39	31	22	224	8.24

NUMBER OF INVALID OBSERVATIONS = 7
TOTAL NUMBER OF OBSERVATIONS = 672

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TABLE 2.3-87B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: FEBRUARY, 1975

PASQUILL #A (FROM AEC/DELTA-T CRITERIA 10-61 METERS
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	2	2	7	2	2	0	0	0	0	16	5.29
NE	0	0	0	2	2	4	3	2	2	0	0	0	15	6.06
ENE	0	0	1	1	1	1	0	1	0	0	0	0	5	4.00
E	0	0	0	0	2	1	3	0	0	0	0	0	6	5.67
ESE	0	0	0	2	0	0	1	0	0	0	0	0	3	4.33
SE	0	0	0	0	0	1	2	2	0	0	2	2	9	7.67
SSE	0	0	0	0	0	2	2	4	0	0	2	1	12	23	10.72
S	0	0	0	0	0	4	5	1	2	3	2	3	1	21	7.40
SSW	0	0	0	0	0	1	2	4	4	0	0	0	4	15	8.21
SW	0	0	0	0	0	6	2	4	4	6	5	5	5	37	8.25
WSW	0	0	1	0	1	2	5	3	4	1	2	2	1	22	6.97
W	0	0	0	0	0	2	5	1	2	0	0	0	0	10	5.86
WNW	0	0	0	0	1	0	2	0	0	0	0	0	0	3	4.97
NW	0	0	2	1	0	0	1	0	0	0	1	0	0	5	4.34
NNW	0	0	0	2	0	2	3	0	1	0	1	0	0	9	5.34
N	0	0	0	0	0	0	2	1	2	0	0	0	1	6	7.65
CALM														1	.60
TOTAL	0	3	5	9	27	43	30	24	12	14	14	24	206	7.23

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL #B (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	2	2	1	0	0	0	0	0	0	5	4.22
NE	0	1	0	4	4	1	0	0	0	0	0	0	10	3.94
ENE	0	0	1	4	1	0	0	0	0	0	0	0	6	3.83
E	0	0	2	1	0	2	2	1	0	0	0	0	8	5.15
ESE	0	1	0	1	1	3	0	4	1	2	0	0	13	6.35
SE	0	0	0	0	1	0	1	5	1	1	1	0	10	7.44
SSE	0	0	2	0	1	5	1	0	0	0	0	0	9	5.00
S	0	0	0	0	1	1	1	0	0	1	0	0	4	6.42
SSW	0	0	0	1	0	2	1	0	0	0	0	0	4	5.48
SW	0	1	0	3	0	2	0	0	0	0	0	0	6	4.83
WSW	0	1	0	1	2	1	0	0	0	0	0	0	5	4.12
W	0	0	0	1	1	1	0	2	1	0	0	0	6	5.17
WNW	0	0	0	1	1	0	0	0	0	0	0	0	2	3.75
NW	0	0	0	1	1	2	0	0	0	0	0	0	4	3.98
NNW	0	0	0	1	1	0	0	0	0	0	0	0	2	3.60
N	0	1	0	2	0	0	0	0	0	0	0	0	3	3.10
CALM													2	.60
TOTAL	0	5	7	23	14	18	8	11	2	4	1	0	99	4.96

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL #C (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	0	0	0	0	0	0	1	3.00
NE	0	0	2	0	1	0	0	0	0	0	0	0	5	1.60
ENE	0	0	2	0	0	2	1	0	0	0	0	0	5	3.60
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	1	1	0	1	0	0	0	3	7.07
SE	0	0	0	0	0	0	1	1	2	0	0	0	3	7.20
SSE	0	0	0	0	0	0	0	0	2	0	0	1	3	8.33
S	0	0	1	0	0	0	0	1	0	0	0	0	0	1	5.10
SSW	0	0	1	0	1	2	0	1	0	0	0	0	0	5	4.20
SW	0	0	1	0	1	2	0	2	0	0	0	0	0	5	4.02
WSW	0	0	0	1	1	0	0	0	1	0	0	0	0	3	4.47
W	0	0	2	1	2	0	0	0	0	0	0	0	0	5	2.40
WNW	0	0	0	2	0	0	0	0	0	0	0	0	0	2	2.95
NW	0	0	0	3	1	0	0	0	0	0	0	0	0	4	2.93
NNW	0	0	0	0	1	0	0	0	0	0	0	0	0	1	3.60
N	0	0	0	1	0	0	0	0	0	0	0	0	0	1	2.20
CALM														4	.60
TOTAL	0	5	12	8	7	5	3	5	1	0	1	0	51	4.201

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	3	4	6	9	4	6	0	1	0	0	33	5.45
NE	0	1	4	7	13	9	7	11	6	11	9	6	82	6.00
ENE	0	2	3	6	7	6	4	8	3	0	1	0	40	5.53
E	0	0	3	2	3	5	7	5	5	1	0	0	31	6.17
ESE	0	1	0	5	2	5	3	4	2	2	0	0	24	5.93
SE	0	0	0	3	3	5	5	9	1	3	3	0	32	6.87
SSE	0	0	2	1	4	8	6	3	1	2	3	13	43	8.10
S	0	0	1	1	2	6	8	6	4	4	4	3	43	7.04
SSW	0	0	1	0	3	4	6	9	7	1	2	2	8	43	7.44
SW	0	0	1	1	6	8	8	11	6	11	11	14	12	93	8.05
WSW	0	0	3	1	3	6	7	5	8	2	6	5	15	81	8.56
W	0	1	0	2	2	3	5	4	6	2	6	4	3	62	6.85
WNW	0	0	0	2	0	3	2	3	1	3	2	2	0	1	2	20	5.69
NW	0	0	0	3	1	5	6	4	0	1	1	2	1	1	27	4.98
NNW	0	0	0	4	4	1	4	0	2	0	2	2	0	1	21	5.40
N	0	0	1	1	2	1	4	5	1	2	2	0	1	22	6.43
CALM														8	.60
TOTAL	1	16	12	60	76	92	80	84	61	52	68	66	655	6.27

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 672

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TABLE 2.3-88A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: MARCH, 1975

PASQUILL "A" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	1	0	0	0	1	8.80
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.60
W	0	0	1	0	0	0	0	0	0	0	0	0	1	2.90
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	1	0	0	0	0	1	0	0	0	3	4.97

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "B" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	0	0	0	0	0	1	5.70
NE	0	0	0	0	0	0	0	0	0	1	0	0	1	9.10
ENE	0	0	0	0	0	1	0	0	0	0	0	0	1	6.00
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	1	0	0	0	0	1	7.60
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	1	0	0	0	0	0	0	0	1	4.10
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	1	1	17.00
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	0	1	1	1	1	0	1	0	1	6	8.38

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "C" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	1	0	1	0	0	0	0	3	6.07
NE	0	0	0	0	0	0	1	1	1	2	0	0	5	8.36
ENE	0	0	0	0	0	0	0	2	1	0	0	0	3	8.03
E	0	0	0	0	0	0	1	1	1	0	0	0	3	7.60
ESE	0	0	0	0	0	0	0	0	1	0	0	0	1	8.60
SE	0	0	0	0	1	2	0	0	0	0	0	0	3	5.17
SSE	0	0	0	0	0	0	1	0	0	0	0	0	1	6.30
S	0	0	1	0	0	0	0	0	0	0	0	0	1	2.60
SSW	0	0	0	0	1	0	1	0	0	0	0	0	2	5.30
SW	0	0	0	0	1	0	0	0	0	1	0	0	2	5.80
WSW	0	0	0	0	0	0	1	0	0	0	0	0	1	5.10
W	0	0	0	0	0	2	0	0	0	0	0	0	2	6.70
WNW	0	0	0	0	0	2	0	0	0	0	0	1	3	7.33
NW	0	0	0	0	0	1	0	0	0	0	0	4	5	11.33
NNW	0	0	0	0	0	0	0	1	0	0	0	0	1	7.20
N	0	0	0	0	1	0	0	1	0	0	0	0	2	6.30
CALM													0	0.
TOTAL	0	0	1	1	4	6	4	7	5	2	1	5	39	7.34

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "D" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	2	1	1	1	1	2	0	0	0	0	9	4.67
NE	0	1	0	1	1	2	1	3	3	0	0	0	12	6.12
ENE	0	0	0	1	1	0	5	5	6	3	3	0	24	7.98
E	0	0	0	0	2	4	2	2	2	2	2	0	16	6.94
ESE	0	0	0	1	0	0	1	3	0	0	1	1	9	7.21
SE	0	0	0	0	0	0	1	1	0	0	0	0	2	6.47
SSE	0	0	0	1	0	0	1	0	1	0	0	0	3	6.34
S	0	0	0	0	0	0	3	1	2	3	2	2	13	10.22
SSW	0	0	0	0	1	1	1	5	1	3	2	5	19	10.00
SW	0	1	0	0	1	0	0	1	5	2	4	10	24	11.33
WSW	0	0	0	0	0	2	1	1	1	3	0	2	12	11.00
W	0	0	0	0	0	1	4	2	0	1	2	1	11	14.55
WNW	0	0	0	1	0	1	1	1	0	1	0	2	7	10.71
NW	0	1	0	1	1	0	2	2	2	1	1	10	21	10.43
NNW	0	0	0	2	2	2	1	1	0	2	0	0	10	8.47
N	0	0	0	0	2	4	1	5	4	0	0	1	22	8.00
CALM													0	0.
TOTAL	0	4	5	14	17	21	30	28	35	19	21	129	317	10.17

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-88B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: MARCH, 1975

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	3	2	1	1	0	1	1	1	0	0	10	5.14
NE	0	0	0	3	3	0	2	0	0	0	0	0	8	4.66
ENE	0	0	1	1	3	1	4	3	0	0	0	1	14	6.14
E	0	0	0	3	1	4	5	0	1	0	0	0	14	5.59
ESE	0	1	0	1	2	3	2	1	0	0	0	1	11	6.17
SE	0	0	0	0	0	1	0	1	1	3	0	4	10	10.35
SSE	0	0	0	0	1	1	2	3	1	4	1	6	19	9.97
S	0	0	0	0	2	2	2	2	3	9	5	11	36	10.02
SSW	0	0	0	0	3	0	5	1	1	1	2	6	19	9.32
SW	0	0	0	2	3	1	1	2	1	1	0	2	13	7.39
WSW	0	0	0	0	1	1	2	2	3	0	2	1	12	8.23
W	0	0	0	2	2	1	4	7	3	3	1	2	25	7.63
WNW	0	0	1	1	0	2	1	1	1	4	0	1	12	7.50
NW	0	0	1	4	2	2	1	3	3	2	1	5	24	7.88
NNW	0	0	1	4	1	6	2	3	0	1	3	3	24	7.05
N	0	0	0	1	4	7	1	0	0	1	0	0	14	5.38
CALM													0	0.
TOTAL	0	1	7	24	29	33	34	30	19	30	15	43	265	7.77

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.70
NE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.30
ENE	0	2	0	0	3	0	2	1	1	0	0	0	9	5.06
E	0	0	0	0	3	1	3	1	0	0	0	0	8	5.00
ESE	0	1	0	1	0	0	1	1	0	0	0	0	4	4.67
SE	0	0	0	0	0	0	0	0	2	1	1	0	4	9.02
SSE	0	0	0	0	0	0	0	1	3	2	2	0	8	9.22
S	0	0	1	0	0	1	1	1	0	0	0	3	7	8.81
SSW	0	0	0	0	5	0	2	1	1	0	0	0	9	5.84
SW	0	0	0	3	2	0	0	0	0	0	0	0	5	4.06
WSW	0	0	1	0	2	2	0	0	0	0	0	0	5	4.70
W	0	0	2	0	1	1	2	0	0	0	0	0	6	4.83
WNW	0	1	1	0	1	0	0	0	0	0	0	0	3	2.57
NW	0	0	0	2	1	0	0	0	0	0	0	0	3	3.90
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	1	0	1	0	0	0	0	0	0	0	0	2	2.25
CALM													0	0.
TOTAL	0	5	5	7	20	5	11	6	7	3	3	3	75	5.81

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.20
NE	0	2	1	1	0	0	0	0	0	0	0	0	4	2.60
ENE	0	0	0	0	2	0	0	0	0	0	0	0	2	4.90
E	0	0	0	0	2	0	0	0	0	0	0	0	2	3.35
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.60
SSE	0	0	0	2	1	0	1	0	1	0	0	0	5	5.20
S	0	0	0	3	2	0	0	0	0	0	0	0	5	3.92
SSW	0	1	0	1	0	0	0	0	0	0	0	0	2	2.55
SW	0	1	1	0	2	0	0	0	0	0	0	0	4	3.20
WSW	0	0	3	0	1	1	0	0	0	0	0	0	5	3.70
W	0	0	0	0	1	1	0	0	0	0	0	0	2	3.60
WNW	0	0	1	0	0	0	0	0	0	0	0	0	1	2.60
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	2	0	1	0	0	0	0	0	0	0	3	1.17
CALM													0	0.
TOTAL	0	4	10	10	10	1	1	0	1	0	0	0	47	3.56

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	6	3	4	3	2	4	1	1	0	0	25	5.01
NE	0	3	1	5	5	2	4	4	5	3	0	0	32	5.83
ENE	0	2	1	2	9	2	11	11	8	3	1	1	53	6.85
E	0	0	0	7	8	7	11	6	4	2	0	1	44	6.20
ESE	0	2	0	5	2	3	4	6	1	0	1	2	26	6.44
SE	0	0	1	0	1	4	1	1	3	4	1	6	22	8.80
SSE	0	0	0	3	2	1	5	6	8	6	3	8	40	9.02
S	0	0	2	3	5	6	4	5	6	11	7	19	68	9.22
SSW	0	1	0	2	10	1	13	3	5	1	7	22	67	9.10
SW	0	2	1	7	7	1	1	3	7	1	4	12	48	8.48
WSW	0	0	4	1	6	6	3	3	6	6	4	23	56	9.47
W	0	0	3	3	7	6	8	7	6	5	4	15	82	11.09
WNW	0	1	4	1	4	3	2	1	2	4	2	9	38	8.10
NW	0	1	1	7	5	2	3	5	5	1	1	20	56	9.10
NNW	0	0	1	6	1	7	5	4	0	1	1	11	43	7.75
N	0	1	2	2	8	11	4	7	4	1	0	1	43	6.65
CALM													0	0.
TOTAL	0	14	29	57	86	65	81	72	69	55	42	172	742	8.14

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-89A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: APRIL, 1975

PASQUILL "A" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	1	0	0	0	0	1	7.60
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	1	0	0	0	0	0	1	6.10
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	1	0	1	0	0	0	0	2	6.50
SSE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.10
S	0	0	0	0	1	0	0	1	0	0	0	1	3	8.30
SSW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.70
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	1	1	0	0	0	0	0	0	0	2	6.30
NNW	0	0	0	0	0	0	0	0	0	0	1	0	1	10.40
N	0	0	0	0	0	2	0	0	0	0	0	0	2	5.80
CALM													0	0.
TOTAL	0	0	0	1	4	4	1	3	0	0	1	1	14	6.49

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL "B" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	1	1	11.30
ENE	0	0	0	0	0	2	0	0	0	0	0	0	2	5.60
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	1	0	0	1	0	0	0	2	4	9.92
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	1	1	0	0	0	0	0	2	6.15
WSW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.30
W	0	0	0	0	0	1	0	0	0	0	0	0	1	5.10
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	1	0	0	1	0	0	4	12.75
NNW	0	0	0	0	0	0	0	0	0	2	0	1	3	11.20
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	1	1	4	2	1	0	3	0	4	20	9.65

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL "C" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.30
ENE	0	0	0	0	0	0	0	1	1	0	0	0	2	7.80
E	0	0	0	0	0	0	1	0	0	0	0	0	1	6.70
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	1	1	0	0	0	0	0	0	2	5.10
S	0	0	0	0	2	2	0	1	0	0	0	2	7	7.99
SSW	0	0	0	0	0	1	1	0	3	1	0	3	9	10.27
SW	0	0	0	1	0	0	1	0	1	0	0	0	3	6.47
WSW	0	0	1	0	1	0	1	0	0	0	0	0	3	4.70
W	0	0	0	0	0	1	0	0	0	0	0	0	1	5.10
WNW	0	0	0	0	0	0	0	1	0	0	0	2	3	12.20
NW	0	0	0	0	0	1	0	1	3	2	1	10	21	11.81
NNW	0	0	0	0	0	0	0	0	2	0	1	4	7	14.17
N	0	0	0	0	0	0	0	0	0	0	1	1	2	10.75
CALM													0	0.
TOTAL	0	0	1	1	6	5	5	6	10	3	3	22	62	10.14

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL "D" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	2	1	0	0	0	0	0	4	5.13
NE	0	0	0	0	0	0	0	0	0	1	0	0	1	9.20
ENE	0	0	0	2	1	2	1	2	3	2	1	1	15	7.10
E	0	0	0	1	0	0	1	0	2	1	1	1	7	7.44
ESE	0	0	0	0	1	2	1	0	0	0	1	0	5	6.38
SE	0	0	0	0	2	3	2	1	1	1	0	0	11	5.87
SSE	0	0	0	0	3	2	2	1	0	1	1	0	10	8.68
S	0	0	0	1	1	0	2	1	0	1	1	0	6	8.48
SSW	0	0	0	1	1	1	0	1	0	2	2	4	12	10.30
SW	0	0	1	0	0	4	3	1	2	0	1	1	13	8.47
WSW	0	0	1	0	1	2	2	2	2	2	2	2	16	10.57
W	0	0	0	1	1	2	2	3	2	4	0	0	15	8.47
WNW	0	0	0	0	2	3	2	3	3	1	2	1	17	8.41
NW	0	0	0	0	1	1	2	1	1	2	1	1	10	8.73
NNW	0	0	0	1	0	0	3	1	1	1	1	1	9	10.29
N	0	0	0	0	0	1	1	0	0	1	1	0	4	8.30
CALM													1	.50
TOTAL	0	1	3	6	13	23	22	16	16	19	14	12	156	9.11

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-89B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: APRIL, 1975

PASQUILL #A (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	1	0	2	0	0	0	0	0	4	5.37
NE	0	3	0	4	0	2	1	1	0	0	0	0	11	3.99
ENE	0	0	1	0	0	1	1	0	0	1	1	0	5	6.83
E	0	0	1	1	2	1	1	0	0	0	0	0	6	4.63
ESE	0	0	0	1	1	1	0	0	0	0	1	0	3	5.60
SE	0	0	0	1	1	2	1	0	2	0	0	0	7	4.89
SSE	0	0	0	0	1	2	8	2	2	0	3	3	23	7.56
S	0	0	0	0	2	5	1	5	5	4	1	1	13	37 9.35
SSW	0	0	1	1	1	3	0	0	1	1	4	3	9	30 9.16
SW	0	0	0	2	4	1	6	4	2	10	2	2	1	36 8.93
WSW	0	0	0	0	1	0	2	1	3	1	0	0	0	8 6.37
W	0	0	0	0	0	2	2	2	6	2	1	0	1	2 18 7.74
WNW	0	0	0	0	0	1	0	1	1	0	0	0	0	4 5.56
NW	0	0	1	0	0	1	1	1	0	1	0	0	1	5 11 9.60
NNW	0	0	0	0	0	1	1	1	2	1	2	1	3	5 16 9.44
N	0	0	1	1	2	1	1	1	0	1	0	0	0	8 4.59
CALM														2 .00
TOTAL	0	6	8	21	21	27	26	24	21	19	15	17	229	7.54

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #B (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	1	0	0	0	0	0	2	4.35
NE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.70
ENE	0	0	0	1	0	0	0	0	0	0	0	0	1	1.50
E	0	0	1	0	0	0	0	1	0	0	0	0	2	4.05
ESE	0	1	0	0	0	1	2	1	0	0	0	0	5	5.58
SE	0	0	1	0	1	0	1	2	1	0	0	0	4	4.17
SSE	0	0	1	1	2	1	4	2	2	4	3	0	16	7.74
S	0	0	0	0	0	0	1	0	0	0	0	0	1	4.10
SSW	0	0	0	1	2	3	2	0	0	0	0	0	8	5.66
SW	0	0	0	1	1	1	0	0	0	0	0	0	3	4.97
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	1	2	1	0	0	0	0	0	5	5.14
WNW	0	1	0	2	3	2	2	1	1	0	0	0	12	5.20
NW	0	0	0	1	1	1	0	0	0	0	0	0	3	4.27
NNW	0	0	0	1	2	1	0	0	0	0	1	0	5	5.22
N	0	0	1	0	0	2	0	0	0	0	0	0	4	4.50
CALM													0	0.
TOTAL	0	2	6	9	14	12	10	4	4	4	4	0	71	5.41

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #C (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	0	2	1	0	1	0	0	0	0	0	5	4.04
NE	0	1	0	0	0	1	0	0	0	0	0	0	1	4.40
ENE	0	0	1	0	0	1	0	0	0	0	0	0	2	2.85
E	0	0	1	0	0	0	2	0	0	0	0	0	3	4.10
ESE	0	0	1	0	2	0	0	0	0	0	0	0	3	2.60
SE	0	0	0	2	3	1	1	0	0	0	0	0	7	3.60
SSE	0	0	1	0	1	0	0	1	0	0	0	0	0	3 3.23
S	0	0	0	0	0	1	0	0	0	0	0	0	0	1 4.60
SSW	0	0	1	1	0	0	1	0	0	0	0	0	0	3 2.60
SW	0	0	1	0	0	0	0	0	0	0	0	0	0	1 2.10
WSW	0	0	2	1	0	0	0	0	0	0	0	0	0	3 1.60
W	0	1	0	1	0	0	0	0	0	0	0	0	0	2 1.55
WNW	0	0	1	2	0	1	0	0	0	0	0	0	0	4 2.17
NW	0	0	2	1	1	0	0	0	0	0	0	0	0	4 1.37
NNW	0	1	1	1	2	0	0	0	0	0	0	0	0	5 2.87
N	0	1	1	0	2	2	0	0	0	0	0	0	0	6 1.62
CALM														2 .00
TOTAL	1	11	17	14	14	5	2	0	0	0	0	0	66	3.21

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	3	2	2	2	5	1	0	0	0	0	16	4.99
NE	0	3	1	4	2	2	1	1	0	1	0	0	15	4.74
ENE	0	0	1	1	3	2	5	2	3	4	1	0	22	6.71
E	0	0	1	3	1	2	4	1	3	1	1	0	27	5.47
ESE	0	2	0	3	2	3	3	1	0	1	0	0	16	5.37
SE	0	0	6	4	6	7	5	2	4	2	1	0	33	5.24
SSE	0	0	1	1	6	8	12	4	4	3	3	0	43	7.51
S	0	0	1	0	3	3	12	5	7	8	5	4	1	24 70 8.00
SSW	0	0	2	3	3	3	10	4	3	3	3	1	4	11 80 8.64
SW	0	0	1	1	6	5	10	8	4	3	4	4	1	27 80 9.06
WSW	0	0	2	3	3	1	4	8	3	4	2	1	1	11 80 8.64
W	0	1	0	2	4	7	7	9	5	5	2	0	0	6 62 7.21
WNW	0	0	2	2	5	7	4	6	4	5	2	0	0	6 67 7.18
NW	0	0	1	2	4	6	5	4	4	2	2	1	0	6 63 7.05
NNW	0	0	1	2	4	5	4	1	2	5	3	1	0	28 72 6.83
N	0	2	1	2	1	8	2	0	1	1	2	1	0	17 67 8.89
CALM														5 .00
TOTAL	1	20	19	61	86	84	68	62	66	54	33	144	720	7.00

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-90A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: MAY, 1975

PASQUILL "A" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	1	0	0	0	0	0	2	5.60
NE	0	0	0	0	0	2	3	1	1	0	0	0	7	6.74
ENE	0	0	0	0	2	1	1	0	0	0	0	0	4	5.35
E	0	0	0	0	0	0	1	0	0	0	0	0	1	6.50
ESE	0	0	0	0	0	1	0	1	0	0	0	0	2	6.45
SE	0	1	0	0	0	0	0	0	0	0	0	1	2	10.05
SSE	0	0	0	1	1	0	0	1	0	0	1	0	4	6.42
S	0	0	0	1	0	0	1	1	2	0	1	1	7	8.10
SSW	0	0	0	1	1	1	0	1	0	0	0	0	4	5.00
SW	0	0	0	0	0	1	0	0	0	0	0	0	1	6.00
WSW	0	0	0	0	0	0	2	0	0	0	0	0	2	5.50
W	0	0	0	0	0	1	0	0	0	0	0	0	1	4.90
WNW	0	0	0	0	0	0	1	0	0	0	0	0	1	5.10
NW	0	0	0	0	0	2	0	0	0	0	0	0	2	4.75
NNW	0	1	1	0	0	0	0	0	0	0	0	0	2	2.65
V	0	0	0	0	1	1	0	0	0	0	0	0	2	4.80
CALM													0	0.
TOTAL	0	2	1	3	6	10	7	5	3	0	2	2	44	6.23

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "B" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.50
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.50
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	1	0	0	0	0	0	0	1	4.80
SE	0	0	0	0	0	2	0	0	1	0	0	0	3	5.60
SSE	0	0	0	0	0	0	1	1	0	0	1	0	3	8.23
S	0	0	0	0	0	0	0	0	0	0	1	0	1	10.20
SSW	0	0	0	1	0	0	0	0	0	0	0	1	2	7.60
SW	0	0	0	0	0	0	2	0	0	0	0	0	2	6.50
WSW	0	0	0	0	0	1	1	0	0	0	0	0	2	6.60
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	1	0	0	0	0	0	0	1	4.30
NW	0	0	0	0	1	0	2	0	1	0	0	0	4	5.57
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
V	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	2	1	5	4	1	0	0	2	1	21	6.43

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "C" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	1	0	0	0	0	0	0	2	5.25
NE	0	0	1	0	0	1	0	0	0	0	0	0	2	4.20
ENE	0	0	0	0	2	0	0	0	1	1	0	0	5	7.44
E	0	0	0	0	0	1	0	0	0	0	0	0	1	4.50
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	1	2	10.00
SSE	0	0	0	0	0	1	0	0	0	1	0	0	2	7.10
S	0	0	0	0	0	1	0	0	0	0	0	0	1	4.80
SSW	0	0	0	0	0	1	2	0	2	0	1	0	6	6.67
SW	0	0	0	0	0	1	1	2	1	1	0	0	7	6.93
WSW	0	0	0	0	0	1	1	2	4	1	1	0	10	6.65
W	0	0	0	0	0	0	1	1	1	0	1	0	4	5.60
WNW	0	0	0	0	0	0	2	0	1	0	1	0	4	6.20
NW	0	0	0	0	0	0	2	1	0	0	0	0	3	6.60
NNW	0	0	0	0	1	1	0	0	0	0	0	0	2	4.50
V	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	1	10	10	8	4	5	4	1	1	57	6.36

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "D" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	4	3	1	1	0	0	0	0	0	1	11	4.22
NE	0	2	2	3	3	3	4	4	1	0	1	0	23	5.51
ENE	0	0	2	2	3	5	7	1	2	2	0	0	24	5.96
E	0	0	1	2	3	3	1	2	1	2	0	0	15	5.81
ESE	0	0	1	1	1	1	4	0	2	2	1	1	15	6.83
SE	0	0	1	3	2	1	2	2	2	3	1	2	20	7.32
SSE	0	0	0	0	0	2	1	3	2	2	5	7	22	9.61
S	0	0	1	0	1	1	4	1	0	0	0	1	14	6.25
SSW	0	0	1	1	1	3	3	5	1	1	0	1	19	6.59
SW	0	0	0	0	5	5	1	2	5	1	0	0	19	5.61
WSW	0	0	1	1	4	2	2	4	2	1	0	0	18	5.69
W	0	0	1	0	6	1	5	1	4	2	2	0	22	7.01
WNW	0	0	0	0	1	1	2	1	4	1	1	1	12	7.03
NW	0	0	0	1	0	4	2	1	2	1	1	0	12	6.07
NNW	0	0	0	2	4	1	1	0	0	1	0	0	9	6.01
V	0	1	0	1	0	1	0	2	0	0	1	0	6	6.15
CALM													1	0.
TOTAL	0	5	14	21	36	42	33	28	25	15	13	16	265	6.56

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-90B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: MAY, 1975

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-A) METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	2	1	5	2	0	0	0	0	0	0	0	10	3.17
NE	0	0	1	5	1	1	1	0	0	0	0	0	9	4.56
ENE	0	0	2	1	4	1	0	0	1	1	0	1	11	5.69
E	0	0	3	3	2	6	1	1	1	0	1	1	19	5.53
ESE	1	0	0	2	1	4	3	2	1	0	0	1	15	6.03
SE	0	0	1	1	0	4	7	3	2	0	0	0	18	4.38
SSE	0	1	1	1	3	4	3	4	2	2	0	1	22	6.41
S	0	0	0	0	4	2	4	1	1	1	0	0	16	6.71
SSW	1	0	1	0	2	1	4	1	2	2	0	0	14	6.21
SW	0	0	0	2	0	1	2	3	1	0	0	0	9	6.23
WSW	0	1	2	3	0	0	2	0	0	0	1	1	10	5.70
W	0	0	1	2	0	2	0	1	0	0	0	0	6	4.87
WNW	2	1	1	0	2	3	0	0	0	0	0	0	9	3.44
NW	0	1	2	4	2	1	1	1	0	0	0	0	12	4.08
NNW	0	0	2	2	0	1	0	0	0	0	0	0	5	3.44
N	1	2	0	2	0	0	0	1	0	0	0	0	6	3.17
CALM													3	.42
TOTAL	5	8	18	33	23	31	29	20	11	6	3	5	194	5.34

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-A) METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	1	0	1	0	0	0	0	0	0	0	3	2.77
NE	0	1	4	3	2	1	0	0	0	0	0	1	12	4.12
ENE	0	2	0	2	1	2	0	0	0	0	0	0	7	3.00
E	1	1	0	1	0	1	0	0	0	0	0	0	4	2.45
ESE	0	0	1	2	1	4	1	1	0	0	0	0	10	5.05
SE	0	0	0	0	0	3	4	4	0	0	0	0	11	6.44
SSE	0	0	1	4	1	2	0	2	0	0	0	0	10	4.75
S	0	0	2	4	1	4	2	0	0	0	0	0	13	4.41
SSW	0	2	1	3	1	1	0	2	2	0	0	0	12	5.07
SW	0	3	1	1	1	0	0	0	0	0	0	0	6	2.63
WSW	0	0	1	0	2	1	0	0	0	0	0	0	4	4.15
W	0	2	0	1	0	0	0	0	0	0	0	0	3	2.46
WNW	0	0	0	1	0	0	0	0	0	0	0	0	1	4.00
NW	0	0	0	3	1	0	1	0	0	0	0	0	5	4.22
NNW	0	1	0	0	1	0	0	0	0	0	0	0	2	3.20
N	0	0	2	0	1	0	0	0	0	0	0	0	3	3.67
CALM													4	.63
TOTAL	1	13	14	25	14	19	8	9	2	0	0	1	110	4.24

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-A) METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	1	0	0	0	0	0	0	0	0	0	2	2.15
NE	2	0	0	2	0	0	0	0	0	0	0	0	4	2.25
ENE	1	1	0	0	0	0	0	0	0	0	0	0	2	1.15
E	0	1	0	0	0	0	0	0	0	0	0	0	1	1.20
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	2	0	0	0	0	2	3.10
SSE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.60
S	0	1	0	0	0	0	1	0	0	0	0	0	2	3.75
SSW	0	1	2	1	0	0	0	0	0	0	0	0	4	2.55
SW	0	0	2	5	1	0	0	0	0	0	0	0	8	3.55
WSW	0	0	3	4	0	0	0	0	0	0	0	0	7	3.07
W	0	0	1	0	1	0	0	0	0	0	0	0	2	4.00
WNW	1	0	1	0	0	0	0	0	0	0	0	0	2	1.90
NW	0	1	1	1	2	0	0	0	0	0	0	0	5	3.32
NNW	0	0	0	0	0	1	0	0	0	0	0	0	1	5.10
N	0	0	0	1	0	0	0	0	0	0	0	0	1	3.70
CALM													0	.00
TOTAL	4	6	12	14	4	1	1	2	0	0	0	0	44	2.73

NUMBER OF INVALID OBSERVATIONS = 0

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-A) METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	5	7	8	6	5	1	0	0	0	0	1	33	3.40
NE	2	1	6	13	6	8	8	5	2	0	1	1	57	4.47
ENE	1	3	4	5	12	10	8	1	4	4	1	1	54	5.55
E	1	2	4	6	6	10	3	3	2	2	1	1	41	5.20
ESE	1	0	2	5	6	10	9	4	1	0	1	2	46	5.26
SE	0	1	2	4	4	8	13	13	4	2	3	4	58	6.05
SSE	0	1	3	6	6	8	5	11	4	4	7	10	65	7.04
S	0	1	1	5	7	7	12	10	4	1	1	1	54	6.10
SSW	1	1	5	8	4	6	4	9	5	5	1	2	52	5.40
SW	0	1	1	8	9	10	6	6	7	1	0	0	52	5.47
WSW	0	1	7	9	7	8	4	5	5	3	1	1	56	5.21
W	0	3	2	9	4	9	2	5	2	2	1	4	43	6.07
WNW	1	1	2	2	6	6	2	2	5	0	1	0	30	5.26
NW	0	2	3	10	4	8	2	4	1	1	1	0	41	4.57
NNW	0	0	2	5	4	3	1	0	0	0	0	0	15	4.13
N	1	1	2	4	2	2	0	1	0	0	1	0	14	4.43
CALM													17	.42
TOTAL	10	24	48	107	106	118	84	81	46	25	21	28	744	5.09

NUMBER OF INVALID OBSERVATIONS = 0

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TABLE 2.3-91A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: JUNE, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	5	2	4	11	10.63
NE	0	0	0	0	1	1	2	0	1	0	1	8	14	10.63
ENE	0	0	0	0	0	2	1	0	0	1	0	0	4	7.02
E	0	0	0	0	0	1	0	0	0	0	1	1	3	8.90
ESE	0	0	0	0	0	0	0	1	1	0	0	0	2	8.10
SE	0	0	0	0	0	1	0	0	2	0	0	0	3	7.73
SSE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.20
S	0	0	0	0	0	0	0	0	0	0	0	1	1	13.40
SSW	0	0	0	0	1	0	0	0	0	0	0	1	2	8.40
SW	0	0	0	0	0	1	1	0	0	0	0	0	3	5.60
WSW	0	0	0	0	1	3	2	1	0	0	0	0	7	5.91
W	0	0	0	0	1	0	2	0	0	0	0	0	3	5.87
WNW	0	0	0	0	0	1	2	0	1	0	0	0	4	5.87
NW	0	0	0	0	0	0	0	1	0	0	0	0	1	7.00
NNW	0	0	0	0	0	0	0	1	0	0	0	0	1	6.80
N	0	0	0	0	0	0	1	1	1	0	1	1	0	5	8.02
CALM														0	0.
TOTAL	0	0	0	1	5	13	11	4	4	7	5	15	65	8.40

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	1	0	0	0	1	8.00
NE	0	0	0	0	0	0	0	2	0	2	0	3	7	11.44
ENE	0	0	0	0	0	0	1	1	1	0	0	0	3	7.33
E	0	0	0	0	1	0	1	1	0	1	2	0	6	8.35
ESE	0	0	0	0	0	0	0	1	0	0	0	0	1	8.00
SE	0	0	0	0	0	0	0	0	0	0	0	1	1	11.20
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	1	1	12.50
SW	0	0	0	0	2	1	1	0	1	0	0	0	5	5.64
WSW	0	0	0	1	1	0	0	0	0	0	0	0	2	4.45
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	1	0	0	0	1	8.30
NNW	0	0	0	0	0	0	0	1	0	0	0	0	1	8.40
N	0	0	0	0	0	0	1	0	0	0	0	0	1	6.90
CALM														0	0.
TOTAL	0	0	0	1	4	1	4	5	5	3	2	5	30	8.50

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	2	1	1	1	1	1	0	1	8	7.02
ENE	0	0	0	0	0	0	0	0	0	1	1	2	4	12.75
E	0	0	0	0	0	0	0	0	4	4	2	3	13	9.82
ESE	0	0	0	0	0	0	0	0	1	0	1	0	2	9.85
SE	0	0	0	0	0	0	0	0	0	1	0	1	2	9.40
SSE	0	0	0	0	0	0	0	1	0	0	0	0	1	6.70
S	0	0	0	0	0	0	0	1	1	0	0	0	3	8.53
SSW	0	0	0	0	0	1	0	2	0	0	0	0	3	7.10
SW	0	0	1	0	0	3	3	1	0	0	0	0	8	6.89
WSW	0	0	0	0	0	0	5	3	2	1	1	0	12	7.66
W	0	0	0	0	0	0	2	1	1	0	0	0	4	6.10
WNW	0	0	0	0	1	1	0	1	0	0	0	0	3	6.93
NW	0	0	0	0	0	1	0	1	0	0	0	0	2	5.90
NNW	0	0	0	0	0	1	0	1	0	0	0	0	2	7.37
N	0	0	0	0	0	0	0	1	1	0	0	0	0	2	6.95
CALM														0	0.
TOTAL	0	0	1	1	3	12	12	8	8	7	6	9	72	7.78

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	2	1	1	1	3	9	10.61
NE	0	0	1	0	3	1	3	4	1	2	1	2	18	6.96
ENE	0	0	0	0	3	2	7	6	5	2	2	2	29	7.79
E	0	0	0	0	2	1	2	2	1	0	2	1	11	7.68
ESE	0	0	0	0	0	0	1	4	4	2	2	3	16	9.34
SE	0	0	0	0	0	1	1	0	0	1	2	3	8	10.31
SSE	0	0	0	1	0	0	0	3	2	0	1	1	8	7.97
S	0	0	0	0	0	2	1	2	1	1	0	1	8	7.97
SSW	0	0	0	0	1	2	1	4	1	0	1	0	10	8.45
SW	0	0	0	0	0	2	0	4	2	0	1	0	11	7.46
WSW	0	0	0	0	1	6	4	9	4	3	0	1	28	8.28
W	0	0	0	0	1	1	5	2	5	2	3	2	21	7.66
WNW	0	0	0	1	0	1	5	1	1	0	1	0	10	6.17
NW	0	0	0	0	0	1	1	1	1	0	0	0	4	6.17
NNW	0	0	0	0	0	1	1	1	1	0	0	0	4	6.34
N	0	0	0	0	0	2	1	1	1	0	1	0	1	7	6.50
CALM														0	0.
TOTAL	0	0	2	5	24	29	44	41	27	20	18	18	242	7.94

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-91B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: JUNE, 1975

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	3	3	1	0	0	3	0	0	0	0	11	4.36
NE	0	0	1	0	7	4	3	3	1	0	0	0	19	5.65
ENE	0	0	2	1	1	1	4	2	1	2	0	0	14	6.21
E	0	0	0	0	4	0	2	1	0	0	0	0	7	5.71
ESE	0	0	0	1	1	3	3	2	0	0	0	0	10	5.95
SE	0	0	2	0	1	2	0	0	0	0	0	0	5	4.03
SSE	0	0	1	0	4	5	3	4	0	0	0	1	18	6.12
S	0	1	1	2	1	2	3	0	2	0	2	0	14	5.96
SSW	0	0	1	1	3	6	2	1	0	0	0	0	14	5.19
SW	0	0	2	2	6	5	1	0	0	0	0	0	16	4.59
WSW	0	0	0	0	6	5	3	0	0	2	0	0	16	5.88
W	0	0	0	0	2	2	3	0	1	0	0	0	8	5.06
WNW	1	0	0	0	0	3	0	0	0	0	0	0	4	4.40
NW	0	0	0	1	2	1	1	0	0	1	0	0	6	5.67
NNW	0	1	0	0	1	1	1	0	0	0	0	0	4	4.60
N	1	1	2	4	2	1	1	0	0	0	0	0	12	3.41
CALM													1	.60
TOTAL	2	4	15	17	42	42	27	17	4	5	2	1	179	5.31

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	0	0	0	0	0	0	0	0	0	0	1	1.20
NE	0	1	1	1	0	1	0	0	0	0	0	0	4	3.12
ENE	0	1	0	1	2	2	0	0	0	0	0	0	6	4.10
E	0	1	0	1	1	1	0	0	0	0	0	0	4	3.80
ESE	1	0	1	0	1	0	3	1	0	0	0	0	7	4.94
SE	0	1	1	0	0	0	1	1	0	0	0	0	4	4.55
SSE	0	0	2	0	0	0	0	0	0	0	0	0	2	2.45
S	0	0	1	0	1	0	1	2	1	0	0	0	6	6.15
SSW	1	0	0	1	3	2	3	0	0	0	0	0	10	5.05
SW	0	0	1	2	2	2	0	0	0	0	0	0	7	4.37
WSW	0	0	2	2	1	2	0	0	0	0	0	0	7	3.90
W	0	1	1	5	1	0	0	0	0	0	0	0	8	3.37
WNW	0	0	1	0	1	0	0	0	0	0	0	0	3	3.43
NW	0	1	0	1	2	1	0	0	0	0	0	0	5	4.04
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	1	1	1	1	0	0	0	0	0	0	0	4	2.83
CALM													3	.61
TOTAL	2	6	11	16	15	12	8	4	1	0	0	0	91	4.04

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	2	1	0	0	0	0	0	0	0	0	3	2.97
NE	1	1	1	2	0	0	0	0	0	0	0	0	5	2.64
ENE	0	1	0	2	0	0	0	0	0	0	0	0	3	2.77
E	0	0	1	0	0	0	0	0	0	0	0	0	1	2.10
ESE	0	0	0	0	0	0	1	0	0	0	0	0	1	5.30
SE	0	0	1	0	0	0	1	0	0	0	0	0	2	4.30
SSE	0	0	0	0	0	1	0	2	0	0	0	0	3	6.17
S	0	0	0	0	1	0	0	0	0	0	0	0	1	3.80
SSW	0	2	1	1	3	3	0	1	0	0	0	0	11	4.40
SW	0	0	2	0	2	1	0	0	0	0	0	0	5	4.10
WSW	0	1	0	1	2	0	0	0	0	0	0	0	4	3.47
W	0	1	1	0	0	0	0	0	0	0	0	0	2	2.15
WNW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.20
NW	1	0	1	0	0	0	0	0	0	0	0	0	2	1.70
NNW	0	2	1	0	0	0	0	0	0	0	0	0	3	1.77
N	0	0	0	0	1	0	0	0	0	0	0	0	1	4.30
CALM													1	.63
TOTAL	2	8	11	8	10	6	2	1	0	0	0	0	51	3.63

NUMBER OF INVALID OBSERVATIONS = 0

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	2	5	4	1	0	1	5	2	6	3	7	36	7.26
NE	1	2	4	3	11	8	9	12	4	5	2	12	75	7.21
ENE	0	2	2	4	6	7	13	9	7	6	3	6	65	7.09
E	0	0	1	1	1	1	3	5	4	5	5	7	33	7.69
ESE	1	0	1	1	2	4	7	9	6	2	3	3	44	7.52
SE	0	0	1	4	0	1	5	2	1	3	1	3	25	7.16
SSE	0	0	3	1	5	6	6	7	2	0	1	2	33	5.34
S	0	0	1	2	3	2	4	6	5	4	1	2	35	7.19
SSW	1	0	2	2	5	11	11	9	5	0	1	5	58	6.02
SW	1	0	2	4	4	10	11	8	2	7	3	1	53	5.62
WSW	0	0	1	2	5	7	10	11	7	2	1	2	44	5.87
W	0	0	2	2	8	5	10	5	7	4	3	2	48	6.03
WNW	0	1	1	1	2	6	11	2	2	0	1	0	27	5.30
NW	1	1	1	1	3	6	5	7	1	2	2	0	30	5.60
NNW	0	1	1	0	1	2	4	1	1	1	1	0	13	5.23
N	1	2	3	5	6	5	7	3	0	2	1	1	36	5.11
CALM													7	.61
TOTAL	6	21	48	49	108	115	108	80	49	52	41	44	720	

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TABLE 2.3-92A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: JULY, 1975

PASQUILL "A" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	0	0	0	0	0	1	6.60
NE	0	0	0	0	0	0	0	1	0	0	0	0	1	7.60
ENE	0	0	0	1	0	0	0	0	0	0	0	0	1	4.00
E	0	0	0	0	0	2	1	0	0	0	0	0	3	5.60
ESE	0	0	0	1	1	0	0	0	0	1	0	0	3	5.93
SE	0	0	1	0	0	1	1	0	0	0	0	0	3	4.77
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	2	0	0	1	1	0	1	0	5	6.96
SSW	0	0	0	0	1	0	1	0	0	0	0	1	3	7.67
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	1	0	0	0	0	0	0	1	5.60
W	0	0	0	0	0	0	1	0	0	0	0	0	1	5.80
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	1	0	0	1	0	0	0	1	0	0	0	3	4.87
NNW	0	0	0	0	0	1	0	1	0	0	0	0	2	6.65
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	1	2	5	6	4	3	2	1	1	1	27	6.09

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "B" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	1	0	1	10.50
ENE	0	0	0	1	2	0	0	0	0	1	0	0	4	5.57
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	1	0	0	2	0	0	0	0	0	3	5.53
SE	0	0	0	0	0	0	0	1	0	0	0	0	1	7.30
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	1	0	0	0	0	0	0	1	5.30
SSW	0	0	0	1	0	0	0	1	0	0	2	0	4	7.87
SW	0	0	0	0	0	1	0	0	0	1	0	1	3	9.00
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	1	0	0	0	0	1	0	2	6.40
WNW	0	0	0	0	0	1	0	0	0	0	0	0	1	5.30
NW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.40
NNW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.50
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	3	5	3	2	2	0	3	3	1	22	6.75

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "C" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	1	0	0	0	0	0	0	0	0	1	3.30
ENE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.40
E	0	0	0	0	0	0	1	1	0	0	0	0	2	7.85
ESE	0	0	0	0	0	1	1	0	0	0	1	0	3	6.43
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.40
S	0	0	0	0	0	0	1	1	1	0	1	0	4	8.42
SSW	0	0	0	1	0	0	0	1	1	0	0	0	3	6.50
SW	0	0	0	0	0	0	0	1	3	0	2	0	6	7.92
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	1	1	0	1	0	0	0	0	3	4.60
WNW	0	0	0	0	0	1	1	0	1	0	0	0	3	6.03
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	1	1	>22.10
CALM													0	0.
TOTAL	0	0	1	3	4	2	3	3	5	1	1	1	28	7.14

NUMBER OF INVALID OBSERVATIONS = 0

PASQUILL "D" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.40
NE	1	0	1	0	0	0	0	0	0	0	0	0	2	1.45
ENE	0	1	1	1	0	1	0	0	0	0	0	0	4	3.27
E	0	0	0	0	0	2	0	0	1	0	0	0	3	6.53
ESE	0	0	0	0	1	0	0	0	0	0	1	0	2	7.40
SE	0	0	0	1	0	0	2	0	2	2	1	0	8	8.51
SSE	0	0	0	0	0	2	6	3	1	0	0	0	11	8.51
S	0	0	1	1	2	1	1	7	2	5	1	4	25	8.56
SSW	0	1	0	1	3	2	5	7	3	2	2	0	27	8.11
SW	0	0	2	0	3	1	7	8	2	1	0	2	26	8.92
WSW	0	0	1	0	1	3	4	5	2	0	1	1	18	7.05
W	0	0	0	0	2	3	1	3	2	3	0	2	16	8.75
WNW	0	0	0	0	0	1	0	0	0	0	0	0	1	4.20
NW	0	1	0	2	0	0	1	0	0	0	1	0	5	6.36
NNW	0	0	1	1	0	1	0	0	0	0	0	0	3	5.03
N	0	1	0	1	1	0	0	0	0	0	0	0	3	2.87
CALM													0	0.
TOTAL	1	4	7	10	15	17	29	34	18	9	11	11	166	7.09

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-92B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: JULY, 1975

PASQUILL #A (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	3	4	1	0	0	0	1	0	0	0	0	9	3.00
NE	0	1	1	7	1	3	4	1	2	0	0	1	21	5.43
ENE	0	2	3	3	1	1	1	0	0	0	0	0	11	3.64
E	0	1	2	5	3	2	0	0	0	0	0	0	13	3.73
ESE	0	0	1	4	2	1	3	2	2	2	0	1	18	6.36
SE	0	1	1	8	9	5	6	5	1	2	0	0	37	5.44
SSE	0	0	2	5	4	4	8	5	1	1	2	2	34	6.37
S	1	3	4	6	6	13	13	4	1	0	0	0	51	5.09
SSW	0	1	2	1	12	8	9	7	2	1	0	1	44	6.11
SW	0	3	2	6	7	7	9	5	2	0	0	0	41	5.29
WSW	0	0	1	3	8	5	0	2	1	0	0	0	20	5.01
W	1	0	1	0	2	1	0	1	0	0	0	0	6	4.23
WNW	0	0	0	4	1	0	0	1	0	0	0	0	6	4.33
NW	0	1	3	3	1	2	0	1	0	0	1	1	13	5.15
NNW	0	2	3	0	0	2	0	0	0	0	0	0	7	3.00
N	0	3	0	4	0	0	1	0	2	0	0	0	10	4.33
CALM													7	.43
TOTAL	2	21	30	60	58	54	56	35	14	6	3	6	350	5.14

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	1	2	3	1	2	0	0	0	0	0	0	0	9	2.74
NE	0	1	3	1	1	1	2	0	0	0	0	0	9	3.42
ENE	0	0	2	2	1	2	2	2	3	1	2	0	19	5.89
E	0	0	2	1	2	1	2	1	0	0	0	0	9	4.78
ESE	1	0	0	3	1	1	1	1	0	0	0	0	8	4.63
SE	0	1	1	1	3	6	2	0	0	0	0	0	14	4.72
SSE	0	1	1	2	4	1	0	1	1	0	0	0	11	4.72
S	0	2	4	2	2	0	0	0	0	0	0	0	10	3.05
SSW	0	0	1	0	1	1	0	0	0	0	0	0	5	4.24
SW	0	0	1	0	1	0	0	0	0	0	0	0	5	4.24
WSW	0	0	0	0	4	1	0	0	0	0	0	0	5	4.62
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	1	0	0	0	0	0	0	0	0	1	0	2	6.45
NW	0	1	1	0	0	0	0	0	0	0	0	0	2	2.39
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	1	1	0	0	0	0	0	0	0	0	2	2.44
CALM													1	.43
TOTAL	2	9	26	14	24	14	9	5	4	3	3	0	116	4.39

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.60
NE	0	0	2	0	0	0	0	0	0	0	0	0	2	2.70
ENE	1	1	0	5	1	1	0	0	0	0	0	0	9	3.24
E	0	0	0	0	0	5	1	2	0	0	0	0	8	5.21
ESE	0	0	0	0	0	0	0	1	0	0	0	0	1	4.60
SE	0	2	0	0	0	0	0	0	0	0	0	0	2	1.55
SSE	0	0	0	0	0	1	0	0	0	0	0	0	1	4.70
S	0	0	0	0	0	1	0	0	0	0	0	0	1	4.60
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.80
NW	0	0	0	0	1	0	0	0	0	0	0	0	1	3.00
NNW	0	0	0	0	0	1	0	0	0	0	0	0	1	4.10
N	0	0	0	0	1	0	0	0	0	0	0	0	1	3.00
CALM													1	.43
TOTAL	1	3	3	5	3	7	1	3	0	0	0	0	30	3.93

(OF INVALID OBSERVATIONS = 0
NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	1	5	8	2	2	1	1	1	0	0	0	0	21	3.15
NE	1	4	7	9	2	4	6	2	2	0	1	1	37	4.24
ENE	1	4	6	13	6	5	3	2	1	4	2	0	47	4.04
E	0	1	4	6	10	8	5	2	2	0	0	0	38	4.08
ESE	1	0	1	5	6	3	7	1	2	4	1	1	32	5.01
SE	0	4	3	10	11	14	9	5	3	1	1	1	63	4.77
SSE	0	1	4	7	9	7	14	9	3	1	3	2	60	5.08
S	1	5	9	9	13	15	17	11	5	1	3	2	92	4.97
SSW	0	2	1	4	10	11	15	10	4	1	4	2	65	5.06
SW	1	3	8	6	11	9	17	10	4	1	4	2	76	5.11
WSW	0	1	2	3	13	10	4	7	1	0	1	1	44	4.61
W	1	0	1	3	7	3	4	3	1	0	1	2	26	5.02
WNW	0	1	0	5	1	2	0	2	1	0	1	0	13	4.23
NW	0	2	7	3	1	2	1	1	0	0	1	2	20	4.21
NNW	1	2	4	1	2	4	0	1	0	0	0	1	16	4.00
N	0	4	1	7	1	0	1	0	2	0	0	1	17	4.79
CALM													11	.43
TOTAL	9	48	69	100	128	98	104	80	39	25	24	22	741	4.64

NUMBER OF INVALID OBSERVATIONS = 3
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-93A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: AUGUST, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	1	1	0	0	0	0	0	0	5	4.60
NE	0	0	0	0	1	0	0	0	0	0	0	0	1	5.00
ENE	0	0	0	2	1	4	2	0	0	0	0	0	9	5.08
E	0	0	1	1	1	2	2	0	0	0	0	0	7	4.91
ESE	0	0	0	0	1	0	3	0	0	0	0	0	4	6.10
SE	0	0	1	0	2	0	0	0	0	0	0	0	3	3.87
SSE	0	0	0	1	0	0	0	0	0	0	0	0	1	3.90
S	0	0	0	1	1	2	0	0	0	0	0	0	4	4.70
SSW	0	0	0	0	1	2	1	1	3	1	0	0	11	7.59
SW	0	0	0	0	3	4	1	3	1	2	1	6	21	5.57
WSW	0	0	0	2	0	4	2	2	0	0	0	0	10	4.81
W	0	0	0	3	0	1	0	0	0	0	0	0	4	3.22
WNW	0	0	0	0	2	0	1	0	0	0	0	0	3	4.07
NW	0	0	0	1	2	2	0	0	0	0	0	0	5	3.96
NNW	0	0	0	2	2	2	0	0	0	0	0	0	6	3.38
N	0	0	0	0	0	2	0	0	0	0	0	0	2	4.40
CALM													0	0.
TOTAL	0	0	10	15	19	27	13	7	5	4	0	0	96	5.10

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	1	0	0	0	0	0	0	2	5.10
NE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.20
ENE	0	0	0	1	0	0	1	0	0	0	0	0	2	5.10
E	0	0	0	0	1	0	1	0	0	0	0	0	2	5.70
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	1	0	0	0	0	0	0	0	1	4.20
SSW	0	0	0	1	0	0	1	0	0	2	0	0	4	6.27
SW	0	0	0	0	0	0	3	1	1	2	1	1	9	7.47
WSW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.00
W	0	0	0	0	1	0	0	0	0	0	0	0	1	4.10
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	1	1	0	0	0	0	0	0	0	2	3.35
NNW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.00
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	2	5	4	5	3	1	1	4	1	1	24	5.01

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	0	0	0	0	0	0	0	0	1	3.30
NE	0	0	1	0	0	0	0	1	0	0	0	0	2	4.40
ENE	0	0	0	0	0	1	7	0	0	0	0	0	8	6.50
E	0	0	0	0	1	0	0	0	0	0	0	0	1	3.20
ESE	0	0	0	0	0	2	0	0	0	0	0	0	2	4.90
SE	0	0	0	1	0	1	0	0	0	0	0	0	2	3.80
SSE	0	0	0	0	0	1	1	0	0	0	0	0	2	5.10
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	2	1	1	0	2	0	6	7.55
SW	0	0	0	0	0	1	1	5	1	1	2	0	11	7.74
WSW	0	0	0	0	2	1	2	1	0	0	0	0	6	4.78
W	0	0	0	1	0	0	0	0	0	0	0	0	1	3.00
WNW	0	0	0	1	2	2	0	0	0	0	0	0	5	4.84
NW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.40
NNW	0	0	0	0	1	0	0	0	0	0	0	0	1	3.80
CALM													0	0.
TOTAL	0	0	4	8	11	9	15	8	1	4	0	0	55	5.61

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	3	1	1	0	1	0	0	0	0	0	6	3.67
NE	0	0	7	5	2	5	3	0	1	0	0	0	23	4.65
ENE	0	2	3	1	7	5	2	0	0	0	0	0	20	4.41
E	0	0	1	2	5	1	2	0	0	0	0	0	11	4.19
ESE	0	0	1	1	1	1	0	0	0	0	0	0	4	3.75
SE	0	0	1	2	0	0	0	0	0	0	0	0	3	3.63
SSE	0	0	0	1	0	2	0	0	0	0	0	0	3	4.20
S	0	0	1	1	2	4	1	0	0	0	0	0	9	4.58
SSW	0	0	0	2	3	1	0	1	0	0	0	0	7	4.57
SW	0	1	1	2	4	5	2	2	0	0	0	0	18	5.14
WSW	0	0	1	1	3	7	4	2	0	0	0	0	21	5.29
W	0	0	4	5	1	4	10	5	2	0	0	0	31	5.14
WNW	0	0	2	1	1	4	1	1	1	0	0	0	11	4.55
NW	0	1	2	1	0	1	0	0	0	0	0	0	5	3.20
NNW	0	0	6	8	1	2	0	0	0	0	0	0	17	3.71
N	0	0	1	1	2	0	0	1	0	0	0	0	5	4.22
CALM													0	0.
TOTAL	0	5	37	47	45	49	25	12	5	0	0	0	227	4.76

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-93B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: AUGUST, 1975

PASQUILL #A (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	2	7	1	0	0	0	0	0	0	0	0	10	2.44
NE	0	0	10	0	0	0	0	0	0	0	0	0	10	2.67
ENE	0	0	4	2	0	0	0	0	0	0	0	1	7	4.26
E	0	0	2	5	0	0	0	1	0	0	0	0	8	3.72
ESE	0	0	2	3	0	0	0	0	0	0	0	0	5	3.20
SE	0	1	0	1	0	1	1	0	0	0	0	0	4	4.12
SSE	0	0	0	3	3	1	2	0	0	0	0	0	9	4.84
S	0	2	11	9	13	4	0	0	0	0	0	0	39	3.75
SSW	0	4	6	14	20	3	0	0	0	0	0	0	47	3.90
SW	0	3	12	8	2	0	0	0	0	0	0	0	25	2.96
WSW	1	1	3	1	1	0	0	0	0	0	0	0	7	2.73
W	0	3	4	1	0	0	0	0	0	0	0	0	8	2.17
WNW	1	1	3	0	0	0	0	0	0	0	0	0	5	2.14
NW	0	0	1	0	0	0	0	0	0	0	0	0	1	2.90
NNW	1	2	1	0	0	0	0	0	0	0	0	0	4	1.65
N	0	1	4	0	0	0	0	0	0	0	0	0	5	2.24
CALM													6	.47
TOTAL	3	20	70	68	39	9	3	1	0	0	0	1	200	3.30

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	2	3	0	0	0	0	0	0	0	0	0	5	2.04
NE	0	4	1	2	0	0	0	0	0	0	0	0	7	2.21
ENE	0	3	2	3	0	0	0	0	0	0	0	0	8	2.44
E	0	1	1	0	0	0	0	0	0	0	0	0	2	2.15
ESE	1	0	1	0	0	0	0	0	0	0	0	0	2	1.55
SE	0	3	1	2	1	0	0	0	0	0	0	0	7	2.10
SSE	0	0	3	4	1	1	0	0	0	0	0	0	11	2.55
S	0	7	4	1	8	2	0	0	0	0	0	0	22	3.36
SSW	0	0	7	1	4	0	6	0	0	0	0	0	12	3.25
SW	0	2	5	2	0	0	0	0	0	0	0	0	9	2.59
WSW	0	3	5	1	0	0	0	0	0	0	0	0	9	2.21
W	0	1	1	0	0	0	0	0	0	0	0	0	2	2.00
WNW	0	1	1	0	0	0	0	0	0	0	0	0	2	1.75
NW	1	2	1	0	0	0	0	0	0	0	0	0	4	1.77
NNW	0	1	0	0	0	0	0	0	0	0	0	0	1	1.10
N	1	3	2	0	0	0	0	0	0	0	0	0	6	1.83
CALM													4	.47
TOTAL	3	33	38	16	18	3	0	0	0	0	0	0	115	2.67

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	4	0	0	0	0	0	0	0	0	0	0	4	1.77
NE	0	2	1	0	0	0	0	0	0	0	0	0	3	1.73
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	1	0	0	0	0	0	0	0	0	0	1	2.10
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	1	0	0	1	1	0	0	0	0	0	0	3	4.00
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	3	1	0	0	0	0	0	0	0	0	0	4	2.25
SSW	0	1	3	0	0	0	0	0	0	0	0	0	4	2.32
SW	0	0	4	0	0	0	0	0	0	0	0	0	4	2.12
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	2	0	0	0	0	0	0	0	0	0	0	2	1.50
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	6	2	1	0	0	0	0	0	0	0	0	0	3	1.77
NNW	2	0	0	0	0	0	0	0	0	0	0	0	2	.45
N	0	1	1	0	0	0	0	0	0	0	0	0	2	2.00
CALM													1	.47
TOTAL	2	16	12	0	1	1	0	0	0	0	0	0	35	2.00

NUMBER OF INVALID OBSERVATIONS = 0
NE NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-41 METE)
WINDS AT 10.5 METE LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	8	13	4	5	2	1	0	0	0	0	0	33	3.02
NE	0	6	20	7	4	5	3	1	1	0	0	0	47	3.57
ENE	0	5	9	9	8	10	12	0	0	0	0	1	54	4.56
E	0	1	6	9	7	3	3	1	0	0	0	0	40	4.12
ESE	1	0	4	6	4	1	3	0	0	0	0	0	19	4.06
SE	0	5	4	5	7	2	1	0	0	0	0	0	24	3.55
SSE	0	0	3	11	7	5	2	0	0	0	0	0	28	4.21
S	0	13	17	14	26	9	0	1	0	0	0	0	80	3.65
SSW	0	5	17	17	34	14	6	4	5	5	0	0	107	4.71
SW	0	6	22	20	20	16	14	5	8	4	1	0	116	4.34
WSW	1	4	14	11	11	8	11	5	2	0	0	0	68	4.03
W	0	6	11	4	3	4	3	1	1	0	0	0	33	3.73
WNW	1	3	8	5	2	2	0	0	0	0	0	0	21	3.14
NW	1	4	11	11	4	2	0	0	0	0	0	0	33	3.15
NNW	4	3	6	4	2	0	0	0	0	0	0	0	19	2.53
N	1	5	8	2	6	0	0	1	0	0	0	0	23	2.70
CALM													11	.47
TOTAL	9	76	173	139	144	81	59	19	17	9	1	1	744	3.72

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-94A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: SEPTEMBER, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS - 1
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	0	0	1	0	0	1	0	0	3	6.67
NE	0	0	0	1	0	0	1	0	0	0	0	0	2	5.05
ENE	0	0	0	1	0	0	0	0	0	0	0	0	1	3.33
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	1	0	0	0	0	0	0	1	4.50
SE	0	0	0	0	0	2	0	0	0	0	0	0	2	4.50
SSE	0	0	0	0	0	0	1	0	0	1	0	0	2	7.00
S	0	0	0	0	0	0	2	1	1	1	0	0	5	7.17
SSW	0	0	0	0	1	0	1	2	0	0	0	0	4	5.50
SW	0	0	0	1	0	0	0	0	0	0	0	0	1	2.20
WSW	0	0	0	0	1	0	0	0	0	0	0	0	1	3.30
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	2	0	0	0	0	0	0	0	2	3.25
NW	0	0	0	0	2	1	3	1	0	0	0	0	7	4.64
NNW	0	0	0	0	2	2	0	0	0	0	0	0	4	4.00
N	0	0	0	1	2	1	2	0	0	0	0	0	6	5.17
CALM													0	0.
TOTAL	0	0	1	12	8	8	8	1	1	3	0	0	42	5.24

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS - 1
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	2	0	0	0	0	0	0	3	5.33
NE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.00
ENE	0	0	0	0	0	0	0	0	1	0	0	0	1	8.33
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	1	0	0	0	0	0	1	8.00
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	1	0	0	0	0	1	7.00
S	0	0	0	0	0	0	0	0	1	0	0	0	1	9.00
SSW	0	0	0	0	0	0	0	0	0	1	0	0	1	10.00
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	0	1	3	1	1	2	1	0	0	9	7.67

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS - 1
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	0	0	0	0	2	1	1	0	5	8.25
NE	0	0	0	1	1	0	0	0	0	0	1	1	3	6.67
ENE	0	0	1	0	0	0	0	1	2	0	1	4	9	9.78
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	1	0	0	1	0	0	1	3	8.67
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	1	0	0	1	0	0	2	6.50
SSW	0	0	0	0	0	0	0	1	0	0	0	0	1	6.50
SW	0	0	0	0	0	0	1	0	0	0	0	0	1	6.50
WSW	0	0	0	0	0	0	1	0	0	0	0	0	1	6.50
W	0	0	0	0	0	0	1	0	0	0	0	0	1	6.50
WNW	0	0	0	0	1	2	0	0	0	0	0	0	3	7.67
NW	0	0	0	0	1	0	0	0	0	0	0	0	1	6.50
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	1	1	0	0	0	0	1	1	0	4	9.00
CALM													0	0.
TOTAL	0	0	3	6	6	0	1	2	6	4	2	6	46	7.29

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS - 1
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	5	3	1	1	1	0	0	1	1	2	17	6.47
NE	0	2	6	4	1	3	5	1	0	1	0	0	23	5.61
ENE	0	2	6	3	4	5	3	5	1	1	0	0	30	5.63
E	0	0	0	0	1	2	1	5	1	0	0	0	10	7.11
ESE	0	0	0	1	1	2	1	3	1	2	0	0	11	7.32
SE	0	1	0	0	2	2	3	1	1	0	0	0	10	6.80
SSE	0	1	6	0	0	6	2	1	1	0	0	0	17	6.24
S	0	0	6	1	0	1	1	3	1	1	0	0	14	6.75
SSW	0	0	1	0	0	1	2	1	2	1	0	0	8	6.88
SW	0	0	0	0	0	1	1	2	1	1	0	0	6	7.67
WSW	0	0	0	1	0	1	2	1	0	1	0	0	6	6.67
W	0	0	1	1	0	1	1	2	1	0	0	0	7	6.43
WNW	0	0	0	2	1	1	1	0	0	1	0	0	6	6.67
NW	0	0	2	2	1	1	0	0	1	0	0	0	7	6.14
NNW	0	0	1	1	1	0	0	1	0	0	0	0	4	6.25
N	0	0	1	0	1	1	2	2	0	0	0	0	6	6.50
CALM													1	0.
TOTAL	0	7	38	19	17	38	25	32	10	11	1	2	201	6.40

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-94B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: SEPTEMBER, 1975

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	2	3	1	2	0	3	7	1	0	0	0	19	5.43
NE	0	2	1	4	3	7	4	3	3	1	2	4	36	6.94
ENE	0	1	5	3	3	1	2	0	0	0	0	0	15	3.79
E	0	1	0	2	2	2	3	0	0	0	1	0	11	4.73
ESE	0	0	0	1	2	1	0	0	2	1	1	0	8	7.04
SE	0	0	0	2	1	1	2	0	1	1	4	2	0	22	6.91
SSE	0	0	1	1	2	5	1	3	0	6	1	0	0	21	5.98
S	0	1	0	0	5	5	2	1	2	0	0	0	1	17	5.08
SSW	0	0	2	4	1	2	1	3	3	2	1	0	0	19	5.24
SW	0	0	2	1	1	0	1	0	1	0	0	0	0	6	3.68
WSW	0	0	0	0	1	1	2	2	0	0	0	0	0	6	5.28
W	0	0	1	1	5	2	3	0	0	0	0	0	0	12	3.79
WNW	0	0	2	1	4	4	0	1	2	0	0	0	0	14	4.26
NW	0	1	1	5	0	2	4	0	1	0	0	0	0	14	3.93
NNW	0	0	1	3	1	1	0	1	0	0	0	0	0	6	4.00
N	0	1	1	2	3	0	0	0	0	0	0	0	0	7	2.64
CALM														4	.65
TOTAL	3	16	31	35	41	28	28	20	15	8	6	7	242	5.21

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	1	0	0	0	1	0	0	0	0	3	4.[illegible]
NE	0	0	0	0	3	5	2	1	1	0	0	0	12	5.81
ENE	0	0	1	1	0	1	0	0	0	0	0	0	3	3.97
E	0	2	2	0	0	2	0	0	0	0	0	0	6	3.47
ESE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.[illegible]
SE	0	1	1	1	2	1	0	1	0	0	0	0	0	4.[illegible]
SSE	0	1	1	0	2	0	1	0	0	0	0	0	4	4.[illegible]
S	0	0	2	1	2	0	0	1	0	0	0	0	6	4.17
SSW	0	0	1	0	0	0	0	0	0	0	0	0	1	2.[illegible]
SW	1	1	3	1	0	0	0	0	0	0	0	0	6	3.33
WSW	0	0	2	1	0	0	0	0	0	0	0	0	3	2.[illegible]
W	0	0	1	1	1	0	0	0	0	0	0	0	3	2.[illegible]
WNW	1	1	0	0	1	1	0	0	0	0	0	0	4	3.[illegible]
NW	0	1	0	0	2	0	0	0	0	0	0	0	3	3.77
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													1	.[illegible]
TOTAL	2	6	15	9	10	11	2	4	1	1	0	0	64	3.[illegible]

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	1	1	0	0	0	0	0	0	0	2	3.05
ENE	0	0	1	0	1	0	0	0	0	0	0	0	2	2.50
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	1	0	0	0	0	0	0	0	0	0	1	1.30
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	1	0	0	0	0	0	0	0	0	1	2.30
SW	0	0	2	0	0	0	0	0	0	0	0	0	2	1.50
WSW	0	0	1	1	1	0	0	0	0	0	0	0	3	2.23
W	0	0	1	1	0	0	0	0	0	0	0	0	4	2.19
WNW	0	0	0	0	1	0	0	0	0	0	0	0	1	3.70
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	1	0	0	0	0	0	0	0	0	0	0	0	1	.90
CALM													7	.60
TOTAL	1	0	5	4	1	0	0	0	0	0	0	0	24	1.73

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	3	9	7	4	5	5	17	11	5	2	2	70	5.[illegible]
NE	0	4	7	11	9	14	12	10	7	4	5	19	106	7.[illegible]
ENE	0	4	13	9	7	7	5	6	7	6	2	11	77	5.[illegible]
E	0	3	4	2	5	7	1	1	5	4	1	1	34	4.[illegible]
ESE	0	0	1	2	4	1	0	3	5	1	1	0	18	6.[illegible]
SE	0	3	3	2	6	5	11	6	3	7	3	7	56	7.[illegible]
SSE	0	2	1	4	6	3	5	1	7	5	0	3	37	7.[illegible]
S	1	0	3	6	9	5	4	7	5	1	0	0	42	5.[illegible]
SSW	0	2	4	2	4	9	4	8	3	1	0	5	43	6.[illegible]
SW	0	0	5	5	2	4	2	2	3	1	0	2	27	5.[illegible]
WSW	0	0	1	4	4	7	10	3	1	0	2	1	33	5.[illegible]
W	0	0	5	6	6	6	4	2	3	0	1	0	33	4.[illegible]
WNW	1	1	2	11	11	2	2	4	1	0	0	0	35	3.[illegible]
NW	1	2	7	5	5	8	1	2	1	0	0	0	32	3.[illegible]
NNW	0	0	5	5	4	0	1	2	1	0	0	0	18	3.[illegible]
N	2	1	4	5	5	2	4	2	1	1	0	0	26	3.[illegible]
CALM													11	.[illegible]
TOTAL	5	18	82	84	92	86	74	75	65	42	18	56	717	5.[illegible]

NUMBER OF INVALID OBSERVATIONS = 3
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-95A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: OCTOBER, 1975

PASQUILL BAR (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	1	0	0	0	0	0	2	4	11.00
NE	0	0	0	0	0	0	0	0	1	0	0	0	1	8.70
ENE	0	0	0	0	0	0	1	0	0	0	0	0	2	7.00
E	0	0	0	0	0	0	0	1	0	0	0	0	1	7.60
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	1	0	0	0	0	0	0	0	1	5.50
SW	0	0	0	0	1	0	0	0	0	0	0	0	1	6.00
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	1	0	0	0	0	0	0	0	0	1	7.00
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	2	2	0	1	1	2	1	0	0	2	11	7.91

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL *BW (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	0	0	0	0	0	2	3	14.33
NE	0	0	0	0	0	0	0	0	0	1	0	0	1	9.00
ENE	0	0	0	0	0	0	1	1	0	0	0	0	2	7.50
E	0	0	0	0	0	0	0	1	0	0	0	0	1	7.60
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	1	0	0	0	0	0	0	1	6.00
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	1	0	0	0	0	0	0	1	6.00
CALM													0	0.
TOTAL	0	0	0	0	1	2	1	2	1	1	0	2	10	7.45

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL *CW (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	1	1	0	0	1	4	9.52
NE	0	0	0	0	0	2	2	0	1	1	1	0	7	8.01
ENE	0	0	0	0	0	0	0	1	1	2	0	0	7	7.43
E	0	0	0	0	0	1	0	0	1	1	0	0	3	5.33
ESE	0	0	0	0	0	0	1	0	1	0	0	0	2	6.50
SE	0	0	0	0	0	0	1	0	0	0	0	0	1	4.50
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	1	0	1	0	0	0	0	2	5.50
SSW	0	0	0	0	0	0	1	0	1	0	0	0	2	5.50
SW	0	0	0	0	0	1	0	0	0	0	0	0	1	4.00
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	1	0	0	0	0	0	0	1	6.00
N	0	0	0	0	0	1	0	0	0	0	0	0	1	5.00
CALM													0	0.
TOTAL	0	0	0	0	0	7	6	2	4	3	1	1	32	6.44

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL *DW (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	1	0	0	0	0	1	1	1	0	5	8.00
NE	0	0	1	0	0	2	0	0	0	1	0	0	4	8.25
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	1	0	0	0	0	0	0	1	6.00
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	1	0	0	0	0	0	0	1	6.00
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	2	1	0	4	0	0	1	2	1	0	11	7.27

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-95B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: OCTOBER, 1975

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-41 METER
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	3	0	2	3	0	4	1	2	4	20	7.47
NE	0	1	2	4	4	4	5	3	4	3	0	0	34	5.03
ENE	0	1	0	1	1	1	2	0	0	0	0	0	6	4.77
E	0	0	1	2	2	0	2	0	0	0	0	0	7	4.00
ESE	0	0	0	0	4	1	3	0	2	1	0	0	11	5.47
SE	0	0	0	0	1	2	1	3	1	0	0	4	12	9.33
SSE	0	0	1	0	0	1	1	0	0	0	0	0	3	12.23
S	0	0	1	1	2	0	1	1	0	0	0	0	6	9.15
SSW	0	0	1	2	2	2	4	2	3	0	0	0	16	8.16
SW	0	0	1	3	1	0	3	3	1	1	0	1	14	8.27
WSW	0	0	1	2	0	1	1	5	1	1	0	1	13	8.85
W	0	0	1	2	1	2	1	4	1	0	0	0	12	6.61
WNW	0	0	1	1	1	2	0	0	0	0	0	0	5	6.34
NW	0	0	1	3	2	1	1	0	0	0	0	0	8	3.76
NNW	0	0	1	5	2	1	2	0	0	0	0	0	11	3.64
*	0	0	1	5	1	1	1	1	0	0	0	0	10	4.69
CALM													0	0.
TOTAL	0	6	22	30	24	26	35	21	17	6	3	16	209	8.24

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-41 METER
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	1	2	2	3	1	0	0	0	0	0	10	6.65
NE	0	0	3	1	5	2	4	2	2	2	0	0	21	5.71
ENE	0	0	2	2	4	1	1	0	0	0	0	0	10	4.32
E	0	0	2	0	0	1	1	0	0	0	0	0	4	4.25
ESE	0	1	2	0	1	2	2	0	0	0	0	0	8	4.37
SE	0	0	1	0	2	2	4	5	1	0	0	0	13	6.66
SSE	0	0	1	0	1	1	2	0	1	0	0	0	6	6.17
S	0	0	0	0	1	0	4	2	0	0	0	0	7	5.91
SSW	0	0	0	3	1	0	4	2	0	0	0	0	10	5.96
SW	0	0	0	0	0	1	1	0	0	0	0	0	2	5.25
WSW	0	0	1	1	0	0	2	0	0	0	0	0	4	5.13
W	0	0	1	0	0	1	0	0	0	0	0	0	2	3.75
WNW	0	0	2	1	2	0	0	0	0	0	0	0	5	3.76
NW	0	0	1	1	0	0	0	0	0	0	0	0	2	3.01
NNW	0	0	2	2	1	1	2	0	1	0	0	0	9	4.47
CALM													0	0.
TOTAL	0	11	24	10	17	28	14	9	5	2	0	0	122	4.73

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-41 METER
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	2	4	1	0	0	0	1	0	0	0	0	11	2.36
NE	0	1	1	1	0	0	0	0	0	0	0	0	3	3.20
ENE	0	0	0	1	1	1	0	0	0	0	0	0	3	3.67
E	0	0	1	0	0	1	1	0	0	0	0	0	2	4.66
ESE	0	0	1	0	0	1	0	0	0	0	0	0	2	2.66
SE	0	0	2	1	0	1	0	1	0	0	0	0	5	3.60
SSE	0	0	1	2	0	0	0	0	1	0	0	0	3	2.93
S	0	0	1	3	0	0	1	0	0	0	0	0	5	3.14
SSW	0	0	5	3	2	2	1	1	0	0	0	0	14	3.00
SW	0	0	5	4	1	1	0	0	0	0	0	0	11	2.35
WSW	0	0	2	1	0	0	0	0	0	0	0	0	3	2.15
W	0	0	3	2	1	0	0	0	0	0	0	0	6	1.44
WNW	0	0	7	1	1	0	0	0	0	0	0	0	11	2.11
NW	0	0	6	1	2	1	0	0	0	0	0	0	10	2.27
NNW	0	1	6	1	1	0	0	0	0	0	0	0	9	2.17
N	0	1	4	1	1	0	0	0	0	0	0	0	7	1.93
CALM													0	0.
TOTAL	1	52	44	11	4	1	2	1	0	0	0	0	124	2.63

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #LL (FROM AEC/DELTA-T CRITERIA 10-41 METER
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	6	3	12	7	2	7	11	4	6	2	3	11	72	7.66
NE	0	4	7	8	14	16	9	10	11	11	1	0	97	5.49
ENE	0	1	3	4	5	10	5	2	4	2	1	0	37	4.27
E	0	0	3	4	4	7	7	2	0	2	0	0	50	4.27
ESE	0	2	2	1	10	6	6	0	2	1	0	0	30	5.23
SE	0	2	2	1	2	4	7	6	2	1	0	0	35	5.28
SSE	0	5	3	1	2	4	1	1	2	0	1	0	20	3.65
S	0	1	5	1	2	4	1	1	2	1	0	0	18	3.56
SSW	1	1	6	4	2	12	5	3	1	3	0	0	34	4.09
SW	0	2	6	4	2	7	4	1	3	2	1	0	33	4.27
WSW	0	2	4	1	4	4	4	10	2	2	4	0	37	5.11
W	0	1	4	4	1	4	4	3	2	1	0	0	24	4.22
WNW	0	2	6	2	1	5	1	3	1	0	0	0	21	3.22
NW	0	12	16	2	1	11	4	2	1	1	0	0	50	3.44
NNW	1	4	12	2	1	6	2	2	0	1	0	1	33	3.73
N	1	6	7	3	1	1	2	2	0	1	0	1	25	3.16
CALM													0	0.
TOTAL	9	71	100	72	81	104	78	70	62	35	19	43	744	5.29

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-96A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: NOVEMBER, 1975

PASQUILL *A* (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	1	0	0	0	0	0	0	0	0	0	0	1	1.00
NW	0	0	1	0	0	0	0	0	0	0	0	0	1	2.10
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	1	0	0	0	0	0	0	0	0	0	2	1.55

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL *B* (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.20
SSE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.60
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	1	0	0	0	0	0	0	0	0	0	1	1.00
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	1	0	0	0	0	0	0	0	0	1	6.00
WNW	0	0	1	0	0	0	0	0	0	0	0	0	1	2.60
NW	0	0	0	2	0	0	0	0	0	0	0	0	2	3.65
NNW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.30
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	4	0	1	0	0	0	0	0	0	6	3.64

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL *C* (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	0	1	0	0	0	0	2	6.45
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	1	1	1	1	0	0	4	8.05
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	1	1	1	1	0	0	0	0	4	6.10
S	0	0	2	0	0	0	0	0	0	0	1	0	3	5.27
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	1	1	0	0	0	0	0	0	0	2	6.20
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	3	0	0	0	0	0	0	0	0	3	5.23
WNW	0	0	2	0	0	0	0	0	0	0	0	0	2	2.70
NW	0	0	1	0	2	0	0	0	0	0	0	1	4	7.02
NNW	0	0	1	1	0	0	0	0	0	0	0	0	2	3.15
N	0	1	0	0	1	0	0	0	0	1	0	0	3	5.20
CALM													0	0.
TOTAL	0	1	6	5	5	2	2	3	1	2	1	1	29	5.49

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL *D* (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	0	0	0	3	1	0	0	0	0	0	5	4.56
NE	0	0	0	1	0	1	4	1	0	0	0	0	7	5.99
ENE	0	0	0	0	0	3	2	5	1	0	0	0	11	6.48
E	0	0	0	2	0	1	0	1	2	1	0	0	7	6.59
ESE	0	0	0	1	1	1	0	1	0	0	0	0	4	5.27
SE	0	0	0	2	0	1	2	1	1	1	0	2	12	7.47
SSE	0	0	1	1	2	0	1	1	5	0	1	2	14	7.61
S	0	0	2	0	1	1	1	3	2	2	2	5	19	9.14
SSW	0	0	2	0	0	1	0	1	4	2	0	2	12	8.02
SW	0	0	0	2	1	3	0	0	1	2	0	0	9	6.11
WSW	0	1	1	2	11	4	3	0	0	1	2	2	17	7.24
W	0	0	1	4	3	5	2	6	1	0	0	2	26	6.40
WNW	0	0	4	2	0	0	2	3	1	1	0	0	13	5.00
NW	0	0	3	1	2	5	1	1	0	1	0	15	29	9.59
NNW	0	2	2	6	1	8	2	3	1	1	0	2	32	5.71
N	0	0	0	2	2	2	0	1	0	0	0	0	7	4.61
CALM													0	0.
TOTAL	0	4	16	26	26	39	21	28	21	16	7	15	241	7.00

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-96B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: NOVEMBER, 1975

PASQUILL #A (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	3	0	0	2	0	0	0	0	0	0	5	3.60
NE	0	1	3	2	1	1	1	0	0	0	0	0	11	3.60
ENE	0	0	0	2	3	4	1	0	0	0	0	0	10	5.65
E	0	0	1	3	0	0	1	0	0	0	0	0	5	2.60
ESE	0	0	0	0	1	0	2	0	0	1	0	0	4	6.13
SE	0	0	0	1	4	3	1	3	1	4	2	3	22	7.81
SSE	0	0	1	0	1	2	3	4	2	1	2	4	22	8.18
S	0	0	0	1	2	1	3	2	0	3	0	4	16	8.75
SSW	0	0	2	0	2	4	1	2	1	2	1	2	17	6.94
SW	0	0	1	2	3	5	0	1	0	0	0	0	13	4.54
WSW	0	0	1	1	2	2	2	1	0	0	0	0	9	4.61
W	0	0	1	1	4	4	1	1	0	0	1	0	14	5.03
WNW	0	0	1	1	0	0	1	0	2	0	0	1	6	5.97
NW	0	0	1	3	0	2	0	0	0	1	0	0	7	3.99
NNW	0	0	3	1	3	1	2	1	1	0	0	0	12	3.67
N	0	0	1	0	1	1	0	0	0	0	0	0	3	3.20
CALM													0	0.
TOTAL	0	0	11	21	10	36	24	15	15	4	11	6	14	178	5.92

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #B (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	3	2	0	0	0	0	0	0	0	0	6	2.73
NE	0	1	0	4	0	1	1	0	0	0	0	0	7	3.01
ENE	0	1	3	2	0	1	2	0	0	0	0	0	9	3.19
E	0	1	1	0	0	1	1	0	0	0	0	0	4	4.02
ESE	0	0	1	0	4	3	1	0	1	0	0	0	10	5.61
SE	0	0	1	1	2	3	5	1	1	0	0	1	15	6.21
SSE	0	0	2	0	1	1	0	0	2	1	0	0	10	7.05
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	1	0	2	1	0	0	0	0	0	0	4	4.50
SW	0	0	2	0	2	3	1	0	0	0	0	0	8	4.81
WSW	0	0	4	2	0	0	1	0	0	0	0	0	7	2.61
W	0	0	1	2	0	0	0	0	0	0	0	0	3	2.51
WNW	0	0	4	0	0	0	0	0	0	0	0	0	4	2.51
NW	0	0	2	2	1	0	0	0	0	0	0	0	5	3.54
NNW	0	0	2	0	0	0	0	0	0	0	0	0	2	2.48
N	0	1	3	0	0	0	0	0	0	0	0	0	4	2.10
CALM													0	0.
TOTAL	0	10	23	10	11	15	11	1	4	1	1	1	99	4.09

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #C (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	4	3	0	0	0	0	0	0	0	0	0	7	2.04
NE	0	1	4	1	1	0	0	0	0	0	0	0	7	2.40
ENE	0	2	1	2	1	0	0	0	0	0	0	0	6	2.73
E	0	3	0	1	0	1	0	0	0	0	0	0	5	2.76
ESE	0	1	2	0	0	0	0	0	0	0	0	0	3	2.47
SE	0	1	3	1	1	0	1	0	0	0	0	0	7	3.56
SSE	0	0	1	0	1	1	0	0	0	0	0	0	3	4.70
S	0	1	1	0	1	0	0	0	0	0	0	0	3	3.20
SSW	0	3	4	1	1	0	0	0	0	0	0	0	9	2.52
SW	0	2	4	1	4	0	0	0	0	0	0	0	11	3.18
WSW	0	5	5	1	0	1	0	0	0	0	0	0	12	2.17
W	0	1	7	0	0	0	0	0	0	0	0	0	10	2.14
WNW	0	11	10	3	0	0	0	0	0	0	0	0	26	2.14
NW	0	14	7	1	0	0	0	0	0	0	0	0	24	1.91
NNW	0	13	2	0	0	0	0	0	0	0	0	0	15	1.59
N	1	12	4	0	0	0	0	0	0	0	0	0	17	1.73
CALM													0	0.
TOTAL	1	78	67	13	9	3	1	0	0	0	0	0	174	2.22

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #D (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	7	9	2	0	6	1	1	0	0	0	0	26	1.91
NE	0	3	7	4	1	3	2	1	0	0	0	0	12	2.11
ENE	0	1	4	5	4	8	5	1	0	0	0	0	28	2.91
E	0	5	4	3	0	4	1	1	2	1	0	0	21	2.33
ESE	0	1	3	1	4	4	2	2	2	0	0	0	21	2.52
SE	0	1	4	5	7	8	9	1	1	2	0	0	37	3.02
SSE	0	0	5	2	7	5	5	6	4	1	2	0	37	3.43
S	0	1	5	1	2	2	4	5	2	5	3	0	31	3.17
SSW	0	1	0	1	5	6	1	3	5	4	3	0	29	3.38
SW	0	1	9	7	14	5	1	1	2	0	1	0	41	2.68
WSW	0	11	9	5	11	8	4	0	0	1	2	0	41	2.66
W	0	5	11	12	7	6	1	1	1	1	0	0	46	2.61
WNW	0	15	10	5	0	1	2	1	1	1	0	0	37	2.06
NW	0	17	17	2	2	5	1	1	0	2	0	0	47	2.21
NNW	0	20	6	11	4	10	1	4	1	1	0	0	58	2.50
N	1	15	7	3	4	2	0	1	0	1	0	0	34	2.00
CALM													0	0.
TOTAL	1	111	127	77	82	86	50	42	17	24	15	51	720	2.71

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-97A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: DECEMBER, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-A) METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	1	0	0	0	0	0	0	0	0	0	1	2.20
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	0	0	0	0	0	0	0	0	0	1	2.20

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-A) METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	1	0	1	0	0	0	0	0	0	0	0	2	2.20
SW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.60
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	0	1	1	0	0	0	0	0	0	0	3	3.40

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-A) METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.80
E	0	0	0	0	1	0	0	0	0	0	0	0	1	5.00
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	1	0	0	0	0	0	0	1	4.80
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	2	1	0	0	0	0	0	0	0	3	2.13
WNW	0	1	0	0	0	0	0	0	0	0	0	0	1	2.20
NW	0	0	0	0	0	0	0	0	0	1	0	0	1	8.20
NNW	0	0	0	0	0	0	0	0	0	1	0	0	1	12.20
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	2	1	2	1	0	0	1	1	0	4	13	7.60

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-A) METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	4	5	7	4	5	0	0	0	2	28	6.50
NE	0	0	1	5	4	11	11	1	0	1	0	1	42	5.60
ENE	0	0	1	1	2	3	2	4	0	0	0	0	13	5.46
E	0	0	1	0	2	0	3	1	0	0	0	0	7	5.43
ESE	0	0	1	0	0	2	0	1	0	0	0	0	4	5.12
SE	0	0	0	1	0	1	1	1	0	0	0	0	5	6.40
SSE	0	0	0	1	0	0	0	0	0	0	0	0	1	6.00
S	0	0	0	2	2	0	1	0	0	0	0	0	5	10.20
SSW	0	0	0	2	1	0	1	1	0	0	0	0	5	7.56
SW	0	0	0	0	1	1	0	1	0	1	0	0	4	9.15
WSW	0	0	0	1	1	1	1	0	1	0	0	0	5	7.56
W	0	0	1	1	2	1	2	1	0	1	0	0	9	7.11
WNW	0	0	1	3	1	2	2	2	0	0	0	0	11	6.09
NW	0	0	0	2	3	1	1	1	0	0	0	0	8	5.75
NNW	0	0	0	1	1	1	1	1	0	0	0	0	5	6.00
N	0	0	0	0	1	1	1	0	0	0	0	0	3	6.00
CALM													0	0.
TOTAL	0	0	7	23	25	32	30	22	1	3	0	3	146	6.46

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-97B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: DECEMBER, 1975

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	3	1	2	6	2	1	0	0	0	0	0	15	3.88
NE	0	1	2	1	3	2	1	1	0	0	0	0	11	4.47
ENE	0	0	0	1	6	7	4	0	0	0	0	0	18	5.72
E	0	0	0	0	3	3	2	0	0	1	0	0	9	5.98
ESE	0	0	0	2	2	3	1	0	0	0	0	0	8	4.95
SE	0	0	0	0	0	1	2	0	0	0	0	0	3	6.23
SSE	0	0	1	0	2	3	0	0	0	1	2	2	11	7.55
S	0	0	1	5	3	1	2	3	3	3	1	4	26	7.34
SSW	0	0	1	4	3	3	4	2	0	4	4	2	27	7.20
SW	0	2	3	6	3	7	0	4	2	1	0	5	33	6.49
WSW	0	2	4	3	7	3	0	0	0	0	0	0	19	4.01
W	2	2	3	4	1	1	1	0	1	0	0	0	15	3.61
WNW	0	0	4	2	2	1	0	0	0	0	0	0	9	3.57
NW	0	7	3	5	5	0	2	0	0	0	1	0	23	3.59
NNW	0	0	3	2	2	0	1	2	0	0	2	0	12	5.67
N	0	2	2	0	5	0	0	0	0	0	1	0	10	3.93
CALM													0	0.
TOTAL	2	19	28	37	53	37	21	12	6	10	11	13	249	5.42

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	2	0	0	0	0	0	0	0	0	3	3.07
NE	0	1	0	0	1	2	0	0	0	0	0	0	4	4.15
ENE	0	0	0	0	1	1	0	0	0	0	0	0	2	5.15
E	0	0	1	1	0	1	0	0	0	0	0	0	3	4.07
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	2	3	0	0	1	0	6	7.58
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	2	5	2	1	0	0	1	0	0	0	11	5.15
SSW	0	0	1	0	0	1	0	2	1	0	0	0	5	6.10
SW	0	0	1	0	1	1	0	0	0	0	0	0	3	3.47
WSW	0	1	0	0	1	0	0	0	0	0	0	0	2	3.20
W	0	1	1	0	0	1	0	0	0	0	0	0	3	3.23
WNW	0	0	0	2	0	0	0	0	0	0	0	0	2	3.65
NW	0	2	0	4	0	0	0	0	0	0	0	0	6	3.07
NNW	0	1	2	0	0	0	0	0	0	0	0	0	3	2.47
N	0	0	1	1	0	0	0	0	0	0	0	0	2	2.60
CALM													0	0.
TOTAL	0	6	10	15	6	8	2	5	2	0	1	0	55	4.33

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	6	5	0	2	0	0	0	0	0	0	0	13	2.31
NE	0	6	6	4	0	2	0	0	0	0	0	0	18	2.49
ENE	0	2	0	1	0	0	0	0	0	0	0	0	3	2.00
E	0	2	1	2	0	0	0	0	0	0	0	0	5	2.42
ESE	0	0	4	2	2	0	0	0	0	0	0	0	8	3.25
SE	0	3	1	1	1	1	0	0	0	0	0	0	9	3.44
SSE	0	0	1	2	1	3	1	0	0	0	0	0	8	4.84
S	0	2	3	1	0	2	0	0	0	0	0	0	8	3.10
SSW	1	2	3	4	2	0	0	0	0	0	0	0	12	3.04
SW	1	1	0	6	2	1	0	0	0	0	0	0	11	3.52
WSW	0	5	2	3	0	0	0	0	0	0	0	0	10	2.47
W	1	5	4	1	1	0	0	0	0	0	0	0	12	2.10
WNW	0	2	1	0	0	0	0	0	0	0	0	0	3	1.73
NW	2	7	2	0	0	0	0	0	0	0	0	0	11	1.49
NNW	0	3	1	1	0	0	0	0	0	0	0	0	5	2.22
N	0	8	1	0	0	0	0	0	0	0	0	0	9	1.61
CALM													0	0.
TOTAL	5	54	35	28	11	11	1	0	0	0	0	0	145	2.72

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	9	8	8	11	9	5	5	0	0	0	2	59	4.56
NE	0	8	9	10	11	17	12	2	0	1	0	3	75	4.80
ENE	0	2	1	3	9	12	6	4	0	0	0	0	37	5.28
E	0	2	3	3	6	4	5	1	0	1	0	0	25	4.69
ESE	0	0	5	6	4	5	1	0	1	0	0	0	22	4.14
SE	0	3	1	2	1	5	5	4	1	0	1	0	23	5.61
SSE	0	0	2	2	6	6	1	0	0	1	2	4	24	6.33
S	0	2	8	13	6	5	2	3	4	3	1	4	51	5.56
SSW	1	1	7	10	5	8	8	5	1	5	4	2	59	5.63
SW	1	1	4	11	4	9	1	9	5	3	2	15	71	7.24
WSW	0	8	9	7	11	4	2	2	2	0	0	14	59	5.61
W	1	9	11	7	5	4	3	1	1	0	0	0	44	3.69
WNW	0	5	7	10	8	5	1	1	1	0	0	0	38	3.63
NW	2	16	9	13	8	5	7	3	3	3	5	2	76	4.29
NNW	0	6	11	8	5	4	2	4	1	1	4	6	52	5.57
N	0	18	6	1	6	1	1	0	0	1	1	4	41	4.71
CALM													0	0.
TOTAL	7	84	99	114	112	101	66	44	20	21	28	56	744	5.05

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-98A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: ANNUAL, 1975

PASQUILL *A* (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	2	2	4	2	3	1	0	6	3	6	29	8.39
NE	0	0	8	1	2	3	6	2	4	0	1	8	27	8.66
ENE	0	0	0	4	3	7	5	1	0	1	0	0	21	5.55
E	0	0	1	1	1	5	5	1	0	0	1	1	16	6.17
ESE	0	0	0	1	3	1	3	2	1	1	0	0	12	6.35
SE	0	1	2	1	5	3	1	1	2	0	0	1	17	5.83
SSE	0	0	0	2	2	2	0	1	0	1	1	0	9	6.20
S	0	0	1	2	4	4	2	4	4	1	2	3	27	7.17
SSW	0	0	0	4	4	4	4	2	3	3	0	2	26	6.85
SW	0	0	1	4	9	5	4	1	2	1	0	0	27	5.60
WSW	0	0	2	2	5	8	4	1	0	0	0	0	22	5.13
W	0	0	4	0	1	1	2	0	0	0	0	0	10	4.41
WNW	0	1	0	4	1	4	0	1	0	0	0	0	11	4.48
NW	0	1	4	5	7	3	2	0	1	0	0	0	23	4.78
NNW	0	1	5	5	4	1	1	1	0	0	1	0	19	4.13
N	0	0	0	1	5	5	3	1	0	1	1	0	17	5.05
CALM													1	.00
TOTAL	0	4	22	39	62	58	45	20	17	15	10	21	314	6.13

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL *B* (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	5	1	0	1	0	0	2	12	7.99
NE	0	0	0	0	1	1	0	2	0	5	1	4	14	9.26
ENE	0	0	0	3	4	4	4	2	3	1	0	0	21	6.04
E	0	0	0	0	2	0	2	2	0	1	2	0	9	7.72
ESE	0	0	0	2	1	0	2	2	0	0	0	0	7	5.98
SE	0	0	0	0	3	2	1	2	0	0	0	2	10	6.87
SSE	0	0	1	0	0	0	1	1	0	0	1	0	4	6.50
S	0	0	0	1	3	1	0	1	1	0	2	2	11	7.96
SSW	0	1	1	3	0	1	0	1	2	0	2	2	13	6.91
SW	0	0	1	0	3	6	5	1	3	2	1	1	23	6.87
WSW	0	0	1	3	3	1	1	0	0	0	0	0	9	4.40
W	0	0	0	1	2	1	0	0	0	1	0	0	5	5.60
WNW	0	0	1	0	1	1	1	0	0	0	0	0	4	4.75
NW	0	0	1	5	1	2	1	1	1	1	0	5	18	8.68
NNW	0	0	2	3	1	0	0	0	1	2	6	1	16	6.12
N	0	0	0	0	0	1	1	0	0	0	0	0	2	6.00
CALM													0	0.
TOTAL	0	1	8	21	28	26	20	15	12	13	9	19	172	7.03

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL *C* (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	2	2	3	1	3	3	1	1	1	17	7.14
NE	0	0	2	2	7	4	3	3	3	4	1	2	31	6.55
ENE	0	0	1	0	3	3	12	6	7	6	5	6	49	8.29
E	0	0	0	2	2	1	3	2	6	4	3	3	26	8.14
ESE	0	0	0	0	3	3	3	1	3	2	1	0	16	7.11
SE	0	0	1	2	4	2	0	3	1	2	1	2	18	6.85
SSE	0	0	1	0	4	4	3	1	0	0	1	2	16	6.66
S	0	0	3	1	7	2	4	4	2	0	2	3	28	6.71
SSW	0	0	2	2	3	7	7	4	5	5	0	1	38	7.33
SW	0	0	2	3	7	10	11	5	5	4	0	1	48	6.31
WSW	0	0	1	3	7	10	9	3	2	2	0	2	39	6.28
W	0	0	1	4	5	5	3	1	0	0	0	0	19	4.87
WNW	0	1	6	7	9	1	1	1	0	1	0	3	31	5.48
NW	0	0	1	3	4	3	3	5	5	2	3	15	49	9.17
NNW	0	0	1	5	5	1	2	1	3	1	2	9	30	8.79
N	0	1	1	3	2	0	1	2	1	1	1	2	17	7.44
CALM													0	0.
TOTAL	0	2	23	39	79	59	66	47	47	36	22	56	476	7.21

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL *D* (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	4	19	14	12	21	20	27	13	6	4	16	156	6.76
NE	2	5	24	23	26	33	36	35	16	25	14	28	267	8.04
ENE	0	5	15	13	28	39	34	38	30	16	7	13	238	6.74
E	0	0	6	11	23	23	15	17	21	12	5	4	137	6.56
ESE	0	0	3	13	16	9	10	14	10	4	6	5	90	6.53
SE	0	1	2	14	6	14	11	11	9	8	7	22	107	8.01
SSE	0	0	1	10	4	11	14	13	16	8	16	27	126	8.76
S	0	2	11	8	8	14	15	26	13	16	6	33	152	8.30
SSW	0	1	6	12	25	29	29	28	14	20	11	52	228	8.32
SW	0	1	5	18	31	28	32	32	46	22	27	51	301	8.11
WSW	0	1	13	15	42	32	43	30	29	17	20	83	327	8.44
W	1	2	12	27	23	35	26	32	22	15	15	68	278	8.28
WNW	0	4	11	19	17	23	17	19	12	13	4	14	155	6.60
NW	0	5	16	10	21	12	20	20	10	11	11	37	215	7.26
NNW	0	2	19	21	16	26	16	13	11	11	5	22	182	6.82
N	0	4	5	6	21	16	18	15	8	5	2	9	109	6.53
CALM													4	.00
TOTAL	3	41	170	254	326	385	358	378	280	211	160	490	3056	7.21

NUMBER OF INVALID OBSERVATIONS = 9
TOTAL NUMBER OF OBSERVATIONS = 8760

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TABLE 2.3-98B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
10.5 METER LEVEL: ANNUAL, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	13	29	23	18	16	13	15	8	2	2	4	143	4.91
NE	0	9	21	35	31	33	29	16	14	4	2	7	201	5.43
ENE	0	5	19	19	26	26	20	6	2	4	1	3	131	5.07
E	0	3	17	24	21	24	21	4	2	1	2	1	120	4.91
ESE	1	1	3	19	19	19	18	7	7	6	1	3	104	5.88
SE	0	2	7	14	19	24	29	18	8	15	6	12	156	6.82
SSE	0	2	9	12	32	34	37	26	14	15	12	39	232	7.81
S	2	6	20	33	47	35	38	25	18	24	15	39	302	6.97
SSW	1	9	22	27	55	33	38	24	16	24	11	27	287	6.52
SW	0	12	27	40	38	32	26	28	24	19	8	22	276	6.25
WSW	1	7	15	20	29	27	21	21	8	6	10	7	172	6.00
W	3	8	13	24	23	22	20	17	5	5	4	7	151	5.66
WNW	4	6	13	17	19	16	6	8	2	4	1	1	97	4.74
NW	1	16	23	21	20	14	8	9	3	5	5	12	137	5.40
NNW	1	9	23	17	15	18	7	9	1	4	8	11	123	5.69
N	4	12	14	27	17	12	4	4	4	3	1	2	104	4.39
CALM													26	.63
TOTAL	18	120	275	372	429	385	339	237	136	141	89	197	2764	5.97

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	1	9	15	10	9	6	2	1	0	0	0	0	53	3.65
NE	0	11	13	17	21	14	9	3	3	2	0	1	94	4.65
ENE	1	9	12	20	14	11	9	3	4	3	2	0	88	4.62
E	1	7	12	5	8	12	9	4	0	0	0	0	58	4.60
ESE	3	6	7	7	10	14	12	10	2	2	0	0	73	5.01
SE	0	6	7	5	12	16	21	23	7	3	3	1	104	6.00
SSE	0	4	13	15	14	16	2	12	10	10	7	0	103	5.84
S	0	10	16	13	19	14	9	4	2	1	0	3	91	4.59
SSW	1	2	16	9	22	18	13	10	4	0	0	0	95	5.03
SW	2	8	17	13	18	13	8	3	0	0	0	0	82	4.09
WSW	0	10	14	8	16	15	0	0	0	0	0	0	63	3.73
W	0	4	10	9	5	6	6	2	0	0	0	0	44	3.87
WNW	1	13	4	9	7	4	2	1	1	0	1	0	43	3.63
NW	1	10	13	15	9	4	2	0	1	0	0	0	55	4.65
NNW	0	9	4	3	4	1	0	0	0	0	1	0	22	3.22
N	1	11	14	7	3	4	0	1	0	0	0	0	41	2.95
CALM													10	.61
TOTAL	12	133	187	165	191	168	102	77	34	21	14	5	1127	4.67

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	18	25	4	4	0	1	0	0	0	0	0	52	2.52
NE	4	15	18	12	6	2	0	0	0	0	0	0	57	2.68
ENE	2	12	3	12	9	3	0	0	0	0	0	0	41	3.11
E	0	8	5	5	6	5	3	1	0	0	0	0	33	3.24
ESE	1	4	6	4	3	3	4	0	1	0	0	0	26	3.87
SE	0	10	9	6	5	7	3	4	0	0	0	0	44	3.97
SSE	0	5	4	8	5	6	6	4	2	0	1	0	39	4.84
S	0	9	10	5	7	4	1	0	0	0	0	0	36	3.31
SSW	1	17	18	11	11	4	2	1	0	0	0	0	65	3.14
SW	1	12	19	15	12	4	0	0	0	0	0	0	63	3.14
WSW	0	16	18	11	4	2	0	1	0	0	0	0	52	2.80
W	3	19	19	4	4	0	0	0	0	0	0	0	49	2.14
WNW	1	23	21	9	1	0	0	0	0	0	0	0	55	2.15
NW	4	14	25	10	4	1	0	0	0	0	0	0	60	2.21
NNW	3	24	15	6	3	1	0	0	0	0	0	0	52	2.22
N	3	27	15	4	6	2	0	0	0	0	0	0	57	2.10
CALM													14	.61
TOTAL	25	253	230	126	98	42	20	11	3	0	1	0	819	2.92

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 10.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	1	44	90	55	52	53	41	47	25	15	10	29	462	5.48
NE	5	40	78	90	94	90	83	61	60	46	19	58	691	5.92
ENE	3	31	51	71	87	93	84	56	47	32	18	22	593	5.67
E	1	19	41	48	63	70	58	31	29	18	14	9	400	5.65
ESE	5	11	19	46	55	49	52	36	24	15	8	8	328	5.81
SE	0	20	28	42	54	68	68	63	27	28	17	40	455	6.60
SSE	0	11	29	47	65	71	63	58	42	34	19	68	527	7.15
S	2	27	41	63	95	74	69	64	40	42	27	83	647	6.76
SSW	3	30	65	68	121	96	93	71	44	52	24	86	753	6.66
SW	1	35	72	93	118	98	86	70	80	48	16	81	828	6.55
WSW	1	36	64	62	106	95	78	56	39	25	10	92	664	6.69
W	7	37	59	69	65	70	55	52	27	21	19	75	556	6.64
WNW	6	43	58	65	55	49	27	12	16	17	7	18	393	5.10
NW	6	66	83	89	71	59	36	15	21	21	19	69	777	5.82
NNW	4	45	69	60	44	48	26	24	16	18	17	41	418	5.71
N	5	50	69	48	54	40	31	21	13	12	5	11	351	4.77
CALM													64	.77
TOTAL	58	554	914	1016	1201	1123	950	729	530	438	307	780	8760	6.16

NUMBER OF INVALID OBSERVATIONS = 17
TOTAL NUMBER OF OBSERVATIONS = 8760

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TABLE 2.3-99A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: JANUARY, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	1	1	12.90
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	1	0	0	0	0	0	0	0	0	0	1	7.20
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	1	0	0	0	0	0	0	0	0	0	1	7.10
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	1	0	0	0	0	0	0	0	0	0	0	1	1.30
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	1	0	0	0	0	0	0	0	0	0	0	1	1.00
WNW	0	1	0	0	0	0	0	0	0	0	0	0	1	1.00
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	3	2	0	0	0	0	0	0	0	0	1	6	3.44

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	0	0	0	0	0	0	1	5.00
NE	0	0	0	0	0	0	0	0	0	0	0	1	1	11.00
ENE	0	0	0	1	0	1	0	0	0	0	0	0	2	6.60
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	1	0	0	0	0	0	0	0	0	0	0	1	1.70
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	0	1	1	1	0	0	0	0	0	1	5	5.42

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	2	0	0	0	2	8.30
ENE	0	0	0	0	0	0	0	1	0	0	1	5	7	11.23
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	1	0	0	0	0	0	1	7.00
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.90
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.60
SW	0	0	0	0	1	0	0	0	0	0	0	1	2	12.00
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	1	0	0	0	0	1	2	9.45
NW	0	0	0	0	0	0	1	0	0	0	0	0	1	5.60
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	1	1	12.00
CALM													0	0.
TOTAL	0	0	1	1	1	0	1	1	2	0	1	8	18	9.42

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	1	0	0	1	2	0	0	2	0	6	13	10.84
NE	1	0	0	1	0	2	1	1	0	1	1	1	9	7.12
ENE	0	0	0	2	2	1	2	1	1	1	5	4	17	8.16
E	0	0	2	1	1	1	2	2	1	2	0	2	14	7.24
ESE	0	0	0	0	2	0	1	1	1	1	1	0	9	8.13
SE	0	0	0	0	2	2	0	1	1	1	1	6	14	11.28
SSE	0	0	0	0	2	1	1	0	0	0	0	0	4	5.22
S	0	0	0	0	0	0	0	0	0	0	2	2	4	12.15
SSW	0	0	0	1	0	0	0	0	0	0	1	11	13	16.26
SW	0	0	1	1	4	2	2	0	1	2	0	9	22	9.19
WSW	0	0	0	0	1	4	1	0	0	0	4	28	38	14.62
W	0	1	1	1	1	0	2	0	1	0	1	20	28	15.11
WNW	0	1	1	0	4	5	4	5	1	1	1	1	25	9.92
NW	0	0	0	1	5	4	4	1	0	2	0	3	20	8.56
NNW	0	0	0	2	1	1	2	1	2	0	1	1	11	9.72
N	0	0	0	0	1	0	2	2	0	0	0	1	6	7.55
CALM													0	0.
TOTAL	1	3	8	12	26	24	26	15	11	20	20	101	267	10.21

NUMBER OF INVALID OBSERVATIONS = 9
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-99B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: JANUARY, 1975

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	2	1	0	2	0	4	10	9.57
NE	0	0	0	0	1	0	5	1	1	3	2	10	23	10.13
ENE	0	0	1	0	0	2	0	0	1	2	3	1	10	8.49
E	0	0	0	0	0	1	2	4	1	2	6	8	24	10.03
ESE	0	0	0	0	0	1	0	0	2	0	0	0	3	7.79
SE	0	0	0	0	0	1	2	0	1	1	0	2	7	9.30
SSE	0	0	0	1	2	1	0	1	0	2	0	10	17	13.43
S	0	1	0	0	0	0	0	0	0	1	4	11	17	12.31
SSW	0	0	1	0	0	0	0	1	2	0	2	20	26	13.38
SW	0	0	1	2	1	2	1	1	5	4	1	21	39	12.75
WSW	0	0	0	1	0	1	2	2	2	0	1	23	32	14.04
W	0	0	0	0	0	4	0	1	1	3	2	1	5	17	9.35
WNW	0	0	0	0	0	0	1	2	1	3	1	3	2	13	8.97
NW	0	0	1	1	1	1	0	1	1	0	0	0	1	6	8.08
NNW	0	0	0	0	0	1	0	0	1	0	0	0	4	6	16.95
N	0	0	0	0	0	1	0	1	1	1	2	1	4	11	10.32
CALM														0	0.
TOTAL	0	1	4	5	12	10	14	16	22	22	24	126	261	11.54

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	1	0	0	0	0	0	0	1	1	0	4	6.00
NE	0	0	0	0	0	0	0	1	1	0	1	3	6	10.45
ENE	0	1	0	0	0	0	1	1	0	2	1	5	11	10.04
E	0	0	0	0	0	0	0	1	0	2	0	1	4	9.42
ESE	0	0	0	1	0	1	0	0	0	0	1	2	5	9.90
SE	0	0	0	0	0	0	0	0	0	0	0	5	5	14.52
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	8	8	14.91
SSW	0	0	0	0	0	0	0	0	0	0	1	5	6	13.82
SW	0	1	1	0	0	0	0	1	1	2	1	23	30	12.43
WSW	0	0	2	1	0	0	0	1	0	1	3	10	18	10.66
W	0	0	0	0	1	0	1	0	0	0	0	3	5	10.54
WNW	0	0	0	0	0	1	0	1	1	2	2	2	9	9.43
NW	0	1	0	0	0	1	0	0	0	0	0	0	2	3.20
NNW	1	0	0	0	0	0	1	0	0	1	0	1	4	7.75
N	0	0	0	1	0	0	0	0	0	0	1	0	2	7.25
CALM														0	0.
TOTAL	1	4	4	3	1	3	3	5	3	11	12	68	119	11.05

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	0	0	1	0	0	0	2	5.95
NE	0	0	0	0	0	0	1	1	0	1	0	1	4	9.87
ENE	0	0	0	1	0	1	0	1	0	0	1	1	5	8.06
E	0	0	0	0	0	0	0	1	0	0	0	0	1	7.50
ESE	0	0	0	0	0	0	0	0	1	0	0	5	6	14.88
SE	0	0	0	0	0	0	0	0	0	0	0	2	2	13.75
SSE	0	0	1	0	0	0	0	0	0	1	2	1	5	8.32
S	0	0	1	1	2	0	2	0	2	1	1	2	12	7.79
SSW	0	1	0	0	0	0	0	1	0	0	0	0	2	4.50
SW	0	0	0	0	0	1	1	0	0	1	0	2	5	9.22
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	1	0	0	0	0	0	1	5.60
WNW	0	0	0	0	0	1	0	0	1	0	0	3	5	10.18
NW	0	0	0	0	1	1	0	0	0	0	1	0	3	6.20
NNW	0	0	0	0	0	0	0	0	0	0	0	1	1	12.00
N	0	0	0	0	0	1	0	0	0	0	0	0	1	5.80
CALM														0	0.
TOTAL	0	1	3	3	3	5	4	4	5	3	4	17	55	9.01

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	2	3	0	2	1	4	1	1	5	1	13	33	9.45
NE	1	0	0	1	1	2	7	4	4	5	4	16	45	9.47
ENE	0	1	1	4	2	5	3	4	2	5	9	16	52	8.87
E	0	0	0	3	1	1	2	4	8	2	6	6	33	8.87
ESE	0	0	0	1	1	2	2	2	1	4	1	4	7	24	10.08
SE	0	0	0	1	0	2	3	2	1	2	2	1	16	30	11.10
SSE	0	0	0	2	1	4	2	1	1	4	1	10	27	11.00
S	0	0	1	2	1	2	0	2	0	2	2	7	23	11.26
SSW	0	0	1	1	2	0	0	0	2	2	0	4	16	12.09
SW	0	0	2	3	3	6	5	4	2	7	9	2	56	11.57
WSW	0	0	0	2	2	1	5	3	3	2	1	8	61	12.10
W	0	0	2	1	1	6	1	4	1	4	7	2	28	9.57
WNW	0	0	2	3	0	4	8	7	7	8	6	8	11	64	8.00
NW	0	0	1	1	5	7	5	6	2	0	2	1	4	34	6.50
NNW	1	1	1	0	2	2	1	3	2	2	1	1	9	26	10.14
N	0	0	0	1	2	1	1	1	1	2	2	6	21	9.19
CALM														0	0.
TOTAL	2	13	21	25	44	63	55	62	44	58	51	121	733	10.23

NUMBER OF INVALID OBSERVATIONS = 11
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-100A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: FEBRUARY, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.10
SE	0	0	0	1	1	0	0	0	0	0	0	0	2	3.95
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	1	1	1	0	0	0	0	0	0	3	4.33

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	1	0	1	0	0	0	0	2	6.15
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	1	0	1	0	1	0	0	0	0	0	3	4.63
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	1	1	12.00
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.50
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.60
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	1	2	1	1	1	0	0	0	1	8	5.84

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	1	0	0	0	0	0	0	1	6.10
ENE	0	0	0	0	0	0	0	1	0	1	0	0	2	8.50
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	1	1	0	0	0	0	0	2	6.20
SE	0	0	0	0	1	0	0	1	0	0	0	0	2	6.25
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	1	1	1	0	0	0	0	4	6.07
SSW	0	0	0	0	0	0	0	1	0	0	0	0	1	6.90
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	1	0	0	0	0	0	0	0	1	3.50
NW	0	0	0	0	1	1	0	0	1	1	0	0	4	6.22
NNW	0	0	0	0	0	1	0	0	0	0	0	0	1	5.10
N	0	0	0	0	1	0	0	0	0	0	0	0	1	4.60
CALM													0	0.
TOTAL	0	0	0	2	4	5	4	3	2	1	0	0	19	6.17

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	0	0	0	1	1	1	4	8.77
NE	0	0	0	0	1	1	1	2	1	1	6	26	43	11.61
ENE	0	0	1	0	1	1	2	2	2	5	5	2	21	8.90
E	0	0	1	1	1	1	1	0	1	4	4	2	16	8.63
ESE	0	0	0	1	1	0	0	0	1	0	0	0	1	5.63
SE	0	0	0	0	0	2	0	0	1	2	0	0	5	7.85
SSE	0	0	0	1	0	0	2	0	1	1	0	2	7	8.90
S	0	2	0	0	1	1	1	2	0	1	1	3	12	8.34
SSW	0	1	1	1	1	3	1	1	1	0	0	8	19	8.82
SW	0	0	1	0	0	0	1	3	5	1	3	35	50	13.12
WSW	0	0	1	0	0	0	1	1	0	0	1	24	28	14.61
W	0	0	0	0	0	0	0	2	0	0	1	0	3	7.33
WNW	0	0	0	0	0	1	0	1	0	2	2	5	12	10.84
NW	0	0	0	1	0	0	0	1	1	1	1	0	4	6.97
NNW	0	0	0	0	0	1	2	1	1	1	1	0	7	8.00
N	0	0	0	0	0	0	0	0	0	0	1	0	1	10.00
CALM													0	0.
TOTAL	0	4	6	4	6	12	14	13	13	22	34	126	255	11.61

NUMBER OF INVALID OBSERVATIONS = 11
TOTAL NUMBER OF OBSERVATIONS = 672

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TABLE 2.3-100B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: FEBRUARY, 1975

PASQUILL #A (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	0	0	1	2	3	7	10,57
NE	0	1	1	0	0	0	1	2	0	2	4	12	23	10,11
ENE	0	0	0	0	0	0	0	1	1	0	1	2	5	10,00
E	0	0	0	0	0	0	1	1	0	0	1	2	5	9,60
ESE	0	0	0	0	0	1	2	0	0	0	1	2	6	9,15
SE	0	0	0	0	0	0	1	0	0	2	2	3	8	11,29
SSE	0	0	0	0	0	1	0	0	0	2	2	16	21	15,70
S	0	0	0	0	0	0	0	2	2	4	2	6	16	10,87
SSW	0	0	0	0	0	0	2	2	3	1	0	12	20	12,59
SW	0	1	1	0	0	0	0	2	4	3	3	30	44	12,73
WSW	0	0	0	0	0	0	1	0	2	3	1	16	23	13,31
W	0	0	0	0	0	0	1	0	1	2	0	4	9	10,43
WNW	0	0	0	0	0	0	0	0	0	0	1	0	1	7	10,79
NW	0	0	0	0	0	1	0	0	0	0	0	1	1	3	8,67
NNW	0	0	0	0	0	1	0	0	0	0	0	2	3	6	10,50
N	0	0	0	0	0	0	0	0	0	0	1	1	4	8	11,79
CALM													0	0.
TOTAL	0	2	2	0	2	3	10	9	13	24	23	118	204	12,03

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL #B (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	0	0	1	0	0	2	7,50
NE	0	0	0	0	0	0	1	1	1	1	1	3	8	10,13
ENE	0	0	0	0	0	0	0	0	1	0	1	3	5	11,00
E	0	0	0	0	0	0	0	0	0	0	1	4	5	11,80
ESE	0	0	0	0	0	0	0	1	1	1	0	14	17	14,69
SE	0	0	0	0	0	0	1	0	0	0	0	4	5	12,60
SSE	0	0	0	0	0	0	0	0	1	0	1	7	10	13,50
S	0	0	0	0	0	0	1	0	0	0	1	4	6	12,33
SSW	0	0	0	0	0	0	1	1	0	0	0	1	3	8,77
SW	0	0	0	0	0	0	0	0	0	0	1	6	7	12,71
WSW	0	0	0	0	0	0	1	0	2	1	1	5	10	10,70
W	0	0	0	0	0	0	0	0	0	0	0	1	1	14,10
WNW	0	0	0	0	1	0	0	0	0	0	1	2	4	10,63
NW	0	0	0	0	1	0	0	1	1	0	1	2	7	9,57
NNW	0	0	0	0	0	0	1	0	0	0	0	0	1	5,70
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													2	.*
TOTAL	0	0	0	0	2	1	6	4	6	3	10	56	88	11,75

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL #C (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	1	0	0	0	0	0	0	0	0	1	0	2	6,05
ENE	0	0	0	1	0	1	0	1	0	0	0	2	5	9,24
E	0	0	1	0	0	1	2	0	0	1	1	2	9	9,50
ESE	0	0	1	0	0	0	0	0	0	1	1	2	5	11,74
SE	1	0	1	0	0	0	0	0	0	0	0	3	5	9,84
SSE	0	0	0	1	2	0	0	0	0	0	0	2	5	8,76
S	0	0	0	1	0	0	0	0	0	0	0	1	2	9,75
SSW	0	0	0	0	0	0	0	1	0	0	0	1	2	11,75
SW	0	0	0	0	0	0	0	0	0	0	0	5	6	13,27
WSW	0	0	0	0	0	0	0	0	1	0	0	3	4	13,42
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	1	1	2	10,40
NW	0	0	0	0	0	0	0	0	0	1	0	1	2	12,15
NNW	0	0	0	0	0	0	0	0	1	0	1	0	2	8,80
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	1	2	2	2	3	1	1	3	2	3	5	24	51	10,51

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 672

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	2	0	0	1	3	4	11	9,71
NE	0	2	1	0	1	1	4	5	4	4	12	41	77	10,90
ENE	0	0	1	1	1	1	2	5	3	8	5	12	41	9,63
E	0	0	1	1	1	2	3	2	1	2	5	10	31	9,63
ESE	0	0	1	0	1	1	3	3	1	3	2	1	16	11,56
SE	1	0	2	1	1	2	3	0	2	4	2	10	30	9,63
SSE	0	0	0	2	2	1	2	0	2	1	3	24	43	13,27
S	0	0	2	1	0	2	3	2	5	2	5	4	15	41	9,91
SSW	0	0	1	1	1	1	3	4	4	2	0	22	41	10,56
SW	0	0	1	1	0	1	0	1	5	0	6	8	26	10,88
WSW	0	0	1	1	0	0	1	3	1	4	5	3	19	11,63
W	0	0	0	0	0	0	1	1	0	1	1	3	7	12,07
WNW	0	0	0	0	2	2	0	1	1	0	4	1	9	10,06
NW	0	0	0	1	1	1	0	0	1	5	2	2	20	8,16
NNW	0	0	0	0	0	2	3	2	2	1	2	2	14	8,61
N	0	0	0	0	1	0	0	0	0	1	4	4	10	10,27
CALM													2	.**
TOTAL	1	4	11	10	22	24	36	33	40	44	62	176	463	11,17

NUMBER OF INVALID OBSERVATIONS = 31
TOTAL NUMBER OF OBSERVATIONS = 672

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TABLE 2.3-101A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: MARCH, 1975

PASQUILL "A" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	1	0	1	10.20
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	1	0	0	0	0	0	0	0	0	1	3.60
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	1	0	0	0	0	0	0	0	0	0	1	2.30
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	1	0	0	0	0	0	0	1	0	3	5.37

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "B" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	1	0	0	0	0	1	7.00
NE	0	0	0	0	0	0	1	0	0	0	1	0	2	8.50
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	1	0	0	0	0	1	8.70
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	1	0	0	0	0	0	0	0	1	6.60
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	1	1	10.50
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	0	1	0	1	1	1	0	1	1	5	7.72

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "C" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	1	1	1	0	0	0	4	7.25
NE	0	0	0	0	0	0	0	0	1	1	0	2	4	10.20
ENE	0	0	0	0	0	0	0	0	1	2	1	0	4	9.77
E	0	0	0	0	0	0	0	0	1	0	1	0	2	8.70
ESE	0	0	0	0	0	0	1	0	0	0	1	0	2	8.05
SE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.70
SSE	0	0	1	0	1	1	0	0	0	0	0	0	3	4.00
S	0	0	0	0	0	0	0	2	0	0	0	0	2	7.25
SSW	0	0	0	0	0	0	0	0	0	1	0	0	1	9.20
SW	0	0	0	1	0	0	0	0	0	0	0	0	1	2.50
WSW	0	0	0	0	0	1	1	0	0	0	0	0	2	5.05
W	0	0	0	0	1	0	1	0	0	0	0	0	2	6.45
WNW	0	0	0	0	0	1	0	0	0	0	0	1	2	9.10
NW	0	0	0	0	1	1	0	0	0	0	0	5	7	11.40
NNW	0	0	0	0	0	1	0	1	0	0	0	0	2	5.60
N	0	0	0	0	0	0	0	0	1	0	0	0	1	8.60
CALM													0	0.
TOTAL	0	0	2	2	4	5	2	5	4	4	1	8	39	8.22

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL "D" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	0	0	3	0	0	0	2	2	1	1	10	7.35
NE	1	0	0	1	1	0	0	1	2	2	4	1	13	8.23
ENE	0	0	0	0	1	1	0	1	2	4	3	11	23	10.51
E	0	0	0	0	3	0	2	1	3	0	1	5	15	9.15
ESE	0	0	0	0	2	3	1	0	0	1	0	3	10	8.06
SE	0	0	0	0	0	0	0	2	0	0	0	2	4	10.27
SSE	0	0	0	0	0	0	1	0	0	0	1	2	4	12.82
S	0	0	0	0	1	0	1	1	0	1	3	2	8	12.25
SSW	0	0	0	0	0	0	1	3	4	2	1	4	15	12.70
SW	0	0	0	0	0	1	1	0	1	0	1	3	7	15.22
WSW	0	0	0	0	0	1	0	0	2	0	1	2	6	15.48
W	0	0	0	0	1	0	1	1	2	1	0	1	7	12.43
WNW	0	0	0	1	0	0	0	1	0	0	1	0	3	12.00
NW	0	0	0	0	0	0	1	0	0	1	0	2	4	12.50
NNW	0	1	1	2	0	2	0	4	1	0	0	1	12	11.00
N	0	0	1	0	1	1	2	1	3	4	1	4	18	13.50
CALM													0	0.
TOTAL	1	2	3	5	15	12	11	20	18	21	20	49	177	11.07

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-101B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: MARCH, 1975

PASQUILL #E# (FROM ΔEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	1	0	1	2	1	6	9,47
NE	0	0	0	0	1	1	4	1	0	0	3	4	14	8,81
ENE	0	0	0	0	0	2	2	1	0	0	0	5	10	9,55
E	0	0	0	0	0	0	0	1	1	0	1	1	10	14	12,42
ESE	0	0	0	0	0	1	1	1	2	2	2	7	17	10,06
SE	0	0	0	0	0	0	0	0	0	0	0	8	8	15,97
SSE	0	0	0	0	0	1	1	0	1	0	1	0	11	15	14,49
S	0	0	0	0	0	0	1	1	0	1	2	27	33	14,66
SSW	0	0	0	0	1	2	0	0	1	1	1	2	28	11,13
SW	0	0	0	0	1	0	0	0	0	0	0	1	11	13,62
WSW	0	0	0	0	1	0	0	1	0	1	0	2	10	15	12,65
W	0	0	0	0	0	1	0	1	1	1	0	0	21	25	13,41
WNW	0	0	0	0	0	0	1	0	0	0	0	0	8	9	13,94
NW	0	0	0	1	0	0	0	1	4	0	0	4	16	26	12,04
NNW	0	0	0	0	0	0	0	1	0	2	2	1	9	15	12,71
N	0	0	0	0	0	0	2	2	1	0	3	3	4	15	9,35
CALM													0	0,
TOTAL	0	0	1	3	6	9	15	11	11	12	23	172	283	12,65

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #F# (FROM ΔEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	0	0	0	1	0	0	2	4,00
NE	0	0	0	0	0	0	0	0	0	0	0	1	1	13,70
ENE	0	0	0	0	0	0	0	0	1	1	2	3	7	11,29
E	0	0	0	1	0	0	0	0	0	0	2	6	11	13,15
ESE	0	0	0	0	0	0	0	0	0	0	0	3	3	13,00
SE	0	0	0	0	0	0	0	0	0	0	0	2	2	14,75
SSE	0	0	0	0	0	1	0	0	0	0	0	8	9	14,44
S	0	0	0	0	0	0	0	0	0	0	0	5	5	16,20
SSW	0	0	0	0	0	0	0	0	0	0	0	2	2	15,40
SW	0	0	0	0	0	0	1	0	0	0	0	2	3	15,00
WSW	0	0	0	0	0	0	0	0	2	1	1	11	15	12,13
W	0	0	0	0	0	0	0	0	0	1	0	1	2	10,50
WNW	0	0	0	0	0	0	0	0	1	0	0	6	7	12,29
NW	0	0	0	0	0	1	1	0	0	0	0	2	4	9,87
NNW	0	0	0	0	0	0	0	0	0	0	0	1	1	11,10
N	0	0	0	0	0	0	0	1	0	0	0	0	1	7,00
CALM													0	0,
TOTAL	0	0	1	1	1	2	2	2	4	3	5	53	75	12,75

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM ΔEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
ENE	0	0	0	0	0	0	0	0	0	0	0	1	1	15,20
E	0	1	0	0	0	0	0	0	1	0	1	1	4	8,95
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
SE	0	0	0	0	1	0	0	0	0	0	0	0	1	4,00
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
S	0	0	0	0	0	0	0	0	0	0	0	5	5	13,84
SSW	0	0	3	0	0	0	0	0	0	1	0	1	5	5,60
SW	0	0	0	1	0	0	0	0	0	0	0	1	2	7,85
WSW	0	0	0	0	0	1	0	0	0	0	0	0	1	5,80
W	0	1	0	1	0	0	0	1	0	0	1	1	5	7,24
WNW	0	0	0	0	1	0	0	1	0	1	0	1	4	8,95
NW	0	0	0	0	0	0	0	1	1	0	0	1	3	9,97
NNW	0	0	0	1	0	1	0	0	0	0	0	0	2	4,95
N	0	0	0	1	0	1	0	0	0	0	0	0	2	4,95
CALM													0	0,
TOTAL	0	2	3	4	2	4	0	2	2	3	2	12	36	8,35

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM ΔEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	1	0	1	1	2	3	3	4	3	2	23	7,80
NE	1	0	0	1	2	1	5	2	3	3	4	8	35	8,61
ENE	0	0	0	0	1	3	2	2	4	11	6	20	49	10,55
E	0	1	0	2	3	0	3	3	4	2	5	24	47	10,02
ESE	0	0	0	0	1	4	3	1	3	4	2	13	33	9,80
SE	0	0	0	0	0	2	0	0	2	0	0	12	16	13,60
SSE	0	0	1	0	2	1	1	1	0	1	1	21	31	13,69
S	0	0	0	1	0	2	2	3	1	4	4	45	62	14,05
SSW	0	0	3	1	2	1	3	5	3	4	6	47	75	12,47
SW	0	0	1	2	1	1	1	0	3	5	4	42	57	11,21
WSW	0	0	0	1	1	2	2	1	2	1	2	42	58	14,34
W	0	0	0	3	1	2	2	4	3	0	2	60	78	15,07
WNW	0	0	0	1	0	3	2	0	1	1	1	25	34	12,24
NW	0	0	0	1	1	1	1	0	2	5	1	6	19	11	12,61
NNW	0	0	1	1	1	0	5	2	6	3	1	16	41	10,54
N	0	0	1	1	1	4	4	3	4	2	4	8	33	9,73
CALM													0	0,
TOTAL	1	4	11	16	29	32	41	38	50	51	44	432	749	12,11

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-102A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: APRIL, 1975

PASQUILL #AB (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	1	0	0	0	1	8.60
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	1	0	0	0	0	1	6.90
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	1	1	0	0	0	0	2	6.80
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	2	0	0	1	0	0	0	1	4	8.15
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	1	0	0	0	0	0	0	1	5.20
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	1	0	0	0	0	0	0	1	5.10
NNW	0	0	0	0	0	0	0	0	0	0	0	1	1	11.70
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	0	3	1	2	1	2	0	0	2	11	7.63

NUMBER OF INVALID OBSERVATIONS = 3
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #BB (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	1	1	16.10
ENE	0	0	0	0	0	1	1	0	0	0	0	0	2	5.15
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	1	0	1	0	0	1	3	9.60
SSW	0	0	0	0	0	0	0	0	0	0	0	1	1	15.10
SW	0	0	0	0	1	0	1	0	1	0	0	0	3	5.20
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	1	0	0	0	0	0	1	5.10
WNW	0	0	0	0	0	0	1	0	0	0	0	0	1	5.20
NW	0	0	0	0	0	0	0	1	0	0	0	0	1	5.10
NNW	0	0	0	0	0	0	0	0	0	1	2	4	7	14.14
N	0	0	0	0	0	0	0	0	0	0	0	1	1	16.60
CALM													0	0.
TOTAL	0	0	0	1	0	4	3	2	2	0	1	7	20	10.78

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #CB (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.60
ENE	0	0	0	0	0	0	0	0	0	0	1	0	2	9.35
E	0	0	0	0	0	0	0	0	1	0	0	0	1	7.40
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	1	0	0	0	0	1	6.20
SSE	0	0	0	0	0	1	0	0	0	0	0	0	1	4.60
S	0	0	0	0	0	2	2	0	1	0	0	2	7	8.89
SSW	0	0	0	0	0	1	0	0	1	2	1	1	6	11.63
SW	0	0	0	0	0	1	0	0	0	1	1	0	3	7.63
WSW	0	0	0	1	0	0	0	0	1	0	0	0	2	4.90
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	1	0	0	0	1	4	13.60
NW	0	0	0	0	0	1	0	0	2	2	3	10	20	13.76
NNW	0	0	0	0	0	0	1	0	0	1	1	0	4	7	13.71
N	0	0	0	0	0	0	0	0	0	0	0	2	2	12.65
CALM													0	0.
TOTAL	0	0	1	0	5	3	3	6	8	6	6	24	60	11.51

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #DB (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	0	0	0	1	0	0	0	2	5.60
NE	0	0	0	0	0	0	0	0	1	1	0	2	4	10.67
ENE	0	0	0	0	0	1	0	0	2	1	2	4	10	10.71
E	0	0	0	0	1	1	0	0	1	0	0	1	4	8.22
ESE	0	0	0	0	0	2	3	0	0	1	0	1	6	6.98
SE	0	0	0	0	1	2	3	0	1	0	1	0	9	6.38
SSE	0	0	0	0	1	1	1	1	0	1	0	0	6	5.25
S	0	0	1	0	1	1	1	0	1	0	1	1	8	10.05
SSW	0	0	0	0	1	1	1	0	0	1	0	1	5	11.82
SW	0	1	0	0	0	2	3	2	3	0	1	4	17	14.22
WSW	0	0	0	1	0	2	1	1	0	1	1	2	9	11.61
W	0	0	0	0	0	1	1	0	1	1	5	2	11	14.20
WNW	0	0	0	0	0	1	1	1	1	1	2	0	7	11.71
NW	0	0	0	0	0	1	2	2	1	1	2	2	11	12.24
NNW	0	0	0	1	1	0	1	0	2	0	1	1	7	11.71
N	0	0	0	0	0	0	0	1	1	0	1	2	5	10.24
CALM													0	0.
TOTAL	0	2	1	11	14	16	14	12	20	15	23	115	243	11.47

NUMBER OF INVALID OBSERVATIONS = 7
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-102B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: APRIL, 1975

PASQUILL *E* (FROM AEC/DELTA-T CRITERIA [0-4] METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	0	0	0	0	0	2	3	9,67
NE	0	0	0	0	0	0	0	1	1	1	1	2	7	9,59
ENE	0	0	0	1	0	1	1	1	0	0	0	0	4	10,00
E	0	0	0	1	0	1	0	1	0	0	2	0	4	8,67
ESE	0	0	1	0	1	0	0	1	0	1	4	1	10	8,66
SE	0	0	1	0	0	0	1	0	0	0	1	1	3	9,17
SSE	0	0	0	0	1	0	1	2	1	1	2	5	13	11,23
S	0	0	0	0	0	0	1	3	1	1	4	10	20	13,07
SSW	0	0	0	0	0	2	1	2	3	2	0	5	15	13,66
SW	0	0	0	0	0	0	1	1	3	2	2	22	31	12,64
WSW	0	0	0	0	0	0	0	1	0	1	0	0	2	10,25
W	0	0	0	0	0	0	0	0	1	0	0	0	1	9,00
WNW	0	0	1	0	0	0	1	0	0	1	0	0	3	7,10
NW	0	0	0	0	0	0	0	1	0	1	0	0	2	8,75
NNW	0	0	1	0	0	0	0	0	0	2	2	0	5	10,60
N	0	0	1	0	2	0	0	0	0	1	0	1	5	8,60
CALM													0	0.
TOTAL	0	3	4	2	7	4	15	14	11	14	16	109	229	12,35

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL *F* (FROM AEC/DELTA-T CRITERIA [0-4] METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	2	2	11,50
NE	0	0	0	0	1	0	0	0	0	0	0	1	2	9,00
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	1	0	0	0	1	2	10,50
ESE	0	0	0	0	0	0	0	0	1	0	0	2	3	14,50
SE	0	0	0	0	0	2	0	0	0	1	1	1	5	9,60
SSE	0	0	0	0	0	3	1	0	1	0	0	4	11	14,70
S	0	0	0	0	0	0	0	0	1	0	0	8	9	13,50
SSW	0	0	0	0	0	0	0	1	0	1	0	4	7	10,57
SW	0	0	0	0	0	0	0	0	0	0	0	3	3	12,67
WSW	0	0	0	0	0	0	0	0	0	0	0	1	1	13,00
W	0	0	0	0	0	0	0	0	0	0	0	2	2	11,50
WNW	0	0	0	0	0	0	0	0	0	1	1	0	2	10,00
NW	0	0	0	0	0	0	0	0	0	1	1	7	11	12,64
NNW	0	0	0	0	0	0	0	0	0	2	0	3	5	12,36
N	0	0	0	0	0	0	0	0	0	0	1	5	6	13,17
CALM													0	0.
TOTAL	0	0	0	0	1	1	2	2	1	7	4	50	73	12,51

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL *G* (FROM AEC/DELTA-T CRITERIA [0-4] METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	1	0	0	1	8	10	12,51
NE	0	0	0	0	0	0	0	0	1	0	1	5	6	13,00
ENE	0	0	0	0	0	0	1	0	0	1	0	1	3	10,60
E	0	0	0	0	1	0	0	0	2	1	1	0	5	8,10
ESE	0	0	0	0	0	0	0	0	0	0	0	2	2	14,50
SE	0	0	0	0	0	0	0	0	0	0	0	2	2	11,60
SSE	0	0	0	0	1	0	0	1	0	0	0	1	2	8,90
S	0	0	0	0	1	1	0	1	0	0	0	1	4	8,10
SSW	0	0	0	0	0	0	1	0	1	0	0	0	2	8,97
SW	0	0	0	0	0	0	0	0	0	1	0	0	2	10,05
WSW	0	0	0	0	0	0	0	0	1	0	0	0	2	7,85
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	1	0	0	0	1	8,50
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	1	1	2	1	2	7	9,00
N	0	0	0	0	0	0	0	0	0	1	0	2	3	10,67
CALM													0	0.
TOTAL	0	0	1	3	0	1	4	4	6	5	4	27	55	10,03

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA [0-4] METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	1	0	0	1	2	0	1	12	18	10,06
NE	0	0	0	0	2	0	0	1	2	1	1	11	21	10,66
ENE	0	0	0	1	1	1	1	2	1	1	4	9	25	9,90
E	0	0	0	1	2	1	2	1	1	1	4	6	21	8,52
ESE	0	0	1	0	1	0	2	4	1	0	2	4	15	9,50
SE	0	0	0	1	1	4	3	2	2	1	2	2	18	8,50
SSE	0	0	0	1	1	4	3	4	2	1	2	23	41	10,80
S	0	0	0	1	1	4	3	5	3	3	2	30	52	11,66
SSW	0	0	1	0	1	4	3	4	5	5	4	22	50	13,00
SW	0	0	1	0	2	1	4	6	5	5	5	22	51	12,01
WSW	0	0	0	0	2	2	1	2	4	2	1	21	41	11,65
W	0	0	0	0	0	1	1	1	1	4	2	20	31	11,11
WNW	0	0	1	0	1	1	2	3	2	2	1	11	24	11,15
NW	0	0	0	0	0	1	2	2	2	4	2	6	19	11,00
NNW	0	0	0	0	0	1	2	2	2	4	2	6	19	11,00
N	0	0	0	0	0	0	0	0	0	1	0	2	3	10,67
CALM													0	0.
TOTAL	0	0	5	5	19	12	14	42	44	50	44	177	408	11,03

NUMBER OF INVALID OBSERVATIONS = 12
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-103A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: MAY, 1975

PASQUILL *AA* (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	1	0	0	0	0	0	0	2	4.50
NE	0	0	1	0	0	1	3	1	0	2	0	0	8	8.38
ENE	0	0	0	0	0	0	0	1	1	0	0	0	2	7.35
E	0	0	0	0	0	1	1	0	1	1	0	0	4	8.37
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	1	0	1	0	0	0	0	0	0	1	3	9.50
SSE	0	0	0	0	1	0	0	0	1	0	0	1	3	8.27
S	0	0	0	2	0	0	0	1	2	1	0	2	8	8.17
SSW	0	0	0	1	1	0	0	1	0	0	0	0	3	5.33
SW	0	0	0	1	0	2	1	0	0	0	0	0	4	5.50
WSW	0	0	0	0	0	1	0	0	0	0	0	0	1	5.00
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	1	1	0	0	0	0	0	2	5.50
NW	0	0	0	0	2	0	0	0	6	0	0	0	0	2	4.00
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	1	0	0	0	0	0	0	1	5.70
CALM													0	0.
TOTAL	0	0	2	6	7	7	5	5	4	3	0	4	43	6.75

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL *AB* (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	0	0	0	0	0	1	6.50
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	1	0	0	0	0	0	1	6.50
E	0	0	0	0	1	0	0	0	0	0	0	0	1	6.50
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	1	1	0	0	0	0	0	0	1	5.67
SSE	0	0	0	0	0	0	1	1	0	0	0	0	1	8.33
S	0	0	0	0	0	0	0	0	0	0	0	1	1	12.50
SSW	0	0	0	0	0	0	0	1	0	0	0	0	1	6.50
SW	0	0	0	1	0	0	1	1	0	0	0	0	2	6.25
WSW	0	0	0	0	0	0	0	1	0	0	0	0	1	5.50
W	0	0	0	0	0	0	0	1	0	0	0	0	1	7.50
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	2	0	1	0	0	0	0	0	0	3	6.67
NNW	0	0	0	0	0	1	0	1	0	0	0	0	2	6.75
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	4	2	2	4	5	0	0	0	3	21	6.73

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL *AC* (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	1	0	0	0	0	0	2	5.75
NE	0	0	2	0	0	0	0	0	0	0	0	0	2	2.90
ENE	0	0	0	0	1	0	0	0	0	0	1	2	4	9.72
E	0	0	0	0	1	1	0	1	0	0	0	0	3	5.03
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	1	0	0	0	1	0	1	3	9.29
SSE	0	0	0	0	0	2	0	0	0	0	0	2	4	9.88
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	1	1	0	0	2	0	1	1	7	7.74
SW	0	0	0	1	0	1	3	0	2	0	1	0	8	6.25
WSW	0	0	0	0	1	1	1	0	3	3	1	1	11	7.24
W	0	0	0	0	1	1	2	0	1	0	0	0	5	5.58
WNW	0	0	0	0	0	0	0	0	0	2	0	0	2	8.50
NW	0	0	0	0	2	0	0	0	0	0	0	0	2	3.00
NNW	0	0	0	0	2	0	0	0	0	0	0	0	2	4.75
N	0	0	0	1	1	0	0	0	0	0	0	0	2	4.15
CALM													0	0.
TOTAL	0	0	3	2	12	6	5	2	4	3	1	6	57	6.89

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL *AD* (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	2	3	0	4	0	0	0	0	1	11	5.50
NE	0	0	1	3	2	3	1	1	4	3	2	2	23	7.37
ENE	0	0	0	2	1	1	4	1	3	2	2	2	18	7.79
E	0	0	0	2	1	1	3	4	2	1	2	2	20	7.33
ESE	0	0	0	2	0	3	2	2	0	0	0	1	10	5.65
SE	0	0	0	0	1	2	2	0	1	2	1	2	11	9.82
SSE	0	0	0	0	1	0	1	3	1	1	0	5	13	11.26
S	0	0	0	0	0	2	1	1	4	3	0	1	13	8.05
SSW	0	0	0	0	1	2	3	1	0	2	1	1	12	7.79
SW	0	0	0	0	0	1	0	1	5	1	0	1	9	6.39
WSW	0	0	1	1	0	1	1	1	4	2	1	3	15	7.93
W	0	0	1	0	1	4	2	2	1	1	2	1	15	8.13
WNW	0	0	0	0	1	1	1	1	1	2	1	1	10	7.70
NW	0	0	0	0	1	1	0	1	1	1	0	1	6	6.33
NNW	0	0	0	0	1	0	1	0	1	0	0	0	3	6.00
N	0	0	0	1	1	1	1	1	0	0	1	0	7	6.50
CALM													1	0.
TOTAL	0	2	8	19	26	27	31	25	25	20	14	24	251	8.14

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-103B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: MAY, 1975

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	1	0	1	2	2	0	1	0	1	2	11	7.81
NE	0	1	0	2	0	0	2	1	1	2	0	0	9	6.33
ENE	0	0	0	1	0	0	0	5	1	1	0	1	9	7.88
E	0	0	0	0	1	2	1	2	2	4	1	7	20	10.66
ESE	0	0	0	1	1	0	1	0	0	3	2	5	13	10.35
SE	0	2	1	0	1	1	0	1	1	1	5	11	24	9.75
SSE	0	0	1	1	0	1	1	1	2	1	1	8	17	10.42
S	0	0	0	0	0	0	0	3	2	2	2	9	18	11.07
SSW	0	0	0	0	0	0	0	2	1	2	1	10	16	11.92
SW	0	1	0	0	1	1	2	1	1	3	2	9	21	9.80
WSW	0	0	0	0	1	0	1	0	1	1	0	1	5	11.20
W	0	0	0	0	0	1	0	2	0	3	0	1	7	8.97
WNW	0	0	0	1	1	1	0	0	1	2	2	1	9	7.24
NW	0	1	0	0	0	0	0	0	1	2	0	1	5	7.44
NNW	0	0	0	0	0	0	2	0	1	0	1	0	4	7.10
N	0	0	1	0	1	1	2	0	0	0	0	0	5	5.12
CALM													1	.70
TOTAL	0	6	5	6	6	11	12	21	17	26	16	65	194	9.51

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	1	0	0	0	0	1	8.60
NE	0	0	1	1	0	1	0	0	0	1	0	5	9	10.01
ENE	0	1	0	0	0	0	0	0	1	3	0	3	8	9.67
E	0	1	1	0	1	0	0	0	0	0	0	0	3	2.60
ESE	0	0	0	1	0	0	0	0	0	0	0	5	6	12.17
SE	0	0	0	0	1	0	0	0	0	0	0	8	9	12.59
SSE	0	0	0	0	1	0	0	1	1	0	0	7	10	11.76
S	0	0	2	0	0	0	0	0	0	2	0	6	10	11.00
SSW	0	0	0	1	0	3	0	0	2	2	1	6	15	10.57
SW	0	1	0	0	2	1	0	0	1	1	1	2	9	7.81
WSW	1	0	0	0	1	1	0	0	1	0	0	5	9	9.23
W	0	0	0	0	1	0	1	2	0	1	1	0	7	7.11
WNW	0	0	0	0	0	0	0	1	0	0	0	0	1	7.10
NW	0	0	0	0	0	1	0	0	0	0	1	0	2	4	10.30
NNW	0	0	0	0	1	1	1	0	1	0	1	0	5	8.16
N	0	0	0	0	1	0	0	0	2	1	0	0	4	7.20
CALM													0	0.
TOTAL	1	3	4	3	7	9	2	4	9	13	2	50	110	9.74

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	1	2	0	0	0	0	4	6.65
NE	0	0	0	0	0	0	1	0	0	0	0	1	2	9.20
ENE	0	0	1	0	0	0	0	0	0	0	0	0	1	2.10
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	1	0	0	0	0	0	0	0	0	1	2	7.60
SSE	0	0	0	0	0	0	0	0	0	0	0	1	1	12.50
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	1	0	0	0	0	0	0	1	0	0	2	5.30
SW	0	0	0	0	0	0	1	0	0	1	1	1	4	9.25
WSW	0	0	0	0	0	0	0	1	2	0	1	2	5	11	10.18
W	0	0	0	0	0	0	0	0	2	0	4	2	3	11	10.11
WNW	0	0	0	0	0	0	0	0	0	0	0	1	1	11.70
NW	0	1	0	0	0	0	0	0	0	1	0	1	1	4	8.55
NNW	0	0	0	0	1	0	0	0	0	2	0	1	3	7	10.49
N	0	0	0	0	0	1	0	0	0	0	0	0	0	1	4.20
CALM													2	.50
TOTAL	0	1	3	1	1	2	1	6	4	6	7	17	51	8.87

NUMBER OF INVALID OBSERVATIONS = 0
NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	2	2	5	5	9	3	1	0	1	3	32	6.56
NE	0	1	5	6	2	5	7	3	7	8	1	8	51	7.65
ENE	0	1	1	3	2	1	6	7	5	6	1	8	41	8.19
E	0	1	3	2	5	6	6	5	4	5	1	9	51	8.12
ESE	0	0	2	2	4	2	3	0	0	3	3	10	29	9.10
SE	0	2	1	2	2	4	0	3	4	4	7	10	45	9.86
SSE	0	0	1	2	4	4	5	4	5	1	6	13	45	10.79
S	0	0	2	2	2	1	1	8	7	5	3	21	52	9.85
SSW	0	0	1	4	4	5	1	12	6	6	4	20	64	9.36
SW	0	2	1	3	4	9	9	5	2	0	7	15	66	9.26
WSW	1	1	1	1	7	2	8	10	5	4	9	14	63	8.50
W	0	1	0	5	5	6	4	6	2	9	4	12	56	8.55
WNW	0	0	1	4	3	3	1	3	5	4	1	3	28	7.18
NW	0	2	0	5	2	1	1	3	6	1	4	4	29	7.20
NNW	0	0	0	3	1	6	0	3	2	3	1	1	26	7.49
N	0	0	2	1	4	1	3	0	2	2	0	1	26	5.28
CALM													4	.55
TOTAL	1	12	25	49	61	64	66	75	61	71	57	178	742	8.57

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-104A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: JUNE, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	1	2	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	1	1	0	1	0	3	8,83
NE	0	0	0	1	0	0	0	1	0	0	4	12	18	11,76
ENE	0	0	0	0	0	0	1	1	0	1	0	6	9	12,67
E	0	0	0	0	0	0	1	1	0	0	0	0	3	6,57
ESE	0	0	0	0	0	0	0	0	0	0	2	0	2	4	11,17
SE	0	0	0	0	0	0	1	0	0	1	1	0	0	3	9,20
SSE	0	0	0	0	0	0	0	1	0	0	0	0	0	1	6,60
S	0	0	0	0	0	0	0	0	0	0	0	0	1	1	14,50
SSW	0	0	0	0	0	0	0	0	0	0	0	1	1	15,00
SW	0	0	1	0	0	3	2	0	0	0	0	0	6	5,33
WSW	0	0	0	0	1	0	1	2	0	0	0	0	4	6,67
W	0	0	0	0	0	1	2	2	0	0	0	0	5	5,80
WNW	0	0	0	0	0	0	0	1	1	0	0	0	2	7,00
NW	0	0	0	0	0	1	0	0	0	1	0	0	0	2	6,15
NNW	0	0	0	0	0	0	0	0	1	0	0	0	0	1	7,40
N	0	0	0	0	0	0	1	0	0	0	0	0	0	1	5,70
CALM														0	0,
TOTAL	0	0	1	1	1	5	9	9	1	4	5	22	64	9,65

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	1	2	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	1	0	2	0	0	3	6,67
NE	0	0	0	0	0	1	0	0	0	0	2	0	3	8,50
ENE	0	0	0	0	0	0	0	1	3	0	1	3	8	11,12
E	0	0	0	0	0	0	1	0	0	1	0	0	2	8,00
ESE	0	0	0	0	0	0	0	0	0	1	0	3	4	11,77
SE	0	0	0	0	0	0	0	0	0	0	0	1	1	12,20
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
SSW	0	0	0	0	0	0	0	0	0	0	0	1	1	16,10
SW	0	0	0	0	1	0	1	0	0	1	0	0	3	6,03
WSW	0	0	0	1	2	0	1	0	0	0	0	0	4	6,12
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
NW	0	0	0	0	0	0	0	0	1	0	0	0	1	8,40
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
CALM													0	0,
TOTAL	0	0	0	1	3	1	3	2	4	5	3	8	30	9,64

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	1	2	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	1	0	0	0	0	1	8,00
NE	0	0	0	0	2	0	1	0	0	1	1	0	5	7,14
ENE	0	0	0	0	0	1	0	0	0	0	0	3	4	13,42
E	0	0	0	0	0	0	0	1	0	1	5	4	11	10,83
ESE	0	0	0	0	0	0	0	0	0	1	1	5	7	12,39
SE	0	0	0	0	0	0	0	0	0	0	1	1	2	10,65
SSE	0	0	0	0	0	0	0	1	1	0	0	0	2	7,10
S	0	0	0	0	0	0	1	0	1	0	0	1	3	8,70
SSW	0	0	0	0	0	0	1	0	0	2	0	0	3	7,33
SW	0	0	0	0	0	1	2	2	0	0	0	0	5	5,68
WSW	0	0	0	1	0	0	4	2	2	0	1	0	13	8,32
W	0	0	0	0	0	0	2	2	2	0	0	0	6	6,50
WNW	0	0	0	0	0	0	0	1	0	0	0	0	1	6,70
NW	0	0	0	0	1	2	1	0	1	0	0	0	5	5,18
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0,
N	0	0	0	0	0	0	1	2	0	0	0	1	4	8,50
CALM													0	0,
TOTAL	0	0	1	1	5	12	10	11	7	5	7	18	72	8,74

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	1	2	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	1	0	1	1	0	0	4	7,63
NE	0	0	0	0	0	1	4	2	3	3	1	5	19	10,00
ENE	0	0	1	0	0	3	0	6	6	7	1	8	32	9,28
E	0	0	0	0	0	1	3	2	2	2	2	2	14	9,86
ESE	0	0	0	0	0	0	0	0	3	1	5	7	16	11,88
SE	0	0	0	0	0	1	1	0	1	1	0	6	10	11,72
SSE	0	0	0	0	0	0	1	0	1	2	1	4	9	11,67
S	0	0	0	0	0	0	0	1	2	2	0	1	6	10,16
SSW	0	0	0	0	0	0	3	0	1	0	2	2	8	11,19
SW	0	0	0	0	0	0	1	1	1	2	1	3	9	11,21
WSW	0	0	0	0	0	1	5	2	3	6	1	12	30	10,16
W	0	0	0	0	0	0	2	0	1	6	1	1	11	9,55
WNW	0	0	0	0	0	1	1	2	1	0	1	4	10	9,19
NW	0	0	0	0	0	1	1	2	2	1	0	2	10	9,22
NNW	0	0	0	0	1	1	3	0	1	1	2	0	1	10	7,29
N	0	0	0	0	1	1	2	0	1	2	0	0	2	9	7,00
CALM													0	0,
TOTAL	0	0	1	2	5	25	18	25	40	38	23	73	262	9,94

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-104B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: JUNE, 1975

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	0	1	0	1	0	2	5	8.78
NE	0	0	1	1	0	0	1	1	2	1	3	1	11	8.39
ENE	0	0	0	1	1	1	1	4	4	4	1	10	27	9.99
E	0	0	2	0	1	0	1	2	1	3	2	7	19	9.42
ESE	0	0	0	0	0	0	1	1	0	2	2	2	8	10.36
SE	0	0	0	0	1	0	0	0	1	2	0	4	8	10.54
SSE	0	0	0	0	0	0	1	0	1	2	2	4	10	10.81
S	0	0	0	0	0	0	0	1	1	1	1	5	9	11.79
SSW	0	0	0	1	0	0	1	2	4	1	2	7	18	9.99
SW	0	0	0	0	0	1	1	0	1	2	3	4	5	17	9.72
WSW	0	0	0	0	0	0	0	0	1	1	0	2	9	13	11.42
W	0	0	0	0	0	0	0	2	2	3	1	1	1	12	8.84
WNW	0	0	1	0	0	0	0	0	3	1	0	0	1	6	8.00
NW	0	0	0	0	0	0	1	2	2	0	1	0	1	7	7.91
NNW	0	0	1	0	0	0	0	2	0	2	0	0	1	6	7.42
N	0	0	0	1	0	0	0	0	1	0	0	0	2	2	5.65
CALM														1	.70
TOTAL	0	0	5	4	5	3	12	21	24	24	20	60	179	9.67

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	1	1	1	0	0	0	0	0	0	3	4.77
ENE	0	0	0	0	0	2	0	0	1	2	0	0	5	7.64
E	0	0	0	0	0	1	0	0	1	1	1	3	7	10.20
ESE	0	0	0	0	0	0	1	0	0	0	0	4	5	11.98
SE	0	0	0	0	0	1	0	1	1	0	2	2	7	10.71
SSE	0	0	0	0	0	0	1	0	0	2	0	1	4	10.07
S	0	0	0	0	0	0	0	0	0	0	0	1	1	16.30
SSW	0	0	0	0	0	0	0	0	2	0	0	4	6	11.42
SW	0	0	0	0	1	2	0	0	2	0	0	9	14	11.54
WSW	0	0	0	0	0	1	0	0	0	1	0	2	4	10.35
W	0	0	0	0	1	0	0	0	1	0	0	2	4	9.77
WNW	0	0	0	0	0	0	0	2	0	0	0	1	3	9.10
NW	0	0	0	0	1	1	1	0	4	4	1	1	13	8.65
NNW	0	0	1	0	0	0	0	0	2	0	0	1	4	7.79
N	0	0	0	0	0	0	1	0	0	0	0	0	1	5.60
CALM													0	0.
TOTAL	0	0	1	1	4	9	4	3	14	10	4	31	81	9.92

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	0	0	1	1	0	0	3	7.90
NE	0	0	0	0	0	0	0	2	1	0	0	2	5	10.30
ENE	0	0	0	0	0	0	0	0	0	0	0	1	1	12.10
E	0	0	0	0	0	0	0	0	2	1	0	1	4	10.00
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	1	0	0	1	0	0	0	0	2	6.15
SSE	0	0	0	0	0	0	0	0	1	0	0	1	2	11.30
S	0	0	0	0	0	0	1	0	0	0	0	3	4	10.90
SSW	0	0	0	0	0	0	0	0	0	0	0	2	2	14.85
SW	0	0	0	0	0	0	0	0	0	1	1	4	6	12.15
WSW	0	0	0	0	1	0	0	0	1	0	1	2	5	10.48
W	0	0	0	1	1	0	0	0	0	0	0	0	2	2.80
WNW	0	0	0	0	0	0	1	1	0	1	0	1	4	9.47
NW	0	0	0	0	1	1	1	0	0	0	1	0	0	4	5.75
NNW	0	0	1	0	0	1	0	0	0	1	1	0	4	6.87
N	0	0	0	0	1	1	0	0	1	0	0	0	3	6.33
CALM													0	0.
TOTAL	0	0	2	2	4	5	1	4	7	6	3	17	51	9.29

NUMBER OF INVALID OBSERVATIONS = 0
T NUMBER OF OBSERVATIONS = 720

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	2	1	4	3	5	1	2	19	8.61
NE	0	0	1	1	1	3	6	6	6	5	11	20	66	9.71
ENE	0	0	1	1	1	7	2	12	14	14	3	31	86	10.24
E	0	0	2	0	1	3	6	6	6	9	10	17	60	9.44
ESE	0	0	0	0	0	0	2	1	3	7	8	23	44	11.62
SE	0	0	0	0	0	2	3	1	2	4	5	2	14	33	10.56
SSE	0	0	0	0	0	0	0	5	1	3	4	3	10	28	10.71
S	0	0	0	0	0	0	2	1	4	3	1	2	14	27	11.19
SSW	0	0	0	0	1	0	4	1	3	8	3	6	20	44	10.82
SW	0	0	1	0	4	9	6	2	6	8	8	27	71	9.93
WSW	0	0	1	1	5	10	6	8	8	6	6	20	79	9.71
W	0	0	1	1	2	6	6	5	10	4	4	6	45	8.24
WNW	0	0	1	0	1	1	5	8	2	1	1	7	27	8.70
NW	0	0	0	2	6	5	5	5	9	7	1	4	44	7.80
NNW	0	0	3	1	1	4	2	4	5	3	1	3	27	7.31
N	0	0	0	2	2	4	2	3	4	0	0	1	20	7.17
CALM													1	.70
TOTAL	0	0	11	12	29	63	57	74	94	84	65	229	719	9.71

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-105A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: JULY, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.50
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	1	0	0	0	1	0	0	0	2	6.70
E	0	0	0	1	0	0	1	2	0	0	0	0	4	6.17
ESE	0	0	0	0	1	2	0	0	0	0	0	1	4	6.72
SE	0	0	0	0	0	0	0	1	0	0	0	0	1	7.20
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	1	2	0	0	0	1	0	1	5	7.20
SSW	0	0	0	0	0	0	0	0	0	0	0	1	1	12.40
SW	0	1	0	0	0	0	0	0	1	0	0	0	2	4.50
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	2	0	0	0	0	0	2	5.45
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	1	1	0	2	8.60
N	0	0	0	0	0	1	0	0	0	0	0	0	1	5.50
CALM													0	0.
TOTAL	0	1	0	1	4	7	1	4	2	2	0	3	25	6.75

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.50
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	1	0	1	1	0	0	0	0	1	4	6.47
E	0	0	0	0	1	0	0	0	0	0	0	1	2	8.10
ESE	0	0	0	0	0	0	0	0	1	1	0	0	2	8.95
SE	0	0	0	0	0	0	0	0	1	0	0	0	1	9.00
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	1	1	0	0	0	0	0	2	5.25
SSW	0	0	0	0	0	0	0	0	0	1	0	2	3	10.53
SW	0	0	0	0	0	0	1	0	0	0	0	2	3	10.47
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	1	0	0	1	9.50
WNW	0	0	0	0	0	3	0	0	0	0	0	0	3	8.50
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	1	6	3	1	0	3	2	1	5	22	7.85

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	1	1	28.00
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	1	1	0	0	0	0	0	0	2	4.50
E	0	0	0	0	0	0	1	0	1	0	0	0	2	8.90
ESE	0	0	0	0	0	0	1	0	1	0	0	0	2	6.90
SE	0	0	0	0	0	0	0	0	0	0	0	1	1	10.70
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	2	0	1	0	1	4	8.90
SSW	0	0	0	0	1	0	0	0	1	0	1	0	3	7.13
SW	0	0	0	0	0	0	0	0	1	2	1	1	6	9.23
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	1	0	0	0	1	0	0	0	2	5.60
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	1	0	1	0	0	0	0	2	5.25
NNW	0	0	0	0	1	0	0	0	1	0	0	0	2	5.75
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	3	2	2	1	3	4	3	2	3	27	8.14

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.50
NE	0	1	2	0	0	0	0	0	0	0	0	0	3	2.03
ENE	0	0	0	0	0	0	0	1	0	0	0	0	1	7.10
E	0	0	0	2	0	0	1	1	0	1	0	0	5	5.96
ESE	0	0	1	0	0	1	0	1	0	0	0	0	3	4.93
SE	0	0	0	0	0	0	0	2	2	2	0	5	11	10.41
SSE	0	0	0	0	0	0	1	0	2	2	1	8	15	11.71
S	0	0	0	0	0	0	2	1	4	6	4	2	8	27	9.88
SSW	0	0	0	0	2	0	2	2	4	4	5	3	2	24	8.10
SW	0	0	0	1	1	1	0	4	2	1	5	4	5	24	9.10
WSW	0	0	0	1	0	0	2	2	4	2	7	2	4	24	8.68
W	0	0	0	0	0	1	1	1	2	2	1	0	2	10	8.01
WNW	0	0	0	1	0	1	0	0	0	1	0	0	2	4	8.00
NW	0	0	0	2	0	0	1	0	0	0	0	0	3	6	8.33
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	1	1	0	0	0	0	0	0	0	2	1.50
CALM													0	0.
TOTAL	0	1	3	8	3	10	12	22	19	21	12	19	160	8.91

NUMBER OF INVALID OBSERVATIONS = 8
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-105B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: JULY, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	1	1	2	0	0	0	0	0	0	5	4.20
NE	0	0	1	0	5	2	1	3	3	1	2	1	20	6.60
ENE	0	0	0	3	2	2	2	1	0	1	2	2	15	7.17
E	0	1	0	1	1	1	1	1	0	3	1	1	11	7.45
ESE	0	1	0	0	0	2	0	1	0	6	3	1	14	9.14
SE	0	0	0	0	1	3	3	1	2	2	3	0	15	7.87
SSE	0	0	0	0	1	3	3	1	2	3	3	5	13	9.74
S	0	0	0	0	1	2	5	4	2	2	3	2	11	9.27
SSW	0	3	0	0	5	6	3	6	5	2	5	10	45	8.16
SW	0	0	0	1	0	4	5	4	6	3	5	20	51	9.52
WSW	0	0	0	1	0	0	2	1	3	3	3	6	3	22	9.12
W	0	0	0	0	0	0	1	1	0	0	3	0	1	6	8.20
WNW	0	0	0	0	1	0	0	0	0	1	0	0	0	2	5.00
NW	0	0	0	0	0	0	0	1	1	1	0	0	2	5	10.70
NNW	0	0	0	0	1	0	1	0	0	1	2	0	1	6	8.30
N	0	0	0	0	0	1	1	0	1	1	1	1	0	7	6.47
CALM														1	.60
TOTAL	0	5	3	11	30	34	28	27	35	36	29	73	298	8.68

NUMBER OF INVALID OBSERVATIONS = 52
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	0	0	0	0	0	0	0	1	2	7.50
NE	0	0	2	1	0	1	1	0	0	0	0	0	5	5.14
ENE	0	0	1	1	2	2	3	2	0	1	0	2	16	8.69
E	0	0	0	1	0	0	0	1	3	1	2	2	9	9.29
ESE	0	0	0	0	0	0	0	1	2	1	2	0	6	8.83
SE	0	0	0	0	0	1	0	1	0	1	0	1	4	8.50
SSE	0	0	1	1	1	0	0	0	0	3	1	4	10	9.74
S	0	0	1	3	1	1	0	2	1	1	3	1	15	7.11
SSW	0	1	0	0	1	0	4	3	0	1	2	0	12	7.25
SW	0	0	0	2	2	1	0	0	0	1	1	0	7	7.07
WSW	0	1	0	0	2	1	0	0	0	0	0	0	5	4.46
W	0	0	0	0	1	1	0	1	0	0	0	0	3	4.50
WNW	0	0	0	0	0	0	0	1	0	0	0	0	1	4.00
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.50
N	0	0	0	0	0	0	0	0	0	0	0	0	2	3.65
CALM														0	0.
TOTAL	0	3	9	10	7	7	15	11	5	8	7	14	96	7.15

NUMBER OF INVALID OBSERVATIONS = 20
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	1	0	0	0	1	0	0	2	7.00
E	0	0	0	0	0	1	0	0	0	1	0	0	2	6.50
ESE	0	0	1	0	0	0	0	1	0	0	0	0	2	6.50
SE	0	0	0	0	0	0	0	0	0	0	1	0	1	10.25
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	1	0	0	0	0	0	0	1	8.25
SSW	0	0	0	0	0	0	0	0	0	1	1	0	2	8.85
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	1	0	0	0	0	0	0	0	1	6.00
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	1	1	0	0	0	0	0	0	2	3.50
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM														0	0.
TOTAL	0	0	1	2	3	3	1	1	0	3	2	0	2	15	6.50

NUMBER OF INVALID OBSERVATIONS = 15
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	2	3	3	0	0	0	0	2	11	7.25
NE	0	1	5	1	6	3	2	3	3	1	2	1	28	5.49
ENE	0	0	1	5	6	7	8	5	3	1	2	4	42	8.27
E	0	1	0	5	3	1	3	4	4	5	3	4	35	7.66
ESE	0	1	0	2	0	3	4	3	4	8	6	1	5	36	8.08
SE	0	0	0	0	1	3	4	3	6	5	6	1	11	40	8.46
SSE	0	0	1	2	3	4	1	3	5	5	7	25	56	10.27
S	0	1	3	2	6	10	7	9	9	9	5	28	87	8.95
SSW	0	4	0	3	6	8	9	14	11	10	10	15	90	8.17
SW	0	1	2	3	7	7	7	8	9	10	11	24	93	9.01
WSW	0	1	2	2	0	6	4	7	5	10	8	7	52	8.10
W	0	0	0	2	2	4	3	3	2	5	0	3	26	7.79
WNW	0	0	1	2	2	0	1	1	1	0	0	2	12	6.20
NW	0	0	0	2	1	0	1	1	1	0	0	5	11	8.27
NNW	0	0	1	1	0	1	0	1	1	0	1	0	6	7.17
N	0	1	1	1	1	2	0	1	1	1	1	0	10	7.11
CALM														1	.60
TOTAL	0	10	20	36	55	64	51	71	70	75	51	139	641	8.30

NUMBER OF INVALID OBSERVATIONS = 101
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-106A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: AUGUST, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.70
ENE	0	0	0	1	1	0	3	2	2	1	0	0	10	7.17
E	0	0	1	0	2	0	2	2	1	1	1	0	10	6.74
ESE	0	0	0	1	2	0	1	0	0	1	2	0	7	7.10
SE	0	0	0	0	1	1	0	0	0	0	0	0	2	4.95
SSE	0	0	1	2	2	0	0	0	0	0	0	0	5	3.72
S	0	0	0	1	3	0	1	2	0	0	0	0	7	8.54
SSW	0	0	1	1	3	0	0	2	0	0	2	3	12	7.77
SW	0	0	0	3	0	11	6	2	2	0	1	4	27	7.00
WSW	0	0	0	1	1	2	0	1	1	0	0	0	6	5.90
W	0	0	0	1	1	1	1	0	0	0	0	0	4	3.77
WNW	0	0	0	1	1	0	2	0	0	0	0	0	4	4.32
NW	0	0	0	0	0	1	0	0	0	0	0	0	1	4.40
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	5	12	17	16	11	9	8	3	6	7	96	6.61

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	0	0	0	0	0	1	4.60
NE	0	0	0	0	0	1	0	1	0	0	0	0	2	4.65
ENE	0	0	0	0	0	1	0	0	1	0	0	0	2	7.05
E	0	0	0	0	0	0	0	0	1	1	0	0	2	8.85
ESE	0	0	0	1	0	0	0	0	0	0	0	0	1	3.70
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	1	0	0	0	0	0	0	0	0	1	3.20
SSW	0	0	0	0	0	0	1	0	1	0	2	0	4	4.15
SW	0	0	0	0	0	1	0	2	1	1	0	0	5	4.12
WSW	0	0	0	0	0	1	0	0	0	0	0	0	1	4.20
W	0	0	0	1	0	0	0	0	0	0	0	0	1	2.60
WNW	0	0	0	0	0	1	0	0	0	0	0	0	1	4.10
NW	0	0	0	0	0	1	0	0	0	0	0	0	1	4.10
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	2	0	5	2	3	4	2	1	2	26	7.60

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	1	0	1	2	11.10
ENE	0	0	0	0	0	0	1	0	0	0	1	1	3	9.87
E	0	0	0	0	0	0	0	1	0	0	0	0	1	7.20
ESE	0	0	0	0	0	0	0	1	0	0	0	0	1	6.80
SE	0	0	0	1	0	1	2	0	0	0	0	0	4	6.60
SSE	0	0	0	0	0	1	0	0	0	1	0	0	2	6.10
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	1	0	0	0	2	0	0	1	3	9.60
SW	0	0	0	0	0	0	1	2	4	4	1	0	3	15	8.72
WSW	0	0	1	0	0	0	1	3	0	2	0	0	0	7	5.66
W	0	0	0	0	1	1	0	0	0	0	0	0	0	2	3.85
WNW	0	0	0	1	0	3	0	0	0	0	0	0	0	4	4.07
NW	0	0	0	0	0	0	1	0	0	0	0	0	0	2	5.00
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	2	3	7	8	5	9	5	5	2	10	55	7.57

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	0	1	0	1	0	3	6.60
NE	0	0	0	0	0	1	2	4	3	3	4	1	28	9.36
ENE	0	0	2	0	0	0	0	4	6	2	1	1	18	8.50
E	0	0	2	1	1	0	3	1	1	1	0	1	11	6.62
ESE	0	0	0	1	0	1	2	1	0	1	0	0	7	7.10
SE	0	0	1	2	2	0	0	0	0	0	0	0	5	3.60
SSE	0	0	1	0	0	0	0	1	0	0	0	0	2	3.70
S	0	0	0	0	0	0	2	1	1	0	1	0	5	7.04
SSW	0	0	0	0	1	0	2	2	1	2	0	0	8	6.10
SW	0	1	0	3	3	2	2	3	1	2	1	2	19	8.60
WSW	0	0	1	1	2	3	4	3	7	2	4	12	40	8.82
W	0	0	0	1	2	1	2	4	3	7	1	5	26	8.34
WNW	0	0	0	1	1	1	2	1	2	1	1	0	10	7.60
NW	0	0	0	2	1	1	2	1	0	2	1	0	8	6.10
NNW	0	0	1	0	1	0	1	1	0	1	0	0	5	4.10
N	0	0	0	0	0	0	0	0	1	0	0	0	1	8.00
CALM													0	0.
TOTAL	0	1	8	13	14	10	24	12	10	11	21	20	217	8.00

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-106B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: AUGUST, 1975

PASQUILL #A (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	0	1	1	1	0	1	5	8.54
NE	0	0	1	0	0	1	1	2	2	4	0	0	11	7.69
ENE	0	0	0	0	1	1	0	4	0	1	2	1	10	8.25
E	0	0	0	0	0	0	1	2	3	0	2	2	10	9.10
ESE	0	0	0	0	1	0	0	0	0	3	2	0	6	8.88
SE	0	0	1	0	0	1	0	0	2	0	0	0	4	5.77
SSE	0	0	1	1	0	0	0	1	1	0	1	5	10	11.67
S	0	1	1	0	1	1	2	1	2	0	1	6	16	8.76
SSW	1	0	0	0	0	2	1	5	7	3	5	20	44	10.32
SW	0	0	1	0	2	2	2	3	4	9	6	22	51	10.23
WSW	0	1	0	0	2	1	1	1	4	1	1	2	14	7.00
W	0	0	0	1	1	0	2	1	1	3	0	0	9	7.36
WNW	0	1	0	1	1	2	0	0	0	0	0	0	5	4.24
NW	0	0	0	1	1	0	0	0	0	0	0	0	2	4.10
NNW	0	0	0	0	0	0	0	1	0	0	0	0	1	7.20
N	0	0	0	0	0	0	1	0	0	0	0	0	1	6.70
CALM													1	.58
TOTAL	1	4	4	5	10	12	12	23	27	26	16	59	200	9.13

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	1	0	1	2	0	0	1	5	8.68
ENE	0	1	0	0	0	0	0	0	0	2	0	3	6	9.78
E	0	0	0	0	0	0	0	0	0	0	0	1	1	11.90
ESE	0	0	0	0	0	0	0	0	0	0	1	0	1	10.10
SE	0	0	0	0	1	0	0	0	0	0	1	2	4	10.12
SSE	0	1	0	3	0	2	1	3	0	0	1	2	13	6.56
S	0	1	1	1	2	0	0	1	2	0	3	3	14	8.41
SSW	0	0	0	0	0	2	3	4	2	2	0	13	26	10.33
SW	0	2	0	1	2	1	1	6	2	2	1	3	21	7.68
WSW	0	0	1	0	0	0	0	0	0	0	3	1	5	9.20
W	0	1	1	1	0	0	1	0	1	1	0	1	7	5.11
WNW	0	0	0	1	1	0	1	1	1	0	0	0	5	6.24
NW	0	0	0	2	0	0	0	0	0	0	0	0	2	3.40
NNW	0	1	0	0	1	0	0	0	0	0	0	0	2	4.10
N	0	1	0	0	0	0	0	0	0	0	0	0	1	1.10
CALM													1	.50
TOTAL	0	8	3	9	7	6	8	16	10	7	10	30	115	9.13

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	1	0	0	1	0	0	1	3	8.67
ENE	0	0	2	0	0	0	0	0	0	0	0	0	2	2.40
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	1	0	0	2	3	11.27
SSE	0	0	0	1	0	0	0	0	1	0	0	1	3	7.90
S	0	0	0	0	0	0	0	0	2	0	0	0	2	8.55
SSW	0	0	1	0	0	0	1	0	0	1	0	0	5	7.42
SW	0	0	1	0	0	1	1	0	0	0	0	0	3	4.83
WSW	0	0	0	0	0	0	0	1	0	0	0	0	1	7.10
W	0	0	0	0	0	1	1	0	0	0	0	0	3	5.83
WNW	0	0	0	0	0	1	1	1	0	0	0	0	5	5.58
NW	0	0	0	0	0	0	0	0	1	0	0	0	1	8.80
NNW	0	0	0	0	0	0	0	0	0	1	0	0	1	9.80
N	0	0	0	0	0	1	0	0	1	0	0	0	2	6.85
CALM													1	.50
TOTAL	0	0	4	1	2	7	4	1	7	4	0	4	35	6.91

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	1	2	1	2	1	1	1	9	8.42
NE	0	0	1	0	0	6	3	6	8	14	4	6	58	8.75
ENE	0	1	4	1	2	3	3	10	9	9	4	10	56	8.30
E	0	0	3	1	1	1	7	7	3	5	1	4	35	7.59
ESE	0	0	0	4	2	1	4	0	3	4	5	0	23	7.44
SE	0	1	2	2	5	3	0	0	3	0	1	4	22	6.55
SSE	0	1	2	4	2	2	1	7	3	0	2	4	38	7.79
S	0	2	2	3	5	3	4	5	7	1	4	4	60	7.95
SSW	1	0	2	2	4	6	8	14	14	14	11	11	117	9.54
SW	0	3	2	7	8	16	14	21	16	16	13	40	166	8.76
WSW	0	2	2	2	7	9	5	8	12	7	8	8	70	7.76
W	0	1	3	5	5	3	6	5	4	5	1	2	41	6.39
WNW	0	1	3	3	8	4	4	1	0	0	0	0	25	5.22
NW	0	0	1	5	5	3	1	1	3	0	0	1	20	5.91
NNW	0	1	0	1	1	2	1	1	1	0	0	0	9	6.06
N	0	1	0	0	0	1	1	0	2	0	0	0	5	6.10
CALM													1	.50
TOTAL	1	14	27	45	60	69	65	92	91	77	64	141	744	8.04

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-107A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: SEPTEMBER, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	1	1	2	0	1	0	5	8.28
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	1	1	0	0	0	0	0	0	2	4.85
ESE	0	0	0	0	0	0	0	0	0	0	1	0	1	10.40
SE	0	0	0	1	0	1	1	1	0	0	0	0	4	5.67
SSE	0	0	0	2	0	0	0	0	0	0	1	1	4	7.45
S	0	0	0	0	0	0	2	1	0	2	1	1	7	9.60
SSW	0	0	1	1	0	0	0	1	1	0	0	0	4	5.57
SW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.50
WSW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.70
W	0	0	0	0	0	1	1	1	0	0	0	0	3	6.57
WNW	0	0	0	1	2	1	0	0	0	0	0	0	4	4.37
NW	0	0	0	0	1	0	2	2	0	0	0	0	5	6.40
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	7	4	4	7	7	3	2	4	2	41	6.61

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	2	0	0	0	0	0	2	4.60
ENE	0	0	0	0	0	0	0	0	1	1	0	0	2	8.75
E	0	0	0	0	0	0	0	1	0	0	0	0	1	6.80
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	1	0	0	0	1	2	10.65
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	1	1	11.40
SSW	0	0	0	0	0	0	1	0	0	0	0	0	1	5.10
SW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.50
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	1	0	0	1	4.80
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	0	1	0	0	3	2	2	1	0	2	11	9.15

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	2	1	2	5	10.86
NE	0	0	0	0	0	0	1	0	0	0	0	2	3	11.87
ENE	0	0	0	0	1	0	0	0	1	2	0	3	7	10.41
E	0	0	0	0	1	0	0	0	0	0	0	0	1	3.40
ESE	0	0	0	0	0	1	0	0	0	0	0	0	1	6.00
SE	0	0	0	0	1	1	0	0	0	0	0	3	5	9.22
SSE	0	0	0	0	0	0	0	0	1	0	0	0	1	8.40
S	0	0	0	0	1	0	0	0	1	0	0	0	2	6.50
SSW	0	0	0	0	0	0	0	0	1	0	0	0	1	8.60
SW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.70
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	1	2	0	0	0	0	0	0	3	4.83
WNW	0	0	0	1	0	0	1	0	0	0	0	0	2	4.10
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	1	1	0	2	10.45
CALM													0	0.
TOTAL	0	0	1	4	5	2	2	1	2	6	2	10	35	8.83

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	0	0	0	3	2	2	5	7	4	10	36	9.58
NE	0	0	0	1	0	6	5	6	6	4	6	18	56	10.35
ENE	0	1	0	1	1	3	4	2	8	5	1	10	36	9.64
E	0	0	0	1	1	1	2	4	2	2	2	4	10	29	9.34
ESE	0	0	0	0	0	1	0	0	0	3	1	1	0	6	8.30
SE	0	0	0	0	0	1	1	0	0	6	2	2	2	9	17	12.25
SSE	0	0	0	0	0	0	0	0	2	1	0	3	5	11	14.28
S	0	0	0	0	0	0	0	2	4	1	0	1	4	12	11.82
SSW	0	0	0	0	0	1	2	4	0	3	1	2	5	20	9.60
SW	0	0	0	0	0	1	3	2	3	0	2	0	7	18	10.12
WSW	0	1	2	2	0	3	1	2	0	1	0	0	1	17	5.58
W	0	1	2	2	2	1	2	1	4	1	0	1	0	15	5.53
WNW	0	0	0	0	0	1	0	1	1	1	0	1	1	6	5.27
NW	0	0	0	0	0	0	2	2	0	0	0	0	0	4	3.22
NNW	0	0	0	0	0	0	0	1	1	1	1	0	0	4	7.50
N	0	0	0	0	0	0	0	2	1	1	0	2	0	6	8.23
CALM													1	.63
TOTAL	0	4	5	5	11	11	10	28	16	27	12	60	202	9.54

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-107B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: SEPTEMBER, 1975

PASQUILL #B (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	2	0	0	1	0	0	0	4	7	14	10.11
NE	0	0	0	5	0	1	2	4	0	4	4	16	36	10.94
ENE	0	0	1	0	0	0	2	2	3	3	1	5	17	9.49
E	0	0	1	0	0	2	1	0	4	2	0	3	14	8.64
ESE	0	0	1	0	0	0	1	0	0	2	0	1	5	9
SE	0	0	2	0	0	0	1	0	0	1	2	3	10	11.44
SSE	0	0	2	0	0	0	0	0	1	2	3	10	20	10.31
S	0	0	0	0	0	0	0	2	3	3	4	8	20	11.49
SSW	0	0	0	0	0	0	1	0	2	3	1	5	12	10.69
SW	0	0	1	0	0	0	0	4	2	2	0	4	11	9.67
WSW	0	0	1	0	0	0	0	2	0	1	0	2	6	9.33
W	0	0	1	0	0	2	0	1	0	0	2	3	9	11.33
WNW	0	0	0	0	2	0	0	1	0	0	1	0	4	8.33
NW	0	0	0	1	2	1	0	1	1	1	1	1	9	8.89
NNW	0	0	0	1	2	1	1	5	4	2	3	1	23	9.47
N	0	0	0	3	1	0	1	1	3	1	1	0	12	8.66
CALM													0	0.
TOTAL	0	5	8	15	10	10	11	26	23	33	25	76	242	9.77

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #C (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	0	0	0	0	0	0	0	1	2	9.50
NE	0	0	0	0	1	0	0	0	0	0	0	10	11	13.36
ENE	0	0	0	0	0	0	0	0	0	0	0	4	4	11.25
E	0	0	0	0	0	0	1	0	0	0	0	2	3	10.67
ESE	0	0	0	0	0	0	0	1	1	0	0	0	2	9.25
SE	0	0	0	0	0	1	0	0	0	1	0	0	2	9.75
SSE	0	0	0	0	0	0	1	0	0	0	1	1	3	10.33
S	0	0	0	0	0	0	1	0	0	0	0	5	7	11.17
SSW	0	0	0	0	0	0	1	0	0	0	1	0	2	9.00
SW	0	0	0	0	0	0	0	2	0	0	1	0	3	10.33
WSW	0	0	0	0	0	0	0	0	2	0	1	2	5	10.44
W	0	0	0	0	0	0	0	0	1	0	0	1	2	9.75
WNW	0	0	0	0	0	0	0	0	0	1	0	0	1	8.50
NW	0	0	0	0	0	0	0	1	0	0	0	0	1	8.67
NNW	0	0	0	0	1	0	0	0	1	0	0	1	3	7.33
N	0	0	0	0	1	0	0	0	0	0	0	0	1	5.00
CALM													0	0.
TOTAL	0	0	0	1	3	1	4	4	5	1	4	27	51	9.96

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #D (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	1	1	13.50
ENE	0	0	0	0	0	0	0	0	0	0	1	1	2	11.50
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	1	0	0	0	0	0	0	1	4.50
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	1	0	0	0	0	0	0	0	0	1	2.00
SSW	0	0	0	0	1	0	0	1	0	0	0	0	2	6.50
SW	0	0	0	0	0	2	0	0	0	0	0	0	2	5.25
WSW	0	0	0	0	0	0	1	1	0	1	0	0	3	7.75
W	0	0	0	0	0	0	0	1	0	1	0	2	4	8.63
WNW	0	0	0	0	0	0	0	0	1	1	2	0	4	7.00
NW	0	0	0	0	0	0	0	0	0	1	1	0	2	6.50
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	1	1	1	3	1	2	1	3	3	4	24	7.67

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #E (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	0	3	0	3	4	3	7	0	12	28	62	9.69
NE	0	0	0	4	1	7	10	10	5	9	12	47	105	10.45
ENE	0	1	1	1	2	3	5	4	13	11	5	21	76	9.99
E	0	1	1	2	4	5	6	7	4	2	5	16	53	8.91
ESE	0	0	0	0	2	1	0	1	6	1	4	5	19	9.32
SE	0	2	0	2	5	2	5	3	5	5	4	23	56	10.91
SSE	0	0	0	2	0	0	1	4	5	1	4	17	34	11.71
S	0	2	0	2	1	1	6	5	4	4	3	11	39	10.17
SSW	0	1	1	1	1	4	4	5	4	10	4	10	50	9.75
SW	0	1	0	3	4	2	4	4	5	0	3	12	41	8.95
WSW	0	1	2	3	1	7	1	1	1	2	2	2	28	6.59
W	0	1	3	5	4	4	5	7	10	2	4	2	47	7.81
WNW	0	0	2	1	4	4	1	1	2	4	1	1	21	6.33
NW	0	0	1	2	1	1	1	4	2	1	2	1	17	6.79
NNW	0	0	2	0	2	1	1	1	1	2	1	0	11	7.23
N	0	0	0	1	1	0	2	1	1	2	1	0	11	7.23
CALM													1	0.
TOTAL	1	9	13	37	33	51	65	72	71	56	72	203	716	9.36

NUMBER OF INVALID OBSERVATIONS = 4
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-108A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: OCTOBER, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	2	2	23.35
NE	0	0	0	0	0	1	0	0	0	1	0	0	2	7.70
ENE	0	0	0	0	0	0	0	0	1	0	0	0	1	8.70
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	1	0	0	0	0	0	0	0	1	3.90
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	1	0	0	0	0	0	0	0	1	3.90
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	1	0	0	0	0	0	0	0	0	0	1	2.60
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	1	0	0	0	0	0	0	0	0	0	1	1.60
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	1	2	0	1	0	0	1	1	0	2	9	9.21

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	2	2	23.35
NE	0	0	0	0	0	0	0	1	0	0	1	0	2	8.45
ENE	0	0	0	0	0	0	0	0	1	0	1	0	2	9.20
E	0	0	0	0	0	0	0	0	1	0	0	0	1	8.70
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	1	0	0	0	0	0	0	0	1	4.80
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	2	0	0	0	0	0	2	5.45
CALM													0	0.
TOTAL	0	0	0	0	1	2	0	1	2	0	2	2	10	10.78

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	1	2	1	0	1	0	1	7	8.31
NE	0	0	0	1	0	1	0	0	1	0	1	2	6	9.70
ENE	0	0	0	0	1	1	0	1	0	0	1	0	4	7.17
E	0	0	0	0	0	1	0	1	1	0	0	0	3	7.13
ESE	0	0	0	0	0	0	0	1	0	0	0	0	1	4.60
SE	0	0	0	0	0	1	0	1	0	0	0	0	2	5.50
SSE	0	0	0	0	1	0	0	0	0	0	0	0	1	3.45
S	0	0	0	1	0	0	0	0	1	0	0	0	2	5.33
SSW	0	0	0	1	0	0	0	2	0	0	0	0	3	5.07
SW	0	0	0	0	0	0	1	1	0	0	1	0	3	7.27
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	1	0	0	1	1	0	3	7.83
NNW	0	0	0	0	2	0	1	0	0	1	1	0	6	7.02
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	0	2	5	4	6	7	6	5	2	2	6	45	7.28

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	0	1	0	2	2	5	4	4	21	11.50
NE	0	0	0	0	2	0	1	1	3	4	1	8	20	10.42
ENE	0	0	1	0	3	2	4	3	2	4	1	4	24	9.22
E	0	0	0	0	1	2	3	1	1	0	0	0	8	6.60
ESE	0	0	0	0	0	2	2	2	1	0	0	0	7	5.41
SE	0	0	0	1	0	0	1	0	1	0	0	0	3	5.14
SSE	0	0	0	1	0	0	1	0	0	2	0	0	4	8.68
S	0	0	1	0	2	0	0	0	0	0	0	0	3	14.75
SSW	0	0	0	1	2	1	1	0	1	0	0	0	6	5.03
SW	0	0	2	0	1	2	3	4	5	4	5	4	35	9.23
WSW	0	0	0	0	1	2	2	1	1	0	1	5	13	9.21
W	0	0	0	0	2	1	0	1	1	0	0	2	9	7.67
WNW	0	0	0	0	0	1	1	2	1	1	0	0	7	5.61
NW	0	0	0	0	0	2	4	1	5	2	2	1	18	7.00
NNW	0	0	2	2	1	1	2	3	2	2	0	2	20	7.67
N	0	0	0	1	1	2	0	1	1	0	0	1	7	7.00
CALM													0	0.
TOTAL	0	1	6	11	17	26	22	21	22	25	14	29	217	8.78

NUMBER OF INVALID OBSERVATIONS = 4
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-108B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: OCTOBER, 1975

PASQUILL NEW (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	2	1	0	4	1	0	2	15	26	11.32
NE	0	0	1	0	1	1	3	3	3	5	7	14	38	10.55
ENE	0	0	0	1	0	0	0	3	0	2	2	9	17	9.31
E	0	0	0	1	0	2	2	2	0	0	0	1	8	5.88
ESE	0	0	0	0	0	0	3	1	0	0	1	7	12	12.05
SE	0	0	0	0	0	0	0	1	0	0	0	1	11	13	14.60
SSE	0	0	0	0	0	0	0	0	0	0	0	3	3	25.71
S	0	0	0	0	0	1	1	0	0	0	0	1	2	5	13.00
SSW	0	0	0	0	0	0	2	0	0	0	1	2	6	11	11.67
SW	0	0	0	0	0	1	1	1	1	1	2	1	12	22	10.74
WSW	0	0	0	0	0	1	0	1	0	1	0	1	10	14	11.89
W	0	1	2	1	1	0	1	0	1	0	0	1	10	18	9.60
WNW	0	0	0	0	0	2	0	0	1	0	0	1	0	4	4.77
NW	0	0	1	1	1	0	0	1	0	0	0	0	0	7	5.01
NNW	0	0	1	0	0	2	1	0	1	0	0	1	0	6	5.62
N	0	0	1	0	0	2	0	1	2	2	0	2	0	10	7.01
CALM													0	0.	
TOTAL	0	3	5	6	6	9	10	16	12	9	22	97	209	10.58

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL NEW (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	1	0	0	0	0	0	4	8	10.75
NE	0	0	0	1	0	1	0	0	1	1	2	14	22	12.09
ENE	0	0	1	0	0	0	0	1	0	1	4	4	11	10.65
E	0	0	0	1	0	0	0	0	2	0	2	4	9	10.60
ESE	0	0	0	0	0	0	1	0	1	0	1	5	10	11.10
SE	0	0	0	1	0	0	0	0	0	0	0	3	9	11.33
SSE	0	0	0	0	0	0	0	0	0	0	0	5	5	15.40
S	1	0	0	0	0	0	0	0	0	2	0	1	4	8.27
SSW	0	0	0	0	0	0	0	1	0	0	2	7	10	11.44
SW	0	0	1	0	0	0	0	0	0	1	0	8	10	12.43
WSW	0	0	0	0	0	0	0	0	0	0	2	0	2	10.46
W	0	0	0	0	1	0	1	1	1	0	0	3	7	9.16
WNW	0	0	0	0	0	0	1	0	1	0	0	1	3	8.10
NW	0	0	0	0	0	0	0	0	1	0	1	0	2	8.50
NNW	0	0	1	0	0	1	0	1	0	0	1	0	4	7.77
N	0	0	0	0	0	1	1	2	0	0	0	0	4	7.50
CALM													0	0.	
TOTAL	1	0	4	5	2	4	4	5	6	5	15	66	122	11.13

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL NEW (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	3	0	0	0	0	0	0	2	1	2	8	7.38
NE	0	0	3	1	2	1	0	1	0	1	1	4	14	7.47
ENE	0	0	1	1	1	2	1	0	0	2	0	2	10	6.48
E	0	0	1	2	0	0	0	0	0	1	1	4	9	9.51
ESE	0	0	0	1	0	0	0	0	0	0	0	0	1	2.60
SE	0	0	0	0	0	0	0	1	0	0	0	4	5	12.62
SSE	0	0	1	0	1	0	0	0	0	0	0	1	3	6.63
S	0	0	1	1	0	0	0	1	0	0	0	1	4	5.22
SSW	0	0	0	0	3	1	0	0	0	2	1	0	7	6.23
SW	0	0	0	0	2	0	0	1	0	3	1	0	7	9.99
WSW	0	0	0	0	3	0	1	0	1	2	4	0	11	8.78
W	0	0	0	0	0	1	0	1	1	2	0	0	5	7.71
WNW	0	0	0	1	1	0	0	1	0	0	0	0	3	4.10
NW	0	0	0	0	1	0	1	0	0	1	0	0	3	5.60
NNW	0	0	0	0	1	1	0	2	0	1	0	0	5	5.40
N	0	0	2	2	0	0	1	0	0	1	2	0	10	6.70
CALM													1	.70	
TOTAL	0	0	14	10	9	6	3	7	2	13	11	8	11	124	7.71

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	5	2	2	4	2	7	3	4	7	36	76	11.24
NE	0	0	4	3	5	5	4	4	4	12	14	44	104	10.64
ENE	0	0	3	2	1	4	6	7	9	7	9	12	62	9.45
E	0	0	1	3	1	3	5	5	2	5	7	9	41	8.33
ESE	0	0	1	1	0	2	2	4	2	1	0	4	17	8.13
SE	0	0	0	1	0	2	2	0	1	0	0	4	12	9.04
SSE	0	0	1	1	1	0	0	1	0	0	1	2	7	7.36
S	1	0	2	1	1	1	2	1	0	2	0	1	13	7.22
SSW	0	0	0	1	1	0	1	0	1	0	1	1	6	11.88
SW	0	0	0	0	3	1	1	1	0	1	1	3	11	10.14
WSW	0	0	0	0	3	2	2	4	1	1	1	4	19	9.82
W	0	0	0	0	1	1	3	3	3	2	1	1	15	8.04
WNW	0	0	0	1	1	1	1	2	1	3	2	2	14	8.55
NW	0	0	0	0	1	1	2	1	1	2	1	1	10	8.23
NNW	0	0	1	1	1	2	1	2	1	1	1	2	13	8.10
N	0	1	2	3	1	3	3	5	3	3	4	4	33	7.98
CALM													1	.70	
TOTAL	1	1	20	21	23	31	36	47	32	44	50	136	442	9.66

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-109A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: NOVEMBER, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	1	0	0	0	0	0	0	0	0	0	0	1	1.33
WNW	0	1	0	0	0	0	0	0	0	0	0	0	1	1.33
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	2	0	0	0	0	0	0	0	0	0	0	2	1.65

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.75
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	1	1	0	0	0	0	0	0	0	0	0	0	2	1.50
W	0	0	0	0	1	0	0	0	0	0	0	0	1	4.46
WNW	0	0	0	1	2	0	0	0	0	0	0	0	3	3.13
NW	0	0	0	1	0	0	0	0	0	0	0	0	1	3.46
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	1	1	1	3	1	1	0	0	0	0	0	0	4	3.21

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	1	0	0	0	1	4.00
NE	1	0	0	0	0	0	0	0	0	0	0	0	1	1.00
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	1	0	0	0	1	10.75
SE	0	0	0	1	0	0	0	1	2	0	0	0	4	8.24
SSE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.63
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	1	0	0	1	0	1	0	1	4	0	0	0	8	6.88

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	1	1	0	0	1	0	0	0	0	3	3.00
NE	0	0	1	0	1	2	0	1	0	0	0	0	5	3.40
ENE	0	0	0	0	0	1	1	1	2	1	0	0	6	5.67
E	0	0	1	1	0	1	2	1	0	0	0	0	6	4.33
ESE	0	0	0	0	0	2	1	0	0	1	0	0	4	6.00
SE	0	0	0	0	0	2	1	0	1	1	0	0	5	6.00
SSE	0	1	0	0	0	1	1	1	2	1	0	0	7	5.57
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	1	0	0	0	0	0	1	1	1	0	0	4	4.50
SW	0	1	0	0	0	1	0	1	1	1	0	0	5	4.80
WSW	0	2	1	0	0	2	2	1	1	1	0	0	10	4.70
W	0	1	0	0	1	0	1	1	1	1	0	0	6	4.67
WNW	0	1	0	1	1	1	1	1	1	2	1	0	10	5.10
NW	0	1	0	0	1	1	1	1	1	2	1	0	9	5.11
NNW	0	1	0	0	0	1	1	0	0	1	0	0	4	3.75
N	0	0	1	0	0	1	1	0	0	0	0	0	3	3.67
CALM													0	0.
TOTAL	0	8	5	3	5	18	12	10	11	15	2	0	89	4.83

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-109B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: NOVEMBER, 1975

PASQUILL "A" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	2	0	0	0	1	3	8.87
NE	0	0	0	0	0	2	0	0	0	0	0	2	4	10.25
ENE	0	1	0	0	0	0	1	3	3	3	0	1	12	9.49
E	0	0	0	1	0	0	1	0	1	1	1	1	6	8.31
ESE	1	0	1	0	0	0	0	2	1	2	2	3	12	9.45
SE	0	1	0	0	1	0	1	1	5	0	0	12	21	12.15
SSE	0	1	0	0	2	0	0	0	0	1	4	11	19	12.37
S	0	0	0	0	0	1	0	1	0	1	2	9	14	14.86
SSW	0	0	0	0	0	1	1	1	1	0	2	10	16	11.69
SW	1	0	0	0	0	2	0	0	1	1	1	9	15	10.10
WSW	1	0	0	1	0	0	0	1	0	0	1	6	10	10.59
W	0	1	0	0	1	0	1	0	0	2	3	8	16	11.87
WNW	0	1	0	2	1	0	1	0	1	1	0	4	10	8.79
NW	0	1	0	0	0	0	0	1	0	0	1	4	7	8.91
NNW	0	4	0	0	0	0	0	0	2	1	1	2	6	10.67
N	0	2	2	1	0	0	1	0	0	0	0	0	6	3.07
CALM													2	.50
TOTAL	3	6	3	5	5	6	9	12	16	12	20	80	178	10.44

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL "B" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	1	0	0	1	0	0	0	0	2	6.05
NE	0	0	0	2	0	0	0	1	0	0	0	1	4	9.42
ENE	0	0	0	0	1	0	1	1	0	0	2	2	7	10.39
E	0	0	0	1	0	1	0	0	0	2	1	3	8	10.10
ESE	0	0	1	0	0	1	0	1	0	1	1	2	7	9.11
SE	0	0	0	1	1	0	1	0	0	1	0	14	18	12.61
SSE	0	1	0	0	1	1	2	0	3	1	0	5	15	11.14
S	0	1	0	0	0	0	0	0	0	0	0	1	2	9.39
SSW	0	0	1	0	0	1	0	0	0	0	0	0	2	6.50
SW	0	0	0	0	0	1	0	0	1	0	0	1	3	9.27
WSW	0	1	0	0	0	0	0	0	0	0	0	5	6	12.00
W	1	0	0	0	0	0	0	1	0	0	1	3	6	9.64
WNW	0	0	1	0	0	0	3	0	1	1	1	0	7	7.80
NW	0	1	0	0	0	0	0	1	2	1	0	0	5	7.12
NNW	0	0	0	0	1	0	0	0	0	1	0	0	2	7.25
N	0	0	0	0	0	2	0	0	1	0	0	0	3	6.30
CALM													1	.50
TOTAL	1	4	3	4	5	7	7	4	8	8	4	36	96	9.03

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL "C" (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	1	1	1	0	0	2	1	2	1	1	0	0	11	6.59
NE	0	0	1	1	0	3	0	1	2	0	1	1	10	7.62
ENE	0	0	0	0	0	1	0	0	1	0	0	0	2	7.21
E	0	0	1	0	0	0	1	1	1	2	0	1	6	9.38
ESE	0	0	0	1	0	1	0	1	1	0	0	1	6	8.35
SE	0	0	1	0	1	1	4	2	1	2	0	0	13	9.35
SSE	0	0	1	0	2	0	0	0	1	0	0	1	6	9.85
S	1	0	0	1	1	0	0	2	0	1	0	0	6	8.51
SSW	0	0	1	0	2	0	0	0	0	0	0	1	4	8.02
SW	1	0	0	0	1	0	0	0	0	0	1	0	3	9.11
WSW	0	0	0	1	0	0	0	0	0	1	0	5	9	9.11
W	0	0	1	1	0	1	1	2	0	0	1	0	7	8.69
WNW	0	0	0	0	1	0	1	1	0	1	0	10	14	10.69
NW	0	0	0	2	1	1	1	0	0	1	0	2	8	7.66
NNW	0	0	0	2	0	0	1	1	0	0	1	0	5	6.49
N	0	0	0	0	0	1	1	1	1	1	0	0	7	7.10
CALM													8	.56
TOTAL	2	11	6	11	11	11	11	16	12	12	5	30	166	8.07

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 720

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	1	2	3	1	3	4	2	4	3	3	2	2	34	7.50
NE	1	0	1	3	1	5	0	3	3	2	2	4	31	8.26
ENE	0	1	0	0	1	2	3	5	4	4	3	3	31	8.58
E	0	1	1	1	1	2	4	2	4	5	3	13	41	8.04
ESE	1	0	2	1	0	2	1	4	2	2	3	6	32	8.65
SE	1	2	2	3	4	3	3	4	3	2	1	11	41	10.16
SSE	0	2	0	2	4	3	5	2	5	0	4	23	56	10.16
S	1	1	1	1	0	3	0	2	1	1	1	24	41	11.01
SSW	1	3	1	3	3	2	2	2	2	2	1	15	39	9.31
SW	1	1	1	1	1	2	1	2	1	1	1	10	23	8.55
WSW	1	1	1	1	1	1	4	1	2	2	2	11	31	10.07
W	1	1	1	1	1	1	3	2	2	1	2	21	41	9.17
WNW	0	1	1	6	3	1	4	2	1	2	2	12	35	8.10
NW	1	1	1	3	2	1	3	1	1	4	1	16	34	9.12
NNW	1	1	1	2	1	1	1	1	2	1	1	2	15	7.05
N	0	2	1	2	2	4	5	1	2	1	1	1	21	5.55
CALM													16	.56
TOTAL	11	19	15	31	30	35	41	35	32	32	26	180	711	8.54

NUMBER OF INVALID OBSERVATIONS = 1
TOTAL NUMBER OF OBSERVATIONS = 720

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TABLE 2.3-110A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: DECEMBER, 1975

PASQUILL #AA (FROM AEC/DELTA-T CRITERIA 10-61 METERS - 1
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	1	0	0	0	0	0	0	0	0	0	0	1	2.00
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	0	0	0	0	0	0	0	0	0	0	1	2.00

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #BB (FROM AEC/DELTA-T CRITERIA 10-61 METERS - 1
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ENE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
E	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	1	0	0	0	0	0	0	0	0	0	0	1	1.00
SSW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.00
SW	0	0	0	0	0	1	0	0	0	0	0	0	1	5.70
WSW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	0	0	1	1	0	0	0	0	0	0	1	4.00

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #CC (FROM AEC/DELTA-T CRITERIA 10-61 METERS - 1
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NE	1	0	0	0	0	0	0	0	0	0	0	0	1	.90
ENE	0	0	0	0	0	1	0	0	0	0	0	0	1	5.10
E	0	0	0	0	1	0	0	0	0	0	0	0	1	4.60
ESE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSE	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
S	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
SSW	0	0	0	0	1	0	0	0	0	0	0	0	1	4.00
SW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WSW	0	1	0	0	0	0	0	0	0	0	0	0	1	1.10
W	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
WNW	0	0	0	0	0	0	0	0	0	1	0	0	1	2.00
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
NNW	0	0	0	0	0	0	0	0	1	0	1	0	2	9.60
N	0	0	0	0	0	0	0	0	0	0	0	4	4	17.55
CALM													0	0.
TOTAL	1	1	0	0	2	1	0	0	1	0	1	4	11	8.36

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #DD (FROM AEC/DELTA-T CRITERIA 10-61 METERS - 1
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	1	3	1	1	3	2	2	8	26	9.19
NE	0	1	0	2	3	4	6	2	5	5	5	4	40	7.98
ENE	0	0	1	0	1	3	2	1	0	4	2	4	18	8.63
E	0	1	0	1	0	1	1	0	0	3	0	0	7	5.14
ESE	0	0	1	1	0	2	0	0	0	1	0	0	5	5.60
SE	0	0	0	0	1	0	1	1	1	0	0	0	5	7.24
SSE	0	0	0	0	1	0	0	1	0	0	0	1	3	10.13
S	0	2	2	1	0	0	0	0	0	0	0	0	5	2.90
SSW	0	1	2	0	2	1	0	2	2	1	0	0	11	5.70
SW	0	0	2	1	1	0	0	1	4	2	2	10	23	12.11
WSW	0	0	0	1	1	1	0	0	1	3	2	17	26	15.35
W	0	0	0	1	1	1	2	0	1	2	1	1	10	7.60
WNW	0	2	2	2	0	2	2	0	1	2	1	1	14	7.43
NW	0	1	0	1	0	2	1	1	2	3	1	1	13	9.46
NNW	0	1	0	0	0	2	1	1	2	3	1	15	26	10.92
N	0	2	0	1	0	0	3	1	0	1	0	5	13	8.04
CALM													1	2.00
TOTAL	1	12	11	13	12	22	21	12	24	32	19	68	247	9.11

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-110B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: DECEMBER, 1975

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	1	0	3	3	1	2	0	0	0	10	6.53
NE	0	0	0	0	0	1	2	2	3	3	1	5	17	9.42
ENE	0	0	1	2	0	0	2	1	2	6	1	4	19	9.65
E	0	1	0	0	0	0	0	5	1	2	0	6	15	9.67
ESE	1	0	0	0	0	1	0	0	3	0	0	3	8	9.24
SE	0	0	0	0	0	0	1	1	0	0	0	2	4	11.15
SSE	0	0	0	0	0	0	0	1	2	0	0	0	5	8 12.17
S	0	0	2	0	0	1	0	0	0	0	0	0	8	11 12.51
SSW	0	0	0	0	0	1	3	0	0	0	3	3	10	29 12.14
SW	0	0	0	0	0	1	0	1	3	5	2	2	22	36 12.49
WSW	0	0	0	0	0	0	2	0	0	4	2	3	15	26 11.15
W	0	0	0	1	0	0	0	0	1	2	2	1	3	10 9.53
WNW	0	0	0	0	0	0	1	0	1	1	1	2	1	7 9.34
NW	0	0	0	0	3	0	1	2	0	2	0	3	15	26 10.20
NNW	0	0	0	0	1	1	1	0	4	1	1	0	3	12 9.05
N	0	0	0	1	0	0	1	0	1	0	0	0	0	3 5.63
CALM														8 .52
TOTAL	1	3	3	7	4	14	12	22	26	22	16	111	249	10.27

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	0	0	0	0	3	1	0	0	4	8.85
NE	0	0	0	0	0	1	0	0	0	1	0	3	5	12.04
ENE	0	0	0	0	0	0	0	0	0	0	0	1	1	14.70
E	0	0	0	0	1	0	1	0	0	1	1	2	6	9.75
ESE	0	1	0	0	0	0	0	0	0	0	0	0	1	1.40
SE	0	0	0	0	0	0	0	0	0	0	0	3	3	13.53
SSE	0	0	0	0	0	0	0	0	0	0	0	3	3	16.07
S	0	0	0	0	0	1	1	0	0	1	0	1	4	8.85
SSW	0	0	0	0	0	0	0	0	0	0	1	8	9	14.78
SW	0	0	0	0	0	0	0	0	0	0	1	3	4	11.35
WSW	0	0	0	0	0	0	0	0	0	1	0	1	2	12.25
W	0	0	0	0	0	0	0	0	0	1	0	1	2	9.23
WNW	0	0	0	0	0	0	0	0	0	1	0	2	3	9.70
NW	0	0	0	0	0	0	0	0	0	0	1	3	4	12.19
NNW	0	0	1	0	0	0	0	1	0	0	1	1	4	8.02
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.
CALM													0	0.
TOTAL	0	1	1	0	1	2	3	0	5	7	6	29	55	11.35

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	0	0	0	0	0	0	0	0	0	0	1	1.10
NE	0	1	1	1	0	0	0	0	0	0	0	3	6	8.30
ENE	0	0	0	0	1	0	1	0	0	0	0	2	4	11.15
E	0	0	0	0	0	0	2	2	1	0	1	1	6	8.93
ESE	0	2	0	0	0	1	0	1	1	1	0	1	5	12 8.94
SE	0	0	1	0	0	1	0	1	1	3	2	0	4	14 8.64
SSE	0	0	0	0	0	0	0	0	0	0	0	0	3	3 13.57
S	0	0	0	1	1	0	2	0	0	0	0	0	10	14 10.90
SSW	0	0	1	0	0	0	2	0	1	1	0	2	0	5 11 9.55
SW	0	0	1	0	0	1	1	0	0	1	1	0	3	5 12 9.91
WSW	0	1	0	0	0	0	2	0	0	1	1	4	3	12 24 10.66
W	0	0	0	0	0	0	0	0	2	0	2	1	0	0 5 8.12
WNW	0	1	0	0	0	0	0	0	0	1	0	2	1	2 7 8.79
NW	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0.
NNW	0	0	0	0	0	1	0	0	0	2	0	0	0	3 5.57
N	0	0	0	0	0	1	0	0	0	0	0	0	1	2 8.40
CALM														28 .51
TOTAL	2	7	3	3	10	2	5	4	11	12	4	14	141	8.27

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 744

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-41 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	0	2	3	6	4	2	8	3	2	8	39	8.26
NE	1	2	1	3	1	11	6	4	4	6	5	15	59	8.56
ENE	0	0	2	2	2	4	5	2	2	10	3	11	51	9.22
E	0	2	0	1	2	1	4	7	3	6	1	9	36	8.65
ESE	1	3	1	1	1	3	1	1	4	1	1	6	24	8.08
SE	0	1	1	0	2	0	1	3	4	3	0	4	20	9.25
SSE	0	0	0	0	1	0	1	2	0	0	0	12	16	12.91
S	0	0	3	2	1	4	1	0	0	1	0	13	26	9.57
SSW	0	1	2	0	2	4	1	3	2	2	4	32	52	10.35
SW	0	2	2	2	3	1	1	5	4	4	5	44	81	12.81
WSW	0	2	0	1	3	3	0	1	8	3	7	65	79	12.20
W	0	1	2	1	4	2	4	1	4	3	4	4	32	7.73
WNW	1	1	2	2	0	3	5	4	1	5	5	4	37	7.13
NW	0	1	0	4	0	3	3	1	1	3	7	11	34	10.21
NNW	1	1	1	1	4	1	2	3	1	3	1	17	52	9.85
N	0	2	1	1	1	1	1	2	2	1	0	6	28	8.10
CALM													10	.51
TOTAL	4	11	18	23	37	47	44	45	44	47	39	78	382	9.65

NUMBER OF INVALID OBSERVATIONS = 2
TOTAL NUMBER OF OBSERVATIONS = 744

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TABLE 2.3-111A

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: ANNUAL, 1975

PASQUILL #A# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	2	1	1	2	4	0	2	3	15	10.05
NE	0	0	1	1	0	3	3	2	0	3	5	12	30	9.90
ENE	0	0	0	1	2	0	5	4	4	2	0	6	24	9.27
E	0	0	2	2	4	3	5	6	2	1	1	0	26	6.14
ESE	0	0	0	1	3	3	1	0	0	3	3	3	17	8.06
SE	0	0	1	2	3	3	2	3	1	1	0	1	17	6.79
SSE	0	0	1	5	3	0	1	0	1	0	1	2	14	6.82
S	0	0	1	3	4	2	3	4	3	4	1	6	33	7.63
SSW	0	0	2	4	4	0	0	2	3	0	2	5	22	7.40
SW	0	2	1	5	0	17	7	3	2	0	1	4	42	6.25
WSW	0	1	1	2	3	2	1	3	1	0	0	0	14	5.27
W	0	2	2	1	2	4	3	1	0	0	0	0	17	4.78
WNW	0	2	1	2	1	4	1	1	0	0	0	0	14	4.50
NW	0	1	0	2	4	0	2	2	1	0	0	0	12	5.42
NNW	0	0	0	0	0	0	0	1	1	1	0	1	4	9.22
N	0	0	0	0	0	3	0	0	0	0	0	0	3	5.63
CALM													0	0.
TOTAL	0	8	13	31	39	47	35	34	23	15	16	43	304	7.17

NUMBER OF INVALID OBSERVATIONS = 11
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL #B# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	0	0	2	0	2	2	0	2	0	2	10	10.45
NE	0	0	0	0	0	2	3	2	0	0	4	2	13	9.69
ENE	0	0	0	2	0	5	3	2	6	1	3	3	25	8.59
E	0	0	0	0	0	2	0	1	1	2	2	0	8	7.04
ESE	0	0	0	1	0	1	0	0	2	2	0	3	9	9.33
SE	0	0	1	1	3	0	1	2	1	0	0	2	11	7.64
SSE	0	0	0	0	1	0	1	1	0	0	0	1	4	7.70
S	0	1	0	1	1	2	0	1	0	0	0	4	10	7.97
SSW	0	0	0	0	1	0	2	1	2	0	2	5	13	9.96
SW	0	0	0	3	3	3	4	3	1	1	0	6	24	7.66
WSW	1	1	0	1	3	0	1	1	0	0	0	0	8	4.29
W	0	0	1	0	1	1	0	0	0	1	0	0	4	5.48
WNW	0	0	1	5	4	1	1	0	1	0	0	0	13	4.55
NW	0	0	0	1	1	1	0	1	1	1	2	5	13	11.55
NNW	0	1	0	0	0	0	0	0	0	0	0	1	2	9.05
N	0	0	0	0	0	2	0	0	0	0	0	0	2	5.65
CALM													0	0.
TOTAL	1	3	3	15	22	18	19	17	16	10	11	35	170	8.11

NUMBER OF INVALID OBSERVATIONS = 3
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL #C# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	0	1	0	0	3	4	3	2	3	1	4	21	9.62
NE	2	0	2	1	3	1	3	0	4	3	2	7	28	7.91
ENE	0	0	0	0	4	5	0	5	3	8	6	16	47	9.70
E	0	0	0	2	2	1	1	6	1	3	5	4	25	8.56
ESE	0	0	0	0	0	3	5	1	0	3	1	6	19	9.31
SE	0	0	2	2	6	2	2	1	4	1	1	5	26	7.31
SSE	0	0	2	2	3	2	3	1	2	0	0	3	18	6.44
S	0	0	0	2	2	4	4	6	2	2	0	5	27	7.78
SSW	0	1	1	5	3	1	3	7	4	4	3	7	39	8.26
SW	0	0	2	0	6	7	5	7	7	5	1	5	45	7.45
WSW	0	2	2	1	3	8	5	8	1	2	1	3	36	6.86
W	0	1	1	5	4	5	2	4	0	0	0	0	22	5.14
WNW	0	0	2	2	4	1	2	1	2	0	0	5	19	7.77
NW	0	0	1	6	8	1	2	4	5	1	3	17	52	9.88
NNW	0	1	0	3	2	4	0	2	1	1	0	9	25	9.95
N	0	1	0	2	3	0	2	2	1	1	2	4	18	7.40
CALM													1	.60
TOTAL	2	6	16	33	53	50	41	58	41	39	26	100	468	8.27

NUMBER OF INVALID OBSERVATIONS = 7
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL #D# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	3	5	5	10	10	11	6	15	20	17	18	140	9.19
NE	2	2	3	8	10	25	19	21	33	17	32	72	264	9.66
ENE	0	1	6	5	10	17	19	23	34	40	22	52	229	9.63
E	0	1	9	10	10	13	28	12	15	17	13	30	158	7.99
ESE	0	0	4	3	11	15	12	3	8	7	12	11	86	7.88
SE	0	0	1	5	12	12	2	9	11	16	7	43	118	10.00
SSE	0	1	1	4	5	8	12	9	10	9	11	48	120	10.44
S	0	0	2	2	7	4	9	8	18	15	10	19	115	10.24
SSW	1	2	3	7	8	21	15	22	19	22	19	41	220	10.25
SW	0	5	7	7	15	19	23	25	22	31	32	155	341	11.13
WSW	1	5	8	4	19	14	18	16	23	20	28	151	330	11.32
W	1	4	8	11	16	11	18	19	23	16	13	101	243	11.05
WNW	0	3	10	6	12	14	19	16	11	13	16	48	174	8.93
NW	0	6	4	9	17	18	15	16	17	8	11	43	184	9.68
NNW	0	4	8	12	6	15	9	19	10	10	9	42	152	9.97
N	0	5	4	5	8	7	10	8	11	8	5	17	88	7.95
CALM													8	.17
TOTAL	5	48	83	110	173	248	238	244	275	295	276	1005	2998	9.91

NUMBER OF INVALID OBSERVATIONS = 63
TOTAL NUMBER OF OBSERVATIONS = 8760

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TABLE 2.3-111B

WIND FREQUENCY DISTRIBUTIONS
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
61.5 METER LEVEL: ANNUAL, 1975

PASQUILL #E# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	2	5	7	9	10	11	5	6	11	38	105	9.30
NE	0	3	5	9	9	9	22	21	16	26	27	67	213	9.50
ENE	0	1	3	9	4	9	11	23	19	21	11	39	150	9.07
E	0	3	4	2	8	8	12	23	8	20	14	46	150	9.44
ESE	2	1	1	3	5	4	10	6	14	15	16	39	121	9.49
SE	0	6	2	1	4	5	7	6	14	12	10	68	139	10.74
SSE	0	0	2	6	9	7	5	12	11	16	21	99	186	12.28
S	0	4	1	1	5	9	9	14	14	17	22	117	213	12.06
SSW	1	4	1	2	10	19	12	25	22	20	28	140	326	11.37
SW	1	3	6	3	11	17	15	18	32	36	28	186	352	11.24
WSW	1	1	0	6	6	6	10	10	19	11	19	108	195	11.15
W	0	2	6	6	9	3	15	9	14	20	8	66	158	10.12
WNW	0	2	3	7	6	7	6	13	15	8	9	20	96	8.66
NW	0	2	6	7	6	3	4	11	11	6	11	69	121	9.43
NNW	0	1	0	2	7	5	3	8	9	11	7	39	98	10.66
N	0	4	5	3	9	5	6	6	5	9	10	13	77	7.81
CALM													16	.55
TOTAL	5	38	67	87	117	125	162	216	237	254	250	1176	2760	10.52

NUMBER OF INVALID OBSERVATIONS = 56
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL #F# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	1	3	2	1	1	1	2	3	4	1	10	29	9.66
NE	0	0	3	6	3	6	2	4	5	4	4	44	81	10.72
ENE	0	3	2	1	1	4	7	5	3	13	11	30	82	9.66
E	0	1	1	4	2	1	2	2	2	7	12	31	71	10.47
ESE	1	1	1	2	0	2	1	5	4	5	4	37	66	11.62
SE	0	0	0	2	5	3	6	2	3	2	4	42	70	11.51
SSE	0	2	1	4	2	5	5	5	5	5	4	56	96	11.78
S	1	3	4	3	3	3	3	3	3	5	5	47	85	10.93
SSW	0	1	1	1	1	4	10	10	6	7	7	50	100	10.41
SW	0	4	2	3	7	4	2	9	7	10	8	70	126	10.45
WSW	1	2	4	1	1	4	2	1	4	7	10	32	69	10.10
W	1	1	1	3	4	1	6	3	6	2	2	25	55	9.19
WNW	0	0	1	1	3	3	7	4	5	6	7	8	45	8.64
NW	0	2	0	3	3	2	1	5	7	12	4	14	53	9.37
NNW	1	1	4	4	2	5	3	2	9	0	1	6	62	7.37
N	0	1	0	2	1	3	2	3	3	1	2	5	23	8.23
CALM													4	.19
TOTAL	4	23	30	42	43	54	64	68	72	78	82	510	1107	10.31

NUMBER OF INVALID OBSERVATIONS = 28
TOTAL NUMBER OF OBSERVATIONS = 8760

PASQUILL #G# (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	2	5	0	0	4	2	5	1	6	2	10	39	8.23
NE	0	2	5	3	2	5	2	5	6	1	3	19	53	8.75
ENE	0	1	4	3	3	5	12	2	6	0	3	11	38	8.22
E	0	3	2	1	2	2	1	10	10	6	6	16	59	9.16
ESE	0	3	2	1	1	1	2	2	4	1	1	14	34	9.77
SE	1	2	4	1	0	2	3	4	6	1	0	20	52	8.68
SSE	0	1	1	0	2	1	0	1	4	4	2	15	31	9.20
S	1	1	1	0	4	3	0	3	3	4	2	1	25	8.76
SSW	0	3	5	5	3	1	5	2	4	1	1	12	48	7.65
SW	0	2	1	0	1	5	5	2	1	0	1	30	70	9.57
WSW	0	2	0	0	0	1	0	0	2	1	0	8	14	9.07
W	0	1	3	3	0	4	5	5	0	0	5	6	33	7.21
WNW	1	0	3	2	3	1	1	0	1	0	1	2	15	7.05
NW	0	1	0	0	0	0	0	0	0	0	0	1	2	7.50
NNW	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00
N	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00
CALM													0	.00
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00

NUMBER OF INVALID OBSERVATIONS = 0
TOTAL NUMBER OF OBSERVATIONS = 0

PASQUILL ALL (FROM AEC/DELTA-T CRITERIA 10-61 METERS)
WINDS AT 61.5 METER LEVEL

WIND FREQUENCY DISTRIBUTION
(FREQUENCY IN NUMBER OF OCCURRENCES)

WIND DIRECTION	UPPER CLASS INTERVALS OF WIND SPEED (MPH) 1	2	3	4	5	6	7	8	9	10	11	>11	TOTAL	MEAN SPEED
NNE	0	7	16	12	22	28	31	31	32	41	14	105	339	9.14
NE	0	7	19	27	27	51	54	55	62	77	77	223	681	9.51
ENE	0	6	15	21	26	45	47	64	71	85	56	159	597	9.12
E	0	8	18	21	30	40	50	60	64	56	51	131	480	8.84
ESE	2	5	8	11	20	31	33	37	37	36	39	113	362	9.54
SE	1	8	12	14	45	27	23	27	38	33	22	192	442	10.01
SSE	0	4	8	27	25	23	27	29	33	35	39	324	474	11.05
S	2	14	17	21	24	35	30	49	41	60	48	257	579	10.55
SSW	2	11	13	24	33	48	47	70	66	60	70	360	769	10.62
SW	1	16	17	27	45	74	61	67	76	87	77	456	1002	10.56
WSW	4	14	15	19	37	57	43	47	55	58	46	130	743	10.14
W	2	11	20	22	42	31	49	41	46	45	28	201	563	10.09
WNW	1	7	21	25	35	37	41	41	37	28	31	90	394	9.32
NW	0	14	11	12	31	21	29	39	48	35	14	151	417	9.68
NNW	2	10	17	14	21	25	20	25	47	20	10	170	421	9.11
N	1	11	11	15	24	29	26	20	26	23	23	63	282	7.93
CALM													20	.56
TOTAL	22	154	248	342	490	608	609	702	761	780	705	3119	8760	9.77

NUMBER OF INVALID OBSERVATIONS = 181
TOTAL NUMBER OF OBSERVATIONS = 8760

Table 2.3-112
Minimum Distance From the Reactor Containment Structure
to the Exclusion Zone Boundary

Direction From Plant	Minimum Distance (Meters)
N	1609*
NNE	1639
NE	1639
ENE	1639
E	1639
ESE	1639
SE	1639
SSE	1651
S	1651
SSW	1687
SW	1759
WSW	1820
W	1820
WNW	1808
NW	1747
NNW	1663

* Minimum Exclusion Distance

Table 2.3-117
0 - 2 Hours χ/Q At EAB

Downwind Sector	Distance (Meters)	0-2 hr χ/Q With Wake (sec/m^3)	0-2 hr χ/Q Without Wake (sec/m^3)
S	1609	3.21E-05	3.21E-05
SSW	1609	3.15E-05	3.16E-05
SW	1609	2.89E-05	2.89E-05
WSW	1609	2.62E-05	2.62E-05
W	1609	3.21E-05	3.32E-05
WNW	1609	3.01E-05	3.01E-05
NW	1609	4.47E-05	4.47E-05
NNW	1609	8.49E-05	8.69E-05
N	1609	1.07E-04	1.08E-04
NNE	1609	1.07E-04	1.07E-04
NE	1609	1.20E-04	1.20E-04
ENE	1609	1.24E-04	1.24E-04
E	1609	1.22E-04	1.22E-04
ESE	1609	9.21E-05	9.21E-05
SE	1609	5.55E-05	5.55E-05
SSE	1609	3.15E-05	3.15E-05
MAX χ/Q		1.24E-04	1.24E-04

Table 2.3-118
0 – 30 DAY χ/Q AT LPZ

Downwind Sector	Distance (meters)	Distance (miles)	0-8 hr χ/Q With Wake sec/m^3	8-24 hr χ/Q With Wake sec/m^3	1-4 d χ/Q With Wake sec/m^3	4-30 d χ/Q With Wake sec/m^3	0-8 hr χ/Q Without Wake sec/m^3	8-24 hr χ/Q Without Wake sec/m^3	1-3 d χ/Q Without Wake sec/m^3	4-30 d χ/Q Without Wake sec/m^3
S	4828	3	3.82E-06	2.64E-06	1.19E-06	3.75E-07	3.85E-06	2.67E-06	1.21E-06	3.88E-07
SSW	4828	3	3.79E-06	2.66E-06	1.23E-06	4.05E-07	3.82E-06	2.69E-06	1.25E-06	4.18E-07
SW	4828	3	3.71E-06	2.68E-06	1.32E-06	4.81E-07	3.73E-06	2.70E-06	1.34E-06	4.92E-07
WSW	4828	3	3.34E-06	2.39E-06	1.15E-06	4.07E-07	3.36E-06	2.41E-06	1.17E-06	4.17E-07
W	4828	3	4.18E-06	2.90E-06	1.31E-06	4.18E-07	4.22E-06	2.94E-06	1.34E-06	4.33E-07
WNW	4828	3	3.58E-06	2.42E-06	1.03E-06	3.02E-07	3.62E-06	2.45E-06	1.06E-06	3.16E-07
NW	4828	3	5.67E-06	3.83E-06	1.63E-06	4.80E-07	5.74E-06	3.90E-06	1.69E-06	5.07E-07
NNW	4828	3	1.31E-05	8.88E-06	3.82E-06	1.13E-06	1.33E-05	9.12E-06	3.99E-06	1.22E-06
N	4828	3	1.80E-05	1.23E-05	5.33E-06	1.61E-06	1.84E-05	1.27E-05	5.63E-06	1.76E-06
NNE	4828	3	1.85E-05	1.27E-05	5.59E-06	1.72E-06	1.89E-05	1.31E-05	5.88E-06	1.87E-06
NE	4828	3	2.28E-05	1.58E-05	7.09E-06	2.25E-06	2.33E-05	1.63E-05	7.48E-06	2.45E-06
ENE	4828	3	2.36E-05	1.62E-05	7.09E-06	2.17E-06	2.42E-05	1.68E-05	7.55E-06	2.40E-06
E	4828	3	2.30E-05	1.57E-05	6.79E-06	2.05E-06	2.36E-05	1.62E-05	7.23E-06	2.27E-06
ESE	4828	3	1.49E-05	9.88E-06	4.04E-06	1.12E-06	1.53E-05	1.02E-05	4.27E-06	1.22E-06
SE	4828	3	7.20E-06	4.83E-06	2.03E-06	5.83E-07	7.33E-06	4.96E-06	2.12E-06	6.26E-07
SSE	4828	3	3.60E-06	2.46E-06	1.08E-06	3.32E-07	3.64E-06	2.50E-06	1.11E-06	3.48E-07
MAX χ/Q							2.42E-05	1.68E-05	7.55E-06	2.40E-06

Table 2.3-119
Average Annual Relative Concentration (SEC/Cubic Meter)
Period of Record 01/01/75 to 12/31/75

	Base Distance in Miles/Kilometers							
AFTD SECT	.06/ .10	.31/ .50	.62/ 1.00	1.00/ 1.61	1.86/ 3.00	3.00/ 4.83	4.35/ 7.00	5.59/ 9.00
NNE	1.7E-04	3.7E-05	1.3E-05	4.5E-06	1.1E-06	4.3E-07	2.2E-07	1.5E-07
NE	1.9E-04	4.0E-05	1.4E-05	4.8E-06	1.2E-06	4.6E-07	2.4E-07	1.6E-07
ENE	1.6E-04	3.4E-05	1.2E-05	4.1E-06	1.0E-06	3.9E-07	2.0E-07	1.3E-07
E	1.5E-04	3.3E-05	1.1E-05	3.9E-06	9.6E-07	3.8E-07	2.0E-07	1.3E-07
ESE	1.5E-04	3.2E-05	1.1E-05	3.7E-06	9.2E-07	3.7E-07	1.9E-07	1.3E-07
SE	2.2E-04	4.7E-05	1.5E-05	5.3E-06	1.3E-06	5.3E-07	2.8E-07	1.9E-07
SSE	1.5E-04	3.1E-05	1.0E-05	3.6E-06	8.9E-07	3.5E-07	1.8E-07	1.2E-07
S	1.6E-04	3.5E-05	1.1E-05	4.0E-06	1.0E-06	4.0E-07	2.1E-07	1.4E-07
SSW	1.5E-04	3.2F-05	1.1E-05	3.8E-06	9.4E-07	3.7E-07	1.9E-07	1.3E-07
SW	1.9E-04	4.0E-05	1.4E-05	4.8E-06	1.2E-06	4.6E-07	2.4E-07	1.6E-07
WSW	1.4E-04	3.1E-05	1.0E-05	3.7E-06	9.1E-07	3.6E-07	1.8E-07	1.2E-07
W	1.0E-04	2.1E-05	7.2E-06	2.6E-06	6.4E-07	2.5E-07	1.3E-07	8.6E-08
WNW	8.3E-05	1.8E-05	5.9E-06	2.1E-06	5.4E-07	2.1E-07	1.1E-07	7.3E-08
NW	1.0E-04	2.2E-05	7.4E-06	2.7E-06	6.6E-07	2.6E-07	1.4E-07	9.1E-08
NNW	1.0E-04	2.2E-05	7.4E-06	2.7E-06	6.7E-07	2.6E-07	1.4E-07	9.0E-08
N	1.4E-04	3.0E-05	1.0E-05	3.7E-06	9.2E-07	3.6E-07	1.9E-07	1.2E-07

Table 2.3-119(continued)
Average Annual Relative Concentration (SEC/Cubic Meter)
Period of Record 01/01/75 to 12/31/75
Base Distance in Miles/Kilometers

AFTD SECT	6.21/ 10.00	12.43/ 20.00	18.64/ 30.00	24.85/ 40.00	31.07/ 50.00	37.29/ 60.00	43.51/ 70.00	49.72/ 80.00
NNE	1.3E-07	4.6E-08	2.7E-08	1.9E-08	1.4E-08	1.1E-08	9.3E-09	8.0E-09
NE	1.3E-07	4.9E-08	2.9E-08	2.0E-08	1.5E-08	1.2E-08	9.9E-09	8.4E-09
ENE	1.1E-07	4.1E-08	2.4E-08	1.7E-08	1.3E-08	1.0E-08	8.3E-09	7.1E-09
E	1.1E-07	4.0E-08	2.4E-08	1.6E-08	1.2E-08	9.8E-09	8.1E-09	6.9E-09
ESE	1.1E-07	4.0E-08	2.4E-08	1.6E-08	1.2E-08	9.9E-09	8.2E-09	7.0E-09
SE	1.6E-07	5.8E-08	8.4E-08	2.4E-08	1.8E-08	1.4E-08	1.2E-08	1.0E-08
SSE	1.0E-07	3.9E-08	2.3E-08	1.6E-08	1.2E-08	9.5E-09	7.9E-09	6.7E-09
S	1.2E-07	4.4E-08	2.6E-08	1.8E-08	1.4E-08	1.1E-08	9.1E-09	7.8E-09
SSW	1.1E-07	4.0E-08	2.4E-08	1.6E-08	1.2E-08	9.9E-09	8.2E-09	6.9E-09
SW	1.4E-07	4.9E-08	2.9E-08	2.0E-08	1.5E-08	1.2E-08	1.0E-08	8.5E-09
WSW	1.0E-07	3.8E-08	2.2E-08	1.5E-08	1.2E-08	9.2E-09	7.6E-09	6.5E-09
W	7.3E-08	2.7E-08	1.6E-08	1.1E-08	8.2E-09	6.5E-09	5.4E-09	4.6E-09
WNW	6.2E-08	2.3E-08	1.3E-08	9.2E-09	7.0E-09	5.6E-09	4.6E-09	3.9E-09
NW	7.7E-08	2.8E-08	1.7E-08	1.2E-08	8.8E-09	7.0E-09	5.8E-09	5.0E-09
NNW	7.7E-08	2.8E-08	1.6E-08	1.1E-08	8.6E-09	6.8E-09	5.7E-09	4.8E-09
N	1.0E-07	3.8E-08	2.2E-08	1.5E-08	1.2E-08	9.2E-09	7.6E-09	6.5E-09

Table 2.3-120
Criteria for Gaseous Release From GWPS (Waste Gas Decay Tanks)

Differential Temperature (°F/30m)	Differential Temperature (°F/51m)	Pasquill Stability Class	Minimum Wind Speed (mph)
$\Delta T \leq -1.03$	$\Delta T \leq -1.74$	A	NA
$-1.03 < \Delta T \leq -0.92$	$-1.74 < \Delta T \leq -1.56$	B	NA
$-0.92 < \Delta T \leq -0.81$	$-1.56 < \Delta T \leq -1.38$	C	1.3
$-0.81 < \Delta T \leq -0.27$	$-1.38 < \Delta T \leq -0.46$	D	3.1
$-0.27 < \Delta T \leq 0.81$	$-0.46 < \Delta T \leq 1.38$	E	3.5
$0.81 < \Delta T \leq 2.16$	$1.38 < \Delta T \leq 3.67$	F	5.2
$2.16 < \Delta T$	$3.67 < \Delta T$	G	7.0

Table 2.3-121
ARCON96 Input

Meteorological Input	
Lower measurement height	10 meters
Upper measurement height	61 meters
Wind speed units	meters/second

Source Input	
Release Type	ground level
Building Area	1740 m^2
Vertical Velocity	0
Stack Flow	0
Stack Radius	0

Table 2.3-122
Release Point and Receptor Location Input

Release Point	Release Height (Height – 436') m	Direction from Intake to Release		Straight-line Horizontal Distance (m)	
		Intake 'A'	Intake 'B'	Intake 'A'	Intake 'B'
Main Plant Vent	524'-3" (26.9 m)	38°	42°	89.0	86.9
Purge Exhaust	524'-0" (26.8 m)	38°	42°	87.5	86.3
MS POR 'A'	504'-0" (20.7 m)	64°	59°	64.0	63.1
MS SR's 'A'	495'-0" (B, C, D, E) (18.0 m) 503'-0" (A) (20.4 m)	57°	64°	60.0	60.0
MS POR 'B'	470'-0" (10.4 m)	72°	78°	80.8	82.0
MS SR's 'B'	495'-0" (18.0 m)	71°	76°	75.6	78.0
MS POR 'C'	470'-0" (10.4 m)	69°	73°	105.8	105.8
MS SR's 'C'	495'-0" (18.0 m)	73°	76°	104.5	103.6
Pressure Relief Area	463'-0" (8.2 m)	73°	78°	67.4	69.5
RB Nearest Point	0	63°	57°	61.0	61.0
RWST Overflow	468'-0" (9.8 m)	22°	18°	51.9	55.7

Plant north aligns with true north.

Table 2.3-123
Control Room Diffusion Values

Release Point	Time	Control Room Location		Release Point	Control Room Location	
		Intake 'A'	Intake 'B		Intake 'A'	Intake 'B
		χ/Q (sec/m^3)			χ/Q (sec/m^3)	
RB Nearest Point				MS POR 'B'		
	0-2 hr	1.39E-03	1.30E-03		8.69E-04	8.31E-04
	2-8 hr	1.17E-03	1.09E-03		7.16E-04	6.89E-04
	8-24 hr	5.70E-04	5.27E-04		3.44E-04	3.23E-04
	1-4 d	4.17E-04	3.90E-04		2.49E-04	2.33E-04
	4-30 d	3.00E-04	2.82E-04		1.84E-04	1.69E-04
Main Plant Vent				MS SR 'B'		
	0-2 hr	7.11E-04	7.43E-04		9.61E-04	9.29E-04
	2-8 hr	5.05E-04	5.41E-04		7.64E-04	7.08E-04
	8-24 hr	2.51E-04	2.75E-04		3.67E-04	3.39E-04
	1-4 d	2.04E-04	2.16E-04		2.65E-04	2.44E-04
	4-30 d	1.39E-04	1.49E-04		1.98E-04	1.79E-04
Purge Exhaust				MS POR 'C'		
	0-2 hr	7.23E-04	7.57E-04		5.18E-04	5.10E-04
	2-8 hr	5.24E-04	5.47E-04		4.37E-04	4.34E-04
	8-24 hr	2.59E-04	2.78E-04		2.09E-04	2.05E-04
	1-4 d	2.13E-04	2.19E-04		1.51E-04	1.49E-04
	4-30 d	1.44E-04	1.51E-04		1.11E-04	1.08E-04
IB Pressure Relief Area				MS SR 'C'		
	0-2 hr	1.22E-03	1.12E-03		5.36E-04	5.44E-04
	2-8 hr	1.01E-03	9.16E-04		4.10E-04	4.18E-04
	8-24 hr	4.79E-04	4.32E-04		1.99E-04	2.00E-04
	1-4 d	3.48E-04	3.12E-04		1.44E-04	1.44E-04
	4-30 d	2.53E-04	2.24E-04		1.06E-04	1.06E-04
MS SR 'A' (Reliefs B, C, D, E)				MS POR 'A'		
	0-2 hr	1.50E-03	1.51E-03		1.34E-03	1.37E-03
	2-8 hr	1.15E-03	1.17E-03		1.01E-03	1.03E-03
	8-24 hr	5.64E-04	5.75E-04		4.97E-04	5.07E-04
	1-4 d	4.23E-04	4.18E-04		3.64E-04	3.77E-04
	4-30 d	3.03E-04	3.10E-04		2.69E-04	2.72E-04
MS SR 'A' (A Relief only)				RWST		
	0-2 hr	1.50E-03	1.51E-03		1.96E-03	1.64E-03
	2-8 hr	1.12E-03	1.15E-03		1.45E-03	1.18E-03
	8-24 hr	5.51E-04	5.67E-04		7.02E-04	5.61E-04
	1-4 d	4.15E-04	4.13E-04		5.39E-04	4.19E-04
	4-30 d	2.97E-04	3.02E-04		3.73E-04	2.95E-04

Figure 2.3-1

METEOROLOGICAL DATE SOURCES

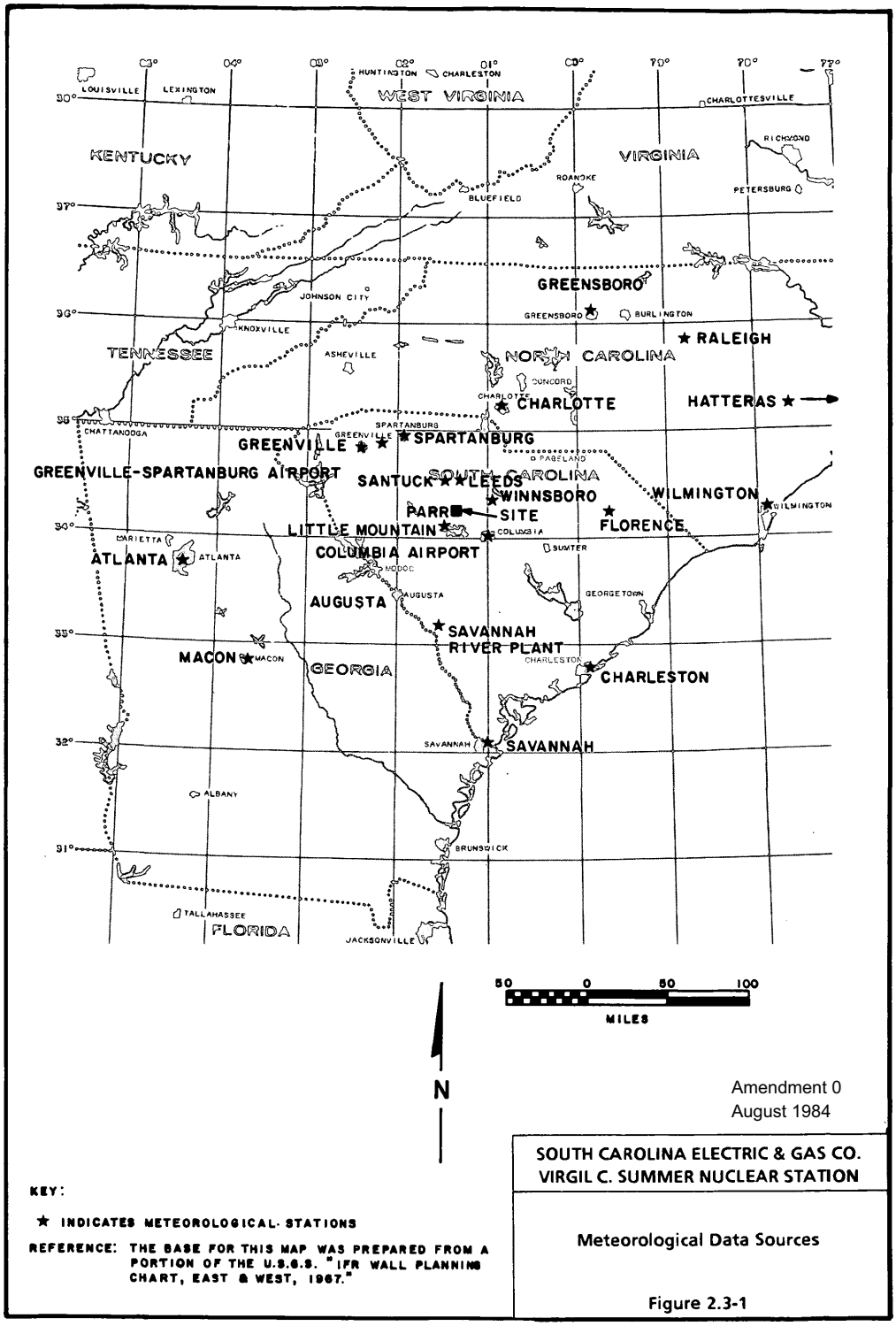
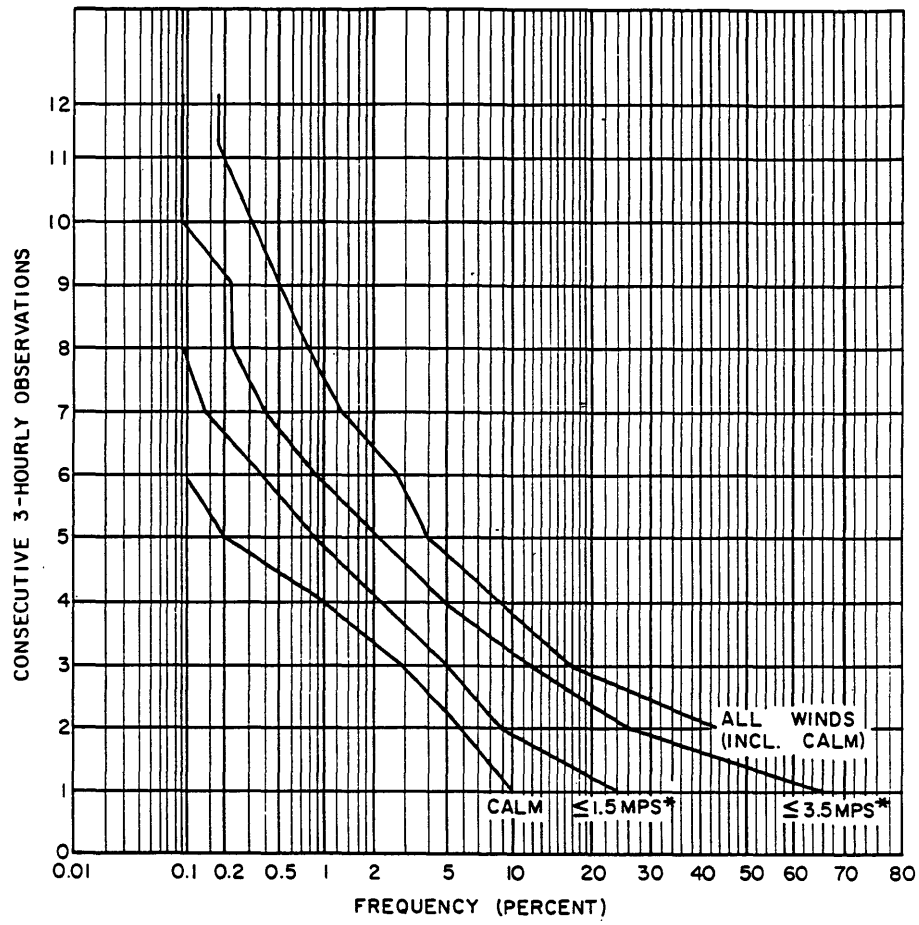


Figure 2.3-2
FREQUENCY OF ONE-SECTOR (22.5°)



*Meters per second

Amendment 0
August 1984

Data: 30-Foot Winds for 1965-69
for Columbia Airport

Data Source: 2.3.2-K

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

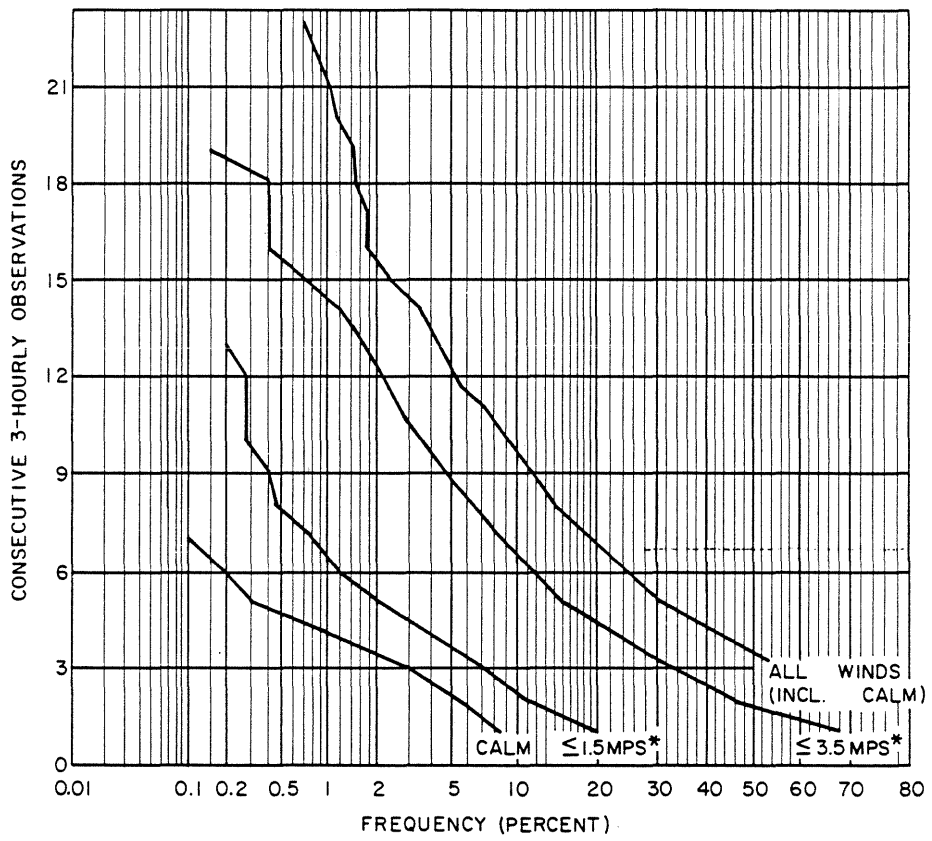
Frequency of One-Sector (22.5°)
Persistence - Columbia

Figure 2.3-2

Figure 2.3-3

FREQUENCY OF THREE-SECTOR (67.5°)

Persistence - Columbia



*Meters per second

Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Frequency of Three-Sector (67.5°)
Persistence - Columbia

Figure 2.3-3

Data: 30-Foot Winds for 1965-69
for Columbia Airport

Data Source: 2.3.2-K

Figure 2.3-4

DETAILED TOPOGRAPHIC FEATURES TO 5 MILES

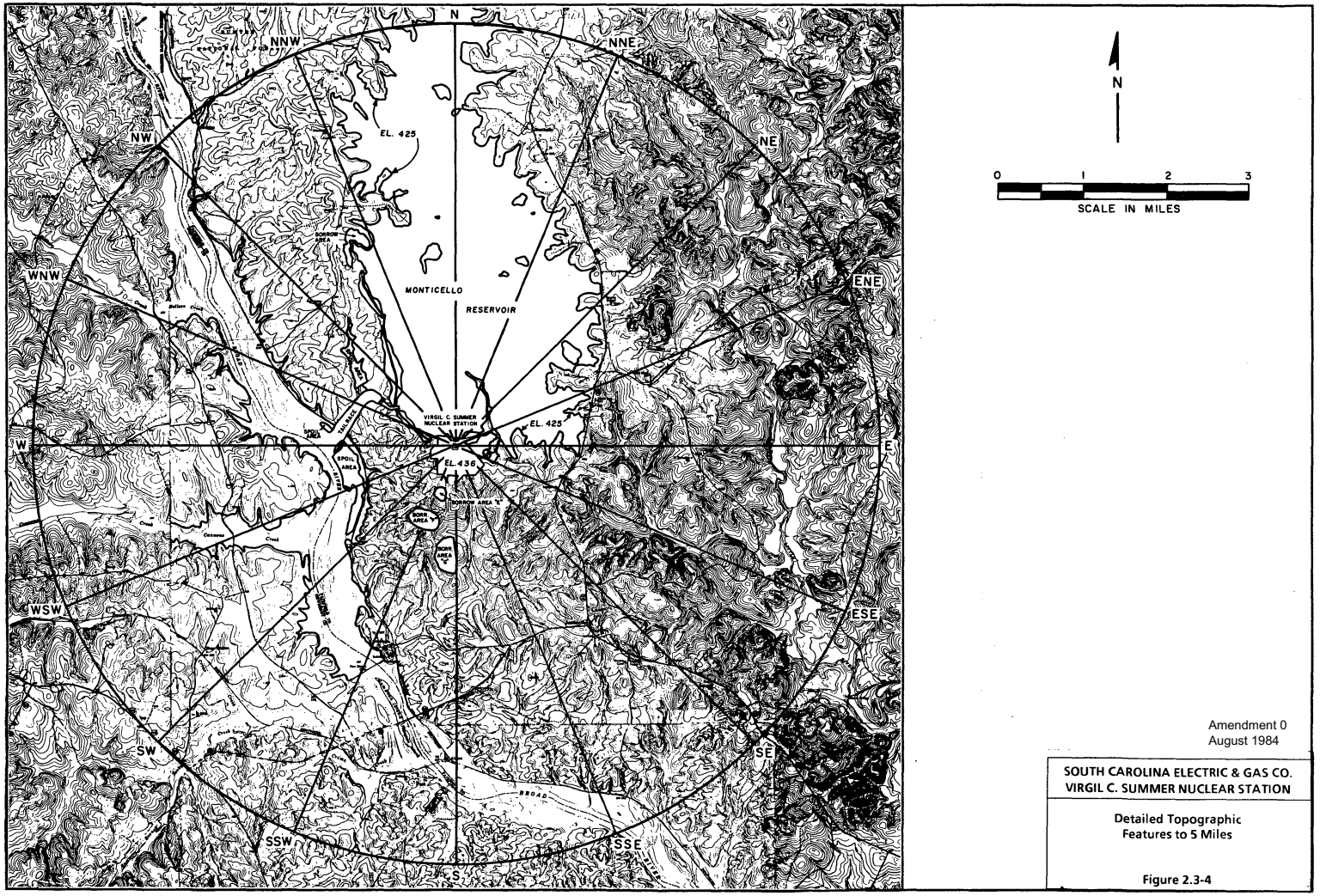


Figure 2.3-5

GENERAL TOPOGRAPHIC FEATURES TO 50 MILES

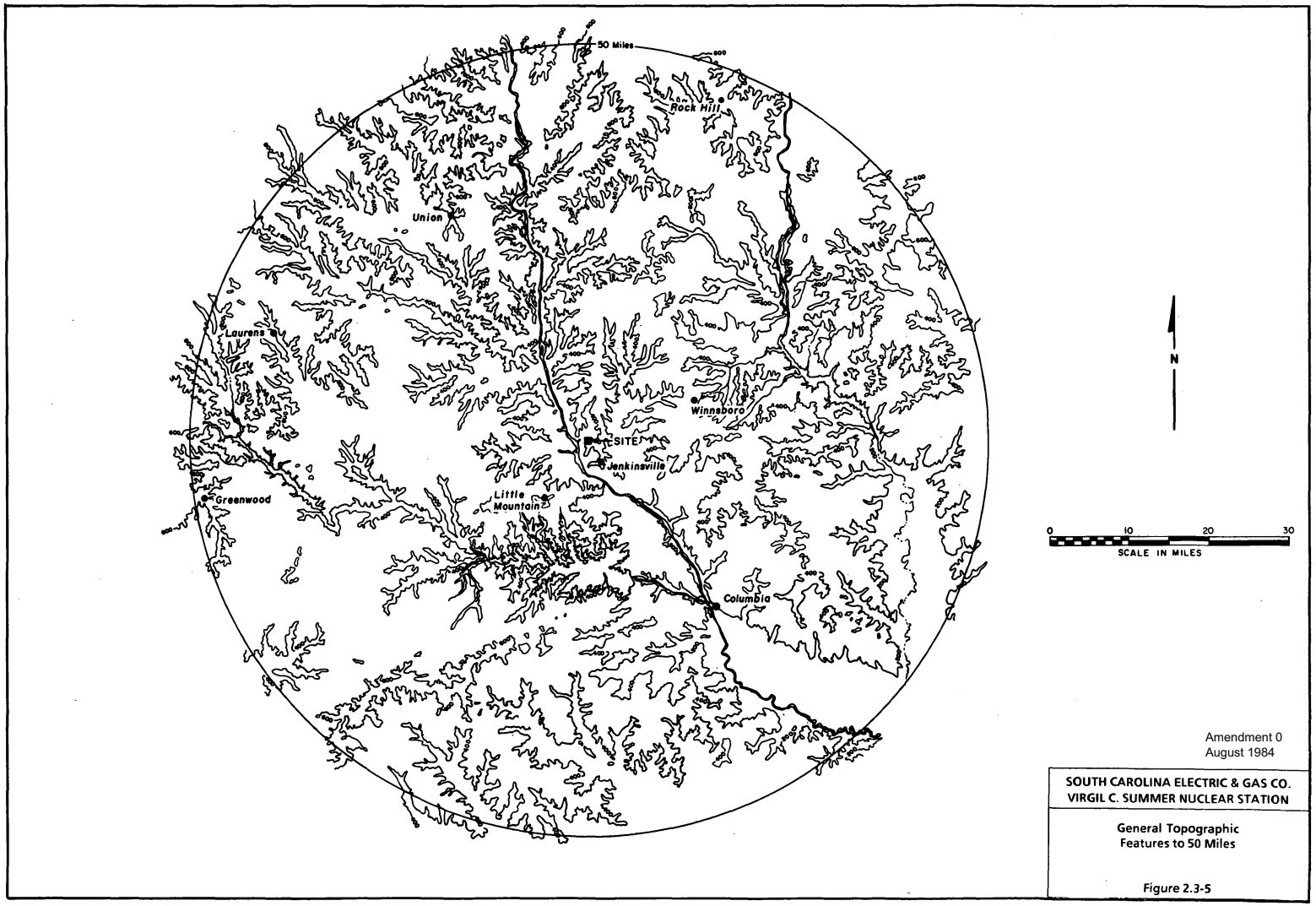
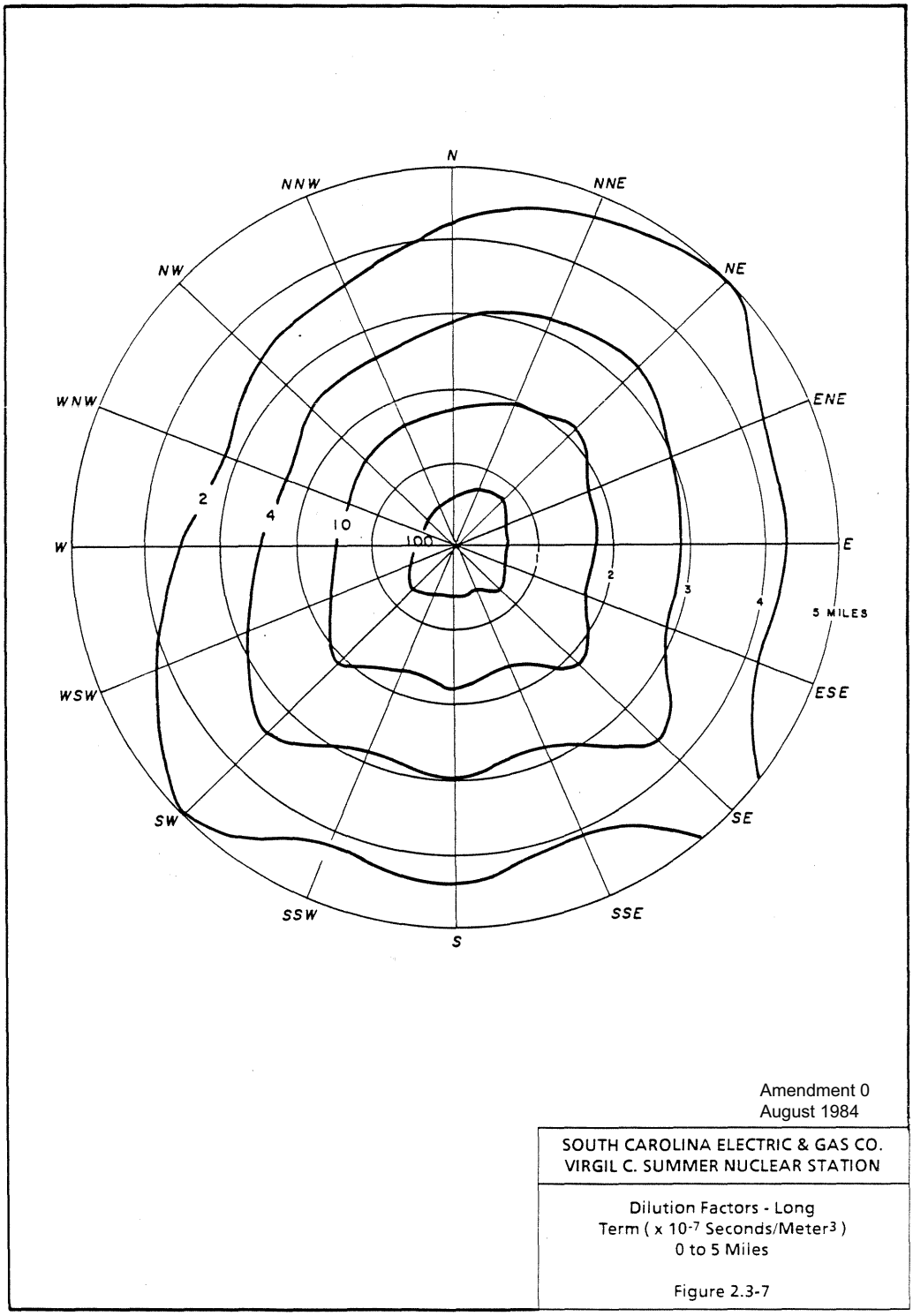


Figure 2.3-6
DELETED

Figure 2.3-7

DIVISION FACTORS - LONG TERM

(X 10^{-7} SECONDS/METER^3) 0 TO 5 MILES



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

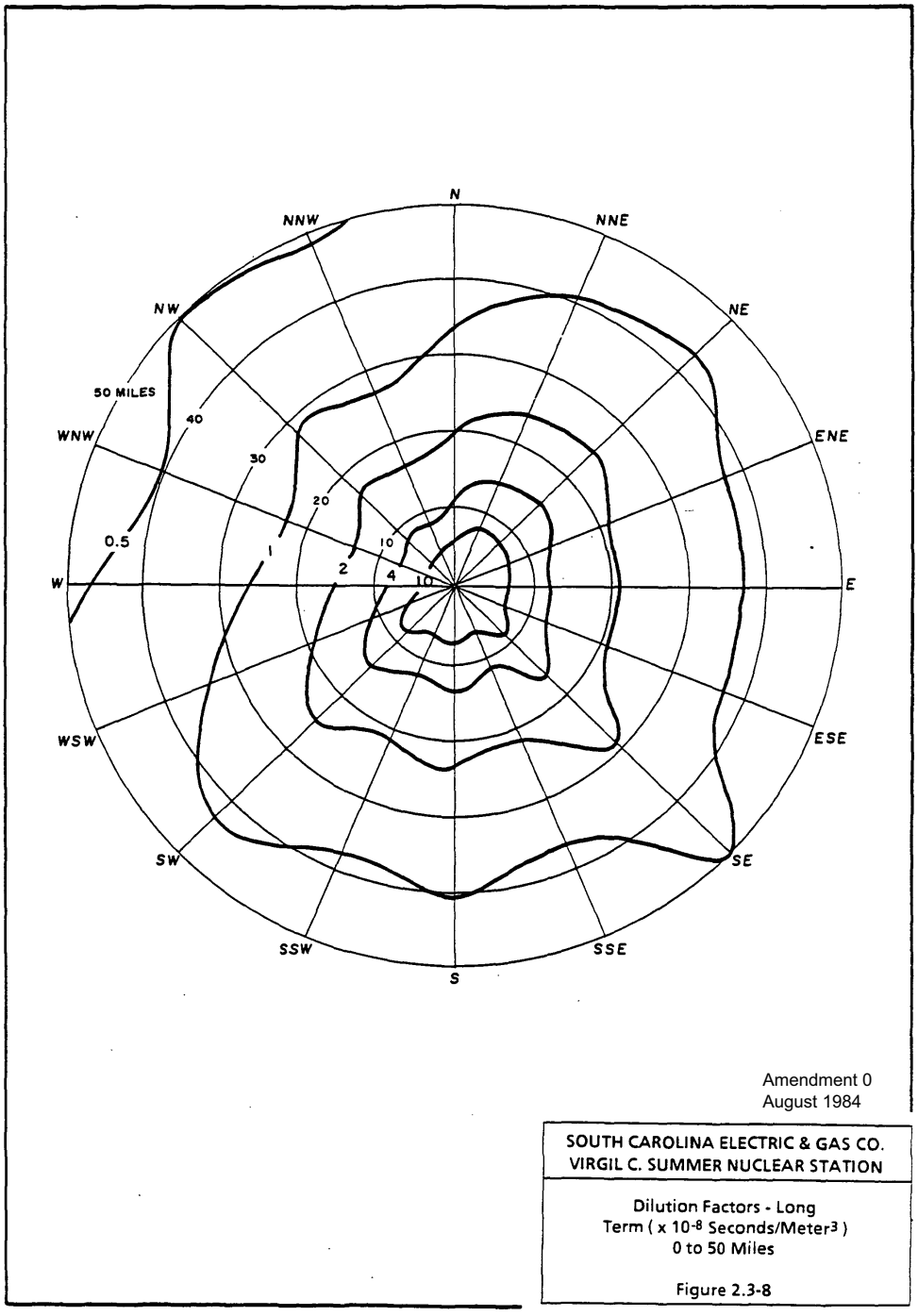
Dilution Factors - Long Term (x 10^{-7} Seconds/Meter^3) 0 to 5 Miles

Figure 2.3-7

Figure 2.3-8

DILUTION FACTORS - LONG TERM

(X 10^{-8} SECONDS/METER^3) 0 TO 50 MILES



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Dilution Factors - Long Term (x 10^{-8} Seconds/Meter^3) 0 to 50 Miles

Figure 2.3-8

2.4 HYDROLOGIC ENGINEERING

2.4.1 Hydrologic Description

2.4.1.1 Site and Facilities

The Virgil C. Summer Nuclear Station is located in Fairfield County, South Carolina, approximately 1 mile east of the Broad River and 2.5 miles northeast of Parr Dam. The site is situated on a hilltop at an average elevation of 435.0’ mean sea level, * about 180 feet above the Broad River floodplain.

Figure 2.4-1 is a site map showing the general site features, layout, topography, and changes to the natural drainage. As shown in this figure, a berm at elevation 438.0’ is located along the north boundary of the site adjacent to Monticello Reservoir, coupled with dams forming the service water pond to the east. Site drainage, except for a narrow strip along the edge of the service water pond, is intercepted and conveyed by storm sewers to the south and west away from Monticello Reservoir. The details of the local drainage system are discussed in (Section 2.4.3.1.3).

The plant site is not susceptible to flooding from the Broad River due to its relative height above the river. Plant grade is approximately 10 feet above the maximum operating level of Monticello Reservoir which is at elevation 425.0’. Protection of safety-related structures, exterior access, equipment, and systems against flooding from Monticello Reservoir is provided through the location, arrangement, and design of the above with respect to the shoreline and possible storm-generated waves, as discussed in the following sections.

2.4.1.2 Hydrosphere

Included in this section is a description of the location, size, shape, and other hydrologic characteristics of the streams and reservoirs comprising the surface water hydrosphere. A description of the ground water environments influencing plant siting is included in (Section 2.4.13.1.1).

*All elevations are referenced in feet above the mean sea level (MSL) datum.

2.4.1.2.1 Rivers and Streams

The region surrounding the site is characterized by a network of small tributaries and a few large rivers draining the rolling, low-profile terrain. The Broad River, the principal hydrologic feature in the site vicinity, drains an extensive basin above the site of about 4,550 square miles formed between 2 southeast-northwest trending ridges stretching from Columbia, South Carolina, to the headwaters about 100 miles northwest in North Carolina. The average annual precipitation is 45 inches with a runoff about 17 inches, equivalent to a runoff volume of 4.3 million acre-feet. In the vicinity of the site, the Broad River is about 2000 feet wide, with depths ranging from a few feet to around 15 feet. Many streams and creeks carry runoff and ground water drainage into this watercourse. Important rivers draining into the Broad River include the Enoree, the Tyger, and the Pacolet. The Broad River joins the Saluda forming the Congaree River near Columbia, South Carolina (Reference 1).

Downstream of the site, the nearest U. S. Geological Survey (USGS) streamflow gaging station on the Broad River is gage 1615 at Richtex, South Carolina. The Richtex station is located about 14 miles downstream of the site, and has a contributing drainage area of approximately 4,850 square miles. Streamflow measurements began in October 1925, and an average discharge of over 6,000 cubic feet per second (cfs) has been observed over the period of record (Reference 2). A map of the Broad River drainage basin at the Richtex gaging station is shown on Figure 2.4-2.

Upstream of the site, the nearest USGS streamflow gaging station on the Broad River is gage 1565 near Carlisle, South Carolina. Streamflow measurements began in October 1938, and an average discharge of almost 4,000 cfs has been recorded over the period of record. The Carlisle station is located about 21 miles upstream of the site, and has a contributing drainage area of approximately 2,790 square miles (Reference 2). As shown on Figure 2.4-2, the Carlisle gaging station is located upstream of the confluences of the Tyger and Enoree Rivers. Its drainage area is nearly 40% less than the 4,550 square miles area of the site, which is located downstream of these 2 tributaries. However, the drainage area at the Richtex gaging station is only about 7% greater than at the site. This fact, plus the longer period of record at the Richtex gage, makes it the more suitable location from which to estimate flow characteristics at the site.

2.4.1.2.2 Lakes and Reservoirs

The nearest body of water to the site is Monticello Reservoir, the upper pool of the Fairfield Pumped Storage Facility and the source of cooling and makeup water for the Virgil C. Summer Nuclear Station. Monticello Reservoir has a drainage area of about 17 square miles, and is formed by the Frees Creek Dams. The main Frees Creek Dam has a maximum height of 180 feet and a crest length of approximately 5,000 feet. Three smaller saddle dams have lengths of 3,400 feet, 1,700 feet, and 900 feet, with maximum heights from 50 to 90 feet. The dams have crest elevations of 434.0' and are of earthfill construction with appropriate riprap protection (Reference 3). These dams are shown on Figure 2.4-3. Due to the size of these structures, Frees Creek channel is submerged to an average depth of 70 feet in the site vicinity.

A 400 foot wide, 600 foot long intake channel is located in the south abutment of the main Frees Creek Dam, terminating at a gated intake structure at invert elevation 375.0', with four 26 foot

diameter surface penstocks bifurcating into eight 18 foot diameter concrete encased penstocks connecting to the Fairfield powerhouse. The powerhouse contains eight reversible pump turbine units having a minimum capability of 83,000 hp each, at a minimum head of 150 feet, directly coupled to eight motor generators, each with a nameplate rating of 64,800 kW in the generating mode and 100,000 hp when operating as a motor. Other appurtenant facilities to the Fairfield system include a switchyard at the powerhouse and two 6,000 foot long, 230 kV transmission lines connecting Fairfield with the Virgil C. Summer Nuclear Station (Reference 3).

Monticello Reservoir has a surface area of about 6,800 acres and a storage volume of about 400,000 acre feet at normal maximum water surface elevation 425'0". The maximum daily withdrawal for generating purposes is 29,000 acre feet, lowering the pool to elevation 420.5' and reducing the surface area to approximately 6,500 acres. Pumping operations during periods of off peak power demand refill the reservoir. Figure 2.4-4 presents area and storage capacity curves for Monticello Reservoir (Reference 3).

The service water pond is a Seismic Category 1 impoundment constructed adjacent to Monticello Reservoir to supply water for the Service Water System under normal and emergency operations. The design of the service water pond and its interconnecting pipe to Monticello Reservoir is discussed in detail in Reference 2.4.8 and 9.2.5. This impoundment is formed by the north, east and south dams and the west embankment as shown on Figure 2.4 1. The three dams and the west embankment are Seismic Category 1 structures.

The north, east and south dams have a crest elevation of 438.0' and crest lengths of about 1,500 feet, 1,150 feet and 765 feet, respectively. The crest of the west embankment is at elevation 435.0', coinciding with the adjoining plant yard grade, and is about 1,900 feet long.

The interconnecting pipe, through the operation of a butterfly isolation valve, permits the service water pond to be supplied from Monticello Reservoir. For normal operating conditions, the Monticello Reservoir and service water pond levels will fluctuate between elevations 420.5' and 425.0'. For a water elevation of 425.0', the service water pond has a volume of 1,408 acre feet and a surface area of approximately 41 acres. In the event of loss of Monticello Reservoir while the isolation valve is open, the invert elevation at the high point of the interconnecting pipe will limit the drop of the pond level to its low water level of elevation 415.0'. For a minimum water elevation of 415.0', the volume of the service water pond is 1,035 acre feet and the surface area is 34.5 acres.

Parr Reservoir constitutes the lower pool of the Fairfield Pumped Storage Facility, and is located approximately 1 mile to the west of the Virgil C. Summer Nuclear Station on the Broad River. This reservoir is formed by Parr Dam, owned by South Carolina Electric and Gas Company, located about 2.5 miles southwest of the site. Parr Dam is a 2,715 foot long, approximately 48 feet high structure, having a 2,000 foot long concrete gravity spillway section with 9 foot high spillway crest gates, with a crest elevation of 266.0'. The dam is joined on the westerly end by an earth dike about 300 feet long and on the easterly end by a 300 foot long integral powerhouse section, a 90 foot long concrete non overflow section, and a 25 foot long earth fill section. Other facilities at Parr Dam include a steel framed brick powerhouse containing six generators rated at

2,480 kilowatts each, and a transmission tie to the 13,200 volt bus at the nearby Parr Internal Combustion Plant (Reference 3).

Parr Reservoir originally had a surface area of 1,850 acres with normal pool elevation of 257.0', extending about 8.5 miles upstream. The Parr Dam crest was raised approximately 9 feet by the installation of spillway crest gates. With the gates in the raised position, a maximum pool elevation of 266.0' is achieved At elevation 266.0', Parr Reservoir extends approximately 13 miles upstream and has a usable storage capacity of 29,000 acre feet with a surface area of approximately 4,400 acres. At normal minimum pool elevation of 256.0', the surface area is about 1,400 acres with a dead storage volume of about 2,500 acre feet. The operating drawdown of the pool is 10 feet. Figure 2.4-5 presents area and storage capacity curves for Parr Reservoir (Reference 3).

In addition to Parr and Monticello, a number of reservoirs exist upstream and downstream of the site on the Broad River and its tributaries. These projects are generally small, low head dams for hydroelectric power generation and water supply. Most of these dams were constructed in the late 1800's and early 1900's. The pertinent data for these projects are included in Table 2.4-1 and their locations indicated on Figure 2.4 2 (Reference 3).

There have been several studies on the Broad River for construction of major dams (Reference 4)(Reference 5). The latest study (Reference 5) reports that the only reasonably feasible location for a major dam is at the Clinchfield site. As shown on Figure 2.4 2, this site is located in the upper reaches of the Broad River basin in North Carolina, approximately 100 river miles upstream of the Virgil C. Summer Nuclear Station. If constructed, this dam would have a drainage area of 571 square miles and a crest elevation of 830.0', 153 feet above the Broad River streambed. The conservation pool would be at elevation 810.5', with 830,500 acre feet of storage and 20,220 acres surface area. The flood control pool would be at elevation 820.0', with 1,036,000 acre feet of storage and 23,180 acres surface area. A volume of 716,000 acre feet would be allocated for water supply, 90,000 acre feet for water quality management and 205,000 acre feet for flood control. The maximum water surface elevation of 825.0' would be reached with the occurrence of the Spillway Design Flood (SDF) coincident with the full flood control pool.

2.4.1.2.3 Water Use

Downstream of the Virgil C. Summer Nuclear Station, surface water is withdrawn by a number of municipalities and industries. The single largest downstream surface water user is the City of Columbia, located approximately 28 miles from the site. Columbia has an average daily use of 23.0 million gallons, with all the municipal water being obtained from the Broad River. Table 2.4-2 includes a summary of other significant downstream surface water users, their location, average daily use, and source of supply (Reference 6). A tabulation of ground water users is included in (Section 2.4.13.2).

2.4.2 Floods

2.4.2.1 Flood History

Information on historical floods since 1925 is available at the Richtex gaging station (Reference 2). These data indicate two flood seasons, one from January to April and the other from July to October. Floods in the later period are generally associated with hurricanes and have usually been of greater magnitude than those occurring from January to April (Reference 7). The flood of record at Richtex had a peak discharge of 228,000 cfs, which occurred on October 3, 1929. Table 2.4-3 presents a summary of the major historical floods at Richtex, their peak discharge rates and maximum water surface elevations. Also included is an estimate of the corresponding discharges and elevations at Parr Dam. The discharge estimates at Parr were obtained by multiplying the values at Richtex by the ratio of the 2 drainage areas, 4,500/4,850. Elevations were estimated using the weir equation, with Parr Dam having a 2,000 foot crest at the original elevation 257.0'. A weir discharge coefficient of 3.97 was adopted for the spillway section (Reference 8). Backwater losses have not been included, since the site is only 2 miles upstream from the dam, and they would be minor when the river is in flood stage. The average flow and associated water surface elevations at Richtex and Parr Dam have also been included in Table 2.4-3 for reference.

2.4.2.2 Flood Design Considerations

Section 2.4.3 through Section 2.4.7 summarize and identify the individual types of flood producing phenomena, and combinations of these events that were considered to establish the flood design basis for the plant safety related features.

The adopted design basis flood is based on an analysis considering the Probable Maximum Flood (PMF) on Frees Creek and Monticello Reservoir, coincident with the maximum operating water level of Monticello Reservoir and related wind setup and wave runup (Reference 7).

Other areas of analysis included the PMF and seismically induced potential dam failures on the Broad River. Because this is a “dry site” from the standpoint of the Broad River, the very conservative analytical procedures delineated herein result in water levels well below site grade elevation. Seiching potential in Monticello Reservoir was found to be negligible. Potential flooding due to tsunamis and ice conditions are not applicable due to the location of the site and the historical lack of significant ice cover in the region.

Regulatory Guide 1.59 and Regulatory Guide 1.27 are addressed in Appendix 3A.

2.4.3 Probable Maximum Flood (PMF) on Streams and Rivers

The conditions producing the PMF as defined by the Corps of Engineers are the hypothetical flood characteristics (peak discharge, volume, and hydrograph shape) that are considered to be the most severe, yet “reasonably possible” at a particular location, based on a relatively comprehensive hydrometeorological analysis of critical runoff producing precipitation (and snowmelt, if pertinent) and hydrologic factors favorable for maximum flood runoff. The PMF for

the Virgil C. Summer Nuclear Station was derived for the two water bodies that could affect site flooding, the Broad River and Frees Creek. There are no other adjacent streams that would have impact on plant flooding. Because the Virgil C. Summer Nuclear Station is a flood dry site (relative to the Broad River) and the equivalent of a dry site as defined in RG 1.102 (relative to Frees Creek), approximate techniques were used coupled with conservative assumptions to maximize water level elevations.

Parr Reservoir, on the Broad River, presents no flooding hazard to the site. A maximum PMF water elevation of 290.5' was calculated at Parr Reservoir in the site vicinity. This is about 150 feet below site grade elevation of 435.0'. Considering coincidental dam breaching, the maximum water surface elevation was very conservatively estimated to be 390.0', still 45 feet below plant grade and clearly demonstrating that the site is “dry” from Broad River influences. Seismically induced floods due to landslides in the site area pose no threat due to the site elevation and the generally flat to rolling terrain.

Another source of potential flooding is from Monticello Reservoir on Frees Creek. The PMF with superposition of wind wave activity is discussed in Section 2.4.3.6.2.

2.4.3.1 Probable Maximum Precipitation (PMP)

2.4.3.1.1 Broad River

Three different methods were considered in evaluating the PMP over the 4,550 square mile watershed of the Broad River tributary to Parr Reservoir. The first method was extrapolation of data in Hydrometeorological Report (HMR) No. 33 to include an area of 5,000 square miles (Reference 9). The second was doubling the precipitation values for the Standard Project Storm obtained from Civil Engineering Bulletin (CEB) No. 52-8 (Reference 10). The third was multiplying by 1.40 (Reference 7) (to obtain saturated atmospheric conditions) the maximum average depth of rainfall, for various durations, for the storm of record which occurred on July 13 to 17, 1916 (Reference 11). The values of the PMP for different durations evaluated by the three methods are shown on Table 2.4-4 (Reference 7).

The values shown for HMR No. 33 and CEB 52 8 are so close that the values for the latter were used in evaluating PMF. The rainfall values used from the 1916 storm are for 4,550 square miles and were obtained by interpolating values from the Pertinent Data Sheet (Reference 11) between 2,000 and 5,000 square miles. The values of rainfall from CEB 52 8 and from the 1916 storm were then arranged in 6 hour sequences in a manner which yields maximum discharge hydrographs. A total storm duration of 72 hours was adopted (Reference 7).

2.4.3.1.2 Frees Creek

The Frees Creek drainage area contributing to Monticello reservoir is 16.5 square miles based on the digital elevation model (DEM) from the South Carolina Department of Natural Resources' (SCDNR) Geodatabase using the terrain surface data for Fairfield County, SC. The DEM is used in conjunction with USGS topographic maps in a GIS software program (Global Mapper) to delineate the drainage area for Monticello Reservoir. According to Section 4.4.3.3 of HMR

52,300 mi^2 is the smallest storm area for which a reduction should be applied for orientation. Therefore, the Probable Maximum Precipitation (PMP) determination for Monticello Reservoir is determined from Figures 18 through 27 of HMR 51.

The 72-hour duration PMP for the drainage area is 47.7 inches depth. No rainfall losses are deducted from the PMP and entire storm was assumed to be stored in Monticello Reservoir.

2.4.3.1.3 Effects of Local Intense Precipitation

In accordance with the direction contained in U. S. Nuclear Regulatory Commission (NRC), "Request for Information Pursuant to Title 10 of the Code of Federal Regulations (10 CFR), Section 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3, of the Near-Term Task Force Review of Insights from the Fukushima Dai-lchi Accident," March 12, 2012 (Reference 34), the Local Intense Precipitation (LIP) was reevaluated. The design rainfall to be analyzed for LIP flooding is 19.0 inches which is the 1-hour, 1-square mile PMP as defined by Section 3.2 of NUREG/CR-7046 (Reference 36). Based upon HMR No. 33 (Reference 9), the PMP is about 30.30 inches in 6 hours. The distribution sequence for this 6-hour PMP, according to a U.S. Army Corps of Engineering procedure (Reference 10) is as tabulated in Table 2.4-5. The 6-hour PMP was used to analyze LIP flooding for the service water pond.

The underground storm drainage system is not credited to provide flood protection from the LIP. With the storm drainage system assumed blocked, LIP runoff builds up on the surface of the site until it flows overland to lower elevations. In the power block area, this flow direction is toward to service water pond (SWP).

The storm water drainage analyses model for the LIP included current site topography, structures, and features based on current surveys including the new Independent Spent Fuel Storage Installation (ISFSI). An additional margin was included in the analyses to account for potential future structure additions to the site. Based on the analysis results the design site flood elevation is set at elevation 438.5 feet on the west side of the power block, at elevation 438.0 feet on the north and south sides of the power block, and at elevation 437.5 feet on the east side of the power block. Flood protection against entry of storm water into the buildings where such entry could jeopardize the design function of safety related systems and components is provided by a combination of permanent structures and removable flood protection devices. The flood protection devices are designed to provide protection to at least the design flood elevations defined above. The design site flood elevations defined above incorporate a minimum freeboard of 1 foot above the water level determined by analyses.

Interim corrective action has been implemented as a result of the Near-Term Task Force Review of Insights from the Fukushima Dai-lchi Accident (Reference 35) to ensure flood protection at plant exterior near grade doorways from the license basis flooding due to the LIP. Further development of the interim local flood protection measures at doorways into the power block buildings installs the permanent flood protection design features to mitigate the postulated low probability LIP event. The permanent design consists of features such as sandbag dikes, removable door bulkheads, increasing the height of curbing around the RWST Pit, and other similar measures.

Roof drains discharge directly into the storm drainage system and are designed for an average intensity of 6 in/hr. If the underground storm drainage system becomes blocked, roof drainage will overflow from the inlets at grade and become part of the surface runoff flow. Holes (scuppers) are provided at various locations to allow overflow during locally intense precipitation of more than 6 in/hr, including PMP. The roof edge blocking and gravel stops are provided and designed so that maximum ponding, at only a few locations is 4 inches. The roofs are designed to withstand this water accumulation. It is, therefore, concluded that no hazard to safety related facilities results from PMP.

2.4.3.2 Precipitation Losses

In order to determine the PMP rainfall excess for the Broad River drainage basin, an initial loss of 1.0 inch followed by an infiltration rate of 0.10 inch per hour was adopted (Reference 7). These values are consistent with those used by the Corps of Engineers in a study of a proposed reservoir site in the Broad River basin (Reference 5). The PMP calculation for Frees Creek assumed no initial or infiltration losses.

2.4.3.3 Runoff Models

2.4.3.3.1 Broad River

The storm of August 10 to 17, 1940 was selected for developing a unit hydrograph at the Richtex gage, since a series of isohyetal maps of the storm were available for use (Reference 12). Average rainfall values over the Broad River drainage basin above Richtex for several time periods were determined and the discharge hydrograph was plotted as shown on Figure 2.4-7 (Reference 13). A baseflow estimate was made and the volume of storm runoff was determined to be 1.66 inches over the total area. The hyetograph of rainfall, infiltration and excess rainfall is shown on Figure 2.4-7, along with the hydrographs. The storm runoff was divided between the two 12 hour periods of excess rainfall, one having a runoff of 1.345 inches and the other 0.315 inches, and unit hydrographs were derived for each period. By trial and error, the process was repeated until the 2 unit hydrographs were essentially similar in shape and displaced by 12 hours, by means of the S curve technique (Reference 14, Reference 7).

A 6 hour unit hydrograph was then derived from the 12 hour unit hydrograph. The derived 6 hour unit hydrograph is shown on Figure 2.4-7, and was used in subsequent calculations (Reference 7). Since the PMF water level determined in Section 2.4.3.5.1 is nearly 150 feet below site grade, no adjustments of the unit hydrograph for non linearity were made.

2.4.3.3.2 Frees Creek

Since Monticello Reservoir inundates nearly 70% of the Frees Creek drainage basin, a traditional unit hydrograph runoff model is not appropriate. Precipitation on the reservoir will raise its level directly. The entire 72-hour PMP of 47.7 inches of rainfall was assumed to enter Monticello Reservoir. The resulting water surface was calculated based on reservoir topography to yield the still water surface elevation to be used in wave height determination.

2.4.3.4 Probable Maximum Flood (PMF) Flow

2.4.3.4.1 Broad River

Infiltration losses were subtracted from the 2 PMP rainfall patterns to determine the hyetographs of rainfall excess, as shown on Figure 2.4-8. These rainfall excess values were then applied sequentially to the derived 6 hour unit hydrograph to yield the 2 hydrographs at Richtex. The discharge values at Richtex, with a drainage basin of 4,850 square miles, were converted to discharge values at Parr Dam, with a drainage basin of 4,550 square miles, by the ratio of drainage areas, and are shown on Figure 2.4-8. The larger flood hydrographs, which are those obtained from the CEB 52 8 rainfall patterns, were adopted for use in subsequent analyses. This storm resulted in a peak PMF discharge of 960,000 cfs (Reference 7) at Parr Dam.

As discussed in Section 2.4.1, existing dams in the Broad River basin which might contribute to the PMF flooding due to their potential failure are generally small, low head structures constructed in the late 1800's and early 1800's. The proposed Clinchfield Dam would be designed to withstand the PMF at that location (Reference 7), thereby attenuating the 960,000 cfs peak discharge at Parr Dam. No credit was taken for this potential reduction, and a domino type failure assuming vanishment of the five existing dams on the Broad River between Clinchfield and the site was assumed to occur coincident with the peak PMF discharge attributable to the PMP. These were the only dams within range of influencing the estimated total site PMF. The dam failure method of analysis, discussed in Section 2.4.4, results in a peak discharge of 4,391,000 cfs at the site. This value, when added to the previously determined PMP derived discharge of 960,000 cfs, results in a total discharge of 5,351,000 cfs.While the adopted techniques are very conservative, they demonstrate in Section 2.4.3.5.1 the margin of safety against flooding which exists for the Virgil C. Summer Nuclear Station.

2.4.3.4.2 Frees Creek

Releases from Monticello Reservoir are controlled by the intake channel and penstocks connected to the Fairfield Pumped Storage Facility, as discussed in Section 2.4.1.2.2. Assuming that Monticello Reservoir is at its maximum operating level at the beginning of the PMP and no releases are made through the Fairfield Pumped Storage Facility, the remaining storage of Monticello Reservoir is sufficient to completely contain the storm runoff. The analysis of the peak PMF water level in Monticello Reservoir is presented in Section Section 2.4.3.5.2; therefore, a discussion of the PMF flow in Frees Creek, which is submerged by Monticello Reservoir, is not appropriate.

2.4.3.5 Water Level Determinations

2.4.3.5.1 Broad River

The PMF hydrograph shown on Figure 2.4-8, having a peak discharge of 960,000 cfs, is the inflow hydrograph to Parr Reservoir. The resulting depth of water behind Parr Dam is influenced by the operation of the spillway crest gates which when raised provide a crest elevation of 266.0'.

During flood discharges, the gates are lowered to the concrete ogee dam crest at elevation 257.0' to reduce reservoir flood stage (Reference 7).

Analyses have been performed using very conservative assumptions to evaluate the Parr Reservoir stage for the PMF The following assumptions were adopted:

1. Spillway crest gates on Parr Dam are held at elevation 266.0', rather than lowered to elevation 257.0'.
2. Maximum discharge is 960,000 cfs.
3. No attenuation of the peak discharge is assumed; 960,000 cfs passes over spillway.

Computations using these conservative assumptions indicate the depth of water would be 24.5 feet above the dam crest. This results in a Parr Reservoir flood stage at elevation 290.5', nearly 150 feet below the site grade of elevation of 435.0' (Reference 7).

When considering the PMF with coincident upstream dam failures, it is unlikely that Parr Dam would remain intact with the passage of a peak discharge of 5,351,000 cfs. The slope area method was used to determine the water level on the Broad River. It was assumed that Parr Dam had either failed or, due to the great submergence, had no significant upstream influence. In the site vicinity, the flood plain has an average width of 2,000 feet at elevation 260.0' and valley side slope of about 9:1 (horizontal:vertical). The average river bed slope, from Parr Dam to Columbia, is approximately 0.07%. In a recent flood hazard information report, the Corps of Engineers has determined Manning's “n” to be 0.03 to 0.04 for the Broad River and 0.065 for its overbank areas (Reference 15). Conservatively adopting a Manning's “n” of 0.065 for the entire cross section, the depth of flow would be about 130 feet. Therefore, the maximum water surface elevation under these extremely conservative conditions is approximately 390.0', still well below site grade elevation of 435.0'.

2.4.3.5.2 Frees Creek

It was calculated that the stage increase in Monticello Reservoir resulting from the PMP runoff and direct PMP on the reservoir surface is 6.07 feet in 72 hours. It is conservatively assumed that Monticello Reservoir will be at the maximum pool elevation of 425.0' at the beginning of the storm, and that no reservoir releases through the Fairfield Pumped Storage Facility are made during the storm period. On this basis, the 72 hour PMP results in a maximum pool elevation of 431.07' (Reference 7).

2.4.3.6 Coincident Wind Wave Activity

2.4.3.6.1 Broad River

Since the PMF water level with coincident dam failures determined in Section 2.4.3.4.1 is 45 feet below plant grade, an analysis of coincident wind wave activity was not performed since this situation is not a design basis at the Virgil C. Summer Nuclear Station.

2.4.3.6.2 Frees Creek

Procedures used in evaluating wind setup and waves are described in Engineering Technical Letter No. 1110 2 8 (Reference 16). The setup will accumulate on the lee side of the reservoir, and the waves will runup on the bank or on manmade structures. The magnitude of the setup and runup are dependent upon the reservoir fetch, depth, and other parameters. For these analyses, an effective fetch of 3 miles was determined from Figure 2.4-9. The average reservoir depth, about 70 feet, is great enough to consider deep wave conditions (Reference 7).

Other parameters in this evaluation included wind velocity, bank slope and cover, and wave height spectrum. A conservative 50 mph overland wind speed along the central fetch was adopted. This velocity has been used by the Corps of Engineers for large reservoirs in the region and thus is considered appropriate for use at the site. A range of bank slopes from 20:1 to 1.5:1 were evaluated, for both smooth and riprapped surfaces. Runup on a vertical wall was also considered. The value of the upper 1%, termed the maximum wave height, was utilized. The results of evaluations using these parameters are shown on Figure 2.4-10 (Reference 7).

Reference to Figure 2.4-10 indicates that for a 2:1 riprapped slope, the wave runup plus setup would be 5.93 feet. It is conservatively assumed that there would be no release of water through the Fairfield Pumped Storage Facility during the PMP, and that the reservoir level would be at a maximum pool elevation of 425.0' during the storm. This, together with the 72 hour PMP of 6.07 feet, results in a maximum water elevation of 437.00'. Along the shoreline of Monticello Reservoir to the north of the plant, the slope is 2:1 and extends upward to nominal elevation 438.0' by a 3 foot high riprapped berm constructed above site grade. The dams and the islands of natural area between the dams are also protected to nominal elevation 438.0' to prevent damage on the reservoir side. In no case is the local elevation of these protective structures less than 437.5'. The design bases for these protective structures is presented in Section 2.4.10. Since the maximum water elevation of 437.00' is less than the nominal crest elevations of 438.0' as well as less than the minimum local elevation of 437.5', there are no adverse effects on safety class structures and equipment due to the coincidental wind wave activity (Reference 7).

An evaluation of the wind setup and waves within the service water pond, made in accordance with procedures described in Engineering Technical Letter No. 1110-2-8 (Reference 16), was conservatively based on an effective fetch of 1,288 feet and 80 mph winds blowing for 30 minutes. This analysis indicated that deep water wave conditions would exist and that the wave runup plus wind setup would be 1.8 feet. This, together with the PMP for 1 hour, results in a value of 7.5 feet (Reference 7).

2.4.4 Potential Dam Failures (Seismically Induced)

The following conditions were considered for the evaluation of potential seismically induced dam failures:

1. Full flood control reservoirs with 25 year flood coincident with an earthquake equivalent to the Safe Shutdown Earthquake (SSE);

2. Full flood control reservoirs with Standard Project Flood (SPF) coincident with an earthquake to the maximum historical earthquake, and a domino type failure due to inadequate flood control capacity.

Since the above conditions would require a rigorous analysis of dam stability under earthquake forces, a more conservative approach was taken to simplify calculations and demonstrate a greater margin of plant safety. Computations were based on the complete and instantaneous vanishment of the dams which could affect plant safety coincident with full flood control pools during the SPF. These structures included the proposed Clinchfield Dam and five existing structures between Clinchfield and Parr Dam. A complete description of the reservoirs, potential modes of failure, and methods of analysis are presented in the following sections.

2.4.4.1 Reservoir Description

A description of the significant existing dams, and the proposed Clinchfield Dam, located in the Broad River basin is presented in Section 2.4.1. Pertinent data has been provided on Figures 2.4-2 through 2.4-5 and Table 2.4-1.

2.4.4.2 Dam Failure Permutations

As discussed in Section 2.4.1, existing dams in the Broad River basin are generally small, low head structures for hydroelectric power generation and water supply. The only feasible location for a major dam is at the Clinchfield site, located on the Broad River about 100 miles upstream of the Parr Dam.

Applying the conservative assumptions it was postulated that the Clinchfield Dam would be instantaneously removed, coincident with the full flood control pool and the Spillway Design Flood (SDF). The SDF is larger than the SPF, and results in a greater dam breach discharge than would the SPF. The resulting flood wave was routed to the site and combined with 1/2 the PMF on the Broad River as determined in Section 2.4.3.

Five smaller dams (Gaston Shoals, Cherokee Falls, 99 Islands, Lockhart, and Neal Shoals) are located on the Broad River between the Clinchfield site and Parr Dam, as indicated on Figure 2.4 2. To be conservative, the passage of the flood wave from Clinchfield was assumed to cause a domino type failure of the other dams. For each dam, a peak discharge corresponding to the complete and instantaneous removal of the structure with reservoir depth equal to the maximum height of the dam was determined. These values were added directly to the previously determined Clinchfield discharge with 1/2 PMF at Parr Dam. No credit was taken for the reductions of discharge due to tailwater effects or flood wave attenuation. All peak discharges were assumed to occur coincidentally at the site.

The above outlined compound dam failure mechanism results in the largest conceivable flood at Parr Dam. While the adopted techniques are extremely conservative, they demonstrate in Section 2.4.4.4 the margin of safety which exists. Other dams located further upstream on the Broad River or on its tributaries were not considered due to their relatively small size and/or great distance from the site.

Because of the low topographic relief of the region surrounding Monticello Reservoir, the possibility of a slope failure and a resulting landslide which could produce a local slide induced flood wave is extremely remote. During the PMP over the Frees Creek drainage basin, the maximum still water elevation in Monticello Reservoir is 431.07', as discussed in Section 2.4.3.5.2. Since this elevation is nearly 4 feet below site grade elevation 435.0', the seismically induced failure of the Frees Creek Dams presents no flooding threat to Seismic Category 1 plant facilities. As is shown on Figure 2.4-3, the nearest Frees Creek Dam is located approximately 1/4 mile from the plant site area. Therefore, the hypothesized failure of this saddle dam would result in no scour and erosion of the plant foundation.

The seismic failure of the Frees Creek Dams and other downstream dams identified in Section 2.4.1.2.2 with regard to low water considerations is addressed in Section 2.4.11.

2.4.4.3 Unsteady Flow Analysis of Potential Dam Failures

The discharge hydrograph at the proposed Clinchfield Dam, under instantaneous removal was evaluated by the method shown in Henderson (Reference 8). The maximum discharge thus determined was 3.61×10^6 cfs and was assumed to continue for about 58 minutes. It was assumed that after this time the flow would decrease linearly until the reservoir was empty. This falling limb of the hydrograph would last an additional 6 hours (Reference 7).

This hydrograph was routed downstream by the method of Gilcrest (Reference 17). Routing coefficients were estimated from the time of passage of the Flood of 1940 at various gaging stations downstream of Clinchfield. The routing was performed from the Clinchfield to the Gaffney gaging station and from there to the Carlisle gaging station. The peak discharge at Gaffney was found to be 810,000 cfs and at Carlisle 280,000 cfs. Routing to Richtex would result in additional attenuation. A peak discharge of 260,000 cfs at the site was adopted. This value when added to 1/2 of the PMF discharge, 480,000 cfs, results in a total discharge of 740,000 cfs (Reference 7).

For the five dams located downstream of Clinchfield, the failure discharge was derived by the method of Stoker (Reference 18). Using this technique, the peak discharge at a dam assuming complete and instantaneous removal is computed by 1.68 LH3/2, where L and H are the length and height, respectively, of the dam failure plane. A summary of the computations is presented in Table 2.4-6. The peak discharge of 4,391,000 cfs for the five dams, when added to the previously determined 740,000 cfs, results in a total discharge of 5,131,000 cfs.

2.4.4.4 Water Level at Plant Site

Since the above discharge is less than the Broad River PMF discharge with coincident dam failures, 5,351,000 cfs, no further consideration is required. The resulting water level would be more than 45 feet below site grade elevation.

2.4.5 Probable Maximum Surge and Seiche Flooding

2.4.5.1 Probable Maximum Winds and Associated Meteorological Parameters

The adopted design basis flood and associated winds are discussed in Section 2.4.3.

2.4.5.2 Surge and Seiche History

The site is not located in a coastal area and there are no natural bodies of water in the site vicinity that could be affected by either surges or seiches.

2.4.5.3 Surge and Seiche Sources

The adopted design basis flood and associated winds are discussed in Section 2.4.3.

2.4.5.4 Wave Action

Wave action is discussed in Section 2.4.3.6.

2.4.5.5 Resonance

Approximating Monticello Reservoir as a closed rectangular basin having a major axis of 5.5 miles and minor axis of 2.6 miles, the longitudinal period is approximately 21 minutes while the transverse period is approximately 10 minutes. Since these periods are much greater than wave periods associated with this type of system, wind generated wave amplification is not possible.

Monticello Reservoir has a surface area of approximately 12 square miles, too small for seiching and resonance due to atmospheric pressure differentials.

2.4.5.6 Runup

Runup is discussed in Section 2.4.3.6.

2.4.5.7 Protective Structures

Protective structures are discussed in Section Section 2.4.10.

2.4.6 Probable Maximum Tsunami Flooding

The Virgil C. Summer Nuclear Station is located nearly 150 miles from the nearest coastal area. Therefore, tsunami effects are not a safety related consideration.

2.4.7 Ice Flooding

The climate of the site vicinity is temperate, and there is no record of ice effects (Reference 2). Broad River temperature data is available at Carlisle, 21 miles north of the site; Richtex, 14 miles

south of the site; and at the Parr Steam Plant intake. These data indicate that a minimum monthly mean temperature in the low 40's occurs in December and January (Reference 1).

Besides the remote chances of natural ice formation, the ambient surface water temperature of Monticello Reservoir and the service water pond are increased due to the discharge of waste heat from plant cooling water. For example, in winter months the service water pond surface temperatures are about 11 F warmer than the ambient water temperatures (Reference 1). This would prevent ice formation and the possibility of blockage and forces on the plant intake structures.

Due to these factors, an analysis of ice effects is not considered a design basis for the Virgil C. Summer Nuclear Station.

2.4.8 Cooling Water Canals and Reservoirs

A safety class impoundment is constructed in a small arm of Monticello Reservoir to supply water for the Service Water System under normal and emergency operating conditions. It is possible to safely shutdown the nuclear plant at any time using only the service water pond, without any reliance upon Monticello Reservoir. As shown in the plot plan, Figure 2.4 1, the impoundment is created by three earth dams and the west site embankment and is designed and constructed in accordance with Regulatory Guide 1.29 (see Appendix 3A). The service water intake is located along the northwest shoreline of the service water pond on the west embankment.

The service water intake, schematically shown on Figure 2.4-11, provides adequate water from either the service water pond or Monticello Reservoir. Cooling water enters the intake chamber from the service water pond through a tunnel, or from the reservoir through a pipe from the circulating water intake structure by opening the normally closed isolation valve. A profile along the interconnecting pipe and through the service water and circulating water intakes is shown on Figure 2.4-12. A discharge structure for the Service Water System is constructed on the southwest edge of the service water pond along the west embankment.

2.4.8.1 Design Bases

2.4.8.1.1 Capacity

The volume of water stored within the service water pond and surface area as related to water surface elevation are shown on Figure 2.4-13. Following the postulated loss of Monticello Reservoir coincident with the cross connect isolation valve being open, the service water pond level falls with the reservoir level to elevation 415.0'. At this elevation air enters the exposed reservoir end of the 36 inch diameter pipe interconnecting the condenser circulating water intake and the service water intake. This venting and the invert elevation at the high point of the interconnecting pipe limits the drop in pond level to elevation 415.0' (excluding evaporation losses).

The interconnecting pipe is the only hydraulic connection between the service water pond and Monticello Reservoir. It is designed using the conventional design bases, except for the vertical

section, which is part of the Safety Class 2b intake structure. The volume of water remaining in the service water pond below elevation 415.0' is adequate to ensure safe shutdown of the plant and continued cooling for a minimum of 30 days, as required by Regulatory Guide 1.27 (see Appendix 3A) and described in Section 9.2.5. Cooling water is supplied from Monticello Reservoir through the interconnecting pipe and the circulating water intake structure.

During the initial filling of the service water pond, the 36" interconnecting pipe was flow tested to ensure that the requirement for 32,000 gpm for the Service Water System (2 pumps at high speed) was met. During this test, the valve on the interconnecting pipe vent line was closed, since the service water pumps were not operational at that time. Under normal operation of the service water pumps this vent line will be open and the air venting system will be in operation, thus resulting in additional flow rate through the interconnecting line. Venting systems are normally installed for elevation or hydraulic considerations. This venting system, which includes an air ejector, was installed for that purpose.

An annual surveillance of the earthwork above the pipe at ground elevation will be performed to ensure the integrity of the pipe.

The emergency drawdown elevation of 418.0' (Figure 2.4-12) is identified in the SCE&G application for a Federal Power Commission license as the drawdown level for emergency electrical production to represent the worst case operating conditions.

2.4.8.1.2 Operating Conditions

A butterfly isolation valve is installed in the interconnecting pipe to allow chemical treatment of the Service Water system without discharging chemicals to the environment. Chemically treating the Service Water system is one action to address Generic Letter 89 13, “Service Water System Problems Affecting Safety Related Equipment.” The isolation valve is normally closed. The operation of the valve is administratively controlled so that Monticello Reservoir level must be higher than the service water pond before the valve is opened; thus ensuring flow only in the direction from Monticello Reservoir to the service water pond.

When the isolation valve is open, the magnitude of flow in the interconnecting pipe is governed by the water levels in the service water pond and reservoir. The 4.5 foot rise and fall of the reservoir level due to operation of the Fairfield Pumped Storage Facility (8 hour generation, 9.6 hour pumping, 6.4 hour slack) produces an approximate 1 foot normal fluctuation in the service water pond level.

The minimum water levels in the central pump chamber of the service water intake used in the safety evaluation during normal operation, normal shutdown and LOCA conditions is discussed in Section 9.2.5.3.2

2.4.8.2 Protection Against Probable Maximum Precipitation, Waves, and Blockages

Neglecting outflow from the service water pond, the 10 foot minimum freeboard of the dams and embankments surrounding the pond provides capacity for storing considerably more than the 19.0

inch PMP (see Section 2.4.3) plus the overland runoff from the plant site assuming complete blockage of the underground storm drainage system. Since the service water pond is an arm of Monticello Reservoir, impounded by dams, protection of downstream residents is not a consideration.

Refer to Section 2.4.10 for discussion of protection against wind waves, etc.

At the entrance of the tunnel to the service water pump house, a protruding pier prevents complete blockage of the bar racks. Within the Service Water Pump House, a completely separate chamber with bar rack, traveling screen and stop log grooves for maintenance is provided for each pump. Partition walls separating the chambers prevent loss of function in one chamber from affecting operation of the other chambers.

2.4.9 Channel Diversions

Monticello Reservoir and the service water pond, which provide the sources of plant cooling water, are not subject to upstream diversions. The Fairfield Pumped Storage Facility is operated in such a manner to maintain a water surface elevation between 420.5' and 425.0' in both bodies of water. Therefore, channel diversion effects at the Virgil C. Summer Nuclear Station is not a design basis.

2.4.10 Flooding Protection Requirements

The maximum flood elevation of Parr Reservoir due to the PMF and effect of dam break at Clinchfield site has been analyzed. The resulting maximum flood elevations are considerably lower than the site grade elevation (see Section 2.4.2 and Section 2.4.3). The site grade is at nominal elevation 435.0' adjacent to Monticello Reservoir, an approximate 6,800 acre reservoir which is created by constructing a series of dams across Frees Creek, a tributary of the Broad River. Monticello Reservoir is impounded to a nominal pool elevation of 425.0' under typical normal operation range for the pumped storage facility.

Shoreline protection in the vicinity of the plant is designed for wave runup and wind setup due to an overland wind velocity of 50 mph superimposed on the maximum flood elevation of the Monticello Reservoir resulting from the coincidence of 72 hour PMP. The analysis indicates that for a riprap slope as shown on Figure 2.4-10, the wave runup including wind setup is a maximum of 5.93 feet. This, together with the 72 hour PMP results in a value of 12.00 feet. If it is conservatively assumed that there is no release of water through the Fairfield Pumped Storage Facility during the PMP and that the Monticello Reservoir level is at a maximum pool elevation of 425.0' during the storm, then the maximum flood elevation resulting from the coincidence of the PMP, wave runup on a riprapped slope and wind setup is elevation 437.0'. The shoreline along Monticello Reservoir north of the plant and west of the north dam has a 2 to 1 slope (horizontal to vertical) extended upward to nominal elevation 438.0' by a 3 foot high dike (north berm) constructed above site grade. The minimum local elevation along the North berm is 437.5'. The slope is protected with two 9 inch filter zones placed beneath 36 inches of riprap.

The west embankment and three earth dams of the service water pond are the only Seismic Category 1 structures which require protection against wind setup and wave runup. The slopes of the west embankment, north, east, and south dams within the service water pond are protected with riprap 2 feet thick laid over 2 filters, each 9 inches in thickness. The wave runup plus the wind setup coincidental with the 72 hour PMP results in a water elevation of 432.50' within the service water pond. The slopes have been protected up to nominal elevations 435.0' and 438.0' for the west embankment and the three dams, respectively. The minimum local elevations for the top of the west embankment and three dams are 434.5' and 437.5', respectively.

The exterior slope of the north dam is protected by riprap consisting of one uniformly graded primary layer 6 feet in thickness, with 2.5 feet of underlayer and 2 filters each 9 inches in thickness. The exterior of the south dam has 2 feet of riprap with 2 filters each 9 inches in thickness. The exterior slope of the east dam has 3 feet of riprap laid over 2 filters, each 9 inches in thickness. The slopes have been protected up to the nominal top elevation of 438.0'.

For detailed design and gradation of filters and riprap zones for the service water pond dams and west embankment, see Section 2.5.6.

The roofs of safety related buildings are designed to safely dispose of or store to a maximum of 4 inches of local intense precipitation. The site drainage system is sufficient to prevent flooding by a localized PMP. For details, refer to Section 2.4.3.1.3.

Exterior door thresholds across the site below the maximum water surface elevation which lead to safety related equipment are protected from local intense precipitation by attaching temporary flood barriers. These flood barriers are able to be quickly installed and removed due to rapidly changing flooding conditions.

Provisions for protection against internal flooding due to equipment malfunction are discussed in Section 7.6.

2.4.11 Low Water Considerations

2.4.11.1 Low Flow in Rivers and Streams

2.4.11.1.1 Low Flow Resulting From Dam Failures

Monticello Reservoir and the service water pond, which provide the sources of plant cooling water, obtain make up water from Parr Reservoir on the Broad River. The Fairfield Pumped Storage Facility is operated in such a manner to provide a minimum normal pool elevation of 420.5'. If the level of Monticello Reservoir is further reduced, either by accidental releases through the Fairfield system or any failure mode of the Frees Creek Dams, the service water pond level falls with the reservoir level to elevation 415.0'. As long as water level in Monticello Reservoir is higher than elevation 415.0', water is interchanged between the service water pond and Monticello Reservoir through an interconnecting pipe. The invert elevation at the high point of the 36 inch pipe is 415.0'. Therefore, a complete loss of cooling water cannot occur due to this hypothesized accident.

In the event of the failure of the downstream Parr Dam, a complete loss of cooling water availability does not occur. Even in the very conservative case where it is assumed that Parr Dam fails coincident with Frees Creek Dam, a pool having elevation 415.0' remains in the service water pond as discussed above. If Parr Dam is assumed to fail, the only consequence is the loss of make up water from Parr Reservoir to Monticello Reservoir. It is demonstrated in the following section that a loss of make up water coincident with the 100 year drought on the Broad River does not result in a depletion of the nonsafety related water supply for the Virgil C. Summer Nuclear Station.

A failure of other structures located downstream of Parr Dam, as identified in Section 2.4.1.2.2, has no influence on the safety or nonsafety related water supplies for the Virgil C. Summer Nuclear Station.

2.4.11.1.2 Low Flow Resulting From Hydrometeorologic Conditions

During normal plant operation, ambient evaporation from Monticello Reservoir has been estimated to be 33 cfs, with an additional 13 cfs latent evaporation from condenser water (Reference 1). The total evaporation rate of 46 cfs corresponds to an average daily evaporation loss of 92 acre feet. Conservatively, no inflow to the reservoir has been assumed in these calculations. To lower Monticello Reservoir by 2.5 feet from its normal minimum pool level to elevation 418.0', which corresponds to the crown of the 36 inch connecting pipe, a total of 21,000 acre feet of water would have to be removed. More than 1/2 year is required to evaporate this volume of water from Monticello Reservoir. Seepage to the ground water has not been considered, since this loss is negligible due to accumulated sediments as the reservoir matures. Conservatively, no inflow to the Monticello Reservoir has been assumed for those calculations.

Low flow characteristics for the Broad River are available at the Richtex gaging station (Reference 20). Based on data from October 1925 to September 1965, the drought having a return period of 40 years over periods of 120 and 274 consecutive days results in average low flows of 1,060 and 1,970 cfs, respectively. If these data are graphically extrapolated to the 100 year return period, average low flows of approximately 830 and 1,650 cfs, respectively, are obtained for the 2 durations. The average low flow for the 100 year drought over a period of 1/2 year is between these 2 values, or approximately 1,000 cfs. However, it is demonstrated above that more than 1/2 year is required to evaporate a sufficient volume of water from Monticello Reservoir to lower its elevation from minimum pool at 420.5' to elevation 418.0' assuming no make up from the Broad River. Therefore, the 100 year drought on the Broad River does not result in a depletion of the nonsafety related water supply for the Virgil C. Summer Nuclear Station.

2.4.11.2 Low Water Resulting From Surges, Seiches, or Tsunami

Low water considerations are discussed in Section 2.4.11.1.1.

The effects of seiche, tsunami and ice are not applicable to the site.

2.4.11.3 Historical Low Water

Information on historic low flows is available at the Richtex gaging station. The lowest observed average daily flow has been 149 cfs, which occurred on October 13, 1935 and on September 2, 1957. The instantaneous minimum flow of record is 105 cfs (Reference 7).

Since statistical methods were not used to extrapolate flows and/or levels to probable minimum conditions, no further discussion is presented.

2.4.11.4 Future Control

No future uses and/or controls for Monticello Reservoir and the service water pond which could affect the ability of safety related facilities to function adequately are planned for the lifetime of the project.

2.4.11.5 Plant Requirements

A minimum cooling water flow rate of 12,000 gpm is required for the operation of safety related components supplied by the Service Water System under normal operating conditions. The Service Water Pump House has three service water pumps, each with a design capacity of 16,800 gpm at high speed. The sump invert is at elevation 389.0'. The weir in the Service Water Pump House maintains a minimum water level at elevation 399.0' to ensure adequate pump submergence. The service water pond level varies from elevation 422.7' to 423.25' during normal operation (see Section 9.2.5). The emergency drawdown level in Monticello Reservoir is elevation 418.0'. The corresponding equilibrium elevation in the service water pond is 417.5'. In the event of loss of Monticello Reservoir coincident with the cross connect line isolation valve being open, service water pond level would drop to a minimum of elevation 415.0'. For details, see Sections 2.4.8 and 9.2.5.

There are no institutional restraints on the use of water.

2.4.11.6 Heat Sink Dependability Requirements

Under normal and emergency operating conditions cooling water for the service water system is supplied from the service water pond, from Monticello Reservoir through an interconnecting pipe or from both sources simultaneously. The design basis for shut down of the plant utilizes the service water pond without reliance upon Monticello Reservoir. For details, see Sections 2.4.8 and 9.2.5.

2.4.12 Environmental Acceptance of Effluents

2.4.12.1 Surface Water Flow Paths

The following presentation of dispersion, dilution, and travel times of accidental releases of liquid effluents is based upon the highly unlikely postulated spillage of liquid radwastes into the surface water system along overland flow paths. In the event of such an accident, however, the effluent

would most likely reach the ground water system as discussed in Section 2.4.13.1.3. A related analysis of a postulated ground water spillage ultimately reaching the surface water system and downstream users is presented in Section 2.4.1.2.2.

The site is located approximately 1 mile east of the Broad River and 2.5 miles northeast of Parr Dam on an irregularly shaped ridge about 180 feet above the Broad River floodplain. The ridge is the natural drainage divide between Frees Creek (to the north) and Mayo Creek (to the south).

Besides these 2 creeks, the plant site area is laced with numerous other drainage swales which feed into the Broad River, as is shown on Figure 2.4-15. Based on operation procedures and topographic considerations it is highly unlikely that radioactive material from any postulated accident can ever reach Monticello Reservoir. If such an unlikely event occurred the large volume of water in Monticello Reservoir would provide a very large dilution, since even at minimum pool elevation 420.5' the storage volume is 371,000 acre feet. Maximum dilution would be achieved with maximum pool elevation of 425.0', corresponding to a storage volume of 400,000 acre feet. The operation of the Fairfield Pumped Storage Facility could be terminated to prevent the highly diluted radwaste from reaching the Broad River and the downstream surface water users identified in Section 2.4.1.2.3. If this was not done, a maximum of 29,000 acre feet of water could be released during the Fairfield generating phase over 1 day. This highly diluted spilled material would be further diluted in Parr Reservoir. Assuming a very conservative minimum pool elevation of 256.0', Parr Reservoir has a storage volume of 2,500 acre feet. Further dilution would result from the natural streamflow into Parr Reservoir. The minimum daily flow observed at Richtex gaging station was 149 cfs during October 13, 1935 and September 2, 1957 (Reference 2). To be very conservative this minimum river flow into Parr Reservoir is assumed, resulting in a total volume of 315 acre feet over a 24 hour period available for mixing. Additional dilution would be obtained from tributary inflow at downstream locations. The Broad River between Parr Dam and Columbia, S. C. has a typical width of approximately 1,000 feet and a typical depth of about 3 feet. Therefore, travel time may be estimated using Manning's equation for a wide rectangular channel. The average river bed slope from Parr Dam to Columbia is approximately 0.07%. Manning's roughness coefficient, “n”, was estimated by the Corps of Engineers to be approximately 0.04 (Reference 15). From the Manning formula, the typical streamflow velocity is about 2.0 feet per second, or about 1.4 miles per hour. The City of Columbia, the nearest downstream surface water user, is located approximately 28 miles below Parr Dam. Therefore, the travel time to Columbia for the highly diluted accidental radwaste released from Parr Dam would be about 20 hours. During the assumed drought conditions, the travel time would be greater due to the smaller streamflow velocities since typical conditions were assumed for the Broad River.

For a postulated accident condition along a surface water flow path, it is somewhat more conceivable that liquid radwaste could be conveyed instead by the site interior drainage system away from Monticello Reservoir. The accidentally spilled material would ultimately reach the Broad River after an overland flow distance of approximately 1 mile (generally southwestward), as may be seen on Figure 2.4-3. An average overland flow velocity of 1 mph, as determined in Section 2.4.3.3.2, is representative for the rolling terrain surrounding the site. Therefore, the centroid of the radwaste spill would reach the Broad River in approximately 1 hour. If the spill reaches Parr Reservoir, a large volume of water will be available for dilution. To be very

conservative a coincidental minimum pool elevation of 256.0' is assumed in Parr Reservoir corresponding to a storage volume of 2,500 acre feet. Maximum dilution would be achieved at a maximum pool elevation of 266.0', corresponding to a storage volume of 29,000 acre feet. If the spill reaches the Broad River downstream of Parr Reservoir, this dilution would not be available. Further dilution would be achieved by the natural streamflow into Parr Reservoir, as is discussed in the earlier analysis of spillage into Monticello Reservoir. Additional dilution would be obtained from tributary inflow at downstream locations along the Broad River. As determined above, the travel time to Columbia, S. C. for the diluted radwaste released from Parr Dam would conservatively be about 20 hours.

2.4.12.2 Ground Water Flow Paths

In addition to the overland flow paths which are discussed in the previous section, it is conceivable that an accidental radioactive release could originate in the local ground water system, and ultimately reach the surface water system and downstream users. An analysis of such accidental conditions, resulting from the hypothesized rupture of the waste holdup tank, is presented in Section 2.4.13.3. The analysis computes the peak concentrations of various radionuclides at 2 points, corresponding to the locations where 2 possible ground water flow paths would reach the ground surface. The most critical isotope and flow path are determined to be Cs^{137} being emitted from the local aquifer at discharge point A, as shown on Figure 2.4-15. The resulting peak concentration is computed to be 1.7×10^{-3} μCi/ml, as shown in Table 2.4-12, and would occur at the centerline of the spillage flow path.

For the purpose of evaluating the effects of the spill material in the surface water system downstream of the discharge point, the average concentration and discharge of the highly diluted radwaste being emitted from the aquifer must be determined. The spill material would not be emitted only at discharge point A, but also on either side of the flow path centerline due to the lateral dispersion of the spill material in the aquifer. The average width of the portion of the local aquifer which could conceivably be contaminated between the waste holdup tank and discharge point A has been estimated to be approximately 1,650 feet. On the basis of the ground water transport model discussed in Section 2.4.13.3, the maximum concentration of Cs^{137} across this width would vary from the previously determined peak of 1.7×10^{-3} μCi/ml to much smaller values at points away from the plume centerline. The spatially averaged Cs^{137} peak concentration across the effective width of the contaminated local aquifer would be 3.7×10^{-5} μCi/ml. On the basis of Darcy's Equation, this highly diluted spill material would be emitted at a rate of about 0.12 cfs.

Prior to reaching the Broad River, the spill material being emitted would be further diluted by water which originated in uncontaminated portions of the local aquifer tributary to the flow path downstream of discharge point A. Again using Darcy's Equation, the discharge from this uncontaminated portion of the local ground water system is computed to be 0.52 cfs. Therefore, the total flow rate of the highly diluted spill material upon reaching the Broad River would be 0.12 + 0.52 or 0.64 cfs. The corresponding peak concentration of Cs^{137} would be (0.12/0.64) 3.7×10^{-5} or 6.9×10^{-6} μCi/ml.

Upon reaching the Broad River, further dilution of the spill material would result from the natural streamflow into Parr Reservoir. The minimum daily flow observed at the Richtex gaging station on the Broad River was 149 cfs during both October 13, 1935 and September 2, 1957 (Reference 2). Even under these extreme drought conditions, an additional dilution factor of $0.64/(149 + 0.64)$ or 4.3×10^{-3} is achieved. Hence, the peak concentration of Cs^{137} would be $(4.3 \times 10^{-3})(6.9 \times 10^{-6})$ or 3.0×10^{-8} μCi/ml. This concentration is a factor of 33 below the effluent concentration limit for Cs^{137} for unrestricted areas from Appendix B of 10 CFR 20.

The above analysis of the ground water spill material reaching the surface water system has conservatively neglected the initial dilution provided by the water impounded in Parr Reservoir. Even at its minimum pool elevation of 256.0', Parr Reservoir has a storage volume of 2,500 acre-feet available for dilution. Nor has any credit been taken for the additional dilution provided by tributary inflow at downstream locations along the Broad River. As is discussed in Section 2.4.12.1, the travel time of the spill material in the Broad River from Parr Dam to Columbia, S. C., is conservatively estimated to be about 20 hours.

2.4.13 Ground Water

2.4.13.1 Description and Onsite Use

2.4.13.1.1 Regional Ground Water Conditions

The region within a 20 mile radius of the site lies within the Piedmont Physiographic Province, except for a small portion to the southeast near Columbia, which is in the Coastal Plain Province.

The bedrock underlying the region principally consists of Paleozoic crystalline metamorphics and igneous intrusives of the Charlotte Belt and Carolina Slate Belt. Information on the bedrock sequence is not detailed because there are few outcrops -- these being confined somewhat preferentially to the more deeply entrenched drainages and some prominent knobs of resistant rock. The metamorphic and igneous rocks weather to overburden soils of clayey, silty, and sandy composition. The character of the overburden is related to the type of bedrock and degree of weathering. The overburden thickness ranges up to 100 feet or more, but varies considerably from place to place depending on degree of incision of drainages and bedrock composition.

Ground water in the region occurs in 2 types of formations: (1) jointed and fractured crystalline bedrock, and (2) the lower zones in the residual soil overburden. Recharge to these formations is principally by infiltration of precipitation falling on the upland areas. Some of the water infiltrating the surface soils evaporates, transpires from plants, or re emerges at the surface downslope at short distances from points of infiltration. A small portion of the water percolates to perched water zones, or deeper into the water table in the lower soils and the underlying jointed bedrock.

The ground water table, in general, follows the land surface but with more subdued relief. Ground water discharges as visible seeps and springs and/or percolates through the ground into creeks and streams. Some ground water is discharged via wells, but the amount pumped is very small

because the formations generally are not pervious enough to sustain well yields greater than a few gallons per minute.

2.4.13.1.2 Pre-Reservoir Impoundment Ground Water Conditions

Investigations performed at the site reveal that geologic and hydrologic conditions in the site area are essentially the same as the regional conditions described in Section Section 2.4.13.1.1. Local surface topography plays a dominant role in ground water occurrence.

The site is located about 1 mile east of the Broad River on the north flank of an irregularly shaped relatively narrow ridge. The ridge is presently confined between Frees Creek on the north and Mayo Creek on the south, and is laced with numerous drainage swales which feed into the creeks. Both creeks are tributaries to the Broad River. Previous to grading for construction, the site portions of the ridge ranged from elevation 400.0' to 500.0'. The upgraded ground surface at the site slopes irregularly downward in a general northeast direction.

Test borings drilled at the Virgil C. Summer Nuclear Station location encountered metamorphic and igneous rock of the Charlotte Belt at depths ranging from 40 to 95 feet below the original ground surface. The upper 5 to 10 feet of original residual soil overburden consisted of stiff, impervious clayey and silty soils, containing variable quantities of sand. Underlying the upper materials were soils of relatively low permeability, consisting generally of silty sand and sandy silt. These soils graded into weathered and partially decomposed bedrock which overlies the fresh bedrock. The bedrock is impervious except along joints.

Ground water at and around the site occurs principally under water table conditions within jointed bedrock generally at depths of 30 to 90 feet (elevation 350.0' to 420.0') below the original ridge topography, although infrequent lenses of perched water occur in overburden soils.

2.4.13.1.3 Onsite Use of Ground Water

Ground water will not supply any of the water required for operation of the plant

2.4.13.2 Sources

2.4.13.2.1 Regional Use of Ground Water

Ground water within the region is principally used for individual households and for livestock.Within 2 to 20 miles of the site approximately 100 wells have been reported for municipal, industrial, and domestic purposes. Data for these wells are listed in Table 2.4-7. The well locations within approximately 2 to 20 miles of the site are shown on Figure 2.4-14. The data presented for ground water use were primarily taken from South Carolina Department of Health & Environmental Control compilations, providing the latest and most accurate information available. Except for a few cases, data were not available for water levels, elevations, and drawdowns.

Wells in the region range from 62 to 365 feet deep, but are commonly less than 200 feet deep and yield about 10 gpm or less. Yields of up to 55 gpm have been reported. However, such yields are obtainable only from a small fraction of the region's wells. When water requirements are large, surface water must be developed because large yields usually cannot be obtained from wells in either bedrock or overlying soil. Ground water within a 20 mile radius of the site is currently used for domestic and small industry purposes. Since it is generally not possible to develop wells in the area with yields greater than a few tens of gallons per minute, it is likely that the aforementioned well and ground water use parameters will not change significantly in the future. Consumption of ground water should increase in proportion with the area's resident population increase. Estimates of the region's population growth are presented in Section 2.1.

2.4.13.2.2 Local Use of Ground Water

The site is located in a relatively undeveloped area. There are no wells or domestically used springs downgradient from the site. The nearest location of ground water withdrawal is a well approximately 1 mile eastward, just outside of the site boundary. The nearest large group of domestic water wells is along Route 215 about 1.5 miles east of the site and in Jenkinsville approximately 2.5 miles southeast of the site.

Locations of wells within an approximate 2 mile radius were compiled by interviewing residents. These wells are shown on Figure 2.4-15, and are listed in Table 2.4-8. These local wells supply water for 42 residences and 4 stores. The wells extend into rock, range from 65 to 365 feet in depth, and typically yield less than 10 gpm. The water quality is generally acceptable for domestic use.

The only nearby public water supply is the Jenkinsville Water Company. Three of its five wells are within approximately 2 miles of the site. The Jenkinsville Water Company supplies water to 51 residences and one business within 2 miles of the site. Sixteen of the residences are also connected to operable private wells.

Predicted future use of regional ground water is discussed within Section 2.4.13.2.1. Future use of local ground water is also considered related to the area's resident population projections. It is estimated that the resident population within 2 miles of the site will remain approximately static through the year 2019. Local ground water consumption should not, therefore, experience significant deviations from approximate current levels.

2.4.13.2.3 Site and Vicinity Ground Water Levels and Flow Directions

Perforated pipes were installed in 19 exploratory borings to observe water levels at the site. Repeated observations of water levels were made to obtain static level information. Analysis of this information indicated that the principal direction of flow at the site is toward the northeast into Frees Creek, a tributary to the Broad River. Movement of ground water is from the ridge axis toward its flanks as illustrated by the water table contours shown on Figure 2.4-16. The ultimate flow of site ground water is into the Broad River. The estimated rate of flow is expected to be up to 1 foot per day on the steeper ridge flanks.

Observations of water levels in exploratory borings indicated that the ground water table at and around the site occurs at depths ranging from approximately 20 to 90 feet (elevation 350.0' to 420.0') below the original ground surface, generally in jointed bedrock. Local lenses or perched water in soil occur, indicated by seepage high on the ridge flanks. Static water levels and water level contours developed from these data are presented on Figure 2.4-16.

An evaluation of ground water conditions at the site indicates the following:

1. The preconstruction water table slopes downward toward the northeast in the direction of the sloping land surface.
2. The water table gradient is quite flat (0.005 to 0.01, foot/foot) on top of the ridge and steeper (0.02 to 0.07 foot/foot) on the ridge flank.
3. Recharge occurs locally, from surface infiltration, and discharges into Frees Creek.
4. No wells or springs used for water supply are located down gradient of the site.

Ground water levels measured in existing wells within about 2 miles of the site range from 22 to 90 feet in depth.

The overburden soils release water slowly to the lower, more pervious saprolitic and jointed rock zones. As a result of this storage effect, yields of wells and flows of springs remain rather constant, and are sustained during periods of deficient moisture. Review of the available information does not indicate that well dewatering is a problem in the site area, and ground water fluctuations are, therefore, considered to be minor.

2.4.13.2.4 Permeability of Onsite Materials

Laboratory permeability tests have been performed on selected samples obtained from borings drilled at the site of the Virgil C. Summer Nuclear Station structures. The results of these tests are summarized on Table 2.4-9. Permeability tests performed on silty sand to sandy silt samples of soil obtained below the surficial clayey zone indicate a permeability ranging from 3.35×10^{-1} to 4.8×10^{-4} feet per day. A test performed on a sample of the surficial clayey soils indicates a permeability of 6.8×10^{-2} feet per day. These tests are indicative of vertical permeabilities of the site soils.

Field permeability tests have been performed in various soil and rock horizons in borings located in the service water pond. The results of the field permeability tests are presented on Table 2.4-10, and are considered indicative of the horizontal permeabilities of the materials tested. Additional permeability test data are presented in Section 2.5.6.

The locations of borings in which field permeability tests were conducted and associated data are included in Section 2.5.6. Field permeabilities on soils, saprolites, and partially decomposed rock ranged from 5.9 to 5.1×10^{-3} feet per day, with higher values obtained locally in the valley bottom along the north dam grout curtain.

Table 2.4-10 also presents results of additional laboratory permeability tests on soils and rock which are indicative of the vertical permeabilities. The methods utilized for the determination of the permeabilities presented on the tables are described within Section 2.4.6.

The laboratory and field test data indicate that the site subsurface strata generally have low permeability. The ground water velocity is not expected to exceed 1 foot per day.

2.4.13.2.5 Changes in Ground Water Recharge Patterns and Reversibility of Ground Water Flow

Construction of the Virgil C. Summer Nuclear Station includes excavation to a site grade of elevation 435.0'. After Monticello Reservoir is impounded to elevation 425.0', ground water occurrence, movement, recharge and discharge at the site and around the reservoir are expected to change.

In general, the area surrounding the reservoir ranges in maximum elevation from about elevation 450.0' to 500.0'. After Monticello Reservoir is filled, the reservoir surface will be higher than the existing water table at the site. It is estimated that the water table will ultimately rise from its present level, between approximate elevations of 350.0' to 420.0', and approach an approximate elevation of 420.0'. It is anticipated that wells in the area of the reservoir with water levels below elevation 420.0' will experience an increase in water level elevation. The amount of water level rise will be dependent on the present well water elevation and its distance from the reservoir.

The ground water direction will probably be reversed from northeast to the south and west toward Broad River tributaries, and will move at an estimated velocity of less than 1 foot per day. There are no domestic or industrial wells downgradient of the predicted reversal of ground water flow. Ground water observation wells, as described in Section 2.4.13.4, will be monitored during and after the filling of Monticello Reservoir. Changes in site ground water conditions will be documented as they occur.

2.4.13.2.6 Ground Water Quality

Jointed bedrock is not a good aquifer for municipal and industrial water wells. The quality of ground water is acceptable for most uses, but an objectionably high iron content is found in some supplies. The water quality is highly mineralized, due to prolonged contact with, and solution of, rock minerals. The following chemical analyses pertain to water samples obtained from site area borings and are expected to be indicative of typical ground water quality:

	Boring N-23	Boring 3-14	Boring 3-2
pH	6.6	6.7	7.0
Alkalinity (phenolphthalein)	0 ppm *	0 ppm	0 ppm
Alkalinity (methyl orange)	29 ppm	50 ppm	45 ppm
Sodium Chloride	7.37 ppm	10.36 ppm	5.38 ppm

	Boring N-23	Boring 3-14	Boring 3-2
Total hardness	16 ppm	42 ppm	28 ppm
Calcium Hardness	12 ppm	30 ppm	16 ppm
Magnesium Hardness	4 ppm	12 ppm	12 ppm
Conductivity	60 µmho **	140 µmho	100 µmho
Dissolved Solids	50 ppm	608 ppm	332 ppm
Silica	4.7 ppm	22.5 ppm	16.5 ppm
Iron	2.6 ppm	2.7 ppm	4.9 ppm
Copper	0.8 ppm	0.7 ppm	1.0 ppm

* parts per million
** micromho

2.4.13.2.7 Site Dewatering

Following impoundment of Monticello Reservoir, full pool elevation for both the reservoir and the service water pond has been 425.0 feet above mean sea level (msl). As previously described, the proximity of Monticello Reservoir and the service water pond has resulted in a raised water table throughout the site and a reversal from natural ground water flow.

A 2003 ground water study found predominate flow in the shallow aquifer was towards the west-southwest, ultimately feeding into the Broad River. Local ground water elevations ranged from 425.0 to 420.0 feet msl. Site ground water contours are illustrated on Figure 2.4-17. This study was initiated due to persistent issues with ground water intrusion into some plant buildings at elevations below the ground water table. The study sought to determine water sources, identify subsurface flow paths, and characterize site hydrogeology. This effort, which included significant subsurface exploration, was utilized to assess the feasibility of future dewatering efforts.

In 2008, a non-safety dewatering system was installed in proximity to the plant structures experiencing water intrusion issues. This system consists of 16 wells, installed to various depths, ranging from 85 to 180 feet. Most well heads are located within an underground concrete vault and include a submersible pump, level transmitter, and controller to automatically regulate well drawdown levels to a pre-determined setpoint. ell yield is dependent upon permeability of local resident soils and was the bases for pump sizing. Level setpoints were largely determined from water intrusion into nearby structures.

Pumped water is discharged into the local storm drainage system, where it is conveyed by storm sewers to the south and west, away from Monticello Reservoir. This water ultimately enters tributaries of the Broad River. Existing NPDES permitting was revised to address this additional effluent of approximately 70,000 gallons per day (steady state). The storm drainage system has been evaluated to ensure this additional discharge flow does not adversely impact interception and conveyance of overland drainage flow resulting from a postulated 6-hour PMP (Section 2.4.3.1.3).

Settlement of adjoining buildings and structures was evaluated in advance and monitored during the incremental drawdown of the water table. Following stabilization of the ground water regime, observed displacements were within acceptable limits established in the structural evaluation (i.e., settlement was not structurally significant).

A subsequent review of ground water conditions was performed in August 2009 and found subsurface flows toward the installed dewatering wells in all directions. Generally, ground water was flowing south from Monticello Reservoir, west from the service water pond, and north from the Transformer area. Ground water intrusion into plant structures had been mitigated and ground water depth maintained in the installed wells ranged from 402.0 to 372.0 feet msl. Site ground water contours are illustrated on Figure 2.4-18.

FSAR Section 2.4.12.1 and Section 2.4.12.2 discuss dispersion, dilution, and travel times associated with an accidental release of liquid radwaste effluents into the surface water (site drainage system and overland flow) and ground water (soil mass) systems, respectively.

Additionally, an analysis describing a postulated accidental release of radionuclides into the ground water system is presented in Section 2.4.13.3. Operation of the subject dewatering system does not alter these discussions and conclusions.

Applicable plant procedures secure the dewatering pumps if groundwater contamination is discovered.

2.4.13.3 Accident Effects

2.4.13.3.1 Introduction

An accidental release of radionuclides into the ground at the site will not affect local or regional ground water supplies. The direction of future ground water flow is expected to reverse and no local or regional domestic, municipal, or industrial ground water sources lie downgradient of the site.

A rupture of a waste holdup tank results in the worst case potential impact to the local surface and groundwater sources.

The following analysis describes the potential effect of an accidental rupture of the waste holdup tank, located 21 feet south and 85 feet west of the center of the reactor building, on ground water quality. The bottom of the tank is located approximately at elevation 375.0'. The tank is supported on a 9 inch pad overlying a concrete structural mat 4 feet in thickness, and 2 feet of lean concrete fill which rests directly on bedrock.

At the location of the tank, the material at foundation level consists of highly weathered to moderately weathered crystalline rock, composed of granodiorite or migmatite; these materials are in the transition zone between fresh rock and saprolite. The saprolite in this area may generally be classified as a micaceous silty sand containing small to large fragments of slightly weathered rock.

The capacity of the tank is 10,000 gallons. For conservatism, it is assumed that at the time of rupture the tank is full and has an isotopic composition equivalent to the composition of reactor coolant with an assumed failed fuel fraction of 0.12% consistent with NUREG-0017 (Reference 33). At the time of the accident, it is assumed that the tank, the entire underlying foundation, and the adjoining walls rupture. Thus, the liquid in the waste holding tank would make immediate contact with the saturated geologic materials adjacent to the tank. The problem analyzed, therefore, is the disposition of a 10,000 gallon slug of liquid radwaste which has been instantaneously introduced into the local ground water regime.

It is assumed that at the time of rupture the Monticello Reservoir is at elevation 425.0', and that the resulting elevation of the water table adjacent to the waste holding tank has reached equilibrium level, approximately at elevation 420.0'. At this time the general water table gradient will probably be toward the west and the south. Two (2) possible flow paths are suggested. The contaminants could move west southwest toward a small tributary flowing west toward the Broad River (Figure 2.4-15). In this case the likely point of discharge to the surface would be about

3,070 feet from the waste holdup tank, at the point where the tributary becomes a perennially flowing stream due to discharging ground water (discharge point A, Figure 2.4-15). The other flow path would be in a south southeast direction from the tank toward Mayo Creek (Figure 2.4-15). It is assumed the ground water would be discharged 3,680 feet from the tank, at the point where this creek also becomes a perennially flowing stream (discharge point B, Figure 2.4-15). As described in Section 2.4.13.3.2, an analytical model has been used to estimate the concentration of radionuclides in the ground water at these 2 discharge points following the postulated accidental rupture.

No water wells or developed springs occur between the waste holdup tank and the general vicinities of the 2 discharge points.

2.4.13.3.2 Description of Model

The equation utilized for the analysis was derived from the Equation # 1 for the instantaneous introduction of a slug having an infinitesimally small volume (Reference 21):

(#1)

$$\frac{C_i}{m} = \frac{1}{n(4\pi D'_x t)^{1/2}(4\pi D'_y t)} \exp - \left\{ \frac{(x - U'_x t)^2}{4D'_x t} + \frac{y^2}{4D'_y t} + \frac{z^2}{4D'_y t} + \lambda_i t \right\}$$

for the case where $U_y = U_z = 0$, and where $Dy = D_z$ where,

c = Quantity of radionuclide cation per ml of interstitial solution, at any time t and at any point x,y,z,
m = Total quantity of radionuclide introduced in slug,
n = Porosity of the aquifer,
x = Distance from point of injection in direction of ground water flow to the point of interest,
y = Distance laterally, perpendicular to ground water flow,
z = Distance vertically, below level at which slug introduced.
λi = Decay coefficient $= .693/T^{1/2}$, where $T^{1/2}$ is the radionuclide half life,
t = Time since introduction of slug of liquid,
U'_x = The average velocity of the radionuclide in the x direction,
$U'_x = (R_f)(U_x)$, where,
U_x = seepage velocity in the x direction,
R_f = the reduction factor due to cation exchange
= (Reference 22)

$$\frac{1}{1 + \left(\frac{P_B}{n}\right)\left(\frac{Q'}{C}\right)(E)} \quad [22]$$

where,
P_B = bulk density of the aquifer (gm/ml),
Q' = concentration of native cations absorbed on the exchange complex the aquifer material (meq/gm), *
C = total concentration of native cations in the ground water at equilibrium (meq/ml),
E = equilibrium exchange constant for exchange process for radionuclide cation displacing native cations on the exchange complex,
D'_x = reduced dispersion coefficient in the x direction: = $D_x R'_f$ (Reference 23)
D'_x = reduced dispersion coefficient in the y direction = $D_y R'_f$

where,
D_x is the dispersion coefficient in the x direction, and
D_y is the dispersion coefficient in the y direction
= D_z.

Equation #1 was then integrated over the volume of the prismatic slug of finite volume. The right hand side of Equation #1 was integrated with respect to x, y, and z, over the limits $x-x_o/2$ to $x+x_o/2$, $y-y_o/2$ to $y+y_o/2$ and $z-z_o/2$ to $z+z_o/2$, respectively. Here x_o, y_o, and zo are the dimensions of the slug in the soil in the respective axes at time zero, and x, y, and z are measured from the center of the prismatic volume of soil occupied by the slug. The resulting expression for the general case where Dy /= Dz is given as Equation # 2:

(#2):

$$c_i = \frac{m}{8nx_0y_0z_0}\left\{\operatorname{erf}\left(\frac{x+x_0/2-U'_xt}{\sqrt{4D'_xt}}\right)-\operatorname{erf}\left(\frac{x-x_0/2-U'_xt}{\sqrt{4D'_xt}}\right)\right\}$$
$$X\left\{\operatorname{erf}\left(\frac{y+y_0/2}{\sqrt{4D'_yt}}\right)-\operatorname{erf}\left(\frac{y-y_0/2}{\sqrt{4D'_yt}}\right)\right\}$$
$$X\left\{\operatorname{erf}\left(\frac{z+z_0/2}{\sqrt{4D'_zt}}\right)-\operatorname{erf}\left(\frac{z-z_0/2}{\sqrt{4D'_zt}}\right)\right\}\{\exp(-\lambda_i t)\}$$

This equation holds for the case of a slug introduced instantaneously into a saturated porous medium, where the slug has a finite volume at t = 0. The inclusion of the factor, exp (-λιt), means that radionuclide decay is accounted for in the calculated concentration (c).

Two (2) certified computer programs, which solve Equation # 2, were used in the analysis - ATIME5 and SLUG3D. ATIME5 provides a sensitivity analysis for each parameter in the range of the parameters applicable for a given site. SLUG3D, in this case, was used to calculate the values of concentration at the particular points of interest over the range of time during which peak occurs.

2.4.13.3.3 Selection of Parameters

1. Horizontal Hydraulic Conductivity (K_h)

   The highest horizontal hydraulic conductivity applicable to the highly weathered to moderately weathered bedrock at the level where the waste holding tank lies is 6.0 ft/day. This value was derived by analysis of the results of packer tests performed in the bedrock and saprolite at the site, described in Section 2.5.6, and was obtained in a narrow zone of atypically higher permeability.

2. Distance to Discharge Points (x)

   As discussed in Section 2.4.13.3.1, the distances to the estimated discharge points A and B are:

   Flow Path A (WSW) - 3,070 feet
   Flow Path B (SSE) - 3,680

3. Ground water Gradient (i)

   For flow path A the elevation of the estimated discharge point is 310.0' and that for flow path B is 330.0'. Assuming a ground water elevation of 420.0' at the tank, the resulting overall hydraulic gradients are:

   Flow Path A - 0.036;
   Flow Path B - 0.025.

4. Porosity (n)

   The sensitivity analysis showed that for the conditions at the site, lower porosities result in greater contaminant concentrations at the points of interest. Thus, for conservatism, the lowest porosity determined for the pertinent geologic materials must be selected. Porosity can be estimated from bulk dry density (P_B) by:

   $n = 1 \quad P_B/P_S$,

   where P_S is the particle density, estimated to be 2.65 gm/ml. To obtain the lowest porosity, the value of P_B representing the highest dry density must be used. The highest value for P_B in the lower saprolite was 117 lbs/ft^3, or 1.88 gm/ml, as reported in the PSAR. The resulting value for n is 0.29.

5. Seepage Velocity (U_x)

The seepage velocity is determined by a modification of Darcy's Equation:

$U_x = K_h\, i/n$

The resulting values for the 2 flow paths are:

Flow Path	U_x (ft^2/day)
A	0.74
B	0.52

6. Dispersion Coefficients

The sensitivity analysis indicates a smaller dispersion coefficient results in a larger concentration. Relatively small values for Dx (longitudinal dispersion coefficient) can be estimated using empirical equations derived from laboratory studies using columns of glass beads or sand (Reference 24), (Reference 25). One such equation is provided by Fried and Combarnous (Reference 24).

$$D_x = D_0\left[0.67 + 0.5\left(\frac{U_x d_{50}}{D_0}\right)^{1.2}\right]$$

where d_{50} is the mean particle size and D_0 is the molecular diffusion coefficient in bulk water. Do is approximately equal to 9.7×10^{-4} ft^2/day, and d_{50} is estimated to be 0.10 cm (.0033 ft.) for the geologic materials near the waste holdup tank. The resulting values are:

Flow Path	D_x (ft^2/day)
A	2.1×10^{-3}
B	1.6×10^{-3}

However, field studies indicate that actual field values of the dispersion coefficients may be increased by 2 orders of magnitude greater than those obtained from laboratory experiments (Reference 26), (Reference 27). Biggar and Nielsen (Reference 26) found that for field surficial soils the longitudinal dispersion coefficient is given by:

$D_x = 0.6 + 2.93\, U_x^{1.11}$, where

U_x is in cm/day, and D_x is in cm^2/day. The resulting values for this accident analysis would be:

Flow Path	D_x (ft^2/day)
A	0.10
B	0.067

In an effort to strike a compromise between low values for longitudinal dispersion coefficients required for conservatism, and high values which appear to hold in the field, the results of laboratory experiments reported by Klotz and Moser are used (Reference 28). Their studies indicate that longitudinal dispersion coefficients generally fall between the 2 extremes. For the seepage velocities indicated above, a uniformity coefficient of 12.5 and a d_{50} of 0.10 cm., extrapolation in Figure 10 by Klotz and Moser (Reference 28) yields:

Flow Path	D_x (ft^2/day)
A	0.033
B	0.022

These are the values adopted for this analysis.

Lateral Dispersion coefficients (D_y) are estimated from data by Lenda and Zuber, Figure 7 (curve No. 5) (Reference 29). The results are:

Flow Path	D_y/D_x	D_x (ft^2/day)
A	0.47	0.015
B	0.52	0.012

Other references (such as Harleman and Rumer (Reference 30) give higher D_y/Dx ratios (approaching 1.0) for seepage velocities of the magnitude involved in this study, but the values from Lenda and Zuber (Reference 29) are used for conservatism.

The lateral dispersion coefficients in the vertical direction (D_z) were assumed to be very low because of the proximity of bedrock to the tank. A value of $D_z = 1.08 \times 10^{-7}$ ft^2/day (1.00×10^{-4} cm^2/day) was assumed for both flow paths.

7. Cation Exchange Capacity (Q)

The logs of borings in the immediate area do not indicate the presence of any significant clay content in the decomposed rock at the location of the waste holdup tank and downgradient. It is, therefore, conservatively assumed that the material has essentially no cation exchange capacity.

8. Concentration of Native Cations in Ground Water (C)

   Because Q = 0, the concentration of native cations in the ground water has no effect, and can be set arbitrarily to 1.0.

9. Equilibrium Exchange Constant (E)

   Because Q = 0, there is no equilibrium exchange constant for any of the radionuclides involved.

10. Size and Dimensions of Slug

    The sensitivity analysis indicates that the concentration at the points of interest increases as the slug approaches the dimensions of a cube. Thus,

    $[(10{,}000 \text{ gallons}/7.481 \text{ gal/ft}^3)/0.29]^{1/3} = 16.64$ ft.

    and, $x_0 = y_0 = z_0 = 16.64$ feet.

11. Radionuclides

    Four of the radionuclides present in the waste holding tank are of special interest from the point of view of public health based on their long half lives and concentration, and were studied in the analysis. Table 2.4-11 lists each of the four radionuclides, their respective half lives, and their assumed quantities in the tank.

2.4.13.3.4 Computational Results

The SLUG3D computer code was executed using the above parameters and an isotopic source based on reactor coolant activities with an assumed failed fuel fraction of 1%. Resulting peak concentrations were adjusted to be consistent with an isotopic source based on reactor coolant activities with an assumed failed fuel fraction of 0.12% consistent with NUREG-0017 (Reference 33) and are presented in Table 2.4-12. Comparing the concentrations at the discharge points in Table 2.4-12 with the 10CFR20 Effluent Concentration Limits (ECL) from 10CFR20, Appendix B, it is seen that the dominant isotope is Cs^{137}. It is demonstrated in Section 2.4.12.2 that the CS137 concentration is reduced to well below the ECL value for unrestricted areas due to dilution provided by the local ground water aquifer and flow in the Broad River.

2.4.13.4 Monitoring and Safeguards Requirements

Seven observation wells will be installed at the site, located to define the ground water flow regime during and subsequent to the impoundment of Monticello Reservoir. The observation wells will provide data on water levels, water table gradient, and direction of flow. Generally, the observation wells will consist of perforated PVC plastic pipe placed in open borings 50 to 80 feet deep. The depth of individual wells will depend on the depth of the fresh rock/saprolite interface. Water levels in the observation wells will be measured quarterly during filling of the reservoir and

for a year after the reservoir is filled. The observation wells will be utilized to provide samples for analysis of the ground water in the event of inadvertent spillage.

2.4.13.5 Design Bases for Subsurface Hydrostatic Loading

Upon completion of the filling of Monticello Reservoir, the ground water level elevations are expected to increase. It is conservatively estimated that the ground water at the principal plant structures ultimately will rise to a maximum approaching elevation 420.0'. During normal operations of the Fairfield Pumped Storage Facility, the Monticello Reservoir water level will fluctuate from elevation 420.5' to 425.0'. These safety related structures are designed to withstand the ground water induced hydrostatic forces, based on a ground water level of elevation 420.0'.

Ground water did not constitute a major problem during construction and dewatering was not critical to the integrity of the safety related plant structures (Section 2.5.4.6). A permanent, non-safety dewatering system has subsequently been installed to address nuisance water intrusion into plant buildings (Section 2.4.13.2.7).

2.4.14 Technical Specification and Emergency Operation Requirements

Safety related facilities constructed at the plant grade elevation of 435.0' are protected as described in Section 2.4.10. Therefore, emergency protective measures and appropriate technical specifications are not required.

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2.4.17 Persons and Agencies Interviewed

Mr. J. S. Brown, Well Driller, Chester, South Carolina. *

Mr. James Duke, South Carolina Water Resources Commission, Columbia, South Carolina.

Mr. E. L. Frick, Well Driller, Lexington, South Carolina. *

Mr. David Garrick, South Carolina Department of Labor, Columbia, South Carolina. *

Professor Humphries, Department of Civil Engineering, University of South Carolina, Columbia, South Carolina.

Mr. Johnson, U. S. Geological Survey, Water Resources Division, Columbia, South Carolina.

Mr. O. Z. Kinard, Well Driller, Pomaria, South Carolina.

Mr. Lawrence Lagman, South Carolina Water Resources Commission, Columbia, South Carolina.

* Phone conversation.

Dr. A. Law, Clemson University, Clemson, South Carolina. *

Mrs. Neda Pearson, Jenkinsville Water Company, Jenkinsville, South Carolina.

Mr. Lewis Shaw, South Carolina Department of Health & Environmental Control, Columbia, South Carolina.

Mr. George E. Siple, Staff Hydrologist, U. S. Geological Survey, Water Resources Division, Room 501, Federal Court House, Columbia, South Carolina.

Mr. John S. Stallings, District Chief, U. S. Geological Survey, Water Resources Division, Columbia, South Carolina.

Mr. W. B. Waldrop, Well Driller, White Rock, South Carolina. *

Mr. John Woods, Williams Engineering, Rock Hill, South Carolina. *

* Phone conversation.

Table 2.4-1
Reservoirs Located in the Broad River Basin

Plant Name Owner	Lake Lure Town of Lake Lure	Tuxedo Duke Power Co.	Turner Duke Power Co.	Cliffside Cone Mill Corp.	Shelby Lily Mills Co.	Gaston Shoals Duke Power Co.
River	Broad[1]	Green	Green	Second Broad	First Broad	Broad[1]
River Mile	161	42	23	2	4	110
Drainage Area, sq. mi.	95	42	126	211	285	1,250
Mean flow, cfs.	170	90	280	295	380	2,030
Spillway design, cfs.	-	6,300	34,000	-	-	-
Elevations, feet, msl						
Top of dam	-	2,020.8	922.6	-	-	613.4
Max. water surface	-	2,017.4	918.6	-	-	614.2
Top of gates	991	-	-	702	660	605.4
Crest of Spillway	-	2,012.6	911.6	698	658	599.4
Max. power pool	991	2,012.6	911.6	702	660	605.4
Min. power pool	975	2,005.6	908.6	698	660	600.4
Normal tailwater	887	1,717.1	825.9	672	635	558.6
Min. tailwater	883	1,715.3	822.8	672	635	553.4
Reservoir						
Max. power pool, acre-ft	-	10,204	11,927	-	-	-
Min. power pool, acre-ft	-	8.069	10,657	-	-	-
Usable for power, acre-ft	13,500	2,136	1,270	Pondage	-	1,150
Max. area, acres	900	324	438	-	-	251
Heads, feet						

Table 2.4-1 (continued)
Reservoirs Located in the Broad River Basin

Plant Name Owner	Lake Lure Town of Lake Lure	Tuxedo Duke Power Co.	Turner Duke Power Co.	Cliffside Cone Mill Corp.	Shelby Lily Mills Co.	Gaston Shoals Duke Power Co.
Gross static	108	297.3	88.8	30	25	52.0
Net effective	100	285.5	83.2	28	25	46.5
Min. net	84	278.5	80.2	26	25	41.5
Power Plant						
Installed capacity, kw	3,600	5,000	5,500	1,625	600	9,140
Auxiliary capacity, kw	0	0	0	0	0	125
Min. head capacity, kw	3,000	5,900	5,600	1,300	600	7,200
Avg. ann. generation, mwh	10,000	21,300	14,600	2,900	1,800	30,100
Construction date	1927	1920	1925	1933	1900	1908

(1) River mileage in the Broad River is measured upstream from its point of confluence with the Saluda River.

Table 2.4-1 (continued)
Reservoirs Located in the Broad River Basin

Plant Name Owner	Cherokee Falls Burlington Industries	99 Islands Duke Power Co.	Spartanburg Comm. of Pub. Wks.	Clifton No. 3 Dan River Mills	Clifton No.1 Dan River Mills	Clifton No. 2 Dan River Mills
River	Broad[(1)]	Broad[(1)]	South Pacolet	Pacolet	Pacolet	Pacolet
River Mile	102	91	2	33	32	31
Drainage Area, sq. mi.	1,500	1,500	93	318	319	320
Mean flow, cfs.	2,350	2,400	150	440	440	440
Spillway design, cfs.	-	-	-	-	-	-
Elevations, feet, msl						
Top of dam	-	523.6	-	-	-	-
Max. water surface	-	524.6	-	-	-	-
Top of gates	543	511.1	778	626	-	575
Crest of Spillway	539	509.1	773	621	597	572
Max. power pool	543	511.1	778	625	597	575
Min. power pool	541	506.1	761	620	592	571
Normal tailwater	524	442.9	722	598	576	558
Min. tailwater	523	437.4	720	597	575	557
Reservoir						
Max. power pool, acre-ft	-	-	4,462	-	-	-
Min. power pool, acre-ft	-	-	1,074	-	-	-
Usable for power, acre-ft	Pondage	4,127	Pondage	Pondage	Pondage	Pondage
Max. area, acres	-	885	1,914	-	-	-

Table 2.4-1 (continued)
Reservoirs Located in the Broad River Basin

Plant Name Owner	Cherokee Falls Burlington Industries	99 Islands Duke Power Co.	Spartanburg Comm. of Pub. Wks.	Clifton No. 3 Dan River Mills	Clifton No.1 Dan River Mills	Clifton No. 2 Dan River Mills
Heads, feet						
Gross static	20	73.7	58	28	22	18
Net effective	19	67.9	56	27	21	17
Min. net	17	62.9	39	22	16	13
Power Plant						
Installed capacity, kw	1,1750	18,000	1,000	1,100	800	532
Auxiliary capacity, kw	0	250	0	0	0	0
Min. head capacity, kw	-	16,300	1,000	1,000	500	500
Avg. ann. generation, mwh	5,000	65,600	4,000	2,800	3,000	2,100
Construction date	1955	1910	1925	1903	1929	1888

(1) River mileage in the Broad River is measured upstream from its point of confluence with the Saluda River.

Table 2.4-1 (continued)
Reservoirs Located in the Broad River Basin

Plant Name Owner	Pacolet Pacolet Mfg. Co.	Lockhart Lockhart Power Co.	Neal Shoals SCE&G Co.	Print Crash Startex Mills	Parr[2] SCE&G Co.	Columbia SCE&G Co.
River	Pacolet	Broad[1]	Broad[1]	Middle Tyger	Broad[1]	Broad[1]
River Mile	23	72	60	10	28	2
Drainage Area, sq. mi.	460	2,600	2,730	72	4,750	5,230
Mean flow, cfs.	620	3,640	3,800	95	5,600	6,300
Spillway design, cfs.	-	-	-	-	-	-
Elevations, feet, msl						
Top of dam	-	410	340.8	-	272.2	171.0
Max. water surface	-	-	-	-	-	-
Top of gates	524	-	334.1	755	-	-
Crest of Spillway	521	400	330.8	753	257.2	153.8
Max. power pool	524	396	334	755	266.0	153.8
Min. power pool	518	390	331	749	256.0	148.8
Normal tailwater	498	344	310	701	223.0	119.3
Min. tailwater	497	343	308	701	223.0	118
Reservoir						
Max. power pool, acre-ft	-	-	-	-	-	-
Min. power pool, acre-ft	-	-	-	-	-	-
Usable for power, acre-ft	Pondage	Pondage	Pondage	Pondage	Pondage	Pondage
Max. area, acres	-	300	600	-	2,925	265

Table 2.4-1 (continued)
Reservoirs Located in the Broad River Basin

Plant Name Owner	Pacolet Pacolet Mfg. Co.	Lockhart Lockhart Power Co.	Neal Shoals SCE&G Co.	Print Crash Startex Mills	Parr[2] SCE&G Co.	Columbia SCE&G Co.
Heads, feet						
Gross static	27	53	26	54	35.0	36.0
Net effective	26	52	24	54	33.0	32.0
Min. net	20	46	21	48	31.0	27.0
Power Plant						
Installed capacity, kw	800	12,300	5,200	1,200	14,880	10,600
Auxiliary capacity, kw	0	0	0	0	0	0
Min. head capacity, kw	600	13,000	0	1,000	13,000	7,000
Avg. ann. generation, mwh	2,700	70,000	30,000	2,300	75,000	50,500
Construction date	1937	1920	1905	1895	1914	1928

(1) River mileage in the Broad River is measured upstream from its point of confluence with the Saluda River.
(2) Prior to installation of the spillway crest gates

Table 2.4-1(Continued)
Reservoirs Located in the Broad River Basin

Plant Name Owner	Green River EPIC, Inc.	
River	Pulliam Cr. (Upper)	Green River (Lower)
River Mile	-	
Drainage Area, sq. mi.	105 (2.0 upper reservoir + 103.0 lower reservoir)	
Mean flow, cfs.		
Spillway design, cfs.	70,000	
Elevations, feet, msl		
Top of dam	2130 upper	1160 lower
Max. water surface	2120 upper	1134 lower
Top of gates		1150 lower
Crest of Spillway	2120 upper	
Max. power pool	2120 upper	1134 lower
Min. power pool	1950 upper	1100 lower
Normal tailwater	-	
Min. tailwater	-	
Reservoir (upper)		
Max. power pool, acre-ft	43,500 upper	83,000 lower

Table 2.4-1(Continued)
Reservoirs Located in the Broad River Basin

Plant Name Owner	Green River EPIC, Inc.	
Min. power pool, acre-ft	3,500 upper	43,000 lower
Usable for power, acre-ft	40,000 upper	40,000 lower
Max. area, acres	467 upper	934 lower
Heads, feet		
Maximum net head	990	
Normal net head	920	
Power Plant		
Installed capacity, kw	2,000,000 (ultimate)	
Auxiliary capacity, kw	-	
Min. head capacity, kw	-	
Avg.ann. generation, mwh	-	
Construction date	-	

Table 2.4-2
Significant Downstream Surface Water Users

	Water User	Location	Average Daily Use (MGD)	Source of Supply
1.	City of Columbia, S. C.	Richland County, S. C.	23.0	Broad River
2.	Carolina Eastman Co.	Calhoun County, S. C.	15.8	Congaree River
3.	Georgia Pacific	Berkeley County, S. C.	0.1	Lake Moultrie
4.	Santee Wool Combing Co.	Berkeley County, S. C.	0.366	Santee River
5.	City of Charleston, S. C.	Berkeley County, S. C.	1.5	Back River Reservoir
6.	Verona Div. Baychem Corp.	Berkeley County, S. C.	(1)	Back River Reservoir
7.	The Dupoint Co.	Berkeley County, S. C.	(1)	Back River Reservoir
8.	S. C. Electric & Gas Co.	Berkeley County, S. C.	(1)	Back River Reservoir
9.	Amoco (Future Plant)	Berkeley County, S. C.	(1)	Back River Reservoir
10.	Unknown User	Georgetown County, S. C.	(1)	N. Santee River

(1) Note: Average daily use not specified for new, future, and unknown users.

Table 2.4-3
Major Historical Floods and Average Flow on the Broad River

	Observed at Richtex Gaging Station		Estimated at Parr Dam	
Date	Peak Discharge (cfs)	Water Elevation (Feet, msl)	Peak Discharge (cfs)	Water Elevation (Feet, msl)
October 3, 1929	228,000	215.54	214,000	266.0
August 17, 1928	222,000	214.94	208,000	265.8
April 8, 1936	157,000	209.80	147,000	264.0
August 16, 1940	120,000	205.92	113,000	262.9
October 18, 1964	102,000	204.09	96,000	262.3
Average Flow	6,000	185.20	5,600	257.8

Table 2.4-4
Probable Maximum Precipitation (Inches)

	Time in Hours				
Source	6	12	24	48	72
HMR No. 33	11.3	14.3	15.9	19.4	
CEB No. 52-8	11.2(1)	13.6(1)	16.0(1)	19.8(1)	21.4(1)
1.4 x 1916 Storm	5.5	10.3	15.2	18.8	19.3

1 These values are twice those contained in this source.

Table 2.4-5
Distribution Sequence for 6 Hour Point Probable
Maximum Precipitation

Hour	Percent	Amount (Inches)
1	10	3.03
2	12	3.64
3	15	4.55
4	38	11.51
5	14	4.24
6	11	3.33
	Total	30.30 Inches

Table 2.4-6
Dams on the Broad River Between Clinchfield
And Parr Dam

Name of Dam	Approximate Stream Distance Upstream of Site (Miles)	Maximum Length (Feet)	Maximum Height (Feet)	Peak Discharge at Failure Plane (cfs)
Gaston Shoals	80	1542	60	1,204,000
Cherokee Falls	70	1500(1)	20	225,000
99 Islands	60	1567	94	2,399,000
Lockhart	40	1035	25	217,000
Neal Shoals	30	1087	33(2)	346,000

(1) Assumed Value
(2) Distance from top of dam to minimum tailwater.

Table 2.4-7
Reported Municipal, Industrial, and Domestic Wells
Within 2-20 Miles of Site*

Well Location	Owner	Source Description	Average Yield (MGD)	Remarks
#1	City of Carlisle	3 wells		
#2	Big Boy Truck Stop	1 well		
#3	Rocky Creek Point	1 well	0.004	
#4	City of Ridgeway	3 wells	0.080	
#5	City of Jenkinsville	3 wells	0.100	
#6	Mid County Water District 2	2 wells	0.002	
#7	Nylene Corp.	4 wells	0.072	
#8	Arrowood S/D **	2 wells	0.016	
#9	Royal Hills S/D **	2 wells	0.040	
#10	McCrorey Liston	2 wells		
#11	Richard Winn Acad.	1 well		
#12	Greenbrier	1 well		
#13	Kelly Miller	1 well		
#14	J. H. Kennedys Store	1 well		
#15	Willinghams	1 well		
#16	Triangle Restaurant	1 well		
#17	Genes Cafe Groc.	1 well		
#18	City of Chapin	3 wells	0.022	
#19	Woodlake Shores	1 well	0.004	
#20	Lakewood Estate	1 well		
#21	Lakeland Shores	2 wells	0.008	
#22	Blackgate Band	1 well	0.004	

* Information presented was obtained by interview with the persons and agencies listed in Section 2.4.17.
** S/D - Subdivision

Table 2.4-7 (continued)
Reported Municipal, Industrial, and Domestic Wells
Within 2-20 Miles of Site*

Well Location	Owner	Source Description	Average Yield (MGD)	Remarks
#23	Murry Lodge Estate	2 wells	0.003	
#24	Stephenson Lake	2 wells		
#25	Indian Cove	2 wells	0.001	
#26	Dutchman Shores	3 wells	0.001	
#27	Milmont Shores	2 wells	0.002	
#28	Vanarsdale S/D**	2 wells	0.004	
#29	Lesene Woods	1 well		
#30	Hallmark Shores	2 wells	0.014	
#31	Arrowhead Shore	2 wells	0.015	
#32	Laurel Meadows	2 wells	0.004	
#33	Selwood Shores	1 well		
#34	Tri City Trailer Pk.	1 well	0.002	
#35	Hoods Trailer Pk.	1 well		
#36	Irmo Trailer Pk.	1 well	0.001	
#37	Wates Trailer Pk.	2 wells		
#38	Hendrix Trailer Pk.	1 well	0.002	
#39	Taylor Landing	2 wells		
#40	Taylors Landing	1 well		
#41	Jakes Boat Landing	2 wells	0.075	
#42	Lake Murray TP	2 wells		
#43	Lindlers Trailer Pk.	1 well		
#44	Moore Mob. Ho. Pk.	1 well	0.011	
#45	Weeds Mob. Ho. Pk.	1 well		

* Information presented was obtained by interview with the persons and agencies listed in Section 2.4.17.
** S/D - Subdivision RN

Table 2.4-7 (continued)
Reported Municipal, Industrial, and Domestic Wells
Within 2-20 Miles of Site*

Well Location	Owner	Source Description	Average Yield (MGD)	Remarks
#46	Rikard Nursing	3 wells		
#47	Utopia School	1 well		
#48	Watergate Conds.	1 well	0.064	
#49	Cemitha Court	2 wells	0.029	
#50	Dutchman Cove	1 well		
#51	Cold Stream Country Club	2 wells		
#52	Prosperity, S. C.	well field	0.270	
#53	Little Mountain, S. C.	2 wells		
#54	Old School Mfg.	1 well	0.005	
#55	Kendall Co. Oakl.	1 well	0.080	
#56	Hollands Landing	2 wells		
#57	Shealy Trailer Pk.	2 wells	0.001	
#58	Brigmans	1 well		
#59	White Mob. Homes	2 wells	0.022	
#60	Koon Trailer Pk.	1 well		
#61	Bill Werts Trailer Pk.	1 well	0.001	
#62	Gateway TP	3 wells		
#63	Buddy Neel Pk.	2 wells		
#64	Bedenbough TP	1 well		
#65	Rikard Elem. School	1 well		
#66	Pomaria Elem.	1 well		
#67	Garmany School	1 well		
#68	Mid Carolina High	1 well		
#69	Boys Farm, Inc.	1 well		

Table 2.4-7 (continued)
Reported Municipal, Industrial, and Domestic Wells
Within 2-20 Miles of Site*

Well Location	Owner	Source Description	Average Yield (MGD)	Remarks
#70	Summer Dr. Inn	1 well		
#71	Hilltop Dr. Inn	1 well		
#72	Bonners Snack Shop	1 well		
#73	Dowd Truck Stop	1 well		
#74	Newberry Inn	1 well		
#75	Sunset Dr. Inn	1 well		
#76	Hailes Truck Stop	1 well		
#77	Mill Dera Apts.	1 well		
#78	Whitakers Lodge	2 wells		
#79	Mollys Rock Rec.	1 well		
#80	Hollands 66 Marina	1 well		
#81	Holiday Acres	1 well		
#82	Dutch Village	4 wells		
#83	Ballentine Est.	1 well	0.008	
#84	Lincolnshire	8 wells	0.629	
#85	Crane Forest	4 wells	0.015	
#86	Raintree Acres	2 wells		
#87	Tiffany Gardens	2 wells		
#88	Lowman Home	6 wells		
#89	Blythewood School	2 wells		
#90	Bethel	1 well		
#91	Wells Marina	2 wells	0.002	
#92	Jones Steak House	1 well		
#93	Whales Tail	1 well		
#94	Jacks Tourist Court	1 well		

Table 2.4-7 (continued)
Reported Municipal, Industrial, and Domestic Wells
Within 2-20 Miles of Site*

Well Location	Owner	Source Description	Average Yield (MGD)	Remarks
#95	South Carolina Electric & Gas	1 well	0.019	Well 62' deep; 4" diameter Monitored by S. C. Div. of Radiological Health
#96	South Carolina Electric & Gas	1 well	0.043	Well 120' deep 6" diameter
#97	Winnsboro Granite Co.	1 well		Supplies 2 homes
#98	Winnsboro Granite Co.	1 well		Supplies finishing plant
#99	Winnsboro Granite Co.	1 well		Supplies 5 homes
#100	Rion Crushed Stone (Martin Marietta)	1 well		Well 100' deep 6" diameter Cased 20'

Table 2.4-8
Wells and Springs Within 2 Miles of Site

Well No.	Name of Owner	Well Depth (Ft.)	Water Level (Ft.) Depth	Water Level (Ft.) Elevation	Casing Depth (Ft.)	Pump Type/Yield (GPM)	Remarks
1	Bernice Brown	-	-	-	-	-	Well
2	John Henry Ginyard	-	-	-	-	-	Well
3	Clara Spencer	-	-	-	-	-	Well
4	Alex Harper III	-	-	-	-	-	Well for 2 houses
5	R. E. Harper, Sr.	141	69	-	40	Jet/6	Well *+
6	Wilbert Gladney	-	-	-	-	-	Well
7	John Henry Stevenson	-	-	-	-	-	Well
8	Bubba Crompton	-	-	-	-	-	Well
9	Ellie Harper	-	-	-	-	-	Well
10	Mae Francie Burns	-	-	-	-	-	Well
11	Mary White	-	-	-	-	-	Well
12	Olin Summers	-	-	-	-	Submersible	Well
13	Andrew Wilson	-	-	-	-	-	Well for 2 houses
14	Mae Richards	-	-	-	-	-	Well
15	Henry Mills	-	-	-	-	-	Well
16	Henry Johnson	185	30	-	-	Jet	Well for store & 4 house trailers

Table 2.4-8 (continued)
Wells and Springs Within 2 Miles of Site

Well No.	Name of Owner	Well Depth (Ft.)	Water Level (Ft.) Depth	Water Level (Ft.) Elevation	Casing Depth (Ft.)	Pump Type/Yield (GPM)	Remarks
17	Eddie Thompson	185	40	398	-	Submersible	Well*
18	Nathan Harper	168	90	-	88	Jet/7	Well for 1 house & 1 trailer *
19	Eddie Martin	207	-	-	-	Jet	Well
20	James Thompson	300+	-	-	-	Jet	Well
21	Carrie Lee Martin	-	-	-	-	-	Well for 1 house & 1 trailer
22	Clement Brothers Cons.(1)	-	-	-	-	Submersible	Well
23	Jenkinsville Water Co. Well No. 3	365	60	-	56	Submersible/ 50	Well 6" diameter
24	W. Martin	115	-	-	-	Jet	Well*
25	B. T. Martin	104	89	-	80+	Jet/3	Well for 2 homes *
26	B. T. Martin	65	-	-	-	Jet	Well for store
27	Siles Eubanks	75	-	-	-	-	Well for 3 houses
28	Whitehall Church	-	-	-	-	-	Well*
29	Robert Martin	235	47	399	-	Jet	Well for 2 houses

(1) Use to be terminated upon operation of the plant.

Table 2.4-8 (continued)
Wells and Springs Within 2 Miles of Site

Well No.	Name of Owner	Well Depth (Ft.)	Water Level (Ft.) Depth	Water Level (Ft.) Elevation	Casing Depth (Ft.)	Pump Type/Yield (GPM)	Remarks
30	Wendel Martin	-	-	-	-	-	Well for 3 houses*
31	Nathan F. Rabb	-	-	-	-	-	Well for 2 houses*
32	Whitehall School	-	-	-	-	Jet	Well*+
33	M. W. Hollins, Sr.	76	35	-	-	Jet	Well
34	Jenkinsville Water Co. Well No. 1	265	60	-	85	Submersible/ 19	Well 6" diameter +
35	Mario Hollins	-	-	-	-	-	Well
36	James Tuck Baten	65	-	-	-	-	Well for store and 1 house
37	Willie Mark Baten	220	-	-	-	Jet	Well for 2 houses+
38	James Edwards	-	-	-	-	Submersible	Well
39	Ruby Martin	-	-	-	-	-	Well
40	Ella B. Martin	-	-	-	-	-	Well for 2 houses +
41	Jenkinsville Water Co. Well No. 2	355	42	-	86	Submersible/ 30	Well 6" diameter +
42	Celese Cook	-	-	-	-	Submersible	Well for store & 1 house+
43	Eilean Baten	65	22	417	-	Jet	Well

Table 2.4-8 (continued)
Wells and Springs Within 2 Miles of Site

Well No.	Name of Owner	Well Depth (Ft.)	Water Level (Ft.) Depth	Water Level (Ft.) Elevation	Casing Depth (Ft.)	Pump Type/Yield (GPM)	Remarks
44	W. G. Heron	120	-	345	-	Jet	Well currently not operating *
45	-	-	-	-	-	-	Spring Currently not used
46	-	-	-	-	-	-	Spring Currently not used
47	C. J. Shealy	-	-	-	-	-	Well+

* Dwellings connected with Jenkinsville Water Co. having operable wells not in use at present.
+ Wells for which S. C. Dept. of Health & Environmental Control, Div. of Radiological Health periodically

Table 2.4-9
Laboratory Permeability Test Data -
Major Plant Structure Area

Soil Description	Boring	Depth (Feet)	Permeability (ft./day)	Permeability (cm/sec)
Micaceous fine sandy silt	N-119	65	4.8×10^{-4}	1.7×10^{-7}
Micaceous silty fine to medium sand	N-22	40	4.0×10^{-2}	1.4×10^{-5}
Micaceous silty fine to medium sand	3-2	40	13.6×10^{-2}	4.8×10^{-5}
Silty fine to medium sand	3-3	60½	17.0×10^{-2}	6.0×10^{-5}
Sandy silty clay	3-5	5½	6.8×10^{-2}	2.4×10^{-5}
Micaceous silty fine to medium sand	3-9	75½	33.5×10^{-2}	11.8×10^{-5}
Micaceous silty fine to medium sand	3-17	30	16.8×10^{-2}	5.9×10^{-5}

Table 2.4-10
Field and Laboratory Permeability Test Data -
Service Water Pond Area

		Field Permeability		Laboratory Permeability		
Horizon	Boring No.	Depth Range of Tests (ft.)	Average Permeability (cm/sec x 10^{-5})	Boring No. and Sample Depth	Consolidation Pressure (tsf)	Average Permeability (cm/sec x 10^{-5})
Colluvium/ Residual Soils	SD-5b	5.0-14.5	0.18	SD- 5 (2')	2.0	1.5
	SD-8b	6.4-16.0	0.48		4.0	0.58
	ED-4	5.5-10.0	1.1	SD- 5 (6')	2.0	0.16
	SS-3	4.0-7.0	0.62	ED- 2 (12')	2.0	0.48
Saprolite	ND-7	8.0-15.0	2.3	ND- 4 (10')	0.0	0.37
	ND-13	4.0-27.0	0.70			
		27.0-30.0	7.6		2.0	4.1
		30.0-33.0	150.0*	ED- 2 (27')	3.9	1.7
	ND-11a	14.0-15.5	29.0**			
		19.0-25.5	6.4			
	ND-20	13.0-24.5	3.7			
	ND-23	9.0-25.0	0.96			
	ND-25	9.0-14.0	0.18			
		14.0-29.0	2.2			
	SD-6	4.2-8.2	0.34			
		14.6-18.0	1.2			
	ED-4	14.6-37.0	3.0			
	SS-3	7.0-37.0	5.9			

Table 2.4-10 (continued)
Field and Laboratory Permeability Test Data -
Service Water Pond Area

		Field Permeability		Laboratory Permeability		
Horizon	Boring No.	Depth Range of Tests (ft.)	Average Permeability (cm/sec x 10^{-5})	Boring No. and Sample Depth	Consolidation Pressure (tsf)	Average Permeability (cm/sec x 10^{-5})
Decomposed Rock	ND-7	15.0-136.0	0.94	ND-4(18')	2.0	0.20
	ND-9	4.0-20.0	0.55	ND-14(7')	2.0	1.2
	ND-9a	20.5-35.0	0.54			
		35.0-45.0	1.80		4.0	0.98
		45.0-70.0	0.46	ND-14 (12')	0.0	0.16
	ND-20	25.0-38.8	0.60			
	ND-22a	4.0-30.0	0.77			
	ND-23	25.0-40.0	1.80			
		40.0-54.0	2.50			
	ND-24	4.0-29.0	0.64			
	SD- 5b	14.5-18.0	0.54			
		18.0-20.8	3.60			
	SD- 6	18.0-38.0	2.50			
	SD- 8b	19.2-25.0	4.10			
	ED- 4	37.0-40.0	1.70			

Table 2.4-10 (continued)
Field and Laboratory Permeability Test Data -
Service Water Pond Area

		Field Permeability		Laboratory Permeability		
Horizon	Boring No.	Depth Range of Tests (ft.)	Average Permeability (cm/sec x 10^{-5})	Boring No. and Sample Depth	Consolidation Pressure (tsf)	Average Permeability (cm/sec x 10^{-5})
Fractured Rock	ND- 13	33.0-34.0	1000.0 (est)			
	ND- 25	29.0-30.0	320.0			
	SD- 5	35.5-44.0	33.0			
	ND- 8	42.0-55.0	25.0			
Intact Rock	ND- 1	21.0-38.5	5.60			
	ND- 11a	40.0-146.5	4.50			
	ND- 21	29.5-146.5	0.60			
	SD- 5	44.0-146.5	4.20			
	SD- 6	38.0-52.0	2.60			
	ED- 4	40.0-48.5	2.40			

*Influenced by fractured rock at 34 fee
** Influenced by very loose alluvium at 13.5 feet
Note: Additional test data are provided in Section 2.5.6.2 and Section 2.5.6.6.

Table 2.4-11
Radionuclides Considered In Accident Analysis

Nuclide	Half Life (days)	Quantity in Tank (μCi)
H^3	4474.9	3.79×10^7
Co^{60}	1934.5	4.54×10^4
Cs^{134}	748.3	5.72×10^5
Cs^{137}	11,092.4	4.09×10^5

Table 2.4-12
Concentrations of Radionuclides at Two Discharge Points Downgradient
of the Waste Holdup Tank Following Postulated Accidental Rupture

	Peak Concentration (μCi/ml)				
	Discharge Point A		Discharge Point B		
Radionuclide	Concentration	Time at Peak (days after rupture)	Concentration	Time at Peak (days after rupture)	Effluent Concentration Limit unrestricted areas * (μCi/ml)
H^3	1.1×10^{-1}	4121	5.7×10^{-2}	7114	1×10^{-3}
Co^{60}	5.8×10^{-5}	4121	1.6×10^{-5}	7113	3×10^{-6}
Cs^{134}	9.1×10^{-5}	4121	4.6×10^{-6}	7113	9×10^{-7}
Cs^{137}	1.7×10^{-3}	4121	1.2×10^{-3}	7114	1×10^{-6}

* Taken from Appendix B of 10CFR20

Figure 2.4-1
DRAWING E-726-403
FSAR FIGURE REFERENCE

Figure 2.4-2

THE BROAD RIVER WATERSHED AT RICHTEX, S.C.
INCLUDING EXISTING AND PROPOSED DAMS

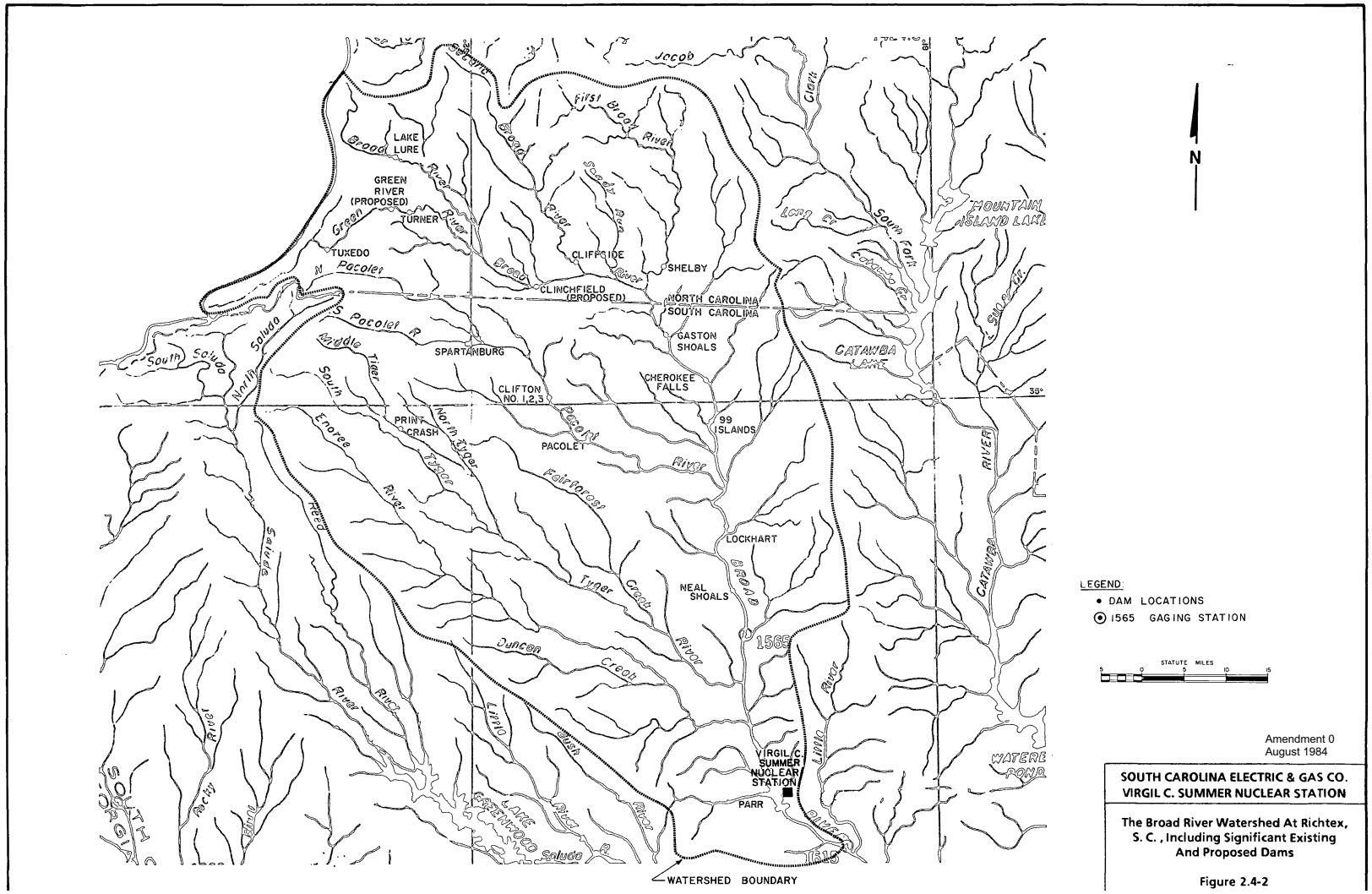


Figure 2.4-3

MAP OF THE SITE VICINITY SHOWING MAJOR HYDROLOGIC FEATURES

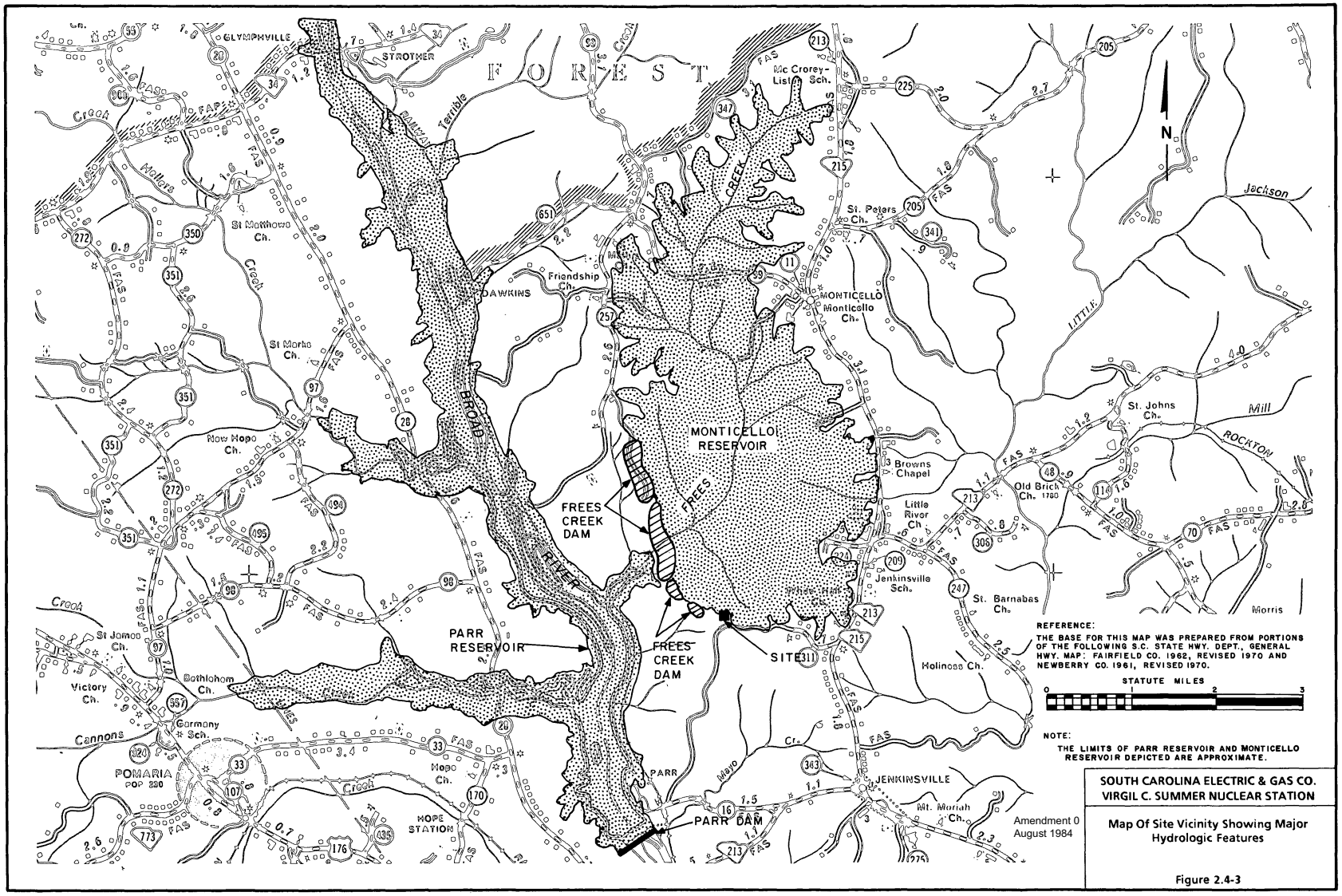


Figure 2.4-4

MONTICELLO RESERVOIR
AREA AND CAPACITY CURVES

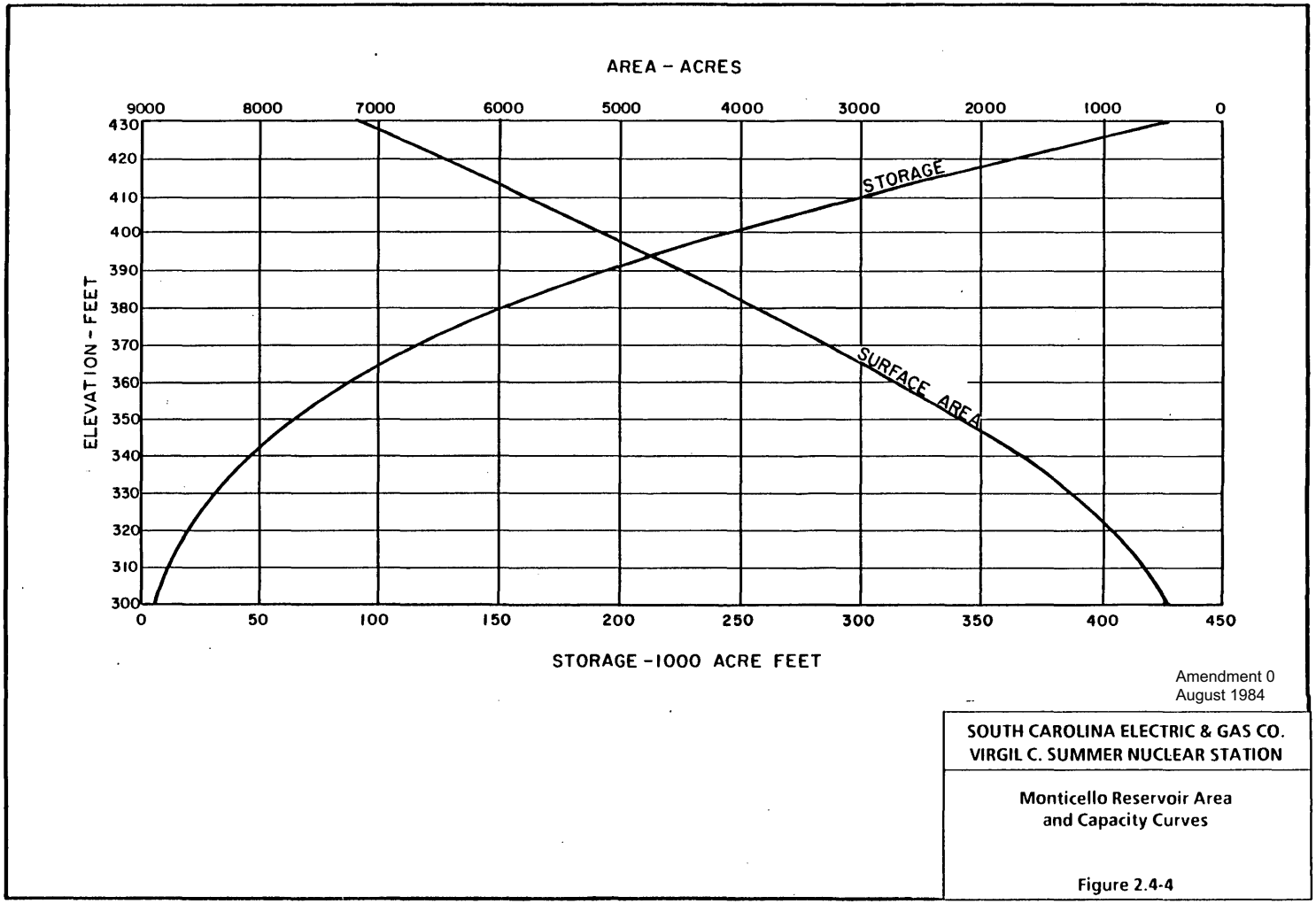


Figure 2.4-5

PARR RESERVOIR AREA AND CAPACITY CURVES

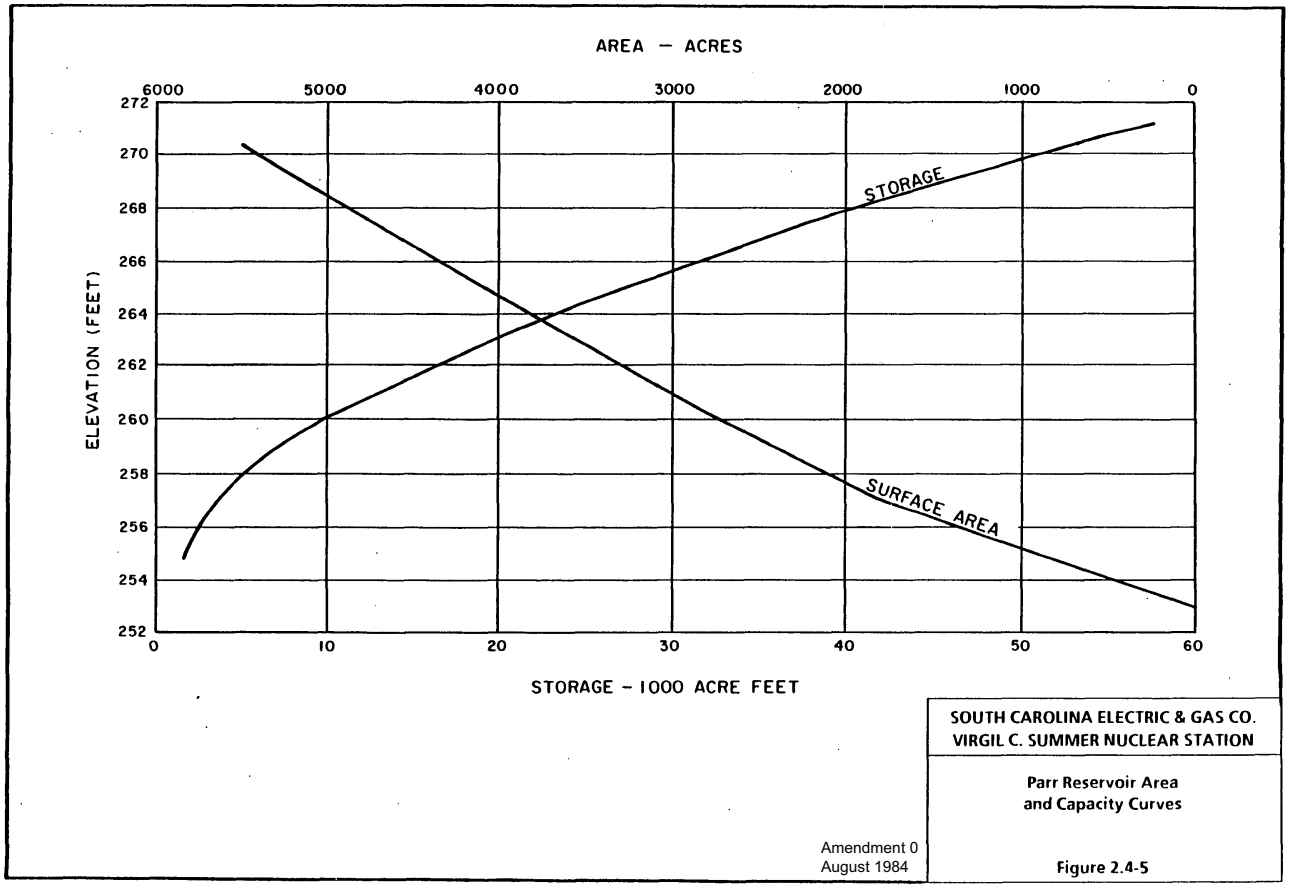
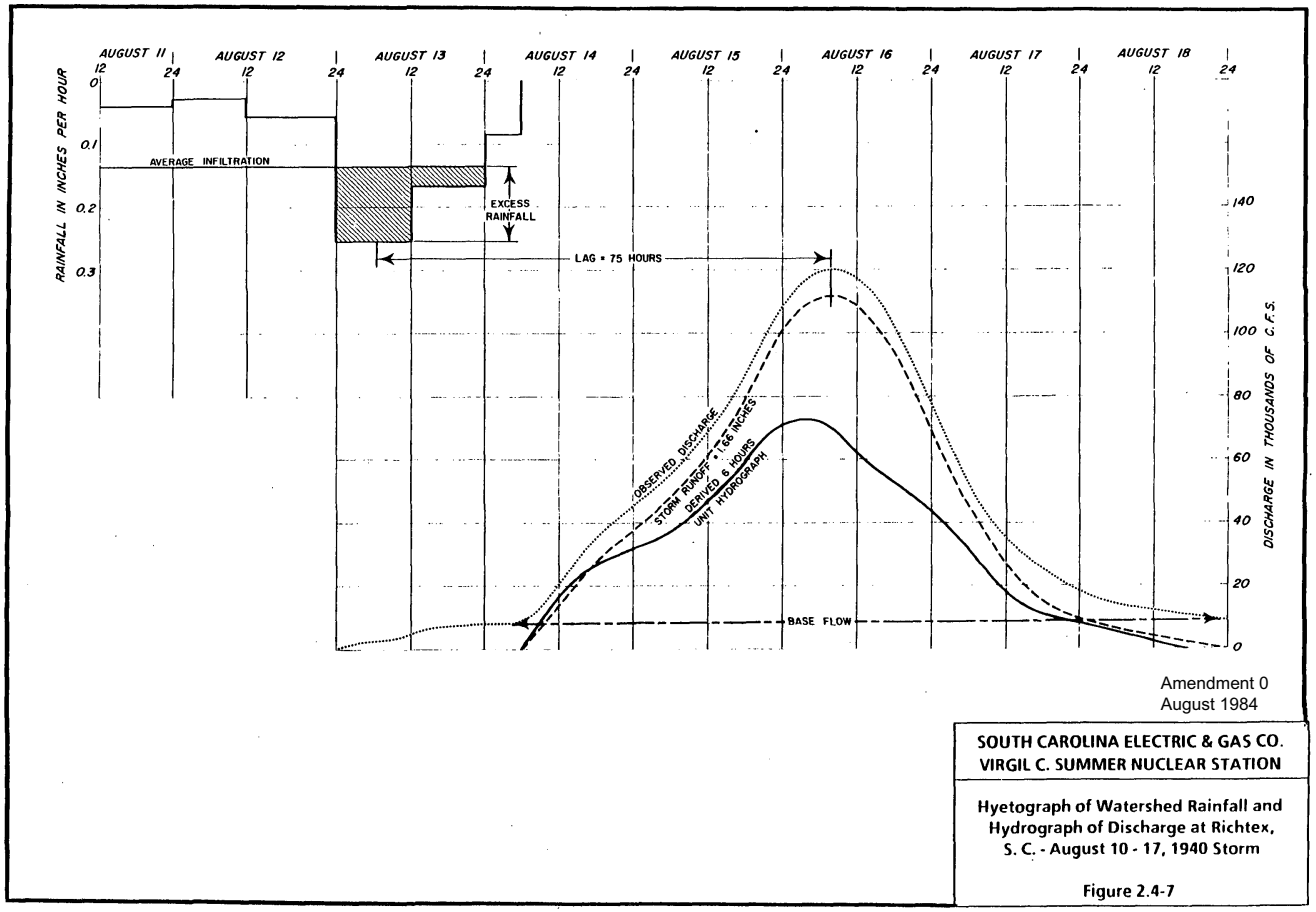


Figure 2.4-6
DRAWING E-744-052
FSAR FIGURE REFERENCE

Figure 2.4-7

HYETOGRAPH OF WATERSHED RAINFALL AND HYDROGRAPH OF DISCHARGE AT RICHTEX, S.C. - AUGUST 10-17, 1940 STORM



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Hyetograph of Watershed Rainfall and Hydrograph of Discharge at Richtex, S. C. - August 10 - 17, 1940 Storm Figure 2.4-7

Figure 2.4-8

HYETOGRAPH OF WATERSHED RAINFALL AND DERIVED PROBABLE MAXIMUM FLOOD HYDROGRAPHS AT PARR, SOUTH CAROLINA

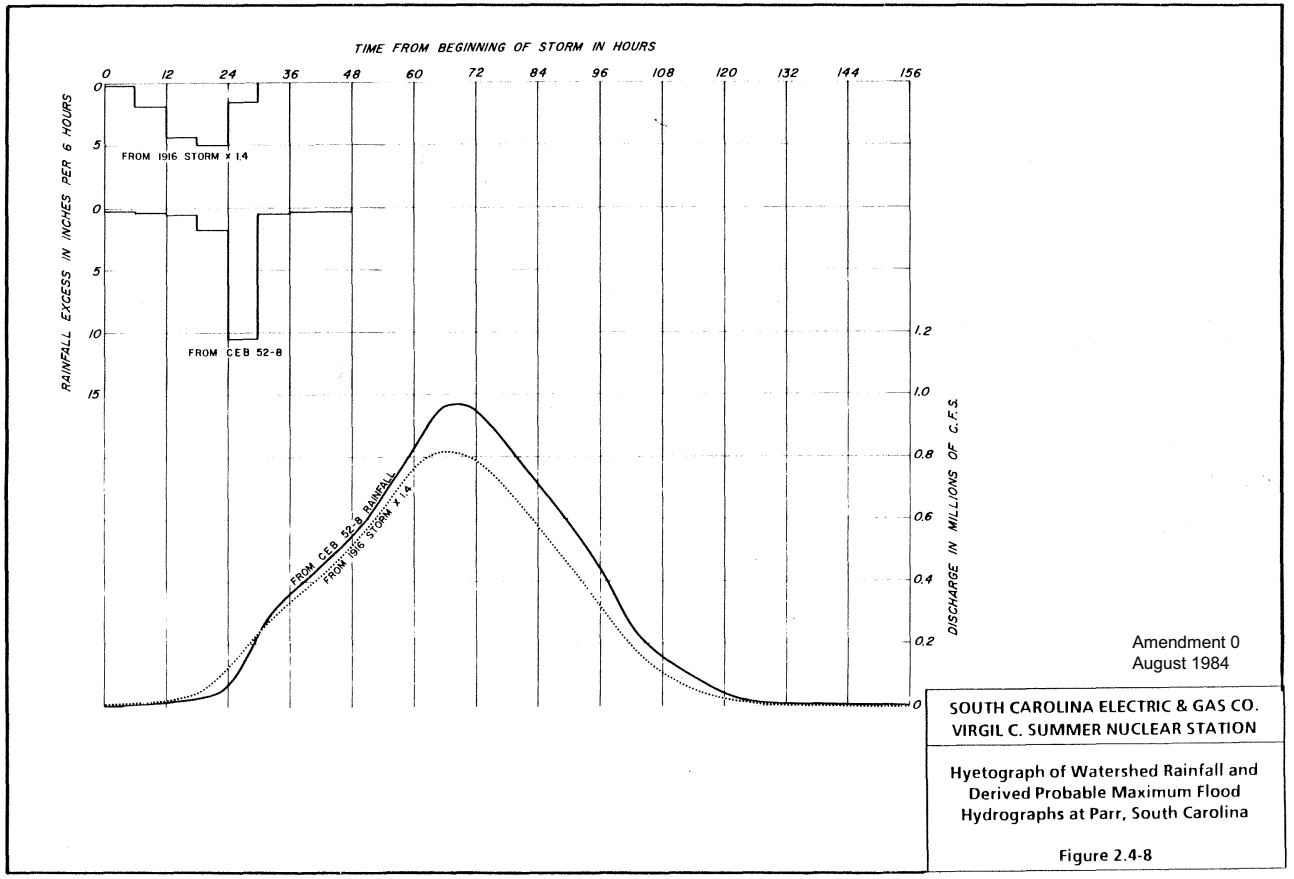


Figure 2.4-9

WIND FETCH ANALYSIS FOR MONTICELLO RESERVOIR

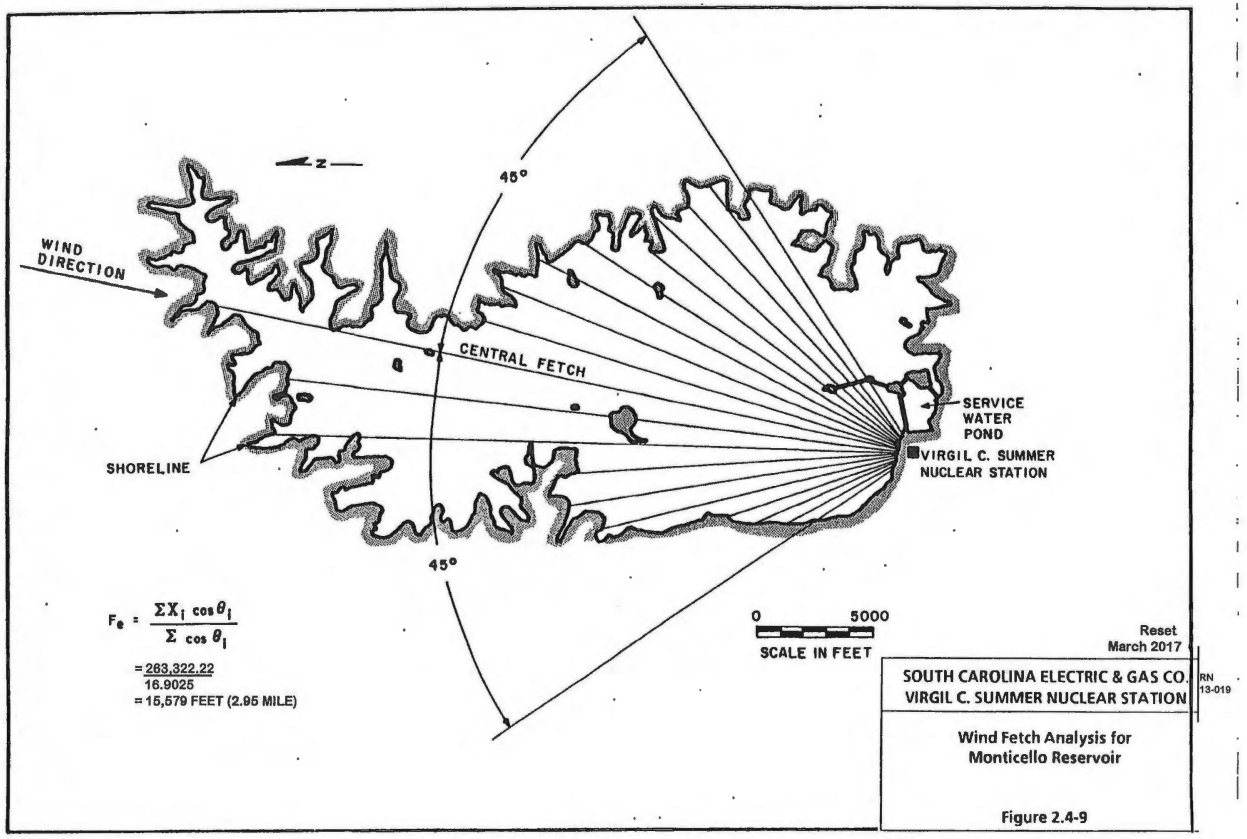
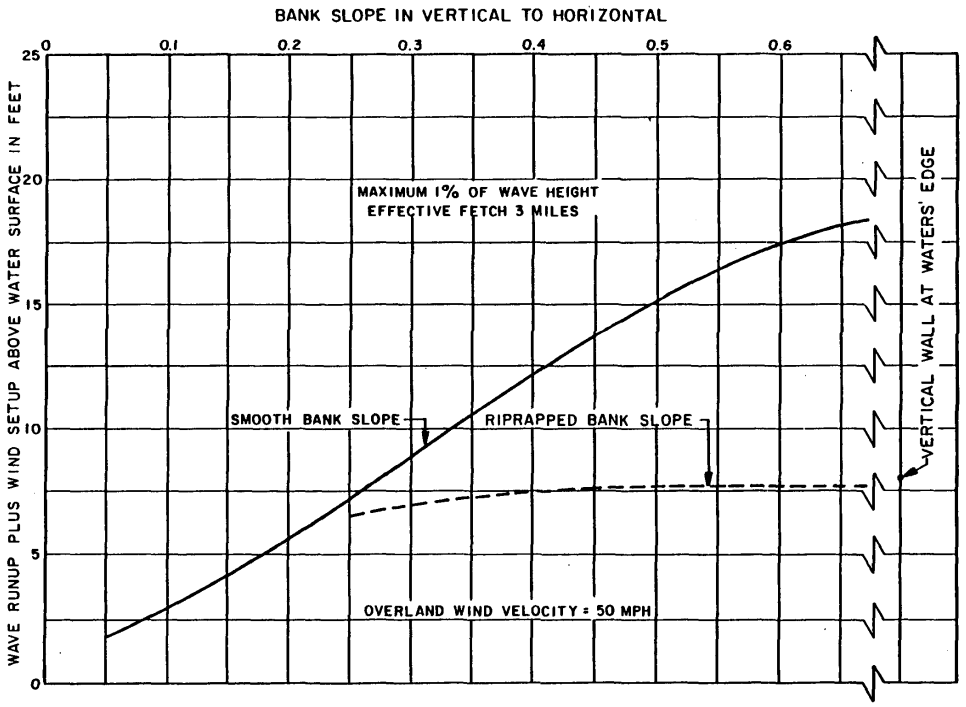


Figure 2.4-10

WAVE RUNUP PLUS WIND SETUP FOR MAXIMUM ONE PERCENT OF WAVE HEIGHTS ON MONTICELLO RESERVOIR



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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Wave Runup Plus Wind Setup for Maximum One Percent of Wave Heights on Monticello Reservoir

Figure 2.4-10

Figure 2.4-11

SERVICE WATER PUMPHOUSE

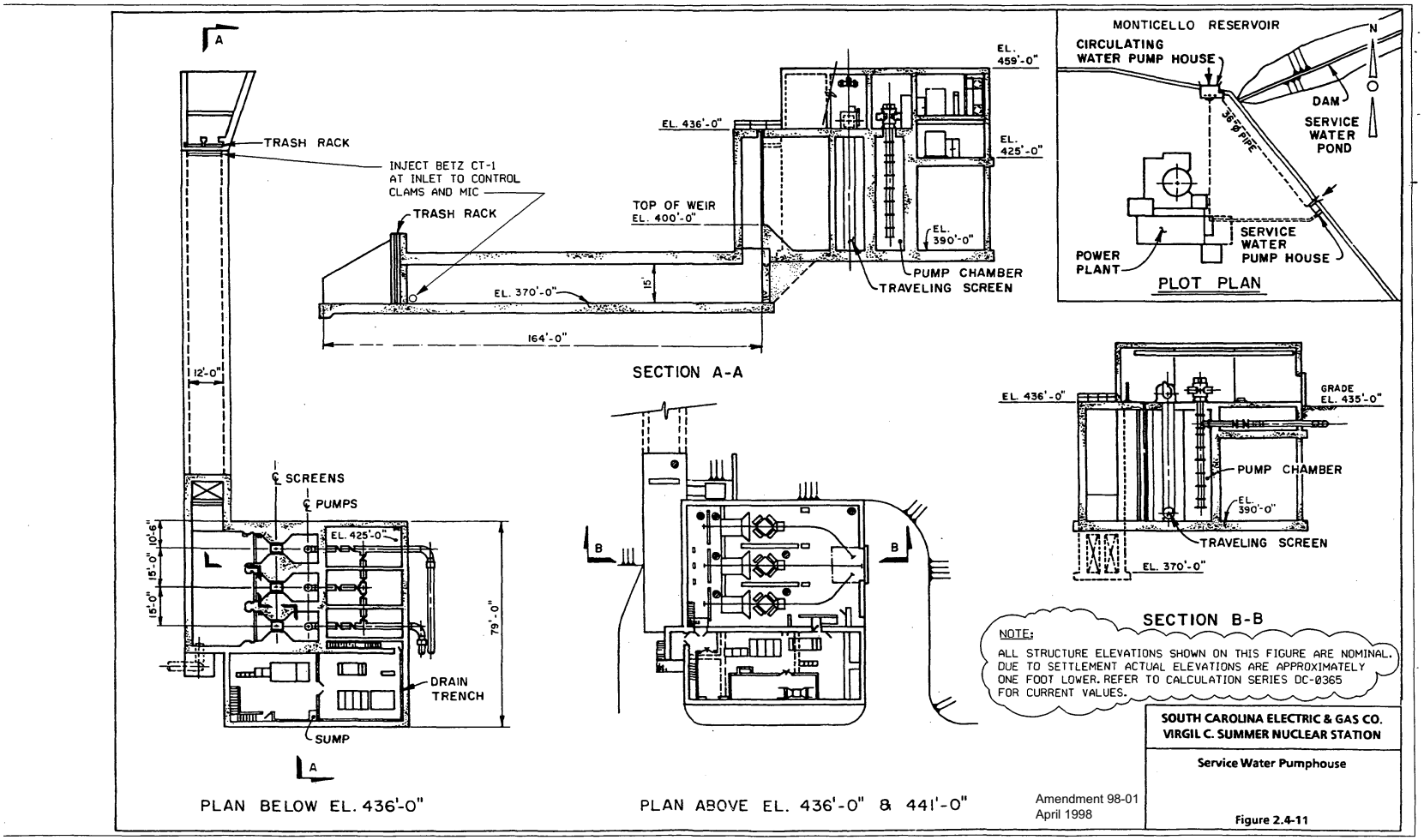
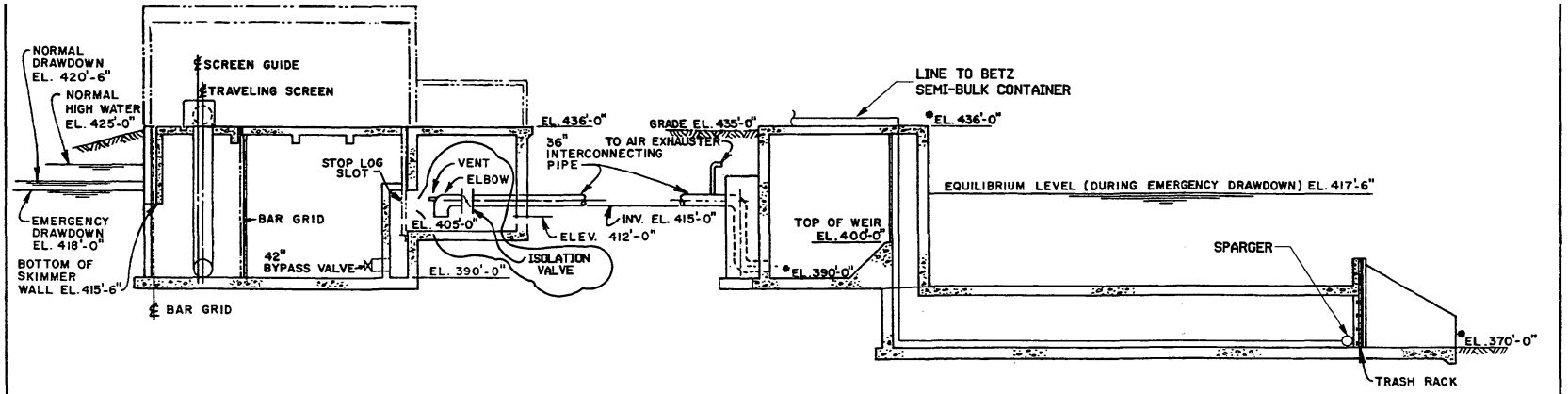


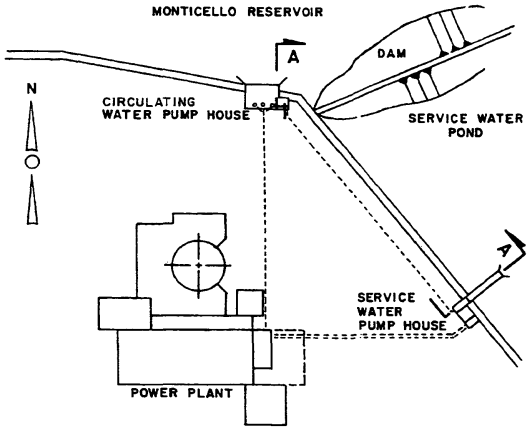
Figure 2.4-12

INTERCONNECTION PIPE BETWEEN INTAKE STRUCTURES



SECTION A-A

*SEE NOTE ON FIGURE 2.4-11



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DECEMBER 2000

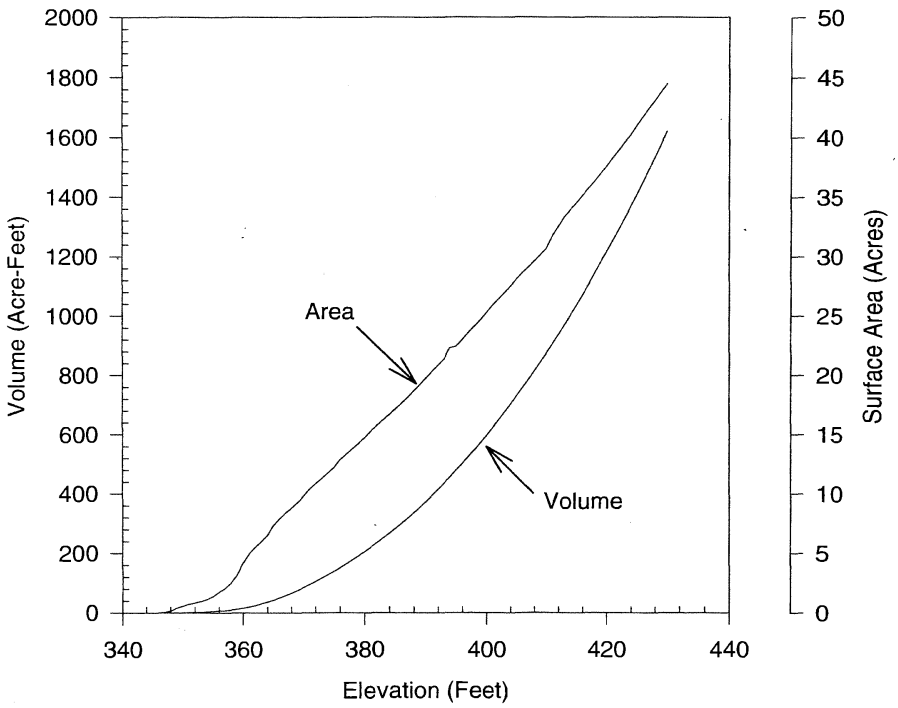
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Interconnection Pipe Between Intake Structures

Figure 2.4-12

Figure 2.4-13

SERVICE WATER POND AREA AND CAPACITY CURVES



AMENDMENT 02-01
MAY 2002

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Service Water Pond Area And Capacity Curves Figure 2.4-13

Figure 2.4-14

REPORTED MUNICIPAL, INDUSTRIAL, AND DOMESTIC WELL LOCATIONS 2-20 MILES

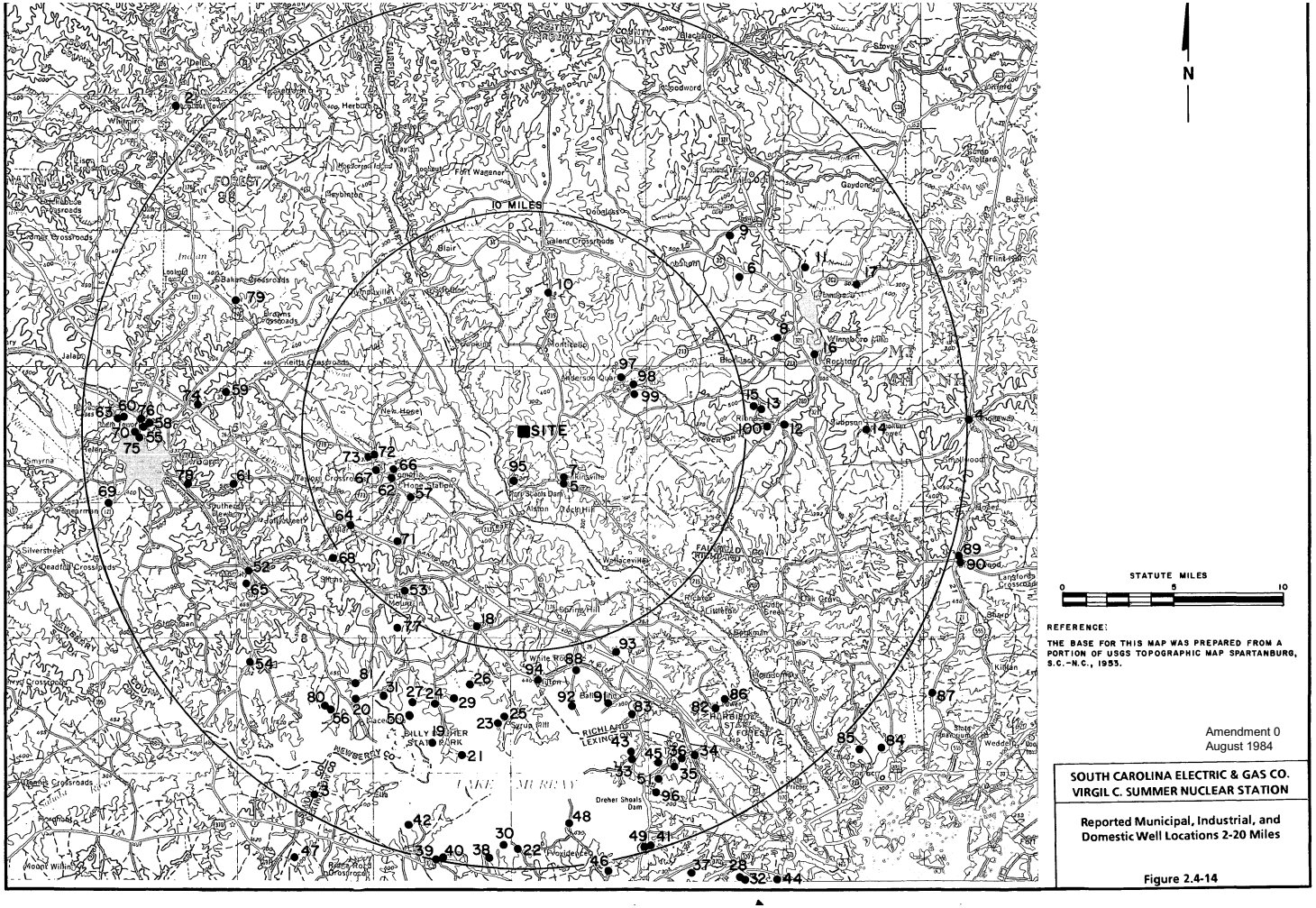


Figure 2.4-15

DOMESTIC WELL AND SPRING LOCATIONS, 0-2 MILES

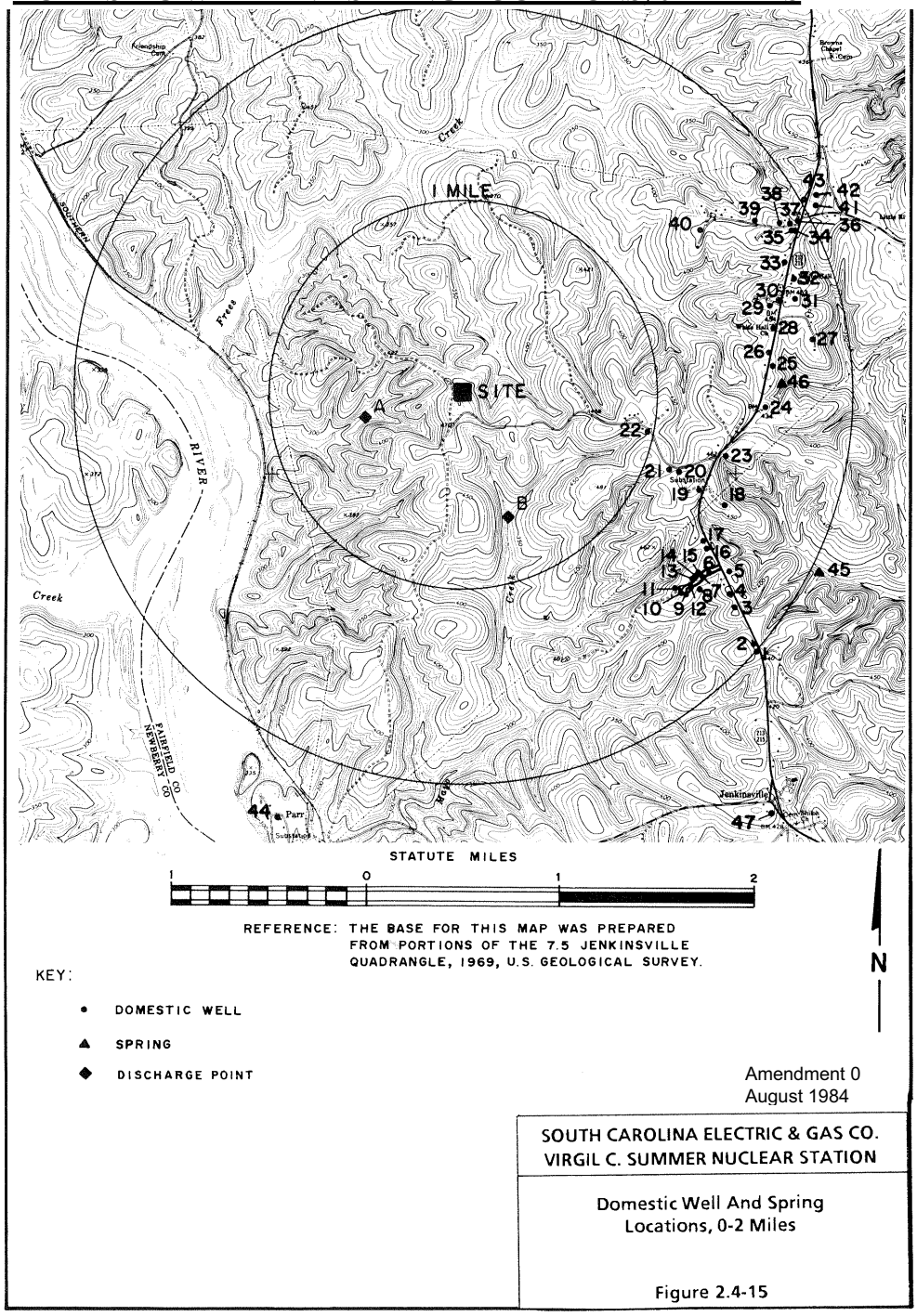


Figure 2.4-16

SITE WATER TABLE

PRE-RESERVOIR IMPOUNDMENT

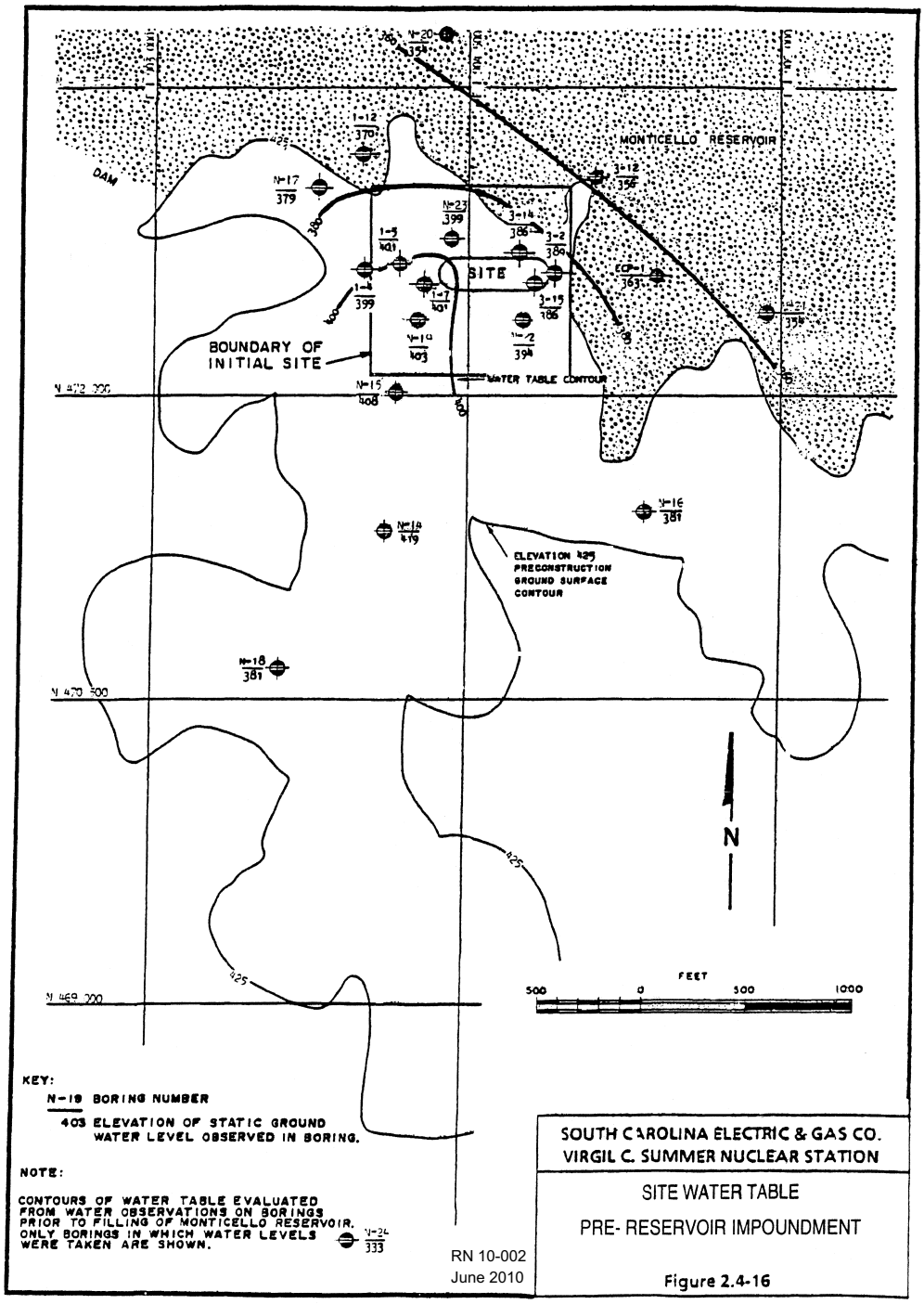


Figure 2.4-17

SITE WATER TABLE
PRE-DEWATERING SYSTEM

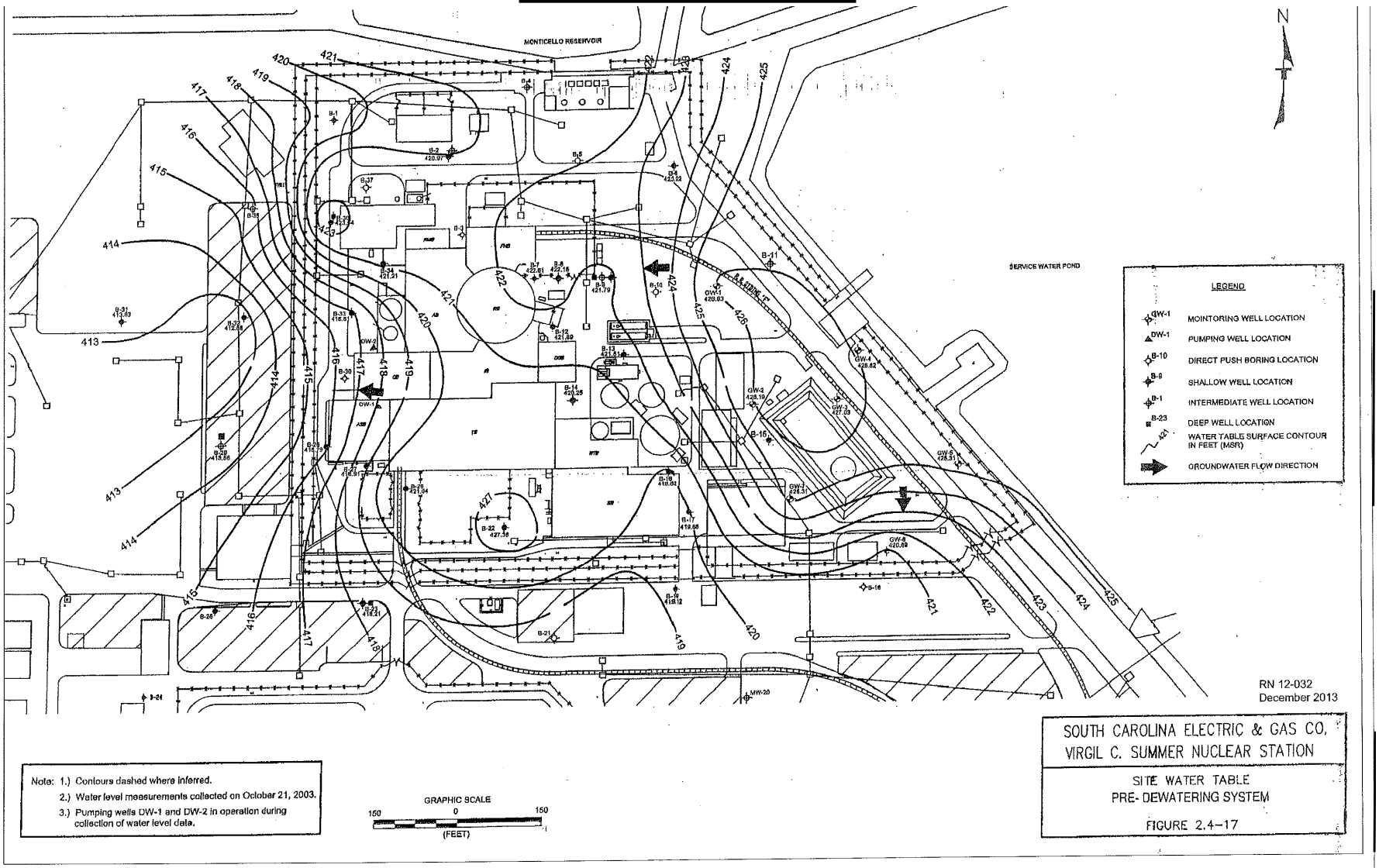
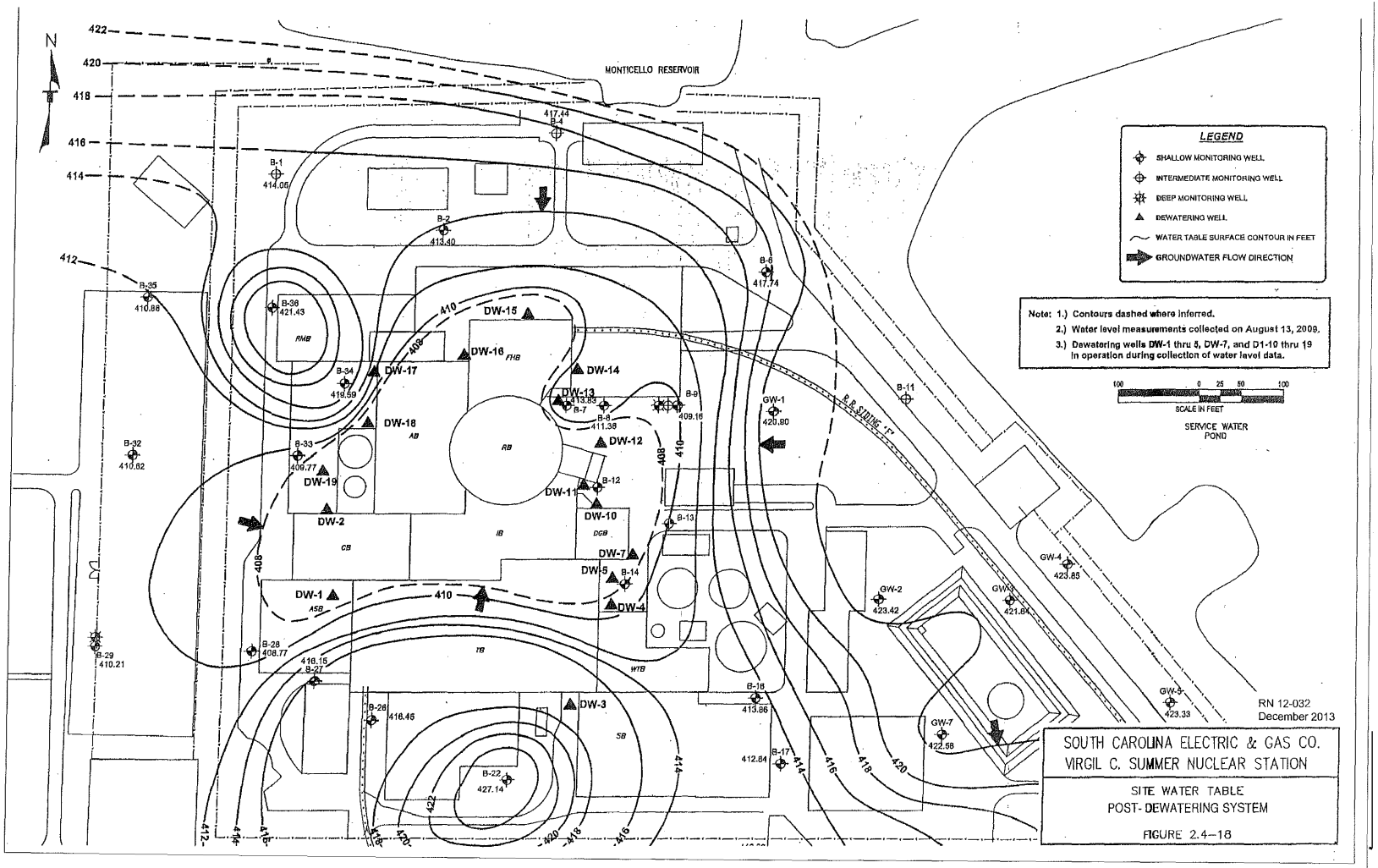


Figure 2.4-18

SITE WATER TABLE
POST-DEWATERING SYSTEM



2.5 GEOLOGY AND SEISMOLOGY

NOTE 2.5
Section 2.5 is being retained for historical purposes only (per RN 00-081).

This section presents the results of the evaluation of geologic and seismic conditions of the region and area around the Virgil C. Summer Nuclear Station. This evaluation was made in sufficient detail to ensure the safe design of the nuclear power facility. Results of the literature review, field studies, foundation exploration, and laboratory test programs are presented. A list of references is provided at the end of this section.

The site is located in Fairfield County, S.C., approximately 3 miles northeast of the town of Parr and 1 mile east of the Broad River. It lies within the Charlotte Belt metamorphic zone of the Piedmont Physiographic Province.

The surface of the Piedmont Physiographic Province is characterized by elevated, gently rolling hills which are separated on the northwest from the intensely folded and faulted Appalachian Mountains by the intervening hills of the Blue Ridge Province and bordered on the southeast by the Atlantic Coastal Plain. The province is underlain by a sequence of at least 15,000 feet of late Precambrian to early Paleozoic age metamorphic rocks which mantle Precambrian gneiss estimated to be 1,100 million years old. The general site area is underlain by a complex series of almandine-amphibolite facies metamorphic rocks consisting of gneisses, amphibolites, schists, and migmatite formed by the intrusion of plutons of granite to granodiorite composition.

Rocks of the Piedmont have been deformed, apparently under a more confined environment than the Appalachians to the west. As a result of confinement, metamorphism of varying grades has accompanied regional folding and faulting resulting in greater mobility and a corresponding lessening of shear forces in the rocks. The major faults in the region are the Brevard, Towaliga, Gold Hill, Jonesboro, and Eastern Piedmont (Goat Rock). The closest approach of any of these features to the site is a splay off the Eastern Piedmont (Goat Rock) system which is located about 13 miles south of the site. These structures are considered to be normal or high angle reverse faults with the exception of the Brevard, which is generally believed to be a strike slip fault. These faults are believed to have formed subsequent to metamorphism, probably toward the close of the Paleozoic era. Most have been intruded by middle to late Paleozoic igneous plutons, cross-cut by undisplaced Triassic-Jurassic diabase dikes, and in places overlain non-conformably by undisplaced sediments of Cretaceous age.

There are no capable faults within 5 miles of the site. The closest fault which could be considered capable is the Belair Fault which is located approximately 75 miles southwest of the site near Augusta, Georgia. Preliminary investigation of this fault indicates that movement has probably occurred within the last 50 million years. Studies are continuing to accurately determine the age of last movement. There is no known seismic activity associated with this feature, and it is not considered of significance in establishing the safe shutdown earthquake.

Minor shearing of the type commonly found in the Piedmont is present in the bedrock underlying the site. The maximum net displacement observed is no greater than 7 feet. The shears are not an integral part of any known fault system. However, the orientation of the shears is consistent with the regional joint pattern. The shears do not penetrate through the soil profile to the ground surface. Subsequent to the termination of all movement hydrothermal minerals were introduced along joints and shears. These minerals include the zeolite laumontite which is present as unsheared subhedral to euhedral crystals. In places laumontite crystals completely fill the shears, having grown inward from both walls. Hydrothermal events within the Piedmont are often associated with Triassic-Jurassic diabase dike emplacement. There are no known occurrences of hydrothermal activity within the stability field of laumontite in the Piedmont since the mid-Mesozoic.

The results of radiometric age determinations indicate that movement along the shears could not have occurred later than 45 million years (m.y.) ago, and, in all probability, the shears have been inactive since 150 to 300 million years before present (BP).

In situ rock stresses at the site are relatively low and the direction of principal stress in the horizontal plane is approximately normal to the shear plane.

The site is located in a broad diffuse zone of seismic activity. There have been 101 shocks with intensities of V or greater within 250 miles of the site. The largest was the 1886 MM (Modified Mercalli) Intensity X Charleston event which dominates the seismic history of the east coast. The largest earthquake within a 50-mile radius was the 1913 MM VI-VII Union County event located about 35 miles northwest of the site. The closest shock to the site was the 1945 MM VI event located approximately 5 miles west-southwest of the site.

Correlation between seismic events and the existence of the shears cannot be made. The possibility of reactivation of the shears, or the inducement of significant earthquake activity related to impoundment of Monticello Reservoir is remote.

No physical evidence was found as a result of the geologic and seismic investigations performed which would indicate adverse behavior of the surficial and subsurface geologic materials to seismic events. The Safe Shutdown Earthquake is considered an MM Intensity VII at the site resulting from a shock similar to the 1913 Union County earthquake occurring close to the site. The design ground motions of 0.15g and 0.25g for rock and soil, respectively, are considered conservative.

Geophysical and foundation engineering investigations have been performed to evaluate the static and dynamic engineering properties of the subsurface materials at the plant site. Based on these field and laboratory investigations, the stability of the Seismic Category 1 structures has been analyzed relative to the foundation type and supporting media. The bearing capacity and settlement of mat foundations (founded on rock and soil) and caisson foundations have been evaluated. The liquefaction potential of the subsurface materials beneath the soil-supported Seismic Category 1 structures, along the west embankment at the plant site, were evaluated for the SSE and OBE conditions. The dynamic (earthquake loading) lateral earth pressure against the

rigid Seismic Category 1 foundation walls was also designed in accordance with the results of these evaluations.

Studies for Seismic Category 1 embankments have included stability analyses of slopes and foundations under static and dynamic conditions, seepage analyses, and settlement analyses.

Work performed in Section 2.5 was done under the direction of Dames & Moore and Woodward-Clyde Associates. Independent consultants in geology and seismology were retained to assist the geologic and seismologic investigations. These consultants were Dr. Paul D. Fullager (University of North Carolina) - radiometric analyses; Dr. Todd M. Gates (Teledyne Isotopes) - radiometric analyses; Dr. Roy Ingram (University of North Carolina) - X-ray diffraction analyses; Dr. Paul C. Ragland (University of North Carolina) - X-ray diffraction analyses; Dr. Gerry L. Stirewalt (University of North Carolina) - structural geology; Dr. Pradeep Talwani (University of South Carolina) - local seismicity; and Dr. H. D. Wagener - petrology.

Geologic and seimologic information developed by the investigations described herein are consistent with pertinent criteria outlined in Appendix A to 10 CFR 100. Based upon the investigations and studies performed, it is concluded that site related geologic, seismologic, and geotechnical engineering conditions do not introduce any potential for ground surface rupture, loci for significant seismic activity, or any other condition requiring modification of the existing design.

2.5.1 Basic Geologic and Seismic Information

Basic geologic and seismic data were obtained for the Virgil C. Summer Nuclear Station site from 1971 to the present, including the PSAR and a series of 5 subsequent geologic reports, all of which have been filed with the NRC on this docket.

The geologic and seismic programs conducted in 1971 for the PSAR included the following:

1. A thorough review of pertinent geologic and seismic literature (published and unpublished) and interviews with geologists knowledgeable with the site area.
2. Geologic mapping of the site and surrounding area within a 10-mile radius.
3. Petrographic analyses of thin sections.
4. Magnetic anomaly survey of the site.
5. Test borings.
6. Seismic refraction survey.
7. Surface wave survey.
8. Micro-motion measurements.

In 1973 and 1974, a detailed geologic investigation was performed at the site of the Reactor Building excavation after the discovery of minor shearing in the bedrock. This investigation,

entitled “Supplemental Geologic Investigation, Virgil C. Summer Nuclear Station - Unit One,” dated January 14, 1974, included:

1. Detailed geologic mapping and sampling.
2. Excavation of trenches.
3. Drilling of an inclined boring.
4. Petrofabric analyses.
5. Structural analyses.
6. Radiometric age dating.
7. X-ray diffraction analyses.
8. In situ stress measurements.
9. Literature search with emphasis on recent tectonic displacements.
10. Air photo and ERTS-1 imagery analysis.
11. Gravity and magnetic data analysis.
12. Evaluation of potential movement along shears due to the filling of Monticello Reservoir.
13. Review of local microseismic data.
14. Correlation of Piedmont seismic activity with reservoir impoundments.

During 1974 and 1975, the detailed geologic mapping was extended to include the staging area excavation, the Control Building excavation, the Intermediate Building excavation, and the Service Water Pond north dam excavation. Results of these investigations were presented in Addenda I, II, III, and IV, respectively, to the Supplemental Geologic Investigation report.

All of the aforementioned studies have been utilized in the preparation of the following sections.

2.5.1.1 Regional Geology

South Carolina lies principally within 2 major geologic provinces: the Piedmont Physiographic Province, underlain by a complex sequence of deformed crystalline rocks, and the Coastal Plain Physiographic Province, underlain by younger relatively undisturbed sediments. The Virgil C. Summer Nuclear Station site is located within the Piedmont Province. Regional deformation during and at the end of the Paleozoic Era, accompanied by periods of igneous intrusion, resulted in consolidation, folding, faulting, and metamorphism of the Piedmont rocks which were originally deposited as a thick sequence of sediments. The latest tectonic episode in the Piedmont has been determined by recent radiometric dating to have occurred about 200 million years ago, and is represented by late- or post-Triassic diabase dikes. No younger tectonism has been identified in the Piedmont.

2.5.1.1.1 Physiography

The Virgil C. Summer Nuclear Station site lies within the Piedmont Physiographic Province. The site location relative to the physiographic provinces of South Carolina is shown on the Regional Physiographic Map, Figure 2.5-1. The surface of the Piedmont Province consists of elevated, gently rolling hills which are separated on the northwest from the intensely folded and faulted Appalachian Mountains by intervening hills of the Blue Ridge Physiographic Province. The Piedmont Province is essentially a dissected peneplain and is characterized by northeast-southwest trending belts of crystalline metamorphic and plutonic rocks. In South Carolina, northwest from the Coastal Plain, 6 belts are recognized; these are the Carolina Slate Belt, Charlotte Belt, Kings Mountain Belt, Inner Piedmont Belt, Brevard Belt, and the Blue Ridge Belt. These belts are shown on the Geologic Belt Map of South Carolina, Figure 2.5-2. It is thought that these belts resulted from variations in regional metamorphism and tectonic activity on originally similar sedimentary and volcanic rocks (Reference 1). Folding, faulting, regional and contact metamorphism, and igneous intrusions have modified the rocks presently exposed. Most major streams and some tributaries in the Piedmont have cut down through great thicknesses of residual soil and are flowing on, or very close to, the crystalline bedrock.

In general, rocks in the Piedmont were formed under many different combinations of heat and pressure, and represent a complex succession of geologic events. The complex geology of these rocks is not well known, and only a small part of the South Carolina Piedmont has been closely studied.

The general distribution of rocks in the site region is illustrated on the Regional Geologic Map, Figure 2.5-3. Most data shown on Figure 2.5-3 have been summarized from a provisional geologic map prepared by the USGS (Reference 1). Much of the data shown on the USGS map was developed by geologic interpretation of agricultural soil maps, published and unpublished geological maps representing but a small part of the state, and a field reconnaissance of a portion of the state (Reference 2).

2.5.1.1.2 Stratigraphy

The Piedmont Province is underlain by at least 15,000 feet of a meta- sedimentary sequence of deformed rocks of late Precambrian to early Paleozoic age which mantle Precambrian gneiss estimated to be 1,100 million years old. The crystalline rocks of the Piedmont Province are unconformably overlain by the sedimentary rocks of the Coastal Plain Province to the southeast and are bordered on the northwest by rocks of the Blue Ridge Province. Elongated Triassic basins containing un- metamorphosed, nearly flat-lying sedimentary rocks occur within the Piedmont from the South Carolina-North Carolina line northward. These basins trend parallel to the Appalachian's regional northeast-southwest trending structures. Isolated basins of Triassic sedimentary rocks have also been identified within Piedmont-type crystalline rock underlying the Coastal Plain from the Georgia-South Carolina line, northward (Reference 3, Reference 4, Reference 5). Pre-orogenic mafic intrusives, and pre- and post-orogenic granitic plutons and diabase dikes are common.

The geologic belts within the Piedmont differ from each other predominantly by the degree of change in the original rocks. Modifications that resulted from folding, regional metamorphism, and igneous intrusions are reflected in the presently exposed rocks. Overstreet and Bell (Reference 1) believe the geologic belts represent metamorphic zones superimposed on a regional stratigraphic sequence. Folding in 1 metamorphic belt persists in trend into another belt; for example, large anticlines and synclines in the Charlotte Belt persist into the Carolina Slate Belt, Figure 2.5-3, supporting this hypothesis in the general site vicinity.

Three (3) metamorphosed sedimentary and volcanic sequences, each with a related intrusive episode, have been postulated to explain the succession of metamorphic and igneous rocks encountered in the Piedmont. Because of insufficient data, these sequences are not universally accepted. This postulation provides a reasonable explanation for some of the complex stratigraphy of Piedmont rocks and is shown in summary in Table 2.5-1.

The Piedmont rocks generally consist of gneisses, amphibolites, schists, and other metamorphic rocks (country rocks) which are intruded by massive igneous materials of predominantly granitic character. Various types of migmatite border the major granitic plutons. The pre-metamorphic and possible mafic character of these rocks has been largely obscured by injection of quartz of eldspathic dikes and sills, and partial or complete assimilation of large areas of the original country rocks.

Near the eastern edge of the Piedmont in South Carolina, a thick sequence of metamorphosed shales, siltstones, and volcanic rocks crop out in the Carolina Slate Belt. Although the exact age of these rocks is uncertain, they appear to be equivalent in age to some of the lower Paleozoic rocks encountered in the Valley and Ridge Physiographic province west of the Piedmont. Overstreet (Reference 1) suggests that rocks of the Slate Belt connect westward with the more intensely metamorphosed rocks of the Kings Mountain Belt in South Carolina and overlie the variably metamorphosed rocks of the Inner Piedmont Belt and southern part of the Charlotte Belt. Although some geologists postulate a fault boundary between the Slate Belt and Charlotte Belt rocks, this boundary in the site area is interpreted to be a metamorphic transition (Reference 6, Reference 7).

Interpretations of recent aeromagnetic maps flown over the Coastal Plain of South Carolina, North Carolina, Georgia, and Alabama in a cooperative project between the USGS, the Coastal Plain Regional Commission, the NRC, and state geological surveys have revealed that the basement rocks underlying the Piedmont are different from those underlying the Coastal Plain. The magnetic grain of the Piedmont basement is predominantly NE-SW whereas the magnetic grain of the basement rocks underlying the Coastal Plain is E-W (Reference 8). It is believed that the Piedmont basement may be continental crust whereas the basement underlying the Coastal Plain may be island arc or oceanic crust. A recent 2,598-foot test hole in the Charleston, S.C., area bottomed in approximately 138 feet of amygdaloidal basalt confirming the contrast in basement lithology (Reference 9). Geophysical and depth analyses indicate that 2 magnetic basements are present, 1 consisting of volcanic rock and dikes within the sedimentary section, and a deeper basement associated with larger intrusive bodies (Reference 10).

2.5.1.1.3 Geologic Structures

Rocks of the Piedmont have been deformed, apparently under a more confined environment than the Appalachians to the west. As a result of confinement, metamorphism of varying grades has accompanied regional Piedmont folding resulting in greater mobility and a corresponding lessening of shear forces in the rocks. What probably once was a high-standing sequence of fold structures parallel to the Appalachians has since been eroded down to a peneplain. Subsurface orientations of some of these features are indicated on Figure 2.5-4 and Figure 2.5-5, Location of Regional Geologic Section and Generalized Regional Geologic Section, respectively. Remnants of these presumed structures exist as the previously mentioned parallel belts of metamorphic rock, which generally increase in metamorphic grade westward.

As indicated on the Regional Tectonic Map, Figure 2.5-6, the Appalachian region is strongly deformed. Southeastward from this region to the Coastal Plain the deformation decreases, and relatively few displacements of regional magnitude occur. Results of seismic profiling in the region (Reference 125) have yielded evidence that the crystalline rocks of the southern Appalachians are an allochthonous thrust sheet, 6 to 15 km thick, which have been thrust some 260 km to the west and overlie relatively flat lying and undeformed sedimentary rocks that cover an extensive area of the central and southern Appalachians. Along the Coastal Plain, a probable basement upwarping, expressed as a broad northwest-southwest trending anticlinal feature, runs through Cape Fear, North Carolina (Reference 11). This broad upwarping has been referred to as the Cape Fear Arch and is bordered by the Salisbury Embayment to the northeast and the Georgia Embayment to the southeast. These embayments are broad sediment-filled basement flexures located 150 miles or more from the site.

2.5.1.1.3.1 Faulting

The known or implied major faults affecting the crystalline rocks of the region are shown on the Regional Tectonic Map, Figure 2.5-6. The largest is the Brevard zone, located adjacent to the Blue Ridge Mountains in the extreme northwestern corner of South Carolina, approximately 100 miles from the site. This fault separates the eastern metamorphic belts from the Blue Ridge metamorphic belts on the west. The Brevard zone, trending northeast-southwest, is believed by some to be a strike-slip fault parallel to, and probably contemporaneous with, the regional tectonism marking the formation of the Appalachian Mountains about 260 million years ago. Displacement may be on the order of hundreds of miles (Reference 12). This type of faulting may be anomalous when considered in light of the regional thrust faulting that accompanied the Appalachian orogeny. A more recent hypothesis suggests that the Brevard fault zone marks the plane of an overthrust from the southeast (Reference 13), or an eastward-dipping splay off the main sole thrust previously mentioned (Reference 125). Whatever the mechanism involved, the Brevard fault zone can be traced from Alabama through north Georgia, the northwest corner of South Carolina, and well into western North Carolina, a distance of some 450 miles.

The similarly trending Towaliga, Eastern Piedmont (Goat Rock), Gold Hill, and Jonesboro Faults, Figure 2.5-6, are considered to be normal or high angle faults. All are believed to have formed subsequent to metamorphism, probably at the close of the Paleozoic era.

The Towaliga and Eastern Piedmont (Goat Rock) Faults, which were previously believed to die out in Georgia, have been extended through South Carolina into North Carolina by Talwani and Howell (Reference 14, Reference 15). The extension of the Towaliga fault zone lies approximately along the contact between the Kings Mountain and Charlotte Belt metamorphic zones. Evidence for extending the fault consists of a sharp contrast in lithology, the presence of cataclastic rocks, and a marked change in the gravity gradient (Reference 15). Howell (Reference 14) as interpreted the Towaliga as a thrust sheet which was subsequently cut by a high angle fault that possibly dips to the northwest. The trace of the fault zone represents the trace of this high angle fault, not the extent of the overthrust, which probably extended farther to the northwest. The closest approach of the extension of the fault to the site is approximately 37 miles to the northwest.

The extension of the Eastern Piedmont (Goat Rock) fault northeastward from the vicinity of Columbia, S.C. is based principally on aeromagnetic lineation. Howell (Reference 14) feels that the Eastern Piedmont (Goat Rock) is not a single fault but is made up of many faults, splays, folds, etc., and is more correctly referred to as the Eastern Piedmont (Goat Rock) Fault System. Howell has proposed the name Modoc Fault for the splay of the Eastern Piedmont (Goat Rock) System that extends from Modoc, S.C. to the area of Lake Murray, S.C. The Modoc Fault of Howell is the same fault shown by Overstreet and Bell (Reference 1) and described by Tewhey (Reference 16) as extending southwestward from the southwest shore of Lake Murray, west of Columbia, and passing into Georgia near Modoc, S.C. Tewhey (Reference 16) considered the formation of this high angle fault to be associated with post-metamorphic activity, and that highly resistant ultra-mylonites are responsible for the straight line portion of the fault at Lake Murray. Based on aeromagnetic lineation, Howell has extended the fault northeastward from the northeastern edge of Lake Murray to just north of Columbia. The closest approach of the extension of this fault to the site is approximately 13 miles to the south. Undisplaced N30W trending diabase dikes of probable Triassic age cross this structure, indicating a pre-Triassic age for this fault (Reference 16).

According to Talwani and Howell (Reference 15), plotted epicenters of historic and recent seismic activity generally fall along the proposed extension of both the Towaliga and Eastern Piedmont (Goat Rock) Systems. Howell (Reference 14) believes that the seismic activity “does not represent fault movement” as he has seen no evidence of displacement of Triassic and/or Jurassic age dikes which cross both faults. He has also seen areas where the Coastal Plain sediments over lie the Eastern Piedmont (Goat Rock) with no evidence of offset. The presence of undisplaced dikes and Coastal Plain sediments indicate that the last significant movement along these faults occurred prior to Cretaceous time, and probably previous to the Jurassic or Triassic periods.

The Gold Hill fault of North Carolina has been extended into South Carolina for the first time by Howell (Reference 14). Howell has traced the fault southward as far as the Edgemore Granite, approximately 40 miles northeast of the site. A 600-foot core taken in the Edgemore Granite revealed weathered and brecciated zones which Howell believes represent the Gold Hill Fault. The granite has been dated at 340 m.y., establishing a maximum age for the fault. The fault cannot be traced southwestward from the Edgemore Granite.

Based on the interpretation of Bouguer anomaly maps, Levander and Talwani (Reference 17) have traced an unnamed fault located approximately 48 miles northeast of the site, from the vicinity of Gastonia, N.C., southwestward as far as Hickory Grove, S.C. This northeast trending fault, terminating near Hickory Grove into a northwest trending anticline, lies along the contact mapped between the Kings Mountain and Charlotte belts, and is located in an area of 2 reported earthquakes (Mb 3.4 and 3.8) that occurred on March 7, 1975. Howell (Reference 18) believes that this fault could be an extension of the Towaliga Fault system. The Towaliga system has shown no evidence of movement later than Jurassic/Triassic.

The Taxahaw (Wildcat Creek) fault near Pageland, S.C., approximately 50 miles northeast of the site, appears to be related to the northeast trending Jonesboro Fault of North Carolina and may be a southwestward extension of the Jonesboro. Both faults are associated with Triassic basins and are considered to be Triassic in age. According to Howell (Reference 18), the Taxahaw fault bounds the eastern edge of the Wadesboro and Crowburg Triassic basins. The Crowburg is a small basin approximately 4 miles in length located southwest of the Wadesboro basin, and is the southernmost outcropping of Triassic sediments in eastern North America (Reference 19). The location of these and other buried Triassic basins in the Piedmont and Coastal Plain Provinces are shown on Figure 2.5-7.

The Orangeburg Scarp is the local name for a more extensive escarpment called the Citronelle Escarpment that extends from Georgia through South Carolina into North Carolina. The Orangeburg Scarp is located in Orangeburg County, approximately 70 miles southeast of the site. It is believed by some investigators (Reference 10, Reference 20) that a portion of this feature may be tectonically controlled. This hypothesis is based on a change in the magnetic lineation in the basement rocks underlying the scarp, geomorphic evidence, strong lineaments along the scarp observed on Earth Resources Technology Satellite (ERTS) imagery, and Tertiary stratigraphic patterns. However, there is no evidence of stratigraphic offset across the scarp in the Cretaceous and overlying rocks (Reference 21), indicating a pre-Cretaceous age for any basement feature.

About 10 miles north of Lake Murray in the vicinity of Little Mountain, McKenzie (Reference 22) has postulated a series of northwest trending faults of unknown length with 1,500 feet of displacement. McKenzie mapped primary fractures at N10W with secondaries at N50E. McKenzie states, “Joints and faults are all part of the same system of fractures.” The existence of these faults has not been corroborated.

Possible faults mapped by Secor (Reference 23) and Wagener (Reference 24), which lie within a 10-mile radius of the site, with 1 exception, have been shown by later work not to exist (Reference 6, Reference 7). The exception is a possible east-west trending fault near the southern boundary of the 10-mile radius. However, the existence of this short fault could not be confirmed, as no field evidence of it was found during the detailed investigation.

The NNE-SSW trending line near Wallaceville, S.C., mapped by Secor and Wagener (1968) as a fault was initially based on the premise that the abrupt lithologic change associated with the feature seemed incompatible with the Slate Belt Stratigraphy as it was known at that time. With the accumulation of additional stratigraphic information, the abrupt change “no longer seems so

unusual" (Secor, 1974 personal comm.). Secor therefore feels that "there is not compelling evidence for major faulting along this line near Wallaceville."

In late 1973, Wagener performed additional and more detailed field work on 3 faults postulated in 1968 (Geology of the Southern 2/3 of the Winnsboro Quadrangle: S. C. State Devel. Board, Div. of Geol., MS-17, 1970) in areas bordering the site on the east. The results of Wagener's findings are:

1. "Fault extending from the central-western border of the 1970 map along Jackson Creek to Jordan Branch. There is a pronounced lithologic boundary along the line of this "fault" within the 1970 map area. However, west of the map area, along 3 traverses across the extended fault line, I could find no evidence of faulting. Therefore, if I were to remap the area today, I would not postulate the existence of this fault."
2. "Fault extending southward from Kennedy Branch, which displaces the Jackson Creek "fault." This fault was postulated in part because of the inferred existence of the Jackson Creek fault (postulation upon postulation). More detailed field study in 1973 failed to yield any evidence of faulting along the line of this fault. It definitely appears that no fault exists here."
3. "Fault extending eastward from the southwest corner of the map. My attempts to re-examine this fault in 1973 were cut short well prior to completion. The fault was inferred in 1968 because of my inability (within the allotted time frame) to reconcile structural complexities west of Little River on the basis of faulting. In my opinion, the existence of this fault remains a possibility."
4. "The fault extending through Simpson (SE corner of the map) was plotted along a lithologic boundary as an extension of a fault mapped by Secor to the southwest. Secor has since determined that this fault is a lithologic contact (conformable) rather than a fault. Consequently, I hereby withdraw my inference that the fault through Simpson exists."

Relatively minor east-west and northeast-southwest trending faults mapped by Secor and Wagener are shown north and west of Columbia on the Regional Geologic Map, Figure 2.5-3. The features and associations discussed can best be illustrated on the regional map, and therefore have not been shown on the Areal Geologic Map, Figure 2.5-13. The bifurcated east-west trending fault north of Columbia appears to be steeply dipping and cuts across east-northeast fold trends at a slight angle. Secor feels that large displacements are involved and further states that "The faults have been intruded by late Paleozoic granitic plutons and are cut by northwest trending Mesozoic diabase dikes." Portions of these faults also are nonconformably overlain by undisplaced Coastal Plain Cretaceous sediments and are therefore older than those deposits. A portion of the northernmost of these faults is approximately 10 miles south of the site. Clarke (Reference 25) found what is probably a westward extension of 1 of these faults in the White Rock-Chapin area, but could not determine the direction or amount of displacement.

The diabase dike-fault relationship discussed by Secor is supported by geophysical work in the Cedar Creek community by Thompson (Reference 26). Thompson's work supersedes an incomplete diabase dike study conducted by Privett (Reference 27). The community of Cedar Creek is located about 20 miles north northwest of Columbia. Based on the results of a magnetic

anomaly survey, Thompson feels he has identified 9 diabase dikes (in the subsurface) crossing the east-west trending fault mapped by Secor and Wagener (Reference 23). Thompson indicates that no appreciable offset has occurred since the intrusion of what he refers to as “Mesozoic diabase dikes.” He feels, considering the relatively large fault displacement postulated by Secor, that little or no movement has occurred since dike emplacement. Triassic and Jurassic diabase dikes tend to follow northwest-oriented faults which transect the Triassic basin and other rock types of the Piedmont. These dikes are generally fairly easy to trace (via magnetic anomalies and field checking) and can be considered indicators to faulting of Triassic age. Locations of all known diabase dikes in the regional and site areas are shown on Figures 2.5-3 and 2.5-13; none of these closely approaches the site. Reinemund (Reference 28), in discussing diabase dikes of the Deep River Coal Field of North Carolina, indicates that where dikes extend to northeast trending Triassic basin faults, they commonly change direction, becoming irregular in width and follow along the fault for short distances. A few dikes extend across faults with little break in continuity. Reinemund (Reference 28) suggests that where dikes are offset by faulting, they are probably formed in the final stages of faulting near the end of the Triassic, but they may be younger.

Other faults previously mapped by Secor and Wagener (Reference 23) beyond the 10-mile radius have been shown by later work not to exist (Reference 6, Reference 7, Reference 24).

Based primarily on unpublished magnetic data (open file, USGS, 1971 Aeromagnetic Map of the southern half of the Knoxville 2 Sheet, scale 1:250,000), Howell (Reference 18, Reference 30) postulates a northwest-southeast trending “structural anomaly” from Spartanburg, S.C., to Hendersonville, N.C. Geophysical evidence for the postulated feature ends at Spartanburg. No field evidence exists for a southeastward extension, and his preliminary conclusions concerning the northwestward projection have not been substantiated by geologic field investigation.

Known faults cutting both Coastal Plain sediments and Piedmont rocks are very localized, rather small features. Zupan and Abbott (Reference 31) describe an exposure a few miles northwest of Columbia, S.C., where Carolina Slate Belt argillite is unconformably overlain by post-Eocene to pre-late Miocene sediments. A number of high and low angle reverse faults were observed at the exposure, and a maximum of 5 feet of displacement was reported. A small horst was described that brought argillite in contact with the sediments. Near the fault plane the sediments exhibited drag, and a number of clastic dikes originating in the argillite cut the younger sediments. The faults were not visible in overlying sediments and could not be traced along the ground surface.

The dikes and associated reverse faulting mapped at the exposure are attributed by Zupan and Abbott (1975) to southeast-northwest compressional forces affecting the Paleozoic basement and overlying post-Eocene sediments.

The clastic dikes originate in the argillite (Paleozoic in age) and transect overlying post-Eocene sediments. Zupan and Abbott believe that some of the faults mapped affected the overlying post-Eocene sediments. The post-Eocene sediments are the youngest sediments shown by Zupan and Abbott as affected by the clastic dikes and faults. The youngest sediment shown as not affected consists of surficial material of undetermined age which overlies the post-Eocene The exposure reported by Zupan and Abbott (1975) was located approximately 21 miles southeast of the plant site, immediately west of and adjacent to Interstate 26 at the Highway 36 intersection. The

exposure was destroyed following investigation by Zupan and Abbott, and did not exist at the time of publication. All published information pertaining to the exposure is found in “Geologic Notes,” Volume 19, No. 1, Spring 1975, South Carolina State Development Board, Division of Geology.

A northeast trending fault apparently terminates approximately 9 miles northwest of the subject exposure; this fault intersects undisplaced diabase dikes of probable Triassic age. The fault may be a northeast extension of the Eastern Piedmont (Goat Rock) Fault, or may be a splay of more complicated “Eastern Piedmont (Goat Rock) Fault System.” The Eastern Piedmont (Goat Rock) Fault is generally considered to be a high angle structure. An extension of the “Eastern Piedmont (Goat Rock) Fault System” has been proposed, based principally upon aeromagnetic lineation, which apparently passes near the exposure reported by Zupan and Abbott. The Zupan and Abbott structures do not correlate with observed ERTS photo linears.

The general strikes of the aforementioned faults fail within the range of strikes observed by Zupan and Abbott. The range of fault strikes and dips observed by Zupan and Abbott is not compatible with the structure mapped at the plant site. The Zupan and Abbott faults exhibited a wide range of northeasterly strikes with northwest to north dips which varied from shallow to steep; most of the northeast oriented shears at the plant site dip steeply to the southeast with a few dipping steeply northwestward, and some northwest striking shears also occur.

The maximum displacement of the Zupan and Abbott structures was measured in the Paleozoic argillite; displacement of the post-Eocene sediments was indicated by upturned gravel layers, and data indicating maximum offset of the post-Eocene material are not available.

Whether displacement occurred in all or only a portion of the originally deposited post-Eocene column of sediments is not known, and the age of the surficial material mapped by Zupan and Abbott is not indicated.

Howell and Zupan (Reference 32) describe exposures northwest of Cheraw, S.C., where the Cretaceous Middendrof formation overlies argillites of the Carolina Slate Belt. An exposure on U.S. Highway 52 shows concordant folding of the Cretaceous material and the argillite. A few clastic dikes originating in the argillite cut the overlying Cretaceous sediments. An exposure along Chesterfield County Road 61 exhibits an apparent high angle reverse fault where the argillite thrusts up and overturns several layers of the overlying sediments. These structures are located on the southern limb of the Cape Fear Arch and could be related to the Tertiary tectonic activity that formed the arch (Reference 32).

The Belair fault zone near Augusta, Georgia, approximately 75 miles southwest of the site, has probably experienced movement within the last 50 million years (Dept. of Interior News Release; 18 November 1976) (Reference 33). The fault zone, which contains at least 7 individual en echelon faults, is traceable for at least 13 miles extending in a northeasterly direction from 10 miles southwest of Augusta to about 5 miles north of the city, and generally parallels the structural grain of the Piedmont. The feature contains reverse faults in which phyllites on the hanging wall (eastern block) have been thrust over high-grade metamorphic rocks on the foot wall (western block). Material in the overlying sediments has been offset, and has been dated by radiocarbon

methods; however, later studies indicate that the dates obtained may be inaccurate, and investigations continue to determine the age of last movement with precision. Recent studies of the Belair fault cited possible left lateral strike displacement of the Augusta fault along this feature as much as 23 km, with attendant vertical separation of unconformities at the base of the Upper Cretaceous and Eocene of 30 m and 10 m, respectively (Reference 126). Current detailed studies have been made northward along the postulated strike of the Belair fault where it should intersect the east/northeast-trending Modoc zone which separates the Carolina Slate Belt and Kiokee Belt (Reference 127). There is no significant offset in the well-marked unconformity at this locale, suggesting that the Belair fault is not present as a major left-lateral strike-slip fault. The mechanism of movement, whether by creep or sudden seismic displacement, has not been determined, although several hypothetical models have been recently advanced (Reference 127) to explain the nature of the apparent displacement along this structure. None of the information available at this time indicates that this feature could be related to structure close to the site, and there is no evidence of historic or recent seismic activity in the area of the fault trace.

A north-south trending normal fault has recently been postulated in the Chapin, S.C. area based on geologic mapping by Professor Donald Secor of the University of South Carolina. The geologic mapping is part of a program funded by the Earthquake Hazards Division of the U.S. Geologic Survey. The entire mapping program covers 4,7-1/2' quadrangles (Chapin, Jenkinsville, Pomaria, and Little Mountain) which would eventually be mapped in detail by the University of South Carolina Geology Department.

The fault has a north-south orientation and displaces metamorphic rocks of the Carolina Slate Belt in a down-to-the-east fashion. The fault roughly parallels Wateree Creek from just north of Hilton, S.C., to about the Broad River, where it has a slightly northwest orientation. Evidence of faulting includes: Discontinuity of magnetic anomaly patterns; apparent drag indicated by disturbed bedding or compositional layering, foliation and lineation patterns; occurrence of silicified and unsilicified fault breccia; occurrence of open extension fractures partially filled with quartz; apparent offset of stratigraphic contacts and the Carolina Slate Belt/Charlotte Belt border zone; apparent offset of older northwest trending silicified breccia zones; and possible offset of a northwest trending diabase dike. Field work is continuing in this area, and at present, the closest approach of this structure is about 4 to 5 miles south of the site. No evidence at present demonstrates any recency of movement on this structure. The Applicant plans to stay abreast of this mapping and report any significant findings to the NRC prior to the ASLB hearings. During the ASLB hearings, Professor Donald Secor testified that the postulated Wateree Creek fault had been dead for a long time, would not extend to the Jenkinsville quadrangle, and would not reactivate due to its unfavorable orientation for activation. The above conclusions were submitted to the NRC ASLB on 2/16/82 by SCE&G in the Applicant Proposed Finding of Facts and Conclusions. The same conclusions were also published in the paper 'Geology of the Area of Induced Seismicity at Monticello Reservoir, SC', Journal of Geophysical Research, by Secor, et al. Vol. 87, No. B8, August 10, 1982.

2.5.1.1.3.2 Jointing and Foliation

Foliation usually has been found to be correlative with regional structure and pre-metamorphic depositional banding except where it is in contact with plutons. Granitic plutons are partially

concordant with regional structure, but clearly discordant where they distort the foliation of country rocks. The regional trend of individual plutons, wherever mapped in the Piedmont Province, shows a general northeastward orientation parallel to the regional structure (Reference 34).

A pronounced N10W to N30W fracture direction is prominent within the Charlotte Belt. This direction corresponds to 1 of the angular drainage patterns containing a considerable number of streams. Another drainage pattern direction ranges from N50E to N70E, which corresponds to a second fracture direction and also the regional strike. Diabase dikes of late Triassic age are generally oriented parallel to a joint pattern throughout the Piedmont.

2.5.1.1.3.3 Geophysical Features

The Regional Bouguer Gravity Anomaly map is presented on Figure 2.5-8. Bouguer Gravity anomalies sometimes coincide with features of the Tectonic Belt. Based on comparison of the available regional gravity anomaly data with the positions of known regional faulting as shown on Figure 2.5-6, there are not sufficient gravity gradient contrasts to permit even major fault identification in the site area.

Magnetic anomalies generally reflect regional lithologic and structural trends and are very sensitive reflectors of Triassic diabase dikes in the lower Piedmont and Coastal Plain Provinces (Reference 35). Regional magnetic data are available for the eastern continental margin of the United States and extend as far west as the site. The broad flightline spacing (aeromagnetic survey) did not resolve small-scale features but does permit tracing of major regional magnetic lineations.

The areas of greatest magnetic relief within the Paleozoic rocks of the Piedmont appear to be associated with basaltic igneous bodies. The variable magnetic patterns within the crystalline Piedmont, therefore, could represent intrusive conditions rather than structural boundaries.

Sharp fault contacts between sedimentary rocks of low magnetic susceptibility and crystalline rocks appear to be identifiable by magnetic anomaly mapping. Beneath the Coastal Plain of North Carolina and South Carolina, there are several northeast-southwest trending buried basins, believed to be of Triassic age, which appear to be identifiable on the Regional Aeromagnetic Anomaly Map, Figure 2.5-9, as does the trace of a portion of the Jonesboro Fault within the Piedmont. A previously unmapped buried Triassic basin lying athwart the South Carolina-Georgia line has been confirmed by deep borings. This feature is quite prominent on a detailed magnetic map by Petty Reference 3.

A pronounced positive magnetic anomaly northeast of the site, Figure 2.5-9, can be directly related to the Dutchman's Creek gabbro (Reference 36). This anomaly continues north and west of the site, possibly reflecting a deep crustal extension of the gabbro. Sharp anomalies on either side of the site, as shown on Figure 2.5-22, Areal Magnetic Anomaly Map, may be related to unexposed gabbroic intrusives.

As discussed in Section 2.5.1.1.2, recent aeromagnetic data from the Coastal Plain of South Carolina has revealed a difference in magnetic grain in the basement rocks compared to the rocks underlying the Piedmont (Reference 8). The magnetic grain in the Coastal Plain basement is predominantly E-W whereas the Piedmont magnetic grain is NE-SW. This change in magnetic grain is interpreted as a difference in the basement lithologies, with the Coastal Plain being underlain by predominantly oceanic and island arc crust whereas the Piedmont is underlain by continental crust.

2.5.1.1.3.4 Linear Topographic Elements

Linear features were studied from ERTS images and topographic maps. The linears identified on the Regional ERTS Photolinear Map, Figure 2.5-10, are generally consistent in orientation with the regional joint pattern. The number of linears identified around the site area reflects the greater effort in examining that area for linears. As distance from the site increases, only the most prominent and readily identifiable linears were recorded. The linears observed may represent lithologic boundaries, folds, faults, or jointing. For comparison, the known major structural features and igneous dikes are also shown on Figure 2.5-10. Although numerous dikes are shown on published geologic maps, none of the ERTS linears are correlative with them; however, many of the northwest trending linears do have similar orientation. The major faults such as the Gold Hill, Jonesboro, and Modoc show relatively good correlation with linears identified from the imagery.

Smaller linear features were identified by study of the 7-1/2 minute USGS Jenkinsville, S.C., topographic map, Figure 2.5-11, which shows trends of linears or curvilinear topographic features which seem to correspond to a regional fracture system. Close correspondence between trends on Figure 2.5-10, Figure 2.5-11, and fracture system data collected at and around the site suggests a direct relationship between regional fracture systems and shears exposed at the site.

2.5.1.1.4 Geologic History

Most metamorphic rocks presently exposed in the Piedmont were originally deposited as a thick sequence of sediments in the Appalachian Geosyncline between 250 and 600 million years ago (Reference 34). A generalized geologic time table is presented in Table 2.5-2. An episode of folding, regional metamorphism, and igneous intrusion apparently followed each of 3 long sedimentation intervals. In South Carolina, from oldest to youngest, these episodes have been referred to as A, B, and C (Reference 1), Table 2.5-1. Near the end of the final depositional period, the previously formed metamorphic rocks and the unmetamorphosed sediments in the geosyncline underwent a final metamorphism of regional magnitude. This third metamorphic episode elevated the Piedmont, and was accompanied by fracture deformation, folding, and intrusion of discordant plutons of episode C. This event correlates with an orogeny that marked the close of the Paleozoic era. During this disturbance, thrust faulting occurred on a major scale in the southern Appalachians, but has not been demonstrated conclusively in the adjacent Piedmont plateau.

This mountain building increased erosion which, by mid-Triassic time, had worn down much of the Piedmont to a broad peneplain which truncated the exposed complex rock structures. A

gradual re-elevation of the region followed, probably accompanied by relaxation of compressive stresses. Subsequent development of numerous sets and/or zones of fractures in the Piedmont crystalline rocks provided appropriate conditions for the formation of graben-type fault blocks. These graben-like troughs are elongated and generally parallel to regional northeast-southwest trending Appalachian structures. As they sank, these structural troughs or basins accumulated sediments eroded from the higher crystalline Piedmont to the northwest and southwest until the end of Triassic time. Sediment-filled Triassic basins are exposed in the Piedmont as low-lying structurally controlled valleys north of the South Carolina-North Carolina boundary. Similar Triassic Plain sediments from the Georgia-South Carolina line northward.

In late Triassic or early Jurassic time, further uplift was accompanied by the intrusion of numerous northwest-southwest trending diabase dikes along pre-existing fractures in the Triassic sediment and surrounding Piedmont crystalline rocks. After another erosional cycle, during which the Piedmont was once again reduced to a plain, continental uplift elevated the region now occupied by the Appalachians and adjacent Piedmont areas; the region lying to the south and east was tilted downward, so that the sea encroached upon and somewhat beyond the present Fall Zone. The Fall Zone, which is oriented northeast- southwest, roughly defines the boundary between the Piedmont and the Coastal Plain and can be traced as far north as New Jersey and as far south as Alabama.

The most recent igneous activity known in the eastern U.S. consists of intrusive rocks of Eocene age (Reference 37). Felsitic (andesitic) intrusive rocks of the Valley and Ridge Province in Highland County, Virginia, and adjacent West Virginia, some 250 miles north of the site, are frequently associated with thermal springs. The 47 million year old andesite dikes and sills have been mapped as intruding mid-Paleozoic strata. Dennison and Johnson (Reference 37) hypothesize that these Tertiary intrusions represent the most recent pulse of volcanism which has been intermittently active in Virginia at least since the Triassic and probably since late Pre-cambrian time.

The sequence of poorly consolidated sediments overlying the southeastward sloping crystalline rocks beneath the Coastal Plain is the result of several depositional and erosional cycles occurring from the Cretaceous to the present. The unconformity formed by the irregularly eroded crystalline surface at the base of the Coastal Plain sequence is generally thought to slope southeastward at a gradient of about 20 feet per mile.

In most places in the Piedmont, a mantle of residual soil and saprolite covers bedrock. Relict features such as foliation, jointing, and cleavage are often recognizable in the saprolite.

2.5.1.2 Site Geology

The site is located within the Charlotte Belt metamorphic zone of the Piedmont Physiographic Province. The area is underlain by a complex series of interlayered and folded almandine-amphibolite facies metamorphic rocks, all of which have been intruded by plutons of granite to granodiorite composition. The detailed structure of the mapped area is difficult to determine due to the complex geologic history, diverse rock types, and limited exposures. Minor shearing with maximum observed displacements of about 7 feet has occurred within the Reactor Building area.

The results of detailed investigations of these shears indicate that movement along the shears could not have occurred later than 45 million years ago, and in all probability the shears have been inactive since 150 to 300 million years BP. The geology of the general site area is discussed in Section 2.5.1.2.1 while the detailed geology of the excavations for Seismic Category 1 structures is discussed in Section 2.5.1.2.2.

2.5.1.2.1 General Site Area

An intensive geologic field study was conducted within a 10-mile radius of the site. Areas previously mapped by others south, east, and west of the site were examined and data correlated where possible. Subsurface conditions were explored by drilling over 200 borings ranging in depth from 6 to 235 feet below the ground surface. Petrographic analyses of thin sections were performed to aid in rock classification, and in the evaluation of the possible existence of faults near the site. Joint and foliation statistical analyses were used as supporting evidence for structural hypotheses. A general site area magnetic anomaly survey was conducted which substantiated geologic interpretations. A geologic map of the general site area was prepared and is presented on Figure 2.5-13, Areal Geologic Map.

2.5.1.2.1.1 Site Physiography

The site is located within the Piedmont Physiographic Province in Fairfield County, approximately 3 miles northeast of Parr, S.C. The site is about 1 mile east of the Broad River and is in a forested area. Topography of the general area is characterized by gently to steeply rolling hills and generally well-drained mature valleys which empty, ultimately, into the Broad River. Superimposed on the topography of the general area can be found steep scattered erosional gullies, possibly resulting from past agricultural practices. Maximum topographic relief in the general site area is approximately 250 feet. An aerial perspective view of the general site area is presented on Figure 2.5-12, Diagrammatic View Parallel to Broad River. This figure shows typical physiographic features discussed.

Drainage follows either a dentritic or trellised pattern, the former sometimes indicating plutonic activity, the latter reflecting either a joint system (approximately N30W, N45E and N67E) or the site area strike (N40E to N75E). The Broad River and its larger tributaries have developed a relatively narrow flood plain with occasional, poorly formed, natural levees. Alluvial deposits consisting of clays and sands range in thickness from a few inches to several feet.

2.5.1.2.1.2 Lithology and Petrology - General Site Area

Excellent agreement of lithologic data was obtained between rock units to the east, geologically mapped by Wagener (Reference 24), and rock units found in the general site area. Secor (Reference 23) and Wagener (Reference 24), and McCauley (Reference 38) have geographically mapped the area south and west of the site, respectively. Different mappable units were used in those studies, but there is a general agreement of lithologic data between the site and those associated areas.

Five (5) mappable rock units were defined during the field investigation: Charlotte Belt Gneiss, Carolina Slate Belt Rocks, Migmatite, Granodiorite, and “Granola”. The surface distribution, structure, and inferred subsurface orientation of the rock units are shown on the Areal Geologic Map, Figure 2.5-13. This figure was prepared from test boring data and field mapping of the surface distribution of saprolites and rock exposures.

The term Charlotte Belt Gneiss is used to denote the complex almandine-amphibolite facies metamorphic rocks of the Charlotte Belt (Reference 12). The unit as defined here underlies most of the area mapped and consists of the following observed rock types:

1. Light grey and black, fine- to medium-grained hornblende-plagioclase gneiss which exhibits macroscopic banding and/or foliation. Bands consist of mineral segregations forming color and textural variations.
2. Tan to yellow-tan, fine- to medium-grained quartz-feldspar gneiss which is low in mafic mineral content.
3. Light grey to black, fine- to medium-grained, banded, hornblende-amphibolite gneiss and black greenish-black hornblende amphibolite formed by increasing hornblende content.
4. Black and white, fine- to medium-grained, banded, biotite gneiss which usually contains excellent foliation by alignment of biotite.
5. Black to light brown, fine- to medium-grained biotite/muscovite schist.

In poorly exposed or extremely weathered road cuts, the Charlotte Belt Gneiss may often be recognized by the remains of compositional or color banding. The unit is cut by large feldspar and secondary quartz dikes, the remnants of which may be observed as blocky float. Folding, where observable, is of a very broad and gentle nature. Varieties of the more salic bands within the gneiss closely resemble igneous and “granofels” type rocks found in the site area. Some of these bands may represent an injection (lit-par-lit) and assimilation process. Some rock cores obtained from the Charlotte Belt Gneiss and Migmatite Units exhibit an increasingly granitic texture with depth, indicating the possibility of subsurface plutons below the depths penetrated by borings.

The Carolina Slate Belt Unit (Reference 39), which is confined to the southernmost portion of the mapped area, contains greenschist facies metamorphic rock types as follows:

1. Tan, fine- to medium-grained quartz-feldspar-muscovite/biotite schist. This rock is generally low in mica content, containing only enough to form moderate schistosity. Quartz content of the schist varies, sometimes forming impure quartzites.
2. Black, fine-grained hornblende amphibolite, observed as massive exposures in stream beds.
3. Various colored (light) relatively pure, very hard quartzites, derived gradationally from the schistose rocks described in rock type 1 above. These rocks exert topographic control from Peak, S.C., southward.

The Migmatite Unit contains a gradational assortment of migmatitic rock types which generally are associated with mapped plutonic phenomena. “Migmatite,” as used herein, is defined by

Turner and Verhoogen (Reference 40) as consisting of 2 lithological elements intimately mixed: country rock variously altered by metamorphism and metasomatism, and granitic. Three (3) general migmatite rock types are defined within the mapped area:

1. Migmatite of gneissic composition which resembles rock of the Charlotte Belt Gneiss Unit, but exhibits disruption, flowage, perfectly healed shears.
2. A contact breccia in which angular to subrounded fragments of fresh-appearing to altered dark grey to black fine-grained country rocks are strewn throughout a fine-grained granitic matrix.
3. Migmatite of granodiorite composition which contains slight to well-foliated characteristics and/or some relic inclusions of altered country rocks. Contactphenomenon (alteration of texture, composition, and individual minerals) sometimes are observable. This is generally fine- to coarse-grained hornblende-plagioclase rock which is sometimes quite similar to ordinary igneous diorite or granodiorite, apparently produced by homogenization of hornblende-plagioclase gneisses through partial fusion, metasomatism, recrystallization, or combinations of these processes. The observable feldspars generally are not zoned, in contrast to the zoned feldspars of the granodiorites.

Field data associate the Migmatite Unit rocks with plutons. Generally, migmatites are present beyond the perimeter of a pluton, and extend a few hundred to over a thousand feet between the pluton and country rocks. Highly contorted gneisses and observed close interlayering of Charlotte Belt gneisses, granodiorites, and granofels were mapped as mignatite. The structure of migmatite zones has been disrupted over large areas, apparently by mobilization of quartz-feldspur gneiss and granofels.

The Granodiorite Unit occurs in an irregular pattern across the central mapped area and consists of 2 types of plutonic rocks:

1. One (1) is a light gray medium- to coarse-grained post-metamorphic or synmetamorphic rock of general granodiorite composition which is similar to the mafic phase of the nearby Winnsboro Adamellite (Reference 24). It also resembles the coarse-grained hornblende-plagioclase migmatite previously described (Type 3), but is distinguished by zones alkali feldspar crystals (phenocrysts). Exposures of this rock are characterized by a coarse-grained, granitic texture and an occasional presence of boulders.
2. The second is a light gray to tannish fine-grained, post-metamorphic rock of approximate granodiorite composition which is similar to the nearby Rion Adamellite (Reference 24).

It is characteristically exposed as large boulders, exhibiting a fine, equigranular, granitic texture. Thin planar dikes of aplite and pegmatite sometimes are present (most exposures do not show these dikes). This rock probably was injected into the older coarse-grained granodiorite shortly after crystallization. Rocks of the Granodiorite Unit sometimes are topographically expressed by higher relief and irregular drainage. Both concordant and discordant contacts were mapped. Due to the complex geologic history of the area, the genetic origin of these plutons is uncertain.

Plutonic rocks observed in Fairfield and Newberry Counties seem to occur along irregular patterns. Some contacts generally are concordant, following the regional strike, while some are discordant, following the prevailing joint system; others are irregularly discordant. The dip and strike of the country rocks often are erratic in the vicinity of plutons.

The Granofels Unit is a light gray to pinkish gray fine-grained rock of granitic texture which resembles the Rion Adamellite but contains slight foliation characteristics with areas showing a predominant grouping or zonation of dark minerals. Irregular veins or pods of quartz and/or pegmatite are present. It often contains a distinct cleavage of undetermined origin that may represent a flow, structural, or metamorphic phenomena. The cleavage causes weathered material to form small rod-like pieces of disc-shaped fragments which are observable on the exposure surface. This unit rarely is exposed as fresh rock, and generally is not represented by boulders. Saprolite exposures, however, are abundant and are mappable. The Granofels Unit may have either an intrusive or interlayered relationship with the gneisses. Field evidence indicates that this rock is a pre-metamorphic granite (or near equivalent) or a granofels (generally defined as a fine- to medium-grained granoblastic metamorphic rock that has the texture and usually the mineralogy of granitic rock). The designation “Granofels Unit” was selected as the most appropriate to distinguish the mappable unit. Large areas are present north and northwest of the site.

There are dikes of aplite, some of which have cleavage and closely resemble the granofels or salic gneiss and are interlayered with the more hornblende-rich rocks. Migmatite and metamorphic zones usually contain dikes or interlayered pegmatites and/or secondary quartz, which are observable as float on the surface. These dikes may be large and irregular as opposed to the thin (8-inch maximum) uniform, and planar dikes of pegmatite and aplite which cut the post-metamorphic granodiorites (quartz float is not present in the Granodiorite Unit areas). Saprolite and soil derived from migmatite frequently contain evidence of weathered relict inclusions which often are ellipsoidal or spheroidal.

The upper 5 to 10 feet of soil, found in the original undisturbed portions of the site area, generally consist of red to reddish-brown stiff clayey and silty soils containing variable quantities of sand. These soils are usually underlain by yellow to reddish-brown micaceous sandy silt and/or silty sand which grades increasingly dense and sandy with depth to rock. Essentially all soils observed in the site area borings are residual. Some alluvium is present along Frees Creek in the valley to the north of the site and in the flatter segments of erosion gullies which incise the ridge flanks.

Geologic borings drilled indicate that the depth of rock weathering varies considerably across the site area. Three (3) subsurface geologic sections have been constructed from data from widely separated deep borings which illustrate an uneven rock surface and inconsistent thickness of soil. The locations of these sections are presented on Figure 2.5-14, Location of Site Subsurface Sections. The subsurface sections, designated A-A', B-B', C-C', are shown on Figures 2.5-15, 2.5-16, and 2.5-17. The thickness of soil found in borings, in general, varies from about 40 to 95 feet. Slight to extensive weathering of rock generally extends from depths of 40 to 120 feet. The variable depth of weathering in the general site area primarily relates to the:

1. Type of rock from which the soils were derived (parent material).

2. Angle of foliation or layering.
3. Density and orientation of jointing.
4. Amount of erosion which has occurred in a given area.

2.5.1.2.1.3 Geologic Structure - General Site Area

The results of the field mapping within a 10-mile radius of the site are presented on the Areal Geologic Map, Figure 2.5-13. According to McCauley (Reference 38, Reference 41), folding within the Carolina Slate Belt is moderately tight and has a general northwestward asymmetry. Individual folds are not traceable in the field, but frequently can be approximately outlined. The Charlotte Belt exhibits a less distinct fold pattern, but the general structural trend is the same. Two (2) inferred synclines are shown on Figure 2.5-13 approximately 5 and 8 miles south of the site that closely parallel the Charlotte Belt/Slate Belt contact, striking approximately N75E.

A statistical analysis of foliation and compositional bedding planes in the general site area indicates a major disruption of country rocks by pluton emplacement. The Areal Foliation Contour Diagram, Figure 2.5-18, presents a plot of 108 such planes from the entire mapped area, and indicates a shift from the N70E average trend in the general area to about N50E, with dips spread unevenly to the southeast and northwest. Both the shift from regional strike and the uneven distribution can be attributed to the disruption resulting from plutonic emplacements. Plutonic rocks have been mapped as fingers, irregular zones, and as small to moderately large plutons which generally trend in an east-west pattern, indicating a general concordance or structural relationship and a connection with the adamellite rock to the east mapped by Wagener (Reference 24). A moderate size granodiorite pluton exists at the western boundary of the site (Figure 2.5-13). The northwest contact with the country rock east of Broad River is concordant, while the others are moderately discordant, probably reflecting the influence of a joint system. Smaller granodiorite plutons are found north and east of the nuclear plant site. Precise boundaries of plutons are difficult to determine because of the peripheral zones of migmatite. The altered character of the migmatites seems to increase as the plutons are approached.

The high density zone in the lower right quadrant of Figure 2.5-18 represents points north of, and adjacent to, the site. This area strikes N43E and dips moderately to the southeast, possibly forming the southeastern limb of a northeast striking anticline. The N43E strike of this area deviates approximately 25° from the usual regional strike, and the isolated density concentrations at the east, south, and west edges of the figure indicate that disturbance is present to some degree.

The density zone near the northern edge of Figure 2.5-18 represents foliation planes located several miles south of the site. The general strike of this area is N78E and closely approximates the regional strike. The dip is steep to the northwest, indicating the presence of the southern limbs of the synclines shown on Figure 2.5-13. The high density areas of this figure are much broader than foliation contour diagrams of nearby localities prepared by others (Reference 41, Reference 23), indicating a significant pluton influence within the general site area.

Figure 2.5-21, the Pluton Area Foliation Contour Diagram, represents a plot of 30 planes from areas of known pluton emplacement. The irregular distribution of high-density zones is very

apparent, illustrating the disruptive effect of plutons on older metamorphic rocks. The field and core data (increasing granitization with depth) enhance the probability of subsurface plutons which disturb northeast-southwest trending folds of metamorphic rocks.

A well developed joint system was observed in most rocks in the mapped area. The Areal Joint Contour Diagram, Figure 2.5-20, represents a statistical analysis of more than 135 joints from the area mapped, and exhibits a system for which the prevailing directions are N30W with an approximate dip of 80° northeast and N67E dipping vertically. The secondary set averages N45E and dips approximately 80° northwest. These joint sets probably represent a combination of vertical diagonal shear jointing, with longitudinal and cross-tension joints, all related to folding. The joint system enhanced development of a trellised drainage pattern which alters to dendritic where influenced by pluton emplacement.

Two (2) diagrammatic sections have been constructed which show some aspects of these general structural relationships. These sections are presented on Figure 2.5-21.

Figure 2.5-21 is a diagrammatic section across a portion of the general site area. The attitudes and relationships shown are not absolute, but depict the most probable gradational subsurface relationships based on the interpretation of surface data.

Three (3) basic rock types are shown: 1) granodiorite (plutonic), 2) migmatite (granodiorite and gneissic in composition), and 3) Charlotte Belt Gneiss (country rock).

The migmatite unit consists of a gradational assortment of migmatitic rocks generally associated with plutonic emplacement. Here the unit consists of 2 lithological elements intimately mixed; country rock (CBG) and granitic (granodiorite). Field data associate the unit with plutons, and the associated mixing generally extends well beyond the perimeter of the pluton.

The plutonic rocks observed at the site (the granodiorite unit) occur along irregular patterns; some contacts are generally concordant, following the regional strike, others are discordant, following the prevailing joint system, while others are irregularly discordant. The dip and strike of the country rock (CBG) are often erratic in the vicinity of plutons.

The detailed field mapping revealed no evidence of shearing or fault displacement in the area of Frees Creek, and no evidence which would indicate the contacts shown on Figure 2.5-21 are not intrusive in nature.

Field evidence suggests a fault in the southwestern Parr area, approximately 3 miles southwest of the site as shown on Figure 2.5-13. Discordance in foliation and beds exists at Parr and 3 miles southwest on S.C. 29. Rock at the S.C. 29 exposure exhibits intense shearing in thin section, and strikes N50E toward the exposure at Parr. Similar rock, also exhibiting shear features, may be traced on strike approximately 2 miles southwest of the S.C. 29 exposure. The similarity of the strike to those proposed by others (Reference 41, Reference 23) and to shears mapped in excavations for the proposed facilities, suggest that this structure is part of a general fault zone. An approximate 90° dip reversal across a narrow disrupted zone exists on the fault strike along S.C. 213, 1 mile northeast of the S.C. 29 exposure. A thin section from this exposure also exhibits

shearing. Slickensides are present in the core of 1 boring drilled on the Parr Dam. Displacement at the Parr exposure seems to be small, and could not be determined at other exposures southwest of Parr due to the lack of evidence (displacements of shears found in the excavations were less than 7 feet, and are discussed in Section 2.5.1.2.2.2). Detailed field reconnaissance for a distance of 2 miles either side of the theoretical northeast projection of this postulated fault was performed, and extended up to County Highway 48, about 6 miles northeast of Parr. Rock cores obtained from borings drilled at the site were examined, and petrographic analyses were performed on selected cores. However, no evidence of faulting was found until the excavation for the Reactor Building exposed non-capable shears in the site bedrock. These near vertical shears were exposed in the bedrock after removal of approximately 100 feet of residual overburden, and are noncontinuous en echelon features which represent oblique slip faults. A complete discussion of onsite faulting including evidence pertaining to the age of these features is presented in detail in Section 2.5.1.2.2.2, Geologic Structure of Excavations.

A ground magnetic survey was conducted to attempt magnetic correlation with geologic features. Measurements were made at 352 stations with a Varian Total Field Magnetometer. The results are presented on the Areal Magnetic Anomaly Map, Figure 2.5-22, using a 100 gamma contour interval. The data illustrates variations in the total magnetic field.

In general, the contours reflect correlation between basement lithologies and the magnetic field. The geologic map is based on observed surface outcrops and cores from test borings, while the magnetic anomaly map reflects deeper or more magnetically intense lithologies. The survey illustrates the variable geologic lithologies encountered during field mapping and in the bore holes. Anomalies of over 1,000 gammas occur within a 500 foot lateral extent. The high magnetic relief noted within the site area should not be misinterpreted as suggestive of greater variability than the surrounding area. The smoother contours farther from the site are a function of wider station spacings.

Magnetic gradients on Figure 2.5-22 have distinct northeast trends, probably related to regional folding, and distinct northwest trends which are roughly aligned with the northwest regional fracture trend. Detailed field investigations over the terrain that includes these magnetic gradients produced no evidence of faulting which would account for the magnetic trends. The northwest magnetic trends appear to be a deflection of the northeast regional magnetic isograd trends produced by the group of 6 pronounced magnetic highs surrounding the site. These highs could be reflections of magnetite-bearing intrusive stocks, such as the granodiorite exposed within the reactor excavation, which have higher magnetic susceptibilities than the surrounding high-rank metamorphic rocks.

2.5.1.2.1.4 Geologic History

The geologic history of the area is highly complex and difficult to establish. However based on the work by Wagener (Reference 24) in the USGS quadrangle immediately east of the site and the results of the radiometric age data obtained as part of the detailed investigation of the reactor excavation (Section 2.5.1.2.2.3), the probable sequence of events is as follows:

1. Deposition of quartzose, argillaceous, silty, and feldspathic arenaceous rocks, and extrusion of mafic volcanic rocks in an early Paleozoic archipelago.
2. Deep burial.
3. Complex folding, faulting, and regional metamorphism of the Charlotte Belt.
4. Intrusion, crystallization, and cooling of granodiorite/adamellite plutons.
5. Production of joints in response to a broad regional stress field.
6. Introduction of fluids which precipitated aplite and pegmatoid dike rock partly along the joint system.
7. Minor displacement along northeast-trending joint system.
8. Very minor displacement along northwest-trending joint system.
9. Hydrothermal alteration along some joints, and alteration and recrystallization of microbreccias along all segments of shears.
10. Epeirogenic uplift, weathering, and erosion.

Radiometric ages of rocks similar to those on the site have been determined (Reference 41) Samples of typical Charlotte Belt granitic type rocks indicated ages (Pb-alpha) of 270 ± 30 million years. These ages indicate a relatively young episode of granitic emplacement in the site area. An age determination (K-alpha) of 357 million years was obtained from quartz-microcline gneiss in the Lake Murray Spillway in Lexington County, about 17 miles south of the site. This determination is interpreted as evidence supporting a much older age for the country rocks in the Piedmont. This value is considered to be close to the age of 1 of the early major regional metamorphic events (Reference 41) Rock samples obtained from excavations for the proposed facilities have been subjected to radiometric analyses, and the ages determined agree closely with those presented above. These analyses are discussed within Section 2.5.1.2.2.3.

2.5.1.2.2 Geology of Excavations

During excavations for the Reactor and Control Building foundations, minor shearing of the type commonly found in the Piedmont was exposed in rock after the removal of about 100 feet of residual overburden. A detailed investigation was conducted to evaluate these features which include detailed geologic mapping and sampling, excavation of trenches, radiometric dating, X-ray diffraction analysis, literature search with emphasis on recent tectonic displacements, air photo and ERTS imagery analysis, gravity and magnetic data analysis, in situ stress measurements, evaluation of potential movement along shears due to the filling of Monticello Reservoir, review of local microseismic data, correlation of Piedmont seismic activity with reservoir impoundments, and offsite geologic reconnaissance. These analyses were integrated to identify the physical and chronological relationships found within the excavation. The structural history of the site was developed on the basis of established geologic principles, cross-cutting relationships, hydrothermal criteria, petrology, and radiometric dating. The detailed descriptions and results of these studies were presented in the “Supplemental Geologic Investigation, Virgil C. Summer Nuclear Station - Unit One,” dated January 14, 1974.

Subsequent to this investigation, detailed geologic mapping was extended into additional areas of excavation in order to maintain a complete record of the rock exposed during construction. Description and results of these studies were presented in a series of addenda to the "Supplemental Geologic Investigation", which included an investigation of: the staging area excavation west of the reactor (Addendum I); the Control Building excavation (Addendum II); the Intermediate Building wall excavation (Addendum III); and the Service Water Pond north dam excavation (Addendum IV). The relative locations of the various areas investigated are presented on the Areas of Detailed Investigation Map, Figure 2.5-23 and on Figure 2.5-29.

The lithologies encountered within the various excavations are basically the same and are discussed in the following Section 2.5.1.2.2.1. The structural geology of each excavation is discussed in Section 2.5.2.2.2. The results of Section 2.5.1.2.2.3 and Section 2.5.1.2.2.4, respectively.

2.5.1.2.2.1 Lithology and Petrology - Excavations

The principal rock units in the excavations are consistent with the model discussed within Section 2.5.1.2.1.2. Detailed geologic maps compiled for the excavations show the distribution of the various units, and are presented on Figure 2.5-24, Figure 2.5-26, and Figure 2.5-29. These units are, as observed in the excavations and based on hand specimen examination:

1. A dark fine-grained hornblende-plagioclase amphibolite typical of amphibolites commonly associated with and mapped as Charlotte Belt Gneiss.
2. Fine-grained contorted biotite gneiss, partly migmatized. The foliation in this rock unit has been severely disturbed. Small-scale discontinuous tight folds (wave-lengths of a few inches) are separated in part by fine-grained granitic veinlets which tend to have diffuse boundaries. Thus, the rock can be superficially confused with the contact breccia unit. However, the deformation in the gneiss has proceeded at least to a large extent via ductile failure, thus producing a distinctive contrast with the angular rock fragments in the contact breccia.

   The contorted gneiss is involved in migmatitic relationships with the granodiorite. Veins, pods, and concordant layers of granitoid rock closely resembling or directly traceable into the granodiorite commonly occur in the gneiss within a few feet of the principal gneiss-granodiorite contact. Slab-like inclusions of gneiss in granodiorite have been ductilely extended, but generally retain their original structural orientation.

   Other facies of this unit include relatively uncontorted granitic gneiss and a fine-grained granitoid rock with easily overlooked subtle foliation.

3. A contact breccia comprised of amphibolitic or basaltic fragments up to a foot or 2 in maximum dimension in a matrix of fine-grained leucocratic granitic material. The angular melanocratic fragments exhibit clear evidence of brittle failure. Large percentages of these, however, have been subsequently rounded. The granitic matrix has foliation patterns indicative of fluid flow around the fragments. The total aspect is that of a diatremic or otherwise explosive volcanic breccia.

Xenoliths of coarse breccia are involved in a contact breccia within certain portions of the margins of the granodiorite. The contact between the granodiorite and the contact breccia unit, however, is a sharply defined, apparently intrusive contact that is generally concordant with strike trends of other rock unit contacts in the Reactor and Control Building foundation excavations. These trends are northwest, opposed to the general northeast regional trends, but are not atypical of strikes of lithologic boundaries in this part of the Piedmont (Reference 24). Dips of the major lithologic contacts in the excavation are steep to the northeast.

The rock association (granodiorite-migmatized, contorted gneiss-contact breccia-coarse breccia), on the scale of the exposed rock system in the excavation, especially as interrelated in the north-central portion of Figure 2.5-24, could be referred to as “migmatite,” or as a migmatite zone (syntectic zone of Wagener (Reference 24)).

4. A medium- to coarse-grained, in part porphyritic, biotite-hornblende adamellite or granodiorite. For consistency, this rock will be referred to herein as granodiorite (the distinction between adamellite and granodiorite is difficult to establish in thin section and is not pertinent to this study). The quartz has undulatory extinction similar to that normally observed in granitic igneous rocks, but the rock exhibits no other sign of internal strain. Plagioclase is euhedral in part, gradationally zoned, rimmed by albite adjacent to microcline crystals, and is, in general, only slightly altered to sericite-like products. Phenocrysts, where present, are of microcline perthite. Hornblende is green-brown, euhedral, and unaltered. Biotite is generally unaltered, but occasional grains have been partly converted to clear green chlorite of the type attributable to deuteric alteration.

   The granodiorite, then, where undisturbed by fractures, exhibits no evidence of having been subjected to shearing stresses, regional chemical metamorphism, or any significant degree of hydrothermal activity.

5. Rion type adamellite or granodiorite. In the eastern portion of the Reactor Building excavation, Figure 2.5-24, 2 sill-like bodies of very fine-grained granitic rock about 2 feet thick lie within the contact breccia unit. The rock closely resembles the Rion Adamellite (Reference 24) and may be intrusive into the contact breccia.
6. Fine-grained granofels (metagranite) associated with amphibolite. This rock group is characteristic of certain Charlotte Belt rocks exposed in road cuts throughout the high-rank regionally metamorphosed portion of the eastern Piedmont. The granofels has inclusions of amphibolite, and is probably a pre-metamorphic intrusive rock.
7. Aplite-pegmatite dikes and discontinuous pegmatite veins. Several dikes from less than 1 inch to about 6 inches thick cross cut all rock types in the excavation except shear zone microbreccia. Some of the dikes are predominantly aplite (fine- to medium-grained quartz-feldspar rock), and some are coarse grained and distinctly pegmatoid. Some change from aplite to permatite (and vice versa) along strike, as is characteristic of such dikes in this part of the Piedmont. In the western portion of the Reactor Building excavation several discontinuous (en echelon) fractures up to about 3 inches thick and several feet long have

been filled with quartz-rich pegmatite containing feldspar crystals up to about 1-1/2 inches long. The aplites and pegmatites tended to follow pre-existing joints in part.

2.5.1.2.2.2 Geological Structure - Excavations

Geologic structures within the site excavations illustrate responses in both ductile andbrittle deformation regimes. Blocks and slivers of Charlotte Belt gneiss caught in the granodiorite intrusion show a well-developed foliation surface containing a mineral alignment lineation. Both of these structures appear distorted by the intrusion and are likely related to pre-intrusion ductile deformation. Reconnaissance of roadcuts in the vicinity of the site reveals a few mesoscopic isoclinal folds with the foliation surface acting as the axial surface of the folds. Also, crenulation of that foliation surface was noted locally which suggests that Charlotte Belt rocks in the vicinity of the site experienced polyphase folding at least on a minor scale prior to intrusion of the granodiorite. The distortion of the early ductile deformation fabrics by the intrusion make it impossible to analyze these fabrics, as observed at the site, for the purpose of obtaining any indication of the regional structure to which they are related. Although the foliation surface is locally concordant with intrusive contacts, it is most commonly discordant and sometimes shows evidence of rotations.

The brittle deformation structures include areas of brecciation possibly related to the intrusion, non-displaced joints, and shear zones, some of which show net slips of 6 to 7 feet.

Pegmatite and aplite veins occur in the site area, some of which have been injected along joints while others are cross cut by jointing. The relationships suggest at least 2 generations of veining and/or jointing. Hydrothermal mineralization occurs along some joints which show no offset; however, this mineralization occurs most strongly along shear zones which show displacement. The field analysis revealed that no joint orientations are confined exclusively to a single rock type.

Reactor Building and Staging Area Excavations

The near-vertical shears exposed in the Reactor Building excavation represent oblique slip faults having a left-lateral component as well as a normal component which is downthrown on the south side. The maximum net displacement is no greater than 7 feet. Individual shears range in thickness from a fraction of an inch to less than 1 foot. They are not continuous but occur as en echelon features which do not penetrate through the soil profile to the ground surface. Maximum strike separations are noted along shears 1 to 2 feet in width which trend N60E and occur in Zone 3, as shown on the Structure Map of Reactor Building and Staging Area Excavations, Figure 2.5-25. Values of net slip were obtained by the standard methods outlined in Donn and Shimer (Reference 51), with the aid of the Wulff stereonet. True displacements of the N60E shear of Zone 3 show no greater than 6 to 7 feet of net slip. The left lateral strike slip component of foot to 5 feet. This segment of the N60E shear appears to be a left-lateral oblique slip normal fault with the northwest side upthrown as indicated on Figure 2.5-25. Figure 2.5-25 also shows that the shears are discontinuous. The 3-dimensional geometry of the motions derived from the stereonet analysis is shown schematically in the Block Diagram, Figure 2.5-33, which illustrates that the displacement decreases southwestward along the shear.

Complex displacements are indicated at the 2 locations along the N60E shear of Zone 3 where displaced veins and slickensides provided enough data upon which to base maximum net slip determinations. The occurrence of fragmented veins and at least 2 orientations of slickensides certainly indicate that shearing is not confined to a single plane but is accommodated through the entire width of the zone. Maximum possible displacement along the zone was provided by the stereonet analysis since it was based upon the relative positions of offset veins. A 45° core boring was located based upon the relative positions of offset veins (see Figure 2.5-24). The 45° core boring intersected what is likely to be the extension of this N60E shear segment of Zone 3 approximately 110 feet vertically below the present rock surface, recovering samples for analysis. These relationships are illustrated on the Profile Along Angle Boring A-1, Figure 2.5-34.

Actual displacement was also determined along a discontinuous shear surface trending N28W which was located at the southwestern end of the excavation. Left lateral strike separation along this surface was 3.5 inches. The computed net slip is 3.9 inches, and is essentially parallel to the strike of the joint. The dip slip component is essentially zero.

Planes or zones which show displacements in the excavation as well as non-displaced fractures greater than 25 feet in length have been documented and are shown on Figure 2.5-25. The N60E shear of Zone 3 shows maximum slip. At other locations where displacements are observed at the excavation, separations, in every case, amount to less than 2 feet and commonly less than 1 foot. Determination of actual net slips at these other locations was not possible; however, the 3 dimensional geometry of offset veins observed precludes slips greater than those determined for the N60E shear of Zone 3.

Discontinuous segments of Zone 3 are traceable no greater than about 170 feet northeast of the excavation. These shears were traced away from the excavation through saprolite, becoming increasingly indistinct with higher elevation. At approximately 10 to 20 feet beneath the original ground surface, visible manifestation of these features disappeared.

Figure 2.5-31 is a Stereonet Diagram showing attitudes of nondisplaced fractures; Figure 2.5-32 presents a Stereonet Diagram showing the orientation of fractures with hydrothermal mineralization and shears which show displacements. The attitudes of fractures within the excavation agree with attitudes within 10 miles of the site (Section 2.5.1.2.1.3). The northeast-striking and northwest-striking trends appear to parallel regional topographic lineaments within the USGS Jenkinsville quadrangle, Figure 2.5-11, and lineaments shown on ERTS photographs, Figure 2.5-10. The orientations of faults suggested by McCauley (Reference 38), Section 2.5.1.2.1.3, also agree with the trends of fractures and shears at the site. A complete discussion of these relationships was provided in the “Supplemental Geologic Investigation.”

Displacement along the N20W to N40W shears, which offset the northeastern shears, illustrates the relative age relationships between the northwest and northeast shears. Of much importance to indicate the present stability and/or lack of geologically recent tectonism of the northeast and northwest shears is the occurrence of euhedral unsheared hydrothermal minerals in the microbreccia zones. The fact that unsheared hydrothermal mineralization occurs in both shear orientations indicates that shearing has not occurred since the hydrothermal event. The pink coloration of crushed rock within the shears and some uncrushed wallrock is related to this post-

deformational hydrothermal event which pervaded northeast trending Shear Zones 1, 2, and 3 (Figure 2.5-25), and affected northwest oriented shears to a lesser extent. This event was characterized by extensive introduction of the zeolite laumontite along shear and joint surfaces. Laumontite was identified by both X-ray diffraction and petrographic techniques. X-ray diffraction analyses were performed on samples recovered from the Reactor Building excavation, the Control Building excavation, and the north dam excavation. The X-ray Diffraction Pattern of Laumontite,Figure 2.5-35, presents a diffraction pattern which is typical of those obtained during the various investigations. Results and details pertaining to typical methodology of the X-ray diffraction studies performed are presented in Appendix 2A.

Vugs up to about 18 inches long lined with euhedral pink laumontite crystals up to about 0.4 inches long were observed in all exposed shear orientations. At 2 points along a principal shear of Shear Zone 3, and elsewhere, laumontite crystals completely fill the shear, having grown inward from both walls. Similar relationships were observed in thin sections of brecciated rock from shears. Also observed in thin sections of microbreccia were the existence of euhedral to subhedral laumontite crystals and crystal groups within the fine fractures indicating the pervasive nature of the hydrothermal event. This event may, in fact, have been the annealing influence.

Laumontite is thermodynamically unstable below about 180oC to 190oC and at less than an equivalent pressure of 150 meters of H2O (Reference 42, Reference 43). Therefore, laumontite present within the shears crystallized in a pressure-temperature regime that no longer exists at the site. Furthermore, hydrothermal events within the Piedmont are often associated with Triassic (Jurassic diabase dike emplacement. There are no known occurrences of hyrothermal activity within the stability field of laumontite in the Piedmont since Triassic-Jurassic time. Apparently only 1 other mineral was introduced during the laumontite event in significant quantities, that being a microcrystalline variety of alpha quartz (identified by X-ray diffraction).

Other materials observed filling or partly filling shears are a soft black substance of the nature of wad (amorphous by X-ray diffraction) and a white clay which yielded X-ray diffractogram peaks for kaolin and alpha quartz. These materials can be produced in soils by weathering or secondary enrichment reactions.

Immediately adjacent to portions of some shears, the granodiorite, although mesoscopically appearing to be otherwise unaffected, is distinctly pink due to coloration of the feldspars. By examination of thin sections it was observed that the plagioclase feldspars contained minute granules of reddish translucent to nearly opaque material, possibly red iron oxide. Some pink granodiorite immediately adjacent to shears has been broken into wedge-shaped slices bound by greenish-black slickensided surfaces. An unfractured 2 mm cube of pyrite was observed to transect 1 such surface. Pyrite crystals also occur along several joint surfaces in the excavation.

The shears generally contain microbreccia produced from whatever rock type the shear transected. Microbreccia along shears is characteristically an inch or 2 thick, but in some shear segments up to several feet long (along strike) it widens abruptly to a maximum width of not greater than 2 feet. Thin microbreccias and pink laumontite fillings also occur along fracture segments which have no demonstrable displacement. The shears within granodiorite generally are

the least affected by weathering, and thus most study specimens of microbreccia were obtained from sheared granodiorite.

Both mesoscopically and microscopically the crushed rock within the shears fits precisely the definition of microbreccia (Reference 44) produced through brittle failure. Angular rock and crystal fragments are suspended in a matrix of similar but finely comminuted material. The matrix, even at magnification 200 to 400 by polarizing microscopic, has the distinct appearance of an interlocking crystal mosaic. There is no evidence of unrecrystallized rock powder.

Laumontite occurs in varying proportions in the microbreccias, both as vein filling and as euhedral to subhedral crystals and crystal groups in microbreccia. The microbreccias, therefore, seem at least partly recrystallized (annealed) and are thoroughly permeated by hydrothermal laumontite. Neither crushed laumontite crystals nor other evidence of any shearing dislocation having postdated the hydrothermal event were observed.

Here and there in the thin sections, even delicate microscopic overgrowths on microcline crystals project into laumontite vein filling or microbreccia and have not been disturbed by shearing or crushing. The hydrothermal event, then, is the latest event of significance (other than weathering) to have affected the rock in the excavation, and certainly postdates shearing present in the excavation.

Control Building Excavation

The Control Building excavation located south of and adjacent to the Reactor Building excavation (Figure 2.5-23) also revealed northwest-trending fractures which showed evidence of displacement; these fractures are shown on the Structure Map of Control Building Excavation, Figure 2.5-27. The most prominent shear in the excavation consists of a northwest-trending displaced fracture set (NW1 on Figure 2.5-27) traceable directly into the locally displaced N15W to N40W fracture set of the Reactor Building excavation (see Figure 2.5-25). Although both northwestern and northeastern joint sets have been mineralized, recognizable slip was observed only along northwest-trending fractures. Strike separations along discontinuous shears NW2 and NW3 (Figure 2.5-27) are less than 3.0 inches, and both show a left lateral sense of displacement which dies out locally within the Control Building excavation.

From the 3-dimensional relationship provided by a combination of offset dikes and veins in the excavation floor, an offset dike in the excavation wall, and nearly down-dip slickensides on the shear surface at several positions in the excavation wall, it was determined that Shear Zone NW1 is a reverse slip type with the easternmost block having moved upward relative to the westernmost block. The maximum calculated net slip along the shear is approximately 3 feet 2 inches, which decreases to about 2 feet over a lateral distance of approximately 25-30 feet toward the Reactor Building excavation. Displacement is concentrated along the N14W segment of NW1 rather than the N29W segment which passes into the Reactor Building area (see Figure 2.5-25). The shear is best qualified as having a reverse, nearly dip slip movement with a weak left lateral strike slip component.

As noted within the Reactor Building excavation, displacement along the northwestern shears offset northeastern-trending joints at the Control Building site to suggest that motions along the northwestern shears were the last movements to occur. Also as noted at the Reactor Building excavation, hydrothermal mineralization occurs in both the northwestern and northeastern shears and joints to indicate that hydrothermal mineralization was the latest event.

A detailed discussion of the studies conducted at the Control Building excavation is contained in Addendum II of the "Supplemental Geologic Investigation."

Intermediate Building Wall Foundation Excavation

The Intermediate Building wall foundation excavation is located south of the Reactor Building excavation (see Figure 2.5-23). The entire excavation base was situated in massive fresh rock. Only 3 joints which exceeded a few feet in length were observed. The joints are illustrated on the Structure Map of Intermediate Building Wall Excavation, Figure 2.5-28. The strike of these joints averaged about N20W with an essentially vertical dip. All of the joints were closed, and there was no evidence of mineralization or displacement. The investigation of this excavation was reported in Addendum III of the "Supplemental Geologic Investigation."

North Dam Excavation

The north dam excavation is located northeast of the Reactor Building excavation, as shown on Figure 2.5-29, Geologic Map of North Dam Excavation. The north dam excavation contains nondisplaced closed joints, joints which have been subjected to hydrothermal mineralization, fractures that exhibit evidence of minor displacements, and some well-developed mineralized fractures along which movement may have occurred. However, positive evidence of displacement along the well developed mineralized fractures was not found.

Figure 2.5-30, Structure Map of North Dam Excavation, shows that the average strike of Shear, Zones 1, 2, and 3 of the Reactor Building excavation (see Figure 2.5-25) coincides with the strike of the mineralized fractures mapped in the north dam excavation indicating that these fractures are probably a northeastward extension of the shear zones mapped in the Reactor Building excavation. X-ray diffraction analysis of samples recovered from mineralized fractures identified laumontite. The locations from which the samples were obtained are shown on Figure 2.5-29. The general pattern formed by the mineralized fractures was very similar to that observed within the Reactor Building, staging area and Control Building excavations.

No evidence was found which would indicate an age younger than that established for the shears in the Reactor Building area excavation (45 ± 5 m.y.) (Section 2.5.1.2.2.3). Additionally, no evidence was found which would indicate that these mineralized fractures were not part of the same structural system mapped and studied in nearby excavations. Complete descriptions, photographs, and discussion of fractures and related features are contained within Addendum IV of the "Supplemental Geologic Investigation."

2.5.1.2.2.3 Geochronology

The results of radioisotopic age determinations on specimens of microbreccia, granodiorite, and aplite are presented in Table 2.5-3. The location of the various samples are shown on Figure 2.5-24. These data were obtained as follows: Rb-Sr ages were determined by Dr. Paul Fullager (Appendix 2B), assisted by Dr. Michael Bottino via mass spectrometry in the laboratories of the University of North Carolina at Chapel Hill; K-Ar ages were determined under the direction of Dr. Todd Gates (Appendix 2C) of Teledyne Isotopes, Inc., via mass spectrometry.

Ages of the 6 unweathered granodiorite control specimens (both Rb-Sr and K-Ar ages) are in close agreement with Rb-Sr ages previously determined by Fullagar (Reference 45) for the Winnsboro plutonic rocks, which lie only a few miles east of the site. The granodiorite in the excavation is quite similar to the Winnsboro adamellites and granodiorites. The age for the excavation granodiorite (about 300 m.y.) shows remarkable consistency between the Rb-Sr and K-Ar methods. It should be noted that the K-Ar age for the slightly weathered granodiorite control specimen SD3.1 is significantly later than 300 m.y. This difference is probably due to argon loss upon weathering of biotite, effects of which (altered edges of biotite crystals) show up in thin section. Therefore, in considering the data of Table 2.5-3, the possibility of argon loss from any weathered specimen should be considered. This would result in a conservative minimum age determination.

Rb-Sr Ages of Hydrothermally Altered Microbreccia and Granodiorite

These ages, except for Specimen SC2.4, are all considered earlier than the granodiorite age (see Table 2.5-3), a fact superficially inconsistent with the field evidence. However, the hydrothermal alteration should have increased the assumed initial Sr87/Sr86 ratio by an amount difficult to assess, thereby causing the specimens to yield an apparent earlier age (Reference 46). Therefore, the Rb-Sr ages of shear zone specimens SC2.2, SD3.2, and NK2.2 are maximum ages for these specimens. Because of the expectable resetting of the radiometric parameters (“radiometric clock”) by pervasive low-temperature hydrothermal activity, the ages of these specimens probably represent maximum ages for the laumontite hydrothermal event. Fullager (Reference 46) is of the opinion, in consideration of his data, the expected resetting, and the petrology of the shear system, that the hydrothermal event may have followed closely upon (within a few million years after) the crystallization and cooling of the granodiorite.

K-Ar Ages of Hydrothermally Altered Microbreccia and Granodiorite

The variations in ages for these specimens (Table 2.5-3), with one exception, do not seem related to any observed lithologic differences, and probably reflect differential loss of argon attendant upon crushing, hydrothermal activity, and weathering. Specimen SC2.4 is similar to Specimen SD3.2, except the plagioclase feldspars in SC2.4 are more extensively altered. Therefore, the much later date for SC2.4 probably reflects greater argon loss during the hydrothermal event.

The average age of the 5 shear zone specimens taken from the bedrock surface is approximately 230 m.y. Assuming an age of 300 m.y. for the hydrothermal event (Reference 46) and an argon loss of 25% (a reasonable assumption for feldspathic rock, according to Gates (Reference 47),

calculation yields an apparent age of about 230 m.y. Therefore, the K-Ar data are not necessarily consistent with Fullagar's opinion that the hydrothermal event may have postdated emplacement of the granodiorite by no more than a few million years.

K-Ar Age of Hydrothermal Laumontite

A specimen consisting of hand-picked laumontite crystals from a vug in Shear Zone 3 has been dated by K-Ar procedures at 45 ± 5 m.y. (specimen X1, Table 2.5-3). This date is considered a "minimum-minimum" age of the specimen (Reference 47).

Laumontite is an open-framework silicate of approximate composition $(Ca,Na)_7Al_{12}(Al,Si)_2Si_{26}O_{80}25$ (H_2O). Such crystal lattices, where K is present, are subject to a high percentage of argon loss. Laumontite has a high ion exchange capacity, as do other zeolites, and thus is expected to take up such ions as the potassium ion (K+) from water solutions in exchange for appropriate ions in the laumontite crystal lattice, or to absorb such ions on defective (locally chemically unbalanced-electrostatically negative) crystal facets (Reference 48). Either at the time of crystallization or later, by the above mechanisms, crystals of laumontite specimen X1 obtained sufficient potassium (0.3%) to be dated by K-Ar techniques. The 45 ±5 m.y. age for these crystals, therefore, represents an absolute minimum age of the potassium ions added to the crystals, because of leakage of radiogenic argon from the crystal lattice. It also represents an absolute minimum age for formation of the crystals, which cannot have obtained the chemically inert radiogenic argon through exchanges with solutions. The radiogenic argon must have begun accumulating in the laumontite crystals when the potassium ions were introduced.

Dr. Todd Gates (Reference 47), who performed the K-Ar analyses, is of the firm opinion that due to argon leakage, the actual age of the potassium, and thus of the crystals, may be as much as about 150 m.y. This brings the possible age of the crystals into the apparent age range of the apparently youngest of the hydrothermally altered rock specimens, SC2.4 (163 ±16 m.y., Table 2.5-3).

By consideration of Rb-Sr and K-Ar radiometric age data obtained on 7 hydrothermally altered specimens from shears, 8 control specimens, and 1 pure laumontite crystal specimens from shears, 8 control specimens, and 1 pure laumontite crystal specimen, the following absolute age chronology has been established:

1. Crystallization and cooling of granodiorite approximately 300 million years ago;
2. Emplacement of aplite dikes no later than 227 million years ago;
3. Shearing along the joint systems; and
4. Hydrothermal introduction of laumontite and annealing of microbreccias within the shears no earlier than 300 and no later than 45 million years ago, and probably between 300 to 150 million years ago.

Because the hydrothermal event obviously postdates the latest movement of measurable significance along all shear zones, it is concluded that this latest movement could not have

occurred later than 45 million years ago and probably occurred between 300 and 150 million years ago.

2.5.1.2.2.4 In Situ Stresses

In situ stress measurements were made on each side of Shear Zone 3 using the overcoring technique. The basic theory and procedures of this technique are described in Appendix 2D.

Hooker and Johnson (Reference 49) made a number of in situ stress measurements along the Piedmont from Georgia to Vermont. They have suggested that the major component of the horizontal compressive stress tends to align in a northeast-southwest direction along with the dominant structural trends of the area. The only apparent disagreement appears to be at a quarry located at Mt. Airy, North Carolina; however, the Mt. Airy intrusive body is post-major tectonic activity (folding and faulting of Piedmont).

Measurements were made on the northwest and southeast sides of Shear Zone 3 in rock of granodiorite composition. The locations of the 2 test holes are shown on Figure 2.4-24, and a description of the rock is contained in Section 2.5.1.2.2.1. The overcoring test at the first test site (OC-1) was taken to a depth of 11 feet, and the test in OC-2 was taken to a total depth of 18.5 feet below the surface of the rock. During overcoring tests where the core broke, the tests were stopped to prevent damage to the gage, and new tests were performed. Plots of the deformation gage digit readings versus position of the overcore bit with respect to the measuring points for the tests are given in Appendix 2D. In most instances it was necessary to continue drilling until the overcoring had progressed approximately 6 inches beyond the point where the piston of the gage was in contact with the rock. The overcored rock for each test was broken loose and used for testing to determine the modulus of elasticity.

The modulus of elasticity was determined for each test section using a biaxial testing device such as the one described by Fitzpatrick (Reference 50). The method of calculation used for the determination is described in Appendix 2D, and the curves showing the results are also presented in that Appendix.

Using the deformation data obtained in the overcoring tests and from the modulus tests, the secondary principal stresses* in the horizontal plane were calculated using the plane stress equations presented in Appendix 2D. The results of these calculations are shown in Table 2.5-4. The map of In Situ Stresses in the Piedmont Area of the United States, Figure 2.5-36, shows the stresses plotted on a map of the east coast of the United States along with the data for other sites in the Piedmont as determined by Hooker and Johnson (Reference 49). It can be seen that for the site the in situ stresses show some relation to the general trend as developed by Hooker and Johnson. The direction of the major compressive stress appears to trend in a general north to northwest direction. The direction of the compressive stress makes it almost perpendicular to Shear Zone 3, and the magnitude of the stresses is well below the estimated strength of the rock.

*The term “secondary” is used since τ_{ZX} and τ_{zy} are not necessarily equal to zero.

2.5.2 Vibratory Ground Motion

2.5.2.1 Geological Conditions of the Site

2.5.2.1.1 Introduction

Discussion and evaluation of the seismo-tectonic characteristics of the Virgil C. Summer Nuclear Station site and surrounding region are presented in this section. The site location is shown in relation to the main regional tectonic features and the significant regional earthquakes on Figure 2.5-37, Regional Epicenter Map. Information presented in Section 2.5.1, Basic Geologic Information, and Section 2.5.4.4, Soil and Rock Characteristics, provides an important basis for conclusions drawn in this section. This information is not repeated in this section, but pertinent facts are cross referenced to other sections where appropriate.

An investigation was conducted to develop seismic design criteria for Seismic Category 1 structures at the site. This investigation included:

1. A comprehensive study of the geologic structure and tectonic history of the region.
2. A review of the seismic history of the region, primarily based on a literature search supplemented by a review of contemporary newspaper accounts and interviews with agencies and individuals.
3. An evaluation of the seismicity of the region considering the relationship of historic earthquakes to known geologic features, tectonics, and earthquake mechanisms.
4. Field geophysical measurements and laboratory testing to evaluate the physical properties of the soils and bedrock at the site (the results of these measurements and testing are presented in Sections 2.5.4, 2.5.5, and 2.5.6).
5. The selection of appropriate earthquakes for the design basis and operating basis conditions.
6. An estimate of the maximum ground acceleration to be expected at the site due to the occurrence of the Safe Shutdown and Operating Basis earthquakes.
7. The preparation of seismic design criteria in the form of response spectra.

2.5.2.1.2 Regional and Site Geology

A detailed description of the lithologic, stratigraphic, and structural geologic conditions of the site and the region surrounding the site, including its geologic history, is presented in Sections 2.5.1.1 and 2.5.1.2. Information concerning the investigation and conclusions regarding shears within the excavations for the Virgil C. Summer Nuclear Station is presented in Section 2.5.1.2.2.

2.5.2.2 Underlying Tectonic Structures

2.5.2.2.1 Regional Geologic Structures

This site is located in the Piedmont Physiographic Province. This province is bounded on the southeast by the Coastal Plain Province and on the northwest by the Blue Ridge Province. The region surrounding the site is generally characterized by rolling and/or ridge topography.

Bedrock of the area generally consists of Paleozoic crystalline metamorphic rocks, with gneisses and schists being more prevalent. These rocks have been intruded by Paleozoic igneous granitic plutons, narrow aplitic dikes, and by diabase dikes believed to be of Triassic age. Bedrock usually is covered by residual soil and saprolite formed by weathering of the bedrock. This weathering generally has been moderately deep, but varies appreciably within short horizontal and vertical distances. The bedrock surface elevation is irregular.

Recent and on-going investigations are attempting to define the structural setting of the southeastern U.S. in terms of plate tectonics. Results of these studies take the form of postulated models to explain the observed seismicity.

Recent investigations in the COCORP program (Consortium for Continental Reflection Profiling) indicate that the crystalline Precambrian and Paleozoic rocks of the Blue Ridge, Inner Piedmont, Charlotte Belt, and Carolina Slate Belt constitute an allochthonous sheet, generally 6 to 15 km thick, which overlies relatively flat-lying autochthonous lower Paleozoic sedimentary rocks (Reference 125). Major regional structures such as the Brevard Zone are thought to be rooted in the base of this horizontal thrust which may have transported the crystalline rocks of the southern Appalachians some 260 km to the west, and controlled the pervasive northeast-southwest structural grain of the Piedmont in South Carolina.

On a regional scale, the upper few kilometers of Piedmont rocks are extensively folded and moderately faulted while the sub-basement is relatively flat-lying and undisturbed.

The closest known regional faulting is a normal fault in the Lake Murray area that is considered to be a splay of the Eastern Piedmont (Goat Rock) Fault, the southwesternmost faulting in the Eastern Piedmont Fault System.

This structure has recently been extended such that the probable closest approach to the site is about 13 miles to the south. The fault trends southwest from Lake Murray. Evidence indicates that this fault has been inactive since at least the end of the Triassic period (about 200 million years).

A north-south trending normal fault has recently been postulated in the Chapin, South Carolina area based on geologic mapping. The geologic mapping is part of a program funded by the Earthquake Hazards Division of the U.S. Geologic Survey. The entire mapping program covers 4, 7-1/2" quandrangles (Chapin, Jenkinsville, Pomaria and Little Mountain) which will eventually be mapped in detail by the University of South Carolina Geology Department.

The fault has a north-south orientation and displaces metamorphic rocks of the Carolina Slate Belt in a down-to-the east fashion. The fault roughly parallels Wateree Creek from just north of Hilton, South Carolina to about the Broad River, where it has a slightly northwest orientation. Evidence of faulting includes: Discontinuity of magnetic anomaly patterns; apparent drag indicated by disturbed bedding or compositional layering, foliation and lineation patterns; occurrence of silicified and unsilicified fault breccia; occurrence of open extension fractures partially filled with quartz; apparent offset of stratigraphic contacts and the Carolina Slate Belt/Charlotte Belt border zone; apparent offset of older northwest trending silicified breccia zones; and possible offset of a northwest trending diabase dike. Field work is continuing in this area, and at present, the closest approach of this structure is about 4 to 5 miles south of the site. No evidence at present demonstrates any recency of movement on this structure.

Northeast of the site, a northeast-trending thrust fault, the Gold Hill Fault, has been identified. This fault has been inactive since the Paleozoic Era (at least 300 million years). The Gold Hill Fault has recently been extended southward into South Carolina. The closest approach of the Gold Hill Fault extension to the site is approximately 40 miles to the northeast.

Recently preliminary work by the USGS and others in the South Carolina Coastal Plain, particularly around the Charleston, S.C. area, has shown evidence of late Tertiary and possibly later disturbance of Coastal Plain Sediments. Also, the USGS is investigating faulting along the fall zone in the vicinity of Augusta, Ga. The Belair Fault Zone, trending northeast, exhibits possible evidence of a tectonic event which probably occurred within the last 50 million years. This structure, a series of southeast dipping en echelon reverse faults trends about N30°E from southwest to northwest of Augusta, Georgia and was originally thought to have displaced the east-west trending Augusta fault an estimated 23 km in the left-lateral sense (Reference 126). Subsequent investigation has determined that the structure apparently dies out near the Savannah River since it is not present a few kilometers northeast along its projected strike. Geologic control in this study area, where a major left lateral strike-slip structure would intersect (and offset) the east/northeast-trending Modoc fault zone, discloses no apparent disruption. It has been concluded that the Belair fault is not present northeast of Augusta, Georgia, or south of the site (Reference 127).

In the vicinity of the site, several folds have been identified or postulated. These structures are shown on Figure 2.5-38, Local Epicenter Map. More detailed information on the regional tectonic framework is discussed in Section 2.5.1.1.3.

2.5.2.2.2 Site Geologic Structure

The site geology is typical of the region. The topography consists of gently rolling hills and ridges with usually gently sloping sides. Residual soils overlie the parent bedrock; the soils range in thickness from about 40 to 85 feet in borings drilled in the site area.

The soil grades from usually clayey and silty soils near the ground surface, where the weathering has been greatest, to dense sandy silt and silty sand saprolites at depth. Bedrock at the site consists primarily of metamorphic rocks of the Charlotte Belt with Paleozoic igneous intrusive zones.

During excavation for the nuclear plant facilities, several minor shear zones of the type common to the Piedmont were exposed. A detailed investigation was conducted to identify:

1. Lithologic relationships to previously mapped local geology.
2. Structural framework of the shear zones, including its geologic history.
3. Geochronological relationships of mineralization within the shear zones to the local geologic framework.
4. In situ stress of the bedrock.
5. Association of the shear zones to local microearthquake data.

A detailed description of the analyses and results of this investigation is presented in Section 2.5.1.2.2.

2.5.2.3 Behavior During Prior Earthquakes

No physical evidence was uncovered during the geologic investigations of the surficial or subsurface materials at the site which would indicate any correlation between historic earthquake activity and site geologic structure.

2.5.2.4 Engineering Properties of Materials Underlying the Site

Dynamic and static engineering properties of residual soil, saprolite, and bedrock at the site have been evaluated for use in foundation interaction analyses. These properties were developed using field geophysical and geologic data, and static and dynamic laboratory test data.

Dynamic and static engineering properties for the foundation materials are presented in Table 2.5-5. These values are appropriate for design at strain levels corresponding to the Safe Shutdown and Operating Basis Earthquakes. The shear moduli and subgrade moduli developed from laboratory and geophysical data have been reduced using factors related to rock quality designation (RQD).

2.5.2.5 Earthquake History

2.5.2.5.1 General

The record of earthquake occurrence in South Carolina and the surrounding area dates back almost 200 years. The site is situated in a region which has experienced a moderate amount of earthquake activity. A number of earthquakes have been reported during this period. The site region has had a well-distributed population during this period, and it is probable that any severe earthquake activity (Intensity VIII* or larger) would have been reported either in local newspapers, private journals, or diaries. The absence of such documentation is indicative of the absence of major earthquake activity in the Piedmont Province during this period.

Intensity ratings of some regional earthquakes may have been overestimated. Structural damage is the rating criteria for larger shocks; and the effect of earthquakes on older structures, such as chimneys, rock walls, etc., is highly variable. Thus, intensity evaluations based on such reports are imprecise. The rather long period of record, however, and earthquake reports from an evenly distributed population provide a reasonable basis for estimates of future activity.

2.5.2.5.2 Regional Seismicity

Epicenters of earthquakes in the region with maximum intensities of V or greater are shown on Figure 2.5-37, Regional Epicenter Map. These shocks are listed in Table 2.5-7. From 1975 to date, magnitudes equal to or greater than 3.0 are also listed.

Most of the reported earthquakes have occurred in the Blue Ridge Province and the Valley and Ridge Province to the northwest of the site. These provinces are characterized by intense folding and faulting, which trend northeast-southwest. The earthquake epicenters generally follow this same structural trend.

Occasional earthquakes have occurred in the Piedmont Province in which the site is located. Some earthquakes also have occurred in the Coastal Plain Province. The majority of these have been centered near Charleston, S.C., although occasional shocks have occurred elsewhere in the Coastal Plain.

There have been 110 shocks with maximum intensities of V or greater reported within about 250 miles of the site since the end of the 18th Century. An earlier earthquake was reported in 1698; however, the data available are not sufficient to allow for an evaluation of intensity. Within 50 miles of the site, there have been 8 shocks of Intensity V or greater reported.

*All references to intensity in this section refer to the Modified Mercalli Intensity Scale of 1931 (see Table 2.5-6).

The largest reported earthquake in the region within 250 miles of the site, was the 1886 Charleston earthquake, which is rated as having an intensity of X (Reference 53). The epicenter of this shock was about 125 miles southeast of the site. Closer to the site, the largest reported earthquake was the 1913 Union County earthquake, which had a maximum intensity of VII. The epicenter of this shock was about 35 miles northwest of the site. The Union County Shock and other local shocks are shown on the Local Epicenter Map, Figure 2.5-38.

A discussion of the more significant shocks (within 250 miles of the site) follows. The descriptions are based on published data and personal communications (References 1, 2, 14, 15) supplemented by contemporary newspaper accounts.

1. Charleston, South Carolina Earthquake of August 31, 1886

   This is the strongest shock in the southeastern United States in historic times (Intensity X). There were 2 main shocks occurring at 9:51 PM and 9:59 PM Eastern Standard Time. Two (2) epicentral tracts were identified, 1 near Summerville, 16 miles northwest of Charleston, and 1 about 13 miles west of Charleston. The approximate epicentral coordinates are 32.9° North Latitude, and 80.0° West Longitude, about 125 miles southeast of the site.

   It is reported that there were loud sounds near Summerville on August 27 and 28. The first shock on August 31 lasted about 35 to 40 seconds and was accompanied by a loud sound. The main shock was followed by aftershocks, some of a rather high intensity, into the next day.

   The shock was felt in an area of about 2,000,000 square miles. The area within a distance of about 100 miles of Charleston was strongly shaken. The most serious reports came from the major population center of Charleston. The degree of damage to structures could generally be correlated with the type of design and construction, as well as with local soil conditions. Much of Charleston is constructed on “made land,” including filled-in creeks. Structures in these areas experienced the greatest damage. Near the epicentral points, cracks, craterlets, and sand boils were noted and railroad rails were bent. The shock was felt as far away as Boston, Milwaukee, New York, Cuba, and Bermuda. The effect of the shock was strong, and some damage resulted in Savannah (90 miles), Augusta (100 miles), and Columbia (100 miles). It is probable that the shocks were felt in the site area with Intensity VI to VII (Reference 53).

   Occasional earthquake activity in the Charleston area has continued to date, the most recent reported felt shocks being an Intensity VI shock in November 1974 and an Intensity IV shock in April 1975.

2. Union County Earthquake of January 1, 1913

The shock occurred at 1:28 PM Eastern Standard Time. The epicenter was about 34.7° North Latitude, and 81.7° West Longitude, about 35 miles northwest of the site. The maximum intensity of the shock was VII and the total affected area was about 43,000 square miles. It was felt in an elliptical area, 55 miles by 25 miles in dimension, trending in a north-northeast south-southwest direction. The shock was accompanied by a loud noise, and lasted about 6 to 10 seconds.

At Union, near the epicenter, damage consisted of cracked brick walls, damaged plaster and mortar, and fallen chimneys. The shock was strong and some damage resulted in Colerain, 9 miles west of Union; West Spring, 11 miles northwest of Union; Crosskeys, 11 miles southwest of Union; and at Spartanburg and neighboring communities, about 20 miles northwest of the epicenter.

The shock probably was felt in the site area with about Intensity IV.

3. Lake Murray Earthquake of July 26, 1945

The shock occurred at 6:32 AM Eastern Standard Time. The epicenter was instrumentally located at 34.3° North Latitude, and 81.4° West Longitude, about 30 miles northwest of Columbia. This location is about 5 miles west-southwest of the site, but it is possible that the actual epicenter was somewhat further south toward Lake Murray. The shock was probably felt in the site area with Intensity IV. Intensity of IV was reported in a large area, including Charleston, Chester, Greenville, and portions of North Carolina. Georgia and Tennessee indicated intensities of I to III. At Columbia, people were awakened by the sharp vibrations, but no damage occurred.

Although the maximum intensity of the shock was listed as IV, the shock has been assigned a maximum intensity of VI, because of the large area over which it was felt and because of instances of cracked chimneys. The total felt area was about 25,000 square miles.

2.5.2.5.3 Local Seismicity

It is likely that the estimated Intensity VI to VII ground motion at the site during the 1886 Charleston earthquake is the greatest level of ground motion at the site in recorded history. In addition, the site area has experienced earthquake shaking from occasional nearby shocks of minor to moderate intensity. The 1913 Union County Shock and the 1945 Lake Murray shock have already been described. A discussion of earthquakes of minor to moderate intensity with epicenters within 50 miles of the site (shown on Figure 2.5-38), some of which may have been felt at the site, follows:

1. Winnsboro Earthquake of October 26, 1879

The shock occurred at 8:00 AM, Eastern Standard Time about 15 miles northeast of the site. It was lightly felt by many in Winnsboro and vicinity. There was no damage, only a rattling of windows and doors. The maximum intensity probably was less than IV.

2. Winnsboro Earthquake of October 31, 1942

   The shock occurred at 10:20 PM, Eastern Standard Time about 15 miles northeast of the site. It was felt by many in Winnsboro and vicinity. There was no damage, only a rattling of windows and doors. The maximum intensity probably was less than IV.

3. Columbia Earthquake of April 20, 1964

   The shock occurred at 2:05 PM, Eastern Standard Time. The epicenter was located by instrumentation approximately 30 miles southeast of the site near Columbia. The felt area included Fairfield, Florence, Lexington, and Richland Counties. The maximum reported intensity was V.

   A rumbling noise accompanied the shock in Columbia. Vibrations were reported as lasting for over 4 minutes and were felt by many people. The shock was recorded by the seismograph of the University of South Carolina at Columbia. Gaston and Jenkinsville reported an intensity of V, with trembling motion that was felt by all residents. Intensity IV was reported at Cayce, Irmo and Lexington with rumbling noises but no damage. Intensity I-III was reported at Columbia, Florence, and Pelion.

4. Chester Earthquake of September 8 - 12, 1965

   There were 4 shocks. The first was felt on September 8, at 11:37 PM (Eastern Standard Time), with succeeding shocks on September 9, at 9:42 AM, September 10 at 2:32 PM, and September 12 at 1:25 PM. The shocks were felt over a 30 square mile area in Chester County, about 25 miles north-northeast of the site, with a probable maximum intensity of less than IV.

5. Columbia Earthquake of September 22, 1968

   The shock was felt at 4:41 PM Eastern Standard Time. The epicenter was about 22 miles southeast of the site. The shock had a maximum intensity of IV. The tremors were felt over approximately 400 square miles, in Richland and Lexington Counties. Gilbert, Irmo, and Lexington reported Intensity I-III.

Since the filling of the Monticello Reservoir and installation of microseismic networks in the site region (late 1977), many minor earthquakes have been recorded in the vicinity of the impoundment, as shown on Figure 2.5-38.

2.5.2.6 Correlation of Epicenters With Geologic Structure

2.5.2.6.1 General

Since the time when the PSAR was docketed (June, 1971) much work has been done investigating the relationship of seismicity to geologic structure within the 200 mile radius about the Virgil C. Summer Nuclear Station. Most of the attention has been directed to the area in and around Charleston, S.C., where USGS scientists are attempting to identify the geologic and tectonic

framework responsible for the 1886 Charleston Earthquake, and the higher frequency of occurrence of seismicity in the general Charleston, S.C. region.

A seismograph network was completed by the USGS in 1974, consisting of 10 stations to monitor seismic activity in South Carolina between the Savannah and Lynch Rivers. One (1) of the stations is located in Jenkinsville, approximately 1-1/2 miles east of the site. Currently, there are about 33 stations monitoring the seismicity of South Carolina, with emphasis on the Charleston area and local seismicity associated with the impoundment of Monticello Reservoir.

2.5.2.6.2 Charleston Seismic Zone

The severest earthquake which has occurred in the southeastern United States was located near Charleston, S.C., in 1886. Since that time, numerous other shocks have occurred in the same general locale, but none have matched or exceeded the 1886 Intensity X event.

Because the 1886 event(s) influences seismic risk assessment in the southeastern U.S. Coastal region, the recurrent seismicity of the Charleston area has been well documented and re-evaluated over the years so that the long historical record, dating back to 1698, is considered complete for significant earthquakes. This zone, on the basis of these historical studies, is one of the few zones in the contiguous U.S. where the consensus of scientific opinion holds that the noted activity is correlated with a discrete structural anomaly, the character and extent of which is not known, but which confines the earthquake activity to a relatively localized area. Although a northwest trend toward the Piedmont has been postulated on the basis of very diffuse activity, there is little hard evidence at present (either tectonic or seismic) to suggest westward migration of large earthquakes.

Since 1974, the USGS has been investigating the geologic and tectonic framework of the Charleston, S.C., area, including the deployment of a seismic monitoring network. Early results indicated the possible presence of previously unrecognized faulting and zones of weakness in the basement rocks beneath and near Charleston (References 54, 55, 56).

Colquhoun (Reference 58) reported a new structure, the Stono Arch, a northwest-southeast trending fold which is probably fault-controlled, and might have been the locus of the 1886 Charleston earthquake.

More recent studies have attempted to define the tectonic setting of the Charleston area within a plate tectonic framework. Talwani and others (Reference 128) based on results from the regional seismic networks, present a model suggesting that the 2 diffuse zones of high seismicity near Bowman and Summerville lie at the intersection of a northwest-trending zone of weakness (colinear with the Blake Spur fracture zone) and 2 northeast trending buried Triassic basins which have been inferred from geophysical and drilling data to underlie each of the 2 seismic zones. Nishenko and Sykes (Reference 129) postulate that Charleston seismicity may be related to the intersection of zones of weakness formed by the Blake Spur fracture zone and a continental suture between Florida and Georgia. More localized studies have inferred a northwest-trending axis of compressive stress on the basis of in-situ stress measurements (Reference 131), or a northeast-trending compression based on focal mechanism solutions (Reference 132) for earthquakes just

west of Charleston, an ambiguity which might be explained by the differences in depth between the stress measurements (300-400 m) and the fault-plane solutions (3-13 km).

An alternative explanation suggests that the horizontal nodal plane as determined in solutions for the earthquakes near the Summerville area, may represent the fault surface at a depth consistent with earthquake occurrences and reflection profiling both on and off shore, a depth of some 13 to 18 km. This interpretation would conform to the postulated Appalachian decollement previously discussed (Reference 131). However, a definitive model for the present day structural regime is conjectural and a reliable model of earthquake generation based on a sub-horizontal shear of this magnitude is not warranted at the present state of knowledge.

Evidence for reactivation of northwest or southeast-dipping Triassic (tensional) faulting by a present northwest compressional stress has been suggested by recent investigators to explain observed seismicity (References 131, 132). There is general agreement that some northeast-trending structures, such as the Belair fault near Augusta, Georgia and the Cooke fault near Summerville, South Carolina may have undergone reactivation in Cenozoic time, although definitive ages for latest movement has not been determined (References 127, 131).

A recent earthquake (Nov. 22, 1974, Intensity VI) in Middleton Gardens - Summerville, S.C., (14 miles NW of Charleston) provided a focal mechanism that is consistent with either reverse faulting on a plane dipping 78°SW or thrust faulting on a plane dipping 12°NE - with both planes striking N42W.

With respect to the largest credible event for this seismic zone, Bollinger (Reference 53) reinterpreted the intensity effects of the 1886 Charleston shock and found that his effort was in general agreement with Dutton (Reference 57). Bollinger also stated that Dutton's maximum intensity of X for the epicentral region appeared to be appropriate. An isoseismal map prepared for the 1886 Charleston event by Dutton in 1889 is shown on Figure 2.5-39.

This map illustrates the very gross isoseismal zones prepared by Dutton. A modern map prepared by Bollinger is presently in press, which locates the site well within the Intensity VII isoseismal zone; however, based upon local reports of the earthquake's effects near the site (such as at Winnsboro; Intensity VI), an Intensity VI-VII has been assigned to the site area.

In summary, there is no conclusive evidence or general agreement which would suggest that the seismogenic structure responsible for the anomalous Charleston earthquake activity is present near, or should be extrapolated toward, the subject site, nor is there reason to believe that large events such as the 1886 Charleston earthquake might occur significantly closer to the Columbia, S.C. area.

2.5.2.6.3 Piedmont Province

As discussed previously, the Virgil C. Summer Nuclear Station site lies within the Piedmont Province. The closest maximum intensity shock to the site, the 1913 Union County earthquake, has not been related to any known geologic structure. In fact, within the Piedmont Province, there

are no conclusive correlations of regions of highest intensity or epicenters to known or suspected geologic structure.

Talwani (Reference 59) has speculated that the Eastern Piedmont (Goat Rock) Fault (see Section 2.5.1.1, Regional Geology) may be extended into South Carolina based on the location of instrumental earthquake epicenters. This particular case, however, remains to be established more firmly.

The Belair Fault Zone near Augusta (see Section 2.5.1.1.3 and Section 2.5.2.2.1) cannot be correlated with any recent or historic earthquake activity and its proclivity for modern movement has not been determined.

2.5.2.6.4 Reservoir - Induced Seismicity

The Applicant installed a Microseismic Monitoring Network in 1977 to record seismic activity in the area of the Virgil C. Summer Nuclear Station and Monticello Reservoir. This network originally consisted of 4 high gain/high frequency seismometers located around Monticello Reservoir with a central recording site. In 1986, the Applicant contracted the University of South Carolina to take over the entire maintenance, operation, and data analysis of the network. At this time the network was modified by relocating several stations. Reports were prepared on a quarterly basis and submitted to the NRC by the Applicant.

In 1995, the Applicant requested the NRC for discontinuation of the network due to a continued subsidence of earthquake activity associated with Monticello Reservoir. The NRC subsequently approved the deletion of Operating License Condition 2.C (Reference 24) which eliminates this seismic monitoring program.

A South Carolina Seismic Network seismometer is currently located about 3.2 miles ESE of the Virgil C. Summer Nuclear Station, near the town of Jenkinsville, and is identified by the locator (JSC). This seismometer became operational in 1973 and is maintained and monitored by the University of South Carolina.

In 1982, the Applicant installed two strong motion accelerometers in the free-field (at ground surface and bedrock) in order to obtain a better understanding of near-field ground motion should a larger seismic event occur near the Virgil C. Summer Nuclear Station. These accelerometers were supplemental to the in-plant seismic instrumentation described in FSAR Section 3.7.4. Although approval to eliminate the seismic monitoring program was granted by NRC in 1995 via License Amendment No. 124, this instrumentation remained in operation until 2004 when lightning strikes and obsolescence rendered the equipment useless. Since the instrumentation never recorded an earthquake in over 20 years of service, removal of this obsolete equipment was undertaken in 2005.

2.5.2.7 Identification of Active Faults

There are no known faults within 200 miles of the site which should be considered as “capable” faults as defined in Appendix A to 10 CFR 100. The Belair Fault Zone, located approximately 75

miles southwest of the site, is still under investigation as well as the newly discovered geologic features in the vicinity of Charleston, S.C. A more detailed appraisal of the significance of these features is included in Sections 2.5.1.1, Regional Geology, and 2.5.2.6, Correlation of Epicenters with Geologic Structure.

2.5.2.8 Description of Active Faults

There are no known faults within 200 miles of the site which should be considered “capable” faults as defined in Appendix A to 10 CFR 100. For further information see Sections 2.5.1.1, Regional Geology, 2.5.1.2, Site Geology, and 2.5.2.7, Identification of Active Faults.

2.5.2.9 Maximum Earthquake

In order to establish criteria for the Safe Shutdown Earthquake, a thorough examination was made of the degree of vibratory ground motion which is probable. The implication of both the seismic history and geologic structure of the region and the specific site area were considered simultaneously. Earthquakes considered as most significant to the site are those which have occurred within the Piedmont Province and the Charleston Seismic Zone.

There has been no correlation to date of any earthquake occurrence to geologic structure within the Piedmont Province. However, due to the requirements of 10 CFR 100, Appendix A, it must be assumed, for design purposes, that the maximum historical or likely event can occur adjacent to the site. The largest shock to have occurred within the Piedmont Province was Intensity VII, similar to the 1913 Union County, S.C., shock about 35 miles northwest of the site. The 1913 Union County shock was probably felt in the site area with Intensity IV or less (Reference 53) The occurrence of an Intensity VII earthquake adjacent to the site would conservatively result in ground motion of about 0.13g in rock (Reference 63) and 0.20g in soil (Reference 62).

Based on a recurrence of an Intensity X shock, similar to the 1886 Charleston Earthquake, at the original 1886 epicentral area, the site would experience low Intensity VII effects (Reference 53). While its duration would be somewhat longer than for the more local Intensity VII shock, the resultant ground motion would be conservatively less than 0.10g in rock and 0.15g in soil.

It is concluded that the maximum earthquake which would affect the site would be the occurrence of a random Intensity VII shock adjacent to the site.

2.5.2.10 Safe Shutdown Earthquake

Based on the data presented in Section 2.5.2.5 and the discussions in Section 2.5.2.9 (and in compliance with requirements in 10 CFR 100, Appendix A), the Safe Shutdown Earthquake is considered as a random occurrence of an Intensity VII earthquake near the site. The event would be similar to the 1913 Union County, S.C., earthquake which occurred some 35 miles northeast of the site. The maximum horizontal ground motion resulting from this shock at the site would conservatively be about 0.13g in rock (Reference 63) and 0.20g in soil (Reference 62). However, more conservative factors of 0.15g and 0.25g are being utilized for the Safe Shutdown Earthquake in rock and soil, respectively. Ground motion at the site as a result of larger, more distant events

(such as a recurrence of the 1886 Charleston, S.C., earthquake of Intensity X) would be 0.10g and 0.15g for rock and soil, respectively. While the duration of shaking would be longer, it is considered that the horizontal design response spectra shown on Figures 2.5-40 and 2.5-41 would adequately envelope all long period motion from such an occurrence. The corresponding vertical design accelerations used in design are 2/3 of the horizontal.

2.5.2.11 Operating Basis Earthquake

Based on the seismic history of the region and site area, there is a possibility that moderate earthquake motion may occur at the site during the economic life of the Virgil C. Summer Nuclear Station. The greatest level of earthquake motion at the site in historic time is believed to be low Intensity VII during the 1886 Charleston earthquake. The 1913 Union County earthquake and the 1945 Lake Murray earthquake probably were felt at the site with intensities of IV.

Based on the foregoing, the Operating Basis Earthquake (OBE) is considered to be that event which would generate a low Intensity VII earthquake ground motion at the site such as that caused by a distant large earthquake (near Charleston). The resulting estimated maximum horizontal accelerations for this shock at the site would be less than 0.10g in rock and 0.15g in soil. These acceleration levels are being used to quantify the Operating Basis Earthquake. The Operating Basis Earthquake acceleration is conservatively greater than 1/2 of the Safe Shutdown Earthquake which has been established as the minimum acceptable criterion by the regulatory agencies. The corresponding vertical accelerations used in design are 2/3 of the horizontal.

Design response spectra for the maximum horizontal ground accelerations from the Operating Basis Earthquake on rock and soil, respectively, are shown on Figures 2.5-42 and 2.5-43.

2.5.3 Surface Faulting

2.5.3.1 Geologic Conditions of the Site

A detailed description of the regional and site geology, including discussion of the lithologies, stratigraphy, structural geology, and geologic history, is presented in Sections 2.5.1.1 and 2.5.1.2.

2.5.3.2 Evidence of Fault Offset

Minor shearing with maximum observed displacements of about 7 feet has occurred in rock underlying the Reactor Building area. The shears are not continuous but occur as en echelon features which do not penetrate through the soil profile to the ground surface. Individual shears range in thickness from a fraction of an inch to less than 1 foot. Evidence of displacement includes displaced aplite and pegmatite veins, and slickensides. The results of the detailed investigations of these shears, as presented in Section 2.5.1.2, indicate that movement along the shears could not have occurred later than 45 million years ago, and in all probability the shears have been inactive since 150 to 300 million years BP and are not considered capable as defined in Appendix A to 10 CFR 100.

2.5.3.3 Identification of Capable Faults

No capable faults have been identified within miles of the site.

2.5.3.4 Earthquakes Associated With Capable Faults

There are no earthquakes associated with faults within 5 miles of the site, and no capable faults have been identified within 5 miles of the site.

2.5.3.5 Correlation of Epicenters With Capable Faults

No capable faults have been identified within 5 miles of the site, and therefore correlation of epicenters with such structures cannot be made.

2.5.3.6 Description of Capable Faults

No capable faults have been identified within 5 miles of the site.

2.5.3.7 Zone Requiring Detailed Faulting Investigation

No capable faults have been identified within 5 miles of the site. Descriptions of the shears found at the site are presented in Section 2.5.1.2.

2.5.3.8 Results of Faulting Investigation

Detailed investigations were conducted to evaluate the minor shearing found in rock underlying the site. These investigations, which are discussed in detail in Section 2.5.1.2, included detail geologic mapping, sampling, petrographic analysis, radiometric dating, X-ray diffraction analyses, literature search with emphasis on recent tectonic displacements, aerial photography and ERTS imagery analysis, gravity and magnetic data analysis, in situ stress measurements, evaluation of potential movement along shears due to the filling of Monticello Reservoir, review of local microseismic data, correlation of Piedmont seismic activity with reservoir impoundments, and offsite geologic reconnaissance. The results of these intensive geologic investigations indicate that the shears are not capable.

2.5.3.9 Design Basis For Surface Faulting

No capable faults have been identified within 5 miles of the site, and shears present at the site do not introduce potential for ground surface rupture, loci for seismic activity, or other conditions requiring modification of the existing design.

2.5.4 Stability of Subsurface Materials

2.5.4.1 Geologic Features

The site is underlain by a complex sequence of metamorphic and igneous rock on the Charlotte Belt metamorphic zone, consisting primarily of gneiss, amphibolite, migmatite, and granodiorite. The overburden soils at the site are primarily residual, derived by the chemical weathering of the underlying metamorphic and igneous rock. There are some alluvial and colluvial soils in stream areas and the lower slopes of some hillsides, but these are restricted to the stream valleys. Geologic features of the site are discussed in detail in Section 2.5.1.2. The subsurface conditions at the plant site and Service Water Pond site are discussed in Sections 2.5.4.10.1 and 2.5.6.2, respectively.

The loading history of the site materials has been one of weathering and erosion since the last epeirogenic uplift; it has not been subject to glaciation during the Pleistocene epoch. A crustal movement map prepared by Meade (Reference 66) shows that the site is located in an area of slight regional uplift of the order of 2 to 3 mm per year. At the site, there are no areas of actual or potential surface or subsurface subsidence. The absence of carbonate zones precludes the possibility of subsidence or collapse due to solutioning. Ground water withdrawal in the area near the site is small and limited primarily to fracture zones in the crystalline bedrock, and is therefore not a potential subsidence problem. Mining operations within 4 miles of the site are restricted to surface mining of crushed stone, dimension stone, and sand and gravel. There are no oil or gas deposits in the site vicinity, and no subsurface mining occurs or has occurred within the area.

There are no areas at the site which are subject to instability caused by faulting, shearing and/or unrelieved residual stresses in the bedrock underlying the site. Minor shearing is present in the bedrock. The maximum observed net displacement is no greater than 7 feet. The results of radiometric age dating of the shear zones indicate that shearing could not have occurred later than 45 million years ago, and probably occurred between 300 million and 150 million years ago. A detailed discussion of the shears is presented in Section 2.5.1.2.2. The results of in situ stress measurement across the shear zone indicate that the direction of the major compressive stress is almost perpendicular to the shear zone, and the magnitude of the stresses are well below the estimated strength of the rock.

There are no rocks or soils at the site that are unstable because of mineralogy, lack of consolidation or inundation, variability, high water content, or solubility. These rocks and soils have no potentially undesirable response to natural (such as seismic events) or induced site conditions. There are no areas subject to liquefaction (Sections 2.5.4.8 and 2.5.6.4).

2.5.4.2 Properties of Underlying Materials

Geologic, seismologic, geophysical, and foundation engineering studies were performed to evaluate the characteristics of the nuclear plant site. The results of the geologic and seismologic studies are given in Sections 2.5.1, 2.5.2, and 2.5.3. The results of the geophysical and foundation engineering studies for the evaluation of the static and dynamic engineering properties of the

underlying natural materials of the plant site are presented in Sections 2.5.4.2.1 and 2.5.1.2.2. A description of the plant site conditions is given in Section 2.5.4.10.1.

In the area of the Service Water Pond, the static and dynamic engineering properties of the natural in situ subsurface materials and the compacted fill materials were also evaluated (Section 2.5.6.5). Because the geologic conditions are essentially the same within the study region, the engineering properties of the natural materials in the area of the Service Water Pond are similar to those at the principal plant structures. Because essentially the same type of fill material was placed and compacted in accordance with similar specifications in the Service Water Pond area and at the principal plant structures, the engineering properties of the compacted fill in the 2 areas are considered similar.

2.5.4.2.1 Geophysical Studies

Details of the geophysical studies are discussed in Section 2.5.4.4. The locations of the geophysical surveys are indicated on Figure 2.5-44. The geophysical data in combination with geologic data and static and dynamic laboratory test data were used to evaluate the dynamic engineering properties of the saprolite and bedrock at the plant site. These properties are given in Table 2.5-8. For the bedrock, the shear moduli and subgrade moduli developed from laboratory and geophysical data were reduced using factors related to rock quality designations (RQD) (Reference 67).

2.5.4.2.2 Foundation Engineering Study

The foundation engineering study included the drilling of 108 test borings and the performance of static and dynamic laboratory tests. The locations of the borings are indicated on Figures 2.5-44 through 2.5-48. The graphical representations of the boring logs are provided in Appendix 2E. Selected data from other borings about 3 miles north of the site were utilized where applicable and are presented herein, although the boring logs are not included.

Laboratory tests were performed on soil samples and rock cores obtained from the test borings at the plant site to evaluate their physical (static and dynamic), index, and chemical properties. The laboratory tests were performed in general accordance with accepted standards or state-of-the-art methods. The laboratory testing program consisted of the following:

1. Direct Shear Tests

   Consolidated-drained double direct shear tests, in general accordance with ASTM D 3080-72, were performed on selected samples of the overburden soils to evaluate their strength characteristics. Unconsolidated-undrained double direct shear tests also were performed on selected samples. The tests were performed with the samples in 2-1/2 inch O.D. brass rings in which the samples were initially obtained during sampling. The sampling procedure is described in Section 2.5.4.4.1. The test results, in terms of normal pressure and maximum shearing resistance, are presented on the boring logs in Appendix 2E. Test data are in terms of total stress except where effective stress is specifically indicated.

2. Triaxial and Unconfined Compression Tests - Soil

   Triaxial and unconfined compression tests were performed on selected samples of the overburden soils obtained from the nuclear plant site to evaluate their strength characteristics. The triaxial tests were performed in general accordance with suggested ASTM methods, while the unconfined tests were performed in general accordance with ASTM D 2166-66. The test results, in terms of confining pressure and peak deviator stress, are presented on the boring logs in Appendix 2E. Test data are in terms of total stress except where effective stress is specifically identified.

3. Triaxial, Unconfined, and Confined Compression Tests - Rock

   Representative cores of rock were subjected to triaxial and unconfined compression tests in general accordance with ASTM D2664-67 and D2938-71a to evaluate their strength and stress-strain (elasticity) characteristics. The results are presented in Table 2.5-9.

   To determine the stress-strain characteristics of highly weathered rock specimens, 2 confined compression tests were performed on specimens retained in the 2-1/2 inch O.D. brass rings during sampling. The tests were performed in a manner similar to a consolidation test (ASTM D2435-70). The data are illustrated on Figures 2.5-49 and 2.5-50.

4. Consolidation Tests

   Consolidation tests were performed in general accordance with ASTM D2435-70 on selected soil samples to evaluate their compressibility characteristics. The tests were performed with the samples in 2-1/2 inch O.D. brass rings in which the samples were initially obtained during sampling. These test results are presented on Figures 2.5-51 to 2.5-59. At the location of the condensate storage tank, the soil samples were obtained utilizing conventional 3 inch diameter shelby tubes (Section 2.5.4.4.1). Two (2) tests were run in accordance with ASTM D 2435-70 except that the tests were performed directly on samples confined within the shelby tubes to eliminate extrusion and trimming disturbance. The shelby tubes with the retained soil samples were carefully cut in approximately 3-1/2 inch sections to avoid distortion of the tubes, and subsequently placed in the consolidation apparatus. The results of these tests are presented on Figure 2.5-60.

5. Dynamic Torsional Shear Tests

   Dynamic torsional shear (resonant column) tests were performed on representative soil samples to evaluate the modulus of rigidity of these materials. The samples were subjected to steady-state, sinusoidal, and torsional forces applied to the top of each sample. The frequency of the force application was varied until the resonant frequency (the frequency associated with the maximum steady-state amplitude) was attained. The modulus of rigidity was computed from the resonant frequency of the sample. The tests were conducted at natural moisture content, over a range of confining pressures and at varying strain levels. The results of the resonant column tests are presented in Table 2.5-10.

6. Compressional Wave Velocity Tests

   Representative samples of soil and rock were tested to measure the velocity of propagation of compressional waves in the materials. The velocity observed in the laboratory was used for correlation with field velocity measurements obtained in the seismic refraction survey. In this test, samples were subjected to a physical shock and the time for the shock wave to travel the length of the sample was measured with an oscilloscope. The velocity of compressional wave propagation was then computed. All the samples were tested in an unconfined state at their natural moisture content. The test results are presented in Table 2.5-11.

7. Moisture and Density Tests- Soil

   The moisture content and dry density of selected soil samples were determined in general accordance with ASTM D2216-71, and procedures similar to ASTM D2937-71. The test results are presented on the boring logs in Appendix 2E.

8. Particle Size Analysis

   Representative soil samples were analyzed in general accordance with ASTM D422-63 to determine their grain size distribution. The test results are presented on Figures 2.5-61 through 2.5-76.

9. Permeability Tests

   Falling head permeability tests in general accordance with suggested ASTM methods were performed on representative soil samples to evaluate permeability characteristics. The test results are presented in Table 2.5-12.

10. Atterberg Limits

    Atterberg limit determinations (liquid and plastic limits) in accordance with ASTM D423-66 and D424-59 were performed on representative soil samples to evaluate plasticity characteristics. Data are presented in Table 2.5-13.

11. Resistivity Tests

    Resistivity tests in general accordance with suggested ASTM methods were performed on representative soil and rock samples to aid in evaluating corrosion and electrical grounding. The test results are presented in Table 2.5-14.

12. Soil Chemical Tests

    Sulphate and pH determinations in general accordance with suggested ASTM methods were made on representative samples of soil for evaluation of corrosion of buried concrete and steel. Test results are presented in Table 2.5-15.

13. Cyclic Triaxial Tests

Cyclic consolidated undrained triaxial tests were performed on representative samples of saprolite to evaluate their dynamic characteristics. The samples were obtained utilizing 3 inch diameter shelby tubes as described in Section 2.5.4.4.1. The laboratory tests included:

a. Six (6) stress controlled cyclic triaxial tests to evaluate the liquefaction characteristics under seismic loading conditions.
b. Two (2) strain controlled cyclic triaxial tests to evaluate shear modulus versus strain and damping versus strain relationships.

All the triaxial test samples were saturated under back pressure and reconsolidated under all-around effective stresses.

For the stress controlled triaxial tests, the samples were subjected to uniform cyclic deviator stresses such that the ratio of cyclic shear stress on a plane at an angle of 45° to the initial effective confining stress ($\tau/\overline{\sigma}_c$) ranged from 0.30 to 0.45. Table 2.5-16 summarizes the stress ratios ($\tau/\overline{\sigma}_c$) and the number of cycles required for 5% and 10% double amplitude axial strains. Also summarized on the table are the index properties of the samples including initial moisture contents and dry densities.

For the strain controlled triaxial tests, the stresses required to produce the test strains were measured. From the area of the stress-strain hysteresis loops, the equivalent viscous damping ratio (D) was computed. The results of the tests are summarized in Table 2.5-17.

2.5.4.3 Plot Plan

Plot plans showing the locations of the test borings and subsurface cross sections in relationship to the principal plant structures are given on Figures 2.5-44 through 2.5-48. The locations of the geophysical surveys are illustrated on Figure 2.5-44. Cross sections through the plant site showing the relationship of the foundations of Seismic Category 1 structures to the subsurface materials are given on Figures 2.5-77 through 2.5-82. Foundation types and supporting media for the Seismic Category 1 structures are presented in Section 2.5.4.10.

2.5.4.4 Soil and Rock Characteristics

The field studies and investigations to evaluate the soil and rock characteristics consisted of test borings, geological investigations, and geophysical studies that included a seismic refraction survey, a surface wave survey and micromotion measurements. The locations of the test borings, and seismic refraction, and surface wave surveys, are presented on Figures 2.5-44 through 2.5-48.

2.5.4.4.1 Test Borings

The subsurface conditions at the plant site and near vicinity were explored by drilling 108 borings to depths ranging from 12 feet to 235 feet below the original ground surface. Figures 2.5-44 through 2.5-48 show the boring locations. The boring logs are presented in Appendix 2E. Selected data from other borings about 3 miles north of the site were utilized where applicable and are presented in Section 2.5.4.2.2, although the boring logs are not included. Test borings drilled for the Service Water Pond are provided in Section 2.5.6.2.

Borings were drilled with truck-mounted rotary-wash drilling equipment except Boring 4-1, which was drilled with hollow stem augers. Overburden soil samples suitable for testing were obtained at frequent intervals, and the underlying rock was continuously cored utilizing standard NX coring equipment. The soils encountered were classified in accordance with the Unified Soil Classification System (USCS) described in Figure 2.5-83, which also presents a key to the sample and core nomenclature utilized on the boring logs. Geologic rock classifications were based on macroscopic and hand lens examination of cores, supplemented by petrographic analyses.

Percent core recovery and RQD information are presented on the boring logs in a manner described on Figure 2.5-83. A Rock Property Indicator number has been presented on each log to conveniently summarize weathering and jointing features. The Rock Property Indicators are:

Rock Property Indicator Number	Description
1	Massive fresh rock, some may be slightly jointed.
2	Moderately weathered rock, slight jointing; and slightly weathered rock, moderately to very jointed.
3	All highly weathered rock; and moderately weathered rock which is highly jointed.

The borings were drilled in the overburden soils by advancing a 4 inch diameter hole to the desired sampling depth. (Hollow stem augers, 3-5/8 inches I.D., were used to advance Boring 4-1.) The drill rods were then extracted, and soil samples were obtained by driving a 3-1/4 inch O.D. sampler (Dames & Moore Soil Sampler Type U) attached to the drill rods with either a 140 pound or a 300 pound weight. The 3-1/4 inch O.D. sampler is illustrated on Figure 2.5-84 and the drive weight which was used is indicated on each boring log. In addition, samples were obtained using a 2 inch O.D. sampler driven by a 300 pound weight and also a 140 pound weight (Standard Penetration Test, ASTM D 1586-67). In Borings 4-1 through 4-8, soil samples also were obtained by hydraulically pushing 3 inch diameter shelby tubes and the 3-1/4 inch O.D. sampler with the thin walled sampling tube attachments. The soil samples were retained in the shelby tubes and thin walled tubes for shipment to the laboratory. Data correlating blow counts of the 3-1/4 inch sampler with blow counts obtained by the Standard Penetration Test methods are presented on

Figure 2.5-85. A correlation inferred between soil consistency and Standard Penetration Test blows is also shown on this figure.

Drilling mud and casing were used when necessary during the drilling of overburden soils. Prior to coring the underlying rock the boring was flushed thoroughly with water.

The 3-1/4 inch O.D. sampler (Dames & Moore Soil Sampler Type U) is a split barrel type. Various types of bits are utilized depending on the type of soil to be sampled, including a thin walled sampling tube attachment (6 inches to 12 inches long) utilized to minimize sample disturbance. The soil core is retained in the thin walled tube attachment and/or in the split barrel by 2-1/2 inch O.D. by 1 inch brass rings. Over 25,000 foundation investigations have been performed utilizing this sampler.

Prior to commencement of field investigations at the nuclear plant site, various types of samplers were considered. The subsurface soils at the site generally consist of dense micaceous silty sands, and for these types of materials, it was decided to utilize the Type U sampler since it was felt that the soil samples obtained would provide satisfactory data for a conservative analysis of site conditions. Subsequent to the initial investigations, the investigation for the Seismic Category 1 soil supported facilities (i.e., Service Water intake and discharge pipes, electrical duct bank, diesel generator fuel oil storage tanks and the condensate storage tank) also utilized 3 inch shelby tubes to sample the underlying soils.

It is recognized that some sample disturbance is obtained utilizing the Type U sampler; however, this is true of all state-of-the-art samplers available today. It is believed that the samples obtained by the Type U sampler are not significantly more disturbed than samples obtained by other sampler types, for the types of soil encountered at the site.

Figure 2.5-86 shows consolidation test data for soil samples obtained by the Type U sampler and a 3 inch diameter thin wall tube Denison sampler during a site investigation for a nuclear plant in Virginia. The soils at the Virginia site were micaceous silty sands, similar to the type of soils encountered at the Virgil C. Summer Nuclear Station site. Both sites are in the Piedmont Physiographic Province. Curves A and B are the test results on samples obtained by the Type U sampler; Curves C and D present results for samples obtained with the Denison sampler. Soil samples represented by Curves B and D were obtained in borings approximately 300 feet apart. Samples obtained with the Type U sampler were recovered by driving the sampler 1 foot with a 300 pound weight falling 30 inches.

The shape of a consolidation curve is influenced by the degree of sample disturbance. It can be inferred from a comparison of the consolidation curves on Figure 2.5-86 that the samples obtained from the Type U sampler are not any more disturbed than the samples obtained with the Denison sampler. Although the consolidation tests were performed on soils which can be considered similar from a foundation standpoint, it can be noted on Figure 2.5-86 that differences in specific consolidation characteristics exist between the Type U sampler curves and the Denison sampler curves. The soils tested were residual soils and saprolites which were derived from weathering of the underlying metamorphic rocks. Because of the variations in structure and composition of the metamorphic rocks, differential weathering of these rocks produces

differences in characteristics of the resulting soil types. Consequently, variations in soil properties can be expected to occur from sample to sample, depending on the parent rock type from which the soils are derived.

Comparative consolidation test data between samples obtained with the Type U sampler and a thin-wall piston sampler at another nuclear station site in Virginia are shown on Figure 2.5-87. The soil is a clayey silt with a trace of fine sand and mica; all samples were obtained in borings within a radius of 350 feet. As shown on Figure 2.5-87, the shapes of the curves are very similar, indicating that there is very little difference in the degree of sampler disturbance between the Type U sampler and the piston sampler.

Whatever sample disturbance occurs utilizing the Type U sampler at the site will result in soil strength obtained from laboratory tests that will be less than the in situ soil strengths. Design analyses, therefore, based on soil parameters obtained from laboratory tests performed on soil samples obtained by the Type U sampler will be conservative.

Two (2) inch diameter plastic pipes were installed in several borings to measure ground water levels. The ground water levels measured after completion of the test boring work are indicated on the appropriate boring logs in Appendix 2E.

2.5.4.4.2 Geologic Investigation

The geologic studies are presented in detail in Sections 2.5.1, 2.5.2, and 2.5.3. Extensive excavations to and into bedrock were made for plant structures (Section 2.5.4.5). Detailed geologic studies of the exposed bedrock were performed, including the comprehensive investigation of rock shear zones. In addition to construction excavation, trenching by drag line and bulldozer also was employed in an attempt to trace rock shears northeastward out of the excavation for the reactor building foundation construction. The need for extensive trenching was precluded by the presence of 3 roadcuts directly across the surveyed strike line of a shear within Shear Zone 3 (Figure 2.5-25). Three (3) extensive efforts were made to trace the shear, but these investigations did not disclose evidence of a shear extension.

2.5.4.4.3 Seismic Refraction Survey

A seismic refraction survey was performed to evaluate on-site rock and overburden dynamic characteristics. Two (2) refraction lines, Numbers 1 and 2, were run at locations shown on Figure 2.5-44. Survey results are presented on Figures 2.5-88 and 2.5-89. Each survey line was approximately 1100 feet long, with geophones spaced at 50 foot intervals. An Electro-Technical Labs ER-75-12 Refraction Seismograph was used to obtain photographic records of the compressional wave arrivals.

The refraction survey results indicated that there is a surficial layer which has a compressional wave velocity of approximately 2300 feet per second. The layer thickness ranges from 50 to approximately 130 feet below the ground surface. The lower 20 to 30 foot zone usually has a gradational velocity varying from 2300 feet per second up to the velocity of the underlying rock. The transition to harder rock was indicated to be very irregular, with local irregularities on the

order of 20 feet. The field studies indicated that the average compressional wave velocity for the harder rock is 15,000 feet per second.

During construction, extensive excavations to and into rock were made for the principal plant structures. The compressional wave velocity of the rock was measured using a Bison Signal Enhancement Seismograph (Model 1570) to aid in the evaluation of the foundation supporting rock. Foundation rock with a measured compressional wave velocity of less than 8,000 feet per second was removed.

2.5.4.4.4 Surface Wave Survey

A surface wave survey (Line 3 on Figure 2.5-44) was performed to analyze the characteristic surface waves at the site and estimate shear wave velocity.

Two (2), 3 component Sprengnether velocity geophones were used to sense ground motions resulting from explosions at each end of Line 3. These geophones had a natural frequency of 1.0 Hz. The output was recorded on an Electro-Technical Labs SDW-100 Recording Oscillograph.

The survey results indicated that surface waves were not well developed; the amplitudes were only slightly greater than the compressional waves produced by the same shot. This indicated strong decoupling of compressional and shear body waves at the site, resulting in low amplitude surface waves.

The predominant frequencies developed by the surface waves vary between 7 and 14 Hz, with the most prominent being 10 and 14 Hz. The only surface wave coherent enough to be tentatively identified is a probable M_2 (Segawa) wave, with an approximate velocity of 1,500 feet per second and a frequency of 10 Hz. There were other surface wave arrivals after the M2 arrival, but these were difficult to identify.

The surface waves suggested that the shear wave velocity in the materials above hard rock averages approximately 1,300 feet per second. No body shear waves were identified from the harder rock at the site.

2.5.4.4.5 Micro-motion Measurements

Measurements were made of the ambient site ground motion to provide additional information regarding dynamic characteristics. Usually, background motion results from surface waves generated by man and his activities. The gain of the Sprengnether Velocity Meter was increased 100 times, using an amplifier, for these measurements. Evaluation of the measurements indicated that the site is extremely quiet. Ambient ground motions are negligible. Construction equipment operating 1,000 or more feet from the instrument confirmed the surface wave survey by producing very small amplitude waves ranging between 7 and 10 Hz.

2.5.4.5 Excavations and Backfill

2.5.4.5.1 Excavations

After the nuclear plant site was cleared, grubbed, stripped of topsoil and organic material, and graded to elevation 435', excavations were made for the foundation mats of the Reactor, Control and Auxiliary Buildings. These excavations extended into rock. The competency of the bearing rock was evaluated by geologic and engineering inspections during construction (Sections 2.5.1.2.2 and 2.5.4.10.2). Weathered or highly fractured rock was removed. These excavations were backfilled with structural fill concrete (Section 2.5.4.5.2).

The side slopes and benches of the excavations for the rock supported mat foundations extended laterally into the areas of the adjacent Seismic Category 1 plant facilities: the Diesel Generator, Fuel Handling, and Intermediate Buildings. Excavations for these buildings were partially backfilled prior to the installation of caissons for the support of the buildings. After caissons were installed, the backfilling of the excavations to foundation grade was completed. The caissons were extended up to foundation grade in a manner described in Section 2.5.4.10.4.

The extent and depth of the excavations and the type of backfill used for the Seismic Category 1 nuclear plant facilities are presented on the cross sections of Figures 2.5-77 through 2.5-82. Dewatering of these excavations is discussed in Section 2.5.4.6.

The excavations for the Turbine Building foundations extended laterally into the area of the condensate storage tank as shown on Figures 2.5-48 and 2.5-82. In addition to this excavation, the in situ soils at the tank site were excavated to elevation 409'. For the support of the tank, compacted crushed rock (Zone III material) was used to backfill the excavation beneath the tank, as shown on Figure 2.5-82. Details of the preparation of the foundation soils for the tank are given in Section 2.5.4.10.3. Dewatering at the tank site was unnecessary.

2.5.4.5.2 Backfill Material

Six (6) types of backfill material used at the nuclear plant site are: fill concrete (1500 psi concrete), river sand, Zone 1 filter material, and Zone I, II, and III materials. Zone I and II materials are basically clay soils and saprolites, respectively. The river sand is a granular material obtained from natural deposits. Zone 1 filter material is crushed rock and is used primarily for dam and embankment construction at the Service Water Pond. Zone 1 filter material is described in detail in Section 2.5.6.4.3.3. The Zone III material is also crushed rock. The locations of the types of the backfill material are indicated on Figures 2.5-77 through 2.5-82. In addition to the six (6) types of backfill used during and subsequent to plant construction, Controlled Low-Strength Material (CLSM), a self consolidating cementitious flowable fill, is used where approved by Engineering in limited applications as an alternative structural backfill for Zone III material. Surveillance and inspection of the placement of the backfill materials at the nuclear plant site are provided by SCE&G Quality Control. An in-place density test is performed, as a minimum, for every 1500 cubic yards of soil backfill placed. The tests are performed utilizing sandcone and nuclear methods in accordance with ASTM D 1556-64 and D 2922-71, respectively. When used in Nuclear Safety Related applications, CLSM samples and testing shall be taken at least once

during each day's placement. Samples shall be obtained in accordance with ASTM D 5971 and tested for flow consistency (ASTM D 6103), density and air content (ASTM D 6023), and compressive strength (ASTM D 4832).

1. Fill Concrete

   Fill concrete (1500 psi concrete) was placed directly on rock beneath the base of the structural foundation mat of the Reactor, Control and Auxiliary buildings. The concrete was designed to obtain a 28 day strength of 1500 pounds per square inch (psi). Prior to placement of the fill concrete, the subgrade rock was inspected by the resident foundation engineer. The competency of the bearing rock was determined by geologic and engineering inspections. Immediately before any concrete was placed on or against rock, the rock was cleaned of all dirt, gravel, boulders, scale, loose fragments, and other objectionable substances by air and/or water jetting. The rock surface was then dampened.

   In lieu of Zone I and II backfill, fill concrete was used below elevation 370' around the Reactor and Auxiliary Buildings. In these areas, where the fill concrete interfered with caisson installation under the Fuel Handling and Intermediate Buildings, blockouts were formed to facilitate caisson installation.

2. Zone 1 and II Materials

   Zone I and II materials are used as primary backfill beneath the Diesel Generator, Fuel Handling, and Intermediate Buildings which are supported on caissons. Select borrow materials from the same sources as the Zone II materials are used for the construction of the Service Water Pond dams. The static and dynamic engineering properties of these materials are discussed in Section 2.5.6.4. The locations of the borrow areas are described in Section 2.5.6.2.

   Zone I material is a reddish clayey soil classified as a CH or CL material in accordance with the USCS. Zone II material is a multicolored (ranging from red to light tan) saprolite ranging from an MH to an SM soil in accordance with the USCS.

   The Zone I and II materials are free of organic material (such as leaves, grass, and roots), stones having a maximum dimension of over 6 inches, or any other unsuitable material. In areas where Zone I or Zone II fill are utilized, the material is placed as homogeneously as possible in horizontal layers not exceeding 8 inches (loose) in thickness. The material is compacted to a dry density of at least 90% of the maximum dry density as determined by ASTM Test Designation D 1557-70, Method C. The moisture content of the placed material is held to +4%, -2% of the optimum moisture content.

3. Zone III Material

   Zone III material is used for the following:

   a. The support of the condensate storage tank and diesel generator fuel oil storage tanks.

b. The support of portions of the Seismic Category 1 electrical duct bank and Service Water intake pipes.

c. Around the Intermediate Building foundation wall.

d. Under portions of the caisson supported Intermediate, Fuel Handling, and Diesel Generator Buildings.

e. As a working surface in areas adjacent to Seismic Category 1 facilities where Zone I and II materials are utilized. When used in these areas, Zone III material is placed in lifts not exceeding 9 inches in thickness and at vertical intervals of not less than 8 feet.

f. The support of some nonsafety-related facilities at the nuclear plant site.

Zone III fill consists of a sound, durable rock with a choice of the following 2 gradations depending on lift thickness:

U. S Standard Sieve Size	Maximum 12 inch lift% by Weight Passing	Maximum 15 inch lift% by Weight Passing
2”	100	100
1-1/2”	90 - 100	95 - 100
1”	70 - 100	70 - 100
1/2”	50 - 80	50 - 80
No. 4	40 - 55	40 - 55
No. 30	10 - 32	10 - 32
No. 200	0 - 15	0 - 10

Both gradations meet the following requirements for soundness and durability:

a. The percent of total weight loss measured in accordance with the Sodium Sulfate Soundness Test, ASTM C-88, performed on the No. 4 and larger fractions shall not exceed 10% after 5 test cycles.

b. The percent of total weight loss during the Los Angeles Abrasion Test, ASTM C535-69, shall not exceed 65%.

The Zone III material is placed in lifts not exceeding 12 inches and 15 inches in thickness depending on the gradation as specified above. The material is compacted using a smooth drum vibratory roller to at least 85% of relative density as determined by the Department of the Army EM-110-2-1906.

Subsequent to March 15, 1982, an alternate gradation to that shown above may be used. The gradation shall be in compliance with that shown as "Composite Mixture" in Section 305.04 of the South Carolina State Highway Department Standard Specifications for Highway Construction, Edition of 1973, as follows:

U. S Standard Sieve Size	Percent By Weight Passing
2"	100
1-1/2"	90 - 100
1"	70 - 100
1/2"	48 - 75
No. 4	30 - 50
No. 30	11 - 30
No. 200	0 - 12

In lieu of the prequalification testing required in paragraphs a. and b. above, the supplier of the Zone III fill must produce certification that his composite mixture has been tested and does meet the requirements of Sections 302.02(a) and (b), 305.02, 305.03, and 305.04 of the South Carolina State Highway Department Standard Specifications for Highway Construction, Edition of 1973. Additionally, where determined acceptable by the Engineer, the gradation described for the "Composite Mixture – Macadam Base Course" in the most recent revision of the South Carolina State Highway Department Specifications for Highway Construction may be used in lieu of Zone III material.

The "Composite Mixture" shall be placed in lifts not to exceed 12 inches.

4. River Sand

River sand is used for backfilling portions of excavations for the Service Water discharge pipes. The material is placed in layers not exceeding 12 inches and compacted to at least 75% of relative density as determined by Department of the Army EM-1110-2-1906. River sand consists of natural deposits with the following gradation:

U. S. Standard Sieve Size	Percent Passing by Dry Weight
3/4 inch	100
No. 4	75 - 100
No. 10	50 - 90
No. 40	10 - 50

No. 200	0 - 5

5. Zone 1 Filter Material

   Zone 1 filter material is used to backfill the southern portion of the interconnecting pipe from the Circulating Water intake structure to the Service Water Pumphouse. This material is also used to backfill excavations near the entrance to the Service Water intake structure. This material is placed in layers not exceeding 12 inches and compacted to at least 70% and 75% relative density at the Service Water intake structure and interconnecting pipe, respectively, as determined by Department of the Army EM-1110-2-1906.

   Zone 1 filter material consists of a sound, durable crushed stone with the following gradation:

U. S. Standard Sieve Size	Percent Passing by Dry Weight
3/4 inch	100
No. 4	75 - 100
No. 10	50 - 85
No. 40	10 - 50
No. 200	0 - 5

6. Controlled Low-Strength Material (CLSM)

   CLSM is a self-consolidating cementitious flowable fill used as an alternative backfill in place of compacted fill materials in limited locations where installation and testing of other approved types of compacted fill is not practical due to the particular configuration such as for narrow trench excavations at buried piping. Materials, Mixing, Transporting, Placing and Quality Control are in accordance with the recommendations in ACI 229R-13 “Report on Controlled Low-Strength Materials.” The Flowable Fill consists of normal density design, with typical 28-day minimum compressive strength of 50 psi and an upper limit typically within a range to permit future excavation with conventional excavation equipment.

2.5.4.6 Ground Water Conditions

The ground water during and prior to construction was located at a significant depth below the ground surface (see Figure 2.4-16). After Monticello Reservoir is impounded (normal high water elevation 425.0' and normal drawdown elevation 420.5'), it is estimated that the ground water at the principal plant structures ultimately will rise to a maximum, approaching elevation 420'. Water levels are likely to fluctuate slightly and will be highest during periods of wet weather.

The rise in the ground water will not affect the stability of the Seismic Category 1 structures supported on rock below the ground water level. These structures are designed to withstand the hydrostatic forces. The rise in the ground water will not affect the stability of the Seismic Category 1 structures that are soil supported. The stability of the Seismic Category 1 soil-supported structures are discussed in Section 2.5.4.10.3. The effect of the rise of the ground water was considered.

Ground water did not constitute a major problem during construction of the nuclear plant facilities. Nor did the construction dewatering adversely affect the stability or the integrity of the Seismic Category 1 structures.

Ground water entering the excavations in sufficient quantities to require dewatering occurred in 3 areas:

1. The northeast corner of the Reactor Building,
2. The southeast side of the Control Building, and
3. The southwest side of the Auxiliary Building.

In the Auxiliary and Reactor Buildings, the majority of the water inflow came from joints in the rock, while in the Control Building the major portion of the inflow came from a fractured quartz dike.

The ground water in these excavations was controlled by a series of French drains and sumps. The French drains consisted of crushed rock capped with grout. Between the grout and the crushed rock, several layers of burlap were placed to prevent the grout from infiltrating the crushed rock. Each sump consisted of a 36 inch diameter corrugated metal pipe.

Only 2 French drains for the Reactor Building and 1 French drain for the Auxiliary Building were located within the perimeter of the concrete mats. The French drains in the area of the Reactor Building foundation were approximately 1 foot in width, while the French drain in the area of the Auxiliary Building foundation had a maximum width of approximately 2-1/2 feet.

After the foundation construction was above the level of the ground water inflow, the sumps were filled with fill concrete. Only the sump for the Control Building was located within the perimeter of the concrete mat.

Caissons were installed for the support of the Diesel Generator, Fuel Handling, and Intermediate Buildings. During construction of the caissons, ground water from joints in the rock sockets entered many of the caisson shafts. Caisson construction is discussed in Section 2.5.4.10.4.

The excavation for the condensate storage tank did not require dewatering.

The permeability of the subsurface materials at the site is discussed in Section 2.4.13.2.4. The results of laboratory permeability tests performed on various types of soil and rock are

summarized in Table 2.4-9. The results of the field permeability tests are presented in Table 2.4-10.

Ground water levels during the life of the plant are discussed in Section 2.4.13.2.5. Ground water fluctuations are discussed in Section 2.4.13.2.3.

Monitoring plans for plant observation wells are discussed in Section 2.4.13.4.

Direction of ground water flow, gradients, and velocities are discussed in Section 2.4.13.2.5. Site ground water contours are illustrated on Figure 2.4-16.

2.5.4.7 Response of Soil and Rock to Dynamic Loading

The testing performed to evaluate the dynamic properties and characteristics of the soil and rock at the nuclear plant site are discussed in Sections 2.5.4.2 and 2.5.4.4. Evaluation of the liquefaction potential at the nuclear plant site is discussed in Section 2.5.4.8. The soil structure interaction analyses are discussed in Section 3.7.2.4. The dynamic response of buried pipelines and earthworks is described in Sections 3.7.3.12 and 2.5.6.5, respectively.

2.5.4.8 Liquefaction Potential

The principal plant facilities are supported on mats or caissons founded on the underlying rock and are therefore not susceptible to the phenomenon of liquefaction. However, facilities such as the Service Water intake and discharge pipes, electrical duct bank, diesel generator fuel oil storage tanks, and the condensate storage tank are supported on soil, as shown on Figures 2.5-46, 2.5-47, and 2.5-48. The potential for liquefaction and settlement under cyclic loading of soils under level ground in this area is evaluated in this section. The stability of the adjacent west embankment and liquefaction potential of the Service Water intake, pumphouse, and discharge structures are discussed in Section 2.5.6.

The general subsurface conditions in the area under consideration are shown on Figures 2.5-80, 2.5-81, and 2.5-82. The facilities involved are founded on compacted fill or on residual soils. The general site and subsurface conditions are described Section 2.5.4.10.1 and the characteristics of the soils and rock are described in Sections 2.5.4.2 and 2.5.4.4. The upper 5 to 10 feet of the natural soils are principally clayey materials. Beneath this is a stratum of silty sand and/or sandy silt, known locally as saprolite. The characteristics of the fill material and the compaction specifications are described in Section 2.5.4.5.2.

Nine (9) borings (3-19, 4-1 through 4-8) have been drilled in the area under consideration prior to or during placement of the fill. The locations of these borings are shown in section on Figures 2.5-80 and 2.5-81, and in plan on Figures 2.5-46 through 2.5-48. The boring logs are shown in Appendix 2E.

In Boring 4-1, loose silty sand was encountered in the upper 20 feet of the natural overburden soils, but these loose soils were excavated as described inSection 2.5.4.10.3. Borings 4-2 and 4-5

encountered soft and loose fill. This condition is being evaluated and appropriate corrective action will be taken as necessary.

Cyclic triaxial tests were conducted on samples of saprolite obtained in Boring 4-1. The results of these tests are presented in Section 2.5.4.2.2, but the corrections to these results that are required to account for sample disturbance and the differences in stress and deformation boundary conditions between the laboratory tests and the field have not been defined. Rather, evaluation of the potential for liquefaction under cyclic loading of the saprolite is based on the results of standard penetration tests as suggested by Seed (Reference 68).

The general ground water conditions at the plant site are described in Section 2.5.4.6. In this evaluation of liquefaction potential, it is conservatively assumed that the ground water will rise to elevation 420' (i.e., 15 feet below plant grade) after the filling of Monticello Reservoir. The actual water table after filling will be monitored as described in Section 2.4.13.4.

The maximum horizontal accelerations generated by the postulated Safe Shutdown Earthquake have been conservatively taken to be 0.15g in rock and 0.25g in soil as discussed in Section 2.5.2.10. These accelerations are associated with the random occurrence near the site of an earthquake with an epicentral intensity of VII or a magnitude of less than 6. It should be noted that the implied amplification of motion in soil is conservative, as recent studies by Donovan (Reference 69) and Seed et al (Reference 70) have shown that peak accelerations recorded in soil tend to be attenuated relative to those in rock for accelerations exceeding about 0.1g. Thus, it appears that a peak ground surface acceleration of 0.15g is adequately conservative for evaluating the response of soils to earthquake induced shaking.

The evaluation of liquefaction potential based on standard penetration test blowcounts involves comparison of the measured blowcounts with the blowcounts which bound all known cases of liquefaction for the relevant magnitude earthquake. In both cases the actual blowcounts are modified in order to account for the effects of overburden pressure. In this evaluation the comparison is made in terms of modified penetration resistance, N_1 where $N_1 = C_nN$ in which N = standard penetration resistance.

$$C_n = 1 - 1.25 \log \frac{\sigma_v'}{1\text{tsf}}$$

σ_υ' = effective overburden pressure

The modified penetration resistances which bound conditions causing liquefaction are computed for a given ground surface peak acceleration using the correlations presented by Seed on Figure 24 of his reference (Reference 68). In this figure values of the cyclic stress ratio, τ/σ'_υ, causing liquefaction are given as a function of modified penetration resistance.

The stress ratio, τ/σ'_{υ}, in which τ = average cyclic shear stress and σ'_{υ} = effective overburden stress are computed by use of the formula:

$$\tau/\sigma'_{v} = 0.65 \frac{\sigma_v}{\sigma'_v} a_{peak} r_d$$

where

σ_v = total overburden stress

a_{peak} = peak ground surface acceleration

r_d = a depth reduction factor which accounts for flexibility of the soil column.

Computed values of the maximum modified penetration resistances for liquefaction under peak ground surface accelerations of 0.15g and 0.25g are presented in Tables 2.5-18 and 2.5-19 using the above expression and Seed's curve for Magnitude 6 earthquakes. In the computations, average total unit weights for fill and saprolite have been assumed to be 117 pcf above the water table and 120 pcf below the water table. Values of the depth reduction factor, r_d, have been taken from Seed and Idriss (Reference 71). Average values were used with the peak ground surface acceleration of 0.15g and lower bound values of r_d were used with the peak ground surface acceleration of 0.25g, since this value requires that the peak accelerations must reduce rapidly with depth in order to be consistent with a peak acceleration of 0.15g in rock. The modified penetration resistances obtained by these computations are plotted on Figure 2.5-90.

Also plotted on Figure 2.5-90 are modified penetration resistances from Borings 3-19, 4-1, 4-3, and 4-7. These modified penetration resistances generally range between 10 and 25. While several values fall within the range indicated for liquefaction under a peak surface acceleration of 0.25g, compatibility of deformations in the field requires that the overall response to cyclic loading be determined by the average properties of the soil, and therefore a clear margin of safety against liquefaction is indicated. An even more substantial margin of safety is indicated for a peak ground surface acceleration of 0.15g.

Additional standard penetration resistances were recorded in the natural soils in Borings 4-2, 4-4, and 4-6, located near the intersection of the Service Water intake pipe and the circulating water pipe. Several of these values are relatively low; however, they have been obtained in the more clayey soils which comprise the original surface layer and on visual inspection are not the type of material shown by experience to be susceptible to liquefaction. Grain size distributions for these and selected other samples obtained in conducting standard penetration tests are shown on Figures 2.5-65 through 2.5-76.

It may be noted that the penetration resistances recorded in the saprolite will tend to be lower than those that would be recorded in alluvial deposits existing under similar states of compactness and in situ stress. This occurs because penetration resistance is a function of the compressibility of a soil as well as its shear strength [71a,71b]. Because of the relatively high percentage of fines (in the order of 20-25% passing the No. 200 sieve) and the significant mica content in the saprolite, this material will tend to be more compressible than the cleaner alluvial deposits which have shown historic evidence of liquefaction. Thus, while use of the maximum modified penetration resistances suggested by Seed, which are based on the historic occurrence of liquefaction in predominantly alluvial deposits, is generally appropriate for this site, the method will tend to be conservative in the case of the more compressible saprolite.

With respect to the fill materials (compacted in accordance with the specifications), the Zone I (clayey soil) and Zone II (crushed rock) materials are not susceptible to liquefaction. While Zone 1 filter material, river sand and Zone II material (silty sand and/or sandy silt) are potentially susceptible to liquefaction, if saturated, there is no historic evidence of the phenomenon of liquefaction in well compacted rolled fills, even under heavier levels of shaking than those postulated for the Safe Shutdown Earthquake.

An estimate of the maximum settlement of the fill and the saprolite that might be caused by cyclic loading induced by the postulated Safe Shutdown Earthquake may be obtained using data presented by Pyke (Reference 72). Using the values of the cyclic stress ratio τ_{av}/σ'_v, that were computed in Table 2.5-19 and typical values of shear modulus for medium dense sands, values of the average cyclic shear strain may be computed as shown in Table 2.5-20. The maximum average cyclic shear strain is on the order of only 0.1% for an assumed peak ground surface acceleration of 0.25g. The data presented by Pyke for Jensen Fill, which is generally similar to the saprolite and fill materials at the nuclear plant site, indicates that insignificant settlements will occur for cyclic strains up to this level.

2.5.4.9 Earthquake Design Basis

The earthquake design basis is presented in Section 2.5.2.

2.5.4.10 Static Analyses

A layout of principal structures comprising the plant is shown on Figure 2.5-46. Seismic Category 1 structures of the principal plant facilities are supported on mats or caissons founded on the underlying rock. However, as shown on Figures 2.5-46, 2.5-47, and 2.5-48, in the area between the plant and the Service Water pond, facilities such as the Service Water intake and discharge pipes, electrical duct bank, diesel generator fuel oil storage tanks, and the condensate storage tank are supported on soil. The foundations for the Seismic Category 1 structures related to the Service Water Pond are discussed in Section 2.5.4.10.6. Pertinent foundation design information for principal Seismic Category 1 structures is presented in Table 2.5-21.

Cross sections illustrating building foundation elevations, general subsurface conditions, and surface topography are presented on Figures 2.5-77 through 2.5-82. The locations of the sections are shown on Figures 2.5-46 and 2.5-47.

2.5.4.10.1 Site Conditions

2.5.4.10.1.1 Surface Conditions

Prior to construction, the site and surrounding area terrain was characterized by moderately sloping ridges and hills and well developed drainage patterns. Frees Creek and Mayo Creek, tributaries to the Broad River, lie in valleys immediately north and south, respectively, of the site ridge. Grade along Frees Creek near the site was approximately elevation 260'. Along Mayo Creek, grade was approximately elevation 300'. The plant site was located on an irregularly shaped ridge approximately 1 mile east of the Broad River. The original ground surface at the plant site ranged from elevation 400' to 500'. The original ground surface sloped downward toward the north and northeast toward the base of the ridge flank. In the floor of the Service Water Pond, the existing grade was approximately elevation 350'. The site and surrounding area was heavily forested.

For construction of the nuclear facilities, the site was cleared, grubbed, stripped of topsoil and organic material, and graded. The plant site area was graded to approximately elevation 435' (finished grade), requiring the removal of very little overburden material at the northeastern portion of the plant site and up to a maximum of approximately 65 feet at the southwestern portion. For a number of the principal plant structures, excavations to and into rock were required for construction of the foundations. These excavations varied to a maximum of approximately 100 feet below finished grade. Plot plans and cross sections through the plant site are provided in Section 2.5.4.3. Excavation and backfill are discussed in Section 2.5.4.5.

2.5.4.10.1.2 Subsurface Conditions

Prior to and during construction, subsurface field investigations that included test borings and geophysical surveys were performed at the site. Details of these investigations are discussed in Section 2.5.4.4. The results of the investigations indicate that the plant site and surrounding area were initially blanketed primarily by moderately thick residual soil derived by weathering of underlying rock. In the Service Water Pond bottom, some alluvial soils were in evidence. Results of the investigations for the Service Water Pond are presented in Section 2.5.6.2. Initially the overburden thickness (based on original site grade) ranged from approximately 40 to 95 feet in the borings drilled at the principal plant structures; and, in general, the elevation of rock decreases toward the north and east. After construction, the overburden thickness (based on finish grade elevation 435') now ranges from approximately 20 to 95 feet (see cross sections provided in Section 2.5.4.3). Additional rock excavation was performed beneath a number of principal plant structures.

The upper 5 to 10 feet of natural soil usually were principally stiff clayey soils (silty clay and clayey silt) containing variable quantities of sand. Surficial alluvium, where present, appeared to be loose sand and/or silty soils. Below the surface zone was saprolite defined as rock that has weathered in place to a soil consistency, but retains diagnostic properties of the parent rock. The saprolite was medium dense to dense silty sand and/or sandy silt that exhibits a slight to low plasticity because of weak cementation. The saprolite generally became denser with depth grading into rock. After construction, soils present below the finish site grade are essentially all in

situ silty sand (saprolite) and backfill (Section 2.5.4.5), except in the area between the nuclear plant and the Service Water Pond where fill overlies the upper zone of in situ clayey soils. The in situ saprolite contains small to moderate quantities of mica and occasional boulders that generally occur near the top of rock.

In a small localized area where the Seismic Category 1 electrical duct bank and the Service Water pipes cross over the circulating water pipe, borings drilled (Borings 4-2 and 4-5) to investigate the fill materials encountered soft and loose fill. This condition was evaluated and documented. The soft and loose fill was removed to competent material and replaced with material compacted in accordance with the original specification requirements.

Many borings indicate that the overburden soils are underlain by a zone of highly weathered rock which sometimes is interlayered with decomposed rock of a granular soil-like consistency. Moderately weathered rock usually is present beneath these materials, and is directly beneath the overburden soils where the highly weathered rock zone does not occur. This, in turn, is underlain by fresh rock which contains some random thin zones of weathered and/or partially decomposed rock. Moderately weathered and/or fresh rock was encountered in borings at the principal plant structures at depths (below original site grade) generally on the order of 65 to 115 feet (elevation 290' to 410'). One (1) boring (Boring 3-20) was terminated at elevation 349' in highly weathered rock. Because of differential weathering, the elevation of fresh rock and the character of weathered and decomposed rock changes appreciably over short distances (horizontal and vertical). This condition was substantiated during foundation construction. Details of the rock excavation are discussed in Sections 2.5.1.2.2, 2.5.4.5, 2.5.4.10.2, and 2.5.4.13. Caisson installation is discussed in Section 2.5.4.10.4.

The performance qualities of the rock were evaluated from detailed rock structure observed, core recovery, RQD, and a Rock Property Indicator. These data are presented on the boring logs in Appendix 2E in a manner described on Figure 2.5-83. Subsurface conditions pertaining to ground water are discussed in Sections 2.4.13 and 2.5.4.6.

2.5.4.10.2 Mat Foundations on Rock

The Seismic Category 1 structures supported on mats founded on rock are the Reactor, Control, and Auxiliary Buildings (Table 2.5-21). The excavations for these foundations are described in Sections 2.5.4.5 and 2.5.1.2.2.

Engineering inspections were performed to verify the competency of the foundation rock. Percussion rock drills were used to evaluate zones of highly weathered rock. The compressional wave velocity of the rock was measured using a Bison Signal Enhancement Seismograph, Model 1570. Rock which was excessively fractured by blasting, or which failed to meet the minimum compressional wave velocity requirement of 8,000 feet per second, was removed. These inspection methods were employed to verify that the rock quality is in compliance with the Safe Shutdown Earthquake and Operating Basis Earthquake criteria for the design of Seismic Category 1 structures supported on mat foundations founded on rock; i.e., the mats are founded on, as a minimum, moderately weathered rock with a compressional wave velocity of 8,000 to 10,000 feet per second (Section 2.5.2).

After the foundation rock was inspected and approved, the excavations were backfilled with fill concrete (Section 2.5.4.5.2).

2.5.4.10.2.1 Mat Bearing Capacity on Rock

The rock bearing capacity at the nuclear plant site was evaluated relative to the Rock Property Indicator numbers described in Section 2.5.4.4.1 and indicated on the boring logs in Appendix 2E. The strength of the foundation rock was tested in the laboratory by means of unconfined compression and triaxial compression tests performed on intact rock core samples (Section 2.5.4.2.2). The results of these tests are summarized in Table 2.5-9. From the results of these tests, the “theoretical” ultimate capacity of the bearing rock was calculated using Griffith's Strength Theory described by Coates (Reference 73).

The design allowable rock bearing capacity utilized provides for safety factors of 30 for the Number 1 rock and 20 for the Number 2 and 3 rock. The safety factors took into account the joints, fractures, and weathered zones present in the in situ rock. The ultimate and allowable bearing values relative to the Rock Property Indicator numbers are summarized in Table 2.5-22.

The pressures on the bearing rock surface caused by the Reactor, Control, and Auxiliary Building mat foundations do not exceed 25 kips per square foot. These pressures are well within the limits of the allowable bearing capacities indicated in Table 2.5-22.

2.5.4.10.2.2 Settlement of Mats on Rock

The settlements of the Reactor, Control, and Auxiliary Buildings supported on mats founded on bedrock were estimated using the elastic theory. Relative to the Rock Property Indicator numbers (Section 2.5.4.4.1), Young's modulus of elasticity was evaluated from the results of the stress-strain data obtained from triaxial, unconfined and confined compression tests performed on rock samples (Section 2.5.4.2.2), and the compressional wave velocity data (Table 2.5-8) developed from the results of the geophysical surveys. These evaluations are summarized below:

Rock Property Indicator Number	Young's Modulus of Elasticity (psi)
1	4×10^6
2	1×10^6
3	2×10^4 to 1×10^5

The range of values for the Number 3 rock was provided to account for the variation of this rock from highly weathered to moderately weathered rock which is highly jointed.

Analysis indicated that the settlements of the Reactor, Control, and Auxiliary Buildings would be on the order of 1/4 inch for loadings ranging up to 25 kips per square foot. The stress-strain data indicates that the rock will behave essentially elastically over the range of applied stresses, and

settlement will occur instantaneously as each increment of load is imposed. Therefore, post construction settlements will be practically nil.

2.5.4.10.3 Foundations on Soil

The soil supported facilities at the nuclear plant site such as the Service Water intake and discharge pipes, electrical duct bank, 2 diesel generator fuel oil storage tanks, and the condensate storage tank are shown in Figures 2.5-46 through 2.5-48. The Service Water pipes and electrical duct bank are supported below finish plant grade in compacted Zone I, II, and III material as illustrated on Figures 2.5-80 and 2.5-81

Each diesel generator fuel oil storage tank is supported on compacted Zone III (crushed rock) material which is shaped to uniformly support the circular bottoms of the tanks. A minimum of 3 inches of sand bedding is placed over the shaped areas to smooth irregularities in the supporting grade. The bottom of both tanks are at elevation 419'. The Zone III material extends to an approximate depth of elevation 404', the depth to which the natural in situ soils are removed. Zone III material also is compacted directly around and above the tanks.

The condensate storage tank site extended over a slope cut during the excavations for the rock supported mat foundations (Section 2.5.4.5) as illustrated on Figures 2.5-48 and 2.5-82. The in situ soils at the tank site were excavated to elevation 409', a depth of approximately 26 feet below the top of the slope. All loose or unsuitable soils were removed from the foundation area. Within the foundation support zone (delineated on Figure 2.5-82 as the zone projecting 5 feet beyond the edge of the tank mat and extending downward on a 1H:2V slope), the excavation was backfilled with Zone III material to foundation grade, elevation 430'. The Zone III materials were compacted to at least 85% of relative density as determined by ASTM Test Designation D 2049-69. Beyond the foundation support zone, the excavation was backfilled with Zone I, II, or III materials in a manner described in Section 2.5.4.5.

2.5.4.10.3.1 Soil Bearing Capacity

The soil bearing pressures of the Service Water pipes, electrical duct bank, and the diesel generator fuel oil storage tanks are insignificant relative to the soil bearing capacity. The heaviest of these facilities, the fuel oil storage tanks, actually weighs less than an equal volume of compacted backfill soil. For these facilities, the safety factor against a soil bearing failure is extremely high.

For the condensate storage tank, the Zone III backfill material (crushed rock) was estimated to have an angle of internal friction of 40 degrees and a cohesion of zero. These strength parameters are conservative for crushed rock compacted with heavy vibratory equipment. For example, Lambe and Whitman (Reference 74) suggest using these values as a minimum for dense sand and gravel mixtures.

Strength properties of the overburden soils were evaluated from the results of triaxial and unconfined compression tests and direct shear tests (Section 2.5.4.2.2). From the results of these tests, the medium dense to very dense granular overburden soils were estimated to have strength

parameters equivalent to at least an angle of internal friction of 32 degrees for the range of stresses produced by the condensate storage tank loadings. Beneath the condensate storage tank below elevation 409', an angle of internal friction equal to 29 degrees and a cohesion of zero for the medium dense to very dense natural soils were utilized to evaluate the bearing capacity.

The ultimate bearing capacity of the soil system beneath the condensate storage tank was computed for the most critical condition; i.e., on the basis of the strength of the weakest stratum (the natural soils below elevation 409'). The stresses on the top of the natural soils due to the tank loading were computed using the sixty degree distribution method (Reference 75 Reference 76) The ultimate bearing capacity of the natural soils was computed using the standard semi-empirical equation for circular footings (Reference 77).

The effect of the ground water level (Reference 78) and the limited depth of the bearing stratum (Reference 79) were considered. The ultimate bearing capacity of the natural soils at elevation 409' was calculated to be 65 kips per square foot. For the normal operating condition, the factor of safety at the top of the natural soils was computed to be approximately 45. For the normal operating bearing pressure and the dynamic bearing pressure (earthquake forces), the factor of safety at the top of the natural soils was calculated to be approximately 20. The effect of the eccentric earthquake loading was taken into consideration (Reference 80).

2.5.4.10.3.2 Settlement of the Foundations of Soil

The settlement of the Service Water pipes, electrical duct bank, and the diesel generator fuel oil storage tanks due to their own weights will be negligible. However, structure settlements of up to several inches are estimated as a result of the weight of the fill in which these facilities are placed.

The post-construction settlement of the well compacted fill is considered to be negligible. From the results of the consolidation tests performed on saprolites, the time-settlement responses indicated that the settlements will occur almost instantaneously upon the application of the loads. Therefore, post-construction settlements of the underlying saprolites will be negligible. Post-construction settlement of the principally clayey natural soils that directly underlie the fill (see Figures 2.5-80 and 2.5-81) was estimated to be less than 1 inch utilizing Terzaghi's consolidation theory (Reference 81).

Total settlement of the condensate storage tank was calculated using 4 independent methods: 1) Terzaghi's consolidation theory, 2) modified empirical method utilizing the results of the Standard Penetration Tests (SPT) and settlement chart given by Terzaghi and Peck (Reference 77, 3) Meyerhof's method (Reference 82, and 4) a simplified elastic theory (Reference 74). The use of these methods of saprolite soils is described by Barksdale and others (Reference 83). For the consolidation theory and the elastic theory methods, the stresses were computed using the Westergaard Stress Distribution Theory (Reference 84). The consolidation theory utilized the results of the 1 dimensional consolidation tests (Figure 2.5-60). The elastic theory used a value of Young's modulus equal to 2.7×10^4 pounds per square inch that was derived from the results of the geophysical surveys (i.e., the shear modulus values) performed on the in situ site materials (Sections 2.5.4.4.3 and 2.5.4.4.4).

For the condensate tank, the total settlement using the 4 methods was computed to be less than 1/2 inch. Settlement within the Zone III material was estimated to be essentially nil and was neglected. Because the settlement of the saprolites will occur almost instantaneously upon the application of the loads, post-construction (after the tank is water tested) settlements will be negligible.

To verify the postulated values outlined above, settlement of the condensate storage tank was computed by comparing the elevation of the tank's concrete pad before installation of the tank with the elevation after the tank was completed and filled for a period of 6 months. The measured settlement of the pad and tank for this 2-1/2 year period since its construction has been approximately 0.04 feet (1/2 inch). This verifies the value computed above. No additional settlement is expected.

As shown by Figures 2.5-81 and 2.5-82, the diesel generator fuel oil storage tanks are supported by approximately 20 feet of Zone III fill (graded crushed rock) overlaying undisturbed natural soils, while the condensate storage tank is supported by 21-30 feet of Zone III fill over the undisturbed natural materials. Since the condensate storage tank has experienced minimal settlement as computed and verified, the diesel generator fuel oil storage tanks are likewise expected to exhibit a similar degree of settlement. Additionally, Figure 9.5-2 shows that couplings are provided in the transfer pump suction lines which could accommodate greater settlement than the minimal settlement expected. Quarterly visual inspections will be made of the ground surface in the area of the diesel generator fuel oil storage tanks for evidence indicating settlement of the tanks. If any evidence of settlement is observed, immediate investigation of the matter will be initiated.

2.5.4.10.4 Caisson Foundations

The Seismic Category 1 structures supported on caissons embedded in rock are the Diesel Generator, Fuel Handling, and Intermediate Buildings. The caissons, 36 and 48 inches in diameter, are designed to be supported by end bearing and/or shaft resistance (skin friction) in the underlying rock. The allowable end bearing and shaft resistance for the various rock types as described in Section 2.5.4.4.1 are presented in Table 2.5-23. The caissons are designed for these allowable values with the exception that the values for the Number 2 rock are used for both the Number 1 and Number 2 rock. For the caissons designed for a combination of end bearing and shaft resistance, the full value for 1 type of resistance plus no more than 2/3 of the other resistance as indicated in Table 2.5-23 are used.

Caissons are socketed a minimum of 1 foot into Number 1 and 2 rock. The total depth of penetration of each rock socket was determined and established by the resident foundation engineer during his inspection of the rock sockets. The depths of the rock sockets are in accordance with the allowable end bearing and shaft resistance values relative to the compressional load, uplift load, and lateral resistance requirements of the individual caisson.

For the construction of each caisson, a temporary casing was installed to rock. After the casing was seated on rock, the socket was drilled with a roller bit. The foundation rock exposed in the caisson sockets was inspected by the resident foundation engineer in evaluating compliance with

design requirements. Probe holes having a minimum depth of at least 2 times the caisson diameter were drilled beneath the bottom of each socket to investigate the competency of the bearing rock.

Immediately prior to concrete placement, each socket was inspected by the resident foundation engineer to insure that it was properly cleaned. Water inflow measurements were taken to determine the method of placement of concrete.

When casing was left in place, the annular space between the casing and the ground was grouted in accordance with applicable procedures.

As indicated in Section 2.5.4.5.1, the caissons were installed prior to completion of the backfilling operations. These caissons were extended to the cut-off elevations utilizing circular metal forms for caisson construction. As the caissons were constructed to the cut-off elevations, the backfilling was completed to foundation grade.

During the installation of the caissons, surveillance was provided by the resident foundation engineer and a SCE&G Quality Control inspector.

2.5.4.10.4.1 Caisson Bearing Capacity

The “theoretical” ultimate and static allowable bearing capacities of the rock relative to the Rock Property Indicator numbers (Section 2.5.4.4.1) are presented in Section 2.5.4.10.2.1. These bearing capacities are applicable for the end bearing of caissons. For short term earthquake loadings, the allowable values were increased. The static and dynamic allowable end bearing values for caissons are presented in Table 2.5-23. The safety factors for the allowable earthquake loadings relative to the “theoretical” ultimate bearing values are approximately 10 for the Number 1 and 3 rock, and approximately 7 for the Number 2 rock. The caissons are designed in accordance with the allowable end bearing values presented in Table 2.5-23 with the exception that the allowable end bearing values do not exceed 100 kips per square foot for static loadings and 300 kips per square foot for earthquake loadings. The larger allowable values for the Number 1 rock are not utilized in the design although many of the caissons are founded on Number 1 rock.

The allowable shaft resistance (shear resistance between the caisson and the side of the rock socket sometimes referred to as skin friction) was evaluated for static and short term earthquake loading conditions, the results of which are summarized in Table 2.5-23. These allowable shaft resistance values relative to the allowable end bearing capacities are in accordance with general design practice, which in many cases are very conservative. The caissons are designed in accordance with the allowable shaft resistance values presented in Table 2.5-23. The values for the Number 2 rock were also used for the Number 1 rock.

Some caissons are designed using the combined allowable end bearing and shaft resistance values. For these cases, the full value for one type of resistance plus no more than 2/3 of the other resistance are utilized in the design as indicated in Table 2.5-23.

Most of the caissons at the nuclear plant site are founded on Number 1 or Number 2 rock. Only a few caissons are founded directly on Number 3 rock.

2.5.4.10.4.2 Settlement of Caissons

Settlements of the caissons were computed using the elastic theory. Values for Young's modulus presented in Section 2.5.4.10.2.2 were utilized in the caisson settlement computations. Caissons with end bearing pressures not exceeding 100 kips per square foot and founded on Number 1 and/or Number 2 rock (the design criteria) were estimated to settle 1/4 inch or less. Settlements are due to the elastic compression of the underlying rock mass and occur immediately as the load is applied.

2.5.4.10.5 Lateral Earth Pressures

Backfill placed against the rigid foundation walls of Seismic Category 1 structures consisted of Zone I, II and III materials, compacted in accordance with the criteria discussed in Section 2.5.4.5.2. No in situ soils abutted Seismic Category 1 foundation walls.

The maximum lateral pressures exerted against the rigid foundation walls by the backfill materials are expected to result from the “at rest” lateral earth pressure conditions under the dynamic Safe Shutdown Earthquake (SSE) loadings. However, the rigid Seismic Category 1 foundation walls were designed for lateral pressures using a more conservative approach, the Mononobe-Okabe Seismic Coefficient Analysis (Reference 85, Reference 86) as modified by Kapila (Reference 87, Reference 88). This analysis considers the passive earth pressure condition under dynamic earthquake loadings.

For the SSE, the maximum horizontal acceleration at the ground surface is 0.25g; the corresponding vertical acceleration is 2/3 of the horizontal (Section 2.5.2). For the backfill materials, average design parameters of 35 degrees for the angle of internal friction, 0 for cohesion, and 120 pounds per cubic foot for the unit soil weight were selected for the analysis. These soil parameters are conservative for the passive earth pressure analysis relative to the “at rest” earth pressure conditions that are expected to occur.

Using the modified Mononobe-Okabe analysis and the above parameters, the computer lateral earth pressures result in an equivalent fluid pressure equal to 290 pounds per cubic foot above the water level and 230 pounds per cubic foot below the water level. These values were used for the design of the rigid Seismic Category 1 foundation walls.

Static and dynamic lateral earth pressure distribution diagrams for typical cases are presented on Figures 2.5-90b and 2.5-90b.

2.5.4.10.6 Structures at the West Embankment

The Service Water Pumphouse, Service Water intake structure, and Service Water discharge structure are located at the west embankment of the Service Water Pond, as shown on Figures 2.5-46 and 2.5-47. The appropriate soil parameters used for calculations are presented in Sections 2.5.6.4 and 2.5.6.5.

2.5.4.10.6.1 Bearing Capacity and Stability

The pump house foundation mat is supported on the west embankment at elevation 386'. The ultimate bearing capacity of the west embankment fill for this structure is conservatively computed to be 50 kips per square foot at the end of construction and 40 kips per square foot upon filling of the Service Water Pond. The minimum factor of safety for bearing capacity failure is 6.

Bearing capacity is not applicable for the Service Water intake structure, since the weight of the intake structure is less than the weight of the displaced west embankment fill.

The base slab of the Service Water discharge structure is supported on decomposed rock at elevation 408'. The ultimate bearing capacity for the structure is conservatively calculated to be greater than 90 kips per square foot, resulting in a minimum factor of safety in excess of 15.

The presence of the Service Water Pumphouse and the Service Water intake and discharge structures within the west embankment does not significantly affect the stability of this slope. Detailed analysis of the west embankment slope at the locations of these structures was not considered necessary because the embankment heights at these locations are significantly less than the critical sections analyzed for the north and south dams, as described in Section 2.5.6.5. In addition, the presence of the structures does not significantly alter the stress conditions on potential failure planes.

2.5.4.10.6.2 Settlement

Estimates of Service Water Pumphouse and Service Water intake structure settlement prior to construction were 3 to 4 inches and 1.5 to 2 inches, respectively. During construction, these structures settled more than had been estimated. A special settlement study was then performed for the Service Water Pumphouse and Service Water intake structure. This study is documented in “Service Water Intake Structure Settlement Effects and Related Work,” prepared by Gilbert Associates, Inc., and Woodward-Clyde Consultants in December, 1977. Additionally, the Service Water Pumphouse and intake structure will be monitored for settlement twice a year during the operating life of the plant, unless a lesser frequency can be shown to be adequate. As a minimum, Operating License condition 2.C.5 requires the following:

a. At the vicinity of the pumphouse and intake structure, four settlement points capable of monitoring both horizontal and vertical movements shall be established to monitor the embankment movements.

b. The submerged slope profile of the west embankment over the intake structure shall be established and monitored to detect any unusual movements that may affect the intake structure.

c. The schedule and reporting requirements of the above inspection shall be in accordance with the recommendations stated in Regulatory Guide 1.127.

d. The condition of the intake structure shall be monitored to detect new cracks and changes to the old grouted or ungrouted cracks. Observed changes (length or width) in existing cracks and any new cracks shall be reported to the NRC. The maximum inspection interval for this monitoring of the intake structure is five (5) years.

e. The condition of the intake structure shall also be monitored as specified in (d) above following any earthquake during which the plant seismic instrumentation indicates that the operating basis earthquake has been exceeded.

Settlement of the Service Water discharge structure, which is founded on decomposed rock, will be negligible.

2.5.4.10.6.3 Lateral Earth Pressures, Static Conditions

Lateral earth pressure diagrams for the Service Water Pumphouse are presented as Figure 2.5-90c. Static lateral earth pressures on the walls of the Service Water Pumphouse were computed for an at rest condition with an earth pressure coefficient of 0.75 for the compacted west embankment fill. For calculation of earth pressures, 122.2 pcf and 125.4 pcf were utilized for moist unit weight and saturated unit weight, respectively. The angle of internal friction used was 29°. The active earth pressure coefficient utilized was 0.35. Earth pressures were computed for the end of construction condition with the pond empty, and for normal operating condition with the Service Water Pond filled to elevation 425'.

Lateral earth pressure diagrams for the Service Water intake structure are presented as Figure 2.5-90d. Static lateral earth pressures on the walls of the Service Water intake structure were computed for an at rest condition with an earth pressure coefficient of 0.75 for the compacted west embankment fill. For calculation of earth pressures, 122.2 pcf and 125.4 pcf were utilized for moist unit weight and saturated unit weight, respectively. Earth pressures were computed for the end of constructure condition with the pond empty, and for the normal operating condition with the Service Water Pond filled to elevation 425'.

Lateral earth pressure diagrams for the Service Water discharge structure are presented as Figure 2.5-90e. At rest and active and passive earth pressure conditions were considered in the design of the service water discharge structure. The at rest earth pressure coefficient used is 0.75. Active and passive earth pressure coefficients were calculated to be 0.45 and 1.60, respectively, taking into consideration the embankment slope. For calculation of earth pressures, 122.2 pcf and 125.4 pcf were utilized for moist unit weight and saturated unit weight, respectively. The angle of internal friction utilized was 29°. Earth pressures were computed for the following conditions:

1. End of construction with the pond empty.
2. Operating condition with the phreatic surface at elevation 425' in the west embankment and the pond level at elevation 417.5'.
3. With the phreatic surface at elevation 425' in the west embankment and pond level at elevation 415' for the postulated loss of the Monticello Reservoir.

2.5.4.10.6.4 Lateral Earth Pressures, Dynamic Conditions

For dynamic loading, lateral earth pressures on the Service Water Pumphouse were computed using the FLUSH finite element program. Lateral earth pressures on the Service Water intake and discharge structures were computed using the Seed and Whitman method (Reference 88) and the Mononobe-Okabe approach (Reference 85 and Reference 86), respectively. Dynamic lateral earth pressure distribution diagrams for these structures are presented as Figure 2.5-90c through Figure 2.5-90e.

2.5.4.11 Criteria and Design Methods

The criteria for foundation support of the Seismic Category 1 nuclear plant structures are based on the properties of the underlying materials (Section 2.5.4.2) and the soil and rock characteristics (Section 2.5.4.4). The criteria for seismic design are based on the information presented in Sections 2.5.2.10 and 2.5.2.11.

The design criteria and methods of establishing the design criteria along with computed safety factors, design considerations, and conservatisms are presented in Sections 2.5.4.7, 2.5.4.8, and 2.5.4.10. The seismic design methods are presented in Section 3.7.2.1.

2.5.4.12 Techniques to Improve Subsurface Conditions

Except for the excavation of unsuitable rock during the construction of the rock supported mat foundations (Sections 2.5.4.5.1 and 2.5.4.10.2) and grouting of the annular around the caissons between the casing and the ground (Section 2.5.4.10.4), no measures to improve foundations such as grouting, vibroflotation, dental work, rock bolting, and anchors were necessary.

2.5.4.13 Subsurface Instrumentation

For rock excavation, blasting was generally required. To monitor the effects on foundations for Seismic Category 1 structures, blast monitoring during rock excavation was performed. When blasting was required, the peak particle velocity was measured and did not exceed 2 inches per second at the locations of Seismic Category 1 structures. The peak particle velocity did not exceed 4 inches per second at the Service Water Pond embankments.

Prior to the start of blasting, a series of test blasts were made to develop a curve of maximum predicted particle velocity versus the distance from the blast to the nearest structure. Based on this curve, blasting was set into 2 categories: shots which required monitoring, and shots which did not require monitoring. If the predicted maximum particle velocity was less than 1/4 of the maximum permitted particle velocity, monitoring was not required. All other shots were monitored.

When monitoring was required, the nearest Seismic Category 1 structure location was monitored using a Sprengnether 3 axis seismograph, which measures vertical, transverse, and longitudinal components of particle velocity. At no time during construction was the maximum permitted particle velocity exceeded at any structure location.

2.5.4.14 Construction Notes

There were no significant construction problems.

2.5.4.15 Seismicity Near Monticello Reservoir

An increase in seismicity near Monticello Reservoir was first observed during the last week of December, 1977, and appears to be related to the filling of the reservoir. The Applicant has installed a Microseismic Monitoring Network in the area as described in revised Section 2.5.2.6.

Applicant began the initial filling of Monticello Reservoir on December 3, 1977, achieving full pond elevation on February 8, 1978. Pronounced seismicity was observed during the last week of December, 1977, with the maximum number of occurrences of over 100 events being recorded on February 22, 1978. During the peak period (February 10 - March 5) there were approximately 30 events with a magnitude greater than 2.0. The seismicity has shown a marked decrease since March 6, 1978, and has been at a level of from 15 to 20 events per day since then. The maximum magnitude for a single event to date was approximately 2.8.

From studies being conducted by the University of South Carolina thus far, it appears that the zone of epicenters is expanding with time. The seismic activity in February, 1978, spread over approximately 60 sq. km as compared with the areal extent observed during the second half of January, 1978, which was an area of about 30 sq. km. The earthquakes have been found to be shallow with a depth of less than 4 km. The seismic activity appears to be located in 2 clusters. The first is in the vicinity of Applicant's Microseismic Site 1 and trends east-west. The second is about 2 km south of the Virgil C. Summer Nuclear Station and does not appear to show any marked trend.

Applicant secured the professional services of Dr. Gil A. Bollinger, a nationally known seismologist, who established a program and method of analysis of data obtained form the microseismic network. Calculation of focal mechanisms was not included in his recommendations. However, from discussions with Dr. Pradeep Talwani, it is understood that the University of South Carolina plans to obtain focal mechanisms as part of its overall research of the phenomena occurring within the region of Monticello Reservoir.

At this time geologic association with the observed seismic activity is not apparent. There is no evidence that the reservoir impoundment will reactivate old faults at the hypocentral depths of the recent earthquakes. The general decrease in activity and lessening magnitude of events suggests against it.

Based on the seismic activity observed thus far, it is not expected that the reservoir impoundment will trigger events larger than those already recorded, comparing Monticello Reservoir's size and depth with other reservoirs which have experienced similar earthquake activity.

Among the approximately 11,000 reservoirs worldwide, 76 are reported to have had a spatial or temporal relationship between impoundment of the reservoir and seismic activity (Woodward-Clyde Consultants, Reference (Reference 138). Within the worldwide population of reservoirs,

approximately 10,700 are shallow, i.e. having maximum water depths less than 92 m (300 feet). Among these 10,700 shallow reservoirs, induced seismicity has occurred at 26 reservoirs (Woodward-Clyde Consultants, Reference (Reference 138).

Monticello Reservoir is a shallow reservoir with a maximum water depth of 49m (160 feet). Subsequent to impoundment of the reservoir in December, 1977, shallow microearthquakes occurred beneath the reservoir. The seismic activity consisted of events of $M < 3.0$ with focal depths of approximately 0.5 km (1600 feet) or less, based on recent hypocenter determinations by Talwani (Reference 137).

The nature of the seismic activity at Monticello Reservoir (primarily the shallow hypocenters) and the geologic conditions at the reservoir (the absence of faults with late Cenozoic displacement - Section 2.5.1.2) place constraints on the size of the largest event which can be expected to occur at the reservoir. Large earthquakes ($M \geq 5$) are not expected to occur at focal depths of less than 0.5 km (1600 feet) because the materials at these depths would not be expected to sustain the strain accumulation necessary for large events. The strain probably would be released in small events as the rock reached the limit of its ability to accumulate strain. Events for which adequate hypocentral data are available support this concept. Examples include the Bear Valley, California event of $M = 5.0$ in 1972 which had a focal depth of 5 km (3 miles) for the main event (Ellsworth, (Reference 134); and the 1975 Oroville, California event of $M = 5.9$ which had a focal depth of approximately 7 km (4 miles) (Morrison and others, (Reference 136). Where data are available, the larger events (those of magnitude greater than 4.5 to 5.0) occur at focal depths substantially in excess of 0.5 km (1600 feet). Conversely, examples of seismic activity with well defined focal depths of 1km (3800 feet) or less are those of $M \leq 3.0$, e.g. Blue Mountain Lake, New York (Aggarwal and others, (Reference 133).

The shallow focal depth of the seismicity at Monticello Reservoir also serves to constrain the failure plane along which strain release occurs, based on considerations of seismic moment and geometry. This constraint limits the size event expected to occur. Assuming a stress drop of between 10 and 100 bars, an earthquake of approximately magnitude 5.3 would require a failure plane of approximately 10 km^2 (Kanamori and Anderson, (Reference 135). Therefore, the focal depths at Monticello of 0.5 km (1600 feet) would infer a failure with an aspect (height to width) ratio of 40:1. Such a ratio is not credible, unless total crustal rupture occurs along a major structural discontinuity such as that which probably occurred during the 1906 San Francisco event and the 1976 Guatemala earthquake. Typically, an aspect ratio of 2:1 or 3:1 would be expected. For example, the Bear Valley event of 1972 had a rupture plane (as defined by the aftershock zone) approximately 10 km (6 miles) long and 5 to 10 km (3 to 6 miles) deep or an aspect ratio of 2:1.

These lines of reasoning suggest that large events will not occur at Monticello Reservoir. This reasoning is supported by studies made at faulting at reservoirs where large events have occurred.

Of the 76 reported cases of reservoir induced seismicity, 10 have had magnitudes of $M \geq 5.0$ (Table 2.5-68). Eight (8) of these 10 reservoirs have been studied in sufficient detail to determine if faults with late Cenozoic displacement are present within the hydrologic regime of the reservoir. All 8 of these reservoirs have faults that have had displacement within the present

tectonic regime and show evidence of continuing late Cenozoic movement. These data suggest that reservoir induced earthquakes of M ≥ 5 have occurred along faults with late Cenozoic displacement. No faults with late Cenozoic displacement have been reported at Monticello Reservoir.

2.5.5 Stability of Slopes

The 3 dams and west embankment, constructed to impound the Service Water Pond, are Seismic Category 1 structures. The stability of these embankment slopes and natural slopes in the vicinity of the Service Water Pond is discussed in detail in Section 2.5.6. There are no other natural or man made slopes the failure of which would prevent safe shutdown of the plant or which pose a hazard to the plant.

2.5.5.1 Slope Characteristics

Slope characteristics are discussed in Sections 2.5.6.1 and 2.5.6.2.

2.5.5.2 Design Criteria and Analysis

Design criteria and analyses are discussed in Section 2.5.6.5.

2.5.5.3 Logs of Borings

See Section 2.5.6.2 concerning logs of borings.

2.5.5.4 Compacted Fill

Compacted fill is discussed in Section 2.5.6.4.

2.5.6 Embankments and Dams

2.5.6.1 General

The Service Water Pond is a safety class impoundment constructed adjacent to Monticello Reservoir to supply water for the Service Water System under normal and emergency conditions. The Service Water Pond site was selected to take advantage of natural topographic features immediately adjacent to the nuclear plant site. The Service Water Pond and its interconnecting pipe to Monticello Reservoir are designed to satisfy the intent of Regulatory Guide 1.27 (see Appendix 3A), as discussed in detail in Section 9.2.5. Upon a postulated loss of Monticello Reservoir coincident with the interconnectiong pipe isolation valve being open, the Service Water Pond retains water at elevation 415'. The volume of water remaining in the Service Water Pond is sufficient to assure safe shutdown of the unit and continued cooling for a minimum of 30 days, as discussed in Sections 9.2.5 and 2.5.6.6. The constructed dams and west embankment that impound the Service Water Pond are Seismic Category 1 earth structures designed to be stable under static and dynamic conditions, and for maximum wave runup from Monticello Reservoir.

The Service Water Pond is formed by impounding a segment of a tributary to Frees Creek. Frees Creek is impounded by dams to form Monticello Reservoir. The Service Water Pond impoundment is formed by the North Dam, East Dam, South Dam and West Embankment as shown by Figure 2.5-91. The mean water level within Monticello Reservoir and Service Water Pond fluctuates between elevations 420.5' and 425'. For the Service Water Pond, the operating pool level during emergency drawdown is at elevation 418'. The low water level, elevation 415', would be attained for the postulated loss of Monticello Reservoir. Following a postulated loss of the reservoir, water would be retained on the reservoir side of the South Dam at approximately elevation 404', the discharge canal bottom elevation. The Service Water Pond is serviced by intake and discharge structures located at the West Embankment.

The Service Water Pond is hydraulically connected with Monticello Reservoir by the interconnecting pipe that extends from the Service Water intake structure to the Circulating Water intake structure. This pipe allows Monticello Reservoir to supply makeup water to the Service Water Pond by opening a normally closed isolation valve. In the event of loss of Monticello Reservoir coincident with the isolation valve being open, the invert elevation at the high point of the interconnecting pipe limits the drop in Service Water Pond level to elevation 415'.

The 3 dams and the West Embankment are homogeneous earth structures. The slopes on the pond side are constructed at 3 to 1 (horizontal to vertical).

The reservoir sides of the dams are constructed at 3.5 to 1. The plant side of the West Embankment joins the plant yard fill along a boundary slope beneath the plant yard at 1 to 1. Natural slopes between the dams and at the reservoir bottom have inclinations ranging from 3 to 1 to 6 to 1, or flatter. Other geometric aspects are listed in Table 2.5-24.

The West Embankment merges with the west abutments of the North and South Dams. Its crest elevation of 435' is less than for the dams, since the elevation of 438' for the dams was selected to be consistent with the maximum wave runup elevation of 436.6' for Monticello Reservoir as discussed in Section 2.4.3.6.

Conservative analyses of the 3 dams and the West Embankment demonstrate that these earth structures have an adequate safety factor against failure under both the SSE motions and under sudden drawdown resulting from a postulated loss of Monticello Reservoir, the most critical static loading condition. Dynamic response analyses using finite element techniques, together with cyclic shear testing of representative samples of the embankment and foundation materials, indicate that the lowest factors of safety against overstressing at any point within the dams and foundations are at least 1.1. The minimum static safety factor realized, assuming instantaneous drawdown conditions of the reservoir-side slope, was found to be at least 1.2. The stability of all natural slopes whose failure might endanger the integrity of the Service Water Pond was analyzed. All such slopes were found to be stable under the design loading conditions.

Graded horizontal drainage blankets and/or toe drains are built within the 3 dams to control seepage and piezometric pressures in the event of a postulated loss of Monticello Reservoir. Zoned riprap is provided on the reservoir and pond sides of the constructed slopes to protect against wave action. A grout curtain was constructed along the centerline of the North Dam and a

clay blanket was constructed on the Service Water Pond bottom adjacent to the South Dam to minimize seepage losses from the Service Water Pond following a postulated loss of Monticello Reservoir.

Flood protection for the nuclear plant site is discussed in Section 2.4.

2.5.6.2 Exploration

2.5.6.2.1 General

As shown in Figure 2.5-91, the area of the Service Water Pond is situated between 2 ridges which merge to the southeast of the South Dam. Prior to construction, the floor of the “V” shaped valley between these ridges generally sloped toward the northwest, emptying into Frees Creek north of the Service Water Pond site. The topographic low of the valley was about elevation 333' and occurred at the northern limit of the North Dam. A topographic low (elevation 418') also existed as a saddle on the eastern ridge at the location of the East Dam. At the South Dam, the topographic low of the valley (at the dam centerline) was approximately elevation 370'. The original slopes of the valley containing the Service Water Pond were generally inclined at slopes of between 6 to 1 and 3 to 1 and converged to a relatively narrow valley bottom in the vicinity of the North Dam. The Service Water Pond site was well drained with the exception of a portion of the valley bottom area.

The main drainage feature of the site was a small stream that flowed through the valley from southeast to northwest. This stream was a tributary of Frees Creek and was fed by small intermittent springs, sidehill seeps, and surface runoff. Erosion gullies were present, usually in areas of surface runoff concentration.

Subsurface explorations were made along the valley bottom and sides, with exploration effort concentrated at the locations of the Service Water Pond embankments. Explorations were made beyond the Service Water Pond at locations of potential borrow areas. The explorations were performed to identify, delineate, and characterize physical parameters of the subsurface strata and to collect samples for laboratory testing. The exploration methods included test borings, auger borings, test pits, and probe soundings. Supplementing the subsurface exploration, in situ permeability tests were made in selected borings to investigate the permeability of the subsoils and rock. Cross-hole seismic surveys were conducted to investigate the elastic wave propagation properties of the subsurface materials.

Test borings and auger borings were utilized for the investigation of potential borrow sources. It was originally intended that onsite materials would be used for the Service Water Pond construction. These materials were to have been obtained from general site grading and from excavation for the discharge canal. However, nearly all of these materials were subsequently utilized for other purposes, necessitating the use of offsite borrow. Several potential offsite borrow sources were investigated, with those designated as Borrow Source F and Borrow Source G chosen for use. The locations of these 2 borrow sources with respect to the site area are shown in Figure 2.5-92.

2.5.6.2.2 Exploration and In Situ Testing Methods

The test borings were usually advanced through the soil overburden by rotary drilling methods using a 3.0 inch diameter “fishtail” bit and recirculating water to remove the soil cuttings from the bore hole. Where necessary, 3 or 4 inch diameter steel casing was inserted to maintain an open bore hole through the overburden. Upon refusal of the “fishtail” bit, a tri-cone roller rock bit was used to advance the boring through decomposed rock zones. Below the tri-cone rock bit refusal level, diamond bit rock coring procedures were utilized.

In nearly all of the test borings, samples were taken at 3 to 5 foot intervals, by the Standard Penetration Resistance (SPR) test method, ASTM D 1586-67. These samples were visually classified and were retained for physical property testing in the laboratory.

Relatively undisturbed samples of the soil and decomposed rock were obtained from test borings using 3 inch diameter, thin wall Shelby tubes in accordance with ASTM D 1587-67. In the softer soils, the Shelby tubes were pushed into the soils using the hydraulic system of the drilling rig. In the decomposed rock horizon, the thin wall tubes were advanced by a Denison type (Pitcher) sampler, as described by Terzaghi and Peck (Reference 89).

Rock cores were obtained using either a standard NX double tube core barrel or a wire line NX double tube core barrel. The standard barrel retrieves a 2-1/8 inch diameter core, while the latter secures a core 1-1/8 inches in diameter. The wire line equipment was used on 5 deep borings.

Surface conditions for potential borrow areas were investigated by means of auger borings in addition to test borings. Six (6) inch diameter bucket augers and continuous flight, open augers were used to continuously sample the potential borrow materials. Bag samples weighing approximately 60 pounds each were generally collected for each 5 foot increment of depth for laboratory testing purposes.

Eight (8) test pits were excavated using a small, tractor mounted backhoe. These test pits were approximately 10 feet long, 3 feet wide and 10 feet deep.

In the valley bottom of the North Dam, a depth survey was made of the soft alluvium deposit. This was accomplished using a 10.5 foot long, smooth steel rod, 0.25 inches in diameter. When this rod was pushed by hand into the valley floor, a significant increase in resistance was noted when the bottom of the alluvium was reached. Using this probe with survey stadia control, an alluvium profile was established throughout the North Dam embankment foundation area. The information obtained from this survey correlated well with the borings and general geologic information and was used for estimating the quantity of unsuitable materials to be removed during foundation preparation (see Section 2.5.6.3).

Field permeability tests were made in borings by inflow methods. Constant head tests (Reference 90) and falling head tests (Reference 91) were made through open casing in soils. Constant head tests were made in intact rock, utilizing single or double packers to isolate test sections in the boreholes. Constant head tests in soils were usually made at a pressure of 5 psig and in intact rock at 20 to 30 psig.

Cross-hole seismic surveys were made at the site of each of the 3 dams to determine compressional (P) and shear (S) wave velocities in the soil and rock layers. These surveys consisted of recording the time of travel for stress waves propagated from a small explosive detonation (shot) to a recording (detector) point located in adjacent bore holes.

The depth and spacing of the shot and detector holes were selected to explore wave transmission properties of the materials encountered by the subsurface exploration. The equipment utilized in the cross-hole survey included multi-channel Electrotech Seismograph used together with HSJ-LP3D Omni-Directional Vibration Detectors.

An additional cross-hole seismic survey was conducted in the South Dam foundation, at locations shown in Figure 2.5-93, using a down-hole hammer that imparts a vertically polarized shear wave through the hammer assembly which is expanded against the borehole wall. To enhance identification of the shear wave arrivals, the impulse technique that was used reversed the polarity of the shear wave without reversing the P-wave polarity. The cross-hole measurement technique used is described by Mirafuente (Reference 92). Results of the survey are summarized in Figures 2.5-94 and 2.5-95. A discussion of the shear wave velocities measured by the 2 different methods is presented in Section 2.5.6.4.

2.5.6.2.3 Extent of Subsurface Exploration

North Dam investigations made for earlier studies included 33 test borings, permeability testing in 14 borings, a cross-hole seismic survey, and probing for alluvium. During construction, 4 additional confirmatory borings were drilled and a geologic map of exposed subsurface materials was developed (see Section 2.5.6.2.4.6). Additional permeability testing was conducted during the installation of the North Dam grout curtain.

South Dam investigations made for earlier studies consisted of 21 test borings, 5 test pits, permeability tests, and cross-hole seismic surveys. The 5 test pits were made to investigate the condition and extent of surficial colluvium. Permeability tests were conducted in 5 borings, including SD-5 which was cored to a depth of 146 feet. During construction, a geologic map of exposed subsurface materials was developed, as discussed in Section 2.5.6.2.4.6.

East Dam investigations made for earlier studies included 6 test borings, permeability testing in 1 boring and cross-hole seismic survey. Fourteen (14) test borings made along the West Embankment for earlier studies were supplemented by 3 test pits and 7 additional borings.

For earlier studies, 7 test borings and 24 auger borings were drilled for borrow exploration in the areas of planned excavation for the discharge canal and general site development grading. The purpose of the borings was to investigate materials at these locations for use as borrow in constructing the embankments at the Service Water Pond. These soils were used to construct the West Embankment up to elevation 386'. For the remainder of the West Embankment, and for the 3 dams, offsite Borrow Sources F and G were used. Borrow Sources F and G were investigated by a total of 27 test borings, 4 auger borings, and 8 test pits.

Logs of test borings and test pits are presented in Appendix 2F. The first sheet of

Appendix 2F presents a key to symbols and terms used in the logs. Prefixes for boring designations are keyed to the areas investigated as follows:

Boring No. Prefix	Area of Investigation
ND, RND	North Dam
SD	South Dam
ED	East Dam
WD, WE, RWD	West Embankment
SS	South Slopes
C	Discharge Canal
F	Offsite Borrow Source F
TBG	Offsite Borrow Source G

Test Pit No. Prefix	Area of Investigation
TP-S	Test Pit Excavations at South Dam
TP-G	Test Pit Excavations at Borrow Source G
TPW	Test Pit Excavations at West Embankment

Borings drilled to study potential borrow materials from general site grading (Prefix “A”) are not included since only a relatively small amount of these materials were used (below elevation 386.0' within the West Embankment). The as-built properties of these materials are documented in Section 2.5.6.4.

The results of the initial (explosive) seismic survey are presented in Table 2.5-25 which summarizes the horizontal and vertical locations of the shot and recording stations, as well as the P and S wave measurements. An interpretation of the results of the cross-hole seismic survey is included as Table 2.5-26. This table relates the measured seismic velocities to the subsurface horizons encountered at the site. The shear modulus (G), Young's elastic modulus (E), and Poisson's ratio (i) computed from pertinent P and S wave velocities are also summarized in Table 2.5-26. The results of the additional (down-hole hammer) seismic survey are presented in Section 2.5.6.4.1. The results of the field permeability testing are presented in Table 2.5-27.

2.5.6.2.4 Subsurface Materials

Overburden materials in the Service Water Pond area are typical of those found in the southern Piedmont Physiographic Province where in situ weathering of the parent rocks has produced a deep weathering profile, locally overlain by transported soils. Although stratification irregularities are characteristic of a weathering profile developed over diverse parent materials,

the subsurface materials have been generalized into 4 horizons overlying the intact rock, as shown in Figures 2.5-97 through 2.5-104. These horizons are described in Sections 2.5.6.2.4.1 through 2.5.6.2.4.4, along with a discussion of their distribution within the area of study. Laboratory test results for the horizons are discussed in detail in Section 2.5.6.4.

2.5.6.2.4.1 Transported Soil Deposits

Materials derived from transportation by stream action (alluvial deposits) or by mass wasting from high to low elevations (colluvial deposits) were found to have an erratic and limited distribution within the area of study, being primarily limited to lower elevations. Alluvial or colluvial soils were removed where encountered at locations of the Service Water Pond embankments.

The alluvium was usually identified as loose fine sandy silt (OL/ML) to soft sandy clays (CL). The distribution of the alluvium within the embankment areas was limited to the North Dam and a small portion of the West Embankment. The thickness of the alluvial deposits, as determined from borings and probes, ranged from a few feet up to approximately 15 feet as shown by Figures 2.5-97 and 2.5-98 and up to 21 feet as determined during excavation and removal operations.

Typical colluvial deposits were identified as red-brown to gray-brown micaceous sandy silty clay (CL) and clayey silty sand/sandy silt (SM/ML) with standard penetration resistances typically ranging from 13 to 35 blows/foot. As shown by Figures 2.5-99 and 2.5-100, these firm to stiff surficial deposits ranged from a few feet to approximately 25 feet in thickness and were encountered in sizeable quantities only beneath the South Dam.

2.5.6.2.4.2 Residual Soil Horizon

Materials of the residual soil horizon, usually occurring as a surficial deposit, were classified as sandy or silty clays and clayey silts of medium to high plasticity (CL, ML, CH, and MH) which do not contain a readily discernible relic rock structure. Consistent with a penetration resistance ranging from 15 to over 50 blows/foot, the residual soils were found to have a stiff to hard consistency and to be widely distributed throughout the area of study. Residual soils were found to exist in various extents beneath the North, South, and East Dams, and beneath much of the West Embankment area. As shown by Figures 2.5-97 through 2.5-104, the most significant deposits were located beneath the South and East Dam sites and were found to have thicknesses ranging from a few feet to as much as 12.5 and 22 feet at the South and East Dams, respectively.

2.5.6.2.4.3 Saprolite Horizon

Materials which weathered in place from the parent rocks and which had retained a readily discernible relic rock structure were found throughout the entire area of study and were usually identified as a friable silty sand (SM) or sandy and clayey silt (ML) of slight to low plasticity. This saprolite, usually underlying the residual soil horizon, was typically found to become less altered and more dense with depth, with SPR values increasing from about 15 to 30 blows/foot near the base of the horizon. The thickness of the saprolite horizon within the proposed embankment

areas, as shown by Figures 2.5-97 through 2.5-104, ranged from a few feet at the North Dam to as much as about 37 feet at the South and East Dams.

2.5.6.2.4.4 Decomposed and Intact Rock

Materials encountered within a transition zone between the soil-like saprolites and the intact, parent rock were identified as a decomposed and fragmented rock containing partially friable and decomposed fragments, some of which disintegrated upon drive sampling into silt and sand-size material. Typically, the decomposed rock was found to be very dense with SPR values in excess of 100 blows/foot. The decomposed rock horizon is characterized by a variable, but often appreciable, thickness and is encountered throughout the area of study. As shown by the typical subsurface cross sections, Figures 2.5-97 through 2.5-104, the thickness of the decomposed and fragmented rock zone ranges from a few feet up to a maximum of over 155 feet at the North Dam.

Intact rock, defined as material which exhibited sizeable diamond core recoveries, was encountered at extremely variable depths, consistent with the differential weathering characteristics of the parent rocks. Core samples recovered from the exploration were usually identified as migmatite of mica gneiss and granodiorite composition, although occasional quartzitic inclusions were encountered. The quality of the intact rock, as judged from RQD values and the pressure testing, was generally rated as fair to good although some jointing and fracturing of core specimens were noted, particularly within the upper portion of the formations. Consistent with the regional geology, the structure of the rocks was found to be extremely complex, and a consistent trend to the attitude of joints, foliations, etc., could not be detected from examination of the rock cores.

2.5.6.2.4.5 Groundwater

Typically, groundwater was encountered only by borings drilled in the valley bottoms and by deep borings extended into the underlying bedrock. In the valley bottoms, groundwater was typically encountered at, or a few feet below, the preconstruction ground surface. At the South Dam, some borings drilled in the valley bottom produced small groundwater flows. Borings drilled on the Service Water Pond natural slopes generally disclosed groundwater within the fractured rock zone at the level where the rock was sufficiently intact to permit rock core recovery. A perched water condition frequently was observed within the more pervious zones of the saprolite as evidenced by seeps and springs on the natural slopes. The residual soil and decomposed rock zones were found to be relatively impervious. Additional information concerning groundwater is presented in Section 2.4.13.

2.5.6.2.4.6 Geologic Mapping of Excavations

The geology of the North Dam excavation is presented in Figures 2.5-29 and 2.5-30.
The major rock units in the North Dam excavation are of granitic and migmatite compositions, with the former being predominant. Except for localized areas of hard, relatively unweathered rock and sparse residual soil cover, the North Dam foundation area consists of moderately to highly decomposed rock due to weathering. The excavation contains nondisplaced closed joints, joints which have been subjected to hydrothermal mineralization, fractures that exhibit evidence

of minor displacements, and some well developed mineralized fractures along which movement may have occurred. However, positive evidence of displacement along the well developed mineralized fractures was not found.

As discussed in Section 2.5.1.2, the average strike of shear zones in the Reactor Building excavation (Figure 2.5-25) coincides with the strike of the mineralized fractures mapped in the North Dam excavation, indicating that these fractures are probably a northeastward extension of the shear zones mapped in the Reactor Building excavation. X-ray diffraction analysis of samples recovered from mineralized fractures identified laumontite. Also, the general pattern formed by the mineralized fractures at the North Dam is very similar to that observed within the Reactor Building, staging area and Control Building excavations. No evidence was found which would indicate an age younger than that established for the shears in the Reactor Building excavation (minimum 45 ± 5 million years, see Section 2.5.1.2.2.3) nor was evidence found to indicate that the mineralized fractures were not part of the same structural system mapped and studied in the nearby excavations.

The geology of the South Dam excavation is shown by Figure 2.5-105. The excavation exposed mainly saprolite, rock decomposed by weathering and lesser amounts of unweathered rock. Granitic intrusive rocks and migmatite are the major rock units present. The migmatite contains discontinuous blocks of Charlotte Belt metamorphic rocks surrounded by granitic rocks which were intruded 200 to 300 million years ago. Rock joints and fractures are essentially vertical in dip and fairly random in strike. Some joints and fractures are not filled and some are mineralized, notably with laumontite, the mineral dated radiometrically at plant excavations, showing that tectonic faulting at the plant excavations ceased at least 45 million years ago (see Section 2.5.1.2).

2.5.6.3 Foundation and Abutment Treatment

2.5.6.3.1 North Dam

The foundation preparation for the North Dam included the removal of alluvium in the valley bottom, removal of all soft or loose surficial materials from the entire embankment foundation area, control of springs and seeps, and installation of a grout curtain and core trench along the dam centerline. The foundation was prepared mainly in very dense decomposed rock and to a lesser extent in dense saprolite. Visual inspection of these materials indicated that their properties were consistent with those determined in the preconstruction design studies.

Excavation of unsuitable foundation materials commenced June 20, 1975, and the last of the major preparation work was completed on April 12, 1976. In the valley bottom the maximum depth of excavation was 21 feet as compared to the anticipated maximum depth of 15 feet. On the abutments, the depth of stripping required was generally somewhat less than the anticipated maximum depth of 3 feet. The limit of excavation for the North Dam foundation area is shown on Figure 2.5-107.

The foundation preparation progressed from the south toe to the north toe in 5 sections. Each section was inspected and evaluated to determine the need for installing sumps, dry packing of springs with cement, or any other special preparatory work that might be needed.

As each prepared section was approved, fill placement commenced immediately to protect the foundation soils. The date each section of the foundation was approved is listed below:

Section Number	Date Approved
I	October 14, 1975
II	October 24, 1975
III	April 5, 1976
IV	April 6, 1976
V	April 14, 1976

When preparation was complete, and upon placing the initial lifts of embankment soil, the exposed foundation soils were visually estimated to be near the optimum moisture content (ASTM 1557-70, Method A), were free of organic materials and were sufficiently dense to accept construction and compaction traffic without deterioration. Decomposed or fresh rock at foundation level was dried or moistened as necessary to facilitate bonding with embankment fill. All fractures and depressions were cleaned and filled with select fill, or in a few instances, a very limited quantity of broom finished concrete. Flows from springs in the excavation were controlled by installing sumps for the larger flows and dry packing with cement for the smaller flows. The sump locations are shown on Figure 2.5-107. All sumps but 1 were subsequently removed because the springs ceased to flow as the fill height and aerial extent progressed. The only sump left in place at the North Dam is sump number 5, located at the junction of the West Embankment and North Dam. This sump is connected to a French drain extending from the base of the West Embankment fill. A detailed discussion of the French drain and sump installation is presented in Section 2.5.6.3.4.

As shown on Figure 2.5-107, all sumps were excavated at least 3 feet below the surrounding grade. The bottom of each sump was covered with at least 12 inches of Zone 2 filter (see Section 2.5.6.4.3.3) and a vertical 42 inch diameter, perforated, corrugated metal pipe was installed over the bedding material and surrounded with Zone 2 filter material. The riser pipe for sump number 5 was eventually filled with 9 cubic yards of 4,000 psi concrete on April 14, 1976, when the fill reached a depth of about 12 feet over the gravel bedding.

Springs which could be controlled by dry packing had flows of approximately 1/2 gpm or less. These spring areas were prepared by excavation to suitable foundation materials and placement of 1 or 2 sacks of Type II cement over the seep to absorb the flow while the overlying fill was placed. This treatment prevented the fill from being saturated during placement and compaction. Two (2) excavations were made in spring areas after several feet of fill were placed to expose the compacted materials in the immediate area of the seep. In both cases, the embankment was observed to be unaltered and the seep area was dry.

Numerous minor seeps of less than 0.05 gpm were also uncovered. These areas were stripped of softened materials and the select fill placed and compacted immediately, before the seep could

cause the embankment material to deteriorate. Once the lower foundation areas were covered with a few feet of compacted fill, no further seepage was encountered.

The preparation of the abutment areas included removal of topsoil and organic material and trimming of the slopes to suitable solid immediately above the level of fill with a motor grader or bulldozer. As each lift was placed, the abutment was benched and the fill was mixed into the abutment foundation to bond the embankment to the natural ground.

In the area where the toe drain was constructed (see Section 2.5.6.4.3.3), most of the foundation consisted of relatively unweathered rock. Consistent with the weathering characteristics of this rock type, many potholes and broader depressions in the rock surface were uncovered and cleaned. In lieu of placing Zone A riprap material directly over the rock in these areas, potholes were filled with Zone 2 filter material to develop a level surface on which to place the Zone A riprap material for the toe drain.

A grout curtain was constructed along the North Dam centerline between Stations 4+00 and 16+75. Along the grout curtain between Stations 7+00 and 12+00, the foundation was excavated to the base of the grout pipes after grouting to attain bonding between the embankment and the foundation. A complete description of the grout certain and core trench excavation is presented in Section 2.5.6.6.

2.5.6.3.2 South Dam

The planned foundation preparation for the South Dam was to include the removal of 11 soft or loose surficial materials from the entire foundation area, which was estimated to be a maximum depth of 3 feet. This stripping of unsuitable surficial soils was expected to expose a foundation of residual materials on the abutments and colluvial soils in the valley bottom. A cutoff trench was to be excavated beneath the South Dam which would extend through the colluvial soils to the very dense decomposed rock. The cutoff trench was to be backfilled with embankment soils.

When preparing the foundation for the South Dam, the colluvial soils were found to be excessively wet and to contain large amounts of organic inclusions. Consequently, all colluvial deposits were removed. This additional excavation resulted in up to 22 feet of colluvial materials being excavated from the South Dam base to reach the underlying residual soils, saprolite soils, and decomposed rock. These are the same types of foundation materials present at the North Dam. The South Dam foundation was prepared as described for the North Dam, wherein the foundation materials attained were at a proper water content, were free of organic materials, and were sufficiently dense to allow proper compaction of the embankment materials without deterioration (see Section 2.5.6.3.1).

Foundation preparation for the South Dam began during the week of February 24, 1976, and was completed on March 2, 1976. The foundation was prepared in 4 sections, progressing from the south toe to the north toe as shown on Figure 2.5-107. The date each section was approved and fill placement commended is listed below:

Section	Date Approved and Fill Commenced
I	February 25, 1976
II	February 28, 1976
III	March 1, 1976
IV	March 2, 1976

With the exception of 1 sump located in the toe drain area, all seeps were controlled by either dry packing with Type II cement or were of such insignificant flow rates that fill was placed directly over the area without adverse affect upon the compacted materials. Only 1 sump was needed at the South Dam. This sump was located within the zoned filter areas. The sump was backfilled with Zone 2 filter material and encased in Zone 1 and 2 filter material to serve as an integral part of the toe drain filter system. Once the lower portions of the foundation were covered with a few feet of fill, no further seepage was encountered. Two (2) exploratory excavations were performed in the fill and each verified the competency of the embankment materials over seepage zones. Figure 2.5-107 shows the location of the sump, dry packed seeps, and the final contours of the South Dam foundation.

In accordance with the directives of the NRC, the core trench area was excavated and carefully inspected for the presence of springs or seeps. Since no springs or seeps were observed in the core trench area, no grouting was performed.

Along the centerline of the South Dam, between Stations 5+50 and 7+50, the foundation material is relatively fresh rock with small depressions and mineralized fractures. The small depressions were broom cleaned and filled with 3,000 psi concrete. The surface of the concrete was broom finished to provide a roughened bond surface with the overlying select fill.

For the South Dam abutments, surficial loose or organic soils were stripped. As each lift was placed, the abutment was benched and fill was mixed into the abutment foundation to bond the embankment to the natural ground.

2.5.6.3.3 East Dam

The foundation of the East Dam was excavated from 1 to 4 feet into firm to stiff residual soil. Subsequently, the foundation was scarified and mixed with the first lift of embankment materials to provide a suitable transition between the foundation and embankment. A plan showing the limits of excavation for the East Dam is presented as Figure 2.5-108.

Prior to filling the Service Water Pond, a dewatering system at the bottom of the pond area discharged into a concrete lined channel constructed through the south abutment of the East Dam. During foundation preparation for the East Dam, the concrete lining and all disturbed soils were removed and the side slopes were trimmed to about 2 horizontal to 1 vertical slopes in stiff residual soil. Select fill was placed and compacted in this channel and the side slopes were benched to provide a bond between fill and foundation soils.

No groundwater was encountered in the preparation of the East Dam foundation.

2.5.6.3.4 West Embankment

The foundation preparation for the West Embankment included the removal of the surficial soft or loose soils and organic materials, grading of gullies and installation of a French drain and sump system for a portion of the embankment. The foundation was prepared on residual materials as transported soils were removed. Removal of unsuitable materials from the West Embankment foundation began on August 13, 1973. A plan showing the limits of excavation for the West Embankment is shown in Figure 2.5-109. In general, the depth of stripping was in accordance with the 3 foot maximum design depth, except in the valley bottom where thicker organic and saturated soft materials required undercutting up to about 15 feet deep.

A peripheral French drain and sump system was constructed to reduce the moisture content of foundation soils wetted by flow from several seeps and springs, as shown by Figure 2.5-109. The French drain and sump bedding materials consisted of a fine filter material and a coarse drainage material designed to meet conventionally accepted filter criteria (Reference 89). Once the system was in full operation for 2 days, all springs and seeps in the foundation area ceased flowing, permitting placement of fill. Each sump riser pipe in this system was backfilled with 3,000 psi concrete or gravel when the fill depth above the bedding materials exceeded 6 feet.

Discharge from the French drain was at the junction of the West Embankment and North Dam and flowed freely into the North Dam area until foundation preparation commenced in that area. At that time, sump Number 5, shown on Figure 2.5-105, was installed and thereafter collected this water for pumping beyond the Service Water Pond area.

Abutment preparation was identical to the North Dam and was performed by trimming and benching as the fill height increased. Pre-existing erosion gullies were completely excavated and the embankment was benched into undisturbed natural soils below the original bottoms and sides of gullies. Where steep natural slopes existed, benching into the natural slopes was performed as the fill was raised.

2.5.6.4 Embankment

2.5.6.4.1 Properties of Foundation Materials

Laboratory testing was performed to determine the physical and engineering properties of the foundation materials underlying the earth structures and materials comprising the natural valley slopes. The results of these tests are presented in Section 2.5-28 and are summarized in the

following sections for the various generalized stratigraphic units encountered within the area of study. Because the alluvial soils encountered by the exploration were limited in extent and were completely excavated from beneath embankment location, only visual classifications of these materials were made and no laboratory testing of these materials was performed.

2.5.6.4.1.1 Physical Properties

The following tests were conducted to determine the physical properties of the foundation materials:

1. Natural water content (ASTM D 2216-66).
2. Specific gravity (ASTM D 854-58).
3. Liquid limit (ASTM D 424-59).
4. Plastic limit (ASTM D 423-66).
5. Grain size distribution (ASTM D 422-63).

In addition to the above tests, unit weight determinations were made on relatively undisturbed Shelby tube and Pitcher samples and all laboratory test samples were visually classified. The physical property test results are presented in Table 2.5-28 according to stratigraphic unit. Grain size distribution curves are shown by Figure 2.5-110.

The colluvial soils were generally identified as red-brown to gray micaceous sandy clayey silts and sandy silty clay (ML and CL). The physical property test results for colluvium are summarized in Table 2.5-29.

Residual soils were identified as materials derived from in situ weathering but which lack discernible relic rock structure. Typically, these materials were classified as red-brown silty clay or clayey silt with high plasticity (CH and MH) to red-brown micaceous fine sandy silty clay or clayey silt with low to medium plasticity (CL and ML). The physical property test results for residual soil are summarized in Table 2.5-30.

Saprolite materials were usually identified as medium dense to very dense sandy clayey silt of low plasticity (ML) or silty medium to fine sand (SM). The results of physical property tests for saprolite materials are summarized in Table 2.5-31.

Decomposed rock was usually identified as very dense, friable to partially friable decomposed and weathered rock which usually was broken into silt, sand, and gravel size fragments during drive sampling. The results of physical property tests on decomposed rock are summarized in Table 2.5-32.

2.5.6.4.1.2 Static Shear Strength

Shear tests applicable to drained and undrained static loading conditions were performed on representative samples of foundation materials. These tests included unconfined compression

tests, unconsolidated-undrained (UU) triaxial compression tests and isotropically consolidated, undrained ($\overline{CIU}$) triaxial compression tests with pore pressure measurements. The results of these tests are presented in Figures 2.5-111 through 2.5-113 and are summarized in Table 2.5-33.

2.5.6.4.1.3 Static Deformation

The static deformation characteristics of the foundation soils were investigated in the laboratory by oedometer (consolidation) tests on representative samples, using conventional double load increments. The test results are shown by Figure 2.5-114. The compression properties measured in these tests are summarized in Table 2.5-34. Additional consolidation tests were performed at the Service Water Pumphouse as presented in "Service Water Intake Structure Settlement Effects and Related Work," prepared by Gilbert Associates, Inc., and Woodward-Clyde Consultants in December, 1977.

2.5.6.4.1.4 Permeability

Laboratory permeability tests were conducted on samples representative of the various generalized horizons at selected loading stages during the consolidation testing program. The results of these tests are presented in Table 2.5-27, together with the results of the field permeability tests.

2.5.6.4.1.5 Dynamic Shear Strength

The dynamic shear strength characteristics of the foundation materials were investigated by conducting cyclic triaxial shear tests on selected, undisturbed samples of the colluvium and saprolite soils. To conservatively reflect the variation of the properties of these foundation materials, test samples were selected to reflect materials having an SRP not greater than about 15 to 20 blows/foot, a value at the lower bound of the SPR value range measured within the portion of the colluvium and saprolite which were expected to remain after foundation preparation. As discussed in Section 2.5.6.3.2, the colluvial materials tested from the South Dam foundation area were ultimately removed during the foundation treatment.

The cyclic triaxial shear tests were performed in accordance with procedures described by Lee and Seed (Reference 93). The procedures used are briefly described by the following testing sequence:

1. Sample consolidation under isotropic consolidation pressure.
2. Application of a cyclic deviator stress of constant amplitude under undrained conditions.
3. Determination of the resulting changes in axial strain and in pore water pressure during cyclic loading.

Cyclic tests were usually continued to define a prescribed level of strain; for example, a 10 to 15% single amplitude strain level. All cyclic triaxial tests were performed using Modular Test System (MTS) equipment.

The results of cyclic triaxial tests are presented in Tables 2.5-35 and 2.5-36 and by Figures 2.5-115 and 2.5-116. As the effect of the test method is likely to cause specimens to develop failure strains at stress levels lower than those which would be realized under corresponding field conditions, adjustment of the laboratory test results is required to simulate field conditions. The adjustment factors were applied to the laboratory data as recommended by Peacock and Seed (Reference 94). A summary of the laboratory strength parameters, the correction factors used and the resulting strength parameters applicable to the in situ soils (under field loading conditions) are presented in Table 2.5-37.

At the conclusion of the cyclic triaxial tests, classification tests were performed on the samples. These tests consisted of sieve analyses and liquid and plastic limit determinations. The results of these classification tests are presented by Figure 2.5-117.

2.5.6.4.1.6 Dynamic Response

Dynamic moduli (G) and damping factors (D) suitable for analysis of ground motions under earthquake loading conditions were derived for the major subsurface horizons from the results of field cross-hole seismic surveys and laboratory cyclic triaxial tests conducted on representative undisturbed samples.

The dynamic shear moduli at very low strain levels (G_{max}) of the foundation materials, including colluvium, saprolite, decomposed rock and intact rock, were derived from shear wave velocities obtained from cross-hole (seismic) wave propagation tests. As discussed in Section 2.5.1.2.2, 2 separate cross-hole seismic surveys were conducted, 1 using a small explosive detonation to impart the dynamic stress waves and the other, a down-hole hammer that imparts a vertically polarized shear wave. The measured shear wave velocities determined by the explosive detonation method, as listed in Table 2.5-25, indicated the range of shear wave velocities (Vs) and corresponding maximum shear moduli (G_{max}) listed in Table 2.5-38 for the foundation materials.

By comparison, the results of the cross-hold seismic survey using the vertically polarized down-hole hammer, presented by Figures 2.5-94 and 2.5-95, indicate a shear wave velocity range of between 1,200 and 3,400 ft/sec for the decomposed rock zone. The corresponding range of G_{max} was interpreted to be 41.2 and 336.4 ksi. Accordingly, the down-hole hammer cross-hole seismic survey method confirms the maximum shear modulus to be of the same order or greater than that which was determined by the explosive detonation technique.

2.51 Soil moduli and damping factors suitable for the dynamic response analyses were also obtained from cyclic triaxial shear testing, described by Seed and Idriss (Reference 95). These results, which are applicable to a higher range of shear strain, were used to confirm the validity of the relationship between shear strain versus shear modulus and damping factor derived from cyclic torsion and field seismic tests. The variations of damping and modulus values used in the response analyses are shown by Figure 2.5-118. The K_2 parameter used to express the shear modulus versus strain relationship for each element within the finite element mesh selected to correspond to the least dense (lowest velocity) materials is shown by Figure 2.5-119. Comparison of the shear modulus and damping

values obtained from the testing program with the data published for different materials indicates that the response of the saprolite and colluvium compares favorably with that of a dense sand as reported by Seed and Idriss (Reference 95).

Sonic velocity tests to determine the compressional (P) and shear (S) wave velocities of representative intact rock specimens were also conducted in the laboratory. The results of the laboratory measurements, together with the interpreted "elastic" modulus and Poisson ratio values, are summarized in Table 2.5-39.

2.5.6.4.2 Properties of Embankment Borrow (Select Fill) Materials

Original design properties for the Service Water Pond embankments were determined from laboratory tests on soil samples obtained from proposed onsite borrow (select fill) sources. As described in Section 2.5.6.2.1, these onsite materials were not used, except within the West Embankment below elevation 386.0'. As presented in the following sections, tests were subsequently conducted on soil samples from the borrow sources actually used, Borrow Sources F and G. These test results are summarized in Table 2.5-40. The soil parameters obtained were subsequently verified by laboratory tests on undisturbed block samples removed from the embankments during construction, as described in Section 2.5.6.4.6. Comparisons of the original onsite borrow material design parameters with those of the offsite borrow material and the verified as-built embankment soil properties are presented in Sections 2.5.6.5 and 2.5.6.6.

2.5.6.4.2.1 Physical Properties

The physical properties of the offsite borrow materials were determined in the same manner as described in Section 2.5.6.4.1.1, except that unit weight determinations were not made. The near-surface borrow materials are classified as residual soil and the deeper materials, as saprolite.

The physical properties of the borrow materials, differentiated as residual soil and saprolite, are presented in Table 2.5-41. Grain size distribution curves are presented by Figure 2.5-120.

2.5.6.4.2.2 Compaction Properties

The compaction characteristics of the potential borrow materials were studied by means of the modified compaction test (ASTM D 1557-70). Summary plots of these compaction tests are presented by Figures 2.5-121 and 2.5-122 for Borrow Sources F and G, respectively.

2.5.6.4.2.3 Static Shear Strength

Unconsolidated-undrained (UU) and isotropically consolidated, undrained ($\overline{CIU}$) triaxial tests were performed on compacted borrow materials. The borrow materials were compacted to approximately 90% of the maximum modified dry density (ASTM D 1557-70) at moisture contents approximately 3 percentage points about optimum. The $\overline{CIU}$ test samples were sheared subsequent to saturation. The static shear strength test results are presented by Figures 2.5-122 (UU tests) and 2.5-123 ($\overline{CIU}$ tests) and are summarized in Table 2.5-42. Additional strength tests at higher moisture contents are described in Section 2.5.6.4.2.8.

2.5.6.4.2.4 Static Deformation

To investigate the compressibility of the borrow materials, oedometer (1 dimensional consolidation) tests were performed on compacted samples using conventional double load increments. The test results are presented in a summary plot showing axial strain versus pressure, Figure 2.5-124.

2.5.6.4.2.5 Permeability

The permeability of the compacted borrow materials was determined during the oedometer tests at various consolidation pressures. A summary plot of the test results is shown by Figure 2.5-125.

2.5.6.4.2.6 Dynamic Shear Strength

Cyclic triaxial tests were conducted to evaluate the dynamic shear strength of the embankment soils under earthquake loading conditions. These tests were performed on reconstituted samples typical of the onsite saprolite soils to be used in constructing the embankments. During construction, when the source of onsite saprolite was depleted from nearby borrow areas, consideration of the use of the higher plasticity residual soil horizon materials from Borrow Source G necessitated performing additional cyclic triaxial shear tests on these materials.

Samples for cyclic testing of the saprolite soils were reconstituted to a moisture content and dry density which simulated anticipated field placement conditions. The maximum dry density of a composite saprolite sample was 119.5 pcf and the optimum moisture content was 13%, as determined by ASTM D 1557-70. Accordingly, the samples were reconstituted to a dry density of approximately 107.6 pcf (90% of maximum density) at a moisture content of approximately 18% (5% above optimum). As shown in Tables 2.5-43 and 2.5-44, the actual dry densities and moisture contents of the reconstituted samples were very close to the desired values.

The residual soil specimens of intermediate plasticity index (PI = 19 ±) material were reconstituted to a dry density of 95.0 pcf. This corresponds to 90% of the maximum density, as determined by ASTM D 1557-70, at a moisture content of 21.7% (2% wet of the optimum water content).

The reconstituted samples had a diameter of 2.0 inches and a height of 4.0 inches. The samples were prepared by placing and compacting the soils in layers approximately 1/2 inch thick. Compaction effort was uniformly applied to each layer using a miniature Harvard kneading compactor.

The samples were saturated and then consolidated isotropically under an all-around pressure, σ_3, in the triaxial cell. For the reconstituted samples of the embankment soils, tests were also performed on samples consolidated anisotropically, i.e., under a vertical stress, σ_1, greater then the later stress, σ_3.

After saturation and consolidation, the samples were subjected to an axial, sinusoidally varying, cyclic deviator stress of peak magnitude $\pm\sigma_d$. The frequency of loading was 1 cycle per second.

The load trace, the axial deflection of the sample, and the pore water pressure were continuously recorded during cycling. All cyclic triaxial tests were performed using MTS equipment.

Eleven (11) tests were performed on reconstituted samples of the saprolite soils consolidated under isotropic conditions. The results of these tests, including the stresses and number of cycles required to cause initial liquefaction, ±5% peak cyclic strain, and ± 10% peak cyclic strain, are presented in Table 2.5-43. Seven (7) tests were performed on the intermediate PI residual soil materials. The results of these tests are presented in Table 2.5-45. The test results are summarized graphically by Figure 2.5-127, showing the relationship between the cyclic stress ratio, $\pm \sigma_d/2\sigma_{3c}'$ and the number of cycles causing ± 5% axial strain.

A cyclic strain of ± 5% has been used as the failure criterion for embankment foundations. Initial liquefaction precedes the development of ±5% strain. The criterion for initial liquefaction was taken as the number of cycles required to cause a peak pore water pressure in the sample equal to the initial effective confining pressure, σ_3, or the number of cycles required to cause a strain of ± 2.5%, whichever occurred first. The data for initial liquefaction were used to establish a correction factor to be applied to the stresses causing ±5% strain as described in the following paragraph.

Recent studies by Finn, Pickering and Bransby (Reference 96), Seed and Peacock (Reference 97), and Seed and Idriss (Reference 98) have shown that cyclic triaxial tests of isotropically consolidated samples provide stress values that are higher than those causing failure in the field. Therefore, correction factors to be applied to triaxial test data were established. The correction factors presented in the above studies are in terms of the relative density of a clean sand and are based upon the stresses and number of cycles required to cause liquefaction. The soils at the Virgil C. Summer Nuclear Station site contain appreciable quantities of fines. Therefore, it is difficult to describe their general behavior in terms of a relative density. However, a comparison of the results of cycle triaxial tests for the Virgil C. Summer Nuclear Station site soils with the data presented by Seed and Peacock (Reference 97) indicates that the cyclic strength characteristics of the site soils are comparable to those of a clean sand having a relative density varying from approximately 75 to 100%. (The higher relative densities correspond to tests made at the lower confining pressures. For these tests, relatively higher values of the stress ratio $\pm\sigma_d/2\sigma_3$ were required to cause failure.) Based upon the test data presented in Table 2.5-43 and on the procedures proposed by Peacock and Seed (Reference 94), the correction factors listed in Table 2.5-46 were established. The use of the correction factors listed in Table 2.5-46 to obtain the field stresses required to cause 5% strain in the embankment soils is described in a subsequent paragraph.

Twelve (12) tests were performed on reconstituted samples of the saprolite soils consolidated under anisotropic conditions. In these tests, the vertical stress during consolidation, σ_1, was greater than the lateral stress, σ_3. Thus, the consolidation ratio, $K_c = \sigma_1/\sigma_3$, was greater than 1.0. Tests were performed at values of $K_c = 1.5$ and $K_c = 2.0$. In addition, 1 test with $K_c = 1.5$ was performed on the intermediate PI residual soils.

The test results for the saprolite soils, showing the stresses and number of cycles required to cause a peak strain of 5% and 10%, are presented in Table 2.5-44. As reported by Seed, Lee and Idriss

(Reference 99), a correction factor for triaxial test data is not required for samples consolidated anisotropically. For this reason, data on initial liquefaction of the anisotropically consolidated samples are not presented.

Cyclic tests of anisotropically consolidated samples are made in order to simulate the condition within the constructed embankment where there are initial static shear stresses on the potential failure planes. The ratio of the initial static shear stress, τ_{fc}, to the normal stress, σ_{fc}, on the plane of failure is designated α. For the constructed embankment, α is determined for various points in the embankment by static finite element analysis. For the laboratory samples, α depends primarily upon the consolidation conditions (i.e., upon the value of K_c). The relationship between K_c and α for the laboratory tests is as follows where $K_c = \sigma_1/\sigma_3$ and $\alpha = \tau_{fc}/\sigma_{fc}$:

1. For $K_c = 1.0$, $\alpha = 0$.
1. For $K_c = 1.5$, $\alpha = 0.19$
2. For $K_c = 2.0$, $\alpha = 0.34$.

The strength characteristics of the embankment soils under cyclic loading conditions are summarized in Figures 2.5-128 and 2.5-129. The data in these figures are presented in terms of the cyclic shear stresses required to cause 5% strain as a function of the initial effective normal pressure.Figure 2.5-128 presents the data for 10 stress cycles and Figure 2.5-129 for 20 stress cycles. The data are presented for samples consolidated isotropically ($K_c = 1.0$, $\alpha = 0$) and for samples consolidated anisotropically ($K_c = 1.5$, $\alpha = 0.19$ and $K_c = 2.0$, $\alpha = 0.34$).

As previously noted, a correction factor need not be applied to the laboratory cyclic shear strengths for samples consolidated anisotropically. Therefore, the data presented in Figures 2.5-128 and 2.5-129 for anisotropically consolidated samples are obtained directly from the laboratory test results summarized in Figure 2.5-130. For isotropically consolidated samples, the cyclic strengths indicated by Figure 2.5-127 have been multiplied by the correction factor, C_r, summarized previously, before plotting the data in Figures 2.5-128 and 2.5-129. Thus, the relationships presented in the latter figures represent the strengths of the embankment soils in the field under cyclic loading conditions. These strengths (expressed as the cyclic shear stress required to cause 5% strain) can then be compared to the stresses induced in the embankment during the earthquake ground motions.

As can be seen from Figures 2.5-128 and 2.5-129, the strengths determined for samples consolidated anisotropically ($K_c = > 1.0$, $\alpha > 0$) are not significantly different from those obtained for samples consolidated isotropically ($K_c = 1.0$, $\alpha = 0$). Therefore, the strength versus effective normal pressure relationships in Figures 2.5-128 and 2.5-130 are approximated as a single curve for all ratios of α.

2.5.6.4.2.7 Dynamic Response

The dynamic material properties required for the computation of the response of a soil mass during earthquakes include shear modulus and damping values. The maximum shear modulus

(i.e., the value corresponding to very low levels of strain) and the variation of shear modulus with strain are also required.

Low amplitude cyclic torsion tests were performed on samples of the embankment soils to determine the shear modulus (G) and the damping values (D) at very low strain levels. The modulus and damping values at high strain levels were obtained from the results of cyclic triaxial shear tests.

The modulus values measured in the cyclic torsion test for the saprolite and residual soil materials are presented by Figure 2.5-131. Also shown are the relationships used in the dynamic response analyses, including the upper and lower bounds. The cyclic torsion test results for the residual soils fall within the range established for the saprolite soils, generally at or below the average. The variation in modulus values as a function of strain was developed using published curves (Reference 98) and the results of the cyclic torsion tests and the cyclic triaxial tests. The relationship used in the analysis is shown on the lower part of Figure 2.5-118.

Damping values for the embankment soils were also obtained from the cyclic torsion and triaxial tests. Variation of the damping values as a function of strain is presented on Figure 2.5-132 and is summarized on the upper part of Figure 2.5-118.

2.5.6.4.2.8 Special Testing for Soil Moisture Content

During construction of the Service Water Pond dams, significant delays were experienced due to weather conditions which resulted in in-situ moisture conditions approximately 1 to 2% above the 4% limit prescribed in the specifications. These delays are summarized by Figure 2.5-198. Consequently, an evaluation was performed to determine the effects of moisture content ranging up to 6% above the optimum defined by ASTM D-1557. This evaluation was performed by constructing a test fill at Borrow Source G and testing undisturbed block samples of the compacted soil at the higher moisture contents. A summary of the test results for the 2 block samples (UDS-21 and UDS-22) retrieved from the test fill is presented by Table 2.5-59a. Grain size distribution curves are shown by Figure 2.5-150a.

The test fills were constructed using the same techniques and equipment used in constructing the Service Water Pond dams. The moisture content of the compacted test fill soil ranged from 5.2 to 6.5% above optimum. The test program also included Atterburg limit, specific gravity, and grain size distribution determinations. Testing confirmed that the test fill materials were within specification limits and were representative of the entire borrow source.

Consolidated - undrained triaxial tests ($\overline{\text{CIU}}$) with pore pressure measurements were performed on the block samples to determine the strength of the soil at these high moisture contents. Results of these tests are presented by Figure 2.5-153a. As shown by Figure 2.5-155a, the strength properties exceed design properties. It was concluded that a maximum allowable moisture content of up to 6% greater than optimum would be suitable and compaction specifications were changed to reflect this conclusion.

2.5.6.4.3 Embankment Features

2.5.6.4.3.1 Geometric Data

Typical cross-sections of the North Dam, South Dam, East Dam, and West Embankment are shown by Figures 2.5-133 through 2.5-136, respectively. Each structure is designed as a homogeneous embankment with riprap slope protection. The North and South Dams contain an internal horizontal drainage blanket and a rock toe to control seepage in the event of sudden drawdown of Monticello Reservoir. The South Dam also includes a relatively impervious upstream blanket for seepage control.

The Monticello Reservoir faces of the dams are inclined at 3.5 to 1. The Service Water Pond faces of the dams and the West Embankment are inclined at 3 to 1. The back slope of the West Embankment is at an inclination of 1 to 1, as shown by Figure 2.5-136. However, the plant fill adjoins the West Embankment. The backslope of the West Embankment is the interface between these 2 fills.

Other pertinent geometric aspects of the Service Water Pond structures are given in Table 2.5-24. The various design features of the structures are described in detail in the following sections.

2.5.6.4.3.2 Embankment Fill

Select fill materials for the earth embankment portion of the North, South, and East Dams and most of the West Embankment consist of residual soil and saprolite excavated from Borrow Sources F and G, except that onsite borrow soils were used for the West Embankment below elevation 386.0'. The liquid limit and plasticity index of select fill materials did not exceed 70% and 25%, respectively. The soil was placed in horizontal lifts not exceeding 8 inches in loose thickness and was compacted to a minimum dry density of 90% of the modified maximum dry density as determined by ASTM D 1557-70. The allowable compaction moisture content ranged from 1% below to 6% above the optimum moisture content as determined by ASTM D 1557-70. The results of field quality control tests and laboratory verification tests conducted on the select fill materials are presented in Section 2.5.6.4.5 and 2.5.6.4.6, respectively.

2.5.6.4.3.3 Internal Drainage

In the event of a drawdown of Monticello Reservoir, internal drainage is provided within the North and South Dams to prevent the eventual steady-state internal phreatic line from intersecting the Monticello Reservoir slope. The drainage provision consists of a horizontal blanket of coarse granular soil (Zone 2 filter) surrounded by finer granular soil (Zone 1 filter) to prevent clogging of the blanket with fines from the embankment soils (Reference 89). The drainage blankets are designed to have sufficient discharge capacity to facilitate the expected seepage flow without excessive hydraulic gradients. The extent and configuration of the drainage blankets are shown in cross-section in Figures 2.5-133 and 2.5-134 and in plan in Figures 2.5-105 and 2.5-107. A photograph of the drainage blanket for the North Dam is presented in Figure 2.5-137.

The Zone 1 and Zone 2 filter materials consist of processed quarry screenings free of deleterious amounts of weak, flat, elongated, friable, decomposed, micaceous, or argillaceous material. The specified gradations of the materials are given in Table 2.5-47. The uniformity coefficient of both materials was required to be greater than 6.0, and the bulk saturated-surface-dry (SSD) specific gravity (ASTM C 126-68) was required to be greater than 2.50. In addition, the Zone 2 filter material was required to have a sodium sulphate loss (ASTM C 88) of not more than 10% after 5 test cycles, an abrasion loss (ASTM C 535-69) of not more than 50% and an inplace coefficient of permeability of at least 1.0×10^{-3} cm/sec. The filter materials were required to be placed in horizontal layers not exceeding 12 inches in loose thickness and compacted to not less than 75% relative density. The results of tests performed during construction to document these filter material properties are presented in Section 2.5.6.4.5.

In addition to the horizontal interior drain, a rock toe was provided in the North and South Dams as shown in Figures 2.5-133 and 2.5-134. The rock toe provides a further safeguard that steady seepage will not emerge from the dam slope in the event of Monticello Reservoir drawdown. The rock toes were constructed of Zone A rock, which is described in Section 2.5.6.4.3.4. A photograph showing construction of the rock toe in the South Dam is presented as Figure 2.5-138.

2.5.6.4.3.4 Slope Protection

All Service Water Pond embankments are provided with riprap slope protection to prevent erosion of the embankment fill by wave action or piping. The extent of the riprap protection is shown by the typical embankment cross-sections, Figures 2.5-133 through 2.5-136. The riprap gradations are based upon criteria developed by the U.S. Army Corps of Engineers (Reference 100). Four (4) riprap gradations are utilized depending upon the environmental conditions at the various locations where the riprap is placed. The specified gradations are given in Table 2.5-48. The significant wave heights used in design are given in Section 2.4.

Zone A rock is utilized for the rock toes of the North and South Dams. Since the rock toes will be submerged by Monticello Reservoir, they will not be subject to wave action. Zone B rock is utilized for all of the Service Water Pond dams and embankments on the inside face of the pond above elevation 415.0' and on the outside face of the South Dam. Zone C rock is utilized on the Monticello Reservoir face on the North Dam above elevation 410.0'. Zone D rock is utilized on the Monticello Reservoir face of the East Dam and as an underlayer beneath the Zone C rock on the North Dam. The gradation also satisfies filtering criteria (Reference 89) with respect to both Zone C rock and Zone 2 filter.

The riprap is underlain by a 2 layer filter to prevent the loss of the embankment fines through the riprap. The filters consist of a minimum thickness of 9 inches of Zone 1 filter material placed against the embankment fill overlain by a minimum thickness of 9 inches of Zone 2 filter material. The specified properties of the Zone 1 and Zone 2 filter materials are given in Section 2.5.6.4.3.3. The filter gradations designs are based upon accepted filter requirements (Reference 89), which allows the flow of water from the finer to the coarser material while restricting the migration of fine soil particles. A photograph showing slope protection construction on the West Embankment is presented by Figure 2.5-139. The Zone 1 and Zone 2 filters are clearly shown adjacent to the rock toe of the South Dam in Figure 2.5-138.

In addition to the gradation requirements for the riprap, a maximum sodium sulfate loss (ASTM C 88) of 10% after 5 cycles, a maximum abrasion loss (ASTM C 535-69) of 50% and a minimum bulk SSD specific gravity (ASTM C 127-68) were required. The results of field quality control tests on these materials are presented in Section 2.5.6.4.5.4.

Prior to constructing the Service Water Pond, it was observed that deep gullying frequently developed in nonsafety class cut slopes and compacted fill slopes that were exposed to surface runoff. The gullied slopes were in residual and saprolite soils, composed mainly of micaceous silt with little or no clay binder. The gullies developed by runoff removing the noncohesive to slightly cohesive soil particles and was aggravated by flow being localized along relict joints in the cut slopes and desiccation cracks that developed in portions of some fills.

At the Service Water Pond, erosion of the slopes of the 3 dams and the West Embankment is prevented by the riprap which dissipates the energy of rainfall onto the embankments and by the filters beneath the riprap which are designed and constructed to prevent soil migration. Erosion protection of the crests of the 3 dams is provided by 12 inches of Zone 2 filter material underlain by 6 inches of Zone 1 filter material. Runoff from the plant yard is directed away from the West Embankment, thus minimizing flow across its crest.

2.5.6.4.3.5 South Dam Seepage Control Blanket

A seepage control blanket was constructed on the upstream (Service Water Pond) side of the South Dam to reduce seepage losses through the South Dam foundation materials in accordance with the AEC (currently NRC) letter of March 1, 1973, from Messrs. Scinto and Conner to Messrs. Head, McCollom, and Lyman. The extent of the blanket is shown on Figure 2.5-107. Construction procedures for placing the blanket included stripping the foundation of loose, soft, or organic materials and placing only the more plastic residual soils. Each lift was approximately 1 foot in thickness and was compacted by at least 3 phases of a self-propelled tamping foot roller.

2.5.6.4.4 Settlement Analyses

Analyses of potential settlement of the North and South Dams were performed based upon as-built dimensions and soil parameters to investigate the potential for the loss of freeboard due to post construction consolidation and the potential for cracking within the embankment due to differential settlements. The method of analysis was based upon the conservative, if not rigorous, assumption that the embankment settlement along the centerline can be expressed as the sum of immediate deformation and 1 dimensional consolidation. To assess the cracking potential, the results of a theoretical determination of tensile strains were compared to field observations of embankments constructed of similar materials which have been reported in the literature. The methods used for the settlement and cracking analyses are described in detail in the following sections, together with the results and conclusions derived therefrom.

2.5.6.4.4.1 Method of Settlement Analysis

Immediate settlement occurs in both the dam foundations and the embankment for 2 reasons: compression of the unsaturated materials, as a combination of elastic and volumetric distortion,

and compression of saturated materials, as elastic distortion. For unsaturated soils with a degree of saturation less than 95%, the immediate volumetric compression can be a significant part of the ultimate soil deformation. An expression for the immediate compression of unsaturated soil can be readily derived in terms of the developed pore water pressure and the pore water pressure parameters A and B (Reference 101) in accordance with Equations (1) and (2), below:

$$S_i = \frac{a_v}{1+e_o} \int_o^h (\Delta\sigma_1 - \Delta_u) dz \quad (1)$$

$$\Delta u = B\left[\Delta\sigma_3 - A(\Delta\sigma_1 - \Delta\sigma_3)\right] \quad (2)$$

where:

S_i = Immediate compression.

Δu = Change in pore pressure due to imposed load.

a_v = Coefficient of compressibility.

e_o = Initial void ratio.

h = Thickness of compressible stratum.

σ_1 = Imposed major principal stress.

σ_3 = Imposed minor principal stress.

A = Pore pressure parameter.

B = Pore pressure parameter.

dz = Increment of depth.

Combining Equations (1) and (2) and rearranging the terms yields:

$$S_i = \frac{a_v}{1+e_o} \int_o^h \Delta\sigma_1 \left\{1 - B\left(A + \frac{\Delta\sigma_3}{\Delta\sigma_1}(1-A)\right)\right\} dz \quad (3)$$

If the width of the loaded area is large with respect to the thickness of the compressible statum, the term [(A + ($\Delta\sigma_3/\Delta\sigma_1$(1-A))] approaches unity and the compression of the unsaturated material can be expressed for materials beneath the crest of the dam in accordance with Equation (4).

$$S_i = \frac{a_v}{1+e_o} \int_o^h \Delta\sigma(1-B)dz \qquad (4)$$

Near the edges of the embankment, however, where lateral distortion is significant, settlement is most appropriately expressed by Equation (3). The parameters A and B are measured by triaxial testing of representative samples (Reference 102). The factor av is determined from conventional oedometer testing (Reference 103).

Consolidation settlement is usually calculated by direct application of results of oedometer tests assuming 1 dimensional compression, where $\Delta\sigma_1 = \Delta u$ and B = 1. Under these conditions, the consolidation settlement can be expressed for saturated soils by Equation (1) or by its equivalent, Equation (5).

$$S_c = \frac{a_v}{1+e_o} \int_o^h \Delta\sigma_1 dz \qquad (5)$$

where:

S_c = Consolidation settlement.

For most unsaturated soils it can be conservatively assumed that consolidation settlement commences upon completion of the immediate settlement and that the rate of settlement is approximately in accordance with 1 dimensional consolidation theory as proposed by Terzaghi (Reference 104).

If representative samples of unsaturated embankment materials are saturated prior to oedometer testing, the soil air voids are replaced with water and the total sample compression during testing occurs as a time dependent deformation. Combined immediate and consolidation settlements can then be expressed by Equation (6) in terms of S_c, determined from saturated samples, and B, determined from equivalent unsaturated samples, assuming that the elastic component of immediate settlement is considered by the parameter B.

Thus:

$$S_t = (1 - B) S_c + U B S_c \quad (6)$$

where:

S_t = Combined immediate and consolidation settlement.

U = Percent consolidation, determined as a function of time and length of drainage path in accordance with the 1 dimensional consolidation theory (Reference 104).

2.5.6.4.4.2 Calculation Procedure

Deformation analyses of the Service Water Pond dams were performed for various locations along the dam crests using Equation (6) together with the following procedure:

1. Estimate the time to construct each dam and divide the dam into layers of equal volume, and hence equal time of construction.
2. Apply each incremental layer in sequence and calculate by superposition the imposed stress (using elastic theory) and settlement realized in the foundation and embankment at the end of construction.
3. Calculate delayed consolidation settlement in each layer as a function of the rate of loading of the layer.
4. For a conservative calculation of post construction settlement, assume the greatest drainage path length for each embankment layer.

2.5.6.4.4.3 Material Property Data

Material properties for the deformation analysis were derived from tests conducted to determine the deformation and consolidation properties of the embankment fill and the saprolite and decomposed rock foundation materials, as well as their pertinent physical properties. A description of the testing program and the results of the tests are presented in Sections 2.5.6.4.1 and 2.5.6.4.2. The material properties used in the deformation analysis are presented in Table 2.5-49 Considering that the limited range of the deformation properties measured will not materially influence the calculated post construction differential settlements, deformation property values were generally selected within the mid-range of the test data. However, the coefficient of consolidation was selected to correspond to a lower bound value to maximize the amount of post construction settlement calculated.

2.5.6.4.4.4 Analysis of Potential Transverse Cracking

The calculated post construction crest settlement was plotted at numerous points along the axis of the dam crest to provide a profile of settlement. An analysis of potential cracking due to the crest distortion was then performed in accordance with the procedure proposed by Leonards and Narain (Reference 105) which simulates the dam as a beam and calculates the longitudinal tensile strain along the crest imposed by the computed settlement profile.

2.5.6.4.4.5 Results of Settlement and Cracking Analyses

The calculated profiles of post construction settlement along the crests of the North and South Dams are shown by Figures 2.5-140 and 2.5-141, respectively. As indicated by these figures, the maximum anticipated post construction settlement is estimated to be 7.0 inches for the North Dam and 4.6 inches for the South Dam. The results of the tensile strain analysis are also shown by Figures 2.5-140 and 2.5-141. As shown by the figures, the maximum computed tensile strains are 0.06% and 0.19% along the crests of the North and South Dams, respectively. These values compare favorably with a crest tensile strain of 0.30% at cracking as calculated by Leonards and Narain (Reference 105) for the Portland Dam which is reported to be constructed by silty clay with a plasticity index of 8 and to have been compacted at approximately 4% dry of optimum moisture content. The Service Water Pond dams, with a somewhat greater plasticity index, were primarily compacted wet of optimum and hence, should be more flexible and should be able to withstand greater tensile strains without suffering transverse cracks.

2.5.6.4.5 Field Control of Embankment Materials During Construction

2.5.6.4.5.1 Control of Select Fill Materials

A rigorous program of sampling and testing was performed during construction to determine that fine grained embankment materials (select fill) were placed in accordance with specification and design requirements. The test procedures and frequencies used to control the placement of these materials are summarized in Table 2.5-50. A summary of construction control physical property test results, by structure, is presented in Table 2.5-51. Figures 2.5-142, , and 2.5-143 contain summaries, by structure, of the construction control gradation tests, compaction curves, and inplace density test results, respectively. Figure 2.5-145 shows, by structure, the distribution of the locations of inplace density tests.

It is seen from the above mentioned tables and figures that testing was performed generally uniformly throughout the embankment fills and that the densities and moisture contents were within required limits for placement. Materials represented by tests that did not fall within the required limits were either reworked, if appropriate, or removed and replaced with acceptable materials.

2.5.6.4.5.2 Control of Zone 1 Filter Material

Similar to select fill materials, Zone 1 filter materials were controlled by a rigorous program of sampling and testing. Table 2.5-52 summarizes the testing procedures and frequencies used to accept these materials for Service Water Pond construction.

Zone 1 filter materials were produced at Quarry A located 4 miles northeast of the site. Acceptable material was either stockpiled onsite near the east abutment of the North Dam or placed directly as necessary to construct filters and drains for all of the Service Water Pond structures.

The results of all gradation tests performed on this material are summarized by Figure 2.5-147. As shown by this figure, all material tested satisfied the requirements discussed in Section 2.5.6.4.3.3.

The results of inplace density tests performed in the horizontal drainage blanket filters at each structure are summarized on Table 2.5-53 together with a summary of specific gravity determinations. Inclined slope protection filters were compacted by at least 6 passes of the treads of a D8 Caterpillar tractor or a self-propelled smooth drum vibratory roller.

2.5.6.4.5.3 Control of Zone 2 Filter Materials

Prior to production processing of Zone 2 filter materials, also produced at Quarry A, prequalification tests were performed in accordance with Table 2.5-54. Additional testing was performed in accordance with the criteria outlined in Table 2.5-54. Results of the production gradation tests are summarized by Figure 2.5-148 which shows that these materials, with few exceptions, satisfied specification requirements. For the failing tests, 2 additional samples for each failure were retrieved from the corresponding day's production and gradation tests were performed. In all cases, the 2 additional samples tested satisfied the requirements and the material was approved.

The results of specific gravity determinations and sodium sulfate soundness tests performed during production processing are summarized on Table 2.5-55 and are compared to the specification requirements. Table 2.5-56 summarizes the results of inplace permeability tests performed in the North and South Dams and compares the results to the specification requirements.

2.5.6.4.5.4 Control of Riprap

Prior to production processing of riprap prequalification testing was performed, as listed in Table 2.5-57, to determine the quality of material being produced from the quarries. The majority of the riprap was produced at Quarry A. A limited quantity of Zone C riprap was produced at Quarry B which is located near Winnsboro, SC. Once the quarry and quarry processing operations were approved, production tests were performed in accordance with the criteria presented on Table 2.5-57.

The results of gradation tests on riprap are presented by Figures 2.5-149 and 2.5-149. A summary of the specific gravity and sodium sulfate soundness tests is presented on Table 2.5-58. All production tests satisfied specification requirements. The processed materials were either stockpiled in a designated area north of the North Dam or placed directly as necessary to construct the Service Water Pond structures. Continuous surveillance was performed so that only acceptable materials were placed and to ensure that segregation was minimized.

2.5.6.4.6 Verification Testing for As-Built Soil Parameters

To verify that design values of the various parameters used in the design of the Service Water Pond embankments were achieved or exceeded in the as-built embankments, relatively undisturbed block samples of the compacted embankment soils were obtained. These samples, generally about 1 cubic foot each in volume, were obtained at a minimum rate of 1 sample per 50,000 cubic yards of fill. The samples were taken in accordance with the United States Bureau of Reclamation procedure for hand sampling, Method E-2, Part A (Reference 90), and appropriate laboratory tests were performed. The results of testing through July 15, 1976, are presented in Table 2.5-59 and are discussed in the following sections.

2.5.6.4.6.1 Physical Properties

Physical property tests conducted on the block samples consisted of water content, liquid and plastic limits, specific gravity, unit dry weight, and grain size distribution. The results of these tests are summarized in Table 2.5-60. The grain size distribution curves are presented by Figure 2.5-150. The degree of compaction was obtained from the maximum density of the compaction curve which was used in the field for density control of the portion of fill from which each individual block was obtained. It is noted that of the 12 samples tested to date, 6 samples appear to have a degree of compaction less than the specified 90.0%. It is believed that this condition is due to the inevitable expansion of the soil during sampling, transportation, and storage since, as discussed in Section 2.5.6.4.3.2, all lifts were compacted to a minimum degree of compaction of 90.0% as controlled by field density tests.

2.5.6.4.6.2 Static Shear Strength

The static shear strength of selected block samples was determined from unconfined compression and unconsolidated-undrained (UU) triaxial compression tests for total stress parameters and from isotropically consolidated, undrained ($\overline{\text{CIU}}$) triaxial compression tests for effective stress parameters.

The results of these tests are presented by Figures 2.5-151 through 2.5-153. Summary plots of the failure envelope for these tests and the design envelopes are presented by Figures2.5-154 and 2.5-155. As the summary plots indicate, the preponderance of the shear strength data for the compacted soil is greater than that used in design.

2.5.6.4.6.3 Static Deformation

Oedometer consolidation tests were performed on selected block samples to document the as-built compression properties of the embankment. A summary plot of the results is presented by Figure 2.5-156. The compression curves of the block samples are seen to be similar to the curves obtained for laboratory compacted samples used for design.

2.5.6.4.6.4 Permeability

Permeability tests were performed during some of the consolidation tests to document the as-built permeability of the embankments. The results are summarized by Figures 2.5-156 and 2.5-158 for vertical and horizontal permeabilities, respectively. The coefficients of permeability measured are conservative with respect to the permeability used in design (see Section 2.5.6.6).

2.5.6.4.6.5 Dispersion Tests

Pin hole dispersion tests (Reference 106) were performed to determine the dispersion characteristics of the embankment fill. The test results are presented in Table 2.5-61. In addition, Soil Conversion Service procedures (Reference 107) were used to determine dispersion characteristics. Typical test results are presented by Figure 2.5-159. All of the test results are summarized in Table 2.5-61a. It is concluded that the embankment soils are nondispersive.

2.5.6.4.6.6 Dynamic Response

The dynamic response of the compacted embankment materials (select fill) was evaluated by cyclic torsion (resonant column) tests and stress-controlled cyclic triaxial tests. The values of maximum shear modulus, G_{max}, obtained at different confining pressures from resonant column tests performed on samples from 9 block samples are shown by Figure 2.5-160. For comparison, the values for G_{max} used in the design analyses, along with the upper and lower bound values analyzed, are also shown. The apparent scatter of the block sample test results, compared to the test results for laboratory reconstituted samples, upon which the G_{max} values are based (Figure 2.5-131), is attributed primarily to small variations in the select fill materials and the degree of compaction. Also, the disturbance caused by sampling, shipment, and storage (without confining pressure) of the block samples is believed to contribute to this apparent variation in G_{max} results. As previously discussed in Section 2.5.6.5.6.1, even the dry unit weight and degree of compaction were noted to have been altered for the block samples from that which was measured in the field adjacent to the sampling locations. However, most of the G_{max} data from block samples still falls within the upper and lower bound values, except at high pressures where the values obtained are lower than the G_{max} values used. It was shown in the analyses conducted for the dynamic stability of the embankments that lower G_{max} values result in lower cyclic shear stresses (see Section 2.5.6.5.7). Therefore, the design analyses performed were conservative.

The damping values obtained from the resonant column tests are shown by Figure 2.5-160a. The relationship used in the design analyses is also shown by Figure 2.5-160a to be a good representation of the block sample test results data.

Six (6) stress-controlled cyclic triaxial tests were also performed on block samples to evaluate the dynamic shear strength. Four (4) of the 6 samples did not attain failure strain level (± 5%) even at the high stress ratios used in the tests. These tests were terminated after the application of 1,000 load cycles. The results are plotted in Figure 2.5-127 for comparison with the data obtained from reconstituted laboratory samples. The results from the cyclic triaxial tests on the block samples shown that the dynamic strength used in the analyses is quite conservative.

2.5.6.5 Slope Stability

2.5.6.5.1 Foundation and Embankment Static Shear Strength Parameters

Static shear strength properties of the foundation and embankment materials for the Service Water Pond dams were investigated as described in Sections 2.5.6.4.1.2 and 2.5.6.4.2.3, respectively. In addition, verification tests were performed on block samples removed from the embankments after compaction, as described in Section 2.5.6.4.6.2.

The strength test results on the foundation materials are presented by Figures 2.5-111 through 2.5-113 and are summarized in Table 2.5-33. Based upon these results, the following shear strength properties were adopted for design:

1. Residual Soil

   Undrained shear strength = 800 psf.

2. Saprolite
   a. Undrained shear strength = 200 psf.
   b. Effective friction angle = 36 degrees.
   c. Effective cohesion = 0 psf.
3. Decomposed Rock
   a. Effective friction angle = 38.5 degrees.
   b. Effective cohesion = 0 psf.

The undrained shear strength of decomposed rock was not determined, but has been conservatively estimated to be 3000 psf for design.

The strength test results for laboratory compacted embankment materials obtained from Borrow Sources F and G are presented by Figures 2.5-122 and 2.5-123 and are summarized in Table 2.5-42. The verification strength test results obtained from the block samples are presented by Figures 2.5-151 through 2.5-153 and are summarized by Figures 2.5-154 and 2.5-155. Based upon these results, the following strength properties were adopted for design of embankment fill:

1. Undrained shear strength = 1600 psf + σ_n tan 20°.
   Where: σ_n is the normal force on the failure plane in psf.

2. Effective friction angle = 28 degrees.
3. Effective cohesion = 300 psf.

The unconsolidated-undrained (total stress) and consolidated-undrained (effective stress) failure envelopes defined by the embankment fill design parameters are shown on the summary plots of the verification test failure envelopes in Figures 2.5-154 and 2.5-155, together with the original design failure envelopes. The undrained shear strength used in the original analysis was 600 psf, the effective friction angle was 29 degrees and the effective cohesion was 160 psf. It may be seen from these plots that the revised failure envelope used for the original analysis, is conservatively below essentially all of the verification test data within the stress range of interest (below 5 tons per square foot). Strength parameters for the rock toes of the embankments could not be practically determined experimentally. A very conservative total stress and effective stress friction angle of 35 degrees was adopted for design.

2.5.6.5.2 Method of Analysis - Static Conditions

2.51 The stability of the Service Water Pond dams was investigated using the circular arc method of analysis as described by Bishop (Reference 108). The analysis was conducted by computer using the ICES LEASE-I Program (Reference 109). In addition to the North and South Dams, a stability analysis was conducted on a natural slope located south of the South Dam using both the circular arc method and the sliding wedge method (Reference 110). The West Embankment and East Dam were not analyzed; since, by comparison with the North Dam, it was determined by observation that the factors of safety of these structures are considerably greater.

2.5.6.5.3 Design Criteria - Static Loading

The various design conditions and the minimum acceptable factor of safety for each which was adopted for design are summarized as follows:

1. End of construction, $FS_{min} = 1.10$.
2. Submerged condition, $FS_{min} = 1.30$.
3. Sudden drawdown, $FS_{min} = 1.20$.
4. Steady seepage, $FS_{min} = 1.30$.

The end of construction case represents the embankment condition when construction has been completed and before the water level has been raised on either slope. The total stress (undrained) strength parameters were used for this analysis, which conservatively assumes that no consolidation of the embankment or foundation materials occurs prior to this time.

The submerged case represents the normal operating condition with both Monticello Reservoir and the Service Water Pond raised to their maximum level of elevation 425.0'. The effective stress strength parameters were used for this and the following analyses.

The sudden drawdown case represents a postulated situation wherein Monticello Reservoir is suddenly emptied. It is conservatively assumed in the analysis that the drawdown occurs instantaneously, that the Service Water Pond remains at the maximum water level of elevation 425.0' and that no drainage occurs within the fine grained embankment materials. It is noted that the minimum water level on the reservoir side of the South Dam is approximately elevation 404.0', corresponding to the bottom elevation of the discharge canal.

The steady seepage case represents the condition at a time subsequent to a postulated sudden drawdown of Monticello Reservoir when steady-state seepage has developed from the Service Water Pond to Monticello Reservoir through the internal drainage system of the dams. The location of the steady-state phreatic line for this case is estimated by Kozeny's method (Reference 111).

A design case analyzed herein which was not considered in earlier analyses is the condition of reverse seepage. This case will develop during the testing of the Service Water Pond when Monticello Reservoir is raised to its normal high level of elevation 425.0' while the Service Water Pond is empty. It was conservatively assumed in this analysis that the test would be of sufficient duration to develop steady-state seepage conditions. The location of the steady-state phreatic line for this condition is estimated using Casagrande's method (Reference 111).

2.5.6.5.4 Analytical Results - Static Loading

The results of the static stability analyses demonstrate that all of the embankments have an adequate factor of safety against shear failure under all postulated design conditions. The results of the analyses for the North and South Dams are presented by Figures 2.5-161 and 2.5-162, respectively. These figures show the geometric configuration of the embankments, the locations of the phreatic line used for each analysis, the critical circular arcs, and the resulting factor of safety for each condition. The bottom of each structure was assumed to be horizontal, conservatively located at the elevation of maximum excavation for each structure. The true irregular bases of the structures would have the effect of increasing the factors of safety. The factors of safety found for the North and South Dams are summarized as follows:

1. North Dam
    a. End of construction, FS = 2.46
    b. Submerged condition, FS = 2.19
    c. Sudden drawdown, FS = 1.20
    d. Steady seepage, FS = 2.09
    e. Reverse seepage, FS = 1.35
2. South Dam
    a. End of construction, FS = 2.81
    b. Submerged condition, FS = 2.28
    c. Sudden drawdown, FS = 1.94

d. Steady seepage, FS = 2.14

e. Reverse seepage, FS = 1.48

Analysis of the natural slope located immediately adjacent to the reservoir-side toe of the South Dam indicates that this slope is stable under the normal operating (submerged) condition and the sudden drawdown (to elevation 404.0') condition. The other design conditions are not applicable to this slope. As shown by Figure 2.5-136, the respective factors of safety for the aforementioned conditions are 3.67 and 2.54 using the circular arc method, and 2.34 using the sliding wedge method for the sudden drawdown condition. A total stress analysis was used for the natural slope because the in situ materials are not subject to any future consolidation. No other natural slope could be defined, the failure of which could be postulated to affect the integrity of the Service Water Pond.

Analysis of potential failure configuration of excavated slopes associated with the discharge canal indicates that failure of these slopes would not affect the integrity of the Service Water Pond. Although the Circulating Water discharge canal is not a safety-related structure, conservative excavated slope angles have been designed and constructed to satisfy the minimum acceptable factors of safety listed in Section 2.5.6.5.3.

2.5.6.5.5 Foundation and Embankment Dynamic Properties

Dynamic shear strength and response parameters of the foundation and embankment materials for the Service Water Pond dams were investigated as described in Sections 2.5.6.4.1 and 2.5.6.4.2, respectively. In addition, verification tests were performed on block samples removed from the embankments after compaction, as described in Section 2.5.6.4.6.6.

The dynamic properties, as a function of shear strain, that were used in the seismic evaluations for the foundation and embankment materials are shown by Figures 2.5-119, and 2.5-131. The foundation shear moduli, as a function of the mean principal stress, used in the dynamic analysis are summarized below:

$$G_{max} = 1000\ K_2\ (\sigma_m)^{1/2}$$

where:

G_{max} = shear modulus at very low strain in psf.

σ_m = mean principal stress.

K_2 = 250 for decomposed rock.

K_2 = 70 for foundation soils.

The following relationships were used for the embankment materials:

1. $G_{max} = 35000\ (\sigma_m)^{1/2}$, for $\sigma_m < 2100$ psf.
2. $G_{max} = 760\ \sigma_m$, for $\sigma_m > 2100$ psf.

In the dynamic analyses, a damping of 10% was used for the embankment soils. As part of the seismic evaluations, parametric studies were performed to evaluate the effects of variations in the dynamic moduli for both the foundation and embankment materials and in the damping value of the embankment soils. The following parametric studies were performed:

1. K_2 for the decomposed rock was varied from 200 to 500, as compared with the probable value of 250.
2. K_2 for the foundation soils was varied from 50 to 120, as compared with the probable value of 70.
3. The shear modulus of the embankment materials was varied from 30% above (upper bound) to 30% below (lower bound) the probable modulus value (see Figure 2.5-131).
4. The 10% damping value of the embankment soils was decreased by 10% to analyze a lower bound of damping.

The results of these parametric studies are summarized in Section 2.5.6.5.7.

2.5.6.5.6 Seismic Stability Evaluations

2.5.6.5.6.1 General

A detailed seismic evaluation of the proposed earth dams for the Service Water Pond was conducted. The proposed dams were evaluated for conditions representative of the SSE. An evaluation of the dams under conditions representative of the OBE was also conducted utilizing the results obtained for the SSE. In these evaluations, conservative estimates of all parameters were incorporated in the analyses.

The maximum sections of the North Dam and the South Dam were analyzed in detail. Three (3) additional heights of dam were also analyzed in detail. With the aid of these 5 analyses, it was possible to evaluate the behavior of all 3 dams.

A summary of each of the proposed dams is given herein; additional details concerning these dams are provided in Section 2.5.6.4.3. The North Dam is approximately 1500 feet long and has a maximum height of approximately 129 feet, based upon the actual depth of undercutting required during the foundation preparation. During the original design analyses, it was assumed that the maximum height of the dam would be approximately 110 feet and this was the section originally analyzed. The profile across the valley where this dam was constructed is shown in the upper part of Figure 2.5-164. The maximum section of this dam is illustrated in the lower part of Figure 2.5-

164, which shows both the assumed stratification for the seismic analysis and the actual depth of undercutting performed during the foundation preparation.

The South Dam is approximately 765 feet long and has a maximum height of approximately 98 feet, based upon the depth of undercutting required during foundation preparation. It was anticipated during the design analysis that the maximum height of the South Dam would be only 67 feet. This height was based upon leaving the colluvial soils in place. However, as described in Section 2.5.6.3.2, the colluvium was removed. The profile across the valley and the maximum section of this dam are shown in Figure 2.5-165. Also shown on this figure is the actual depth of undercutting performed.

The East Dam is approximately 1150 feet long and has a maximum height of approximately 28 feet. The embankment slopes and crest elevation are the same as those of the North and South Dams.

2.5.6.5.6.2 Seismic Loading - Stability Analysis

An evaluation of the stability of earth structures and slopes under the postulated SSE and OBE was conducted in accordance with the following procedure (Reference 112)

1. Evaluation of the time history of accelerations which are likely to be developed in the base rock underlying the site.
2. Determination of the response of the embankment and foundation system to the postulated base motion, including evaluation of shear stresses induced within the embankment and within the foundation.
3. Representation of the induced shear stress time-history by an equivalent number of uniform shear stress applications.
4. Determination of embankment stresses under static conditions, i.e., before the occurrence of an earthquake.
5. Evaluation, by appropriate cyclic shear tests on representative samples, of the cyclic shear stresses required to cause failure or excessive deformation under the simulated earthquake loading conditions.
6. Comparison of the shear stresses required to cause failure or excessive deformation with the equivalent uniform shear stresses induced by the earthquake and assessment of the failure potential.

Each of the aforementioned operations are briefly discussed in the following sections.

2.5.6.5.6.2.1 Base Rock Motions

The base rock motions applied at the level of intact rock were derived from the plant site time history reflecting an SSE acceleration of 0.15g as shown by Figure 2.5-166. The time history used for the stability analysis of the Service Water Pond dams was chosen to correspond to a damping

of 10%, approximately the average damping expected within the earth embankments. The corresponding acceleration response spectrum is also shown in Figure 2.5-166.

It is noted that the maximum amplification factor of 2.0 is 33% greater than the 1.5 amplification recommended by Newmark and Hall (Reference 113) for 10% damping, reflecting an appreciable conservatism in the time history.

2.5.6.5.6.2.2 Response Analysis

Several representative sections of the proposed embankments and slopes were analyzed in detail for the postulated SSE motion using the dynamic finite element method of analysis (Reference 114, Reference 115). Response values for embankment and slope heights not specifically analyzed were obtained by appropriate interpolation and extrapolation. Response values during the postulated OBE motions were evaluated by appropriate interpolation using the results of the detailed analysis aided by the results of a shear slice method of analysis (Reference 116, Reference 117).

The method of analysis utilized a uniform earthquake input applied at the level of rock-like materials characterized by a shear wave velocity of at least 3000 feet per second. These materials were generally identified as a differentially weathered rock, sufficiently intact to enable at least partial core recovery. The width of the dam embankments was generally found to significantly exceed 1/4 of the length of the traveling shear wave, demonstrating the validity of the uniform base motion input.

As discussed in Sections 2.5.6.4.1.6 and 2.5.6.4.2.7, the shear moduli and damping representation of the embankment and foundation materials were obtained by means of field seismic wave velocity determinations and by laboratory cyclic torsion and cyclic shear tests. The results of these tests were used to establish appropriate relationships of modulus and damping versus shear strain. Damping ratios and shear moduli used for analysis of the Service Water Pond dams were expressed as a function of strain amplitude as shown by Figure 2.5-118.

From the response analysis, the time history of the dynamic shear stresses developed within the embankment and foundation materials was used to establish an equivalent number of uniform stress cycles. The results of this interpretation indicated that the SSE could be expressed in terms of 20 equivalent uniform cycles and the OBE could be expressed in terms of 10 equivalent uniform cycles.

The response of the dams and underlying foundation layers was evaluated using the finite element method of analysis (Reference 118) for a total of 5 dam sections. The finite element representation used for the maximum section of the North Dam is shown in Figure 2.5-167. The finite element mesh used to represent the maximum section of the South Dam is shown in Figure 2.5-168. Similar finite element representations were utilized for the other 3 dam sections. The foundation layer beneath all dams analyzed extended to the intact rock at the dam site.

The North Dam was considered to be underlain by a foundation layer consisting of weathered rock as shown by Figure 2.5-164. The South Dam was considered to be underlain by a layer of

colluvium and a layer of weathered rock as shown by Figure 2.5-165. As shown by the figure, the colluvium was removed during construction.

Only the horizontal component of the base motion was used in those response evaluations. The significant response value required to assess the stability of the dam is the shear stress developed during the earthquake along horizontal planes. Previous studies for dams (Reference 119) and for slopes (Reference 112) indicate that these shear stresses are not affected by the vertical component of base rock motion. Therefore, only the horizontal component was used in the present studies.

Shear stresses were computed throughout the embankment and underlying foundation layer for the duration of the applied base rock motion. These stresses were then converted to equivalent uniform shear stresses developed in 20 cycles during the ground motions using the procedure outlined by Seed and Idriss (Reference 120). The variation of these equivalent uniform stresses along the centerline axis of the dam, and for the 5 sections analyzed, are shown by Figure 2.5-169.

The values of equivalent uniform shear stresses developed in 20 cycles along 3 typical horizontal planes within the maximum section of the North Dam are presented by Figure 2.5-170. The results shown by this figure indicate that the maximum values occur in the vicinity of the center of the dam and that the stresses increase with depth.

Similar plots of stresses developed along 3 typical horizontal planes within the originally designed maximum section of the South Dam, an 80 foot high dam, 50 foot dam, and 30 foot dam are shown in Figures 2.5-171 through 2.5-174.

The computed equivalent uniform shear stresses have been used to evaluate the stability of the dams during the postulated earthquake motions.

2.5.6.5.6.2.3 Static Stress Analyses

The static stresses in the dams have been determined using static non-linear finite element procedures (Reference 118, Reference 121). The analyses were performed by incremental construction procedures which simulate the actual sequence of construction operations. Increments of stress for each step of the analyses, which simulate the placement of embankment fill material, were calculated and added to the values for the previous step. The values of normal stresses and shear stresses throughout the embankment were thus developed.

Values of typical static stresses computed for the normal operating (submerged) condition and for the end of construction condition (pond and reservoir empty) are presented by Figure 2.5-175. The top part of this figure shows the variation of effective normal stress along a horizontal plane for these 2 conditions. The values of effective normal stress are considerably smaller for the normal operating condition. The shear stresses along this plane (which are shown in the lower part of the figure) are somewhat lower for the normal operating condition.

The static normal effective stresses computed with the water at elevation 425' in the Service Water Pond while the reservoir is empty are presented by Figure 2.5-176 along a typical horizontal

plane. The stresses for steady-state seepage, for transient seepage, and the normal effective stresses for the normal operating condition are shown in this figure.

The results presented by Figures 2.5-175 and 2.5-176 indicate that the static normal effective stresses are lowest for the normal operating condition (i.e., water at elevation 425' in both the pond and the reservoir).

2.5.6.5.6.2.4 Analysis of Stability

The shearing resistance of the foundation and embankment systems developed during earthquake motions were evaluated by cyclic triaxial compression tests as described in Sections 2.5.6.4.1.5 and 2.5.6.4.2.6. The available shearing resistance was obtained for the appropriate number of stress cycles and the normal pressure on the prescribed plane of failure predicted by the response analysis. The factor of safety of the embankments and slopes against overstressing was subsequently expressed as a ratio of adjusted cyclic shearing resistance to the sum of the static and dynamic shearing stresses derived from the response analysis.

The factor of safety was calculated as the minimum ratio of shearing resistance to shear stress at any point within the embankment induced during the postulated earthquake. Acceptable minimum factors of safety under dynamic conditions are summarized as follows:

1. Normal operating conditions, water at elevation 425' in Service Water Pond and Monticello Reservoir:
   a. Minimum factor of safety, SSE, 1.1.
   b. Minimum factor of safety, OBE, 1.3.
2. Steady-state seepage conditions, water at elevation 425' in Service Water Pond and Monticello Reservoir:
   a. Minimum factor of safety, SSE, 1.1.
   b. Minimum factor of safety, OBE, 1.3.

The extreme conservatism of this method of expressing safety factors is apparent, considering that the “safety factor” expressed is representative of only a limited zone of stress within the embankment and foundation system. A very high degree of conservatism is also inherent in the level of strain adopted to express the failure of test samples during cyclic triaxial testing.

2.5.6.5.6.3 Analytical Results - Seismic Loading

Dynamic stability analyses using recently developed analytical techniques along with conservative design conditions as described in Section 2.5.6.5.6.2 were conducted for a variety of embankment heights and for foundation conditions selected to represent the most unfavorable supporting conditions. The results of these analyses demonstrate that all embankments will be stable under SSE conditions and will have safety factors which satisfy the minimum SSE and OBE requirements. The results of the dynamic stability analyses for the SSE earthquake are

presented in Table 2.5-62 as the minimum safety factors calculated at various horizontal sections within the earth embankment.

The results of the SSE analyses for the 67 foot South Dam, shown in Table 2.5-62, are also a very conservative representation of the stability of the most critical fill slope which can be defined along the West Embankment. The profile for the West Embankment is similar to that of the South Dam in that colluvial materials existed locally at the base of the fill and the maximum heights are similar.

Safety factors of the dams and the West Embankment during the OBE are greater than 1.5. As demonstrated by Table 2.5-62 and Figures 2.5-177 through 2.5-179, the lowest safety factors occur within the dam embankments at elevations which are a function of embankment height. The analyses also demonstrate that the amplification of base rock motions through the very dense decomposed rock is negligible for stratum thicknesses well in excess of those which are applicable to design conditions. For example, an amplification of less than 0.005g is indicated for a decomposed rock stratum thickness of approximately 40 feet at the North Dam. The greatest amplification effect was noted in the colluvium and saprolite horizons. However, the colluvial materials were removed from beneath the South Dam and the actual factor of safety is even greater than that indicated by the analysis which included the colluvial layer.

The calculated crest accelerations, summarized in Table 2.5-62, demonstrate a significant amplification of base rock motions through the dam embankments. Maximum values predicted for a 110 foot North Dam section, a 67 foot South Dam section, and a 30 foot East Dam section are 0.29g, 0.35g and 0.30g, respectively. In addition to the conservatism of the method of analysis previously cited, it is noted that a high degree of conservatism was also used in the selection of the dynamic material properties.

Due to undercutting and removal of marginal foundation soils, the as-built maximum heights for the North Dam, South Dam, and West Embankment are greater than anticipated in the original studies. Although the heights of dams analyzed are less than the as-built heights, the dynamic analyses show that there is no decrease in the factor of safety for dam heights greater than about 65 feet. This is illustrated by Table 2.5-62. Therefore, the minimum factor of safety for the Service Water Pond embankments under SSE conditions using the most probable values of the dynamic properties is 1.20.

2.5.6.5.7 Results of Dynamic Studies for Variation in Dynamic Material Properties

To assess the effects of possible variations in the dynamic properties of embankment material on the response and stability of the proposed dams, the following additional cases were analyzed:

1. Upper Bound on Probable Modulus Values

   The probable modulus values were increased by 30%.

2. Lower Bound on Probable Modulus Values

The probable modulus values were decreased by 30%.

3. Lower Bound on Probable Damping Values

   The probable damping values were decreased by 10%.

The effects of these variations were investigated for the maximum section of the South Dam. The effects of variations in modulus and damping values on the stability of the dam are illustrated by Figures 2.5-180 through 2.5-184. The failure potential along the center line using the upper bound on probable modulus values is illustrated by Figure 2.5-180. The failure potential using the lower bound on modulus values is shown by Figure 2.5-181. A summary of the effects of variations in modulus values on failure potential is presented by Figure 2.5-182. The lowest value of the minimum factor of safety (approximately 1.1) is obtained using the upper bound on probable modulus values. Thus, even with a more conservative selection of modulus values, the minimum factor of safety is at least 1.1, the minimum required.

The effect of using the lower bound on the damping value is illustrated by Figures 2.5-183 and 2.5-184. This variation in the damping value has very little effect on the factor of safety against overstressing.

To assess the effects of variation in the dynamic moduli of the colluvium and weathered rock on the response and the seismic stability of the dams, the maximum sections of the South Dam and the North Dam were re-analyzed in detail. The foundation of the South Dam was considered to consist of a layer of colluvium overlying weathered rock although this colluvium was later removed during construction. The North Dam is founded on weathered rock. For the colluvium, the upper and lower bounds of modulus values were used. For the weathered rock, a reasonably conservative lower bound value was chosen but the measured upper bound value was not used. Instead, a value twice that used in the previous analyses was chosen for the upper bound in the present case. (It should be noted that the use of the measured upper bound modulus value for weathered rock would make this layer behave essentially as intact rock, i.e., the motions transmitted through this layer would be exactly those imposed at the base of the dam-foundation systems.)

For ease of reference, each case is designated either by S-MAX (for the maximum section of the South Dam) or N-MAX (for the maximum section of the North Dam) followed by a Roman numeral I, II, or III. The designation I represents the probable material properties in the foundation layers, II represents the lower bound values, and III represents the upper bound values. A summary of all the cases studied is provided in Table 2.5-63 where the maximum shear modulus parameter, $(K_2)_{max}$, is listed for each case. The results of the additional cases studied are summarized by Figures 2.5-185 and 2.5-186 for the South Dam and North Dam, respectively.

The effects of variations in the dynamic moduli of the colluvium and weathered rock on the response and seismic stability of the proposed earth dams were evaluated and the results of this evaluation led to the following basic conclusions:

1. Use of probable modulus values for the foundation layers provides a reasonable conservative basis for the assessment of the seismic stability of the South Dam; the least values of the factor of safety are obtained for this case (see Figure 2.5-184).
2. Variations in the modulus of the weathered rock have essentially no effect on the factor of safety in the North Dam embankment (see Figure 2.5-186).

Therefore, variations (within a reasonably wide range) in the modulus values of the foundation layers do not significantly affect either the response or the seismic stability of the proposed earth dams. The available data regarding the shear wave velocities in the colluvium and in the weathered rock are sufficient to define a conservative estimate of the probable modulus values in these layers.

2.5.6.5.8 Liquefaction Potential at West Embankment Structures

Three (3) structures, described in Sections 3.8.4 and 3.8.5, are founded within the West Embankment. These structures are the Service Water Pumphouse, Service Water intake structure, and Service Water discharge structure. The influence of these structures on the dynamic stability analyses described in the previous sections is discussed in the following paragraphs.

The dynamic stability (liquefaction) analysis demonstrates that the West Embankment fill at the Service Water Pumphouse location is not subject to excessive strain as a result of ground motions produced by the SSE. Maximum strains during the SSE are expected to be limited to a small zone within the soil mass beneath this structure. In this zone, the predicted strains are less than 5%, consistent with a minimum stress ratio (cyclic strength to cyclic stress) of 1.1. This stress ratio is derived from a limiting 5% strain criterion for the embankment fill materials. There are several conservatisms inherent in the analysis. The most significant include an artificial time history with a 10 second duration of strong motion and an extremely conservative content of near peak amplitudes over a broad frequency band. A more realistic design spectra with about 6 seconds of strong motion (Reference 122) would be expected to appreciably reduce the peak strain level prediction. Therefore, consistent with the conservative nature of the analysis, soil-structure interaction effects at the Service Water Pumphouse location have not been considered.

The order of magnitude of peak strain induced at the Service Water Pumphouse end of the Service Water intake structure is expected to be as described for the Service Water Pumphouse. Because of the position of the Service Water intake structure within the embankment, the expected strain level induced in the fill tends to decrease in the direction toward the Service Water Pond along the structure alignment. Therefore, soil-structure interaction effects on the dynamic stability of the fill supporting the structure are not considered to be significant.

The Service Water discharge structure is founded on very dense decomposed rock which is characterized by standard penetration resistances generally in excess of 100 blows/foot. In its intact state, the decomposed rock is essentially incompressible and mobilizes very high resistance to shear deformation. It is therefore concluded that the foundation materials beneath the Service Water discharge structure are not subject to liquefaction and will experience only very small deformations during ground motions imposed by the SSE.

2.5.6.6 Seepage Control

2.5.6.6.1 General

The permeability of the foundation materials for the Service Water Pond embankments was investigated by in situ permeability tests, as described in Section 2.5.6.2, and by laboratory tests on relatively undisturbed samples of foundation materials, as described in Section 2.5.6.4. The results of these tests are presented by Table 2.5-27. Additional field permeability testing was performed during construction of the grout curtain along the centerline of the North Dam (see Section 2.5.6.6.7). The results of these tests are presented in Table 2.5-64.

During the original design analysis, laboratory permeability tests were performed on compacted samples of the proposed onsite borrow materials. Since very little of this material was utilized in construction of the dams, the associated test data are no longer applicable and are not presented herein. Subsequent testing was performed on compacted samples from Borrow Sources F and G, as presented by Figure 2.5-125, and verification permeability tests were performed on relatively undisturbed block samples removed from the compacted embankments during construction, as presented by Figures 2.5-157 and 2.5-158.

The coefficients of permeability obtained for the foundation materials in the North Dam valley during the grout curtain construction are significantly higher than those obtained in the preconstruction design studies. The coefficients of permeability obtained for the embankments, constructed of soils from Borrow Sources F and G, are also significantly higher than those obtained for the previously proposed onsite borrow soils. Because of these significant increases in the coefficients of permeability, the potential seepage losses from the Service Water Pond have been re-analyzed as described in the following sections.

2.5.6.6.2 Permeability of Foundation and Embankment Soils

Based upon the amplified test data, the North Dam was divided into 4 permeability zones for purposes of re-analyzing seepage. These zones consist of upper and lower foundation zones in the valley (centerline stations 7+00 to 13+00) and homogeneous abutment zones. Based upon the data in Table 2.5-64, a coefficient of permeability of 1.0×10^{-3} cm/sec was chosen to represent the foundation material in the valley above elevation 260.0'. This compares to a coefficient of permeability of 3.2×10^{-5} cm/sec used for the North Dam foundation in the original analysis of underseepage. Below elevation 260.0', the original value was used. The average of the additional tests in the abutments is 3.6×10^{-5} cm/sec, very similar to the original design value of 3.2×10^{-5} cm/sec. A coefficient of permeability of 3.6×10^{-5} cm/sec was used for each abutment in the re-analysis. Conservatively, the reduction in permeability resulting from the installation of the North Dam grout curtain was disregarded for purposes of the analysis.

For re-analysis of the South Dam, the coefficients of permeability chosen for the South Dam foundation were based upon the test data for that location, rather than the average of the permeabilities for the entire Service Water Pond, used in the original analysis. Thus, coefficients of permeability of 2.9×10^{-4} cm/sec and 4.2×10^{-5} cm/sec were used above and below elevation

325', respectively. Also, the permeabilities in the abutments were conservatively assumed to be the same as in the valley, although the test data indicates that the abutments are less pervious.

Based upon the data obtained from the laboratory compacted samples from Borrow Sources F and G and the verification test data on block samples, the design coefficients of permeability for the compacted embankment material have been revised to 2.0×10^{-5} cm/sec, compared to the original design values of 1.0×10^{-6} cm/sec and 1.0×10^{-7} cm/sec in the horizontal and vertical directions, respectively. Analysis of the test data from the block samples does not indicate any significant difference between the horizontal and vertical permeabilities.

The coefficients of permeability used in both the original analyses and the re-analyses are compared in Table 2.5-65.

2.5.6.6.3 Analysis of Seepage Loss

For the most critical seepage loss case, i.e., a postulated sudden loss of Monticello Reservoir, the primary flow paths from the Service Water Pond would be through and under the North and South Dams. Seepage from the east and west sides of the Service Water Pond is considered to be negligible because of the combination of much longer flow paths and the lower permeability of the residual soils which mantle these areas.

The seepage losses at the North and South Dams were computed by considering the embankments and their foundations separately. The definitions of the geometric parameters in the equations of this section are shown schematically in Figure 2.5-187.

Seepage through the embankments was computed using the method of Kozeny as presented by Harr (Reference 111). The seepage quantity is determined from the equation:

$$q = k\left[\left(d^2 + h^2\right)^{1/2} - d\right] \qquad (1)$$

Where:

q = Seepage quantity per unit width.

k = Coefficient of permeability.

d = Distance from seepage entrance to horizontal drain.

h = Head of upstream reservoir.

Where:

Q = Total seepage quantity.

i = Seepage gradient (h/b).

A = Area of flow.

Underseepage at the North Dam was computed in 2 parts. For the upper, more pervious foundation zone, equation (2) was used, where the length, b, was taken as the total length from toe to heel of the embankment. For the lower foundation zone, the following equations derived by Pavlovsky (Reference 111) for underseepage through a stratum of finite thickness were used:

$$q = \frac{khK'(\beta)}{2K(\beta)} \qquad (4a)$$

$$\beta = \tanh\left(\frac{\pi b}{4T}\right) \qquad (4b)$$

Where:

q = Seepage quantity per unit width.

k = Coefficient of permeability.

h = Unbalanced head.

K (β) = Complete elliptic integral of the first kind with modulus ß.

K' (β) = Complementary complete elliptic integral of the first kind with modulus ß.

T = Thickness of pervious zone.

b = Width of structure.

It may be noted that equation (4a) converges with equation (2) when the ratio T/b becomes small. The maximum depth of flow was conservatively taken to be 750 feet which corresponds to the approximate radius of the Service Water Pond.

For underseepage through the upper pervious zone at the South Dam, where a clay blanket was constructed as described in Section 2.5.6.4.3.5, the Corps of Engineers blanket formulae (Reference 123) were used:

For the portions of the embankments below the elevation of the horizontal drains, the following equation was conservatively used:

$$q = khT/b \qquad (2)$$

Where:

q = Seepage quantity per unit width.

k = Coefficient of permeability.

h = Unbalanced head.

T = Thickness of embankment below elevation of horizontal drain.

b = Distance from upstream slope to center of horizontal drain.

Equation (2) is based upon the fundamental relationship:

$$Q = kiA \qquad (3)$$

Where:

Where:

Q = Total seepage quantity.

i = Seepage gradient (h/b).

A = Area of flow.

Underseepage at the North Dam was computed in 2 parts. For the upper, more pervious foundation zone, equation (2) was used, where the length, b, was taken as the total length from toe to heel of the embankment. For the lower foundation zone, the following equations derived by Pavlovsky (Reference 111) for underseepage through a stratum of finite thickness were used:

$$q = \frac{khK'(\beta)}{2K(\beta)} \qquad (4a)$$

$$\beta = \tanh\left(\frac{\pi b}{4T}\right) \qquad (4b)$$

Where:

q = Seepage quantity per unit width.

k = Coefficient of permeability.

h = Unbalanced head.

K (β) = Complete elliptic integral of the first kind with modulus ß.

K' (β) = Complementary complete elliptic integral of the first kind with modulus ß.

T = Thickness of pervious zone.

b = Width of structure.

It may be noted that equation (4a) converges with equation (2) when the ratio T/b becomes small. The maximum depth of flow was conservatively taken to be 750 feet which corresponds to the approximate radius of the Service Water Pond.

For underseepage through the upper pervious zone at the South Dam, where a clay blanket was constructed as described in Section 2.5.6.4.3.5, the Corps of Engineers blanket formulae (Reference 123) were used:

$$q = k_f h \left(\frac{d}{x_1 + L_2} \right) \quad (5a)$$

$$x_1 = \frac{\tanh(cL_1)}{c} \quad (5b)$$

$$c = \left(\frac{K_b}{k_f Z_b d} \right)^{1/2} \quad (5c)$$

Where:

q = Seepage quantity per unit width.

k_f = Coefficient of permeability of foundation.

K_b = Coefficient of permeability of blanket.

h = Unbalanced head.

Z_b = Blanket thickness.

d = Thickness of pervious zone in foundation.

L_1 = Blanket length.

L_2 = Length from heel to toe of dam.

To determine the underseepage through the less pervious zone beneath the South Dam to a depth of 750 feet, Equations (4a) and (4b) were used, conservatively neglecting any effect of the upstream clay blanket.

To determine the total quantity of seepage at the North and South Dams, each dam and its foundation was divided into a number of small vertical sections (perpendicular to the axis of the dam) and the seepage for each section was computed using the appropriate geometric parameters. The total seepage was then found as the sum of the seepage at each section. The results, based upon a Service Water Pond elevation of 425.0', are summarized as follows:

1. North Dam embankment	666 ft^3/day
2. North Dam foundation	11,877 ft^3/day
3. South Dam embankment	168 ft^3/day
4. South Dam foundation	1,065 ft^3/day
5. Total	13,776 ft^3/day

For a pond surface area of 44 acres, a seepage loss of 13,776 ft^3/day represents a loss of 2.6 inches of water from the pond during the design period of 1 month. In the original analysis, performed prior to addition of the clay blanket, the computed loss was less than 1 inch for the 1 month period and it was conservatively stated that it was not expected to exceed 3 inches. The most recent analysis, which considered the clay blanket, resulted in a computed loss of 2.6 inches. This increase in computed loss from less than 1 inch to 2.6 inches is due to the higher than anticipated permeability for the as-built embankment fill and the higher than previously measured permeability of the foundation in conjunction with the partially offsetting effect of the South Dam clay blanket.

2.5.6.6.4 High Permeability Zone

A zone of high permeability was encountered in fractured rock in Boring ND-13, as shown in Table 2.5-27. The permeability of this zone was estimated to be 1 x 10^{-2} cm/sec. Other test borings in the area indicated that this zone was localized and not continuous in extent. However, to investigate an extreme upper limit of seepage loss, a zone of comparatively high permeability within fractured and jointed rock was postulated to exist within the east abutment of the North Dam. As shown by Table 2.5-188, a 10 foot thick, 100 foot wide, highly pervious zone, overlain by a natural blanket of 15 feet of less pervious natural soil was conservatively assumed. The seepage loss for this condition would amount to about 0.4 inches of water from the Service Water Pond in a 1 month period. Table 2.5-188 was developed from Corps of Engineers blanket equations (Reference 123). It is concluded, therefore, that, if such a pervious zone should exist and has not been effectively sealed by grouting, a total seepage loss from the Service Water Pond (including the loss computed in Section 2.5.6.6.3) of about 3 inches could be realized but not appreciably exceeded over an operating period of 1 month.

2.5.6.6.5 Potential for Piping Failure by Underseepage

It was postulated during the construction permit review phase of this project that failure of the Service Water Pond dams might occur by piping through a hydraulically continuous channel existing within the occasionally fractured and jointed surficial zone of the bedrock. It was noted that possible evidence of this potential in the vicinity of the North Dam was given by the existence of 2 intermittently flowing springs and of seeps observed in slope bench cuts. It was concluded, however, that the Service Water Pond dams are not subject to failure of this type for the reasons summarized in the following paragraphs.

Two (2) natural springs and seeps in 3 bench cuts, cited as evidence of a possible groundwater flow through the surficial rock zone, were approximately located as shown by Figure 2.5-189. The stratification interpolated from nearby borings, summarized in Table 2.5-66, shows the overburden at spring No. 1, spring No. 2, and bench cut locations is 21, 61, and 30 feet thick, respectively. The springs were noted to occur near topographic lows, to be flowing intermittently, and to be active only during and after periods of precipitation. The seepage in the bench cuts was observed to issue from relatively porous strata underlain by relatively impervious materials, as shown by Figure 2.5-190. This seepage decreased with time and eventually stopped. This evidence indicates that the groundwater in the Service Water Pond area existed as a perched system, including a seasonally variable, near-surface water level confined within the relatively permeable saprolite or topsoil zones by underlying, relatively impervious, decomposed rock. The near-surface groundwater movement emerged at the lower elevations of the site as intermittent springs.

The test borings drilled within the Service Water Pond area demonstrate that relatively impervious overburden materials exist throughout the area of study. The thickness of these materials ranges from 20 feet to more than 160 feet. Consistent with the residual soil development process and the boring data, a detailed surface reconnaissance of the reservoir and downstream area of the Service Water Pond did not reveal either intact or broken and fractured rock outcrops within the area of interest. The effect of this overburden is to provide a natural blanket which inhibits rapid downward seepage to the rock system. The head loss and associated slow rate of seepage through the overburden blanket and then beneath the dam embankment through a hypothetical pervious layer is demonstrated by the underseepage analysis presented in Section 2.5.6.6.4. The effect of the overburden blanket also prevents a direct hydraulic connection between the reservoir and any postulated pervious zone within the rock.

The dense decomposed rock which comprises the foundation material beneath the dams is highly resistant to piping due to its relatively high in situ shear strength. In addition, Sherard (Reference 124) reports that piping of foundation soils is most likely to occur where the surface of the foundation soil is cohesionless. The decomposed rock, however, is mantled by a layer of saprolite, as described inSection 2.5.6.2.4. This saprolite, being generally dense and having an average plasticity index of 6, would be expected to provide a relatively high degree of piping protection for the underlying decomposed rock.

A full scale seepage test was performed during the initial filling of Monticello Reservoir, as described inSection 2.5.6.6.8. This test demonstrated the resistance to piping of foundation soils

underlying the dams. Seepage into the Service Water Pond primarily entered the monitoring basin below the basin water level and was locally visible below water level near the perimeter of the basin. Several small concentrated seeps and trickling flows were observed immediately adjacent to the monitoring basin and a few springs were observed in other portions of the Service Water Pond. The concentrated seeps had the visual appearance of miniature boils, with diameters ranging from about 1/2 to 3 inches, and heights of less than 1 inch. The trickling flows did not have distinct points of origin.

Many of the concentrated seeps and trickling flows were probably induced by lowering of the monitoring basin by pumping after heavy rainfalls to maintain the volume of the basin within calibration limits. Other seeps were apparently the result of the anticipated general rise of the groundwater level within the Service Water Pond area due to the filling of Monticello Reservoir. The concentrated seeps occurred in the bottom of the Service Water Pond where the surficial soil consisted of disturbed and loosened saprolite or loose soil debris from construction activities. After establishment, the concentrated seeps were essentially stable in size, although the flow quantities fluctuated, and the discharge water was clear. This provided confirmation that progressive piping was not occurring within the confined, dense saprolite soil and decomposed rock comprising the foundations of the dams.

Inspection of the Service Water Pond dams will also be conducted should draining of Monticello Reservoir occur. If any potentially detrimental downstream seepage emergence is observed, immediate remedial measures will be taken to prevent piping. Such measures would include diking of seeps or boils followed by placement of filter blankets designed as inverted filters. Sherard (Reference 124) has described several case histories of dams which have developed downstream seeps or boils for which the time interval after initial detection of piping was adequate for remedial measures to be taken to prevent failure, even where the subsoils consisted of relatively pervious alluvium. Thus, in the unlikely event that piping should occur, there would be adequate time to take remedial action.

2.5.6.6.6 Internal Drainage

The North and South Dams are provided with horizontal blankets and trapezoidal toe drains to relieve seepage pressures in the event of complete drawdown of Monticello Reservoir. The configuration of these features is discussed in Section 2.5.6.4.3.3. The horizontal drains are designed to pass the computed seepage quantities without causing excessive hydrostatic pressures within the embankment.

2.5.6.6.7 North Dam Grout Curtain

During the design review by the AEC (currently NRC) the AEC concluded that a grout curtain should be installed along the centerline of the foundation for the North Dam. The purpose of this grout curtain would be to minimize the possibility of significant underseepage losses during emergency shutdown conditions due to the postulated loss of Monticello Reservoir. The requirement for the subsurface grout curtain is contained in the AEC letter of March 1, 1973, from Messrs. Scinto and Conner to Messrs. Head, McCollom and Lyman.

A single-line grout curtain over 1300 feet long was installed along the centerline of the North Dam, as shown by Figure 2.5-191. An auxiliary line was grouted on either side of the centerline between stations 11+61 and 12+11 to obtain a triple-line curtain where the highest permeabilities were encountered. The grout curtain extends approximately 55 feet and 45 feet beneath the foundation and the core abutments, respectively. Grout holes are spaced 2.5 feet on centers in the valley bottom where the hydraulic head of the Service Water Pond is greatest. Grout holes on the abutments are typically 10 feet apart with closer spacings locally. Grouting characteristics of angle holes, drilled in the plane of the grout curtain after construction of the curtain, confirm a significant reduction in permeability along the grout line.

The following sections describe the general grouting preparations, materials, and procedures used.

2.5.6.6.7.1 Site Preparation and Preliminary Testing

The grout curtain work area was prepared by removing the existing soft alluvial deposits and organic waste materials from the valley bottom, located approximately between Stations 8+51 through 10+71, and replacing this zone with a temporary working pad composed of compacted silty clays derived from adjacent near surface soils. The east and west abutments were stripped to suitable foundation materials that ranged from 6 inches to 24 inches deep in the higher elevations and from 2 feet to approximately 6 feet deep on the lower side slopes.

Prior to commencing the grouting, 2 test borings were drilled and logged at centerline stations 6+19 and 9+48 to verify the anticipated stratification of subsurface materials and to permit field comparisons between subsurface samples and earlier descriptions. The logs of these borings, designated ND-27 and ND-28 appear in Appendix 2F. During the grouting program, 2 more confirmatory borings were drilled at Stations 14+41 and 16+21. Their logs, designated ND-29 and ND-30, appear in Appendix 2F. These test borings were advanced by a truck mounted, rotary earth and rock drill.

Prior to grouting, and at select locations during grouting, water pressure tests were performed to obtain additional information about the permeability characteristics of the foundation materials and to aid in determining the initial grout mixes and pressures. The water pressure tests were performed utilizing driven and grouted steel casing, as shown by Figure 2.5-192.

Pressure tests were performed by pumping water into a bore hole until the pumping pressure began to increase. Excess air was then removed from the top of the hole and the hole was sealed and allowed to stabilize at a designated pressure and flow rate. At this point, the rate of water consumption was recorded at 1 minute intervals for a period of 5 minutes. In most cases, the pressure was then increased and the readings repeated to develop a graph of pressure versus flow rate. The pressure at which the flow rate exhibited a marked increase was considered the threshold pressure, above which grout leakage or damage to the foundation might occur. Threshold pressures ranged from about 20 to 40 psig. Tests of flow rates at specified pressures were made at several locations to verify the continuity of the foundation materials. Values of the coefficients of permeability for the foundation materials determined by these tests are summarized in Table 2.5-64.

2.5.6.6.7.2 Materials and Equipment

Type II cement, conforming to ASTM C 150-72, was used. Mixing water equaled the water quality for the production of safety class concrete. Sand, used on occasion in thicker mixes, was predominantly silica sand having a uniformity coefficient less than 6.

Grout mixes used for this work are defined as the ratio of cubic feet of water to sacks of cement for a standard 94 pound cement sack. In general, if water pressure tests indicated a relatively impermeable hole, grouting was started with a thin mix. For a hole which indicated high permeability, grouting was usually started with a thick mix adjusted as grouting proceeded. Typically, a neat Portland cement was used and sanded mixes were used under conditions of high grout take. The thinnest mix consisted of 7 cubic feet of water with 1 sack of cement, a 7 to 1 mix. The thickest grout used was 1 to 1. The sandiest mix used in this work was 3 cubic feet of sand to 5 sacks of cement for a 1 to 1 mix.

The circulating grout system consisted of Wagner DA32 double tub mixer, Wagner AH-36 agitator holding tub, Moyno 3L6 progressive cavity grout pumps and assorted gauges, valves, piping and tubes. A schematic diagram of the system is presented by Figure 2.5-193. All grout holes were approximately 2.5 inches in diameter and were drilled with an Atlas Copco Air Track Drill, Model R0C601, modified to use air and/or water as the drilling fluid. Water was used to advance drill holes, and air and/or water was used to clean holes once the designated depth was achieved. Steel grout casings, 2-1/2 inch ID, were installed in the valley bottom and sealed with a 1 to 1 grout mix. The casings were seated at least 5 feet and, typically, 7 feet into the foundation materials to minimize the possibility of flow to the surface during water pressure testing and grouting operations. After completing the grout curtain, these casings were undercut and removed between Stations 7+50 and 11+50.

2.5.6.6.7.3 Grouting Procedures

A split spacing method was used wherein primary holes located 40 feet apart were initially drilled and grouted. These were followed by secondary holes midway between the primary holes, and then tertiary holes at the remaining midpoints so that a 10 foot spacing was attained. As a conservative measure, 4th order (quarternary) and fifth order (quinary) holes were employed to attain a 2.5 foot spacing in the valley bottom, where the Service Water Pond hydraulic head is greatest. Also, quarternary and quinary grout holes were employed locally along the abutments where isolated zones of higher permeability were indicated.

Applicable grouting pressures were determined from water tests, supplemented by information from hole drilling and grouting characteristics as grouting operations progressed. Grouting pressures were maintained below 1 psig per foot of depth and generally were about 70 to 85% of threshold pressures determined from water pressure tests.

The grouting was performed through the surface casing seated 5 feet or more into the foundation and grouted in place. Where foundation conditions permitted, grout holes were drilled to final depth and grouted in a single stage. Otherwise, 2 or 3 stages were required. Single stage holes predominated on the abutments and multiple stage holes predominated in the valley.

Occasional leaks of grout at the ground surface were stopped, typically, by reducing the grouting pressure while continuing the grout injection, and then gradually increasing the pressure to the desired magnitude. In some instances, leakage was stopped by thickening the grout mix. In other instances, the grout was allowed to set for a short period after which the hole was cleaned and regrouted.

On the abutments 2 or 3 holes were typically grouted simultaneously, immediately after injecting initial quantities of grout in individual holes to attain comparative grout pressures. In the valley, this multiple grouting procedure was restricted to areas of higher permeability.

The grouting of any hole utilizing a mix of 3 to 1 or thicker continued until the hole refused to take grout at the maximum allowable pressure. For mixes thinner than 3 to 1, grouting continued until the rate declined to less than 1 cubic foot of grout mixture in 20 minutes for pressures up to 50 psig and 1 cubic foot in 15 minutes for pressures greater than 50 psig. In addition, quarternary holes were conservatively employed where more than 0.3 sacks of cement per linear foot of grout hole were utilized for the last stage in tertiary holes. The quarternary holes were drilled on either side of such a tertiary hole and were grouted to meet the 0.3 sacks per linear foot criterion, except where leakage to the ground surface occurred.

During the drilling of holes 11+86P and 11+76T, substantial hole caving and loss of drilling water occurred, indicating high permeability and the possibility of high grout takes. This was confirmed when the holes were grouted and the takes for the upper stages were 340 and 114 sacks of cement at 0.0 pump pressure, respectively. A triple grout line with staggered holes on either side of the centerline was then installed at this location. After drilling and logging holes on both the north and south sides of the centerline, each hole was evaluated to determine the lateral extent of the area of higher permeability. Once the area was delineated, grouting proceeded on the north and south lines to construct curtains to contain the grout in the centerline holes. After completion of the north and south grout lines, the centerline was grouted successfully. To determine the effectiveness of the triple grout line, an angle hole (11+51) was drilled and grouted across the area. The lack of caving of the inclined hole and limited amount of grout injected confirmed the effectiveness of the triple line grouting. The triple line segment of the grout curtain is shown by Figure 2.5-194, Sheet 9.

Angle holes were drilled and grouted at 4 additional locations in the single line curtain, as shown by Figure 2.5-194. Their drilling and grouting characteristics and low grout takes verified that significant reductions in permeability were attained.

2.5.6.6.8 Service Water Pond Seepage Test

A full scale field seepage test was performed that demonstrated the relative imperviousness of the North Dam, East Dam, South Dam, West Embankment, the dam, and embankment foundations and the Service Water Pond bottom. The test was performed during initial filling of Monticello Reservoir by preventing a corresponding filling of the Service Water Pond. The reservoir was filled to elevation 424' while flow was prevented from entering the Service Water Pond through the interconnecting pipe. Excess water due to rainfall and construction site discharges was removed from the Service Water Pond by pumps. This arrangement provided for a reverse

seepage test, indicative of water-tightness expected for a postulated loss of Monticello Reservoir, wherein water would seep from the Service Water Pond.

Seepage monitoring was performed daily from October 6, 1977, to February 22, 1978. Measurements were begun 58 days prior to initiation of the filling of Monticello Reservoir and continued 14 days after the reservoir level reached elevation 424', which is within 1 foot of the maximum operating reservoir elevation of 425'. Seepage into the Service Water Pond under maximum differential head was significantly less than the calculated amount, indicating conservatism in previous analyses.

1. Monitoring Methods

   A monitoring basin was constructed in the bottom of the Service Water Pond. This basin was mapped by an aerial topographic survey.

   The elevation of the water surface in the basin was measured daily. The corresponding volume of water was determined using planimetered measurements of the topographic map of the basin. Seepage rates were calculated by dividing the daily incremental volumes by the corresponding lapsed time.

   Weather instruments were installed at the Service Water Pond to assist in evaluating rainfall, inflow and evaporation losses. These instruments consisted of an anemometer, rain gage, maximum-minimum thermometer and a present temperature thermometer. These instruments were read in conjunction with evaporation pan measurements, for the entire monitoring program.

2. Results

   Weather and evaporation pan data indicated negligible evaporation losses in the monitoring basin and no corrections to measured water elevations were required. Average flow rates and corresponding water levels in the Service Water Pond and Monticello Reservoir are shown in Figure 2.5-194a.

   To determine the seepage rate induced by filling of Monticello Reservoir, it was first necessary to determine the rate of seepage under pre-existing conditions. The pre-existing, or baseline seepage rate is graphically distinguished from rainfall and construction site discharges in Figure 2.5-194a and is approximately 8 gpm.

   For the last 14 days of the testing program, Monticello Reservoir was within approximately 1 foot of its maximum operating level. The average seepage rate for this period was approximately 25 gpm. By subtracting the 8 gpm baseline seepage, a net of approximately 17 gpm is obtained for seepage induced by filling the reservoir. This value is about 20% of the combination of seepage rates estimated in Sections 2.5.6.6.3 and 2.5.6.6.4. Therefore, the total water loss from the Service Water Pond due to a postulated loss of Monticello Reservoir would be well within the limits discussed in Section 2.4.8.1.2.

A stability analysis was performed for the reverse seepage case in the same manner as described in Section 2.5.6.5, except that the actual piezometric levels measured on February 23, 1978, were used as shown in Figure 2.5-197. The resulting factor of safety found was 1.45 compared to the previous result of 1.35 which assumed steady state reverse seepage conditions, and as compared to the project design criterion of 1.30.

3. Observed Seepage

During the monitoring program, isolated seepage was observed at scattered locations at the valley bottom and lower portions of natural slopes within the Service Water Pond. Much of the inflow apparently was into the bottom of the monitoring basin, which occupied the lowest elevation in the Service Water Pond, and was not visible due to water collected in the basin. No seepage was observed from the slopes of the 3 dams or the west embankment.

Piezometers installed in the North Dam as shown in Figure 2.5-195 and Table 2.5-66a reflected the filling of Monticello Reservoir; as expected, steady-state seepage conditions were not attained.

Water levels measured in each piezometer are shown by Figure 2.5-194a.

2.5.6.7 Diversion and Closure

The construction of the North Dam closed a natural valley, containing a small northward flowing stream, to create the Service Water Pond. The East Dam closes a natural saddle to prevent the outflow of the impounded water. The West Embankment constitutes a filling of low ground on the west side of the Service Water Pond up to the general plant site grade. The South Dam closes the uppermost portion of the valley. Surface water runoff from the southern headlands of the valley to the south are diverted by the South Dam through the discharge canal and into Monticello Reservoir as shown in Figure 2.5-91. The only connection between the Service Water Pond and Monticello Reservoir is the interconnecting pipe discussed in Section 9.2. The methods and procedures used to handle the limited seepage and runoff of rainfall in the Service Water Pond area during construction are discussed in the following paragraphs.

The Service Water Pond site was generally well drained before construction, with all flow trending northward through the natural valley which is now closed off by the construction of the North Dam. The main drainage features were 2 small streams which originated in the area of the South Dam and West Embankment. These streams converged near the south toe of the North Dam forming 1 stream which flowed northward into Frees Creek. Both streams were fed by small springs and side hill seeps. Prior to construction, a dry season flow of these combined streams was measured with a sharp crested “V”-notch weir and was found to be less than 15 gpm which indicates the low order of magnitude of flow in the valley.

Diversion of surface runoff and closure of the North Dam, South Dam and West Embankment were performed by constructing sumps to collect and discharge the water by pumping from the Service Water Pond area and by dry packing small seeps with dry Type II cement. Detailed descriptions of the techniques employed to divert or stop this flow, permitting placement of fill

under dry conditions, are discussed in Section 2.5.6.3. The East Dam is situated on higher terrain and is not influenced by seeps or springs.

During the foundation preparation phases and throughout fill placement, rainfall runoff was controlled by a series of side hill interceptor ditches. These ditches were constructed on the natural side hill slopes and dam abutments just above the fill elevations. Ditches at progressively higher elevations were constructed as the fill height increased.

2.5.6.8 Instrumentation

2.5.6.8.1 Settlement and Alignment Monitoring

Instrumentation is installed in the North and South Dams to measure post construction crest settlement and horizontal movement. The monuments are positioned at intervals of 100 feet along the dam crests as shown by Figures 2.5-195 and 2.5-195b. Monuments are installed as shown by Figure 2.5-194.

Vertical and horizontal movements measured from time of installation in December, 1977, through April, 1980, are listed in Tables 2.5-66b through 2.5-66e. This period included filling of Monticello Reservoir and the Service Water Pond. Measurements were made several times a week during filling of Monticello Reservoir and the Service Water Pond. However, since the rate of movement was extremely slow, the measurements listed in Tables 2.5-66b through 2.5-66e were selected at approximately 10 day intervals. These measurements indicate that maximum post construction settlement of the North Dam was less than 1 inch and that the North Dam is now experiencing rebound due to buoyancy. The maximum rebound to date is about 1.5 inches. Settlement of the South Dam was negligible and maximum rebound of this structure has been about 1.9 inches to date. Maximum net horizontal movements of the North Dam are about 1.5 inches, to date, except for 2 monuments which were probably disturbed by construction activities. This disturbance is indicated by the fact that the large movements (about 2 to 4 inches) occurred suddenly and that the monuments then became relatively stable again. Also, the affected monuments were scattered along the dam crest and each is surrounded by monuments showing small movements. Maximum horizontal movements of the South Dam are less than 1/2 inch to date.

Settlement of the monuments closest to the maximum sections of the North and South Dams in relation to filling of Monticello Reservoir and the Service Water Pond is shown by Figure 2.5-196a. The measured piezometric levels in the North Dam crest piezometers (described in Section 2.5.6.8.2) are also shown in Figure 2.5-196a.

Settlement and alignment of the dams will be monitored throughout the operating life of the plant. Monitoring frequency will be in accordance with approved procedures.

2.5.6.8.2 Piezometers

A series of 4 piezometers are installed at each of 3 cross-sections of the North Dam (Stations 8+00, 10+00, and 12+50) as listed in Table 2.5-66a and shown in plan by Figure 2.5-194 and in a

typical profile in Figure 2.5-98. All piezometers are conventional well point stand pipe piezometers as shown by Figure 2.5-194. The piezometers located on the crest of the North Dam and on the Service Water Pond side of the dam were used to monitor the transient phreatic water level within the dam during the reverse testing of the Service Water Pond (see Section 2.5.6.6.8). After the reverse testing was completed, the Service Water Pond side piezometers were inundated by the filling of the pond. The piezometers on the crest of the dam were monitored until the phreatic levels of the piezometer locations stabilized at approximately the water level on both sides of the dam.

Six (6) Casagrande type piezometers have been installed in the vicinity of the Service Water Pumphouse as shown by Figure 2.5-197a. These piezometers were monitored until the groundwater level stabilized. A surface elevation monument was also installed adjacent to each piezometer.

The piezometers located on the Monticello Reservoir side of the dam (over the horizontal drainage blanket) are installed primarily to monitor the phreatic surface near the toe of the North Dam in the event that Monticello Reservoir is emptied. The dams have been designed for the most critical seepage condition which can be postulated, the sudden drawdown condition discussed in Section 2.5.6.5. It is considered desirable, nonetheless, to have these piezometers in place so that the phreatic level above the toe drain can be monitored in the unlikely event that the reservoir is emptied or its level drastically lowered.

The phreatic levels are expected to decrease with time after a sudden drawdown of reservoir level, to a level approaching the reduced reservoir level. In the event that the phreatic level does not decline significantly, the Monticello Reservoir slope of the North Dam would be carefully examined for any evidence of excessive seepage or surface slumping which would be indicative of slope instability. If any detrimental conditions are observed, corrective measures, such as constructing a downstream berm, will be implemented.

The plant procedures for the Virgil C. Summer Nuclear Station include monitoring the Monticello Reservoir side piezometers in the event that the reservoir level should recede below the tops of the piezometers. These piezometers will be monitored until it is determined that an essentially steady-state or a noncritical condition has been obtained. The piezometers along the crest of the North Dam will also be monitored on the same basis during an emergency shutdown period involving a lowered reservoir level.

2.5.6.9 Construction Notes

Principal pieces of equipment used to prepare and construct the various features of the Service Water Pond dams and embankments are summarized by Table 2.5-67. This table presents the type and quantity of equipment available which was used as necessary to perform this work. Figure 2.5-198 presents the progress of construction for each of the structures by showing the quantity of fill placed and percent completion versus the date. It is noted that considerable delays are shown because of adverse weather conditions or rescheduling of work because of other construction commitments. A photograph of typical compaction operations is presented in Figure 2.5-199.

The 3 dams and the West Embankment were constructed in strict compliance with the specification requirements discussed in Section 2.5.6.4.5. When construction control tests indicated that specification requirements were not satisfied, the condition was corrected to satisfy the specification requirements and construction techniques were adjusted to prevent recurrence.

A few modifications of design were based upon field conditions. These modifications are discussed in Sections 2.5.6.9.1 through 2.5.6.9.4.

2.5.6.9.1 North Dam

As shown by Figure 2.5-191, a core trench was excavated between Stations 7+50 and 11+50 to the base of the grout pipes. The trench was excavated with 1 to 1 side slopes and a base width ranging from 22 feet to 29 feet. Each end was sloped at approximately 2.5 to 1 slopes.

As shown by Figures 2.5-105 and 2.5-133, a spoil berm was provided to a maximum elevation of 350.0' on the north side of the North Dam. To assure drainage from the toe drain in the event of rapid drawdown of Monticello Reservoir, a 40 foot wide Zone B riprap drainage outlet was constructed from the rock toe to the natural drainage channel. The riprap was capped with 2, 12 inch layers of Zone 2 and Zone 1 filter material to prevent the infiltration of fines.

2.5.6.9.2 South Dam

Although the design provided for leaving the colluvial deposits in place under the South Dam, soft, wet conditions and large pockets of organics rendered this material unacceptable and it was removed. Therefore, a core trench which was originally planned to extend through the colluvium was eliminated in the lower elevations. This core trench does extend up each abutment approximately 50 feet beyond the design limits and feathers into natural ground. The trench was excavated with 1 to 1 side slopes and a base width ranging from 32 feet to 40 feet.

A relatively high concentration of clay filled vertical joints occur within a small portion of the foundation area of the South Dam between stations 5+50 and 6+00 as shown in Figure 2.5-104. These joints and other isolated joints were excavated, cleaned, inspected, and were found to be relatively tight and essentially impervious. As a conservative measure to minimize the potential for foundation seepage in the event of lowering Monticello Reservoir, these joints were brushed clean, packed with slurry grout, and covered with 12 to 18 inches of 3000 psi concrete.

2.5.6.9.3 East Dam

As discussed in Section 2.5.6.3.3, a concrete lined channel was constructed through the south abutment of the East Dam as part of the Service Water Pond dewatering system. This concrete was removed and the channel was backfilled with select fill prior to embankment construction.

2.5.6.9.4 West Embankment

As discussed in Section 2.5.6.3.4, a peripheral French drain system was constructed to reduce the moisture content of the foundation soils. The location of this drain is shown by Figure 2.5-109.

To prevent erosion during construction, the riprap was extended downward from the design riprap bottom elevation of 415.0'.

2.5.6.10 Operational Notes

Post-construction visual inspections and instrumentation monitoring are performed and maintained in accordance with plant procedures and regulatory requirements.

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2.5.9 PERSONS AND AGENCIES INTERVIEWED

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Table 2.5-1
Inferred Stratigraphic Succession and Sequence of Igneous Episodes in the Piedmont of South Carolina (Adapted From Overstreet and Bell, 1965a, Table 2)

Inferred geologic age	Sequences of sedimentary and pyroclastic rocks and intrusive episodes	Inner Piedmont Belt	Kings Mountain Belt	Charlotte Belt	Carolina Slate Belt
		Syenite pegmatite		Minette and syenite pegmatite	Minette and syenite pegmatite
Permian	(250 MY)		Syenite	Syenite	Syenite
		Gabbro, pyroxenite, and norite	Gabbro and pyroxenite	Gabbro, pyroxenite, and norite	Gabbro, pyroxenite, and norite
Permian and Carboniferous	Intrusive episode C	Yorkville Quartz Monzonite	Yorkville Quartz Monzonite	Yorkville Quartz Monzonite	
		Muscovite permatite Cherryville Quartz Monzonite	Cherryville Quartz Monzonite	Granite in circular plutons at Chester, Winnsboro, and Liberty Hill	Granite in circular plutons at Winnsboro, Liberty Hill, and Cayce
		Marble*	Marble		

* In part

Table 2.5-1 (continued)
Inferred Stratigraphic Succession and Sequence of Igneous Episodes in the Piedmont of South Carolina (Adapted From Overstreet and Bell, 1965a, Table 2)

Inferred geologic age	Sequences of sedimentary and pyroclastic rocks and intrusive episodes	Inner Piedmont Belt	Kings Mountain Belt	Charlotte Belt	Carolina Slate Belt
Carboniferous	Upper sequence	Biotite schist* Quartzite*	Sericite schist* Quartzite Sericite*	Mica gneiss*	Argilite* Muscovite schist*
		Unconformity			
	Middle sequence	Biotite granite gneiss			
	~~(450 MY)~~	~~Toluca~~ Quartz Monzonite			
	Intrusive episode B	Metamorphosed gabbro and soapstone	Metamorphosed gabbro Oligoclase tonalite	Metamorphosed mafic dikes	Metamorphosed mafic dikes
Devonian through Ordovician		Biotite schist* Marble*	Sericite schist*	Mica gneiss*	Argillite* Muscovite schist*

Table 2.5-1 (continued)
Inferred Stratigraphic Succession and Sequence of Igneous Episodes in the Piedmont of South Carolina (Adapted From Overstreet and Bell, 1965a, Table 2)

Inferred geologic age	Sequences of sedimentary and pyroclastic rocks and intrusive episodes	Inner Piedmont Belt	Kings Mountain Belt	Charlotte Belt	Carolina Slate Belt
	Middle sequence	Quartzite* Henderson Gneiss Biotite gneiss and migmatite*			Quartzite
		Hornblende gneiss*	Hornblende schist		Quartz-microcline gneiss Amphibolite
		Unconformity			
	(550 MY)				
	Intrusive episode A	Biotite gneiss at Iva, Anderson County	Not recognized	Porphyritic granite in Abbeville County and gneissic granodiorite in York County	Not recognized
Cambrian and Late Precambrian	Lower sequence	Hornblende gneiss* Biotite schist* Biotite gneiss and migmatite*	Granitoid gneiss	Granitoid (Migmatite)	Granitoid gneiss
		Unconformity (not observed in Piedmont)			

Table 2.5-1 (continued)
Inferred Stratigraphic Succession and Sequence of Igneous Episodes in the Piedmont of South Carolina (Adapted From Overstreet and Bell, 1965a, Table 2)

Inferred geologic age	Sequences of sedimentary and pyroclastic rocks and intrusive episodes	Inner Piedmont Belt	Kings Mountain Belt	Charlotte Belt	Carolina Slate Belt
	(1100 MY)				
	Basement	Unobserved in Piedmont			

Table 2.5-2
General Geologic Time Scale

ERA	PERIOD	EPOCH	APPROXIMATE AGE (in years) BEFORE PRESENT
CENOZOIC	QUATERNARY	Holocene	10,000
		Pleistocene	1,000,000
	TERTIARY	Pliocene	13,000,000
		Miocene	25,000,000
		Oligocene	36,000,000
		Eocene	58,000,000
		Paleocene	63,000,000
MESOZOIC	CRETACEOUS		135,000,000
	JURASSIC		180,000,000
	TRIASSIC		230,000,000
PALEOZOIC	PERMIAN		280,000,000
	PENNSYLVANIAN		310,000,000
	MISSISSIPPIAN		345,000,000
	DEVONIAN		405,000,000
	SILURIAN		425,000,000
	ORDOVICIAN		500,000,000
	CAMBRIAN		600,000,000
PRECAMBRIAN			

Table 2.5-3
Summary of Results of Radiometric Age Determinations

Ages in Millions of Years. For model ages, $(Sr^{87}/Sr^{86})_0$ assumed = 0.7050

Specimen	Rock Type	Condition	Rb-Sr Model Age	Rb-Sr Isochron Age	K-Ar Age	Comments
SC2.1	Granodiorite control	Unweathered	295 ± 15		291 ± 15	Biotite ages
SC2.3	Granodiorite control	Unweathered	315 ± 15		288 ± 14	Biotite ages
SD3.1	Granodiorite control	Slightly weathered	317 ± 15		264 ± 16	Biotite ages (Edge of biotite crystals in thin section altered by weathering)
SD3.3	Granodiorite control	Unweathered	314 ± 15		297 ± 18	Biotite ages
NJ1.1	Granodiorite control	Unweathered	299 ± 15		290 ± 17	Biotite ages
NK2.1	Granodiorite control	Unweathered		292 ± 10(1)	292 ± 17	Biotite age (K-Ar)
SC2.2	Microbreccia of granodiorite	Weathered, but thoroughly lithified	345 ± 70(2)		196 ± 18	Whole rock ages
SC2.4	Pink granodiorite with slickensides	Unweathered		299 ± 10(3)	163 ± 16	Whole rock age (K-Ar) (Biotite largely altered to chlorite)

(1) Average of biotite + whole-rock ages
(2) Reflects low radiogenic Sr^{87}
(3) Average of biotite-chlorite + whole-rock ages.

Table 2.5-3 (CONTINUED)
Summary of Results of Radiometric Age Determinations

Ages in Millions of Years. For model ages, $(Sr^{87}/Sr^{86})_0$ assumed = 0.7050

Specimen	Rock Type	Condition	Rb-Sr Model Age	Rb-Sr Isochron Age	K-Ar Age	Comments
SD3.2	Slightly pink granodiorite wedge bounded by laumontite-filled shears	Slightly weathered	358 ± 40(2)		256 ± 15	Biotite + chlorite age (Rb-Sr). Whole-rock age (K-Ar).
NK2.2	Microbreccia of granodiorite	Weathered	521 ± 70(2)		264 ± 16	Whole-rock ages (Biotite altered to chlorite)
NK2.3	Microbreccia of aplite	Slightly weathered	(Rb-Sr too low for analysis)		273 ± 16	Whole-rock age
SB2.1	Sheared aplite	Slightly weathered	NOT ANALYZED		209 ± 13	Whole-rock age
SB2.2	Aplite control	Unweathered	NOT ANALYZED		227 ± 14	Whole-rock age
SH1	Granodiorite control from slant hole core	Unweathered	NOT ANALYZED		289 ± 17	Biotite age
SH4	Microbreccia of granodiorite from slant hole core	Slightly weathered	NOT ANALYZED		141 ± 86	Whole rock age
X1	Laumontite crystals	Essentially unweathered	NOT ANALYZED		45 ± 5	Hydrothermal mineral age

(2) Reflects low radiogenic Sr87

Table 2.5-4
Overcoring Data From OC-1 and OC-2
Virgil C. Summer Nuclear Station

Hole Number	Test	p'	Q'	θ
OC-1	a	Data questionable because core broke		
	b	97 bars (1430 psi)	44 bars (650 psi)	325°
	c	49 bars (730 psi)	40 bars (590 psi)	330°
OC-2	a	38 bars (560 psi)	-20 bars* (-290 psi)	0°
	b	42 bars (620 psi)	-0.7 bars (-10 psi)	10°
	c	31 bars (450 psi)	0.7 bars (10 psi)	15°

* Negative value indicates tension.

Table 2.5-5
Dynamic and Static Engineering Properties
of Foundation Material

Foundation Material	Compressional Wave Velocity (ft/sec)	InSitu Density (lbs/cu ft)	Poisson's Ratio (μ)	Shear Modulus (G) or Modulus of Rigidity (lbs/sq in)	Modulus of Subgrade Reaction (lbs/cu ft)
Saprolite	1000-3000	110-135	0.35	1×10^4	$\frac{5 \times 10^6}{\sqrt{BL}}$ **
Weathered and jointed rock	(12,000-13,000) *	(140-160) *	0.30	5×10^5	$\frac{2 \times 10^8}{\sqrt{BL}}$ **
Sound rock	15,000	165	0.20	2×10^8	$\frac{8 \times 10^8}{\sqrt{BL}}$ **

* Numbers in parentheses are estimated values.
** "BL" is contact area of square foundation. For other contact area shapes, subgrade modulus must be modified (see Barkan, 1962).
NOTE: Young's Modulus, $E = 2(1+\mu)G$

Table 2.5-6
Modified Mercalli Intensity (Damage) Scale (Abridged)

I.	Not felt except by a very few under especially favorable circumstances. (I Rossi-Forel Scale.)
11.	Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing. (I to II Rossi-Forel Scale.)
111.	Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motorcars may rock slightly. Vibration like passing of truck. Duration estimated. (III Rossi-Forel Scale.)
1V.	During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, doors disturbed; walls make creaking sound. Sensation like heavy truck striking building. Standing motorcars rocked noticeably. (IV to V Rossi-Forel Scale.)
V.	Felt by nearly everyone, many awakened. Some dishes, windows, etc., broken; a few instances of cracked plaster; unstable objects overturned. Disturbances of trees, poles, and other tall objects sometimes noticed. Pendulum clocks may stop. (V to VI Rossi-Forel Scale.)
VI.	Felt by all, many frightened and run outdoors. Some heavy furniture moved; a few instances of fallen plaster or damaged chimneys. Damage slight. (VI to VII Rossi-Forel Scale.)
VII.	Everybody runs outdoors. Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable in poorly built or badly designed structures; some chimneys broken. Noticed by persons driving motorcars. (VIII Rossi-Forel Scale.)
VIII.	Damage slight in specially designed structures; considerable in ordinary substantial buildings with partial collapse; great in poorly built structures. Panel walls thrown out of frame structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected in small amounts. Changes in well water. Persons driving motorcars disturbed. (VIII+ to IX Rossi-Forel Scale.)
IX.	Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb; great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked conspicuously. Underground pipes broken. (IX+ Rossi-Forel Scale.)
X	Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations; ground badly cracked. Rails bent. Landslides considerable from river banks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks. (X Rossi-Forel Scale.)

Table 2.5-6 (continued)
Modified Mercalli Intensity (Damage) Scale (Abridged)

XI.	Few, if any, (masonry) structures remain standing. Bridges destroyed. Broad fissures in ground. Underground pipelines completely out of service. Earth slumps and land slips in soft ground. Rails bent greatly.
XII.	Damage total. Waves seen on ground surface. Lines of sight and level distorted. Objects thrown upward into the air.

Table 2.5-7
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1776	Nov 6		35.0	83.0	Jackson County, N.C.			IV-V	
1828	Mar 9	2200-2300			Probably Virginia	190,000		V	
1844	Nov 28	0800	36.0	84.0	Nr. Knoxville, Tenn.			VI	EQH
1852	Apr 29	1300			Probably Virginia	150,000		VI	BOL
1855	Feb 2	0300	37.0	78.6	Charlotte Courthouse, Virginia	9,000		V	EQH
1857	Dec. 19	0904	32.8	79.8	Charleston, S.C.				
1861	Aug 31	0522			Probably Virginia	300,000		VI	
1872	June 17	1500	33.1	83.3	Milledgeville, Ga.			V	EQH

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1874	Feb 10 to Apr 17		35.7	82.1	McDowell County, N.C. (Six Shocks)	Local		V	GIT
1875	Nov 1	2155	33.8	82.5	Northern Georgia	25,000		VI	EQH
1875	Dec 22	2345	37.6	78.5	Arvonia, Virginia	50,000		VI	EQH
1877	Nov 16	0238	35.5	84.0	Western N.C. and Eastern Tenn.	5,000		V	EQH
1879	Dec 13	0200	35.2	80.8	Charlotte, N.C.	Local		V	EQH
1884	Jan 18	0800	34.3	78.0	Wilmington, N.C.	Local		V	EQH
1885	Aug 6	0800	36.2	81.6	Watauga County, N.C.	Local		IV-V	EQH
1886	Aug 31	2151 2159	32.9	80.0	Near Charleston, S.C. (Two Shocks)	2,000,000	6.8/7/1	X	BOL

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1886	Oct 22	0520 1445	32.9	80.0	Charleston, S.C.	30,000		VI VII	EQH GIT
1886	Nov 5	1220	32.9	80.0	Charleston, S.C.	30,000		VI	EQH
1897	May 3	1218	37.1	80.7	Near Pulaski City, Va.	150,000		VI	EQH
1897	May 31	1358	37.3	80.7	Giles County, Va.	280,000		VIII	
1897	Oct 21	2220	36.9	81.1	Wytheville, Va.	20,000		V	EQH
1898	Feb 5	1500	37.0	80.7	Western, Va.			VI	EQH
1898	Nov. 25	1500	37.0	81.0	Pulaski-Wytheville, Va.			IV-V	BOL
1899	Feb 13	0430	37.0	81.0	Western Virginia	30,000		V	EQH
1902	May 29	0230	35.1	85.3	Chattanooga, Tenn.	Local		V	EQH

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1902	Oct 18	1700	35.0	85.3	Southeastern Tenn. & Northwestern Ga.	1,500		V	
1903	Jan 23	2015	32.1	81.1	Georgia & S.C.	10,000		VI	EQH
1904	Mar 4	1930	35.7	83.5	Eastern Tenn.	5,000		V	EQH
1907	Apr 19	0330	32.9	80.0	Near Charleston, S.C.	10,000		V	EQH
1911	Apr 21	2200	35.2	82.7	NC-SC Border	600		V	GIT
1912	Jun 12	0530	32.9	80.0	Summerville, S.C.	35,000		VII	EQH
1912	Jun 20		32.0	81.0	Savannah, Ga.			V	GIT
1913	Jan 1	1328	34.7	81.7	Union County, S.C.	43,000		VII	EQH
1913	Mar 28	1650	36.2	83.7	Eastern Tenn.	2,700		VII	EQH
1913	Apr 17	1130	35.3	84.2	Eastern Tenn.	3,500		V	EQH
1914	Jan 23	2224	35.6	84.5	Eastern Tenn.	Local		V	

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1914	Mar 5	1505	33.5	83.5	Georgia	50,000		VI	EQH
1914	Sept 21	2130	35.0	82.6	Nr Greenville, S.C.			V	
1914	Sept 22	0204	33.0	80.3	Near Summerville, S.C.	30,000		V	EQH
1915	Oct 29	0100	35.8	82.7	Near Marshall, N.C.	1,200		V	EQH
1916	Feb 21	1739	35.5	82.5	Near Skyland, N.C.	200,000	5.0	VI	EPB
1916	Mar 1	1902	34.5	82.7	Anderson, S.C.			IV-V	GIT
1916	Aug 26	1335 1436	36.0	81.0	Western N.C. (Two Shocks)	3,800		V	EQH
1918	Jun 21	2000	36.1	84.1	Lenoir City, Tenn.	3,000		V	EQH
1920	Dec 24	0230	36.0	85.0	Eastern Tenn.	Local		V	EQH
1921	Jul 15		36.6	82.3	Near Mendota, Va.	Local		V-VI	BOL

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1924	Oct 20	0330	35.0	82.6	Pickens County, S.C.	56,000		V	EQH
1924	Nov 13	0030	36.6	82.1	Bristol, Tenn-Va.			IV-V	
1924	Dec 25	2330	37.3	79.9	Roanoke, Va.	Local		V	EQH
1926	Jul 8	0450	35.9	82.1	South Mitchell County, N.C.	Local		VI	WQH
1927	Jun 10	0216	38.0	79.0	Near Charlottesville, Va.	2,500		V	
1928	Nov 2	2303	36.0	82.6	Tenn-N.C. Border (Western N.C.)	40,000		VI	CGS
1929	Dec 26	2156	38.1	78.5	Near Charlottesville, Va.			VI	
1933	Dec 19	0912	33.8	80.2	Summerville, S.C.	Local		IV-V	GIT
1935	Jan 1	0315	35.1	83.6	N.C.-Ga. Border	7,000		V	USE

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1945	Jun 13	2225	35.0	84.5	Cleveland, Tenn.			V	
1945	Jul 26	0532	34.3	81.4	Lake Murray, S.C.	25,000		VI	USE
1949	Sep 17	0430	36.7	83.0	Lee County, Ga.			IV-V	
1952	Nov 19	1900	32.8	80.0	Charleston, S.C.			V	GIT
1954	Jan 22		35.3	84.4	Near Athens & Etowah, Tenn.			V	
1955	Sep 27	2102	36.6	81.4	N.C.-Tenn. Border	1,700		V	BOL
1956	Sep 7	0836 & 0849	35.5	84.0	Eastern Tenn. (Two Shocks)	8.300		VI	USE
1957	May 13	0925	35.7	82.0	Western N.C.	8,100		VI	EQH
1957	Jun 23	0134	36.5	84.5	Eastern Central Tenn.			V	EQH
1957	Jul 2	0433	35.5	82.5	Western N.C.			VI	EQH

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1957	Nov 24	1506	35.0	83.5	N.C.-Tenn. Border	4,100		VI	EQH
1958	Mar 5	0654	34.5	77.7	Wilmington, N.C.			V	EQH
1958	Oct 20	0116	34.5	82.6	Anderson, S.C.	Local		V	GIT
1959	Apr 23	1559	37.5	80.5	Va.-W. Va. Border	3,000		VI	EQH
1959	Aug 3	0108	33.0	79.5	Southeast S.C.	25,000		VI	CGS
1959	Oct 26	2107	34.5	80.2	Northeast, S.C.	4,800		VI	GIT
1960	Mar 12	0748	33.0	79.0	Near Coast of S.C.	3,500		V	CGS
1960	Apr 15	0510	35.7	84.0	Eastern Tenn.	1,300		V	EQH
1960	Jul 23	2237	33.0	80.0	Charleston, S.C.	Local		V	GIT
1963	Oct 28	1739	36.7	81.0	Near Galax, Va. (Two Shocks)	1,300		V	CHC
1964	Feb 18	0431	34.8	85.5	Ga.-Ala. Border			V	EQH

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1964	Mar 12	2020	33.2	83.4	Near Milledgeville, Ga.		4.4	V	CGS
1964	Apr 20	1405	34.0	81.0	Near Columbia, S.C.			V	GIT
1967	Oct 23	0404	33.4	80.7	Charleston-Summerville, S.C.		3.8	V	USE
1969	Jul 13	1651	36.1	84.3	Eastern Tenn.	20,000	3.5	V	EQH
1969	Nov 19	2000	37.4	81.0	Giles County, Va.			V-VI	
1969	Dec 13	0519	35.1	83.0	Nr. Highlands N.C.			V	USE
1970	Jul 30	1015	37.0	82.2	Western, Va.		4.0	V	CGS
1970	Sept 9	2041	36.1	81.4	Northwest N.C.			V	USE
1971	May 19	0754	33.3	80.6	S. Central S.C.		3.4	V	NOS
1971	Oct 9	1143	35.9	83.5	E. Tennessee		3.4	V	ERL
1972	Feb 3	1811	33.5	80.4	S. Central S.C.		4.5	V	ERL

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1973	Oct 30	1758	35.7	84.0	E. Tennessee		3.4 GS	V	GS
1973	Nov 30	0248	35.8	84.0	E. Tennessee		4.6 BLA	VI	GS
1974	Aug 2	0352	33.9	82.5	Nr. Augusta, Ga		4.9 GS	VI	GS
1974	Nov 22	0025	32.9	80.1	Nr. Charleston, S.C.		4.7	VI	GS
1975	Nov 11	0310	37.2	80.8	S.W. Virginia	-	-	VI	USE
1975	Nov 25	1018	34.9	82.6	L. Jocasse, S.C.	-	3.2	IV	GS
1976	Jan 19	0121	36.9	83.8	Kentucky	-	4.0 M_b	VI	GS
1976	Feb 4	1554	35.0	84.8	Tenn.-Ga. Border	-	3.0 M_b	VI	USE
1976	Jun 19	0054	37.4	81.6	S. W. Virginia	-	4.7 M_b	V	USE
1976	Sep 13	1355	36.6	80.8	Va.-N.C. Border	-	3.3 M_b	VI	GS
1976	Dec 27	0157	32.2	82.5	S. E. Ga.	-	3.7 M_b	V	USE
1977	Jan 18	1329	32.9	80.2	Charleston	-	3.0 M_b	V	USE
1977	Jul 27	1703	35.4	84.4	Tenn.	-	3.5 M_b	V	GS

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
1977	Aug 25	0420	33.4	80.7	Bowman, S.C.	-	3.1 M_b	V	GS
1977	Dec 15	1415	32.9	80.2	Charleston	-	3.0	V	GS
1978	Mar 17	1327	36.7	80.7	S. W. Virginia	-	2.8	V	GS
1979	Jan 19	0856	34.6	82.8	L. Keowee	-	3.4 M_b	-	SEN
1979	Aug 13	0519	35.2	84.3	S. E. Tenn.	-	3.7 M_b	V	GS
1979	Aug 25	2132	34.8	82.9	L. Jocassee, S. C.	-	3.7 M_{bLg}	-	SEN
1979	Sep 6	2038	35.3	83.2	West, N. C.	-	3.2 M	-	SEN
1979	Sep 12	0624	35.6	83.9	Marysville, Tenn.	-	3.2 M_b	V	GS
1979	Oct 8	0854	36.4	82.0	N. E. Tenn.	-	3.6 M	-	SEN

The following abbreviations for references were used -

BOL	-	Bollinger (1969)	GIT	-	Georgia Institute of Technology
CGS	-	Coast and Geodetic Survey	BLA	-	WWSSN, Blacksburg, Virginia
EPB	-	Earth Physics Branch, Dept. of Ener. Mines and Res., Canada	CHC	-	WWSSN, Chapel Hill, N. C.

Table 2.5-7 (continued)
Significant Earthquakes Within 250 Miles of Site
(Intensity V or Greater)

Year	Date	Local Time	N. LAT.	W. LONG.	Locality	Percep-Tible Area (sq mi)	Magnitude	EPICENTRAL INTENSITY	REFERENCE
EQH	-	Earthquake History of the United States, Coffman and Von Hake (1973)						U. S. Geological Survey	
						GS	-		
ERL	-	Environmental Research Laboratories (NOAA)				NOS	-	National Ocean Survey (NOAA)	
						USE	-	U. S. Earthquakes, Yearly Publication (NOAA)	
						SEN	-	Southeastern Seismic Network	

* M_b - Body wave
M - Local (Duration)
M_{bLg} - Body wave (Nuttli)

Table 2.5-8
Foundation Seismic Design Parameters

Foundation Material	Compressional Wave Velocity (ft/sec)	In Situ Density (lbs/cu ft)	Poisson's Ratio (μ)	Shear Modulus (G) or Modulus of Rigidity (lbs/sq in)	Modulus of Subgrade Reaction (lbs/cu ft)
Saprolite	1000-3000	110-135	0.35	1×10^4	$\frac{5 \times 10^6}{\sqrt{BL}^{**}}$
Weathered and jointed rock	(12,000-13,000)*	(140-160)*	0-30	5×10^5	$\frac{2 \times 10^8}{\sqrt{BL}^{**}}$
Sound rock	15,000	165	0.20	2×10^6	$\frac{8 \times 10^8}{\sqrt{BL}^{**}}$

* Numbers in parentheses are estimated values.
** "BL" is contact area of square foundation. For other contact area shapes, subgrade modulus must be modified (see Barkan, 1962).
Note: Young's Modulus, $E = 2(1 + \mu)G$

Table 2.5-9
Rock Compression Test Results

Boring	Depth (Feet)	Unit Weight (lbs/cu ft)	Unconfined Compressive Strength (lbs/sq in)	Triaxial Tests			Poisson's Ratio
				Confining Pressure (lbs/sq in)	Peak Deviator Stress (lbs/sq in)	Young's Modulus E (lbs/sq in)	
			Borings On or Adjacent to Site				
N-15	90	163	37,700			8.1 x 106	0.18
N-16	101	169	11,300			7.4 x 106	
N-16	176	161	29,900			1.1 x 107	
N-19	88	162		8,000	81,000	5.5 x 106	
N-19	94	163		5,000	81,000	6.1 x 106	
N-22	151	170		5,000	21,600	5.0 x 106	
3-1	91	169	26,500			8.0 x 106	0.24
3-2	108	173	19,000			4.4 x 106	
3-2	117	170	31,000			9.0 x 106	0.22
3-2	118	168	32,000			8.2 x 106	
3-2	126	171	13,000			8.6 x 106	
3-6	97	172	11,000			4.9 x 106	

Table 2.5-9 (CONTINUED)
Rock Compression Test Results

Boring	Depth (Feet)	Unit Weight (lbs/cu ft)	Unconfined Compressive Strength (lbs/sq in)	Triaxial Tests			
				Confining Pressure (lbs/sq in)	Peak Deviator Stress (lbs/sq in)	Young's Modulus E (lbs/sq in)	Poisson's Ratio
3-9	114	161	900			1.4 x 105	
3-14	118	173	22,000			4.9 x 106	
3-14	174	173	25,000			6.5 x 106	
3-17	120	166	32,000			4.5 x 106	
		Other Borings Approximately Three Miles North of Site					
N-2	111	169		8,000	73,500		
N-2	112	171	16,800			7.0 x106	0.17
N-11	36	191		4,000	92,000		
N-11	36 1/2	194		3,400	92,000		
N-11	37	193	33,200			1.3 x 107	0.20

Table 2.5-10
Soil Dynamic Torsional Shear Test Results

Boring Depth:	N-2* 27 feet	Soil Type: Micaceous silt and sand
Dry Density:	101 lbs. per cu. ft.	
Moisture Content:	10.6 percent	

Confining Pressure (lbs/sq ft)	Range of Shear Strain ($\times 10^{-5}$)	Range of Modulus of Rigidity (lbs/sq ft $\times 10^{5}$)
1000	2 to 24	4.1 to 3.7
2000	1 to 13	12.5 to 11.6
4000	1 to 10	18.4 to 17.4
8000	1 to 7	28.6 to 28.3

Boring Depth:	N-2* 32 feet	Soil Type: micaceous silt and sand
Dry Density:	84 lbs. per cu. ft.	
Moisture Content:	18.7 percent	

Confining Pressure (lbs/sq ft)	Range of Shear Strain ($\times 10^{-5}$)	Range of Modulus of Rigidity (lbs/sq ft $\times 10^{5}$)
1000	3 to 26	4.1 to 3.2
2000	3 to 22	6.2 to 4.3
4000	1 to 11	15.6 to 15.2
8000	1 to 8	23.2 to 22.1

* Torsional Shear Tests performed on samples recovered from borings drilled approximately 3 miles north of the site. The soils tested are similar to that at the plant site.

Table 2.5-10 (CONTINUED)
Soil Dynamic Torsional Shear Test Results

Boring Depth:	N-2* 38 feet	Soil Type: micaceous sand with silt and fine gravel
Dry Density:	117 lbs. per cu. ft.	
Moisture Content:	8.6 percent	

Confining Pressure (lbs/sq ft)	Range of Shear Strain ($\times 10^{-5}$)	Range of Modulus of Rigidity (lbs/sq ft $\times 10^{5}$)
1000	2 to 19	7.7 to 6.9
2000	2 to 15	11.1 to 10.3
4000	1 to 9	20.7 to 32.0
8000	1 to 6	32.3 to 32.0

Boring	N-2*	Soil Type: micaceous sand with silt and fine gravel
Depth:	50 feet	
Dry Density:	130 lbs. per cu. ft.	
Moisture Content:	7.0 percent	

Confining Pressure (lbs/sq ft)	Range of Shear Strain ($\times 10^{-5}$)	Range of Modulus of Rigidity (lbs/sq ft $\times 10^{5}$)
1000	4 to 24	4.9 to 4.4
2000	2 to 16	12.0 to 10.0
4000	1 to 8	24.8 to 23.6
8000	1 to 5	41.3 to 40.7

* Torsional Shear Tests performed on samples recovered from borings drilled approximately 3 miles north of the site. The soils tested are similar to that at the plant site.

Table 2.5-10 (CONTINUED)
Soil Dynamic Torsional Shear Test Results

Boring:	3-14	Soil Type: brown silty micaceous sand
Depth:	55 feet	
Dry Density:	91 lbs. per cu. ft.	
Moisture Content:	24.0 percent	

Confining Pressure (lbs/sq ft)	Shear Strain ($\times 10^{-5}$)	Modulus of Rigidity (lbs/sq ft $\times 10^{5}$)
1000	20	6.5
2000	17	10.5
4000	11	17.2
8000	8	26.5

Boring:	3-7	Soil Type: reddish brown silty micaceous fine sand
Depth:	30.5 feet	
Dry Density:	86 lbs. per cu. ft.	
Moisture Content:	27.0 percent	

Confining Pressure (lbs/sq ft)	Shear Strain ($\times 10^{-5}$)	Modulus of Rigidity (lbs/sq ft $\times 10^{5}$)
1000	20	7.8
2000	16	11.0
4000	12	16.4
8000	10	22.5

* Torsional Shear Tests performed on samples recovered from borings drilled approximately 3 miles north of the site. The soils tested are similar to that at the plant site.

Table 2.5-11
Compressional Wave Velocity Test Results

Tests on Soil Samples

Boring	Depth (feet)	Dry Density (lbs/cu ft)	Moisture content (percent)	Velocity of Compressional Wave Propagation (ft/sec)
N-14	36.5	118	14.0	1100
N-15	11.5	97	13.8	1700
N-15	16.5	99	10.8	1000
N-15	46.5	90	25.0	900
N-19	6	93	25.8	1200
N-19	20	96	18.9	1000
N-22	6	96	25.9	2900
N-22	26	95	22.0	1000
N-22	61	112	11.3	1000

Tests on Rock Samples

Boring	Depth (feet)	Velocity of Compressional Wave Propagation (ft/sec)
N-16	184	16,400
N-17	60	12,400
N-17	82	14,400
N-17	97	14,100
N-17	149	14,200
N-18	223	13,400
N-19	90	10,800

Table 2.5-11 (continued)
Compressional Wave Velocity Test Results

Boring	Depth (feet)	Velocity of Compressional Wave Propagation (ft/sec)
N-19	123	13,400
N-19	149	13,500
3-1	111	10,400
3-2	105	12,100
3-2	124	16,700
3-17	86	12,800
3-17	106	12,900
3-17	132	11,300
N-1 *	104	11,400
N-1 *	129	13,600
N-1 *	163	15,400

* These samples were obtained from other borings drilled approximately three miles north of the Station site. The rock tested is similar to that at the plant site.

Table 2.5-12
Permeability Test Data - Overburden

Boring	Depth (feet)	Permeability (ft/day)	Permeability (cm/sec)
N-19	65	4.8×10^{-4}	1.7×10^{-7}
N-22	40	4.0×10^{-2}	1.4×10^{-5}
3-2	40	13.6×10^{-2}	4.8×10^{-5}
3-3	60 1/2	17.0×10^{-2}	6.0×10^{-5}
3-5	5 1/2	6.8×10^{-2}	2.4×10^{-5}
3-9	75 1/2	33.5×10^{-2}	11.8×10^{-5}
3-17	30	16.8×10^{-2}	5.9×10^{-5}

Table 2.5-13
Atterberg Limit Data

Boring	Depth (feet)	In Situ Moisture Content (percent)	Liquid Limit	Plastic Limit	Plasticity Index
3-3	1/2	23	29	22	7
3-7	1/2	24	58	48	10
3-14	1 1/2	24	39	38	1
3-15	1/2	22	44	30	14
3-18	65	14	39	Nonplastic	
3-20	1	26	46	31	15
AR-1	1	20	46	21	25
AR-2	5	22	53	37	16
AR-3	5	21	45	Nonplastic	
AR-6	5	21	66	30	36
AR-9	1 1/2	17	36	24	12

Table 2.5-14
Resistivity Test Results

Boring	Sample Depth (feet)	Material	Laboratory Resistivity (ohm-centimeters)
3-1	375	Rock (3)	118×10^6
3-1	375	Rock (4)	74×10^3
3-3	51	Soil (1)	159×10^3
3-3	51	Soil (2)	124×10^3
3-4	78	Rock (3)	$>700 \times 10^6$
3-4	78	Rock (4)	66×10^3
3-6	317	Rock (3)	680×10^6
3-6	317	Rock (4)	89×10^3
3-7	66	Soil (1)	140×10^3
3-7	66	Soil (2)	72×10^3
3-8	36	Soil (1)	191×10^3
3-8	36	Soil (2)	112×10^3
3-11	88	Rock (3)	55×10^6
3-11	88	Rock (4)	44×10^3
3-14	126	Rock (3)	8×10^6
3-14	126	Rock (4)	91×10^3
3-16	21	Soil (1)	162×10^3
3-16	21	Soil (2)	77×10^3

(1) Tested at natural moisture content
(2) Tested at saturated moisture content (saturated with ground water)
(3) Tested at moisture content less than natural due to air drying of rock core
(4) Tested at saturated moisture content (saturated with ground water)

Table 2.5-15
Soil Chemical Test Results

Boring	Sample Depth (feet)	pH	Total Sulphates (parts/million)	Dissolved Sulphates (parts/million)
3-3	50 1/2	5.7	352.6	303.4
3-7	65	5.8	319.8	262.4
3-8	35	5.7	262.4	246.0
3-16	20	5.4	352.6	352.6

Table 2.5-16
Summary of Stress Controlled Cyclic Consolidated
Undrained Triaxial Tests

Test No.	Boring No.	Sample No.	Depth (ft)	Initial Moisture Content (%)	Initial Dry Density (pcf)	Moisture Content After Consolidation (pcf)	Dry Density After Consolidation (pcf)	Effective Consolidation Pressure $\bar{\sigma}c$ (psf)	Cyclic Deviator Stress ($\sigma1$-$\sigma3$) Max. (psf)	Stress Ratio $\tau/\bar{\sigma}3$ Max*	Number of Cycles: 5% Double Ampl. Axial Strain	Number of Cycles: l0% Double Ampl. Axial Strain
1	4-1	5	15	13.6	87.2	31.0	89.7	1750	691	0.39	6	16
2	4-1	9A	25	18.5	90.0	24.0	93.6	2475	1068	0.43	9	30
3	4-1	9B	25	11.8	92.3	28.0	95.1	2475	1006	0.41	5	11
4	4-1	11	30.5	7.9	107.8	18.6	112.6	2875	1334	0.47	6	50
5	4-1	5B	15.0	15.5	81.8	35.0	84.8	1750	553	0.32	5	10
6	4-1	13A	35.0	7.5	97.5	21.2	102.0	3165	1061	0.34	10	37

* $\tau = \frac{(\sigma1 - \sigma3)}{2}$ Max.

Table 2.5-17
Summary of Strain Controlled Cyclic Consolidated Undrained Triaxial Tests

Test No.	Boring No.	Sample No.	Depth (ft)	Initial Moisture Content (%)	Initial Dry Density (pcf)	Moisture Content After Consolidation (%)	Dry Density After Consolidation (pcf)	Effective Consolidation Pressure $\overline{\sigma}c$ (psf)	Single Ampl. Cyclic Shear Strain (%)	Shear* Modulus (ksf)	Shear* Modulus (ksf)
1	4-1	9C	25	12.2	87.6	29.0	91.2	2475	.0047	4355	9.5
“	“	“	“	“	“	“	“	“	.0093	3305	10.5
“	“	“	“	“	“	“	“	“	.0187	2367	15.6
“	“	“	“	“	“	“	“	“	.3691	175	17.5
“	“	“	“	“	“	“	“	“	.7382	102	20.9
2	4-1	13B	35	8.1	97.0	20.8	102.1	3165	.0048	5707	7.4
“	“	“	“	“	“	“	“	“	.0095	4503	10.4
“	“	“	“	“	“	“	“	“	.0189	3178	13.8
“	“	“	“	“	“	“	“	“	.3750	205	17.6
“	“	“	“	“	“	“	“	“	.7500	106	19.3

* Poisson’s Ratio assumed to be 0.50

Table 2.5-18
Computation of Maximum Modified Penetration
Resistances for Liquefaction Under Peak
Ground Surface Acceleration of 0.15g

Depth (feet)	σ'_v (pdf)	σ_v / σ'_v	r_d	τ_{av} / σ'_v	N_1
15	1755	1.0	0.97	0.09	6.5
25	2325	1.27	0.94	0.12	8.7
35	2895	1.44	0.90	0.13	9.4
45	3465	1.55	0.80	0.12	8.7
55	4035	1.62	0.71	0.11	8.0
65	4605	1.68	0.63	0.10	7.2
75	5175	1.73	0.56	0.09	6.5

Table 2.5-19
Computation of Maximum Modified Penetration
Resistances for Liquefaction Under Peak
Ground Surface Acceleration of 0.25g

Depth (feet)	σ'_v (pdf)	σ_v / σ'_v	r_d	τ_{av} / σ'_v	N_1
15	1755	1.0	0.95	0.15	10.9
25	2325	1.27	0.91	0.19	13.8
35	2895	1.44	0.84	0.20	14.5
45	3465	1.55	0.70	0.18	13.1
55	4035	1.62	0.55	0.15	10.9
65	4605	1.68	0.43	0.12	8.7
75	5175	1.73	0.35	0.10	7.3

Table 2.5-20
Computation of Average Cyclic Shear Strains
For Peak Ground Surface Acceleration of 0.25g

Depth (feet)	σ' (pdf)	τ_{av} / σ'_v	τ_{av} (psf)	γ_{av} (percent)
5	585	0.16	94	0.02
15	1755	0.15	263	0.04
25	2325	0.19	442	0.07
35	2895	0.20	579	0.09
45	3465	0.18	624	0.08
55	4035	0.15	605	0.07
65	4605	0.12	552	0.06

Table 2.5-21
Foundation Design Information For Seismic Category I Structures

Structure	Approximate Plan Dimensions (feet)	Approximate Foundation Elevation (feet)	Foundation Embedment Below Finish Grade (feet)	Foundation Type	Foundation Loads and Bearing Pressures
Reactor Building	134, outside diameter	396 to 408*	39	Mat	Load bearing pressures do not exceed 25 KSF
Control Building	84 x 141	407 to 411*	28	Mat	“
Auxiliary Building	120 x 190			Mat	“
North		384 to 388*	51		
South		370 to 374*	65		
Diesel Generator Building	66 x 67	394 to 421*	41 and 14	Caissons into rock	Loads on individual caissons vary. Caissons designed in accordance with values on Table 2.5-23
Fuel Handling Building	75 x 123	409 to 430**	26 and 5	Caissons into rock	“
Intermediate Building	85 x 198	394 to 409**	39 and 26	Caissons into rock	“
Condensate Storage Tank Foundation	58 diameter	430	5	Mat on Soil	Refer to Section 2.5.4.10.3

Table 2.5-21 (continued)
Foundation Design Information For Seismic Category I Structures

Structure	Approximate Plan Dimensions (feet)	Approximate Foundation Elevation (feet)	Foundation Embedment Below Finish Grade (feet)	Foundation Type	Foundation Loads and Bearing Pressures
Diesel Generator Fuel Oil Storage Tanks	Two Tanks	419	16	Soil-Supported	Refer to Section 2.5.4.10.3
Service Water Pump House	70 x 79	386	49	Mat on soil	Refer to Section 2.5.4.10.6
Service Water Intake Structure	18 x 166	367	-	Mat on soil	Refer to Section 2.5.4.10.6
Service Water Discharge Structure	33 x 35	408	15	Mat on soil	Refer to Section 2.5.4.10.6

* Indicates the elevation at which the structural concrete (3000 psi concrete) is founded on the fill concrete (1500 psi concrete) which in turn is founded on bedrock. The base of the fill concrete corresponds approximately to the excavation depth contours presented on Figure 2.5-24. The approximate base of the fill concrete is as follows:

Reactor Building	Elevation (feet)
North	341
East	348
South	362
West	367
Auxiliary Building	
North	354
South	368
Control Building	366 and 371

** Elevation of Cap. Elevation of bottom of caissons vary.

Table 2.5-22
Ultimate and Allowable Rock Bearing Capacity

Rock Property Indicator Number (from Section 2.5.4.4.1)	"Theoretical" Ultimate Bearing Capacity (ksf)	Design Allowable Bearing Capacity (ksf)
#1	6,000	200
#2	2,000	100
#3	800	40

Table 2.5-23
Caisson End Bearing and Shaft Resistance

Rock Property Indicator Number (from Section 2.5.4.4.1)	"Theoretical" Ultimate End Bearing Capacity (ksf)	Allowable Static Loading*		Allowable Dynamic Loadings* (Short-Term Earthquake Loadings)	
		End Bearing Capacity (ksf)	Shaft Resistance (skin friction) (ksf)	End Bearing Capacity (ksf)	Shaft Resistance (skin friction) (ksf)
#1	6,000	200	10	600	20
#2	2,000	100	10	300	20
#3	800	25	5	75	10

* The caissons are designed in accordance with the allowable values with the exception that, for caissons founded in #1 and/or #2 rock, the values for the #2 rock are used. For design considering combined bearing and friction, the full value for one type of resistance plus no more than 2/3 of the other resistance are utilized.

Table 2.5-24
Summary of Embankment Geometry

	North Dam	South Dam	East Dam	West Embankment
Crest Elevation (feet)	438.0	438.0	438.0	435.0
Crest Width (feet)	30.0	30.0	40.0	50.0
Approximate Crest Length (feet)	1,500	765	1,150	1,900
Maximum Height (feet)	129	98	28	96
Approximate Volume (1,000 cubic yards)	785	273	44	1,169 (1)

(1) Includes nonsafety class fill west of West Embankment.

Table 2.5-25
Cross-Hole Velocity Measurements
North, South, and East Dam Locations

Recording Station		Shot Station			Velocity (ft/sec)	
Boring No.	Depth (ft)	No.	Depth (ft)	Horizontal Distance (ft)	Compress.	Shear
ND-4	35	ND-1	40	200	13,300	7,680
	35		30	200	13,300	7,400
ND-11	45	ND-4	45	215	14,200	7,600
						8,000
	65	ND-17	75	175	14,000	7,600
SD-5	45	SD-1	45	160	16,000	8,000
					15,200	
ND-11	45	SD-8	45	212	13,250	7,300
	15	SD11a	20	20	4,000	
	15		20	20	4,000	1,550
						1,800
			20	20	4,000	1,450
						1,550
	15		20	20	3,600	1,550
						1800
	15		20	20		1,800(1)
	15	SD-11b	20	35	4,400	1,950
	15	SD-11c	20	48	4,800	
					4,000	1,500
						1,850
	15		20	48	4,800	1,600
					4,000	1,500

Table 2.5-25 (continued)
Cross-Hole Velocity Measurements
North, South, and East Dam Locations

Recording Station		Shot Station			Velocity (ft/sec)	
Boring No.	Depth (ft)	No.	Depth (ft)	Horizontal Distance (ft)	Compress.	Shear
						1,850
	15		20	48	4,800	1,600
					4,000	1,500
SD-5	15	SD-5a	14	25	4,150	1,650
						1,550
ED-2	20	ED-2a	25	25	1,560 (1)	1,090 (1)
						835 (1)
	15		25	25	1,400	860 (1)
	25		25	25	1,190	
	25		25	25		660
	15		15	25	1,085	
	15	ED-5/2	15	80	1,950	1,100
	15		15	80	2,000	1,125
	15		25	80	1,700 (1)	1,100

(1) Poor definition of wave arrival.

Table 2.5-26
Results of Cross-Hole Seismic Survey

Horizon	Vs (ft/sec)	Vp (ft/sec)	G (ksi)	E (ksi)	μ
Intact Rock	7650	14500	2083	5444	.307
	7600	14000	2055	5307	.291
	7600	14200	2055	5341	.299
	7400	13300	1949	4972	.276
	7680	13300	2099	5247	.250
	7300	13250	1896	4862	.282
	8000	16000	2277	6073	.333
	8000	15200	2277	5960	.308
Decomposed Rock	1550	4150	69.9	198.5	.419
	1550	4000	69.9	197.5	.412
	1850	4000	99.6	271.8	.364
	1500	4000	65.5	185.8	.418
	1600	4150	74.5	210.6	.413
	2300	4600	154.0	410.7	.333
Saprolite and Transported Soils	1100	1850	33.9	83.2	.227
	1125	2000	35.5	90.0	.263
	1100	1950	33.9	85.9	.267
	860	1400	20.7	49.6	.197
	1090	1560	33.3	68.2	.023
	835	1560	19.5	50.8	.299

Vs = Shear wave velocity
Vp = Compressional wave velocity
G = Shear modulus
E = Young's modulus
μ = Poisson's ratio

Table 2.5-27
Permeability Test Results

	Field Permeability			Laboratory Permeability		
Horizon	Boring No.	Depth Range of tests (ft)	Average Permeability (cm/sec x 10^{-5})	Sample No.	Consolidation Pressure (tsf)	Average Permeability (cm/sec x 10^{-5})
Colluvium/ Residual Soils	SD-5b	5.0-14.5	0.18	SD-5(2')	2.0	1.5
	SD-8b	6.4-16.0	0.48		4.0	0.58
	ED-4	5.5-10.0	1.1	SD-5(6')	2.0	0.16
	SS-3	4.0-7.0	0.62	ED-2(12')	2.0	0.48
					4.0	0.79
Saprolite	ND-7	8.0-15.0	2.3	ND-4(10')	0.0	0.37
	ND-13	4.0-27.0	0.70	ED-2(27')	2.0	4.1
		27.0-30.0	7.6		3.9	1.7
		30.0-33.0	150.0+			
	ND-11a	14.0-15.5	29.0++			
	ND-20	19.0-25.5	6.4			
	ND-23	13.0-24.5	3.7			
	ND-25	9.0-25.0	0.96			
		9.0-14.0	0.18			

Table 2.5-27
Permeability Test Results (continued)

	Field Permeability			Laboratory Permeability		
Horizon	Boring No.	Depth Range of tests (ft)	Average Permeability (cm/sec x 10^{-5})	Sample No.	Consolidation Pressure (tsf)	Average Permeability (cm/sec x 10^{-5})
Saprolite (Continued)	SD-6	14.0-29.0	2.2			
		4.2-8.2	0.34			
	ED-4	14.6-18.0	1.2			
	SS-3	14.6-37.0	3.0			
		7.0-37.0	5.9			
Decomposed Rock	ND-7	15.0-136.0	0.94	ND-4(18’)	2.0	0.20
	ND-9	4.0-20.0	0.55	ND-14(7’)	2.0	1.2
	ND-9a	20.5-35.0	0.54		4.0	0.98
		35.0-45.0	1.8	ND-14(12’)	0.0	0.16
		45.0-70.0	0.46			
	ND-20	25.0-38.8	0.60			
	ND-22a	4.0-30.0	0.77			
	ND-23	25.0-40.0	1.8			
		40.0-54.0	2.5			
	ND-24	4.0-29.0	0.64			

Table 2.5-27
Permeability Test Results (continued)

	Field Permeability			Laboratory Permeability		
Horizon	Boring No.	Depth Range of tests (ft)	Average Permeability (cm/sec x 10^{-5})	Sample No.	Consolidation Pressure (tsf)	Average Permeability (cm/sec x 10^{-5})
Decomposed Rock (Continued)	SD-5b	14.5-18.0	0.54			
	SD-6	18.0-20.8	3.6			
	SD-8b	18.0-38.0	2.5			
	ED-4	19.2-25.0	4.1			
		37.0-40.0	1.7			
Fractured Rock	ND-13	33.0-34.0	1000.0 (est)			
	ND-25	29.0-30.0	320.0			
	SD-5	35.5-44.0	33.0			
	SD-8	42.0-55.0	25.0			
Intact Rock	ND-1	21.0-38.5	5.6			
	ND-11a	40.0-146.5	4.5			
	ND-21	29.5-146.5	0.60			
	SD-5	44.0-146.0	4.2			
	SD-6	38.0-52.0	2.6			

Table 2.5-27
Permeability Test Results (continued)

	Field Permeability			Laboratory Permeability		
Horizon	Boring No.	Depth Range of tests (ft)	Average Permeability (cm/sec x 10^{-5})	Sample No.	Consolidation Pressure (tsf)	Average Permeability (cm/sec x 10^{-5})
Intact Rock (Continued)	ED-4	40.0-48.5	2.4			

(1) Influenced by fractured rock at 34 feet.
(2) Influenced by very loose alluvium at 13.5 feet.
(3) Additional test results are presented by Table 2.5-64.

INSERT

TABLES 2.5-28 SHEETS 1-21

Table 2.5-28
Summary of Laboratory Test Results
Foundation Soils

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TABLE 2.5-28
Sheet 1 of 21

SUMMARY OF LABORATORY TEST RESULTS
FOUNDATION SOILS

SUMMARY OF LABORATORY TEST RESULTS - COLLUVIUM

BORING and SAMPLE No.	DEPTH feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT %	ATTERBERG LIMITS LIQUID LIMIT	ATTERBERG LIMITS PLASTIC LIMIT	UNCONFINED COMPRESS STRESS	UNCONFINED COMPRESS STRAIN %	UNIT DRY WGT pcf	SPECIFIC GRAVITY	GRAIN SIZE SIEVE	GRAIN SIZE HYDR	OPT MOIST	CONSOLID	TRIAXIAL UU	TRIAXIAL CIU	TRIAXIAL CELL PRESSURE psi	TRIAXIAL BACK PRESSURE psi
SD-1	4.0- 5.5	CL		14.5														
	11.0-12.5	CL		26.8														
SD-1A	2.0- 3.5	SM		13.2														
	5.0- 6.5	ML		29.9														
SD-5	2 - 4.5	CL	(1)	17.5	23	15			110.6	2.67				*				
			(2)	18.7														
				22.3														
				19.9														
				18.2														
	6.0- 8.5	ML	(2)	18.7	39	27			99.0	2.67				*	*			
				21.6														
				25.4														
SD-8	2.0- 3.5	CL		20.1														
	5.0- 6.5	CL		23.2														
	8.0- 8.5	CL		28.8														
	11.0-12.5	CL		26.5														
	14.0-15.5	CL		23.0														
	1 .0-18.5	CL		17														

* [illegible] (1) Permeability (2) Cyclic Tr [illegible] Shear

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TABLE 2.5-28 (Cont'd)
Sheet 2 of 21

SUMMARY OF LABORATORY TEST RESULTS - COLLUVIUM

BORING and SAMPLE No	DEPTH feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
				19.7														
SD-9B	4.0- 6.5	ML		26.4	38	26			87.5						*			
				22.2					106.1									
	7.0- 9.5	CL-ML		20.6	26	19			99.9					*	*			
				22.0														
				11.5					109.5									
	10.0-12.5	ML		16.7					110.8					*	*			
				13.8														
				24.3					98.9									
SD-9D	4.0- 6.5	CL		19.7	31	20			95.6					*	*			
				26.4														
				22.4														
				24.5														
	10.0-12.2	ML			21	17												

* See Text

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TABLE 2.5-28 (Cont'd)
Sheet 3 of 21

SUMMARY OF LABORATORY TEST RESULTS - RESIDUAL SOIL

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			U.U.	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
ND-3	2.0- 3.5	ML		22.9														
	5.0- 6.5	ML		5.6														
	8.0- 8.6	ML		16.3														
ND-15	2.0- 3.5	CH		29.2	61	29												
	5.0- 6.5	CH		17.9														
ND-16	2.0- 3.5	CL/CH		24.6 30.7														
SD-3	2.0- 3.5	CL		36.2														
	5.0- 6.5	CL		25.6														
SD-7	2.0- 3.5	CL		37.3														
ED-2	2.0- 4.4	ML		27.3 29.4	47	36	0.81	4.5	88.6									
	4.4- 5.8	ML/MI		41.4														
	7.0- 9.5	MI		50.8 46.3	60	51	0.46	1.0	78.8									
	9.5-11.0	ML/MI		43.9														
	12.0-14.5	MI		59.7 60.4	65	58			69.8					*				
	14.5-16.0	MI		45.8														

* See Test Curves

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TABLE 2.5-28 (Cont'd)
Sheet 4 of 21

SUMMARY OF LABORATORY TEST RESULTS - RESIDUAL SOIL

BORING and SAMPLE No	DEPTH feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
ED-2	17.0-19.5	MH			54	48			67.5					*				
	19.5-21.0	MH		43.4														
WD-1	2.0- 3.5	CL/CH		40.3 37.4														
	5.0- 6.5	CL/CH		39.3 29.7														
WD-2	2.0- 3.5	CL		29.7 29.9														
	5.0- 6.5	CL		29.4 26.2														
	8.0- 9.5	ML		28.1 24.1														
	11.0-12.5	ML		23.8 22.6														
	14.0-15.5	ML		21.6 28.4														
WD-5	2.0- 3.5	CL		20.7														
	5.0- 6.5	ML		24.5														
WD-6	2.0- 4.2	MH		42.6 35.7	54	37	1.04	4.0	87.8									
WD-7	2.0- 3.5	CL		30.7														
	5.0- 6.5	CL		29.9														

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - RESIDUAL SOIL

BORING and SAMPLE No	DEPTH feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
WD-7	8.0- 9.5	ML/MI		24.5														
	11.0-12.5	ML/MI		19.3														
WD-8	2.0- 4.5	CH		41.3 36.1	58	24	1.94	14.0	84.0 88.9	2.65				*				
	4.5- 6.5	CH		29.8 27.2														
WD-9	2.0- 3.5	CH		27.1														
WD-10	2.0- 3.5	CL/CH		21.7														
	5.0- 6.5	SC		18.3														
	8.0- 9.5	SC		19.2														
SS-1	2.0- 3.8	MI		38.5 35.9	55	43	0.92	3.0	83.5									
SS-5	10.0-12.5	MI		31.9 44.0	59	40	0.26	4.0	72.1									
C-1	2.0- 3.5	MI		31.0 42.3	56	50												
	5.0- 6.5	MI		33.1	59	43												
	8.0- 9.5	MI		26.7														
	11.0-12.5	MI		28.6	72	43												

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - RESIDUAL SOIL

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
C-2	14.0-15.5	MI		30.0														
C-3	2.0- 4.0	CL		22.9 25.0 24.0	49	20	1.07	2.5	102.0									
	4.0- 5.5	MI		33.6	87	39												
	10.0-11.8	MI		48.1 34.7 34.3	59	54	1.31	1.0	84.5									
C-6	2.0- 3.5	MI		30.7 32.1														
	5.0- 6.5	MI		33.3 39.8 28.5 28.2	66	53												
	8.0- 9.5	MI		28.6 31.7 27.3 27.4														
	11.0-12.5	MI		28.4 28.7 31.4	60	46												
	14.0-15.5	MI		32.5	50	43												
C-7	2.0- 3.5	MI		32.1														
	5.0- 6.5	MI		32.9	67	47												

* See Test Curves

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TABLE 2.5-28 (Cont'd)
Sheet 7 of 21

SUMMARY OF LABORATORY TEST RESULTS - RESIDUAL SOIL

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS.		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
C-7	8.0- 9.5	MI		31.6														
	11.0-12.5			30.6														
C-8	0.0- 5.0	CH		28.2	70	32					*	*						
	5.0-10.0	CH		25.3	66	26					*	*						
	10.0-15.0	ML		26.7	50	30					*	*						
C-10	5.0-10.0	MI		21.2	69	46					*	*						
	10.0-15.0	MI		23.6	71	50					*	*						

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - SAPROLITE

BORING and SAMPLE No	DEPTH feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
ND-4	10.0-11.0	SM	(1)	18.6					97.9					*		*		
	11.0-11.5	SM		15.0														
ND-5	2.0- 3.5	ML		17.8														
ND-15	8.0- 9.5	CL		17.7														
	11.0-12.5	ML		12.9	31	28												
	14.0-15.5	ML		19.9														
	17.0-18.5	ML		7.6 8.3														
SD-1A	8.0- 9.5	SM/ML		11.7														
SD-3	8.0- 9.5	ML		20.5														
	11.0-12.5	ML		17.6														
	14.0-15.5	ML		23.0														
	17.0-18.5	ML		17.3														
	20.0-21.5	ML		16.3														
	23.0-24.5	ML		22.9														

* See Test Curves (1) Permeability

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - SAPROLITE

BORING and SAMPLE No	DEPTH feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
SD-3	26.0-27.5	ML		13.9														
	29.0-30.5	ML		14.5														
	32.0-33.5	ML		20.3														
	35.0-36.5	ML		20.4														
SD-7	12.5-14.0	ML		18.0	43	40												
	20.5-22.0	ML		22.7	36	NP												
	27.5-29.0	ML		18.7														
	33.0-34.5	ML		14.9														
SD-8	20.0-21.5	SM		15.4														
ED-2	23.8-25.3	ML		32.1														
	27.0-28.9	ML	(1)	36.7 37.3	45 40	NP NP			69.8 87.3	2.67				*	*			
	29.0-30.5	ML		35.0														
ED-3	32.0-33.0	ML		31.2														
	42.0-42.8	ML		26.6														

* See Test Curves (1) Permeability

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SUMMARY OF LABORATORY TEST RESULTS - SAPROLITE

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS LIQUID LIMIT	ATTERBERG LIMITS PLASTIC LIMIT	UNCON COMPRESS STRESS (tsf)	UNCON COMPRESS STRAIN (%)	UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE SIEVE	GRAIN SIZE HYDR	OPT MOIST	CONSOLID	TRIAXIAL UU	TRIAXIAL $\overline{CIU}$	TRIAXIAL CELL PRESSURE (psi)	TRIAXIAL BACK PRESSURE (psi)
WD-1	10.0-11.5	SM		12.4 17.0														
	15.0-16.5	SM		27.1 29.8														
	20.0-21.5	SM		11.9 17.1														
WD-2	17.0-18.5	ML		18.0 19.6														
	20.0-21.5	ML		18.7														
	23.0-24.5	ML		23.2 27.2														
	26.0-27.5	ML		29.4 27.9														
	32.0-33.5	SM/ML		20.8														
	35.0-36.5	SM/ML		9.4														
	38.0-39.5	SM/ML		17.6 8.9														
WD-5	8.0- 9.6	SM		14.9														
	11.0-12.5	SM		18.7														
	14.0-15.5	ML		20.1														
	17.0-18.5	ML		32.2														

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - SAPROLITE

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
WD-5	20.0-21.5	ML		23.8														
	23.0-24.5	ML		15.4														
	26.0-27.5	ML		24.1														
	29.0-30.5	SM		16.5														
	32.0-33.5	SM		11.6														
	35.0-36.5	SM		10.8														
	38.0-39.5	SM		9.0														
WD-6	10.0-12.5	SM		35.4	37	NP			78.1 99.9	2.69				*	*			
	12.5-14.0	SM		17.7														
	18.0-20.2	SM		32.2	36	NP			85.9						*			
WD-7	14.0-15.5	ML		27.4														
	17.0-18.5	ML		15.7														
	20.0-21.5	ML		15.8														
	24.0-25.5	ML		30.5														

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - SAPROLITE

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS.		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
WD-7	26.0-27.5	ML		24.0														
WD-8	10.0-11.8	ML		30.9	45	NP			88.9						*			
	11.8-13.3	ML		17.7 26.0														
WD-9	5.0- 6.5	SM/SC		17.8														
WD-10	11.0-12.5	ML		19.5														
	14.0-15.5	ML		17.4														
WD-14	2.0- 3.5	SM		16.7														
SS-1	14.5-16.0	ML		24.6														
	20.0-21.5	ML		22.0														
	27.4-28.8	ML		23.5														
SS-4	2.0- 3.5	ML			40	NP												
	3.5- 4.7	ML		26.5														
	10.0-12.0	ML		31.1 24.0	40	NP			80.1						*			
	12.3-13.8	ML		19.9														

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - SAPROLITE

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
SS-4	18.0-20.3	ML		26.9	31	NP			93.8						*			
	20.3-21.8	ML		19.8														
SS-5	18.0-20.5	ML		24.5	42	NP	0.44	3.0	91.1									
C-1	5.0- 6.5	ML		13.8	30	NP												
	8.0- 9.5	ML		17.9														
	11.0-12.6	ML		17.3	35	NP												
	14.0-15.5	ML		18.3														
	17.0-18.5	ML		17.3	30	NP												
	20.0-21.5	ML		22.6														
	23.0-24.5	ML		14.6	29	NP												
	26.0-27.5	ML		15.5														
	29.0-30.5	ML		19.9	32	NP												
C-2	17.0-18.5	MI		29.1	57	56												
	20.0-21.5	MI/MI		33.9														

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - SAPROLITE

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			U.U.	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
C-2	23.0-24.5	ML		30.5	46	38												
	26.0-27.5	ML/MI		24.9														
	29.0-30.5	ML		22.7	37	NP												
	32.0-33.5	ML		25.3	35	NP												
	35.0-36.5	ML/MI		30.2														
	38.0-39.5	ML		25.0	45	42												
	41.0-42.5	ML/MI		25.6														
	44.0-45.5	ML		28.6														
	47.0-48.5	ML		24.5														
	50.0-51.5	ML		21.0														
C-3	18.0-20.3	MI		44.7	53	49			81.3						*			
C-5	4.0- 5.5	SM		21.6	31	27												
	7.0- 9.5	SM		35.7 23.9	35 35	25 32			74.5						*			
	14.0-15.5	SM		25.0	35	30												

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - SAPROLITE

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
C-5	17.0-19.4	SM		36.5 23.0	35	30			97.8 87.3							*		
	19.4-20.5	SM		19.4	30	NP												
C-6	20.0-21.5	MI		29.6 25.4														
	23.0-24.5	ML		32.5	45	NP												
	26.0-27.5	ML		24.4														
	29.0-30.5	ML		25.9	44	NP												
C-7	19.0-20.5	ML		25.2														
	22.0-23.5	ML		25.2	40	39												
	30.0-31.5	ML		30.3														
	33.0-34.5	ML		25.8 30.5	37	NP												
	40.0-41.5	ML		23.1														
C-8	15.0-20.0	CL		18.2	31	21					*	*						
	20.0-25.0	ML		24.3	47	32					*	*						
	25.0-30.0	MI		19.7	50	32					*	*						

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - SAPROLITE

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
C-8	30.0-35.0	MH		21.9	57	33					*	*						
C-9	15.0-20.0	ML									*	*						
	30.0-35.0	ML									*	*						
	35.0-40.0	MH			74	46												
	40.0-45.0	MH			65	43												
C-10	15.0-20.0	MH		21.7	72	46					*	*						
	20.0-25.0	MH		25.1	70	55					*	*						
	25.0-30.0	MH		21.1	53	36					*	*						
	30.0-35.0	ML		15.3	40	31					*	*						
	35.0-40.0	ML		17.9	46	29					*	*						
	40.0-45.0	ML		17.0	40	26					*	*						
C-11	5.0-10.0	ML									*	*						
	15.0-20.0	ML			41	NP												
	20.0-25.0	ML			43	NP					*	*						

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - DECOMPOSED ROCK

BORING and SAMPLE No.	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID.	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
ND-1	11.0-12.3	SM		11.3														
ND-2	2.0- 3.5	ML		20.6														
	5.0- 6.5	ML		18.9														
ND-4	10.0-11.0								97.7 128.8					*		*		
	18.0-20.5	SM	(1)	10.1					119.7	2.64				*				
ND-5	5.0- 5.5	SC/SM		10.0														
ND-6	2.0- 3.5	SC/SM		13.6														
	8.0- 9.5	SM		13.9														
	11.0-12.5	SM		4.5														
ND-7	4.3- 4.6	CL		21.5														
ND-14	2.0- 3.0	SM		9.0														
	7.0- 8.4	SM	(1)	7.9					126.6					*		*		
	12.0-13.8	SM	(1)	6.1					140.1	2.66				*		*		
ND-15	23.0-24.5	ML		14.1	23	NP												

* See Test Curves (1) Permeability

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - DECOMPOSED ROCK

BORING and SAMPLE No.	DEPTH feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
ND-16	5.0- 6.0	SM		13.6														
	10.0-11.0	SM		12.4														
ND-18	2.0- 3.0	ML		22.9														
	5.0- 6.5	ML		11.1														
	7.0- 7.5	ML		15.5														
ND-19	2.0- 3.1	ML		11.5														
	5.0- 5.7	ML		9.8														
	8.0- 8.3	SM		10.8														
SD-1A	11.0-12.5	SM/ML		11.5														
SD-3	38.0-39.2	SM		8.8														
SD-4	4.9- 5.5	ML		5.8														
[illegible]	12.5-14.0	SM		10.7														
SD-7	60.0-60.3	SM		11.6														
SD-8	23.0-23.2	SM		14.6														

* See Test Curves

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TABLE 2.5-28 (Cont'd)
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SUMMARY OF LABORATORY TEST RESULTS - DECOMPOSED ROCK

BORING and SAMPLE No	DEPTH feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (psf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
SD-8	26.0-26.3	SM		16.5														
ED-2	32.0-34.0	SM		19.8														
ED-3	50.6-15.6	SM		16.0														
WD-1	25.0-26.5	SM		7.5 9.4														
WD-5	41.0-41.8	SM		9.4														
WD-8	15.0-17.0			5.7 6.3 6.1														
WD-9	8.0- 9.5	SM/SC		10.6														
	11.0-11.8	SM/SC		9.3														
WD-10	17.0-18.5	ML		15.4														
	20.0-20.8	ML		18.1														
	23.0-23.7	ML		15.1														
WD-14	5.0- 6.5			10.3														
	10.0-11.2			5.3														

* See Test Curves

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SUMMARY OF LABORATORY TEST RESULTS - DECOMPOSED ROCK

BORING and SAMPLE No	DEPTH feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
SS-4	29.0-29.2	SM		12.8														
C-1	32.0-33.5	SM		18.0														
	35.0-36.3	SM		14.7	26	NP												
C-2	56.0-56.8	ML		20.2														
C-5	24.0-25.0	SM		18.0														
	28.0-29.5	SM		16.1														

* See Test Curves

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TABLE 2.5-28 (Cont'd)
Sheet 21 of 21

SUMMARY OF LABORATORY TEST RESULTS - INTACT ROCK

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			U-U	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
ND 7-2	169.0		(1)						150.1									
ND 7-3	169.0		(1)						176.4									
ND 7-4	169.0		(1)						179.5									
SD 1-1	32.0-37.0		(1)						185.2									
SD 1-2	32.0-37.0		(1)						185.4									
SD 1-3	32.0-37.0		(1)						175.5									
SD 1-4	32.0-37.0		(1)						176.3									

* See Test Curves (1) Sonic Velocity

Table 2.5-29
Physical Properties of Colluvium

Property	Range	Average	Number of Tests
Natural Water Content,%	11.5 to 29.9	21.2	31
Liquid Limit,%	21 to 39	30	6
Plasticity Index,%	4 to 12	9	6
Unit Dry Weight, pcf	87.5 to 110.8	102.0	9
Specific Gravity	2.67	2.67	2

Table 2.5-30
Physical Properties of Residual Soil

Property	Range	Average	Number of Tests
Natural Water Content,%	5.6 to 60.4	30.9	89
Liquid Limit,%	47 to 87	61	24
Plasticity Index,%	5 to 48	20	24
Unit Dry Weight, pcf	67.5 to 102.0	82.5	11
Specific Gravity	2.65	2.65	1

Table 2.5-31
Physical Properties of Saprolite

Property	Range	Average	Number of Tests
Natural Water Content,%	7.6 to 44.7	22.0	133
Liquid Limit,%	29 to 74	42	47
Plasticity Index,%	0 to 28	6	47
Unit Dry Weight, pcf	69.8 to 99.9	86.7	14
Specific Gravity	2.67 to 2.69	2.68	2

Table 2.5-32
Physical Properties of Decomposed Rock

Property	Range	Average	Number of Tests
Natural Water Content,%	4.5 to 22.9	12.5	49
Liquid Limit,%	23 to 26	24	2
Plasticity Index,%	0	0	2
Unit Dry Weight, pcf	97.7 to 128.8	122.6	5
Specific Gravity	2.64 to 2.66	2.65	2

Table 2.5-33
Shear Strength Properties of Foundation Soils

Total Stress Parameters

	Undrained Shear Strength, Cu (psf)			
Stratigraphic Horizon	Minimum	Maximum	Average	Number of Tests
Colluvium	600	2220	1210	4
Residual Soil	260	1940	935	9
Saprolite	440	5920	2530	9

Effective Stress Parameters

Stratigraphic Horizon	Test Series	Effective Friction Angle, $\bar{\phi}$ (degrees)	Effective Cohesion, $\bar{c}$ (psf)
Colluvium	SD-5-Series 2	25	660
	SD-5-Series 3	25	1760
Saprolite	C-5-Series 1	36	0
	C-5-Series 2	36	0
Decomposed Rock	ND-14-Series 1-2	41.5	0
	ND-14-Series 3	38.5	0

Table 2.5-34
One Dimensional Compression Properties of
Foundation Materials

Horizon	Test Number	Water Content	Initial Void Ratio	C'_r	C'_c	C'_s	P_o (tsf)	P_c (tsf)	P_c / P_o	C/P_o
Colluvium	SD-5 (2')	18.4	0.51	0.007	0.08	0.016	0.1±	1.0±	10	-
	SD-5 (6')	24.3	0.68	0.015	0.10	0.023	0.23	2.0±	9	-
	SD-9b (7')	19.7	0.57	0.007	0.08	0.013	0.35	5.0±	14	0.9
	SD-9b (10')	14.3	0.50	0.007	0.084	0.015	0.42	5.0±	12	2.6
	SD-9d (4')	23.1	0.68	0.008	0.097	0.016	0.26	3.0±	11	2.0
Residual	WD-8 (2')	36.0	0.97	0.013	0.12	0.028	0.17	2.0±	12	5.7
	ED-2 (12')	49.5	1.39	0.007	0.23	0.026	0.75	5.0±	7	-
Saprolite	ED-2 (27')	55.0	1.39	0.012	0.22	0.021	1.57	4.0±	2.5	0.8
	WD-6 (10')	22.6	1.15	0.013	0.19	0.025	0.55	2.0±	3.6	5.4
Decomposed Rock	ND-4 (10')	28.3	0.691	0.008	0.10	0.016	0.35	2.0±	5.7	
	ND-4 (18')	15.0	0.377		0.058	0.009	0.75	4.0±	5.3	
	ND-14 (7')	7.9	0.311	0.006	0.037	0.008	0.55	3.0±	5.5	
	ND-14 (12')	3.9	0.185		0.024	0.008	0.90	4.0±	4.5	

C'_r = Recompression index, unit strain basis

C'_c = Virgin compression index, unit strain basis

C'_s = Swell index, unit strain basis

P_o = Existing overburden pressure

P_c = Estimated maximum preconsolidation pressure

C = Cohesion as determined from undrained shear strength

Table 2.5-35
Results of Cyclic Triaxial Tests On
Undisturbed Samples of Colluvium

Boring No.	Sample No.	Moisture Content (%)	Dry Density (pcf)	Confining Pressure σ_3 (psf)	Peak Cyclic Deviator Stress, (1) $\pm\sigma_d$ (psf)	Stress Ratio (1) $\pm\sigma_d$ $2\sigma_{3c}$	No. of Cycles to Cause Initial Liquefaction	No. of Cycles to Cause ± 5% Strain	No. of Cycles to Cause ± 10% Strain
BSD-SC	1-(Lab A)	22.2	104.2	3000	2505	0.417	4		
					2460	0.41		21.5	
					2430	0.405			30
	1-(Lab B)	20.2	109.2	3000	2820	0.47	4		
					2790	0.465		11.5	
					2700	0.45			17.5
	1-(Lab C)	20.1	110.8	6000	4800	0.40	4		
					4680	0.39		7.6	
BSD-9C	1-(Lab A)	24.3	100.5	1500	1350	0.45	8		
					1320	0.44		39	440
	2-(lab A)	20.8	106.7	750	705	0.47			
					690	0.46		560(2)	-

Table 2.5-35 (continued)
Results of Cyclic Triaxial Tests On
Undisturbed Samples of Colluvium

Boring No.	Sample No.	Moisture Content (%)	Dry Density (pcf)	Confining Pressure σ_3 (psf)	Peak Cyclic Deviator Stress, (1) $\pm\sigma_d$ (psf)	Stress Ratio (1) $\pm\sigma_d$ / $2\sigma_{3c}$	No. of Cycles to Cause Initial Liquefaction	No. of Cycles to Cause ± 5% Strain	No. of Cycles to Cause ± 10% Strain
	3-(Lab A)	14.4	117.3	1500	1245	0.415	15	610(2)	-
	3-(Lab B)	17.2	110.1	3000	2550	0.425	8		
					2505	0.417		35	
					2460	0.41			63
BSD-9D	3-(Lab A)	17.4	112.3	750	600	0.40	30	600(2)	-
	3-(Lab A)	18.1	110.1	3000	2520	0.42	4		
					2475	0.412		14.5	
					2415	0.402			37.5
	5-(Lab B)	19.9	108.7	6000	4980	0.415	4.7	8.5	
					4890	0.407			14
	5-(Lab C)	22.5	106.1	3000	2715	0.452	4.5	10.5	
					2625	0.438			25

(1) Cyclic deviator stress varied slightly during tests. Values reported are the average values for the number of cycles corresponding to initial liquefaction, ± 5% strain, and ± 10% strain.
(2) Extrapolated values

Table 2.5-36
Results of Cyclic Triaxial Tests On
Undisturbed Samples of Saprolite

Boring No.	Depth (ft)	Moisture Content (%)	Dry Density (pcf)	Confining Pressure σ_{3c} (psf)	Peak Cyclic Deviator Stress, $\pm\sigma_d$ (psf)	Stress Ratio $\pm\sigma_d$ $2\sigma_{3c}$	No. of Cycles to Cause		
							Initial Liquefaction	± 5% Strain	± 10% Strain
C-5	12-14	27.5	85.1	3,000	2,640	0.440	1.8	3.6	6.6
SS-1	18-20	20.9	91.3	3,000	2,880	0.480	2.9	14.2	22.5
ED-3	34-36	16.8	94.8	3,000	2,750	0.458	2.1	5.6	11.3
ED-3	42-44	30.8	90.2	6,000	5,200	0.434	2	7	10

Table 2.5-37
Cyclic Strength Characteristics of In Situ Soils

Confining Pressure σ_3 (psf)	Laboratory Stress Ratio Causing 5% Strain, $\frac{\pm \sigma_d}{2\sigma_3}$		Factor Correction Cr	Field Stress Ratio Causing 5% Strain, $\pm \tau^{(1)}/\sigma$	
	10 Cycles	20 Cycles		10 Cycles	20 Cycles
750	0.51	0.49	0,80	0.41	0.39
1500	0.485	0.46	0.79	0.38	0.36
3000	0.43	0.41	0.75	0.32	0.31
6000	0.39	0.365	0.72	0.28	0.26

Note:

(1) τ = cyclic shear stress
σ = effective normal pressure

Table 2.5-38
Shear Wave Velocities and Maximum Shear
Moduli For Foundation Materials

Horizon	Shear Wave Velocity (ft/sec)	Maximum Shear Moduli (ksi)
Intact Rock	7400 to 8000	1896 to 2277
Decomposed Rock	1500 to 2300	65.5 to 154
Saprolite and Transported Soils	835 to 1125	19.5 to 35.5

Table 2.5-39
Sonic Velocity Test Results

Sample	Vp (ft/sec)	Vs (ft/sec)	G (ksi)	μ	E (ksi)	γ (pcf)
ND 7-2	15598	8063	2104	.318	5546	150.1
ND 7-3	13066	7302	2028	.273	5163	176.4
ND 7-4	15401	8028	2494	.313	6553	179.5
SD 1-1	14795	8430	2838	.260	7151	185.2
SD 1-2	16404	8622	2971	.309	7780	185.4
SD 1-3	10555	6503	1599		3821	175.5
SC 1-4	12836	7783	2303	.209	5569	176.3

Vs = Shear wave velocity
Vp = Compressional wave velocity
G = Shear modulus
μ = Poisson's Ratio
E = Young's Modulus
γ = Unit Moist Weight

Note:
(1) All tests conducted without axial or confining stress on sound rock cores.

INSERT TABLES 2.5-40 SHEETS 1-6

Table 2.5-40
Summary of Laboratory Test Results

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SUMMARY OF LABORATORY TEST RESULTS - BORROW SOURCE F

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		SHRINKAGE LIMIT	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			UU	CIU	CELL PRESSURE (psi)	BACK PRESSURE (psi)
F- 1 Bag	0 -43.5	SM-ML	(1)		NP	NP			36.0	2.73	*	*	*	*	*	-	3 point	series
F- 3 Bag	0 -43.5	SM-ML	(1)		NP	NP			36.0	2.73	*	*	*	*	*	-	3 point	series
RES-1F	0 -15.0	MH-ML (Note 1)	(1)		51	46				2.65	*	*	*	*	*	-	3 point	series
F- 7 B-1	5.0-10.0	ML-SM	(1)	30.1	53	45			28.8	2.81	*	*	*	*	*	-	3 point	series
F- 7A B-1	25.0-30.0	SM	(1)	20.8					31.6	2.78	*		*	*		*	3 point	series
F-11 B-1	7.5-10.0	ML		23.6							*							
F-11 B-2	30.0-35.0	ML		26.4							*							
F-13 B-1	10.0-15.0	SM	(2)	22.0	43	41			32.8	2.74	*	*	*					
F-13 B-2	35.0-40.0	SM		23.1	50	47			37.3	2.77	*	*	*			*	3 point	series
F-15 B-1	10.0-15.0	SM		23.4	47	36			34.2		*		*					
F-15 B-2	40.0-45.0	SM		25.7					33.8	2.71	*		*		*	-	3 point	series

* See Test Curves (1) Permeability (2) Torsion

Note 1 - Test sample consists of combination of selected samples derived from a depth of 0 to 15 feet (13 samples) from Borings F-1 through F-4

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TABLE 2.5-40 (Cont'd)
Sheet 2 of 6

SUMMARY OF LABORATORY TEST RESULTS - BORROW SOURCE G

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	Shrinkage Limit	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR.			U.U.	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
TBG-2 S-3	15.0-16.5	SM									*							
S-1	20.0-21.5	SM									*							
S-6	30.0-31.5	SM									*							
S-8	40.0-41.5	SM									*							
TBG-3 S-1	5.0- 6.5	CH	28.3		51	27												
S-3	15.0-16.5	MH	28.7		60	41					*	*						
S-5	25.0-26.5	ML			50	45					*	*						
S-8	40.0-41.5	ML									*	*						
S-9	45.0-46.5	SM									*							
TBG-5 S-1	5.0- 6.5	MH		24.9	50	36												
S-2	10.0-11.5	MH	26.2		54	32												
Bag	20.0-25.0	ML								2.73	*	*						
S-5	25.0-26.5	SM									*							
Bag	35.0-40.0	ML									*	*						
Bag	45.0-50.0	ML									*	*						

* See Test Curves

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TABLE 2.5-40 (Cont'd)
Sheet 3 of 6

SUMMARY OF LABORATORY TEST RESULTS - BORROW SOURCE G

BORING and SAMPLE No	DEPTH feet	CLASSIFICATION	Shrinkage Limit	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			U.U.	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
TBG-7 S-3	15.0-16.5	ML			44	42					*	*						
Bag	40.0-45.0	ML									*	*						
TBG-8 S-1	5.0- 6.5	MH		28.2	65	33					*	*						
S-3	15.0-16.5	ML		27.3							*	*						
S-7A	35.0-35.5	ML		22.3	35	27					*	*						
S-7B	35.5-36.5	MH		37.1	66	54					*	*						
TBG-10 S-1	5.0- 6.5	CH		22.5	51	28												
S-3	15.0-16.5	ML	22.5	20.3	45	36												
S-7	35.0-36.5	SM		23.9	20	NP					*	*						
TBG-12 S-3	15.0-16.5	MH			66	60					*	*						
S-5	25.0-26.5	SM		22.9							*							
S-6	30.0-31.5	ML		26.3	44	NP												
Bag	30.0-35.0	ML									*	*						
Bag	40.0-45.0	ML									*	*						
TBG-14 S-2	10.0-11.5	ML			35	NP												

* See Test Curves

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TABLE 2.5-40 (Cont'd)
Sheet 4 of 6

SUMMARY OF LABORATORY TEST RESULTS – BORROW SOURCE G

BORING and SAMPLE No.	DEPTH feet	CLASSIFICATION	Shrinkage Limit	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS.		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR.			UU	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
TBG-14																		
S-3	20.0-21.5	SM			52	42					*	*						
S-8	40.0-41.5	SM								2.81	*	*						
TBG-15																		
S-1	5.0- 6.5	ML	26.2		53	41												
S-3	15.0-16.5	ML									*	*						
S-4	20.0-21.5	ML									*	*						
Bag	20.0-25.0	ML									*	*						
S-7	35.0-36.5	SM								2.64	*	*						*
Bag	35.0-40.0	ML									*	*						
TBG-16																		
Bag	5.0-10.0	SM									*	*						
Bag	25.0-30.0	SM									*	*						
TBG-17																		
S-1	5.0- 6.5	ML	24.4	25.9	48	33												
S-3	15.0-16.5	ML									*							
Bag	35.0-40.0	ML									*	*						
TBG-20																		
S-1	5.0- 6.5	ML		23.4	53	31												
S-2	10.0-11.5	ML		29.8	69	44												

* See Test Curves

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SUMMARY OF LABORATORY TEST RESULTS - BORROW SOURCE G

BORING and SAMPLE No	DEPTH feet	CLASSIFICATION	Shrinkage Limit	NATURAL WAT. CONTENT (%)	ATTERBERG LIMITS LIQUID LIM.	ATTERBERG LIMITS PLASTIC LIMIT	UNCON COMPRESS STRESS (tsf)	UNCON COMPRESS STRAIN (%)	UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE SIEVE	GRAIN SIZE HYDR	OPT MOIST	CONSOLID	TRIAXIAL U.U	TRIAXIAL $\overline{CIU}$	TRIAXIAL CELL PRESSURE (psi)	TRIAXIAL BACK PRESSURE (psi)
TBG-23 S-1	5.0- 6.5	CH		25.2	53	23												
S-2	10.0-11.5	MH	33.7	28.2	59	37												
S-5	25.0-26.5	MH		34.0	60	51					*	*						
S-7	35.0-36.5	SM									*							
TPG- 4	5.0-10.0	MH	28.0		56	38				2.72	*		*					
TPG- 9	9.0-10.0	MH			53	31				2.71	*		*					
TPG-11	7.0-11.0	MH			52	38				2.83	*		*					
TPG-18	8.0-12.0	MH			57	41				2.79	*		*					
TPG-21	10.0-13.0	SM			NP	NP				2.69	*		*					
TPG-22	9.0-12.0	ML			NP	NP				2.84	*		*					
TPG-24	12.0-15.0	MH			52	34				2.81	*		*					
TPG-25	12.0-15.0	ML	27.5		46	33				2.77	*		*					

* See Test Curves

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TABLE 2.5-40 (Cont'd)
Sheet 6 of 6

SUMMARY OF LABORATORY TEST RESULTS — BORROW SOURCE G

BORING and SAMPLE No	DEPTH - feet	CLASSIFICATION	SPECIAL TESTS	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS		UNCON COMPRESS		UNIT DRY WGT (pcf)	SPECIFIC GRAVITY	GRAIN SIZE		OPT MOIST	CONSOLID	TRIAXIAL			
					LIQUID LIMIT	PLASTIC LIMIT	STRESS (tsf)	STRAIN (%)			SIEVE	HYDR			U.U.	$\overline{CIU}$	CELL PRESSURE (psi)	BACK PRESSURE (psi)
TPG-4					66	36												
TPG-5					67	37										*		
TPG-24		High PI mixture	(1)															
					55	30												
					67	39												
					63	28												
TPG-11					59	37												
TPG-18					58	35										*		
TPG-25		Intermediate PI mixture	(1)															
					62	37												
					62	40												
Bag 1	439.2				76	43				2.71	*	*	*					
					59	35								*				
Bag 2	445.2		(2)		64	38				2.74	*	*	*	*				
Bag 3	439.6				56	37				2.82	*	*	*					
Bag 1&2 mixture			(2)		63	36								*				

* See Test Curves (1) Torsion (2) Permeability

Table 2.5-41
Physical Properties of Borrow Material

Residual Soil

Property	Range	Average	Number of tests
Natural Water Content, %	22.5 to 29.8	26.0	8
Liquid Limit, %	46 to 69	55	18
Plasticity Index,	12 to 32	21	18
Specific Gravity	2.77 to 2.84	2.80	2

Saprolite

Property	Range	Average	Number of tests
Natural Water Content, %	20.8 to 37.1	25.7	15
Liquid Limit, %	35 to 66	47	15
Plasticity Index, %	0 to 12	6	15
Specific Gravity	2.64 to 2.81	2.78	10

Table 2.5-42
Shear Strength Properties of
Laboratory Compacted Borrow Material

Total Stress Parameters

Test Series	C_ξ (psf)	φ_u (degrees)
F-1	1,320	18.5
F-3	2,000	19.4
RES-1F	3,700	15.4
F-7	2,200	19.7
F-15	2,000	15.0

Effective Stress Parameters

Test Series	$\overline{C}$ (psf)	$\overline{\varphi}$ (degrees)
F-7A	550	24.0
F-13	700	21.0
Int. PI	230	30.0
High PI	230	28.0

Table 2.5-43
Results of Cyclic Triaxial Tests On Isotropically
Consolidated Reconstituted Samples

Confining Pressure, σ_3 (psf)	Sample No.	Moisture Content %	Dry Density (pcf)	Peak Cyclic Deviator Stress. [1] $\pm \sigma_d$ (psf)	Stress Ratio, [1] $\pm \sigma_d / 2\sigma_3$	No. of Cycles to Cause		
						Initial Liquefaction	± 5% Strain	10% Strain
750	17	18.3	107.2	810	0.54	41	> 1000[2]	---
	18	18.2	107.3	630	0.42	83	> 1000[2]	---
1500	1	17.5	108.0	1185	0.395	46		
				1280	0.425		900[2]	---
	6	17.8	107.7	1385	0.462	5		
				1580	0.525		48	> 1000[2]
	7	17.6	107.9	1320	0.44	9		
				1500	0.50		52	> 1000[2]
3000	2	17.7	107.8	2460	0.41	1	6.2	70
	3	17.8	107.7	2670	0.445	1	3.9	
				2730	0.455			15.7

Table 2.5-43 (continued)
Results of Cyclic Triaxial Tests On Isotropically
Consolidated Reconstituted Samples

Confining Pressure, σ_3 (psf)	Sample No.	Moisture Content %	Dry Density (pcf)	Peak Cyclic Deviator Stress. (1) $\pm \sigma_d$ (psf)	Stress Ratio, (1) $\pm \sigma_d / 2\sigma_3$	No. of Cycles to Cause		
						Initial Liquefaction	± 5% Strain	10% Strain
	5	18.2	107.4	2320	0.385	4.8	21.7	> 1000(2)
6000	4	18.0	107.5	4920	0.41	1	2.1	8.1
	8			4460	0.372	1	3.7	13
	12	17.9	107.6	4300	0.35	3.1	9.8	
				4100	0.342			35

NOTES

(1) Cyclic deviator stress varied slightly during tests. Values reported are the average values for the number of cycles corresponding to initial liquefaction, ± 5% strain, and ± 10% strain.
(2) Extrapolated values.

Table 2.5-44
Results of Cyclic Triaxial Tests On Anisotropically
Consolidated Reconstituted Samples

Confining Pressure, σ_3 (psf)	Consolidation Ratio Kc = $\sigma 1 / \sigma 3$	Sample No.	Moisture Content %	Dry Density (pcf)	Peak Cyclic Deviator Stress. (1) $\pm \sigma_d$ (psf)	Peak Cyclic Shear Stress on Failure Plane (1) $\pm \gamma$ (psf)	No. of Cycles to Cause ± 5% Strain	No. of Cycles to Cause 10% Strain
400	1.5	23	18.1	107.5	410	170	2000(2)	---
		24	18.1	107.6	570	240	15	> 1000(2)
	2.0	25	18.0	107.6	590	250	34	> 1000(2)
		26	18.1	107.4	675	285	9.5	> 1000(2)
750	1.5	16	18.2	107.4	755	330	60	> 1000(2)
		21	17.8	107.7	1065	445	11	
					1110	465		143
1500	1.5	11	18.1	107.4	1500	635	11	
					1510	640		170
		13			1920	810	3.3	
					1980	840		25

Table 2.5-44 (continued)
Results of Cyclic Triaxial Tests On Anisotropically
Consolidated Reconstituted Samples

Confining Pressure, σ_3 (psf)	Consolidation Ratio Kc = $\sigma 1 / \sigma 3$	Sample No.	Moisture Content %	Dry Density (pcf)	Peak Cyclic Deviator Stress. (1) $\pm \sigma_d$ (psf)	Peak Cyclic Shear Stress on Failure Plane (1) $\pm \gamma$ (psf)	No. of Cycles to Cause ± 5% Strain	No. of Cycles to Cause 10% Strain
	2.0	14	18.1	107.4	2050	845	1.6	
					2090	865		11.5
		15	18.5	107.1	1500	630	6.6	
					1545	645		130
3000	1.5	9	17.9	107.6	2590	1080	4.2	
					2640	1120		24.8
		10	18.0	107.5	2980	1250	1.5	
					3010	1265		7.4

(1) Cyclic deviator stress varied slightly during tests. Values reported are the average values for the number of cycles corresponding to initial liquefaction, ± 5% strain, and ± 10% strain.
(2) Extrapolated values.

Table 2.5-45
Results of Stress-Controlled Cyclic Triaxial Tests
On Intermediate Residual Soils(1)

Test No.	Initial Effective Confining Pressure σ_{3c} (psf)	K_c	Cyclic Stress Ratio $\pm \sigma_d/2\sigma_{3c}$	Number of Cycles Required to Cause 5% Strain
C-112	3000	1.5	0.436	9
C-19	6000	1.0	0.348	381
C-110	6000	1.0	0.385	3-1/2
C-113	6000	1.0	0.384	3-1/2
O-11	6000	1.0	0.361	3
O-12	6000	1.0	0.345	6
O-13	6000	1.0	0.339	6
O-14	6000	1.0	0.316	11-1/2

(1) PI approximately 19

Table 2.5-46
Correction Factors

Confining Pressure, σ_3 (psf)	Correction Factor, C_r
1500 or less	0.80
3000	0.70
6000	0.65

Table 2.5-47
Specified Gradations of Filter Materials

Zone 1 Filter

Sieve Size US Standard Mesh	Percent Passing by Dry Weight
3/4 inch	100
No. 4	75 - 100
No. 10	50 - 85
No. 40	10 - 50
No. 200	0 - 5

Zone 2 Filter

Sieve Size US Standard Mesh	Percent Passing by Dry Weight
6 inch	100
3 inch	75 - 100
1-1/2 inch	40 - 85
3/8 inch	15 - 60
No. 10	0 - 10

Table 2.5-48
Specified Gradations of Riprap

Zone A		Zone B	
Size (inches)	Percent Finer by Weight	Size (inches)	Percent Finer by Weight
30	100	18	100
18	40-90	12	35-85
12	25-60	6	10-40
3	0-10	3	0-10

Zone C

	Rock Size in Inches for a Specific Gravity Range of				
	2.55 to 2.65	2.65 to 2.74	2.75 to 2.84	2.85 and up	Percent Passing by Count
(1)	45	43	39	37	100
(2)	39	37	34	32	90-100
(3)	33	31	29	27	0-5

Zone D

Size (inches)	Percent Finer by Weight
30	100
18	40-90
15	25-60
8	0-10

Table 2.5-49
Properties Used For Deformation Analysis

Material	Yt (pcf)	S (%0	B	Cv (ft2/day)	C'c	C'r
Embankment	120	83	0.23	4.00	0.054 to 0.064	NA
Saprolite	105	100	1.0	NA	0.22	0.012
Decomposed Rock	139	100	1.0	NA	NA	0.007

NA = Not applicable

Yt = Total unit weight

S = Degree of saturation

B = Pore pressure parameter

Cv = Coefficient of consolidation

C'c = Virgin Compression index, unit strain basis

C'r = Recompression index, unit strain basis

Table 2.5-50
Select Fill Placement Testing Procedures and Frequencies

Placement Tests	ASTM Designation	Test Frequency (3)
Moisture Content	D 2216 or DD 1556 (1)	C,D,H
Gradation	D 422	F, I
Atterburg Limits	D 423, D424	F, I
Specific Gravity	D 854	F, J
Compaction Standard	D 1557, Method A	F, G, J
In-Place Density Test	D 1556 (2), D 2922	A, B, C, D, E, F

(1) After calibration, the Speedy Moisture Tester can be used in lieu of ASTM D 2216, provided at least every tenth test is checked against ASTM D 2216.
(2) After calibration, the Troxler Nuclear Method, ASTM D 2922, can be used, provided at least every tenth test is checked against ASTM D 1556.
(3) Test frequency letter designations are as follows:

A - In areas where degree of compaction is doubtful.
B - In area where earth fill operations are concentrated.
C - At least one for each earth fill shift.
D - One for every 2,000 cubic yards of fill for control.
E - For record tests at location of any embedded items.
F - Where material identify is questionable.
G - One point test for field density tests as needed.
H - Where soil appears too wet or too dry.
I - One for every 12,000 cubic yards for record and control.
J - One for every 50,000 cubic yards for record and control.

Table 2.5-51
Summary of Construction Control
Physical Property Tests on Select Fill

	Maximum	Minimum	Average	Number of Tests	Specification Requirements
North Dam					
Liquid Limit (1)	61	50	54	7	≤ 70
Plastic Limit (1)	53	43	47	7	N/A
Plasticity Index (1)	11	3	7	7	≤ 25
Specific Gravity	2.88	2.67	2.74	50	N/A
South Dam					
Liquid Limit (1)	67	53	58	5	≤ 70
Plastic Limit (1)	54	44	47	5	N/A
Plasticity Index (1)	17	5	10	5	≤ 25
Specific Gravity	2.88	2.69	2.74	25	N/A
East Dam					
Liquid Limit (1)	57	51	53	7	≤ 70
Plastic Limit (1)	48	39	44	7	N/A
Plasticity Index (1)	18	6	10	7	≤ 25
Specific Gravity	2.85	2.72	2.76	10	N/A
West Embankment					
Liquid Limit (1)	68	45	55	9	≤ 70

Table 2.5-51 (continued)
Summary of Construction Control
Physical Property Tests on Select Fill

	Maximum	Minimum	Average	Number of Tests	Specification Requirements
Plastic Limit (1)	53	38	45	9	N/A
Plasticity Index (1)	15	6	9	9	≤ 25
Specific Gravity	2.86	2.59	2.70	52	N/A
Borrow Source Control Tests					
Liquid Limit (1)	70	43	57	21	≤ 70
Plastic Limit (1)	58	28	44	21	N/A
Plasticity Index (1)	28	4	13	21	≤ 25
Specific Gravity	2.93	2.62	2.77	53	N/A

(1) Data excludes all nonplastic test results:
North Dam - 69 tests
South Dam - 24 tests
East Dam - 3 tests
West Embankment - 47 tests
Borrow Control - 50 tests

Table 2.5-52
Testing Requirements for Zone 1 Filter Materials

Pre-Qualification Test	Placement Test	ASTM Designation	Test Frequency (1)
Gradation	--	C 136	A, B
Specific Gravity	--	C 128	B
--	Gradation	C 136	A, C
--	Specific Gravity	C 128	C
--	Compaction Standard (2)	D 2049	A, D
--	In-Place Density Test (horizontal filter only) (3)	D 1556	C

(1) Test frequency:
A - Where material identify is questionable.
B - One at each quarry source prior to delivery to site.
C - One for every 8,000 square yards for record and control.
D - 8 tests in horizontal filter materials for each dam.

(2) Minimum density to be determined by ASTM D 2049. Maximum density to be determined by the Department of the Army, EM 110-2-1906, Appendix XII, “Maximum Density of Cohesionless Soils, Modified Providence Method.”

(3) Relative density to be determined from results of in-place density test and compaction standard data.

Table 2.5-53
Zone 1 Filter for Horizontal Filter Blankets
Summary of Bulk Specific Gravity and
In-Place Density Tests (1)

	Bulk Specific Gravity	Relative Density
Minimum Specification Requirement	2.50	75.0%
Minimum Test Result	2.62	75.6% (1)
Maximum Test Result	2.67	106.7% (1)
Average Test Result	2.65	95.6
Number of Tests	21	14

(1) Data range is wide because the number of coverages by compaction equipment varied from four to nine passes and often compacted the materials to densities greater than could be achieved using the specified ASTM procedure.

Table 2.5-54
Zone 2 Filter Material Testing Procedures and Frequencies

Pre-Qualification Test	Placement Test	ASTM Designation	Test Frequency (1)
Gradation	--	C 136	B
Specific Gravity	--	C 127	B
Sodium Sulfate Soundness	--	C 88	B
LA Abrasion	--	C 535	B
--	Gradation	C 136	A, C or D
--	Specific Gravity	C 127	E
--	Sodium Sulfate Soundness	C 88	C
--	In-Place Permeability (3)	By Engineer	E

(1) Test frequency:
A - Where material identity is questionable.
B - One at each quarry source prior to delivery to site.
C - One for every 8,000 square yards for record and control.
D - One from the conveyor belt for every 2,000 cubic yards produced for record and control.
E - Eight tests in horizontal filter materials for each dam.

(2) Minimum density to be determined by ASTM D 2049. Maximum density to be determined by the Department of the Army, EM 1110-2-1906, Appendix XII, "Maximum Density of Cohesionless Soils, Modified Providence Method.

(3) For record and control on horizontal filters only.

(4) Relative density to be determined from results of in-place density test and compaction standard data.

Table 2.5-56
Summary of In Situ Permeability Test
on Horizontal Drainage Blankets

North Dam		
Specification Requirement, cm/sec	$K \leq 1.0 \times 10^{-3}$	
Maximum Recorded Value, cm/sec	$K = 198.0 \times 10^{-3}$	
Minimum Recorded Value, cm/sec	$K = 1.4 \times 10^{-3}$	
Average Value, cm/sec	$K = 71 \times 10^{-3}$	
Number of Tests		8
South Dam		
Specification Requirements, cm/sec	$K \leq 1.0 \times 10^{-3}$	
Maximum Recorded Value	218×10^{-3}	
Minimum Recorded Value	10×10^{-3}	
Average Value	59×10^{-3}	
Number of Tests		8

Table 2.5-57
Riprap Testing Procedures and Frequencies

Pre-Qualification Test	Placement Test	ASTM Designation	Test Frequency (1)
Gradation	--	Special Procedure	B
Specific Gravity	--	C 127	B
Sodium Sulfate Soundness	--	C 88	B
LA Abrasion	--	C 535	B
--	Gradation	C 136 for < 6 in. Visual > 6 in.	A, C
--	Specific Gravity	C 127	C
	Sodium Sulfate Soundness	C 88	C

(1) Test frequency:
A - Where material identify is questionable.
B - One at each quarry source prior to delivery to site.
C - One for every 12,000 cubic yards for record and control.

Table 2.5-58
Riprap Summary of Bulk Specific Gravity and
Sodium Sulfate Soundness Tests

	Bulk Specif Gravity	Sodium Sulfate Loss	
Particle Size	--	1 1/2" to 3/4"	3/4" to 3/8"
Specification Requirement	2.50	10%, Maximum	10%, Maximum
Maximum Test Result	2.75	8.1%	6.8%
Minimum Test Result	2.62	0.0%	0.6%
Average Test Result	2.70	1.9%	2.5%
Number of Tests	12	16	16

INSERT TABLE 2.5-59 SHEETS 1-8

Table 2.5-59 and 2.5-59A
Summary of Block Sample Test Results for Dams

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TABLE 2.5-59 (Sheet 1 of 8)

SUMMARY OF BLOCK SAMPLE TEST RESULTS FOR

[illegible] DAM

BLOCK SAMPLE NO.	COORDINATE LOCATION	ELEV. (ft.)	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS L.L.	P.L.	P.I.	S.L.	SPECIFIC GRAVITY	UNIT DRY WGT. (pcf)	COMP. STD. NO.	MAX. DRY DENSITY (pcf)	OPT. MOIST. (%)	PERCENT COMP.	GRAIN SIZE SIEVE	HYDR.	% < 200	CONSOLID.	PERMEABILITY	UU SERIES ϕ (deg)	UU SERIES c (psf)	CTU SERIES $\bar{\phi}$ (deg)	CTU SERIES $\bar{c}$ (psf)	OTHER TESTS
UDS- 5	N473,035 E1,905,847	338.0	26.6	59	46	13			93.3	68	100.6	25.5	92.7	*	*	80	*						NOTE: Fill removed due to adverse weather and moisture conditions
			26.8						92.3	68	100.6	25.5	91.7										
			24.5																				
			20.8																				
			27.5						92.4	88	103.8	20.0	89.0										
			28.7						91.7	88	103.8	20.0	88.3						19.0	2800			
			28.0						92.7	88	103.8	20.0	89.3										
UDS- 6	N473,[illegible] E1,905,858	336.0	SAMPLE [illegible] SHIPPAGE																				
UDS- 8	N473,034 E1,905,812	342.0	23.4	57	49	8																	Resonant Column
			22.7	55	41	14																	
			23.6																				
			22.4																				
			24.9																				
			23.2						88.0	68	100.6	25.5	87.4						21.5	3000			
			25.1						92.9	68	100.6	25.5	92.3										
			23.6						96.8	68	100.6	25.5	96.2										
			22.8	47	42	5		2.74	90.7	68	100.6	25.5	90.0				*						
UDS-12	N473,258 E1,905,841	330.0	25.2	59	45	14	30		82.7					*	*	59							
			24.6						83.5	88	103.8	20.0	80.4										
			26.4						95.8	88	103.8	20.0	92.3								25.6	600	
			24.2						96.8	88	103.8	20.0	93.3										Dispersion by SCS Procedures
									89.3								*	*					Pinhole dispersion
																	*	*					
UDS-14	N473,212 E1,905,751	336.0	18.4	48	44	4	30	2.81	99.0	72	106.0	18.5	93.4	*	*	63							Resonant Column
																							SCS dispersion
																							Pinhole dispersion
UDS-15	N473,031 E1,905,849	348.0	21.1	57	41	16	32	2.71	91.8	67	100.7	23.8	91.2	*	*	73							Dispersion by SCS Procedure
			21.1						87.5	67	100.7	23.8	85.9						22.0	3000			
			21.1						94.9	67	100.7	23.8	94.2										Pinhole Dispersion Test
			22.1						92.7	67	100.7	23.8	92.1				*	*					
			21.6						93.5	67	100.7	23.8	92.8				*	*					
UDS-16	N473,031 E1,905,852	348.0	SAMPLE [illegible]																				

"* SEE TEST CURVES"

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TABLE 2.5-59 (Sheet 2 of 8)

SUMMARY OF BLOCK SAMPLE TEST RESULTS

NORTH DAM

BLOCK SAMPLE NO.	COORDINATE LOCATION	ELEV. (Ft.)	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS				SPECIFIC GRAVITY	UNIT DRY WGT. (pcf)	COMP. STD. NO.	MAX. DRY DENSITY (pcf)	OPT. MOIST. (%)	PERCENT COMP.	GRAIN SIZE			CONSOLID.	PERMEABILITY	UU SERIES		CU SERIES		OTHER TESTS
				L.L.	P.L.	P.I.	S.L.							SIEVE	HYDR.	% < 200			φ (deg)	c (psf)	$\bar{\phi}$ (deg)	$\bar{c}$ (psf)	
UDS-19	N473,418 E1,905,637	344.0	22.0	52	45	7		2.69	89.1	145	106.9	19.3	83.3	*	*	71							
			22.2						97.1	145	106.9	19.3	90.8				*	*					
			22.4						98.8	145	106.9	19.3	92.4				*	*					
			21.6						86.9	145	106.9	19.3	81.3								33.2	0	
			22.0						93.3	145	106.9	19.3	87.3										
			20.9						87.2	145	106.9	19.3	81.6										
UDS-21A	N473,276 E1,905,790	363.0	SAMPLE NOT TESTED							146	106.9	19.4											
UDS-26	N473,396 E1,905,594	369.0	21.5																				
			21.8																				
			20.2	47	34	13		2.69						*	*	54							
			20.2						88.9	178	105.7	20.0	84.1										
			26.9 (1)						89.0	178	105.7	20.0	84.1										Resonant Column
			25.4 (1)						91.0	178	105.7	20.0	84.1										
			22.9 (1)						89.1	178	105.7	20.0	84.1										
			21.9 (1)						90.0	178	105.7	20.0	84.1										
UDS-27	N473,018 E1,905,8[illegible]	361.0	21.1	NP	NP	NP										69							
			22.2																				
			21.4																				
			23.3						92.5	167	105.9	18.5	87.3								31.0	140	
			23.3						93.0	167	105.9	18.5	87.8										
			23.1						93.1	167	105.9	18.5	87.9										
UDS-30	N473,249 E1,905,715	379.0	20.1	51	44	7		2.74						*	*	53							
			21.5																				
			21.0																				
			20.1						93.7	I-39	108.2	18.2	86.6										
			21.5						92.2	I-39	108.2	18.2	85.2						35	1200			
			21.0						91.7	I-39	108.2	18.2	84.8										
UDS-31	N473,355 E1,905,670	381.0		54	41	13		2.70						*	*	56							
				NP	NP	NP																	
			21.6						95.1	221	111.8	15.5	85.1				*	*					
			19.1						98.8	221	111.8	15.5	88.4										
			18.9						98.7	221	111.8	15.5	88.3										
			19.2						97.7	221	111.8	15.5	87.4								28	230	
32	N473,110 E1,905,890	375.0	SAMPLE NOT TESTED							222	113.4	15.3											

(1) Initial moisture contents computed after testing

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TABLE 2.5-59 (Sheet 3 of 8)

SUMMARY OF BLOCK SAMPLE TEST RESULTS
NORTH DAM

BLOCK SAMPLE NO.	COORDINATE LOCATION	ELEV. (Ft.)	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS L.L.	P.L.	P.I.	S.L.	SPECIFIC GRAVITY	UNIT DRY WGT. (pcf)	COMP. STD. NO.	MAX. DRY DENSITY (pcf)	OPT. MOIST. (%)	PERCENT COMP.	GRAIN SIZE SIEVE	HYDR.	% < 200	CONSOLID.	PERMEABILITY	UU SERIES φ (deg)	UU SERIES c (psf)	CTU SERIES $\bar{\phi}$ (deg)	CTU SERIES $\bar{c}$ (psf)	OTHER TESTS
UDS-35	N473,210 E1,905,701	387	SAMPLE NOT TESTED							237	108.7	17.7											
UDS-37	N473,099 E1,905,955	384	21.3 21.6 20.2 21.2 19.9	NP	NP			2.70	 93.3 92.7 98.2	 247 247 247	 109.0 109.0 109.0	 18.7 18.7 18.7	 85.6 85.1 90.1	*	*	66					31	460	
UDS-38	N473,388 E1,905,967	394	20.3 20.2 21.9	52 52 52	44 44 44	8 8 8		2.73 2.74 2.74	98.1 98.7 96.0	250 250 250	110.8 110.8 110.8	16.0 16.0 16.0	88.5 89.1 86.6	*	*	59							Cyclic Testing
UDS-39	N473,110 E1,905,529	401	SAMPLE NOT TESTED																				
UDS-42	N473,150 E1,905,383	405	SAMPLE NOT TESTED							264	111.6	16.2											
UDS-43	N473,342 E1,905,905	408	SAMPLE NOT TESTED							275	112.8	14.5											
UDS-44	N473,342 E1,905,908	408	20.6 17.6 18.4 18.8	43	36	7		2.70	 97.8 99.0 100.5	 275 275 275	 112.8 112.8 112.8	 14.5 14.5 14.5	 86.7 87.8 89.1	*	*	59					26	400	
UDS-45	N473,254 E1,906,088	413	SAMPLE NOT TESTED																				
UDS-50	N473,276 E1,905,989	433	SAMPLE NOT TESTED																				

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TABLE 2.5-59 (Sheet 4 of 8)

SUMMARY OF BLOCK SAMPLE TEST RESULTS
SOUTH DAM

BLOCK SAMPLE NO.	COORDINATE LOCATION	ELEV. (Ft.).	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS				SPECIFIC GRAVITY	UNIT DRY WGT. (pcf)	COMP. STD. NO.	MAX. DRY DENSITY (pcf)	OPT. MOIST. (%)	PERCENT COMP.	GRAIN SIZE			CONSOLID.	PERMEABILITY	UU SERIES		CĪU SERIES		OTHER TESTS
				L.L.	P.L.	P.I.	S.L.							SIEVE	HYDR.	%<#200			φ (deg)	c (psf)	φ̄ (deg)	c̄ (psf)	
USD-11	N472,049 E1,906,645	364.9	24.3	61	43	18		2.77						*	*	62							
			24.5	64	42	22																	
				62	45	17																	
			24.1						89.2	85	103.0	22.5	86.6										
			24.4						90.0	85	103.0	22.5	87.4										
			25.4						90.1	85	103.0	22.5	87.5								31.0	250	Resonant Column
			21.8						91.1	85	103.0	22.5	88.4				*	*					
UDS-13	N472,172 E1,906,738	375.0	18.8	60	49	11	35	2.77															
			18.6																				
			18.6											*	*	63							
			20.0						85.7	72	106.0	18.5	80.9				*	*					
			18.1						89.7	72	106.0	18.5	84.6				*	*					
			18.8						91.2	72	106.0	18.5	86.0										
			18.6						85.1	72	106.0	18.5	81.2						20.0	2200			
			18.6						86.1	72	106.0	18.5	81.2										
			19.5						85.4	72	106.0	13.5	80.6										
UDS-17	N471,942 E1,906,758	391	19.1	NP	NP	NP		2.73	90.4					*	*	52							
			19.1	NP	NP	NP		2.73	96.3	116	107.6	14.8	89.3				*	*					
			18.7	NP	NP	NP		2.73	93.5	116	107.6	14.8	86.9				*	*					
			19.1						89.4	116	107.6	14.8	83										
			18.5						91.4	116	107.6	14.8	85								30.9	0	
			16.7						90.4	116	107.6	14.8	84										
UDS-18	N472,114 E1,906,727	402	22.7	68	44	24	27	2.73						*	*	72							SCS Dispersion
			19.0						95.7	115	104.6	17.7	91.5										
			23.7						94.2	115	104.6	17.7	90.0								30	580	
			22.3						100.0	115	104.6	17.7	95.6										
UDS-20	N472,171 E1,906,740	407	25.4	60	32	18		2.70						*	*	68							
			25.2																				
			24.7	60	32	18		2.70	85.8	162	105.8	19.0	81.1				*						
UDS-24	N472,031 E1,906,547	422	22.5 avg.	NP	NP	NP		2.70						*	*	67							
			24.4					2.70	91.2								*						
			22.3						91.8	178	105.7	20.0	86.8				*						
			22.9						83.1	178	105.7	20.0	78.6						21.0	2000			
			20.4						87.1	178	105.7	20.0	82.4										
UDS-25	N472,034 E1,906,548	422	SAMPLE NOT TESTED																				

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TABLE 2.5-59 (Sheet 5 of 8)

SUMMARY OF BLOCK SAMPLE TEST RESULTS
EAST DAM

BLOCK SAMPLE NO.	COORDINATE LOCATION	ELEV. (Ft.)	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS				SPECIFIC GRAVITY	UNIT DRY WGT. (pcf)	COMP. STD. NO.	MAX. DRY DENSITY (pcf)	OPT. MOIST. (%)	PERCENT COMP.	GRAIN SIZE			CONSOLID.	PERMEABILITY	UU SERIES		$\bar{CTU}$ SERIES		OTHER TESTS
				L.L.	P.L.	P.I.	S.L.							SIEVE	HYDR.	% < 200			ϕ (deg)	c (psf)	$\bar{\phi}$ (deg)	$\bar{c}$ (psf)	
UDS-48	N472,960 E1,907,210	431	25.4 25.6 25.5 26.4	55	48	7		2.73	95.9 96.9 95.4 94.0	284 284 284 284	104.4 104.4 104.4 104.4	22.7 22.7 22.7 22.7	91.9 92.8 91.4 90.0	*	*	84	*		37	960			
UDS-49	N473,672 E1,906,930	430	24.6 24.5	57	44	13		2.74		284	104.4	22.7		*	*	74							

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TABLE 2.5-59 (Sheet 6 of 8)

SUMMARY OF BLOCK SAMPLE TEST RESULTS FOR
WEST EMBANKMENT

BLOCK SAMPLE NO.	COORDINATE LOCATION	ELEV. (Ft.)	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS L.L.	P.L.	P.I.	S.L.	SPECIFIC GRAVITY	UNIT DRY WGT. (pcf)	COMP. STD. NO.	MAX. DRY DENSITY (pcf)	OPT. MOIST. (%)	PERCENT COMP.	GRAIN SIZE SIEVE	HYDR.	% < #200	CONSOLID.	PERMEABILITY	UU SERIES φ (deg)	UU SERIES c (psf)	$\bar{CTU}$ SERIES $\bar{\phi}$ (deg)	$\bar{CTU}$ SERIES $\bar{c}$ (psf)	OTHER TESTS
UDS-1	N472,375 E1,905,400	369.0	24.0	60	38	22		2.64						*	*	58							
			24.6																				
			24.7	43	33	10																	
			29.5																				
			29.7	41	36	5																	
			29.5						87.6	15	108.3	17.5	80.9				*	*					
			29.8						91.4	15	108.3	17.5	84.4										
			24.1						91.5	15	108.3	17.5	84.5								19.7	1480	
			23.8						93.0	15	108.3	17.5	85.9										
			29.4						93.7	15	108.3	17.5	86.5										UU-Single Test $\frac{\sigma_1-\sigma_3}{2}$ = 5.6 tsf
UDS-2	N472,591 E1,905,450	383.0	23.3	43	33	10		2.65						*	*	58							
			23.2																				
			22.4																				
			23.2						89.9	15	108.3	17.5	83.0										
			22.2						88.9	15	108.3	17.5	83.0				*						Unconfined Compression $\sigma_{1_{max}}$ = 1.7 tsf
UDS-3	N 472,416 E1,905,445	383.5	23.8					2.67															
			21.7	45	35	10																	
			22.8																				
			24.7	42	31	8								*	*	62							
			23.2						96.4	15	108.3	17.5	89.0				*	*					
			24.1						97.8	15	108.3	17.5	90.3				*	*					
			22.3						101.5	15	108.3	17.5	93.7										
			22.5						102.0	15	108.3	17.5	94.2								27.8	900	
			25.2						99.4	15	108.3	17.5	91.8										
UDS-4	N472,745 E1,905,425	390.0	16.0	41	37	4		2.71						*	*	58							
			19.7																				
			22.0																				
			23.2																				
			21.2						93.6	25	107.6	18.0	87.0										
			20.3						93.6	25	107.6	18.0	87.0										Unconfined Compression $\sigma_{1_{max}}$ = 2.5 tsf
UDS-7	N472,380 E1,905,643	400.0	23.6	51	35	16		2.78						*	*	78							
			24.7	59	34	25		2.76						*	*	76							
			24.2	60	35	24		2.87						*	*	77							
			24.8																				
			24.3																				
			25.3																				
			25.0																				
			25.9																				Resonant Column

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TABLE 2.5-59 (Sheet 7 of 8)

SUMMARY OF BLOCK SAMPLE TEST RESULTS FOR
WEST EMBANKMENT

BLOCK SAMPLE NO.	COORDINATE LOCATION	ELEV. (Ft.)	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS				SPECIFIC GRAVITY	UNIT DRY WGT. (pcf)	COMP. STD. NO.	MAX. DRY DENSITY (pcf)	OPT. MOIST. (%)	PERCENT COMP.	GRAIN SIZE			CONSOLID.	PERMEABILITY	UU SERIES		$\bar{CTU}$ SERIES		OTHER TESTS
				L.L.	P.L.	P.I.	S.L.							SIEVE	HYDR.	% < #200			ϕ (deg)	c (psf)	$\bar{\phi}$ (deg)	$\bar{c}$ (psf)	
UDS-7 (cont.)			24.7					2.76	86.0	67	100.7	23.8	85.4				*	*					
			23.6						82.2	67	100.7	23.8	81.6				*	*					
			20.3						82.8	67	100.7	23.8	82.2										Resonant Column
			28.6						80.0	67	100.7	23.8	79.4										
			29.6						92.7	67	100.7	23.8	92.0										
			24.4						80.1	67	100.7	23.8	79.5										
			25.6						95.7	67	100.7	23.8	95.0										
UDS-A	N472,510 E1,905,400	385.0	22.9	NP	NP	NP		2.71															
			23.0																				
			22.4																				
			22.3																				
			23.8																				
			23.8																				
			19.9						98.5	95	107.3	18.6	91.8										
			19.4						97.8				91.1								27.0	650	
			20.6						92.3				86.0										
			23.4						94.0				87.6				*						Resonant Column
			20.0						98.5				91.8										
			23.0						98.2				91.5										
			26.5						98.7				92.0										
UDS-9	N472,348 E1,905,569	421.0	24.3	69	43	26		2.74						*	*	77							
			24.2	57	39	18																	
			23.4	69	42	27																	
			24.3	69	43	26			97.3	67	100.7	23.8	96.3				*	*					
			23.3						97.2	67	100.7	23.8	96.5										
			22.5						97.2	67	100.7	23.8	96.5								29.8	576	
			24.3						99.6	67	100.7	23.8	98.9										
			22.3						96.9	67	100.7	23.8	96.2										Resonant Column
UDS-10	N472,152 E1,905,801	431.0	SAMPLE NOT TESTED																				
UDS-23	N472,525 E1,905,410	399.0	SAMPLE NOT TESTED																				
UDS-36	N472,536 E1,905,470	416.0	22.7	NP	NP	NP	36	2.73						*	*	39							SCS Dispersion
			23.1																				
			23.3						89.9	211	113.0	15.5	79.6				*	*					
			22.6						89.2	211	113.0	15.5	78.9				*	*					
UDS-41	N472,648 E1,905,377	415.0	SAMPLE NOT TESTED							262	110.8	16.0											

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TABLE 2.5-59 (Sheet 8 of 8)

SUMMARY OF BLOCK SAMPLE TEST RESULTS
WEST EMBANKMENT

BLOCK SAMPLE NO.	COORDINATE LOCATION	ELEV. (Ft.)	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS				SPECIFIC GRAVITY	UNIT DRY WGT. (pcf)	COMP. STD. NO.	MAX. DRY DENSITY (pcf)	OPT. MOIST. (%)	PERCENT COMP.	GRAIN SIZE			CONSOLID.	PERMEABILITY	UU SERIES		$\overline{CTU}$ SERIES		OTHER TESTS
				L.L.	P.L.	P.I.	S.L.							SIEVE	HYDR.	% < .005			ϕ (deg)	c (psf)	$\bar{\phi}$ (deg)	$\bar{c}$ (psf)	
UDS-46	N472,781 E1,905,272	429.0	SAMPLE NOT TESTED							289	106.8	19.7											
UDS-47	N472,781 E1,905,274	429.0	SAMPLE NOT TESTED							289	106.8	19.7											

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TABLE 2.5-59a

SUMMARY OF BLOCK SAMPLE TEST RESULTS
TEST FILL - BORROW G

BLOCK SAMPLE NO.	COORDINATE LOCATION	ELEV. (Ft.)	NATURAL WATER CONTENT (%)	ATTERBERG LIMITS				SPECIFIC GRAVITY	UNIT DRY WGT. (pcf)	COMP. STD. NO.	MAX. DRY DENSITY (pcf)	OPT. MOIST. (%)	PERCENT COMP.	GRAIN SIZE			CONSOLID.	PERMEABILITY	UU SERIES		CTU SERIES		OTHER TESTS
				L.L.	P.L.	P.I.	S.L.							SIEVE	HYDR.	% < #200			φ (deg)	c (psf)	$\bar{\phi}$ (deg)	$\bar{c}$ (psf)	
UDS-21	Not Applicable	N/A		49	41	8		2.75						*	*	58							
								2.73								59							
			24.6						93.8	177	106.0	19.1	88.5										
			25.6						92.5	177	106.0	19.1	87.3								32.0	350	
			25.2						92.8	177	106.0	19.1	87.5										
UDS-22	Not Applicable	N/A	24.4	44	39	5		2.63						*	*								
			23.9					2.75								59							
			24.4													63							
			23.4						93.7	165	106.8	17.8	87.7										
			23.7						93.4	165	106.8	17.8	87.5								31.7	350	
			23.4						92.5	165	106.8	17.8	86.6										
UDS-28	Not Applicable	N/A	21.4	NP	NP	NP		2.69						*	*	53							
			21.0																				
			20.7					2.69	100.2	I-37	108.8	17.0	92.1				*	*					
			21.6						99.4	I-37	108.8	17.0	91.4										
UDS-29	Not Applicable	N/A	SAMPLE NOT TESTED							I-37	108.8	17.0											

Table 2.5-60
Physical Properties of Block Samples

Property	Range	Average	Number of Tests
Natural Water Content,%	160.0 to 29.8	22.8	170
Liquid Limit,%	41 to 69	55	38(1)
Plasticity Index,%	4 to 27	14	38(1)
Unit Dry Weight, pcf	80.0 to 102.0	92.8	108
Specific Gravity	2.64 to 2.87	2.73	35

(1) Does not include seven tests that were nonplastic.

Table 2.5-61
Pinhole Dispersion Test Results on Block Samples

Sample Number	Head (inches)	Flow (ml/sec)	Color[1]	Dispersion Classification [2]
UDS-12	2	0.25	D	ND 1
	7	0.76	D	
	15	1.31	D	
	40	2.43	D	
UDS-12	2	0.29	D	ND 1
	7	0.80	D	
	15	1.40	D	
	40	2.50	D	
UDS-15	2	0.08	D	ND 1
	7	0.16	D	
	15	0.90	D	
	40	2.18	D	

(1) Color code:
A = Dark
B = Slight to Medium
C = Barely Visible
D = Completely Clear

(2) Dispersion code:
D1, D2 = Dispersive and erodible.
ND1, ND2 = Non-dispersive and highly erosion-resistant.
ND3, ND4 = Non-dispersive and intermediate erosion resistant.

Table 2.5-61a
Summary of SCS Dispersion Test Results

Sample No.	Location	Elevation (ft.)	MC %	PL %	LL %	Percent Dispersion
UDS-12	North Dam	330.0	25.2	59	45	0
UDS-14	North Dam	336.0	18.4	48	44	0
UDS-15	North Dam	348.0	21.1	57	41	0
UDS-18	South Dam	402.0	22.7	68	44	0
UDS-36	West Embankment	416.0	22.7	NP	NP	0

Table 2.5-62
Computed Maximum Crest Acceleration and
Minimum Safety Factor for Safe Shutdown Earthquake

Height of Embankment (ft.)	Maximum Crest Acceleration (%g)	Minimum Factor of Safety	Elevation at Which Minimum Safety Factor Occurs (ft.)
110 (North Dam)	29	1.20	370
80	34	1.20	370
67 (South Dam)	35	1.20	375
50	35	1.35	400
30 (East Dam)	30	1.35	405

Table 2.5-63
Cases Studied for Dynamic Shear Moduli Variations

Designation	Section	Embankment	Weathered Rock [1] (K_2) max	Colluvium [1] (K_2) max
S-MAX-1	South Dam, max section	Probable Values [2]	250	70
S-MAX-II	South Dam, max section	Probable Values [2]	200	50
S-MAX-III	South Dam, max section	Probable Values [2]	500	120
N-MAX-I	North Dam, max section	Probable Values [2]	250	--
N-MAX-II	North Dam, max section	Probable Values [2]	200	--
N-MAX-III	North Dam, max section	Probable Values [2]	500	--

NOTES:

(1) $G_{max} = 1000\ (K_2)\ max\ \sigma o^{1/2}$

(2) $G_{max} = 35{,}000\ \sigma o^{1/2}$ for $\sigma o \leq 2100$ psf, in which σo is the mean effective normal pressure. $G_{max} = 760\ \sigma o$ psf for $\sigma o > 2100$ psf.

Table 2.5-64
Results of Field Permeability Tests
Conducted During Grouting of North Dam

Tests in Valley

Test Hole	Test Elevation (ft)	Average Coefficientof Permeability (cm/sec x 10^{-4})	Test Hole	Test Elevation (ft)	Average coefficient of permeability (cm/sec x 10^{-4})
7+06P	370-339	4.20	9+66S	316-299	15.59
7+46P	362-331	4.06	9+67T	314-300	11.74
8+26P	338-307	7.73		316-304	7.44 (1)
8+66P	333-287	1.67	9+86P	316-300	20.26
8+86S	325-303	7.35	9+96T	316-299	12.72
8+96T	323-303	6.34	10+06S	317-302	20.68
9+06P	320-301	9.01	10+11Q	317-300	14.77
	300-265	3.59	10+16T	316-300	7.75
9+26S	318-301	7.46	10+21Q	318-300	0.96
9+41Q	314-301	14.66	10+46S	322-300	11.50
9+46P	317-298	13.12	10+48.5Q	327-300	10.41
	313-302	9.26 (1)	10+51Q	323-300	10.09
	302-264	6.66	10+53Q	326-300	6.41
9+56T	317-300	10.59			

Tests in Abutments

Test Hole	Test Elevation (ft)	Average Coefficient of Permeability (cm/sec x 10^{-4})
5+46P	401-356	0.62
13+06P	393-349	0.39
13+46P	399-360	0.46
14+26P	407-366	0.22

Table 2.5-64 (continued)
Results of Field Permeability Tests
Conducted During Grouting of North Dam

Test Hole	Test Elevation (ft)	Average Coefficient of Permeability (cm/sec x 10^{-4})
15+06P	412-368	0.14
15+46P	414-470	0.39
16+26P	418-474	0.30

(1) Partially grouted.

Table 2.5-65
Summary of Design Coefficients of Permeability

Zone	PSAR Coefficient of Permeability (cm/sec)	FSAR Coefficient of Permeability (cm/sec)
Embankment		
Horizontal	1.0×10^{-6}	2.0×10^{-5}
Vertical	1.0×10^{-7}	2.0×10^{-5}
North Dam Foundation		
Valley Upper Stratum (1)	3.2×10^{-5}	1.0×10^{-3}
Valley Lower Stratum	3.2×10^{-5}	3.2×10^{-5}
Abutements	3.2×10^{-5}	3.6×10^{-5}
South Dam Foundation		
Upper Stratum (2)	3.2×10^{-5}	2.9×10^{-4}
Lower Stratum	3.2×10^{-5}	4.2×10^{-5}

(1) Thickness = 52 feet
(2) Thickness = 15 feet

Table 2.5-66
Stratification at Spring and Seep Locations

Source	Residual Soil and Saprolite Thickness [1] (ft)		Decomposed Rock Thickness [1] (ft)		Combined Thickness of Overburden (ft)
Spring No. 1	0-34	9	0-18	12	21 (12) [2]
Spring No. 2	20-34	27	34	34	61 (20) [2]
Bench Cut Seeps	0-8	5	10-60	25	30 (12) [2]

(1) Based on a review of closest test boring data.
(2) Depths in ( ) represent the minimum possible depth of overburden that could be postulated from the adjacent borings which were terminated within the decomposed rock before penetrating the "fractured rock" zone.

Table 2.5-66a
Piezometer Locations

Piezometer No.	North Dam Centerline Station	Offset In Feet [1]	Tip Elevation
8-1	8+00.2	148.4-M	382.8
8-2	8+05.5	114.8-M	389.4
8-3	8+04.7	14.8-S	374.4
8-4	8+03.9	202.4-S	358.4
10-1	10+00.9	280.3-M	340.7
10-2	10+02.8	220.6-M	348.0
10-3	10+04.7	14.4-S	334.2
10-4	10+06.5	200.9-S	333.8
12+50-1	12+51.4	199.3-M	373.5
12+50-2	12+51.1	140.0-M	387.4
12+50-3	12+50.6	15.0-S	390.7

INSERT TABLE 2.5-66b - 66e

Table 2.5-66b - Table 2.5-66e
North Dam Readings

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TABLE 2.5-66b
NORTH DAM SETTLEMENT MONUMENT READINGS

Date	Settlement (feet)																	
	-(0+04)	0+00	1+00	2+00	3+00	4+00	5+00	6+00	7+00	8+00	9+00	10+00	11+00	12+00	13+00	14+00	15+00	16+00
12/02/77	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/12/77	0.00	0.00	0.00	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.00	0.00	0.00	0.00	-
12/23/77	0.00	0.00	-0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.04	0.04	0.03	-	0.01	0.00	0.00	-
1/02/78	-0.01	-0.01	-0.02	-0.02	-0.01	-0.01	-0.01	0.00	0.00	0.01	0.04	0.04	0.02	-	0.00	-0.01	0.00	-0.01
1/11/78	0.00	0.00	-0.01	-0.01	-0.01	0.00	0.00	0.01	0.01	0.02	0.05	0.05	0.03	0.02	0.01	0.01	0.00	0.00
1/20/78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.03	0.05	0.05	0.04	0.02	0.01	0.00	0.00	-0.01
1/30/78	0.00	0.00	-0.01	0.00	-0.01	0.00	0.00	0.01	0.02	0.02	0.05	0.04	0.03	0.02	0.00	0.00	-0.01	-0.01
2/10/78	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.01	0.02	0.02	0.05	0.05	0.04	0.01	0.01	0.00	0.00	-0.01
2/20/78	0.00	0.00	-0.01	0.00	-0.01	0.00	0.02	0.01	0.02	0.01	0.05	0.06	0.04	0.01	0.00	0.00	-0.01	-0.02
3/01/78	0.01	0.01	0.00	0.00	-0.01	0.01	0.03	0.03	0.03	0.03	0.06	0.06	0.04	0.04	0.00	-0.01	-0.02	-0.03
3/09/78	0.01	0.00	0.00	0.00	0.01	0.00	0.03	0.02	0.03	0.03	0.06	0.06	0.05	0.04	0.01	-0.01	-0.01	0.00
4/04/78	-0.01	-0.01	-0.01	-0.01	-0.02	-0.01	0.01	0.01	0.01	0.02	0.05	0.22	0.05	0.03	-0.01	-0.02	-0.02	-0.04
5/01/78	0.00	0.00	-0.01	0.00	-0.02	-0.01	0.02	0.01	0.01	0.01	0.05	0.22	0.04	0.03	-0.01	-0.02	-0.03	-0.05
6/05/78	-0.02	-0.01	-0.02	-0.01	-0.03	-0.01	0.01	0.01	0.01	0.00	0.04	0.21	0.03	0.01	-0.02	-0.03	-0.03	-0.06
7/06/78	-0.02	-0.01	-0.02	-0.01	-0.03	-0.02	0.01	0.01	0.00	0.00	0.03	0.20	0.02	0.01	-0.02	-0.03	-0.04	-0.06
8/02/78	-0.02	0.00	-0.01	-0.01	-0.03	-0.02	0.01	0.01	0.00	0.00	0.02	0.20	0.02	0.01	-0.02	-0.03	-0.03	-
9/05/78	-0.02	0.00	-0.01	-0.01	-0.04	-0.02	0.01	0.01	0.00	-0.01	0.02	0.19	0.02	0.01	-0.02	-0.03	-0.04	-
10/03/78	-0.02	-0.01	-0.01	-0.01	-0.04	-0.02	0.01	0.00	-0.01	-0.02	0.01	0.17	0.01	0.00	-0.07	-0.04	-0.04	-
11/02/78	-0.02	0.00	-0.01	-0.01	-0.04	-0.01	0.02	0.01	0.00	-0.01	0.01	0.10	0.01	0.01	-0.03	-0.03	-0.04	-
12/05/78	-0.01	-0.01	-0.02	-0.02	-0.05	-0.02	0.00	0.00	-0.02	-0.02	-0.01	0.17	0.00	0.00	-0.04	-0.03	-0.04	-
1/04/79	-0.02	0.00	-0.01	-0.01	-0.03	-0.02	0.01	0.00	-0.01	-0.02	-0.01	0.17	0.00	0.00	-0.04	-0.03	-0.03	-
1/30/79	-0.03	-0.01	-0.02	-0.02	-0.05	-0.02	0.00	0.00	-0.02	-0.02	-0.01	0.17	0.00	0.01	-0.04	-0.03	-0.04	-
3/05/79	-0.04	-0.02	-0.02	-0.03	-0.05	-0.03	0.00	-0.02	-0.02	-0.04	-0.01	0.15	-0.01	-0.01	-0.05	-0.04	-0.05	-
4/02/79	-0.03	-0.01	-0.03	-0.02	-0.06	-0.02	-0.01	-0.01	-0.03	-0.03	-0.02	0.16	-0.01	0.00	-0.05	-0.04	-0.04	-
5/02/79	-0.05	-0.03	-0.04	-0.04	-0.07	-0.05	-0.01	-0.03	-0.04	-0.06	-0.03	0.16	-0.02	-0.02	-0.05	-0.05	-0.05	-
6/07/79	-0.05	-0.03	-0.03	-0.04	-0.07	-0.04	-0.01	-0.03	-0.03	-0.05	-0.03	0.14	-0.03	-0.02	-0.06	-0.05	-0.05	-
7/04/79	-0.06	-0.03	-0.04	-0.04	-0.07	-0.04	-0.02	-0.03	-0.04	-0.06	-0.04	0.13	-0.03	-0.03	-0.06	-0.06	-0.05	-
8/02/79	-0.05	-0.03	-0.04	-0.04	-0.07	-0.04	-0.02	-0.03	-0.04	-0.05	-0.04	0.14	-0.03	-0.02	-0.06	-0.05	-0.05	-
8/28/79	-0.05	-0.03	-0.04	-0.04	-0.07	-0.04	-0.02	-0.03	-0.04	-0.06	-0.04	0.13	-0.03	-0.02	-0.06	-0.05	-0.05	-
10/08/79	-0.05	-0.03	-0.04	-0.04	-0.07	-0.04	-0.02	-0.03	-0.04	-0.06	-0.04	0.13	-0.03	-0.02	-0.06	-0.05	-0.05	-
11/05/79	-0.06	-0.03	-0.04	-0.04	-0.07	-0.04	-0.02	-0.04	-0.04	-0.06	-0.04	0.13	-0.03	-0.03	-0.06	-0.06	-0.06	-
12/03/79	-0.06	-0.03	-0.04	-0.04	-0.07	-0.04	-0.02	-0.04	-0.04	-0.06	-0.04	0.13	-0.04	-0.03	-0.07	-0.06	-0.06	-
1/02/80	-0.05	-0.03	-0.04	-0.04	-0.07	-0.04	-0.02	-0.04	-0.04	-0.06	-0.05	0.13	-0.04	-0.03	-0.07	-0.06	-0.06	-
2/07/80	-0.06	-0.03	-0.04	-0.04	-0.08	-0.04	-0.03	-0.04	-0.05	-0.07	-0.05	0.12	-0.05	-0.03	-0.07	-0.06	-0.07	-
3/04/80	-0.06	-0.03	-0.04	-0.04	-0.07	-0.04	-0.03	-0.04	-0.05	-0.06	-0.05	0.12	-0.05	-0.03	-0.07	-0.06	-0.07	-
4/02/80	-0.06	-0.03	-0.04	-0.05	-0.07	-0.05	-0.03	-0.05	-0.05	-0.07	-0.06	0.11	-0.05	-0.03	-0.07	-0.06	-0.06	-

NOTE: Monument 12+00 destroyed 12/21/77 and replaced 1/4/78. Statement of 0.01 feet which had been measured through 12/21/77 has been added to settlements measured after 1/4/78.

Monument 16+00 removed due to construction of guard tower.

Negative readings indicate uplift.

BEST COPY AVAILABLE

TABLE 2.5-66c
NORTH DAM ALIGNMENT MONUMENT READINGS

Date	Horizontal Movement (feet)																	
	-(0+84)	0+00	1+00	2+00	3+00	4+00	5+00	6+00	7+00	8+00	9+00	10+00	11+00	12+00	13+00	14+00	15+00	16+00
12/02/77	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/12/77	0.00	0.00	0.01N	0.00	0.00	0.00	0.00	0.00	0.00	0.03N	0.02N	0.04N	0.00	0.03N	0.00	0.01N	0.00	-
12/23/77	0.00	0.00	0.04S	0.01N	0.04S	0.00	0.00	0.00	0.00	0.02S	0.05N	0.07N	0.03N	-	0.03N	0.00	0.01N	-
1/02/78	0.00	0.00	0.00	0.00	0.02S	0.03S	0.03S	0.03S	0.01N	0.04N	0.06N	0.04N	0.03N	-	0.02N	0.03N	0.03N	0.01N
1/11/78	0.00	0.00	0.00	0.01S	0.03S	0.02S	0.01S	0.00	0.03S	0.04N	0.07N	0.04N	0.04N	0.02S	0.03N	0.02N	0.04N	0.01N
1/20/78	0.00	0.00	0.00	0.01N	0.01S	0.03S	0.02S	0.00	0.03S	0.03N	0.05N	0.07N	0.00	0.02S	0.01N	0.02N	0.01N	0.00
1/30/78	0.00	0.00	0.00	0.01N	0.03S	0.03S	0.00	0.00	0.03S	0.01N	0.05N	0.04N	0.00	0.03S	0.01N	0.01N	0.01N	0.00
2/10/78	0.00	0.00	0.01S	0.01N	0.05S	0.04S	0.29S	0.02S	0.04S	0.01N	0.05N	0.05N	0.00	0.05S	0.00	0.01N	0.01N	0.00
2/20/78	0.00	0.00	0.00	0.01N	0.02S	0.04S	0.29S	0.00	0.03S	0.01N	0.05N	0.05N	0.03S	0.08S	0.02S	0.01S	0.01N	0.00
3/01/78	0.00	0.00	0.00	0.02S	0.04S	0.04S	0.29S	0.02N	0.06S	0.02S	0.00	0.05N	0.02S	0.19S	0.03S	0.00	0.00	0.00
3/09/78	0.00	0.00	0.00	0.01N	0.04S	0.04S	0.26S	0.02N	0.06S	0.05S	0.04S	0.10S	0.04S	0.24S	0.04S	0.01S	0.01S	0.00
4/04/78	0.00	0.00	0.01S	0.00	0.04S	0.06S	0.20S	0.01N	0.00S	0.07S	0.06S	0.11S	0.00S	0.22S	0.06S	0.02S	0.02S	0.01S
5/01/78	0.00	0.00	0.00	0.02N	0.04S	0.05S	0.27S	0.02N	0.00S	0.07S	0.03S	0.11S	0.06S	0.22S	0.05S	0.02S	0.02S	0.01S
6/05/78	0.00	0.00	0.00	0.01S	0.04S	0.05S	0.25S	0.00	0.00S	0.09S	0.06S	0.12S	0.04S	0.26S	0.04S	0.01S	0.02S	0.00
7/06/78	0.00	0.00	0.00	0.00	0.05S	0.06S	0.25S	0.01N	0.06S	0.07S	0.07S	0.09S	0.05S	0.23S	0.04S	0.01S	0.03S	0.00
8/02/78	-	0.00	0.00	0.01S	0.05S	0.05S	0.24S	0.02N	0.00S	0.05S	0.07S	0.12S	0.05S	0.23S	0.05S	0.00	0.03S	-
9/05/78	-	0.00	0.00	0.00	0.05S	0.05S	0.27S	0.02N	0.07S	0.05S	0.06S	0.10S	0.05S	0.22S	0.04S	0.06S	0.02S	-
10/03/78	-	0.01S	0.00	0.00	0.05S	0.05S	0.27S	0.01N	0.07S	0.05S	0.05S	0.10S	0.05S	0.22S	0.04S	0.01S	0.02S	-
11/02/78	-	0.00	0.00	0.00	0.05S	0.05S	0.27S	0.01N	0.07S	0.06S	0.06S	0.10S	0.05S	0.22S	0.05S	0.01S	0.02S	-
12/05/78	-	0.01N	0.01N	0.00	0.05S	0.06S	0.27S	0.03N	0.07S	0.07S	0.07S	0.09S	0.05S	0.24S	0.04S	0.02S	0.03S	-
1/04/79	-	0.00	0.00	0.00	0.05S	0.05S	0.27S	0.02N	0.07S	0.05S	0.06S	0.10S	0.06S	0.22S	0.04S	0.01S	0.03S	-
1/30/79	-	0.01S	0.00	0.00	0.05S	0.06S	0.27S	0.01N	0.00S	0.05S	0.05S	0.10S	0.05S	0.22S	0.04S	0.02S	0.02S	-
3/05/79	-	0.01S	0.00	0.00	0.05S	0.05S	0.26S	0.01N	0.07S	0.05S	0.05S	0.10S	0.05S	0.22S	0.04S	0.02S	0.02S	-
4/02/79	-	0.00	0.02S	0.01S	0.00S	0.07S	0.24S	0.00	0.07S	0.00S	0.07S	0.12S	0.05S	0.22S	0.01S	0.02S	0.02S	-
5/02/79	-	0.00	0.01S	0.01S	0.07S	0.06S	0.24S	0.00	0.07S	0.00S	0.07S	0.12S	0.05S	0.22S	0.05S	0.02S	0.02S	-
6/07/79	-	0.01S	0.01S	0.00	0.07S	0.06S	0.24S	0.01N	0.07S	0.07S	0.06S	0.13S	0.05S	0.20S	0.04S	0.00	0.01S	-
7/04/79	-	0.01S	0.01S	0.00	0.07S	0.05S	0.25S	0.01N	0.06S	0.07S	0.06S	0.12S	0.05S	0.21S	0 04S	0.00	0.01S	-
8/01/79	-	0.01S	0.01S	0.00	0.07S	0.05S	0.25S	0.01N	0.07S	0.07S	0.06S	0.12S	0.05S	0.21S	0.04S	0.00	0.02S	-
8/28/79	-	0.01S	0.01S	0.01N	0.07S	0.05S	0.25S	0.01N	0.07S	0.07S	0.06S	0.13S	0.05S	0.20S	0.04S	0.00	0.02S	-
10/08/79	-	0.01S	0.01S	0.01N	0.07S	0.06S	0.26S	0.01N	0.00S	0.06S	0.06S	0.13S	0.05S	0.20S	0.04S	0.00	0.02S	-
11/05/79	-	0.01S	0.01S	0.01N	0.07S	0.06S	0.26S	0.02N	0.00S	0.06S	0.06S	0.13S	0.05S	0.20S	0.04S	0.00	0.02S	-
12/03/79	-	0.01S	0.01S	0.01N	0.07S	0 06S	0.26S	0.02N	0.00S	0.06S	0.06S	0.13S	0.05S	0.21S	0.01S	0.00	0.02S	-
1/02/80	-	0.01S	0.01S	0.01N	0.07S	0.07S	0.26S	0.02N	0.00S	0.06S	0.06S	0.13S	0.05S	0.21S	0.04S	0.00	0.02S	-
2/07/80	-	0.01S	0.02S	0.02N	0.07S	0.07S	0.26S	0.02N	0.00S	0.07S	0.05S	0.13S	0.05S	0.21S	0.04S	0.01S	0.03S	-
3/04/80	-	0.01S	0.02S	0.02N	0.07S	0.06S	0.29S	0.02N	0.07S	0.07S	0.05S	0.13S	0.05S	0.21S	0.04S	0.01S	0.03S	-
		0.02S	0.02S	0.01N	0.07S	0.06S	0.27S	0.02N	0.00S	0.07S	0.04S	0.13S	0.04S	0.22S	0.03S	0.01S	0.03S	-

NOTE: Monument 12+00 destroyed 12/21/77 and replaced 1/4/78. Alignment readings after 1/4/78 do not include previous movement.
Monument 16+00 removed due to construction of guard tower

BEST COPY AVAILABLE

TABLE 2.5-66d
SOUTH DAM SETTLEMENT MONUMENT READINGS

Date	Settlement (feet)										
	0+00	1+00	2+00	3+00	4+00	5+00	6+00	7+00	8+00	9+00	10+00
12/13/77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/23/77	0.02	0.02	0.00	0.02	0.00	0.01	0.00	0.02	0.00	0.00	0.00
1/02/78	0.00	0.00	-0.01	0.00	-0.01	0.00	0.00	0.01	0.00	0.00	-0.01
1/11/78	0.01	0.01	0.01	0.01	0.00	0.01	0.00	0.02	0.00	0.00	0.00
1/20/78	0.01	0.01	0.00	0.01	0.00	0.01	0.00	0.02	-0.01	0.00	0.01
1/30/78	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	-0.01	0.00	-0.01
2/10/78	0.01	0.01	0.01	0.01	0.00	0.00	-0.01	0.01	-0.01	0.00	-0.01
2/20/78	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.02	0.00	-0.02	-0.01	-0.01
3/01/78	0.01	0.00	0.00	0.00	-0.01	-0.01	-0.01	0.00	-0.02	-0.02	-0.01
3/09/78	0.00	0.01	0.00	0.00	-0.01	-0.01	-0.02	0.00	-0.02	-0.01	-0.01
4/04/78	-0.01	-0.01	0.00	-0.02	-0.02	-0.04	-0.03	-0.02	-0.03	-0.03	-0.01
5/02/78	-0.02	-0.01	-0.02	-0.02	-0.04	-0.05	-0.04	-0.03	-0.04	-0.04	-0.01
6/05/78	-0.04	-0.02	-0.03	-0.03	-0.06	-0.06	-0.05	-0.04	-0.05	-0.04	-0.01
7/06/78	-0.04	-0.03	-0.02	-0.04	-0.06	-0.08	-0.06	-0.05	-0.06	-0.05	-0.01
8/02/78	-0.04	-0.02	-0.02	-0.03	-0.07	-0.08	-0.07	-0.05	-0.06	-0.05	-0.01
9/05/78	-0.04	-0.02	-0.02	-0.03	-0.07	-0.08	-0.07	-0.06	-0.07	-0.05	0.00
10/04/78	-0.05	-0.02	-0.02	-0.04	-0.08	-0.10	-0.09	-0.07	-0.08	-0.06	-0.01
11/02/78	-0.05	-0.02	-0.03	-0.04	-0.09	-0.10	-0.09	-0.07	-0.08	-0.05	-0.01
12/05/78	-0.06	-0.03	-0.03	-0.05	-0.10	-0.11	-0.11	-0.09	-0.09	-0.06	-0.01
1/04/79	-0.06	-0.03	-0.03	-0.05	-0.10	-0.12	-0.11	-0.10	-0.09	-0.07	-0.02
1/30/79	-0.06	-0.03	-0.02	-0.05	-0.10	-0.12	-0.10	-0.09	-0.09	-0.07	-0.01
3/01/79	-0.05	-0.03	-0.02	-0.05	-0.10	-0.12	-0.12	-0.10	-0.10	-0.06	-0.01
4/02/79	-0.05	-0.02	-0.02	-0.04	-0.10	-0.12	-0.13	-0.10	-0.10	-0.06	-0.02
5/02/79	-0.06	-0.02	-0.02	-0.05	-0.10	-0.13	-0.13	-0.11	-0.10	-0.06	-0.02
6/04/79	-0.06	-0.02	-0.03	-0.05	-0.11	-0.14	-0.13	-0.11	-0.10	-0.07	-0.02
7/04/79	-0.06	-0.02	-0.02	-0.05	-0.11	-0.14	-0.14	-0.11	-0.11	-0.06	-0.02
8/02/79	-0.05	-0.02	-0.02	-0.06	-0.11	-0.14	-0.14	-0.12	-0.11	-0.07	-0.02
8/28/79	-0.05	-0.02	-0.02	-0.05	-0.10	-0.13	-0.14	-0.11	-0.11	-0.06	-0.01
10/09/79	-0.05	-0.02	-0.02	-0.06	-0.11	-0.14	-0.14	-0.12	-0.11	-0.07	-0.02
11/05/79	-0.05	-0.01	-0.02	-0.05	-0.11	-0.14	-0.14	-0.12	-0.11	-0.06	-0.02
12/04/79	-0.05	-0.01	-0.02	-0.05	-0.11	-0.14	-0.14	-0.12	-0.11	-0.06	-0.01
1/02/80	-0.05	-0.01	-0.02	-0.05	-0.11	-0.14	-0.14	-0.12	-0.11	-0.06	-0.02
2/05/80	-0.05	-0.02	-0.02	-0.05	-0.12	-0.15	-0.16	-0.13	-0.11	-0.07	-0.02
3/04/80	-0.04	-0.01	-0.02	-0.04	-0.11	-0.14	-0.15	-0.11	-0.11	-0.06	-0.02
4/02/80	-0.05	-0.01	-0.02	-0.05	-0.11	.0.15	-0.16	-0.12	-0.11	-0.06	-0.03

NOTE: Negative reading indicates uplift

BEST COPY AVAILABLE

TABLE 2.5-66e
SOUTH DAM ALIGNMENT MONUMENT READINGS

Date	Horizontal Movement (feet)										
	0+00	1+00	2+00	3+00	4+00	5+00	6+00	7+00	8+00	9+00	10+00
12/13/77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/23/77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/02/78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/11/78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/20/78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/30/78	0.01S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2/10/78	0.01S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04S	0.00
2/20/78	0.01S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04S	0.00
3/01/78	0.02S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02S	0.00
3/09/78	0.01S	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02S	0.00
4/04/78	0.01N	0.00	0.00	0.02N	0.02N	0.02N	0.02N	0.03N	0.00	0.03S	0.00
5/02/78	0.01N	0.00	0.00	0.01N	0.02N	0.02N	0.02N	0.04N	0.00	0.03N	0.00
6/05/78	0.02N	0.00	0.00	0.01N	0.02N	0.01N	0.01N	0.03N	0.00	0.02N	0.00
7/06/78	0.02N	0.00	0.00	0.01N	0.02N	0.02N	0.00	0.01N	0.00	0.01N	0.00
8/01/78	0.02N	0.00	0.00	0.01N	0.04N	0.03N	0.02N	0.02N	0.02N	0.02N	0.00
9/05/78	0.02N	0.00	0.00	0.02N	0.04N	0.03N	0.03N	0.04N	0.03N	0.02N	0.00
10/04/78	0.02N	0.00	0.00	0.02N	0.04N	0.03N	0.03N	0.04N	0.03N	0.03N	0.00
11/02/78	0.02N	0.00	0.00	0.03N	0.04N	0.03N	0.04N	0.04N	0.04N	0.03N	0.00
12/05/78	0.02N	0.01N	0.01N	0.03N	0.04N	0.03N	0.04N	0.04N	0.04N	0.03N	0.00
1/04/79	0.02N	0.01N	0.01N	0.03N	0.05N	0.03N	0.03N	0.05N	0.04N	0.02N	0.00
1/30/79	0.02N	0.01N	0.01N	0.03N	0.05N	0.03N	0.03N	0.04N	0.04N	0.03N	0.00
3/01/79	0.02N	0.00	0.01N	0.05N	0.05N	0.05N	0.03N	0.05N	0.04N	0.03N	0.00
4/02/79	0.00	0.00	0.01N	0.03N	0.04N	0.03N	0.03N	0.03N	0.03N	0.02N	0.00
5/02/79	0.00	0.00	0.01N	0.03N	0.04N	0.03N	0.03N	0.03N	0.03N	0.02N	0.00
6/04/79	0.00	0.00	0.01N	0.03N	0.04N	0.03N	0.03N	0.03N	0.03N	0.02N	0.00
7/04/79	0.00	0.00	0.01N	0.03N	0.04N	0.03N	0.03N	0.03N	0.03N	0.02N	0.00
8/02/79	0.00	0.00	0.01N	0.03N	0.04N	0.03N	0.03N	0.03N	0.03N	0.02N	0.00
8/28/79	0.00	0.00	0.05N	0.03N	0.04N	0.03N	0.04N	0.03N	0.03N	0.02N	0.00
10/09/79	0.00	0.00	0.01N	0.03N	0.04N	0.03N	0.04N	0.03N	0.03N	0.02N	0.00
11/05/79	0.00	0.00	0.01N	0.03N	0.04N	0.03N	0.04N	0.03N	0.03N	0.02N	0.00
12/04/79	0.00	0.00	0.01N	0.03N	0.04N	0.03N	0.04N	0.03N	0.03N	0.02N	0.00
1/02/80	0.00	0.00	0.01N	0.03N	0.04N	0.03N	0.04N	0.03N	0.03N	0.02N	0.00
2/05/80	0.00	0.01N	0.00	0.02N	0.03N	0.02N	0.03N	0.03N	0.03N	0.02N	0.01S
3/04/80	0.00	0.00	0.01N	0.02N	0.03N	0.02N	0.03N	0.04N	0.03N	0.02N	0.01S
4/02/80	0.00	0.00	0.01N	0.03N	0.03N	0.02N	0.02N	0.03N	0.03N	0.02N	0.01S

Table 2.5-67
Principal Equipment Used to Construct the
Service Water Pond Dams

	No. of Pieces	Model Number	Manufacturer
Foundation Preparation			
Mucking and Cleaning	1	225 Cat Backhoe	Caterpillar Tractor Company
	4	D-9 Pushers	Caterpillar Tractor Company
	1	Model 6 Dragline	Northwest Engineering Company
	1	Model 41 Dragline	Northwest Engineering Company
	2	TS-14 Scrapers	Terex (General Motors)
	6	TS-24 Scrapers	Terex (General Motors)
Select Fill Placement			
Excavation and Hauling	8	641 Scrapers	Caterpillar Tractor Company
	16	631 Scrapers	Caterpillar Tractor Company
	1	480 Michigan Pusher	Clark Equipment Company
	4	D-9 Pushers	Caterpillar Tractor Company
Placement and Compaction	4	D-5 Dozers	Caterpillar Tractor Company
	4	D-8 Dozers	Caterpillar Tractor Company
	2	631 Water Wagons	Caterpillar Tractor Company

Table 2.5-67 (continued)
Principal Equipment Used to Construct the
Service Water Pond Dams

	No. of Pieces	Model Number	Manufacturer
Placement and Compaction (Continued)	4	No. 16 Motor Graders	Caterpillar Tractor Company
	2	No. 14 Motor Graders	Caterpillar Tractor Company
	2	No. 12 Motor Graders	Caterpillar Tractor Company
	3	825 Compactors	Caterpillar Tractor Company
	2	Buffalo - Springfield Rollers	Koehring Company
	1	Ferguson Roller	Ferguson Company
	2	Vibro Plus Roller	Vibro Plus Corporation
	2	Tampo Rollers	Tampo Manufacturing Company
Filters and Riprap	6	R-22 Rear Dumps	Euclid Corporation
	4	R-40 Rear Dumps	Terex (General Motors)
	4	D-5 Dozers	Caterpillar Tractor Company
	4	D-8 Dozers	Caterpillar Tractor Company
	2	Vibro Plus Roller	Vibro Plus Corporation
	1	235 Backhoe with Grapple	Caterpillar Tractor Company
	1	225 Backhoe with Grapple	Caterpillar Tractor Company
	4	R-122 Rear Dumps	Terex (General Motors)

Table 2.5-67 (continued)
Principal Equipment Used to Construct the
Service Water Pond Dams

	No. of Pieces	Model Number	Manufacturer
Filters and Riprap (Continued)	1	Cruz Air 80 Backhoe with Grapple	Drott Manufacturing Div. J.I. Case, Aternnero Company
	1	60 Ton Crane with Orange Peel Grapple	Northwestern Engineering Company
	1	Hydro-Scopic 300 Grad II	Warner & Swasey Company
	11	DM600 Rear Dumps	Mack Truck, Inc.
	6	DM600 Rear Dumps	Mack Truck, Inc.
	2	Autocar Rear Dumps	Autocar Trucks Div. White Motor Corporation

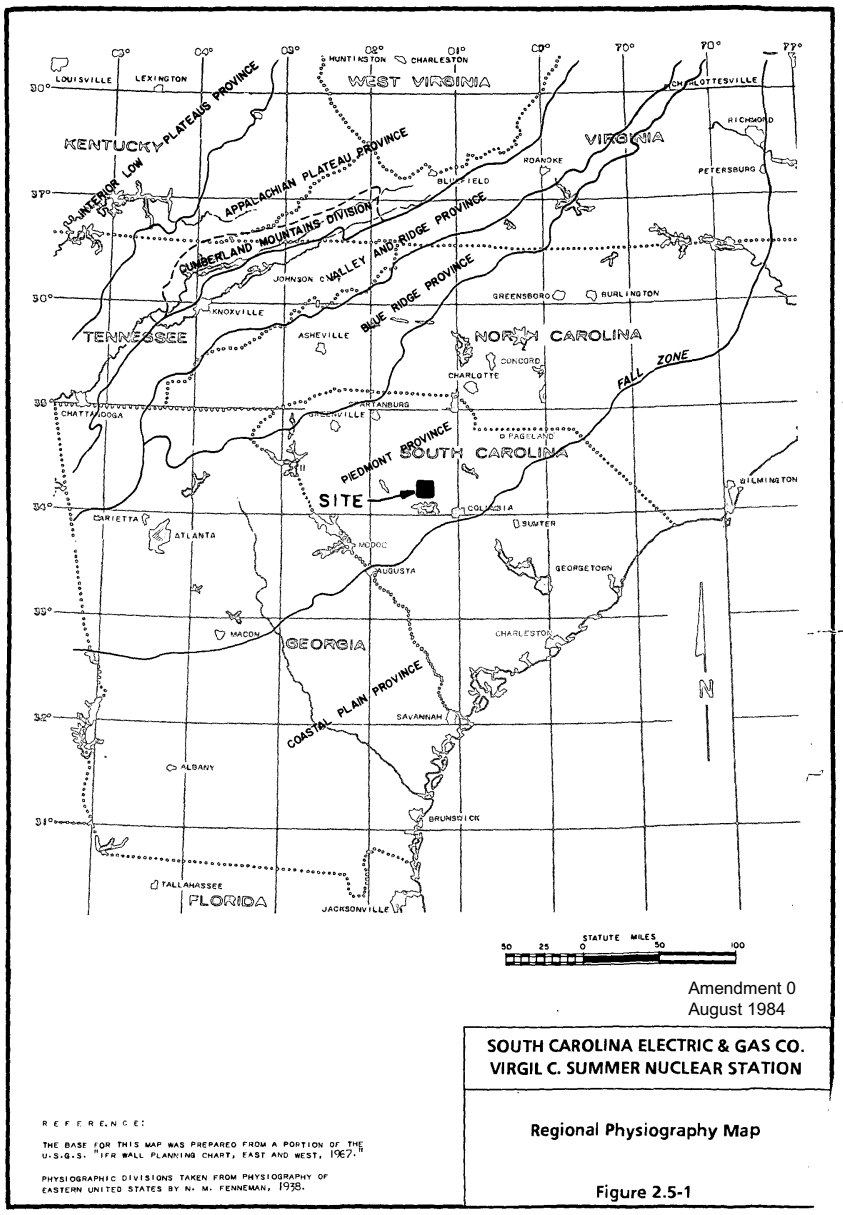
Table 2.5-68
Summary of Large Reservoir Induced Earthquakes

Reservoir/Dam	Depth (M)	VOLUME (x 10^6 M^3)	Size (M)	Focal Depth (KM)	Active Faults
Benmore	96	2040	5.0	12	Yes
Eucumbene	106	4761	5.0	17	Yes
Hoover	191	36,703	5.0	16	Yes
Kariba	122	175,000	6.3	10	Not Known
Koyna	100	2780	6.5	27	Yes
Kremasta	120	4750	6.3	10	Yes
Marathon	60	41	5.8	15	Not Known
Mendocino	30	151	5.2	9.9	Yes
Oroville	204	4400	5.7	5-10	Yes
Xinfengjiang	80	13,896	6.0	5	Yes

Data Source: Woodward-Clyde Consultants, 1979

Figure 2.5-1

REGIONAL PHYSIOGRAPHY MAP



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Regional Physiography Map

Figure 2.5-1

REFERENCE:

THE BASE FOR THIS MAP WAS PREPARED FROM A PORTION OF THE U.S.G.S. "IFR WALL PLANNING CHART, EAST AND WEST, 1967."

PHYSIOGRAPHIC DIVISIONS TAKEN FROM PHYSIOGRAPHY OF EASTERN UNITED STATES BY N. M. FENNEMAN, 1938.

Figure 2.5-2

GEOLOGIC BELT MAP OF SOUTH CAROLINA

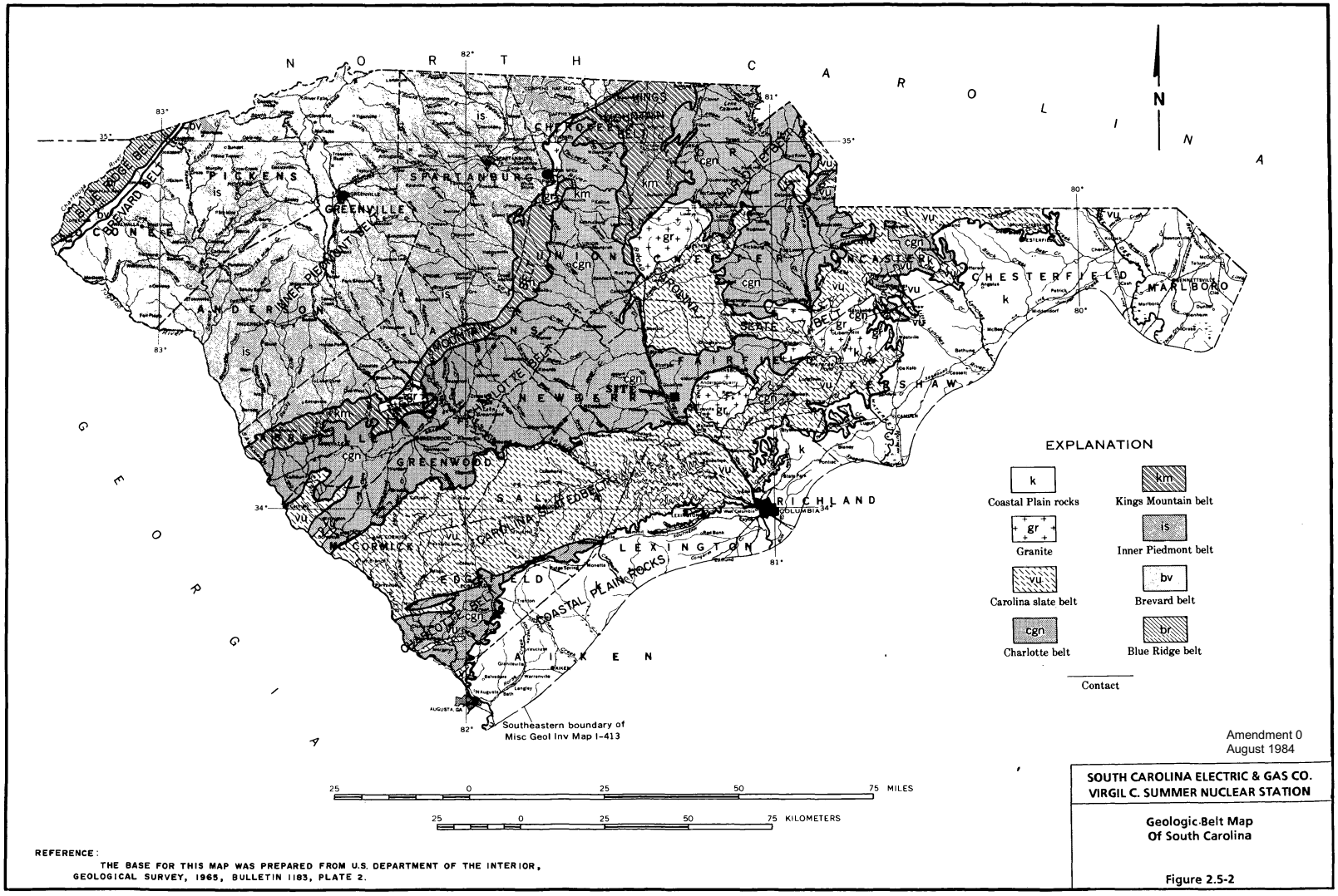
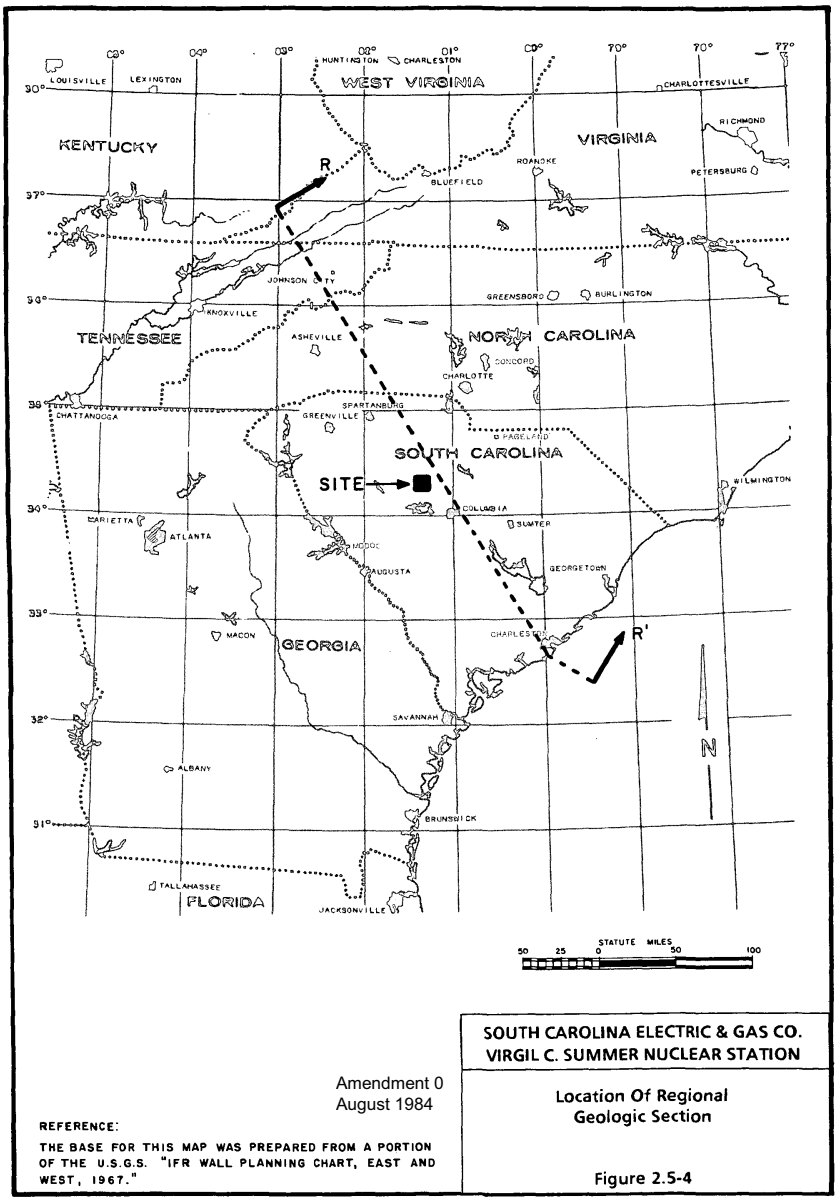


Figure 2.5-4

LOCATION OF REGIONAL GEOLOGIC SECTION



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Location Of Regional Geologic Section

Figure 2.5-4

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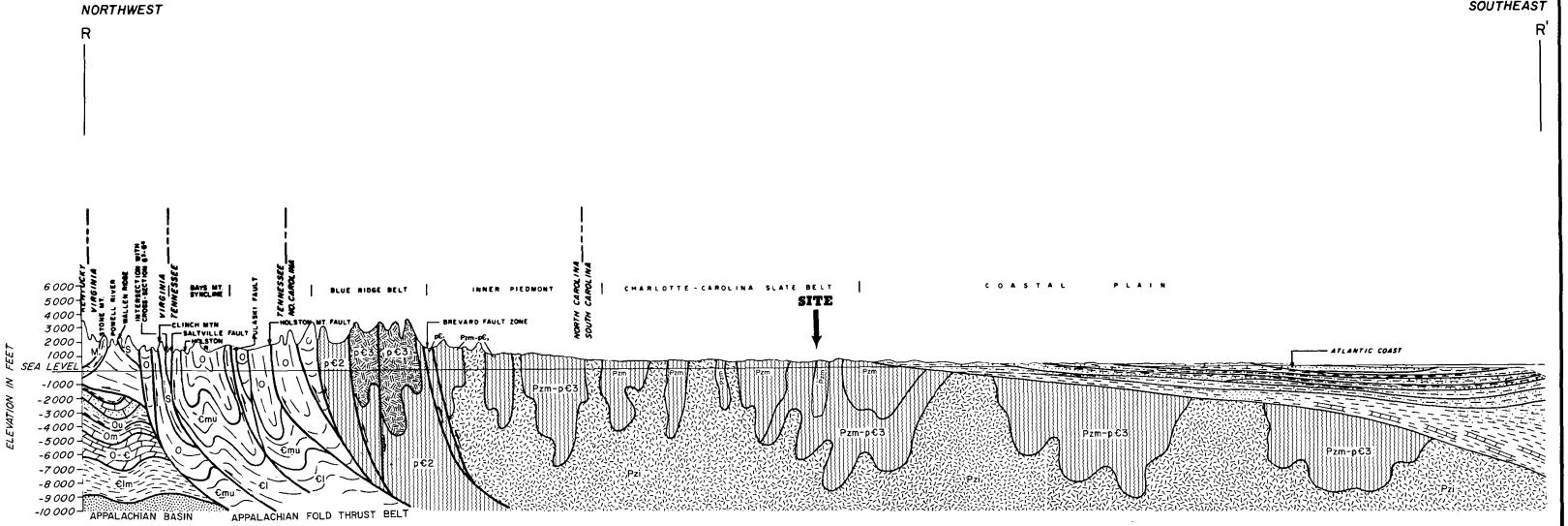
August 1984

REFERENCE:

THE BASE FOR THIS MAP WAS PREPARED FROM A PORTION OF THE U.S.G.S. "IFR WALL PLANNING CHART, EAST AND WEST, 1967."

Figure 2.5-5

GENERAL REGIONAL GEOLOGIC SECTION



AGE	SYMBOL	DESCRIPTION REGIONAL	SOUTH CAROLINA
MISSISSIPPIAN	M	LIMESTONE, SHALE, SANDSTONE & CHERT	
SILURIAN	S	SANDSTONE, SHALE & LIMESTONE	
ORDOVICIAN (UPPER)	Ou	LIMESTONE, SANDSTONE & SHALE	
(MIDDLE)	Om	LIMESTONE	
(LOWER TO UPPER)	O	LIMESTONE, DOLOMITE, SHALE & CHERT	
ORDOVICIAN-CAMBRIAN	O-C	DOLOMITE, LIMESTONE, CHERT & SANDSTONE	
CAMBRIAN (MIDDLE TO UPPER)	Cmu	LIMESTONE, DOLOMITE & SHALE	
(LOWER TO MIDDLE)	Clm	SLATE, SHALE & SANDSTONE	
(LOWER)	Cl	SANDSTONE, QUARTZITE & SHALE	
PRECAMBRIAN THRU PALEOZOIC	PZI	INTRUSIVES	GRANITES-UNDIVIDED
	PZM	METAMORPHICS	METASEDIMENTARY & METAVOLCANIC ROCKS OF THE CAROLINA SLATE, CHARLOTTE, KINGS MT., INNER PIEDMONT & BREVARD BELTS
	PC2		
	PC3		

SECTION A-A

HORIZONTAL SCALE IN MILES
10 0 10 20 30 40 50

REFERENCE:

THE AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS, ENTITLED "MID-ATLANTIC REGION, GEOLOGICAL HIGHWAY MAP, 1970".

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August 1984

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VIRGIL C. SUMMER NUCLEAR STATION

Generalized Regional Geologic Section

Figure 2.5-5

Figure 2.5-6
REGIONAL TECTONIC MAP

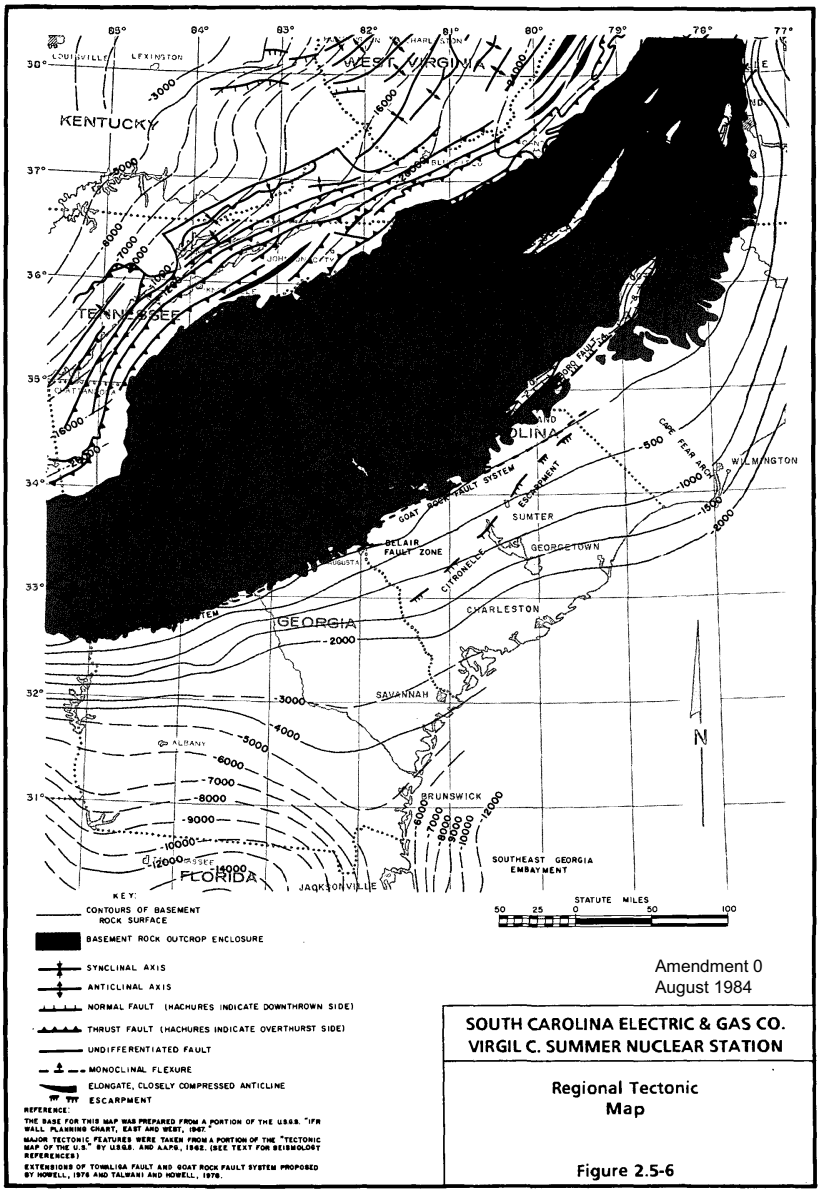


Figure 2.5-7
TRIASSIC BASINS

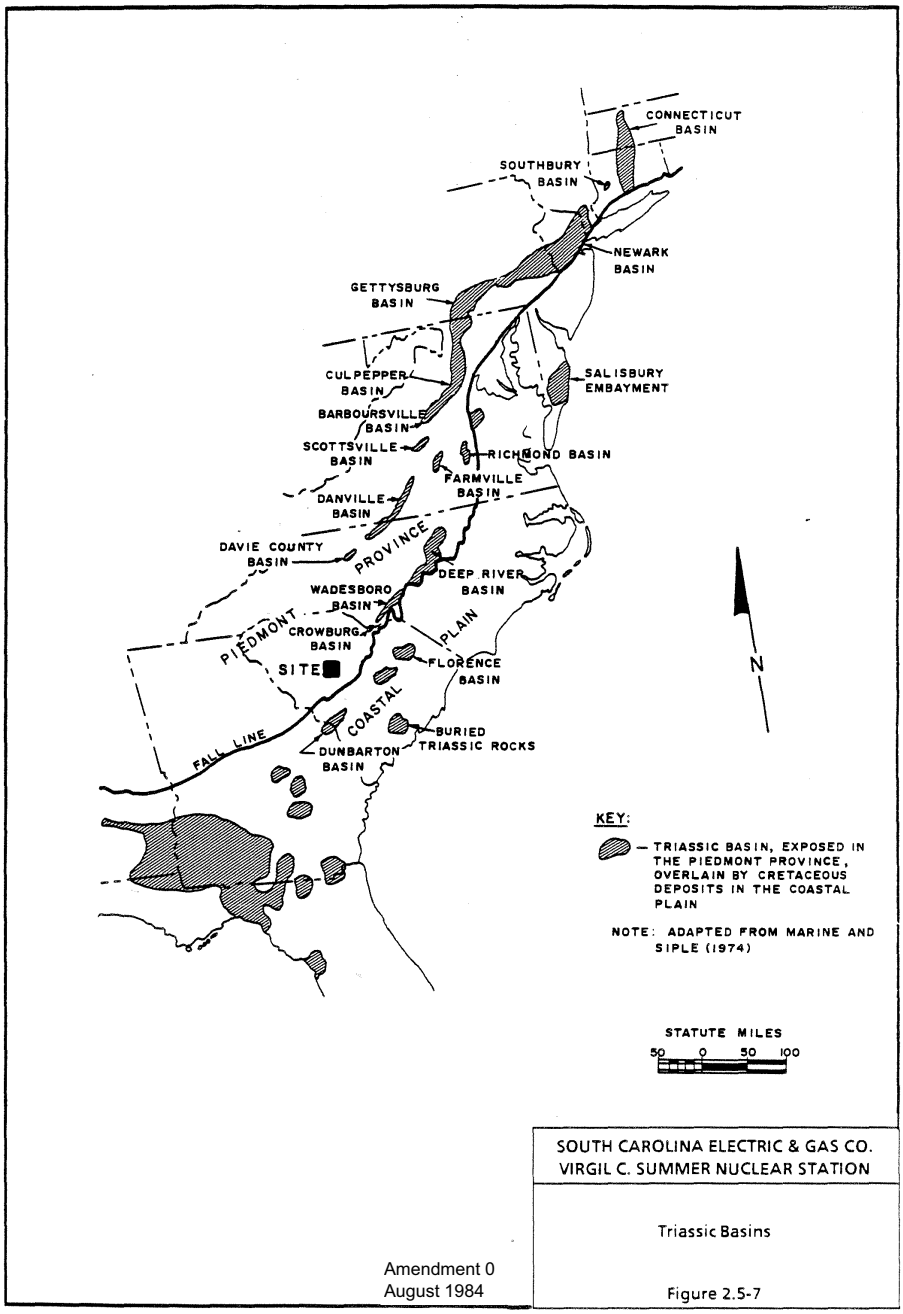
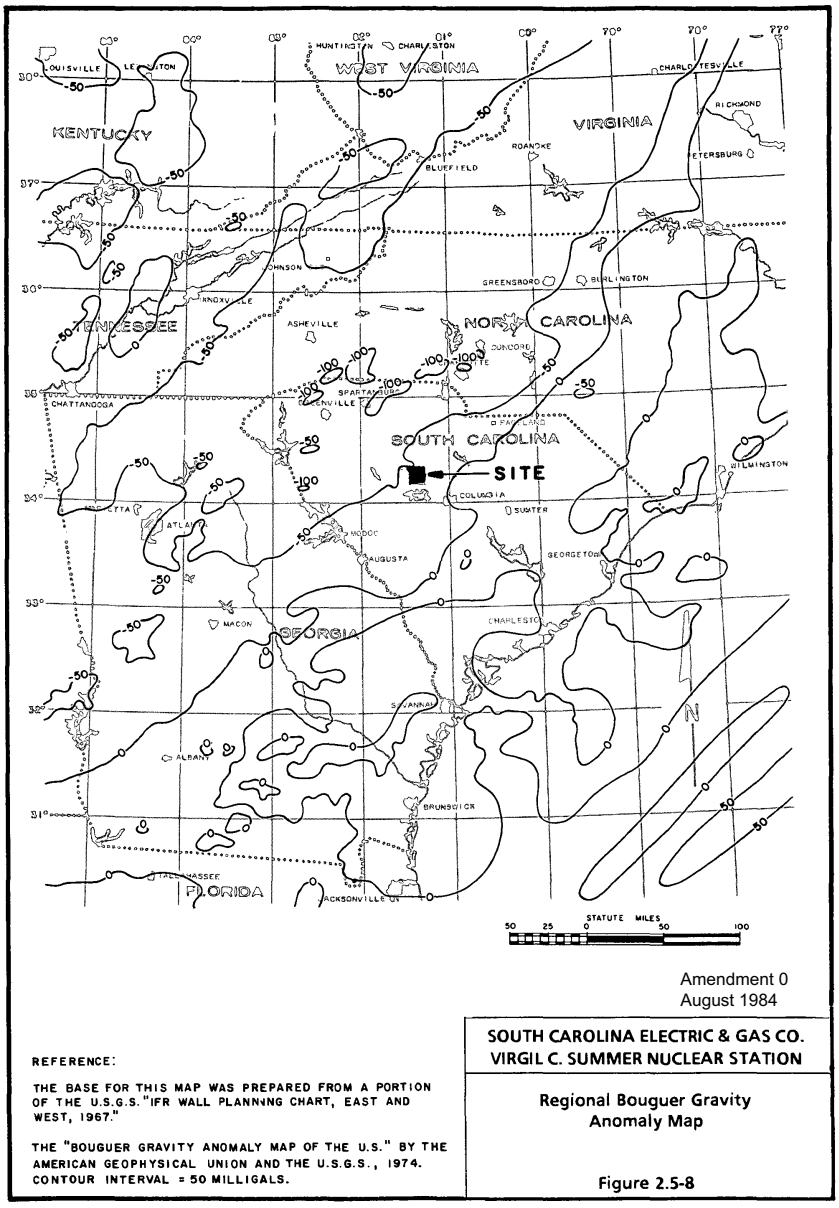


Figure 2.5-8
REGIONAL BOUGUER GRAVITY ANOMALY MAP



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REFERENCE:

THE BASE FOR THIS MAP WAS PREPARED FROM A PORTION OF THE U.S.G.S. "IFR WALL PLANNING CHART, EAST AND WEST, 1967."

THE "BOUGUER GRAVITY ANOMALY MAP OF THE U.S." BY THE AMERICAN GEOPHYSICAL UNION AND THE U.S.G.S., 1974. CONTOUR INTERVAL = 50 MILLIGALS.

SOUTH CAROLINA ELECTRIC & GAS CO.
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Regional Bouguer Gravity Anomaly Map

Figure 2.5-8

Figure 2.5-9

REGIONAL AEROMAGNETIC ANOMALY MAP

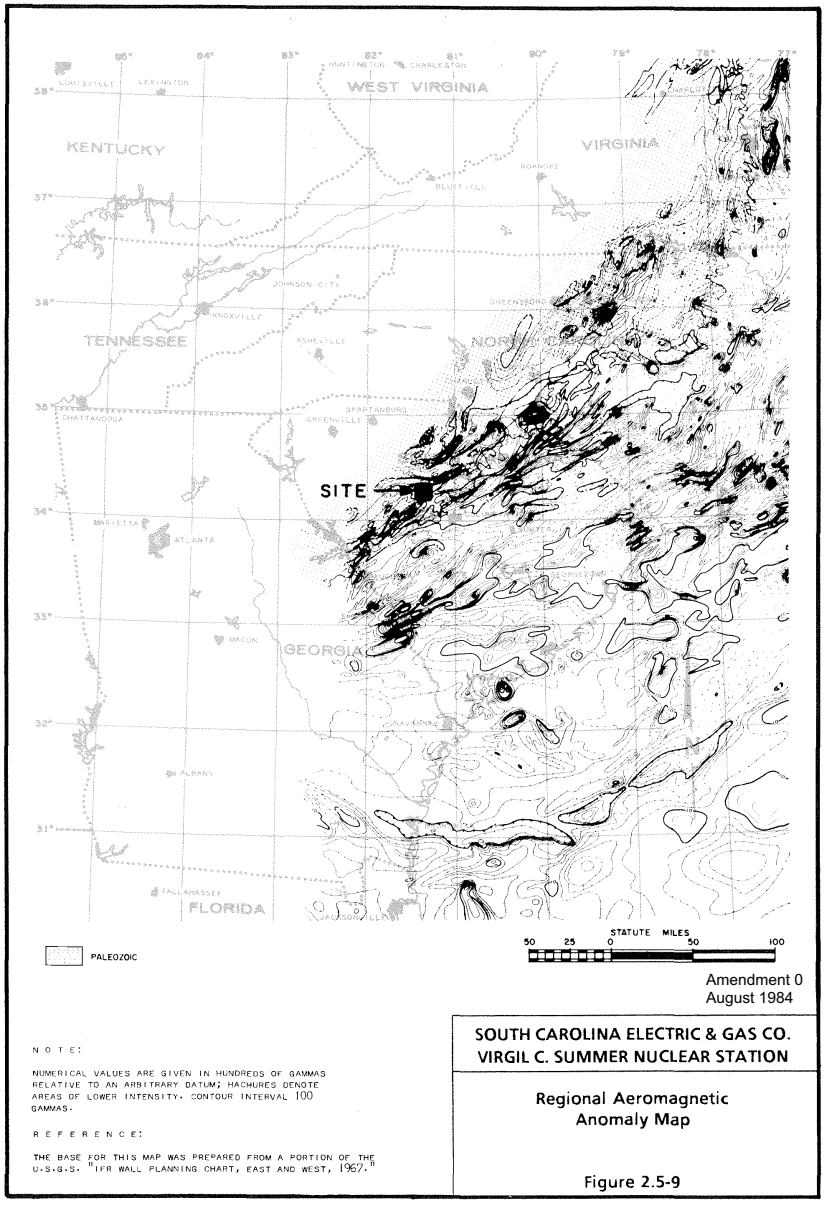


Figure 2.5-11
LINEAR FEATURES MAP

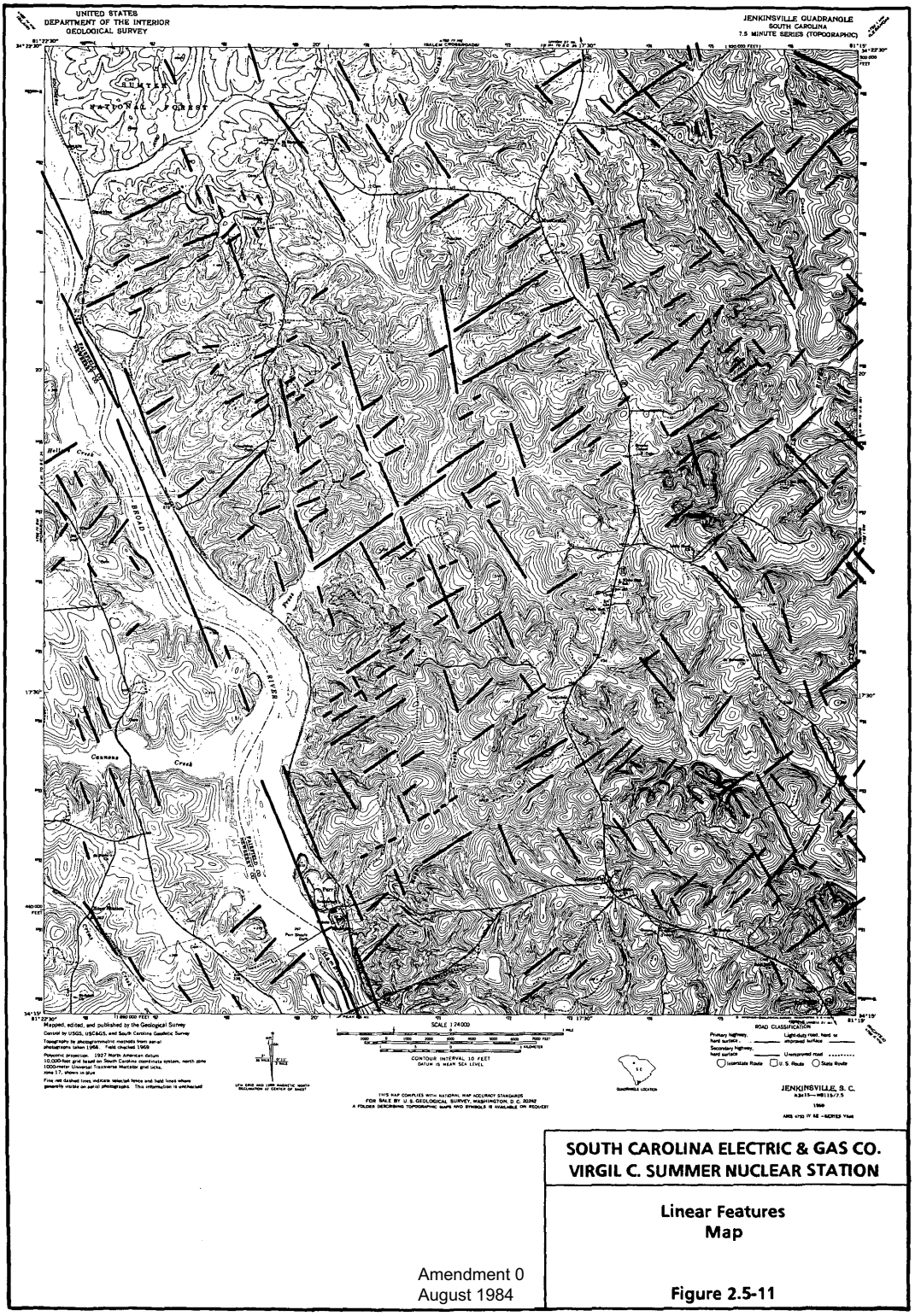
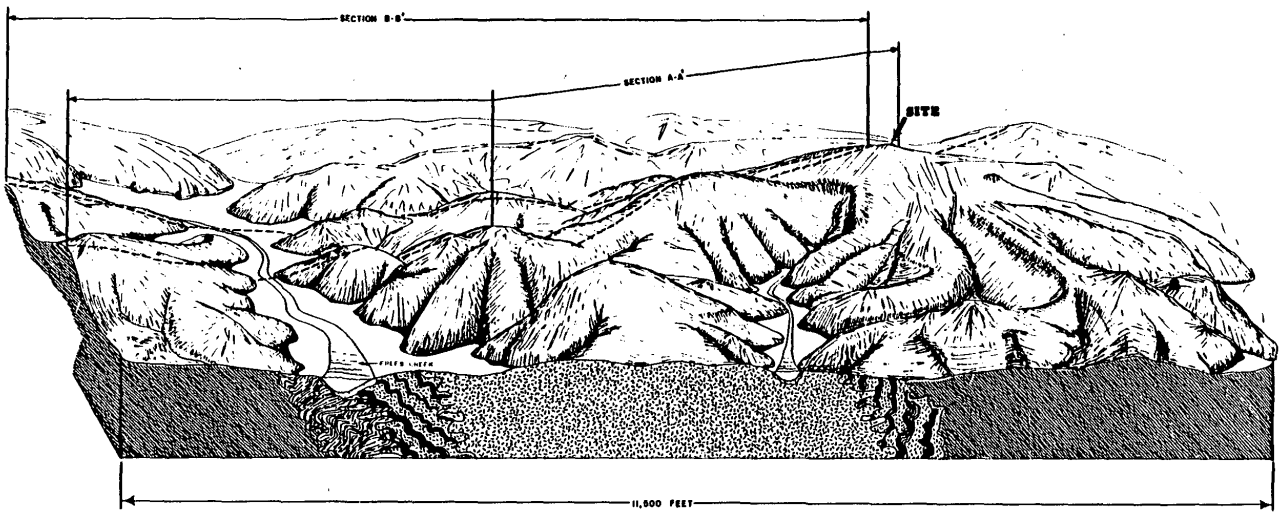


Figure 2.5-12

DIAGRAMMATIC VIEW PARALLEL TO BROAD RIVER



KEY:

- GRANODIORITE
- MIGMATITE OF GRANODIORITE COMPOSITION
- MIGMATITE OF GNEISSIC COMPOSITION
- CHARLOTTE BELT GNEISS

NO SCALE - DIAGRAMATIC ONLY

NOTES:
1) THE DIAGRAMMATIC SECTIONS SHOWN REPRESENT OUR EVALUATION OF THE MOST PROBABLE CONDITIONS BASED UPON INTERPRETATION OF PRESENTLY AVAILABLE DATA. SOME VARIATIONS FROM THESE CONDITIONS MUST BE EXPECTED.

2) DIAGRAMMATIC SECTIONS A-A' AND B-B' ARE SHOWN ON FIGURE 2.5-21.

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SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Diagrammatic View Parallel to Broad River

Figure 2.5-12

Figure 2.5-14

LOCATION OF SITE SUBSERVICE SECTIONS

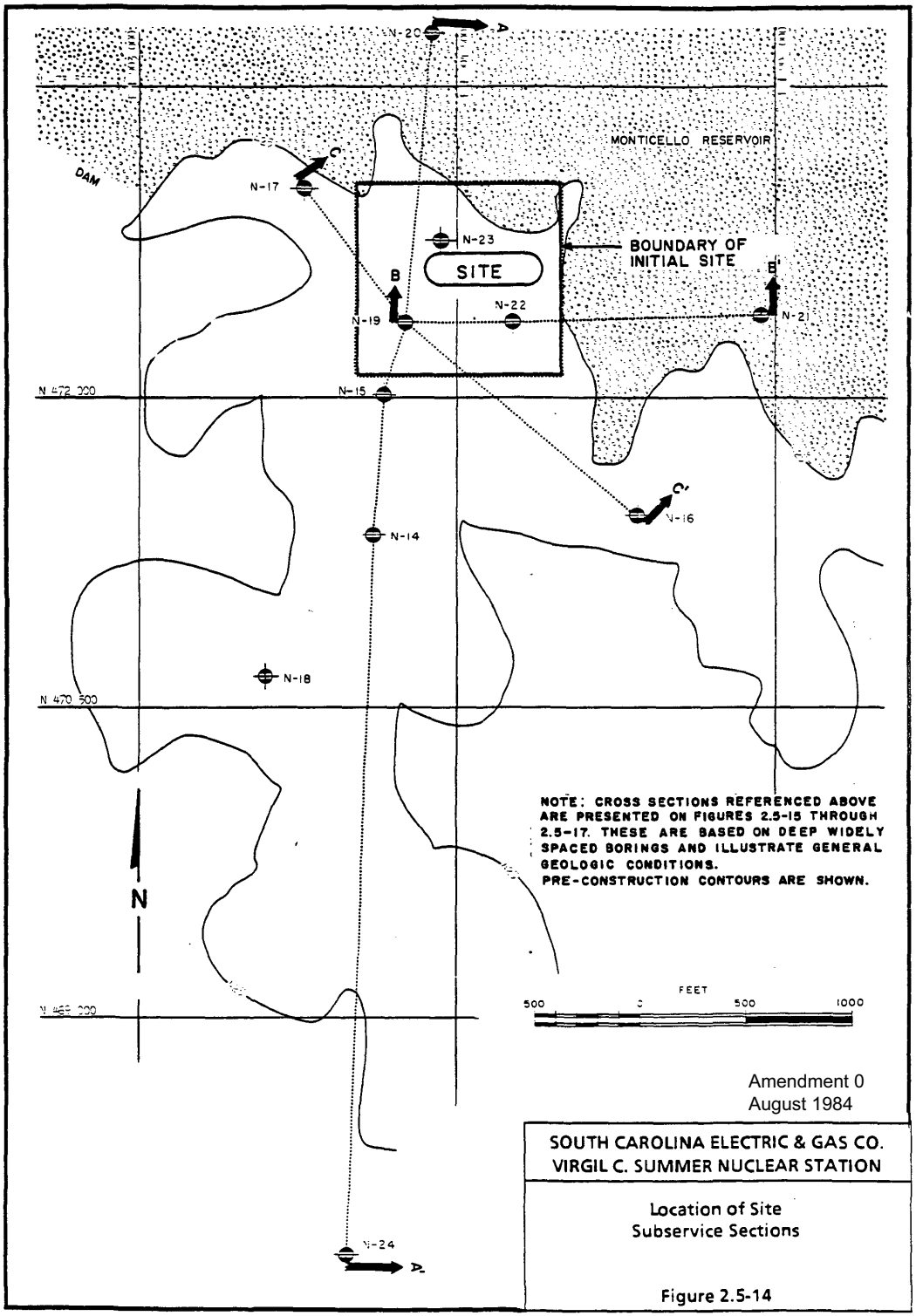


Figure 2.5-15

SITE SUBSERVICE SECTION A-A'

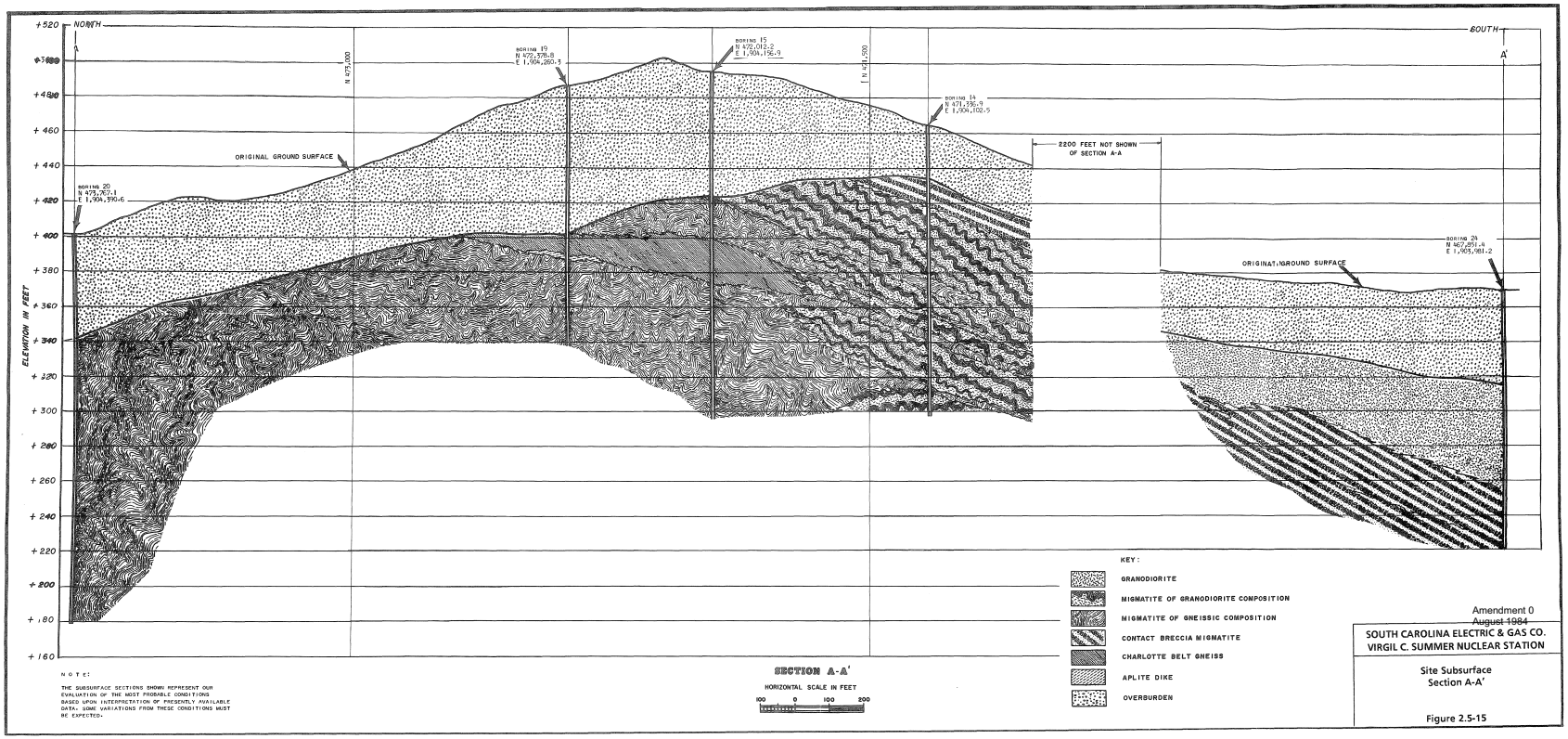


Figure 2.5-16

SITE SUBSURFACE SECTION B-B'

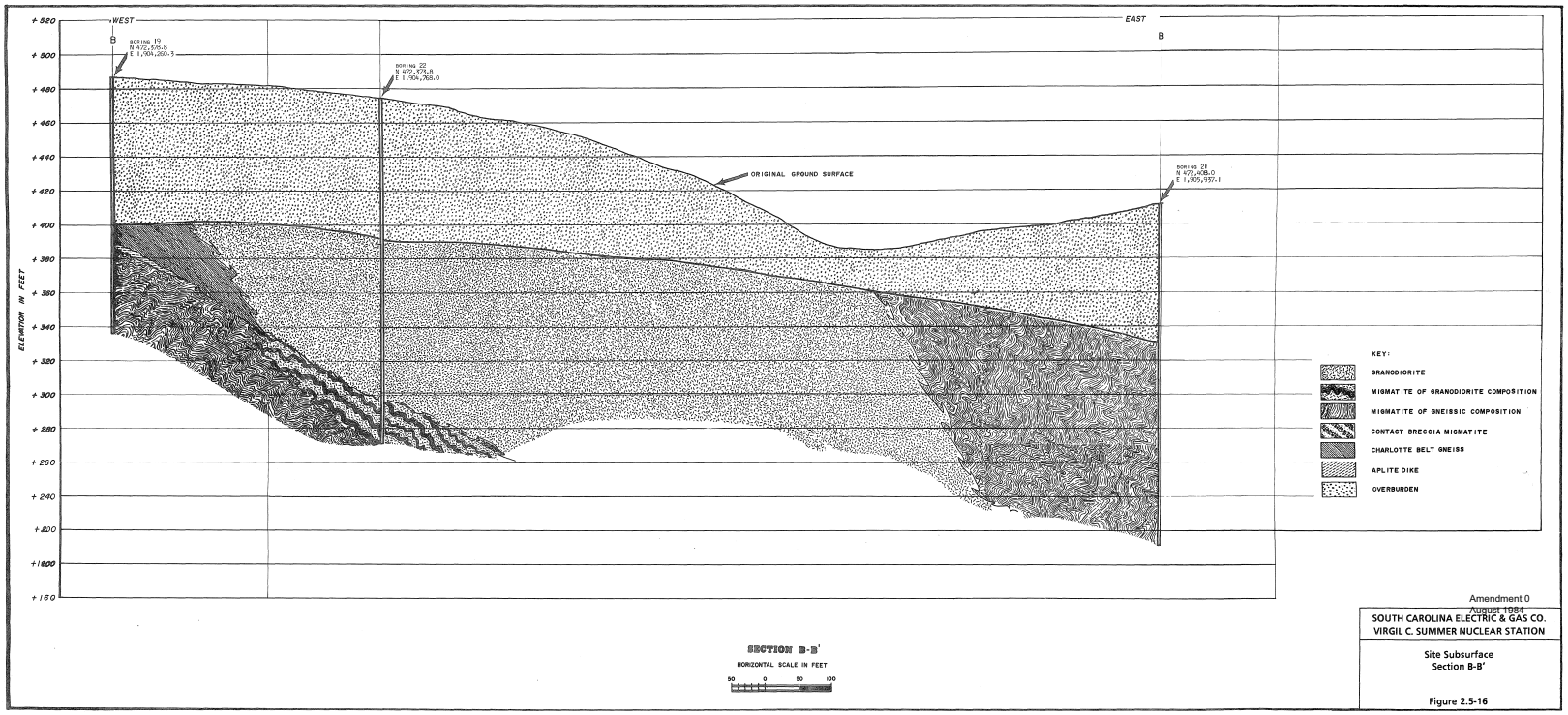


Figure 2.5-17

SITE SUBSERVICE SECTION C-C'

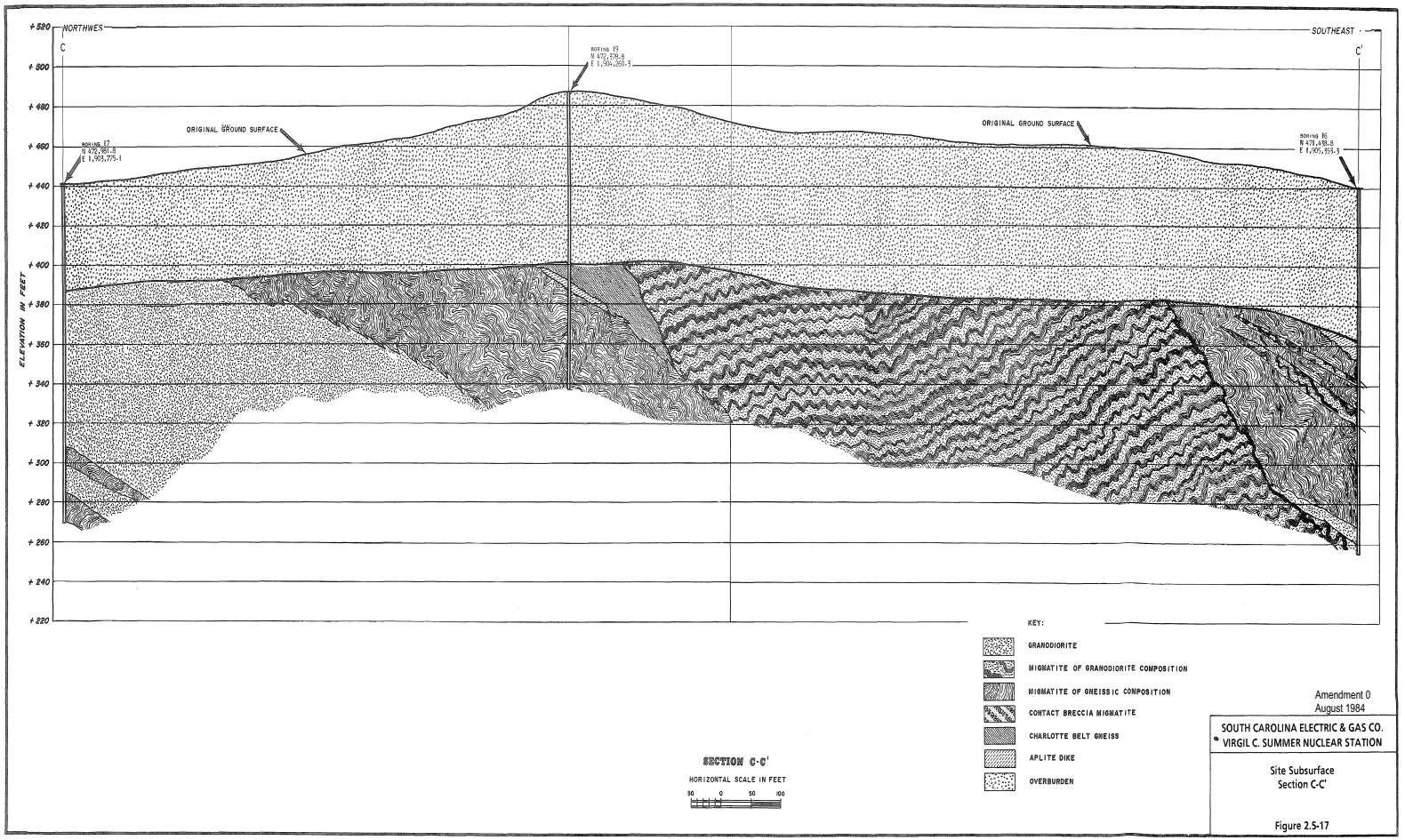


Figure 2.5-18
AREAL FOLIATION CONTOUR DIAGRAM

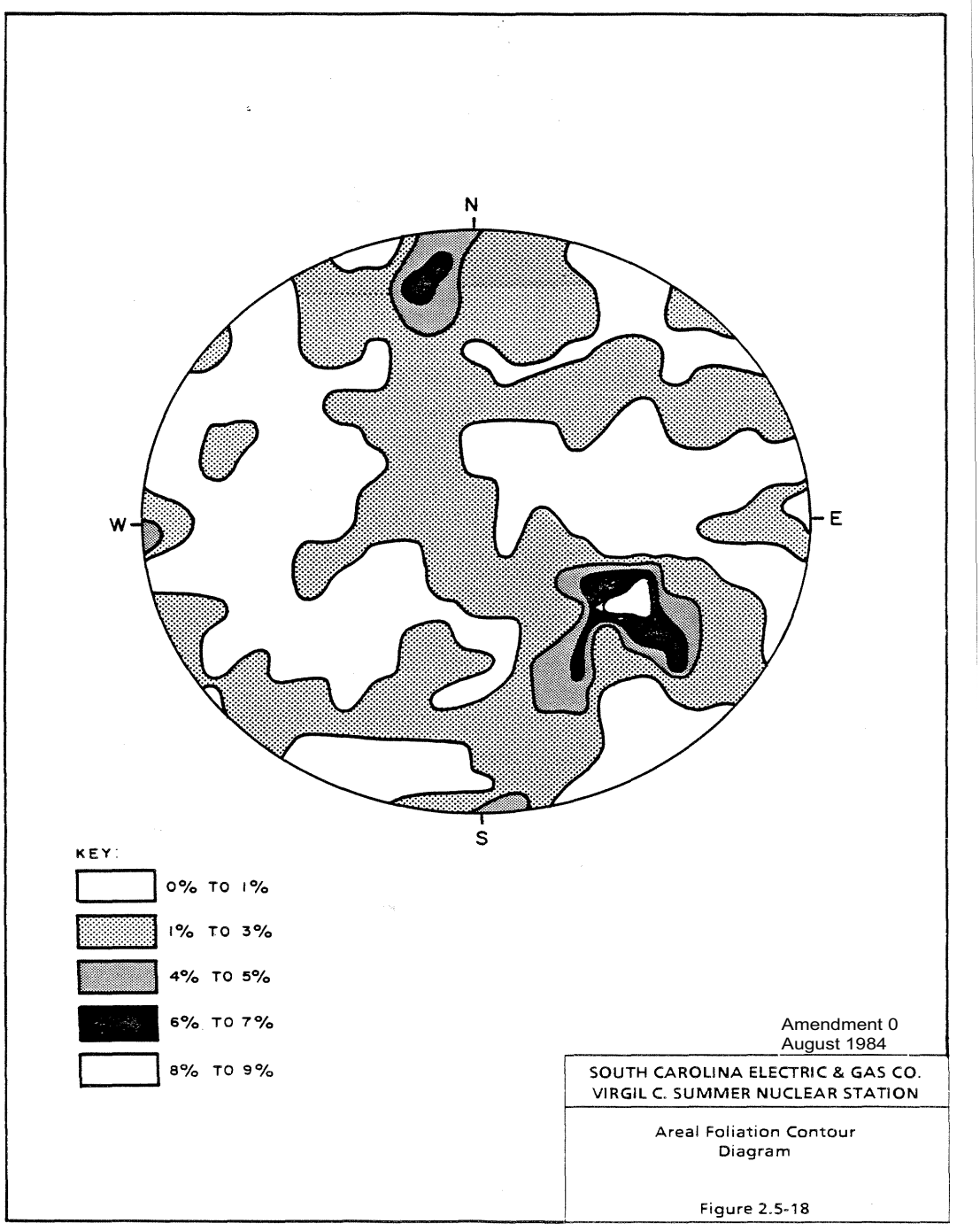


Figure 2.5-19
PLUTON AREA FOLIATION CONTOUR DIAGRAM

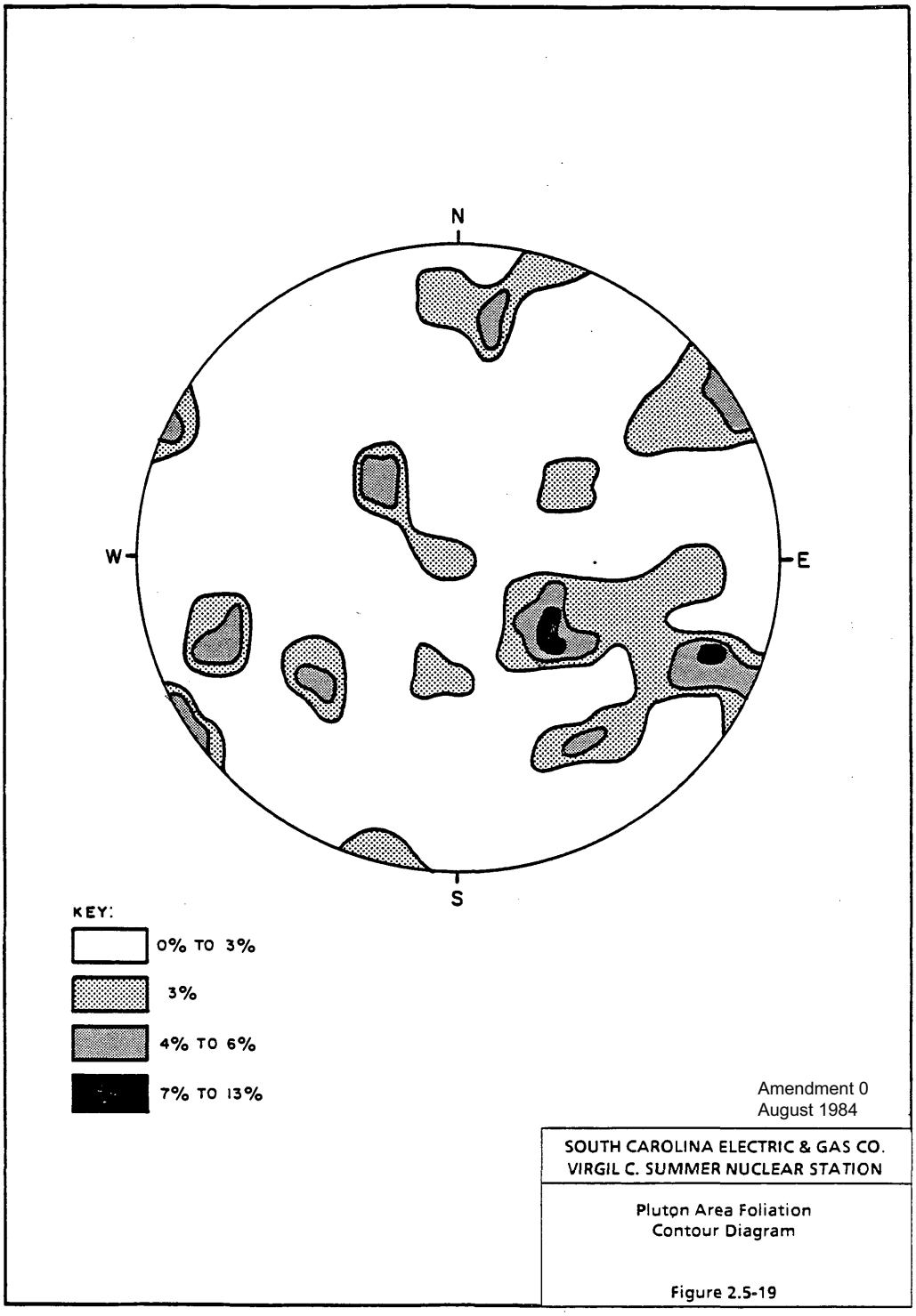


Figure 2.5-20
AREAL JOINT CONTOUR DIAGRAM

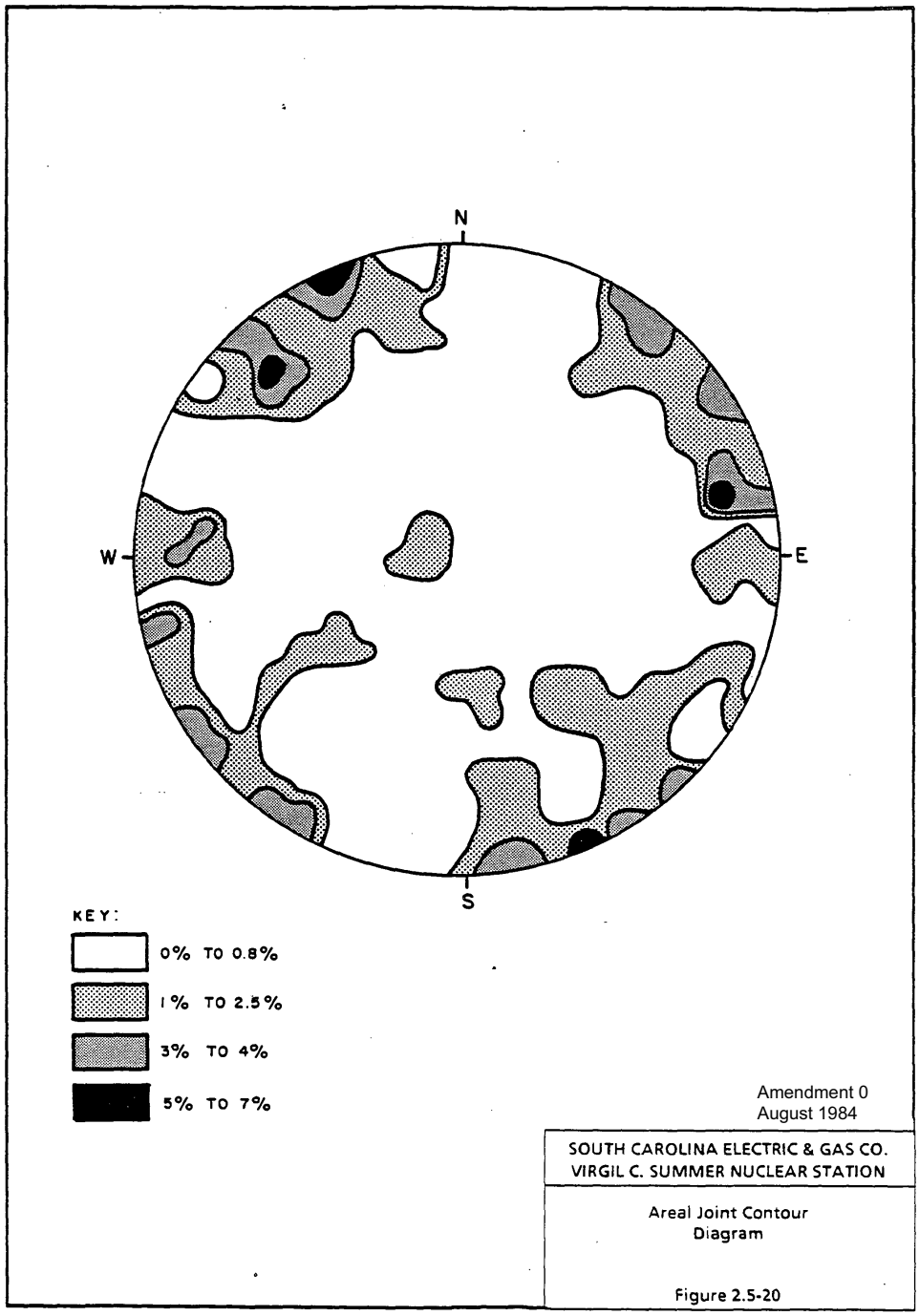
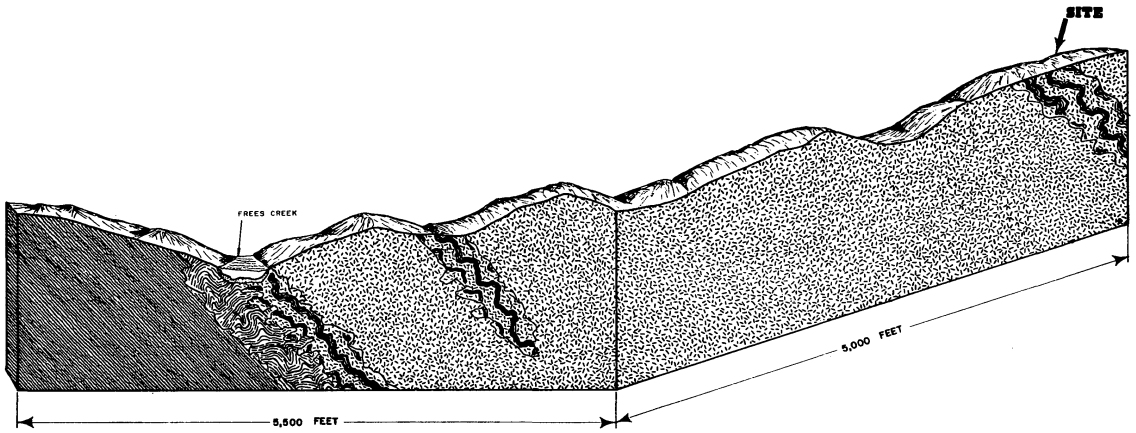
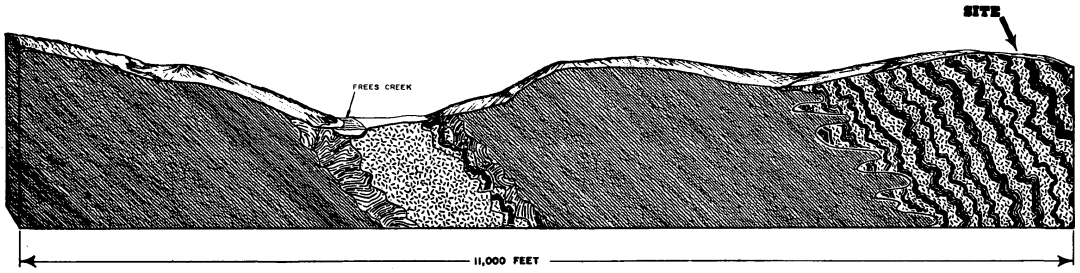


Figure 2.5-21

DIAGRAMMATIC SECTIONS A-A' AND B-B'



DIAGRAMMATIC SECTION A - A' ALONG PROPOSED DAM AXIS



DIAGRAMMATIC SECTION B - B' THROUGH SITE

KEY:

- GRANODIORITE
- MIGMATITE OF GRANODIORITE COMPOSITION
- MIGMATITE OF GNEISSIC COMPOSITION
- CHARLOTTE BELT GNEISS

NO SCALE - DIAGRAMMATIC ONLY

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Diagrammatic Sections
A-A' and B-B'

Figure 2.5-21

Figure 2.5-22

AREAL MAGNETIC ANOMALY MAP

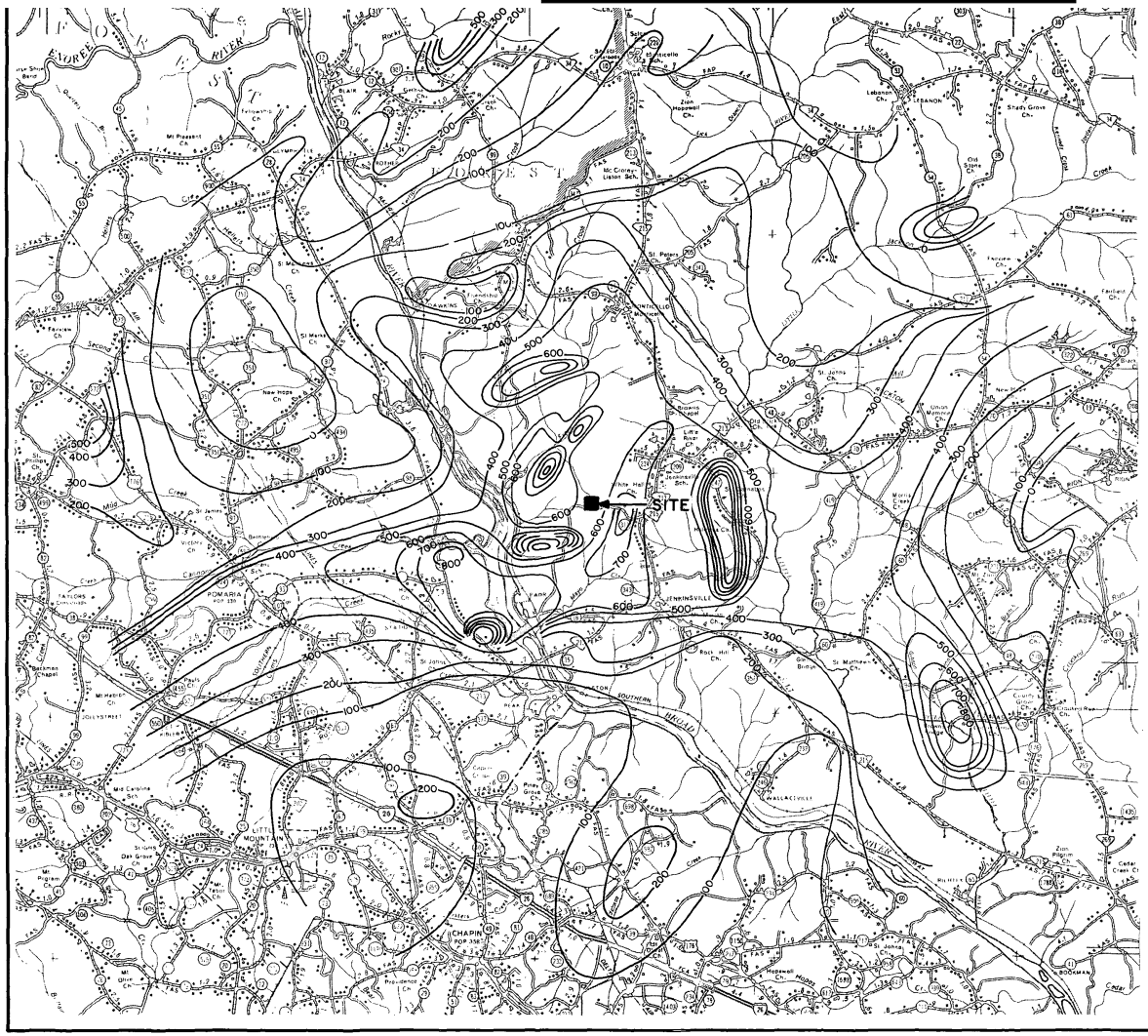

Figure 2.5-23

AREAS OF DETAILED INVESTIGATION

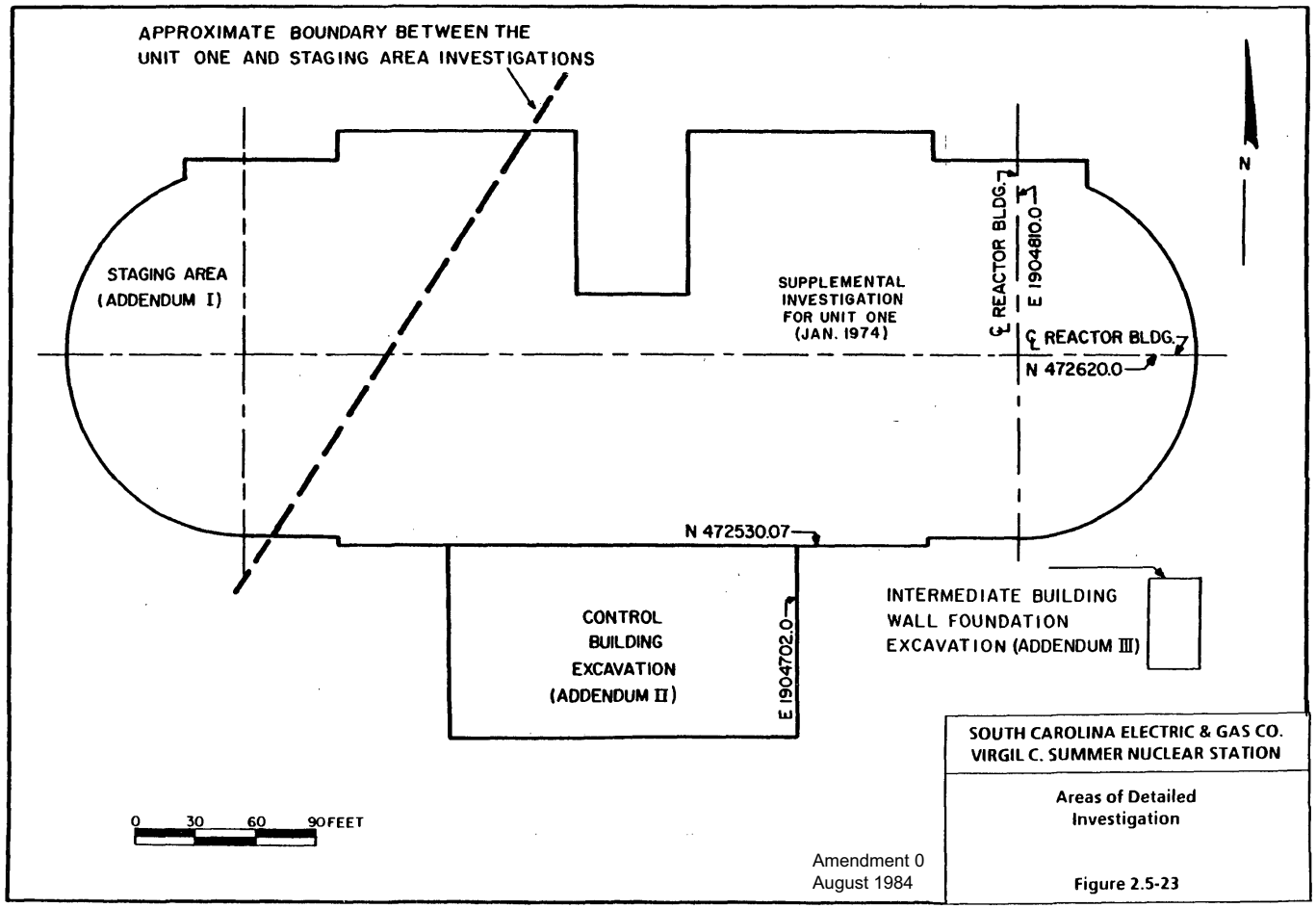

Figure 2.5-24

GEOLOGIC MAP OF REACTOR BUILDING AND STAGING AREA EXCAVATIONS

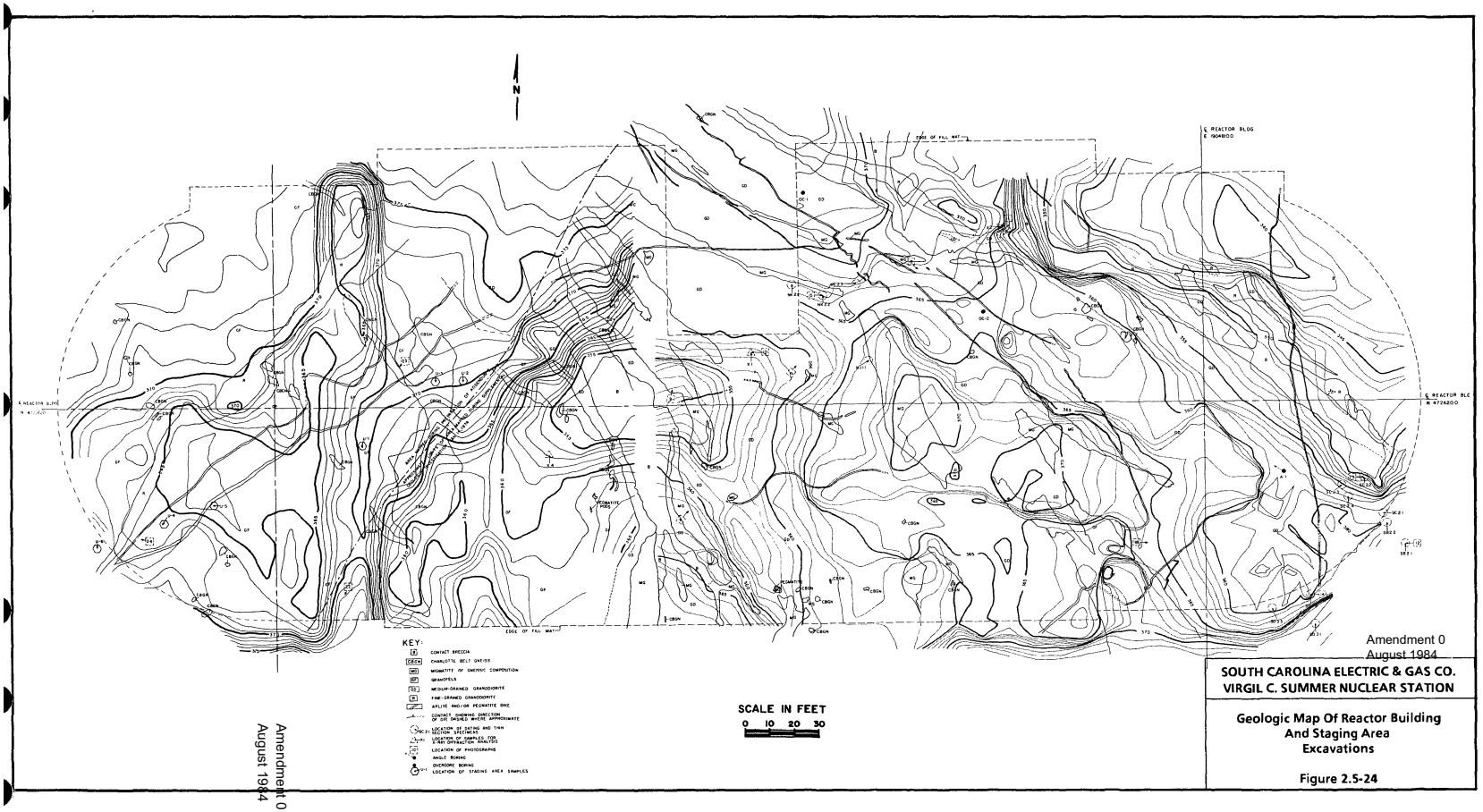

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Figure 2.5-26

GEOLOGIC MAP OF CONTROL BUILDING EXCAVATION

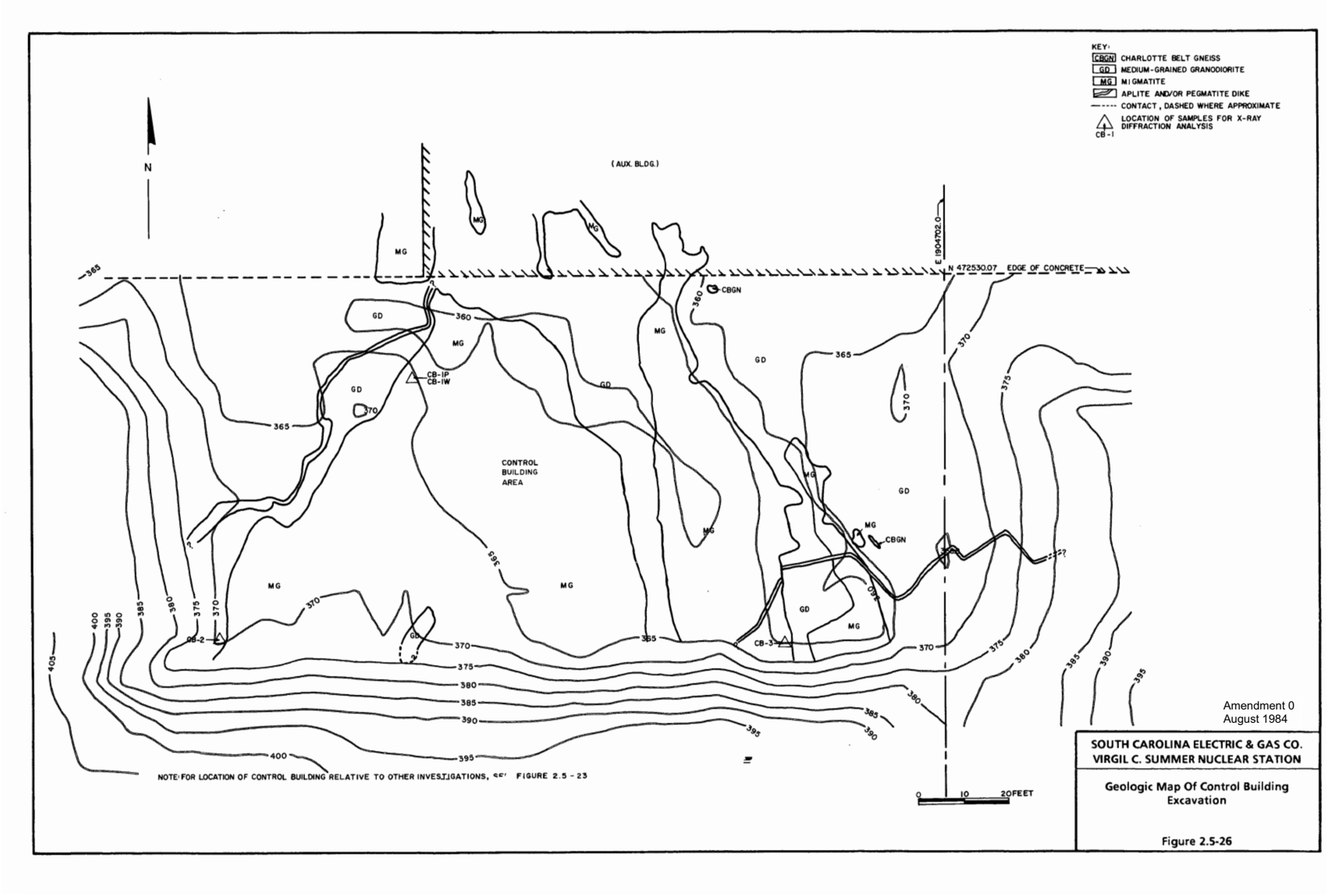

Figure 2.5-28

STRUCTURE MAP OF INTERMEDIATE BUILDING WALL EXCAVATION

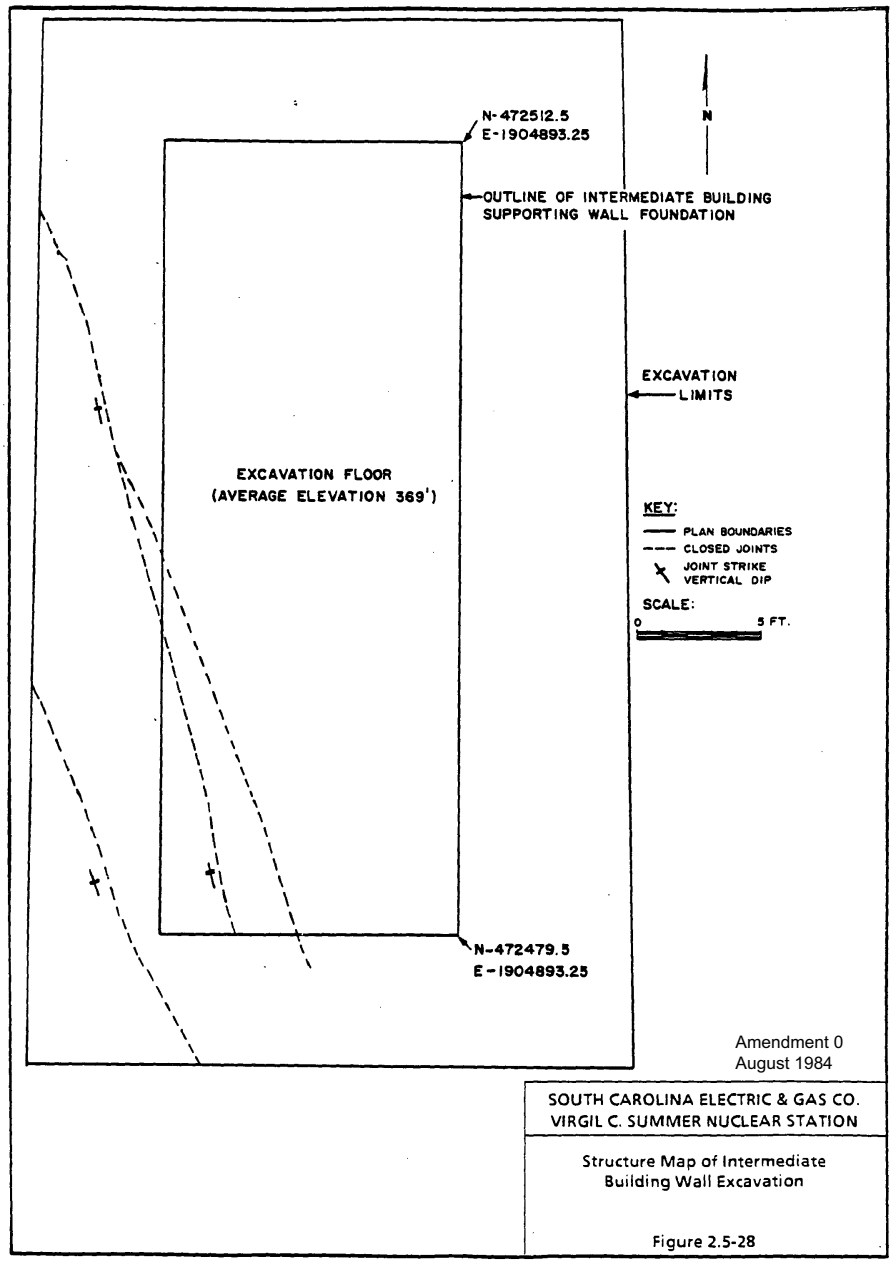

Figure 2.5-29

GEOLOGIC MAP OF NORTH DAM EXCAVATION

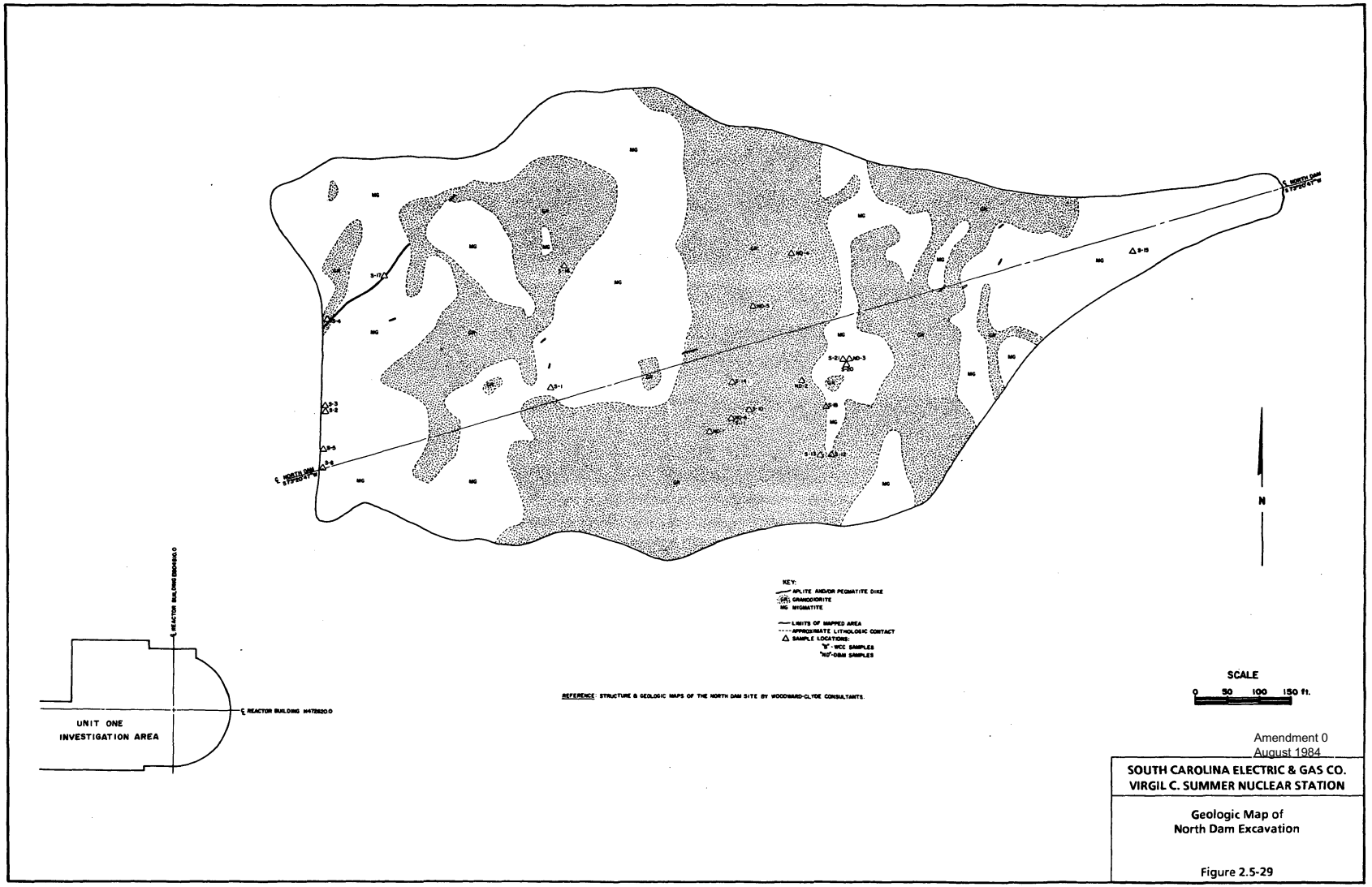

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Figure 2.5-30

STRUCTURE MAP OF NORTH DAM EXCAVATION

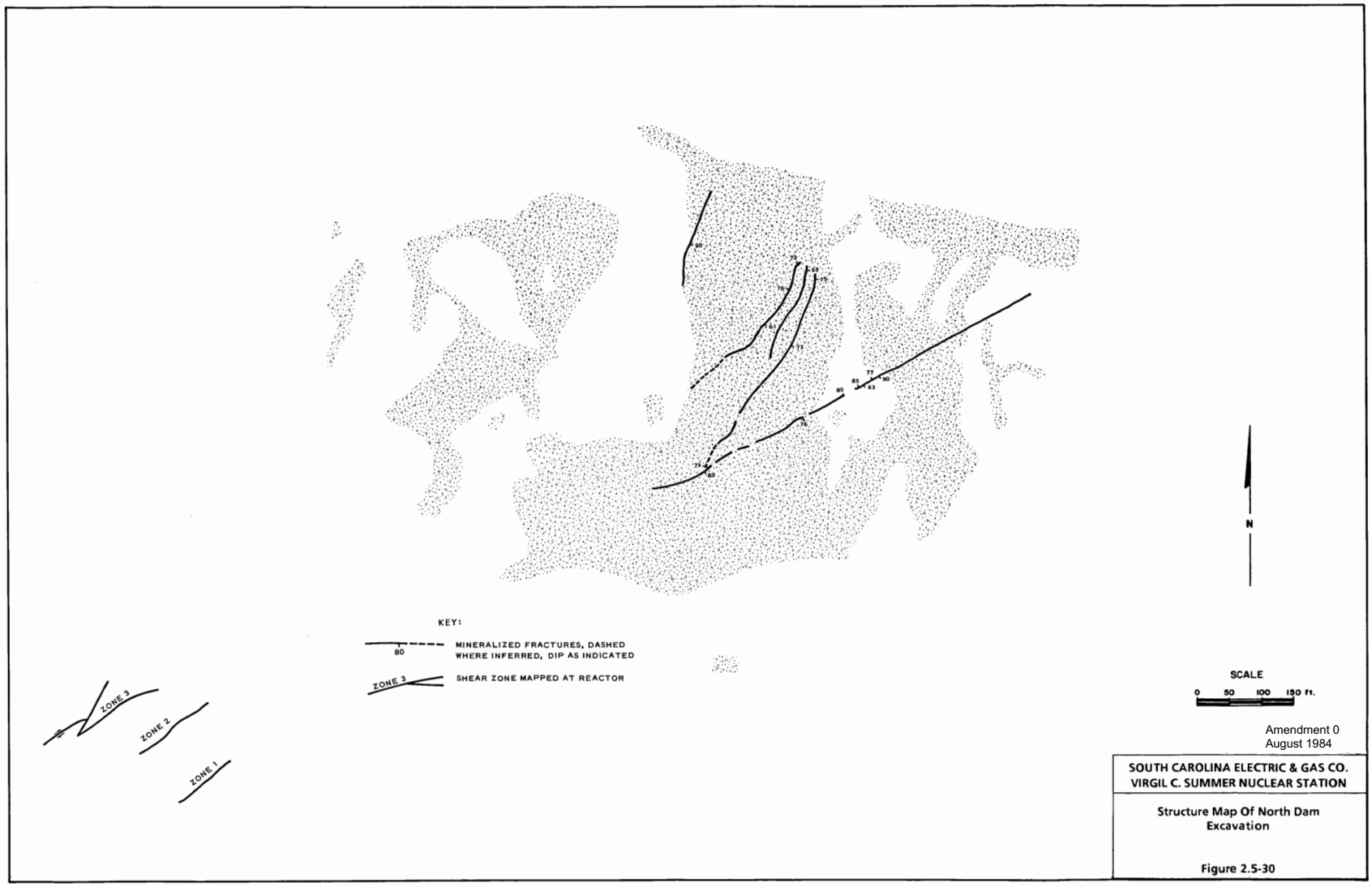


Figure 2.5-31

STEREONET DIAGRAM NON-DISPLACED FRACTURES

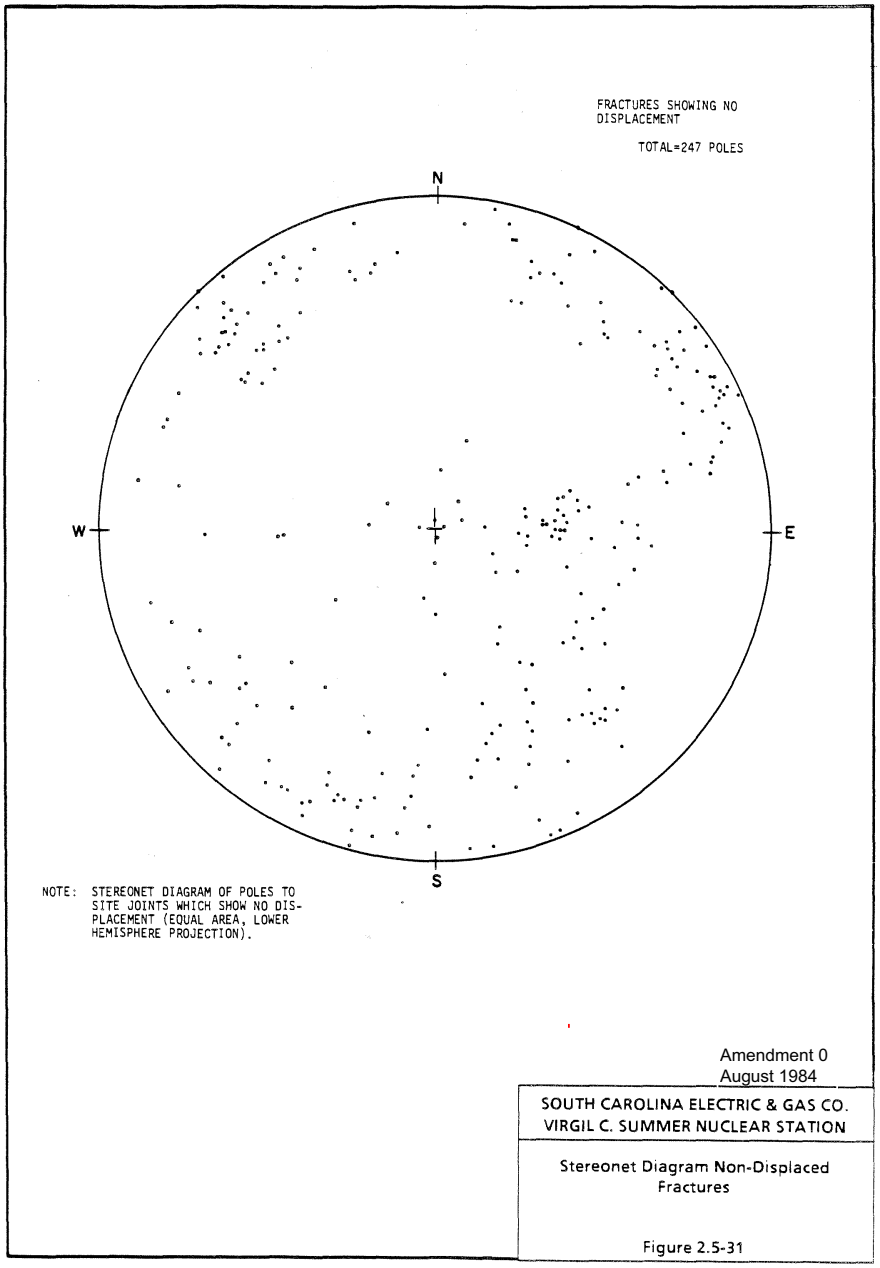


Figure 2.5-32

STEREONET DIAGRAM HYDROTHERMAL MINERALIZED AND/OR DISPLACED FRACTURES

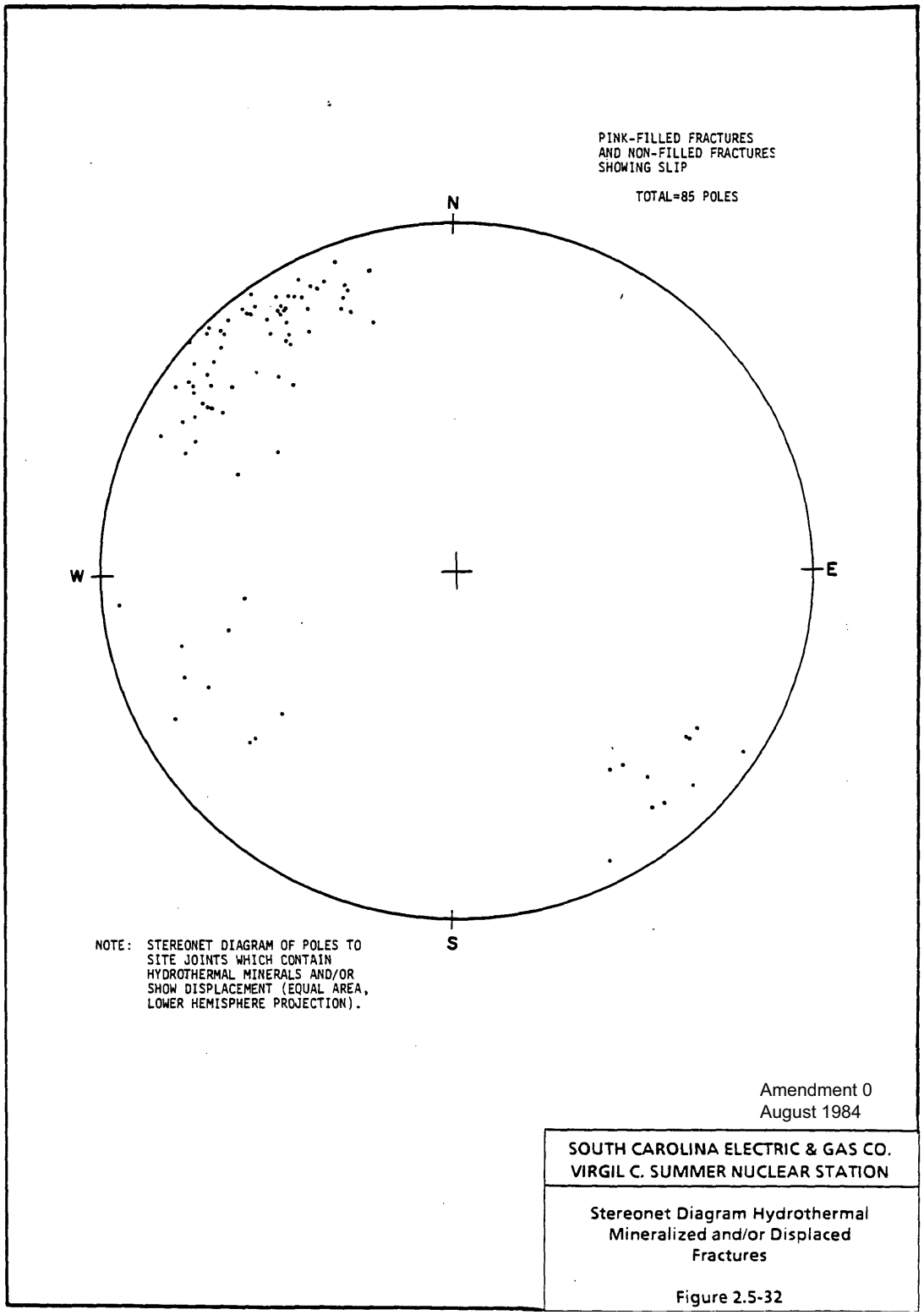
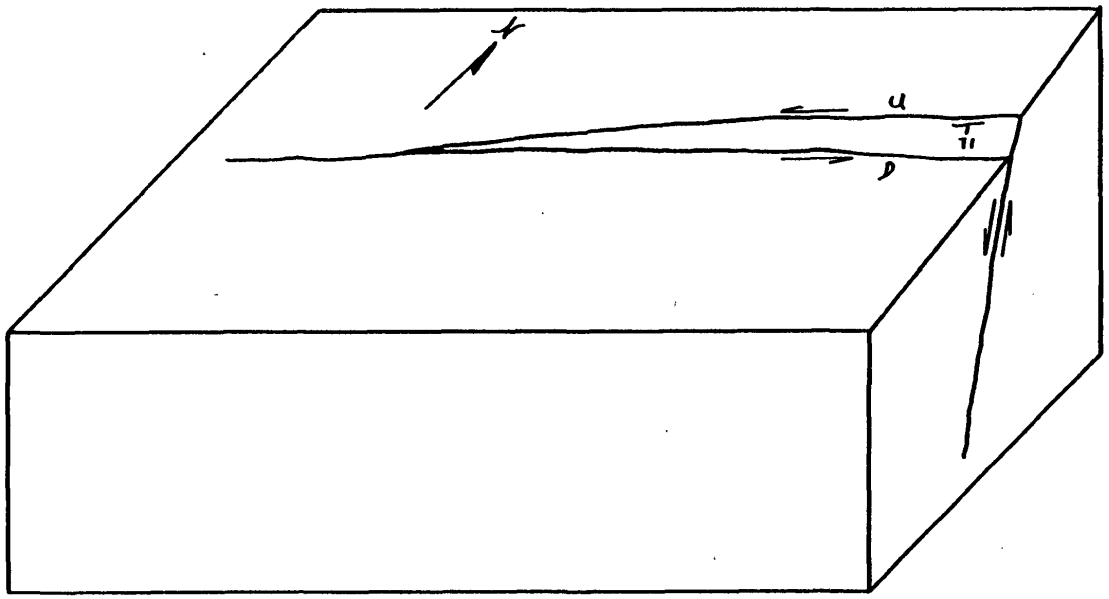


Figure 2.5-33
BLOCK DIAGRAM OF SHEAR



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NOTE: SKETCH OF THE N60E SEGMENT OF SHEAR ZONE 3 ILLUSTRATING THE THREE-DIMENSIONAL GEOMETRY OF THE DISPLACEMENT AS DETERMINED IN THIS STUDY. NOTE THAT DISPLACEMENT ALONG THE SHEAR DECREASES TO THE SOUTHWEST. (NOT TO SCALE)

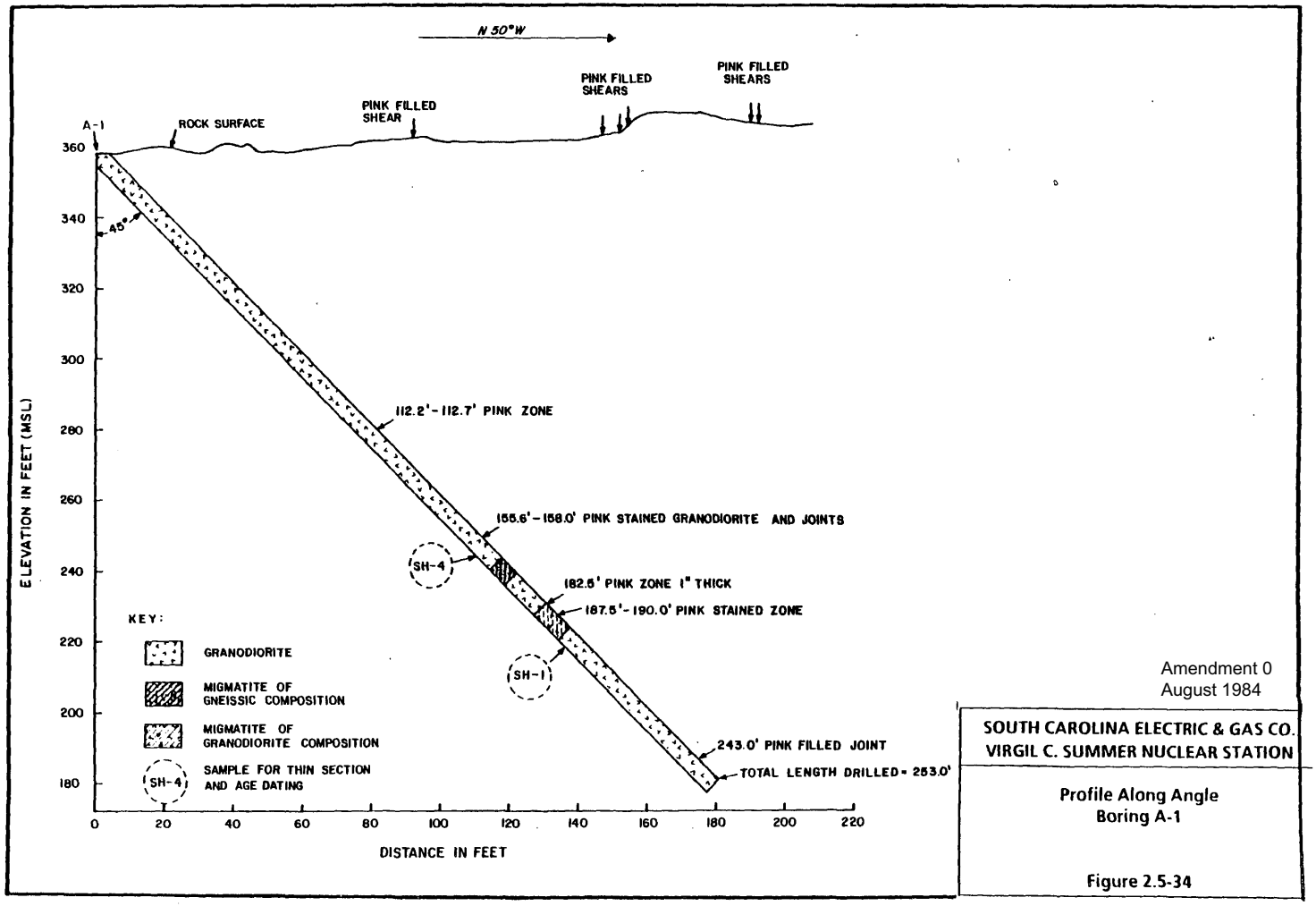
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Block Diagram
of Shear

Figure 2.5-33

Figure 2.5-34

PROFILE ALONG ANGLE BORING A-1



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VIRGIL C. SUMMER NUCLEAR STATION

Profile Along Angle
Boring A-1

Figure 2.5-34

Figure 2.5-35

X-RAY DIFFRACTION PATTERN OF LAUMONTITE

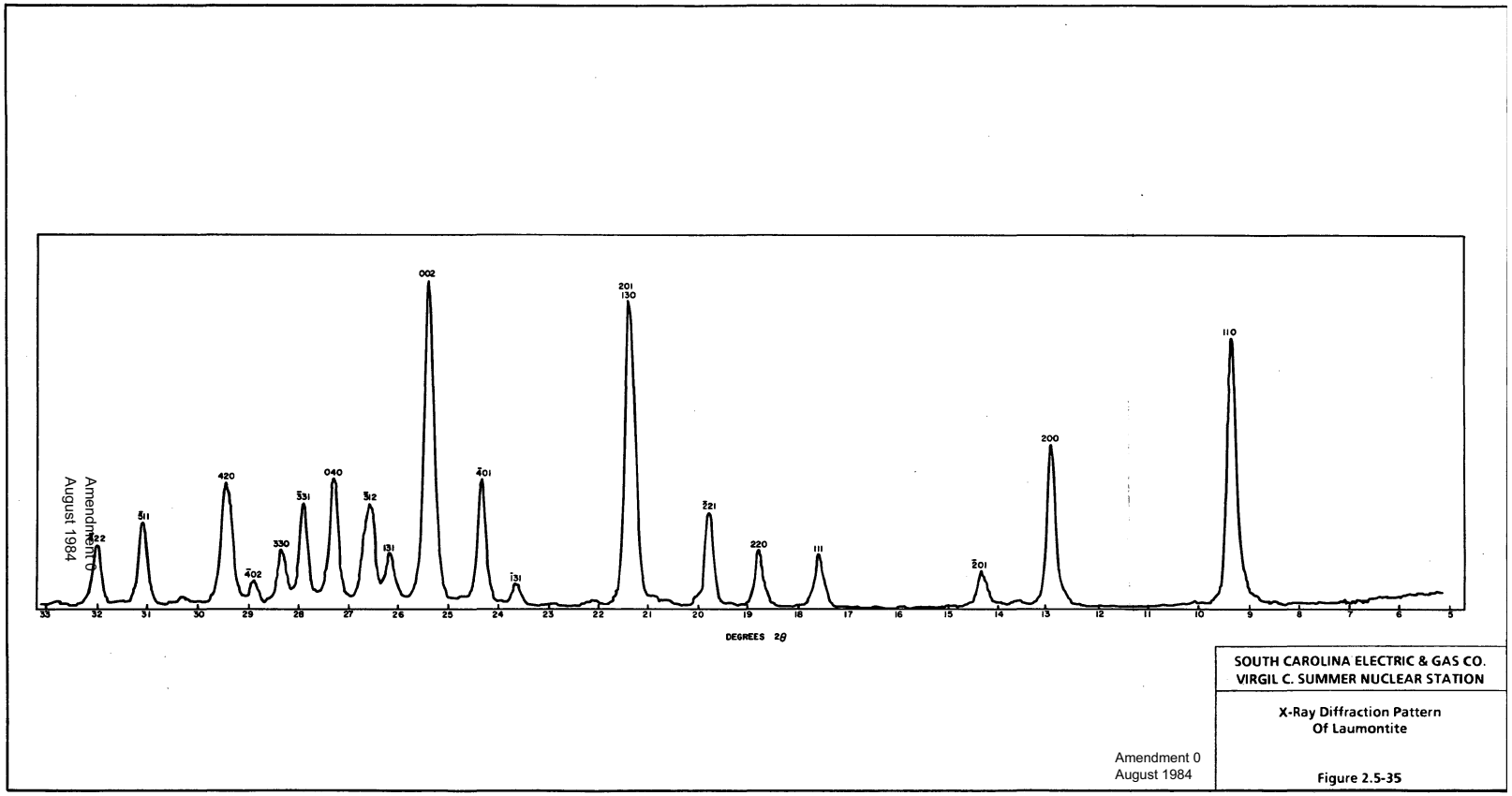


Figure 2.5-36

MAP OF INSITU STRESSES IN THE PIEDMONT AREA OF THE UNITED STATES

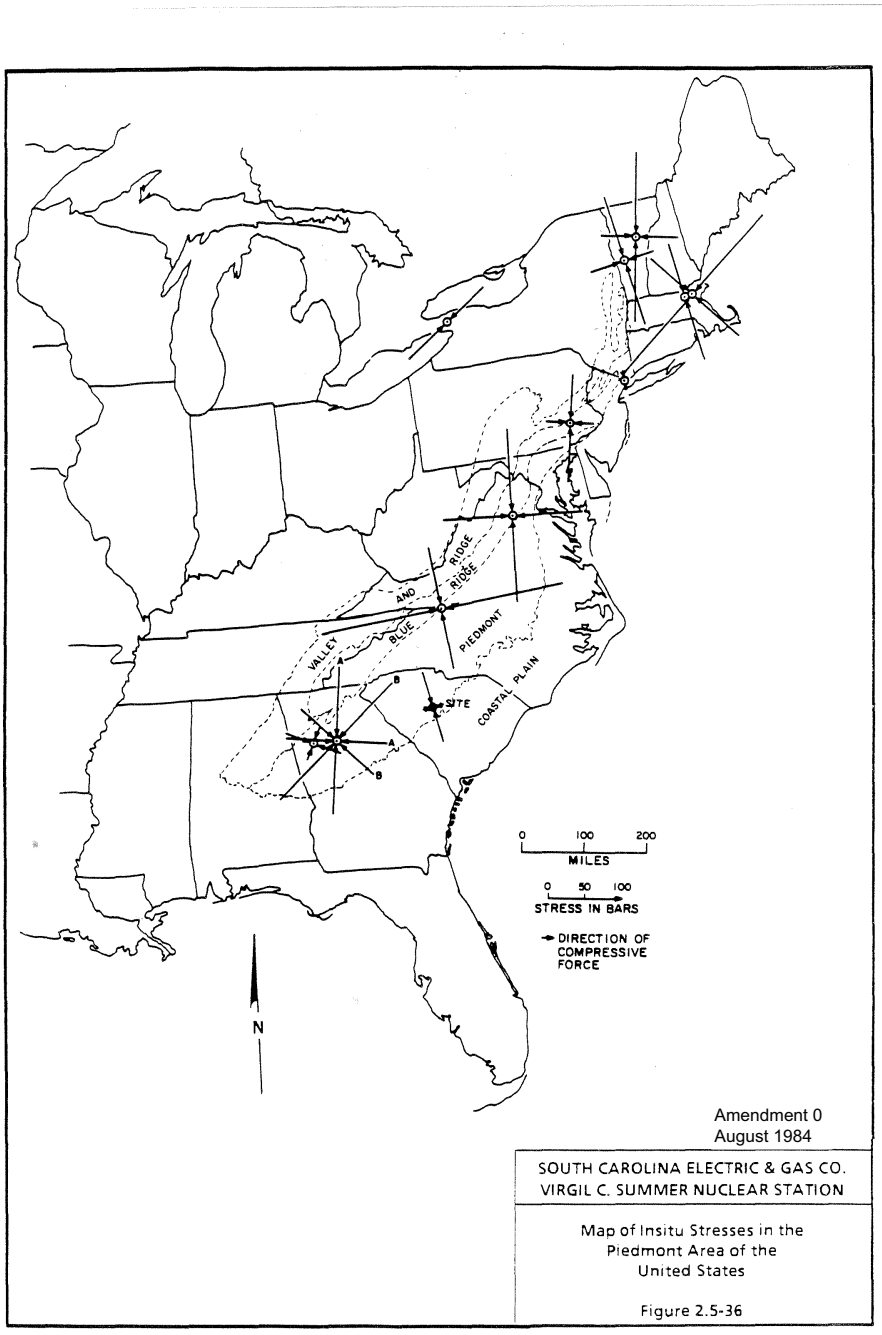


Figure 2.5-37

REGIONAL EPICENTER MAP

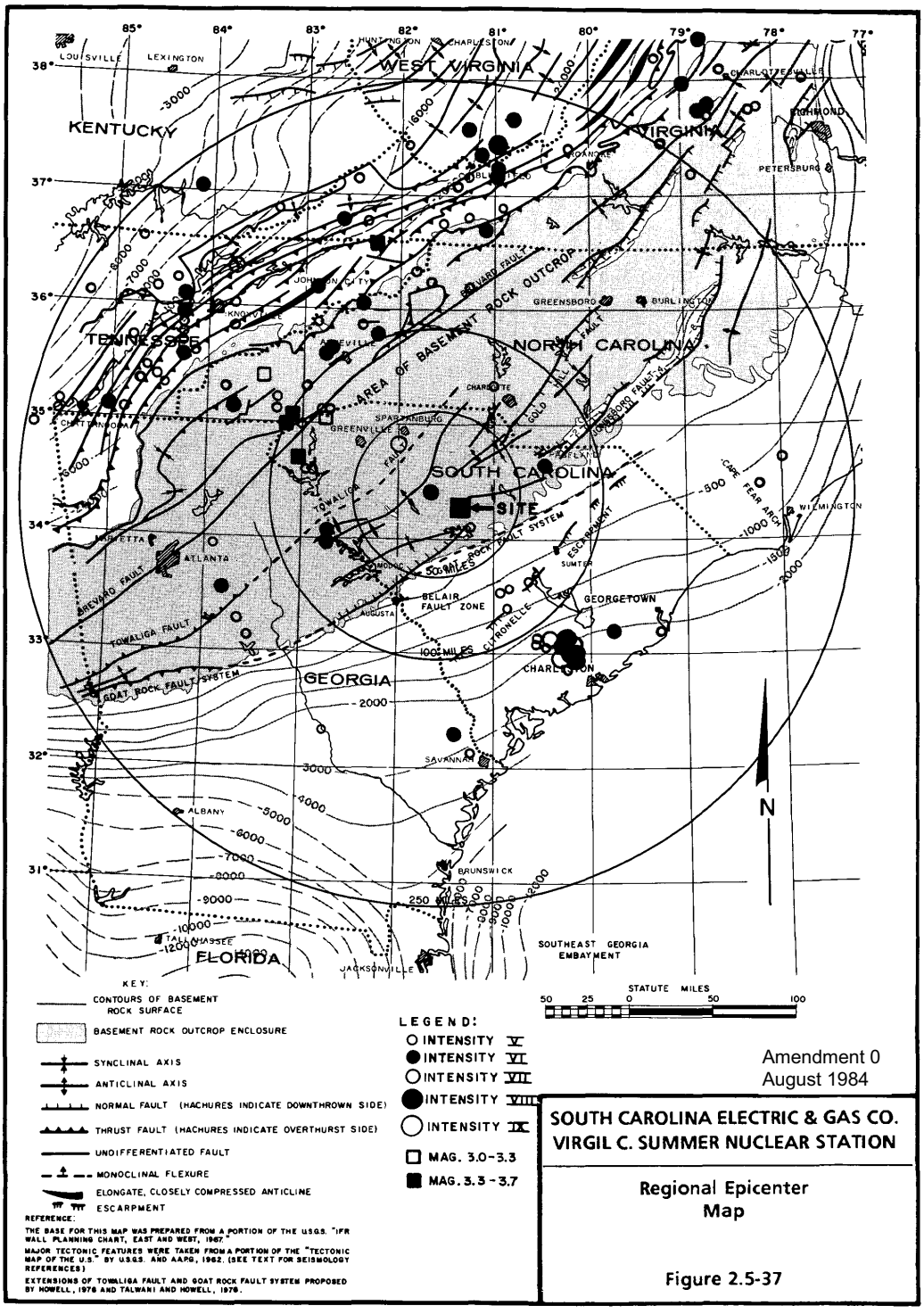


Figure 2.5-38
LOCAL EPICENTER MAP

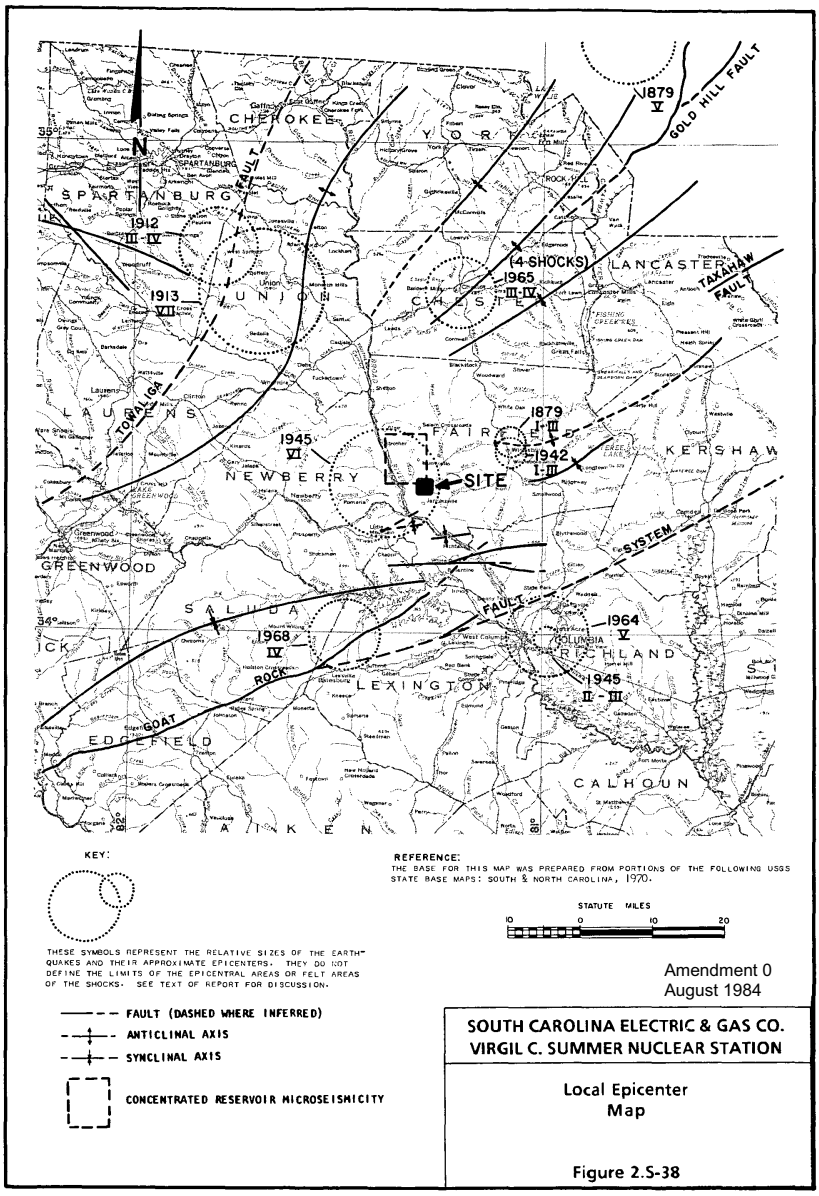


Figure 2.5-39
CHARLESTON, S.C. EARTHQUAKE
AUGUST 31,1886, ISOSEISMAL MAP-
MODIFIED MERCALLI INTENSITY SCALE

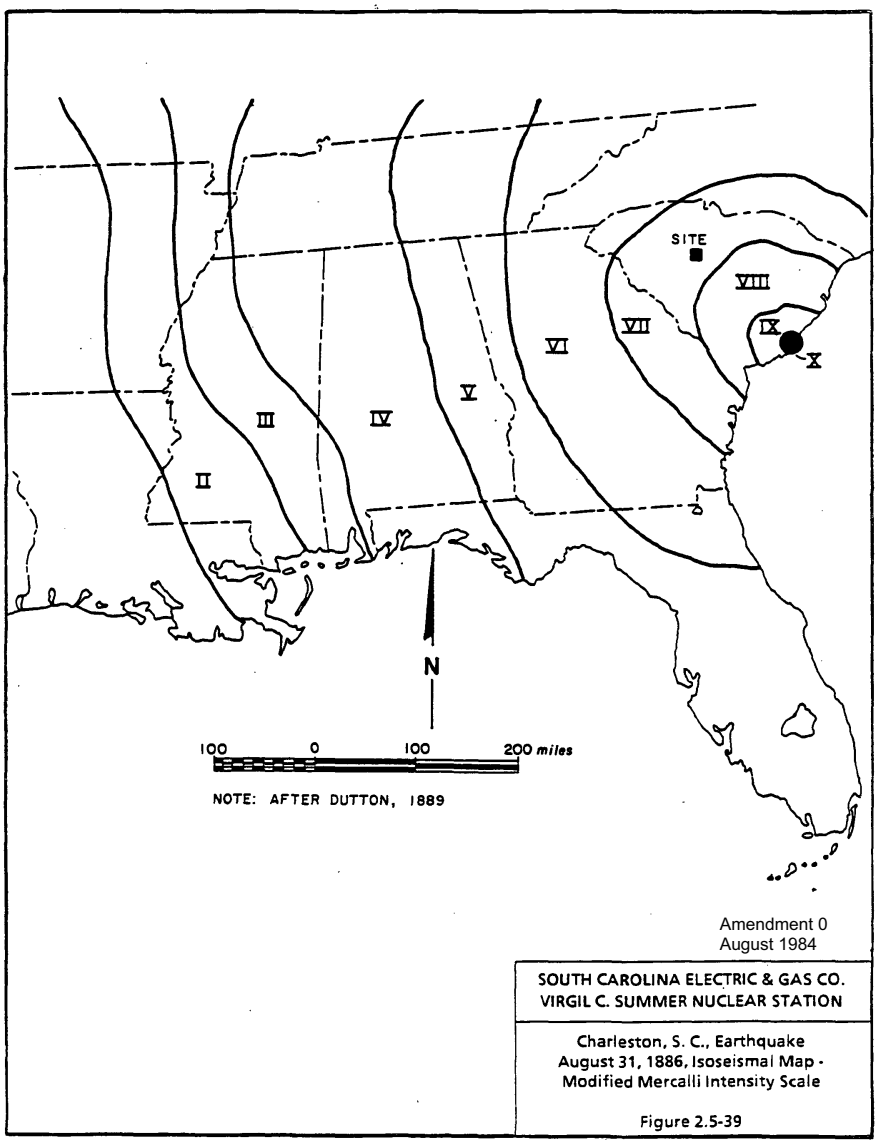


Figure 2.5-40
HORIZONTAL DESIGN RESPONSE SPECTRA - SSE - STRUCTURES FOUNDED ON ROCK

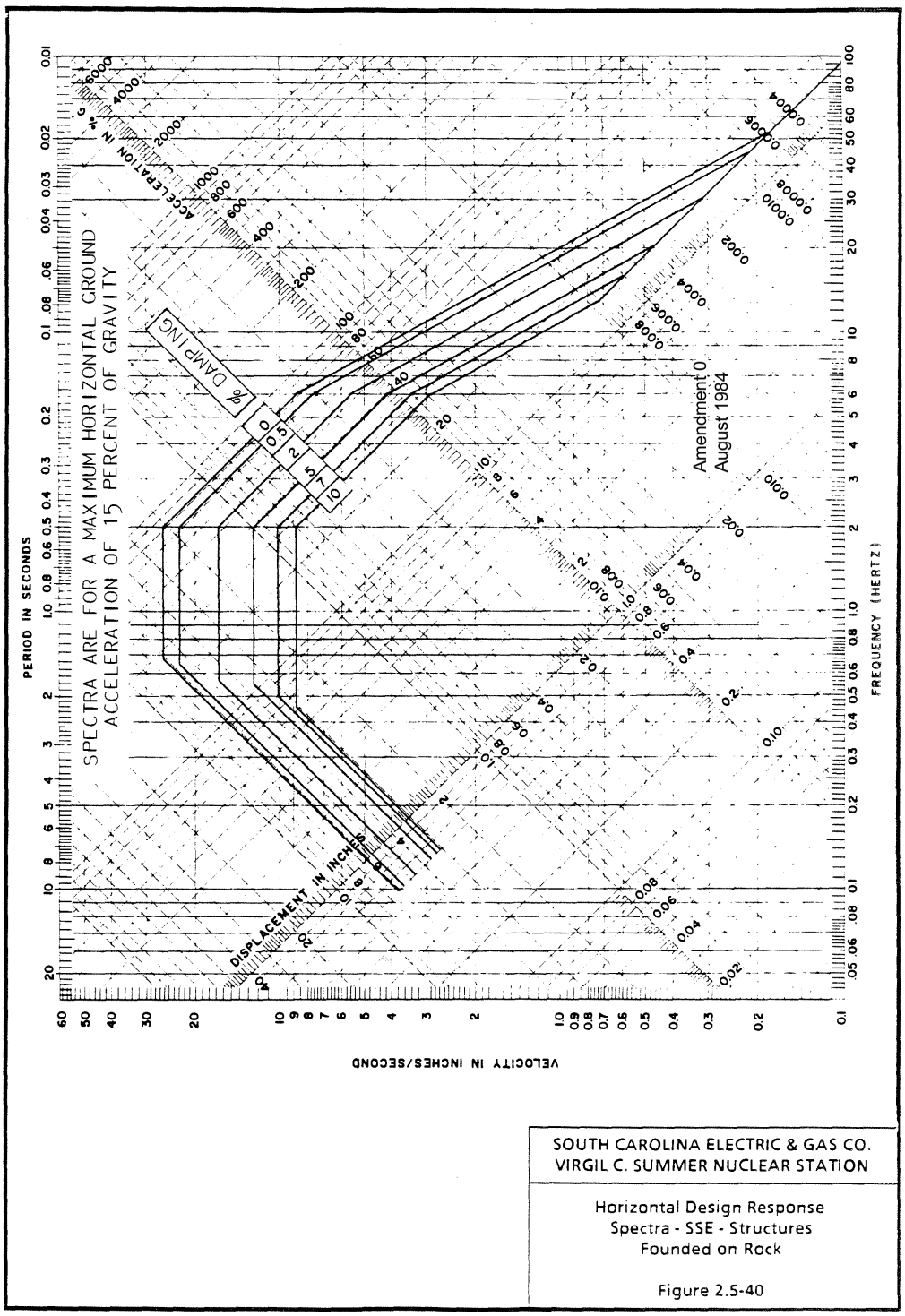


Figure 2.5-41
HORIZONTAL DESIGN RESPONSE SPECTRA - SSE - STRUCTURES FOUNDED ON SOIL

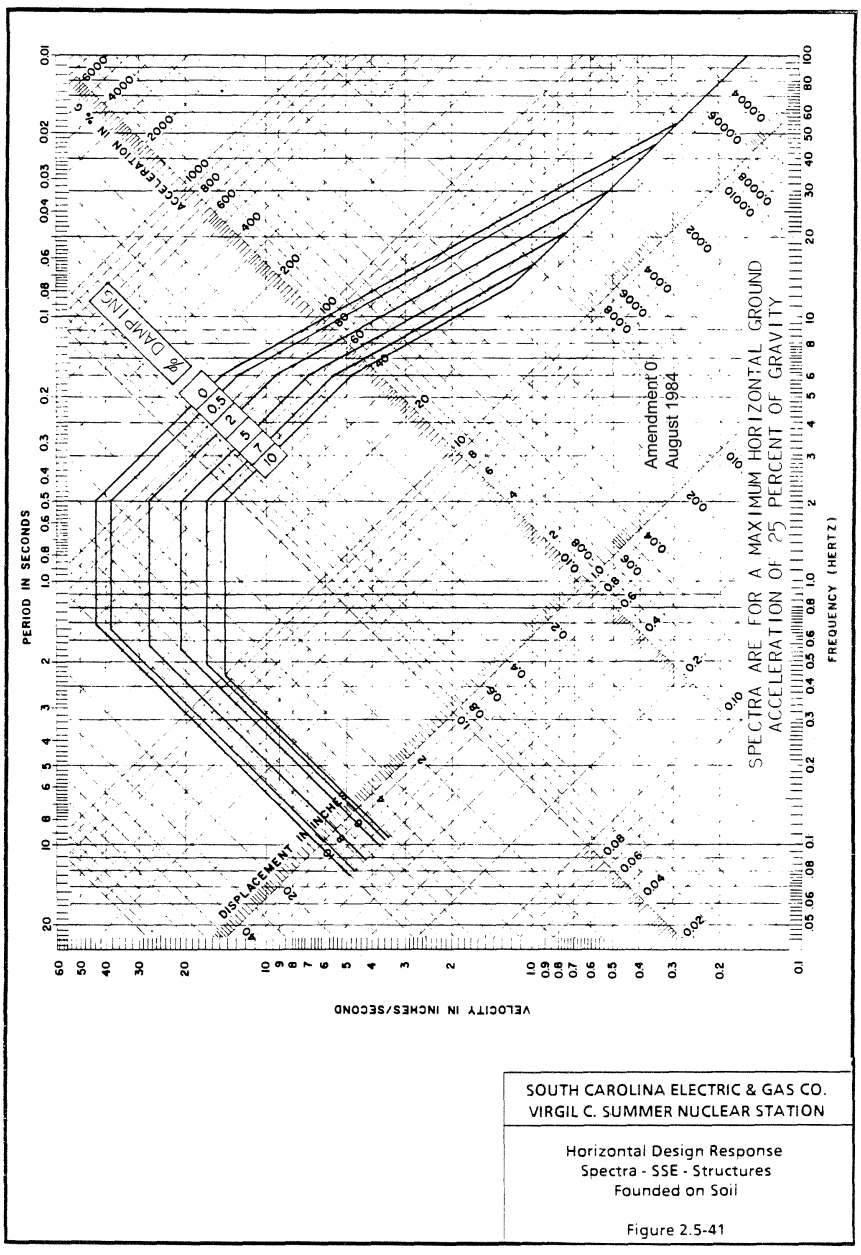


Figure 2.5-42

HORIZONTAL DESIGN RESPONSE SPECTRA - OBE - STRUCTURES FOUNDED ON ROCK

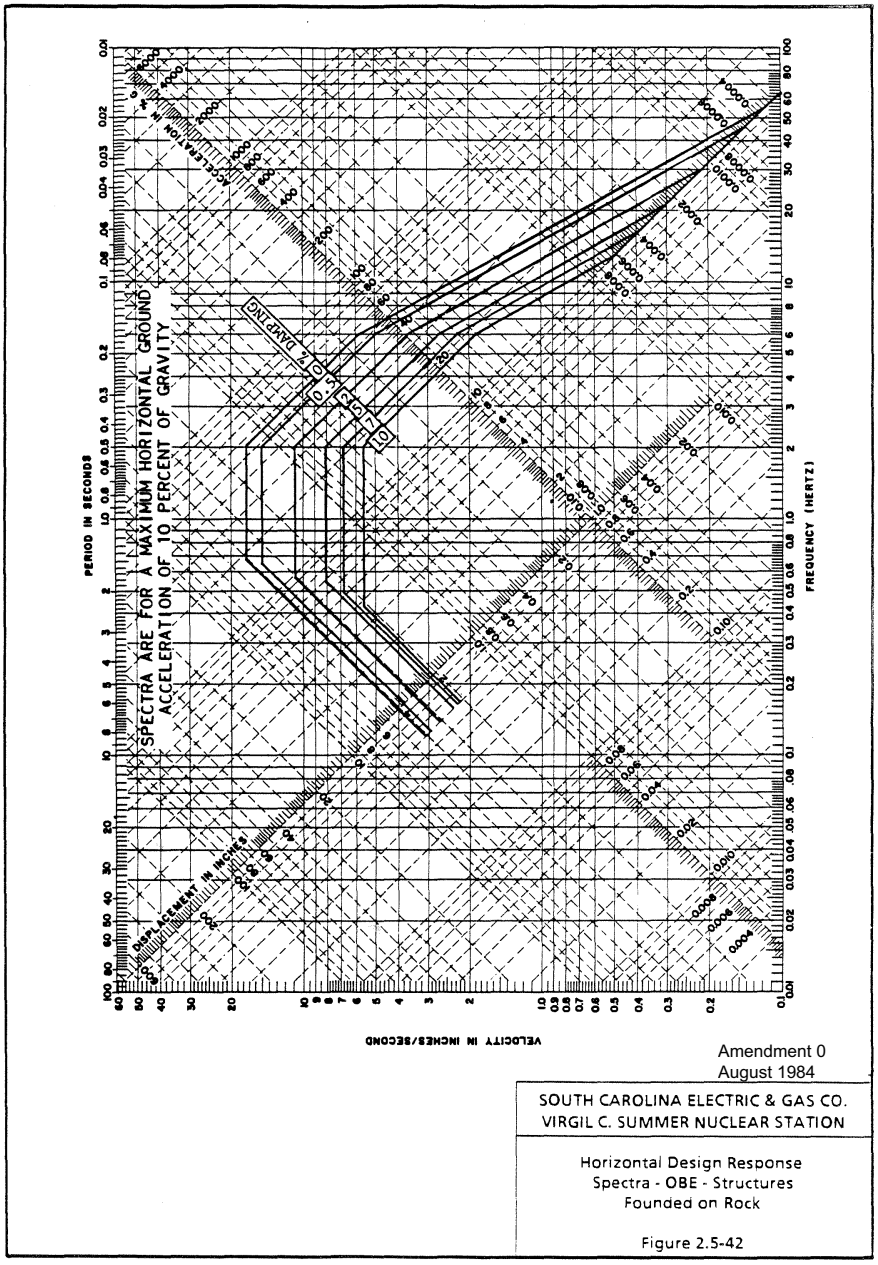
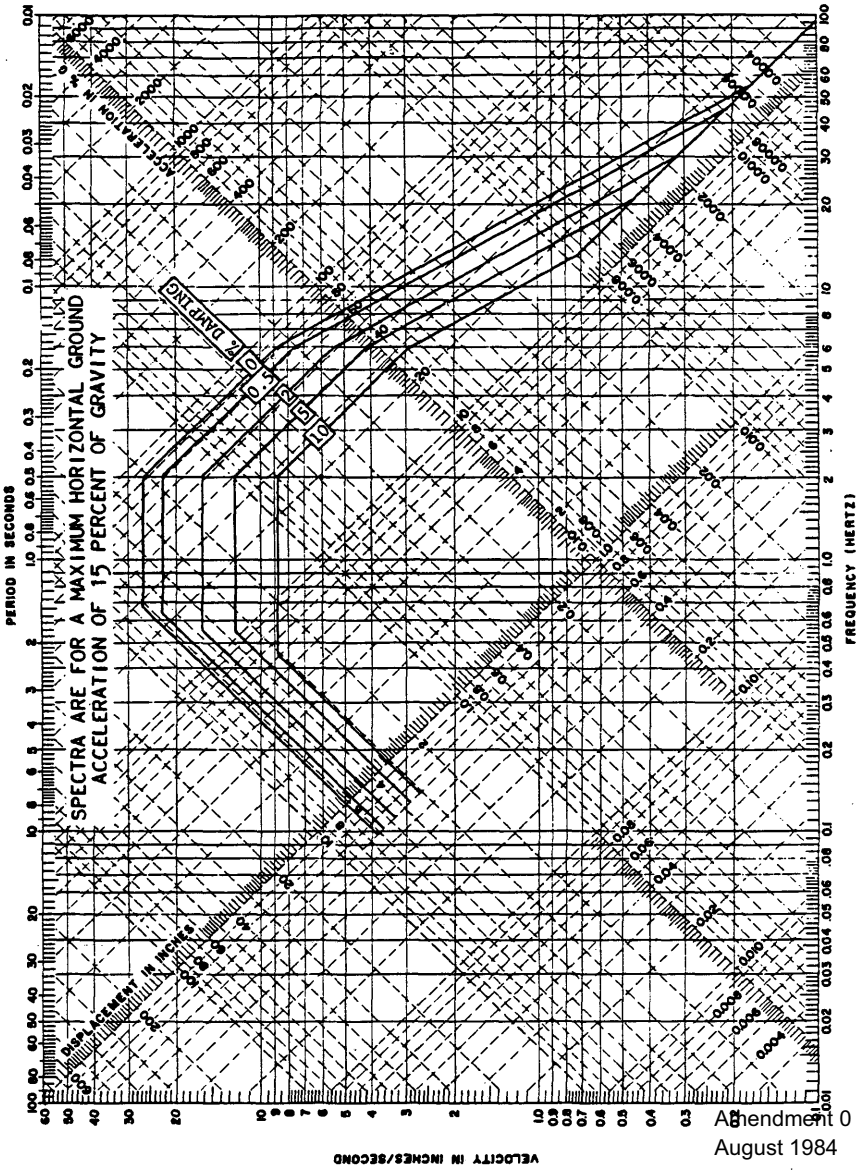


Figure 2.5-43
HORIZONTAL DESIGN RESPONSE SPECTRA - OBE - STRUCTURES FOUNDED ON SOIL



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SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Horizontal Design Response
Spectra - OBE - Structures
Founded on Soil

Figure 2.5-43

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Figure 2.5-44

PLOT PLAN A

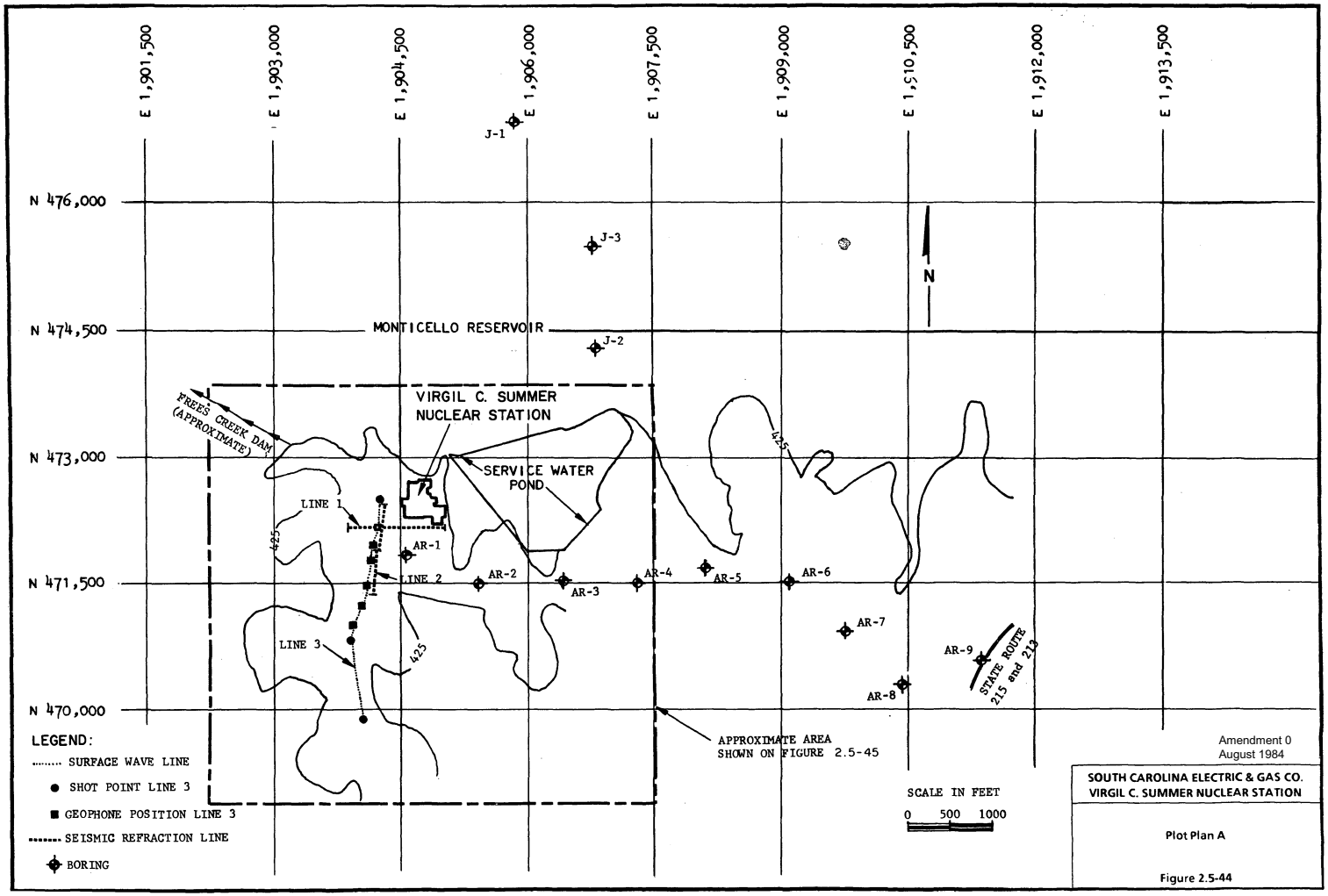

Figure 2.5-45
PLOT PLAN B

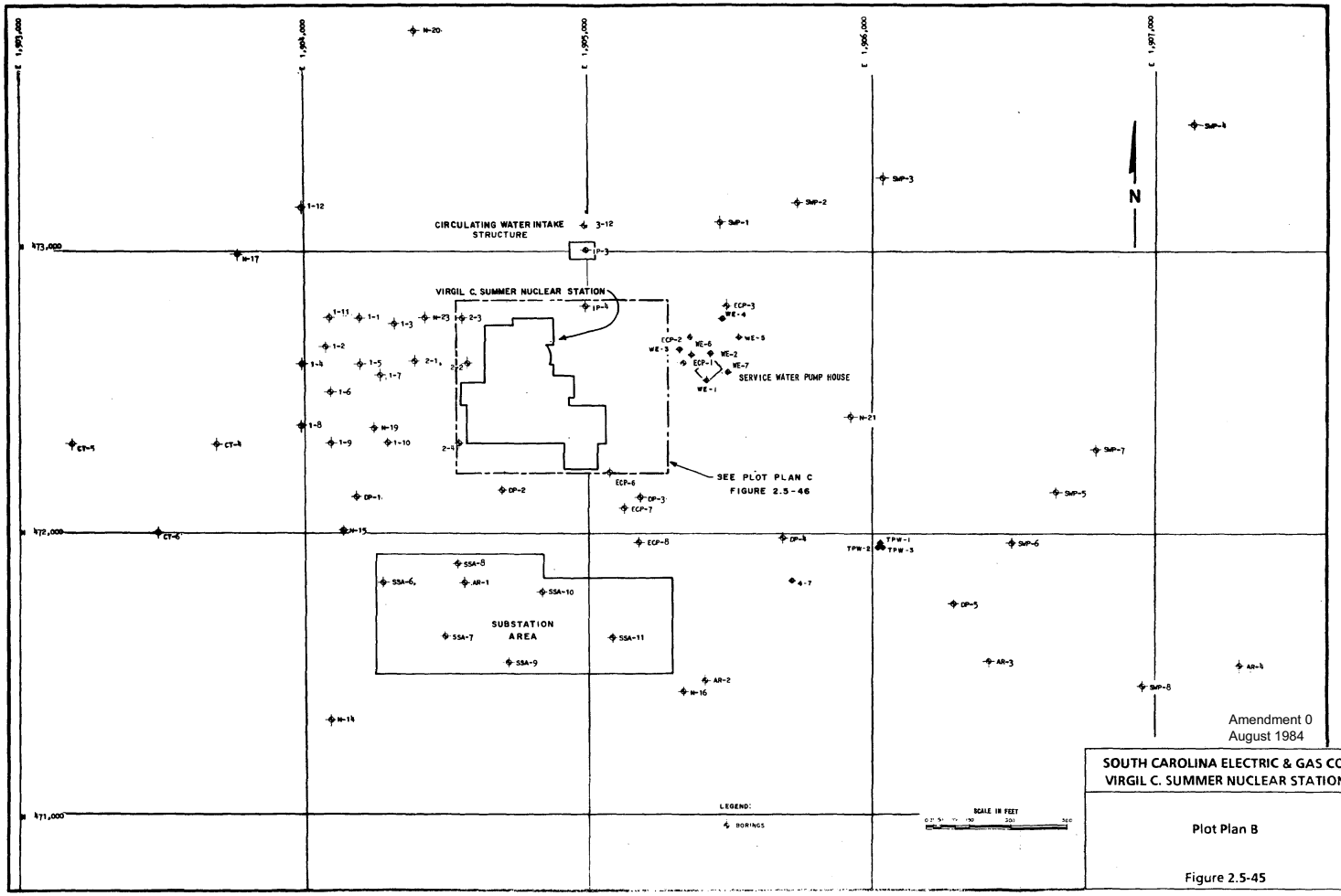

Figure 2.5-46

PLOT PLAN C

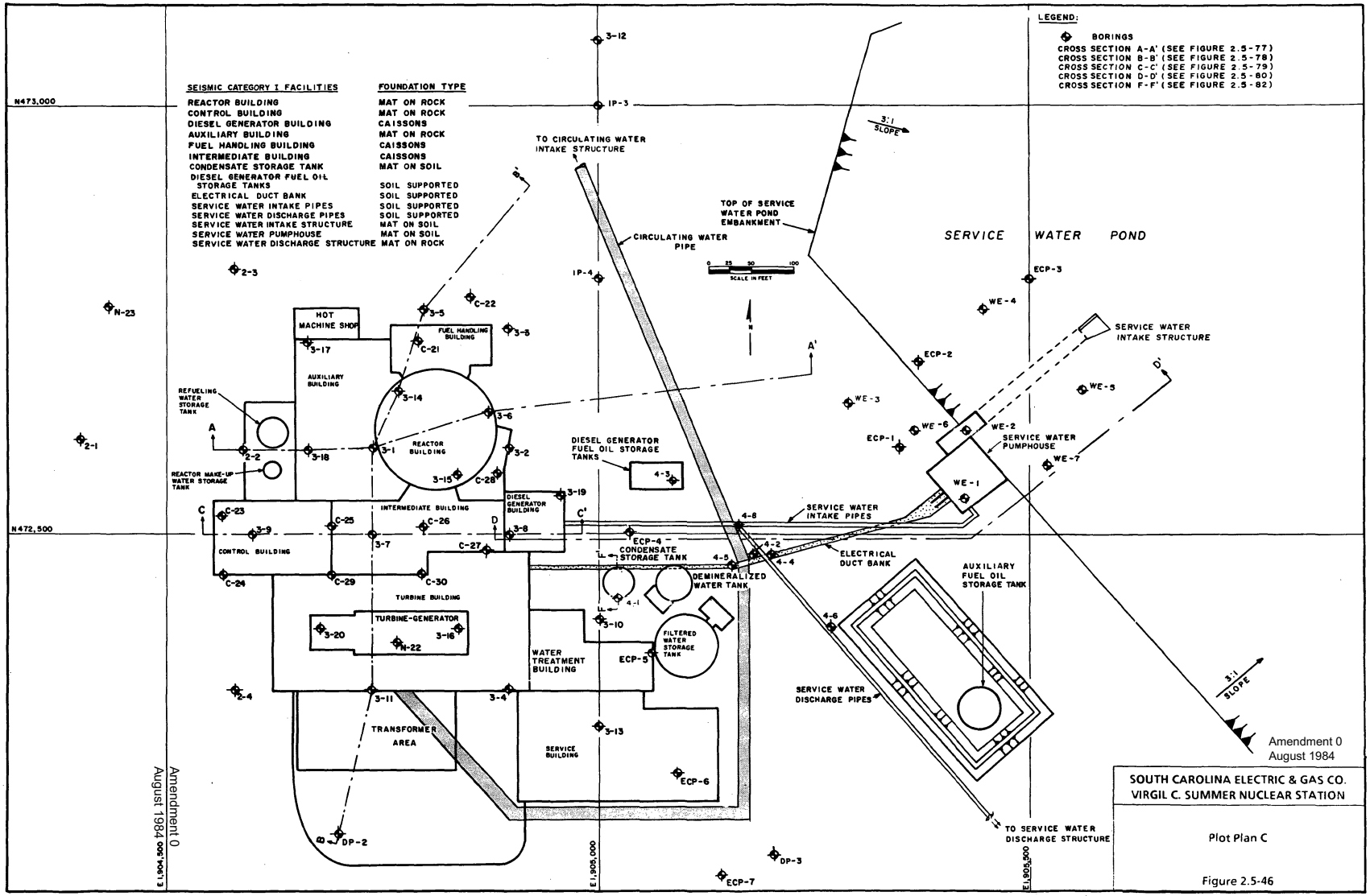

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Figure 2.5-47

PLOT PLAN D

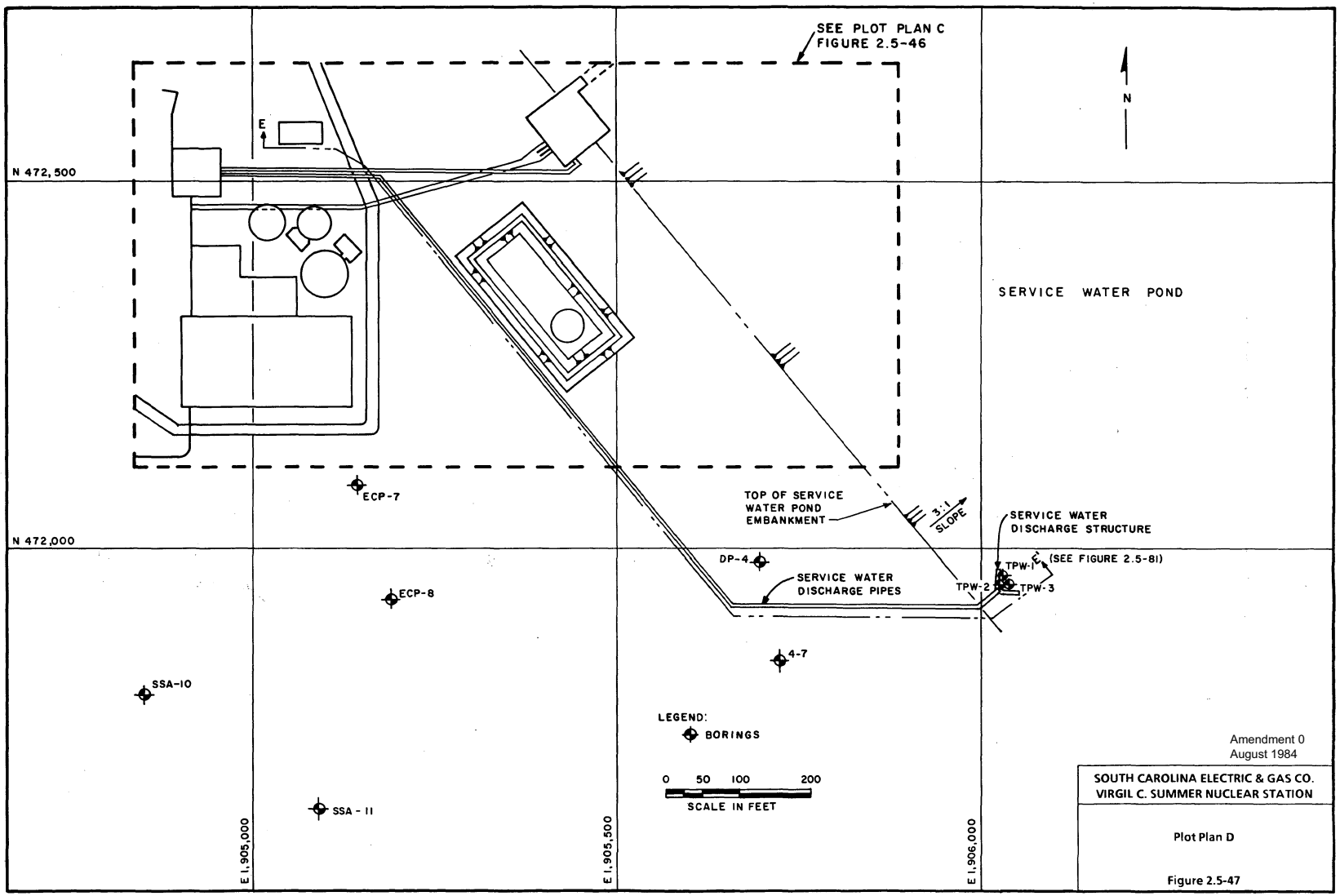


Figure 2.5-48

PLOT PLAN E

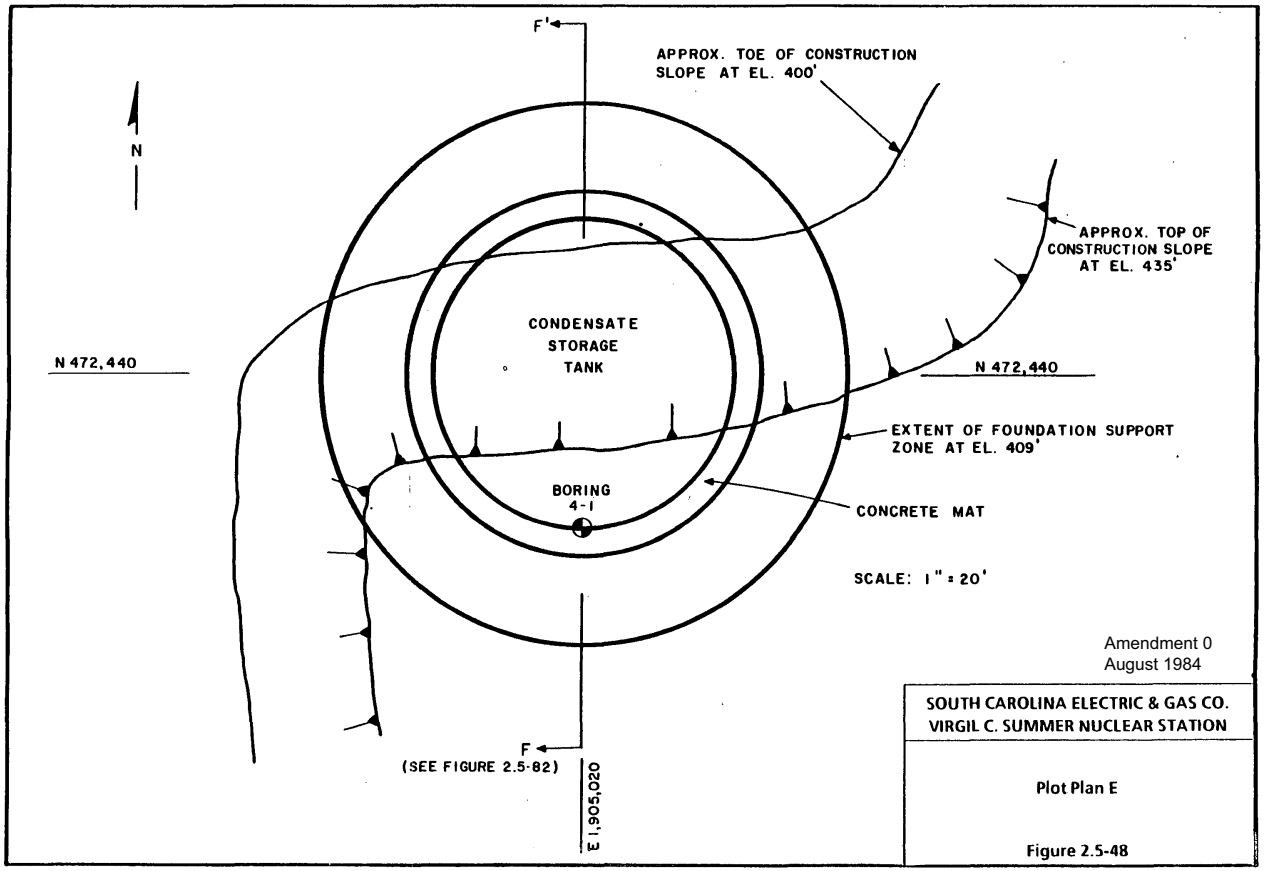


Figure 2.5-49
STRESS STRAIN DATA
(HIGHLY WEATHERED ROCK)

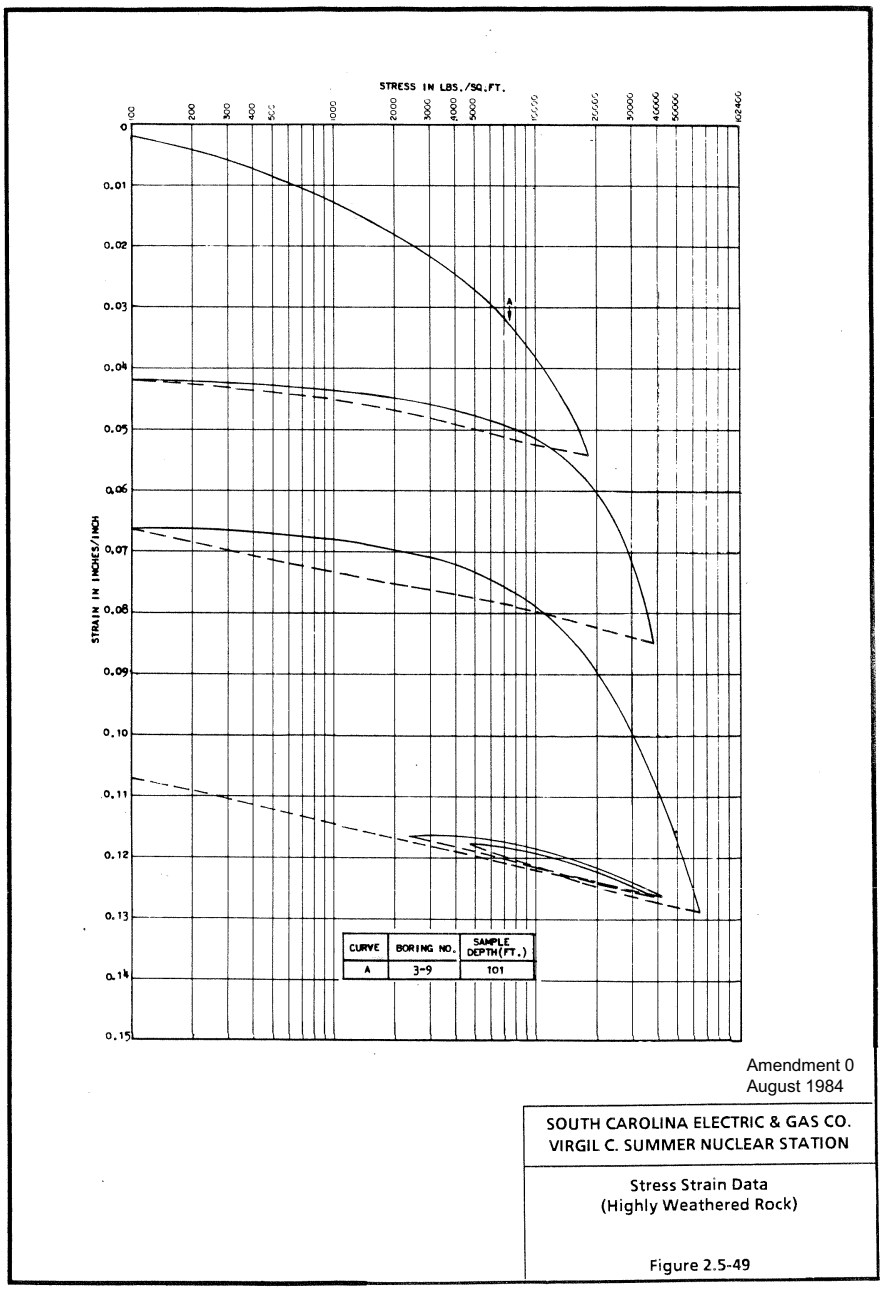
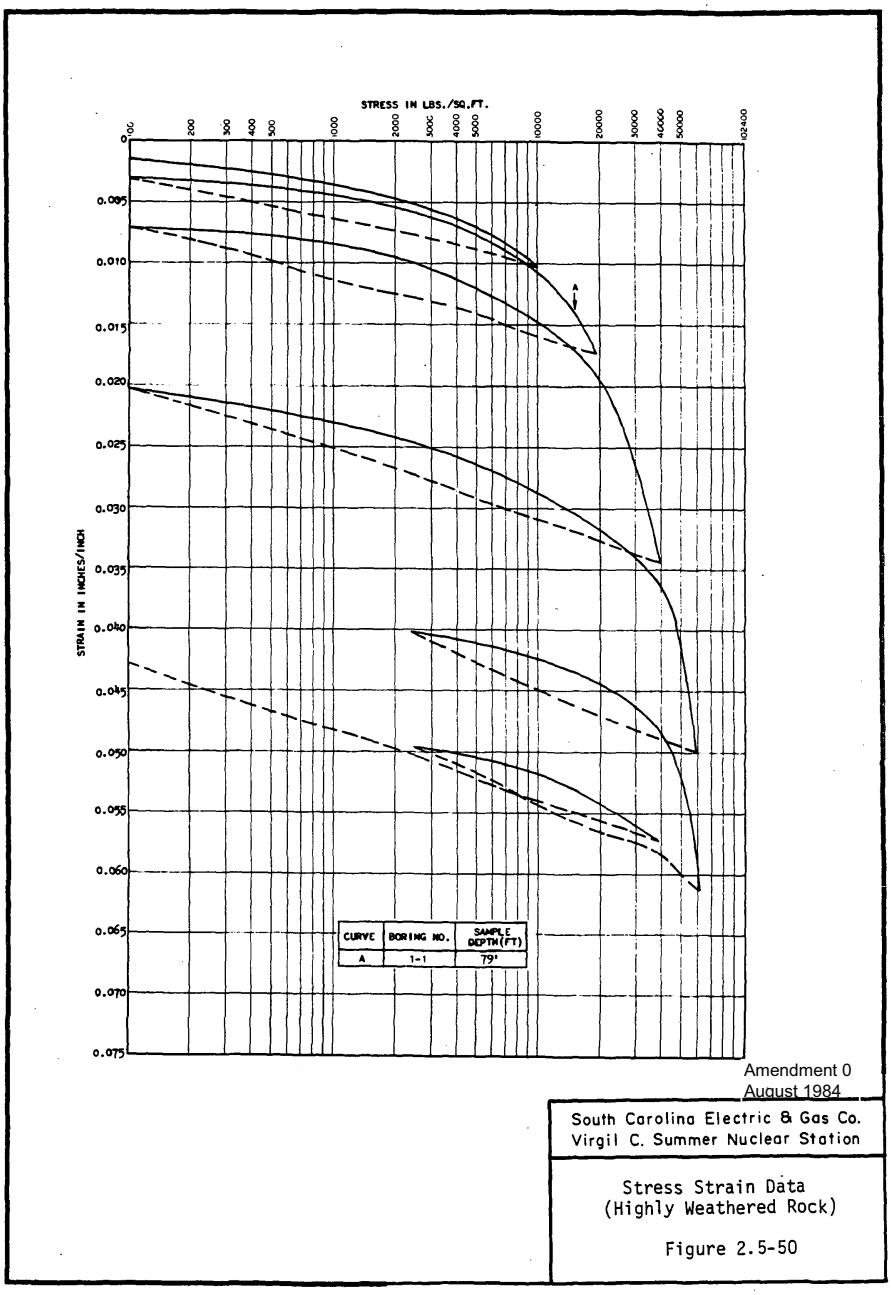


Figure 2.5-50
STRESS STRAIN DATA
(HIGHLY WEATHERED ROCK)



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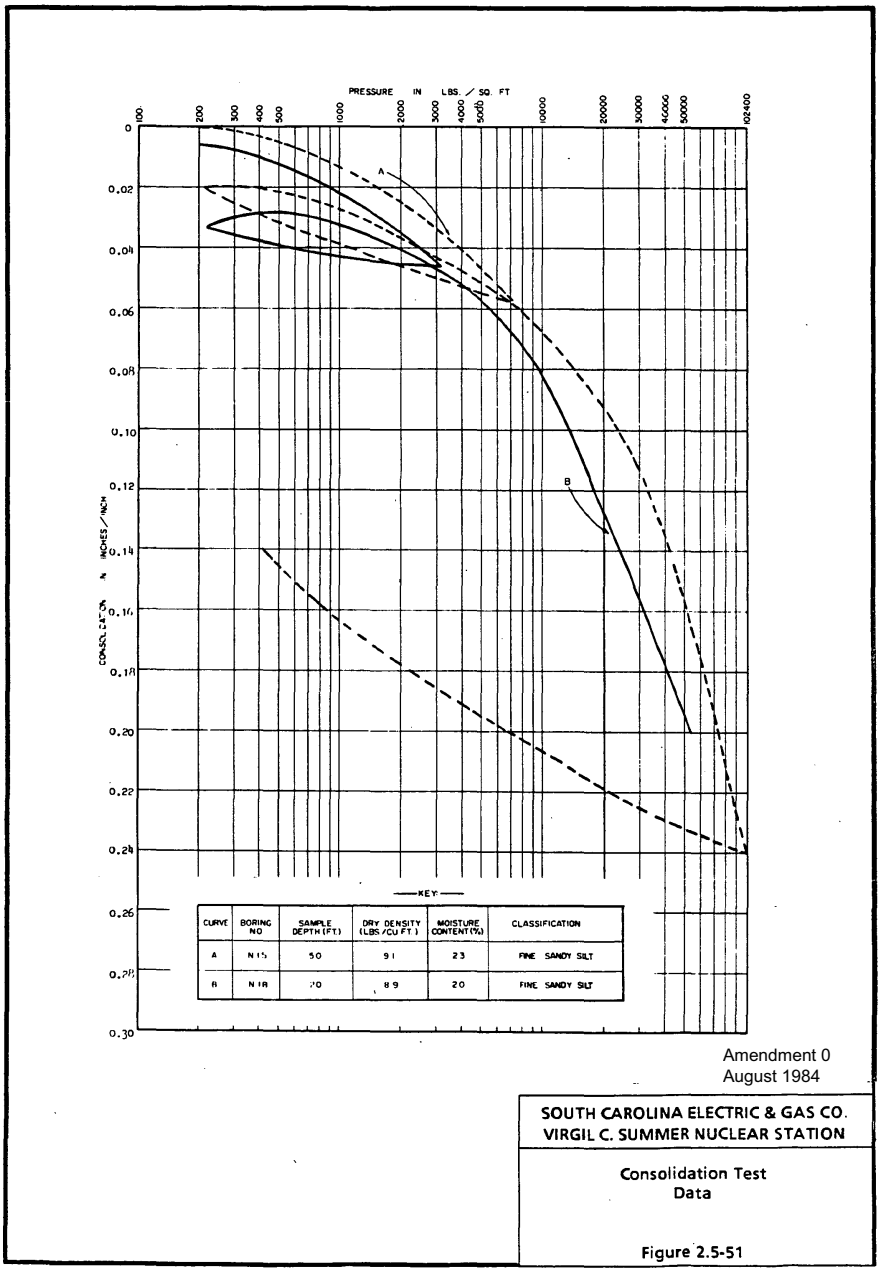
South Carolina Electric & Gas Co.
Virgil C. Summer Nuclear Station

Stress Strain Data
(Highly Weathered Rock)

Figure 2.5-50

Figure 2.5-51
CONSOLIDATION TEST DATA



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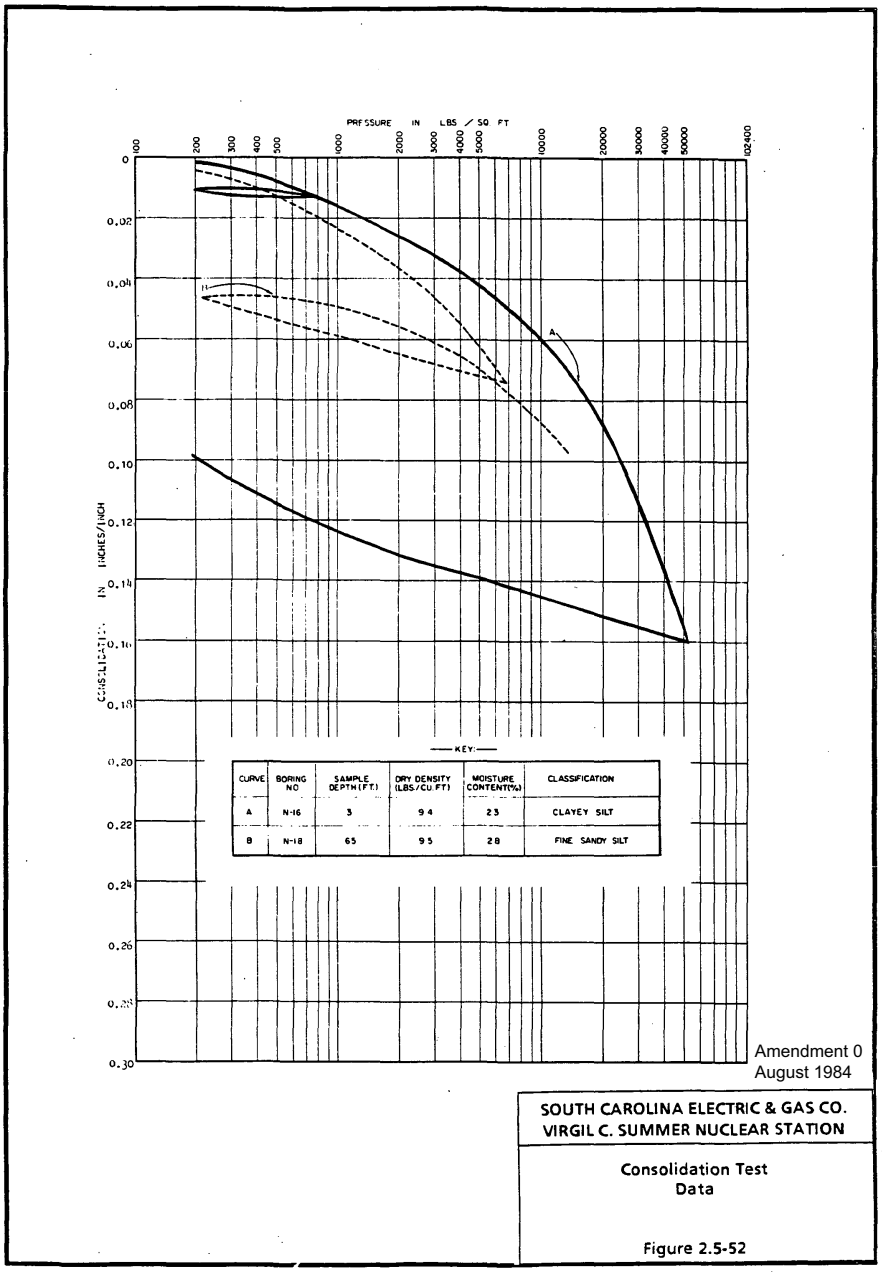
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Data

Figure 2.5-51

Figure 2.5-52
CONSOLIDATION TEST DATA



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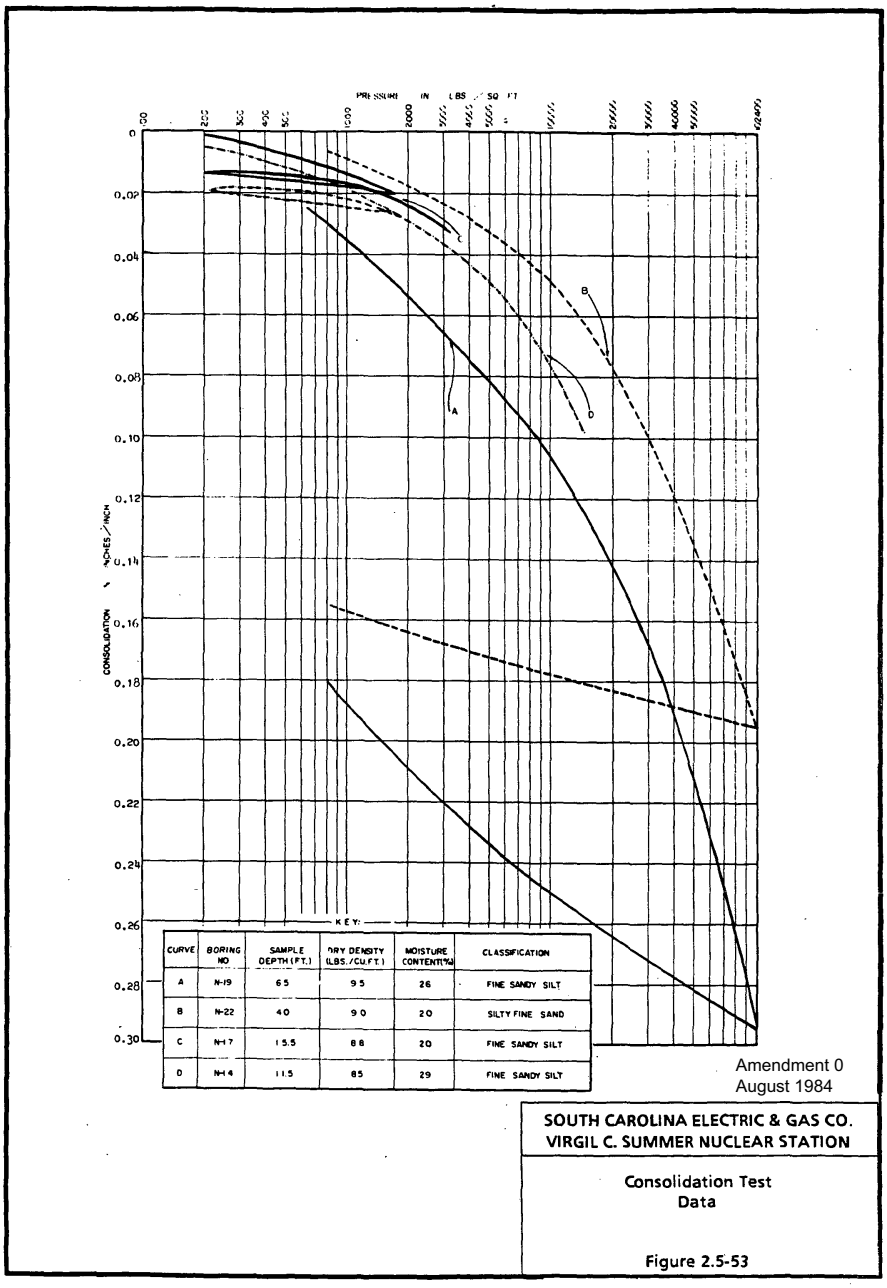
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Data

Figure 2.5-52

Figure 2.5-53
CONSOLIDATION TEST DATA



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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Data

Figure 2.5-53

Figure 2.5-54
CONSOLIDATION TEST DATA

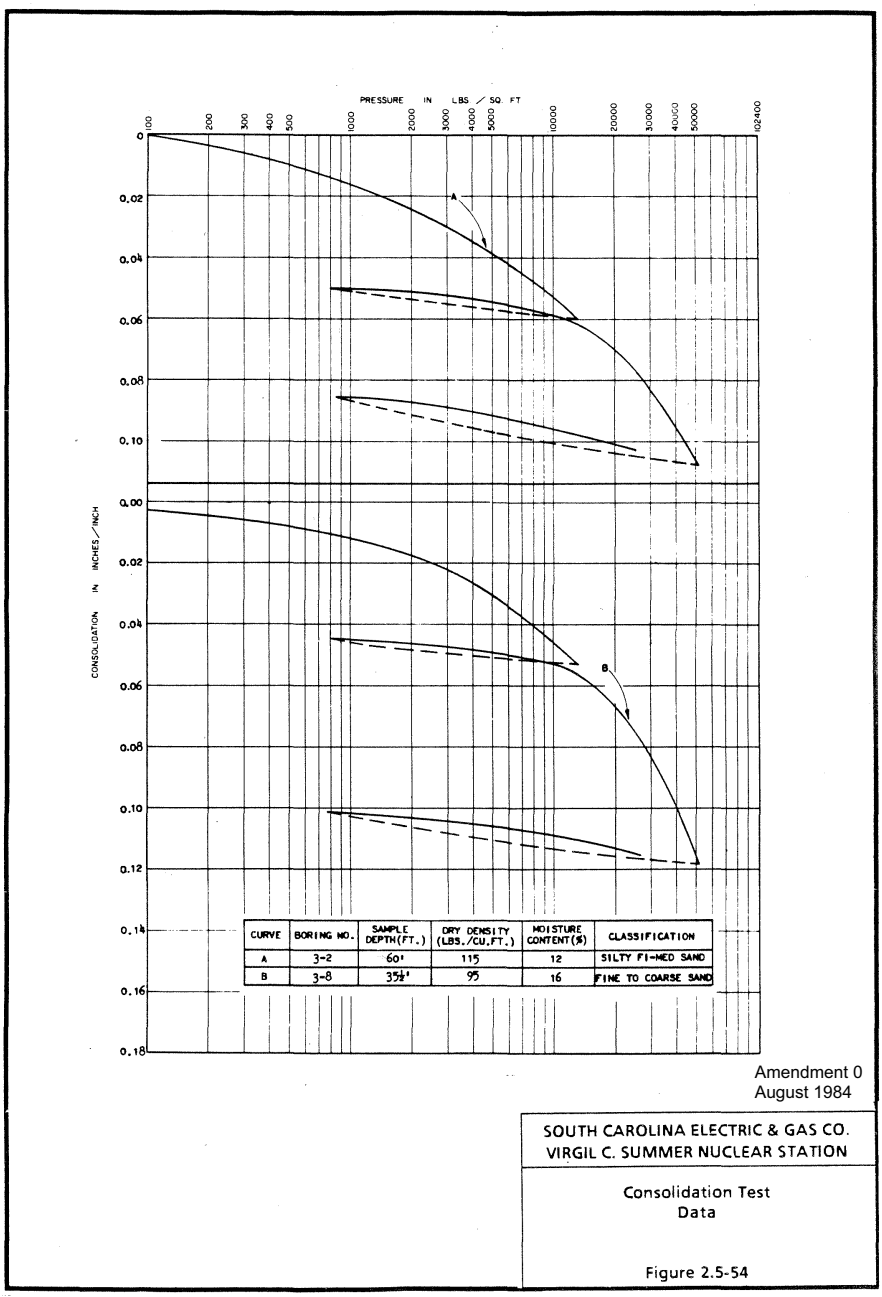
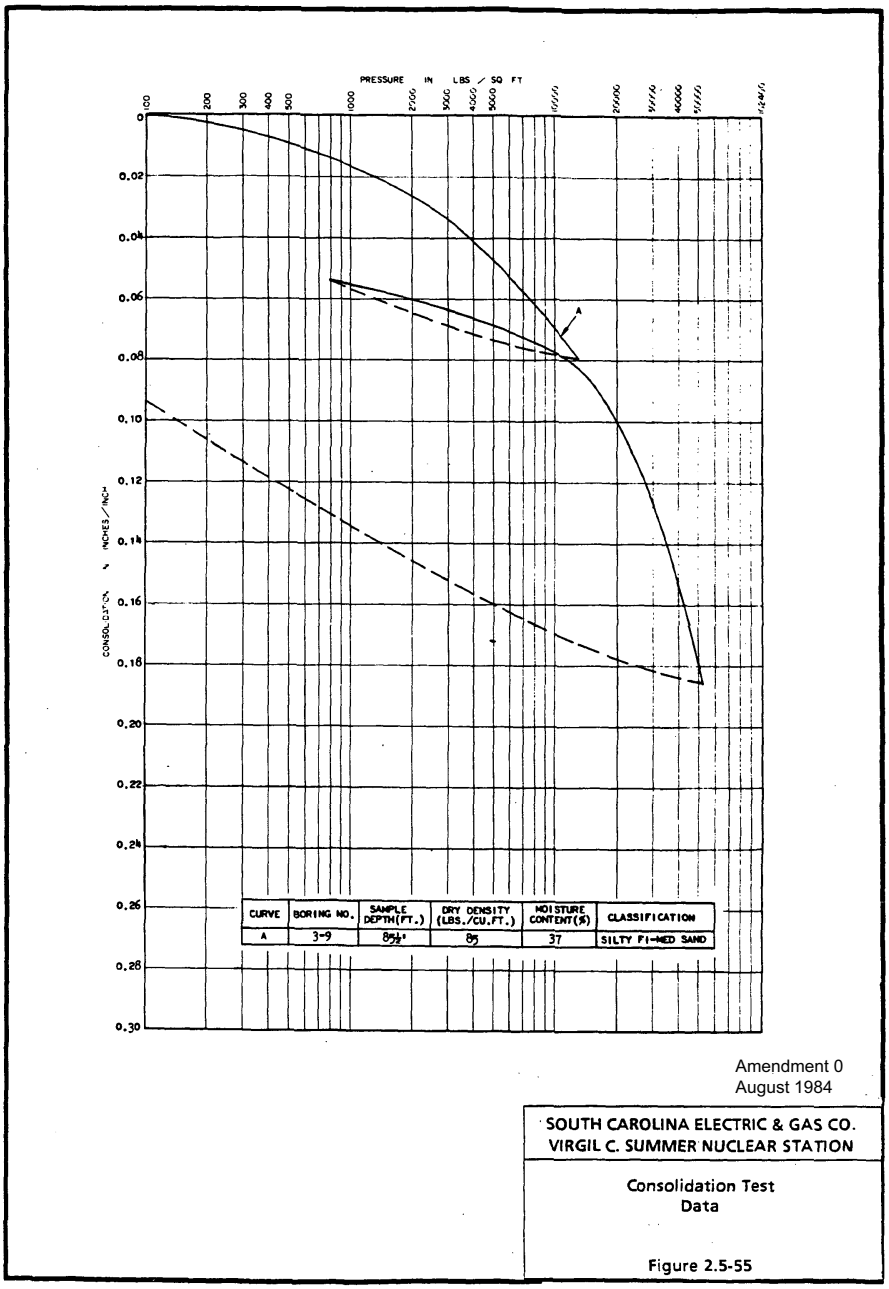


Figure 2.5-55
CONSOLIDATION TEST DATA



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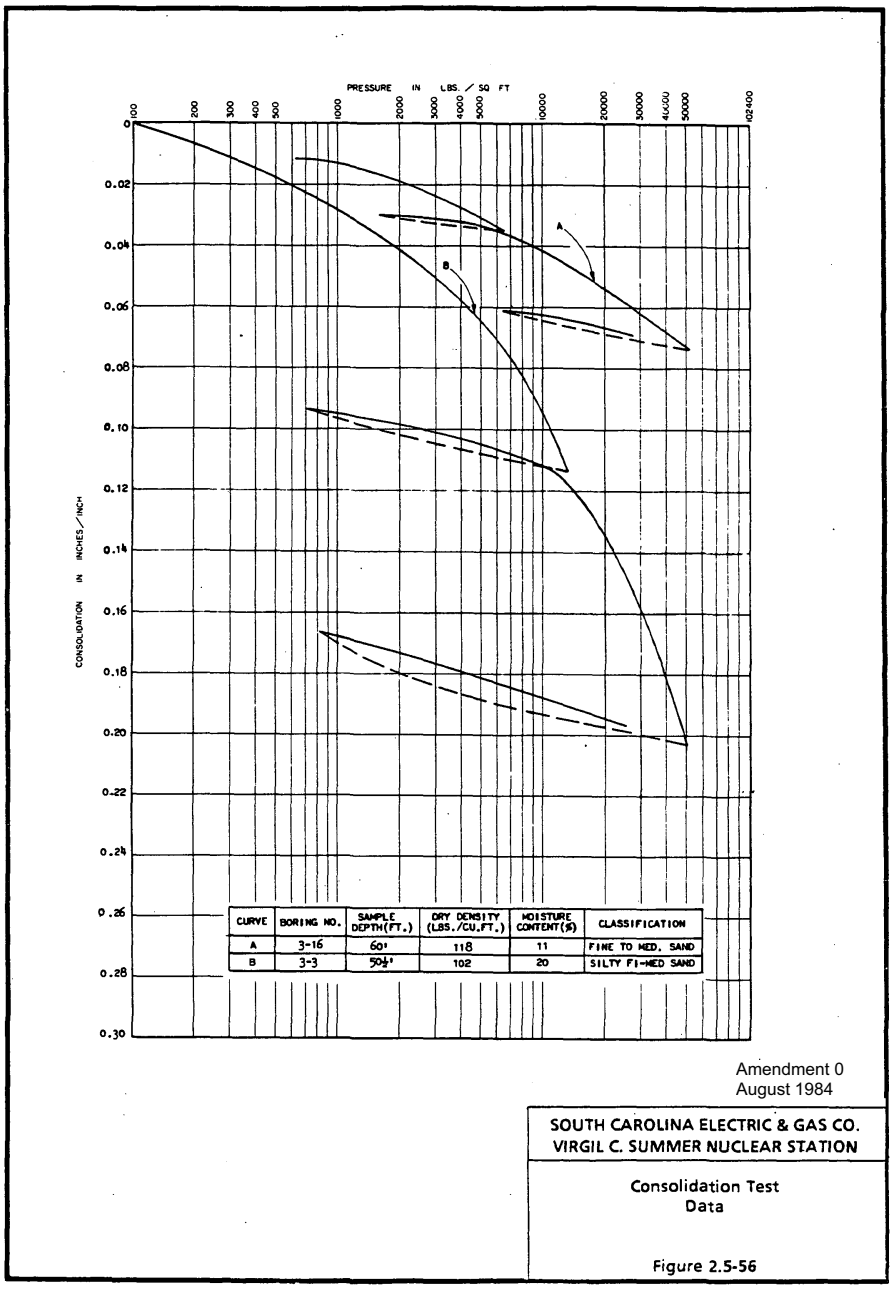
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test
Data

Figure 2.5-55

Figure 2.5-56
CONSOLIDATION TEST DATA



CURVE	BORING NO.	SAMPLE DEPTH (FT.)	DRY DENSITY (LBS./CU.FT.)	MOISTURE CONTENT (%)	CLASSIFICATION
A	3-16	60'	118	11	FINE TO MED. SAND
B	3-3	50½'	102	20	SILTY FI-MED SAND

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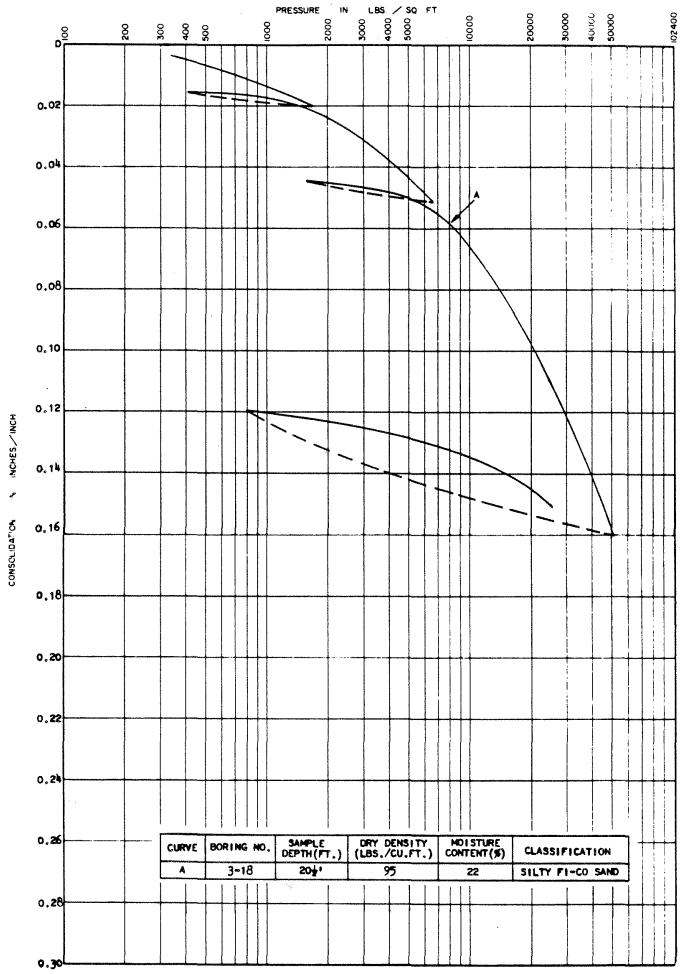
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test
Data

Figure 2.5-56

Figure 2.5-57
CONSOLIDATION TEST DATA



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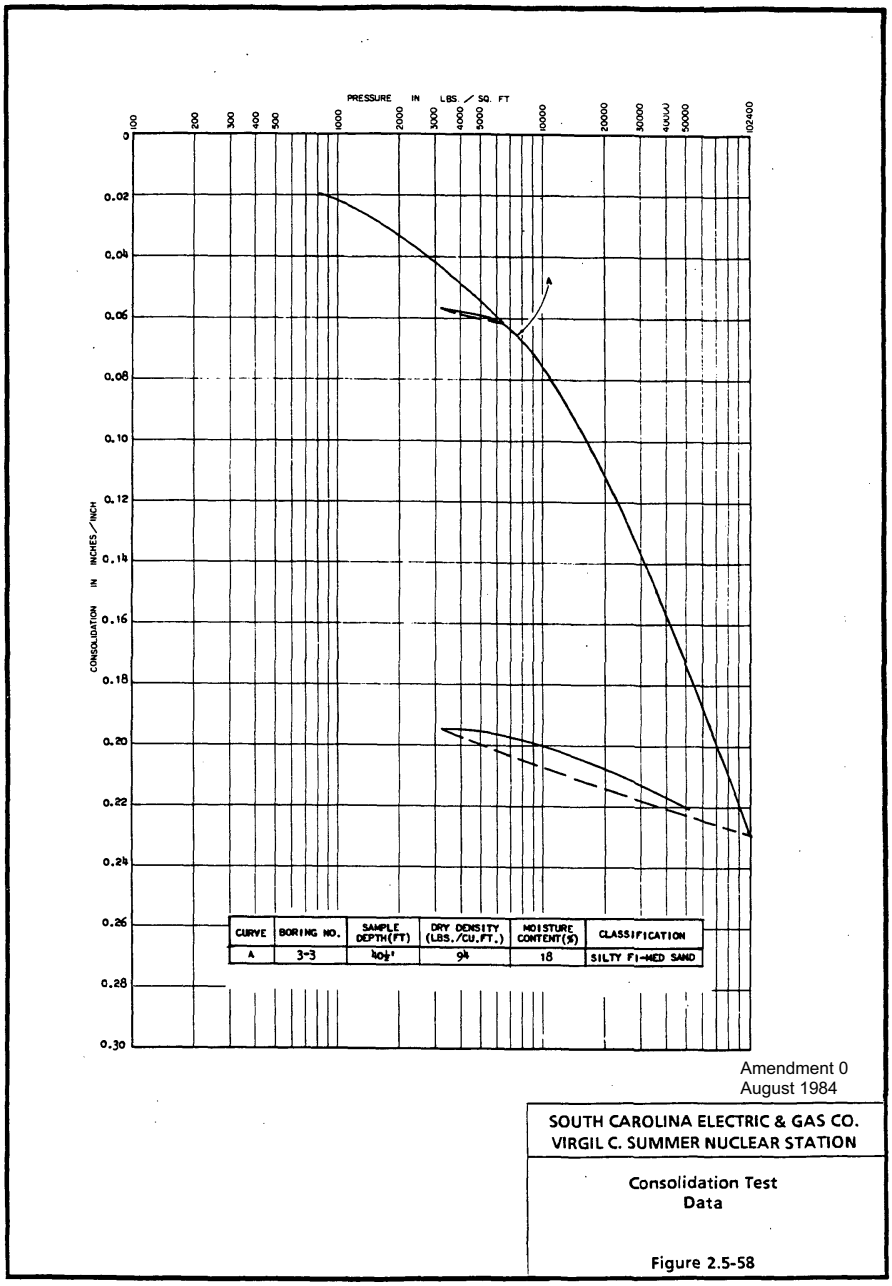
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Data

Figure 2.5-57

Figure 2.5-58
CONSOLIDATION TEST DATA



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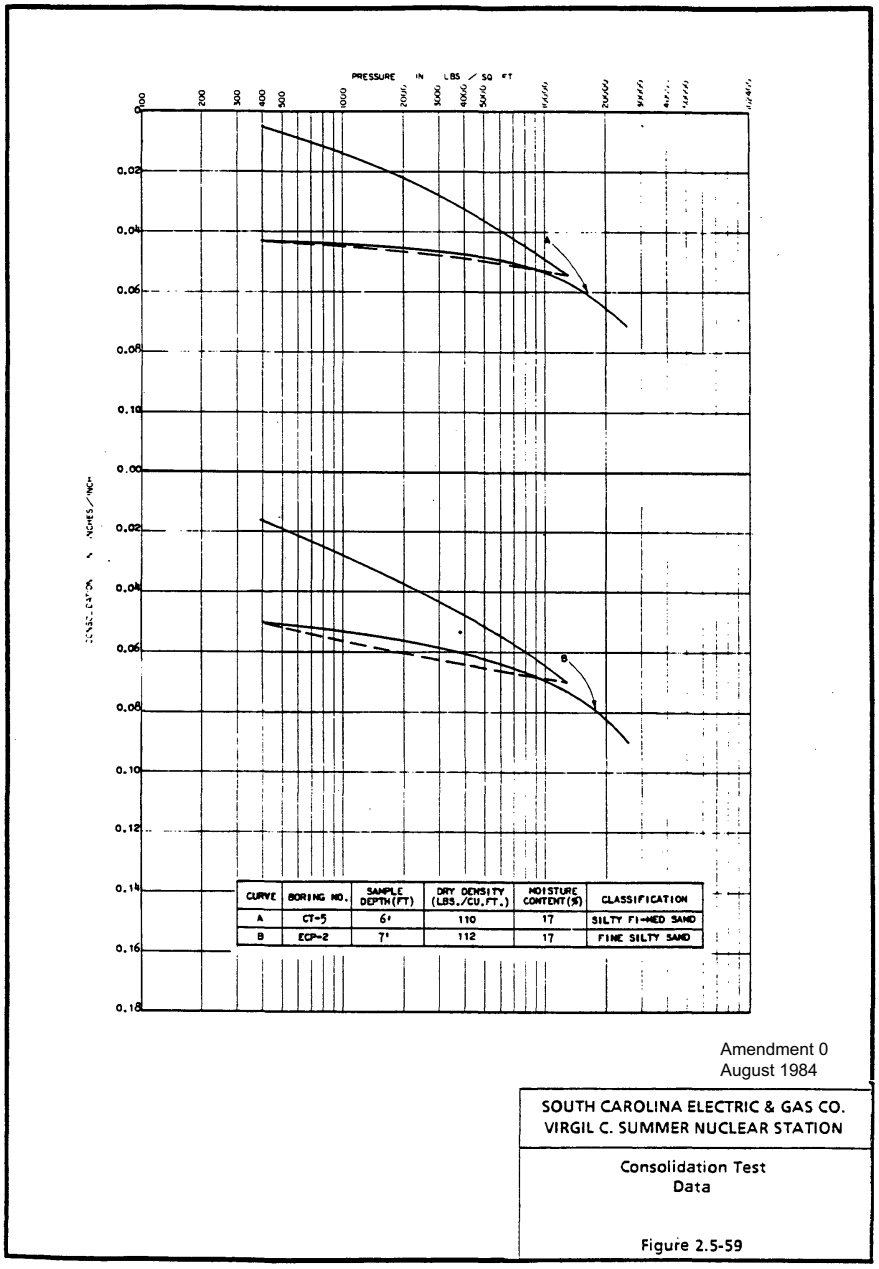
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Data

Figure 2.5-58

Figure 2.5-59
CONSOLIDATION TEST DATA



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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Data

Figure 2.5-59

Figure 2.5-60
CONSOLIDATION TEST DATA

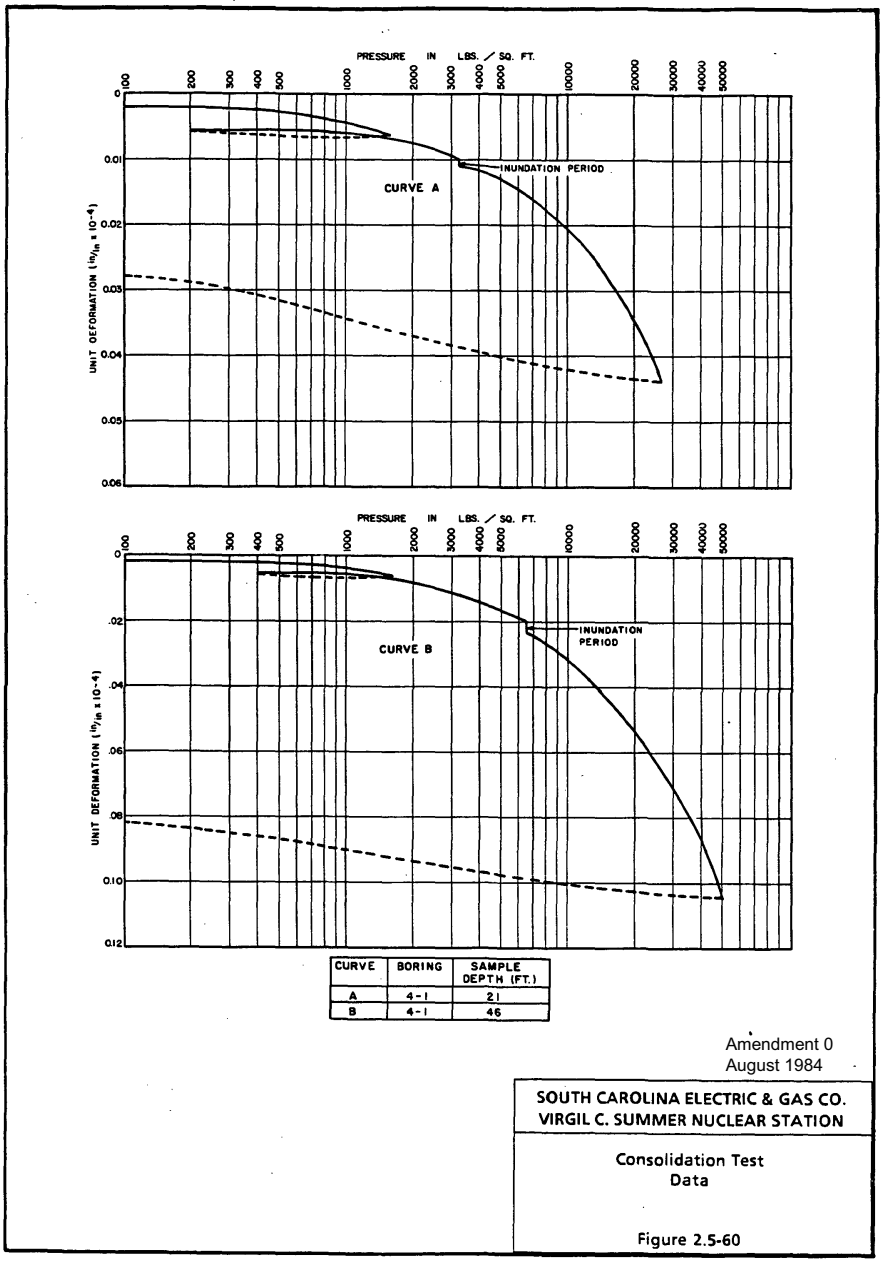


Figure 2.5-61
GRADUATION CURVES

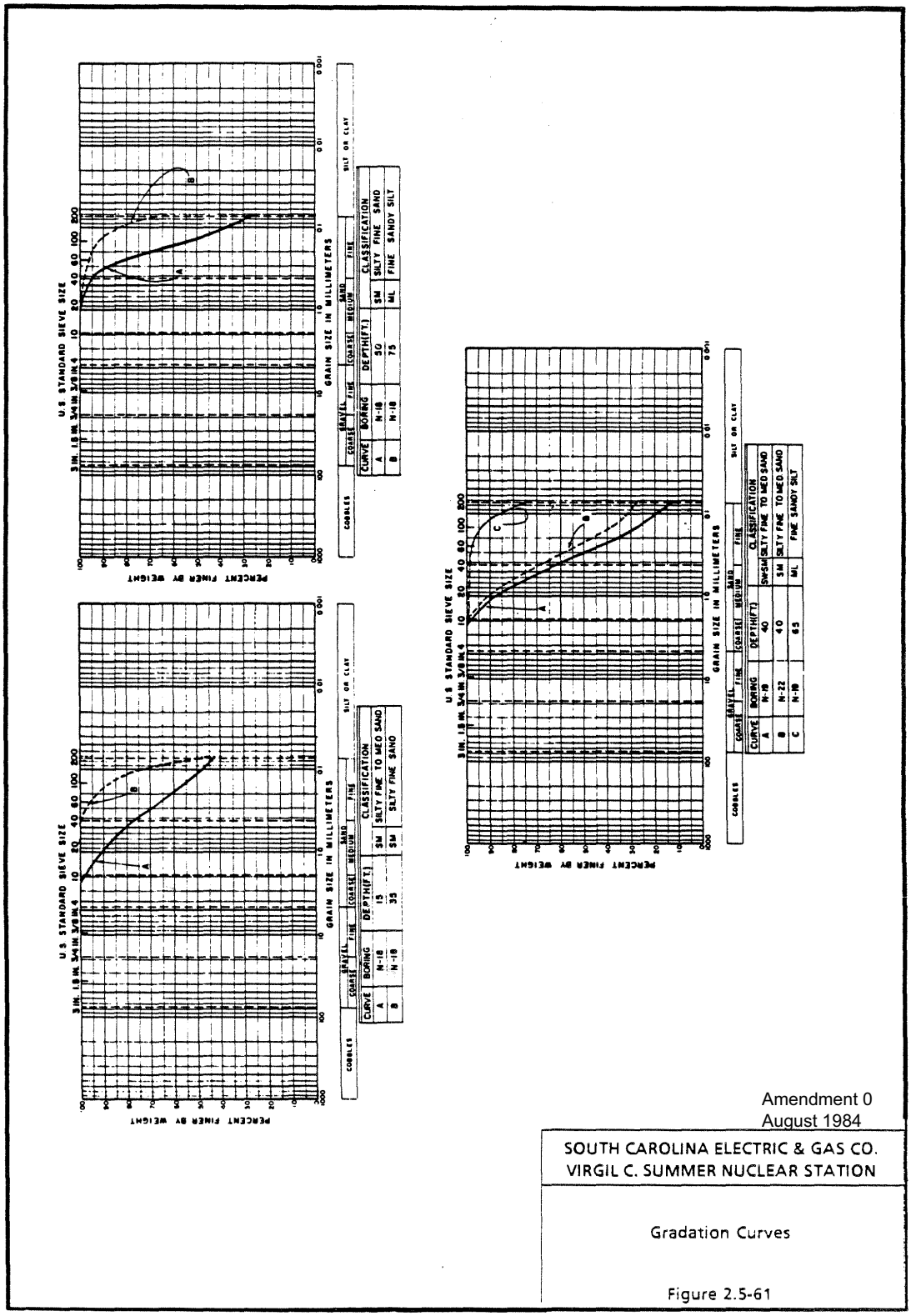


Figure 2.5-62
GRADATION CURVES

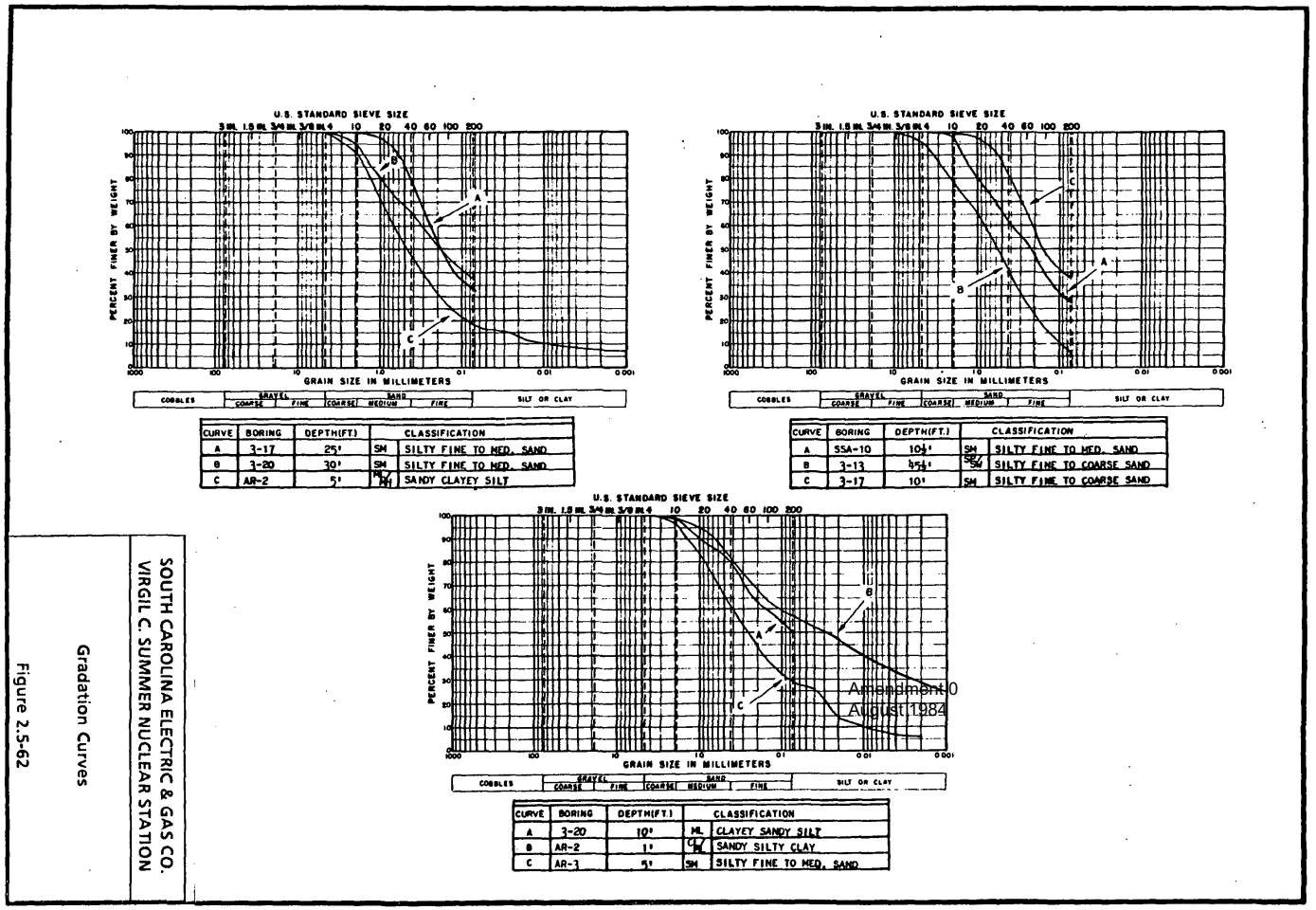


Figure 2.5-63
GRADATION CURVES

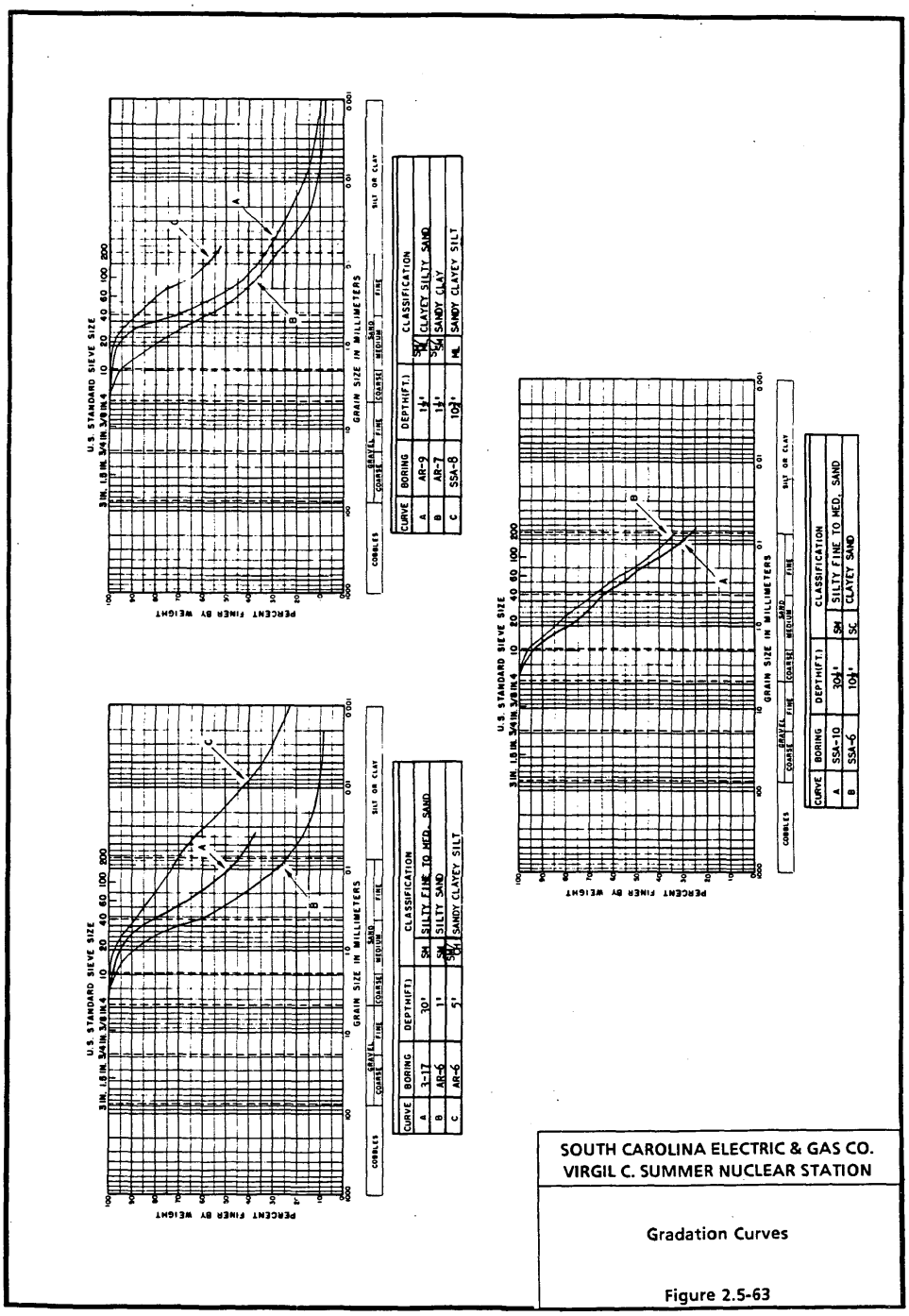


Figure 2.5-64
GRADATION CURVES

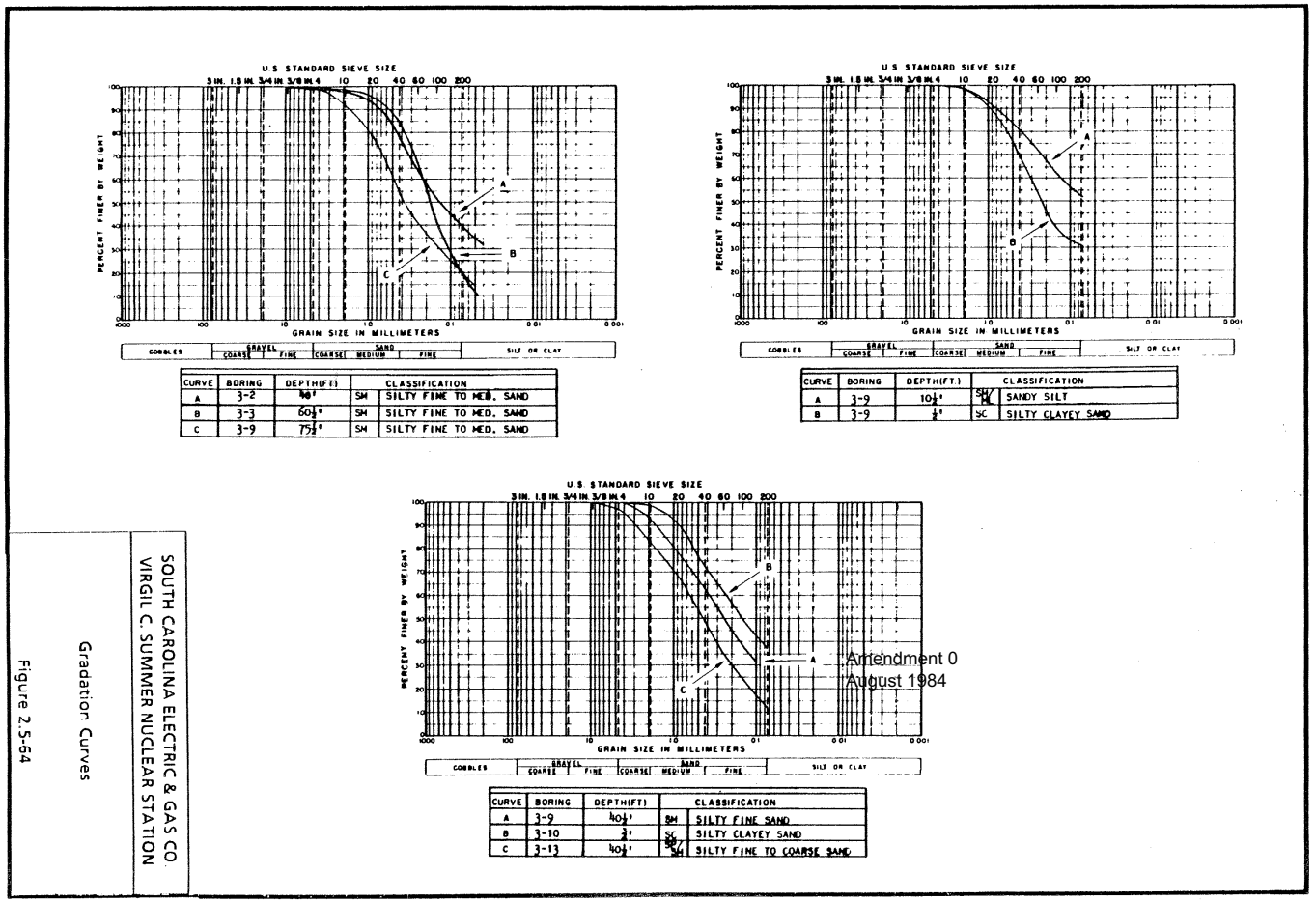
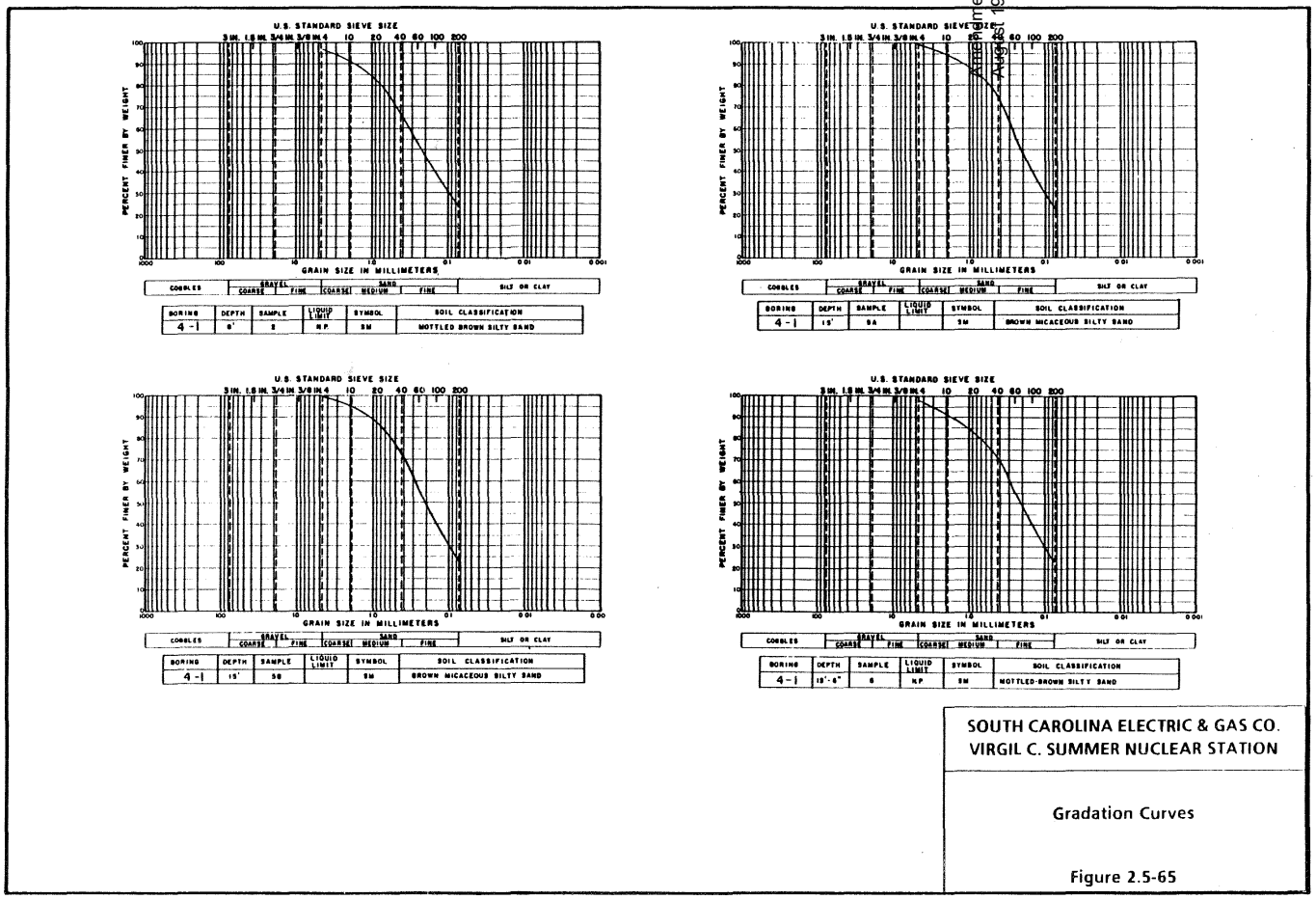
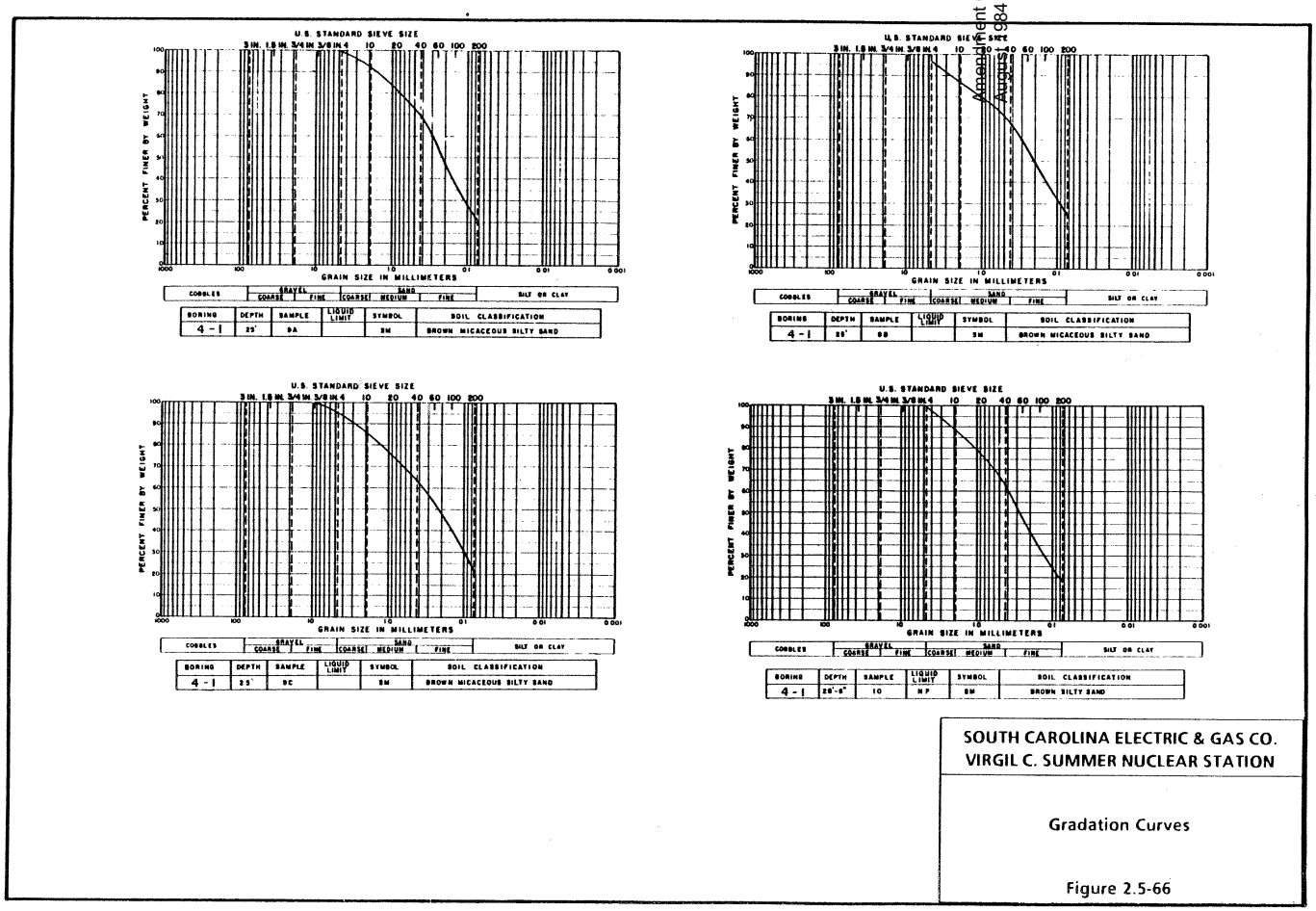


Figure 2.5-65
GRADATION CURVES



Amendment 0
August 1984

Figure 2.5-66
GRADATION CURVES



Amendment 0
April 1984

Figure 2.5-67
GRADATION CURVES

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August 1984

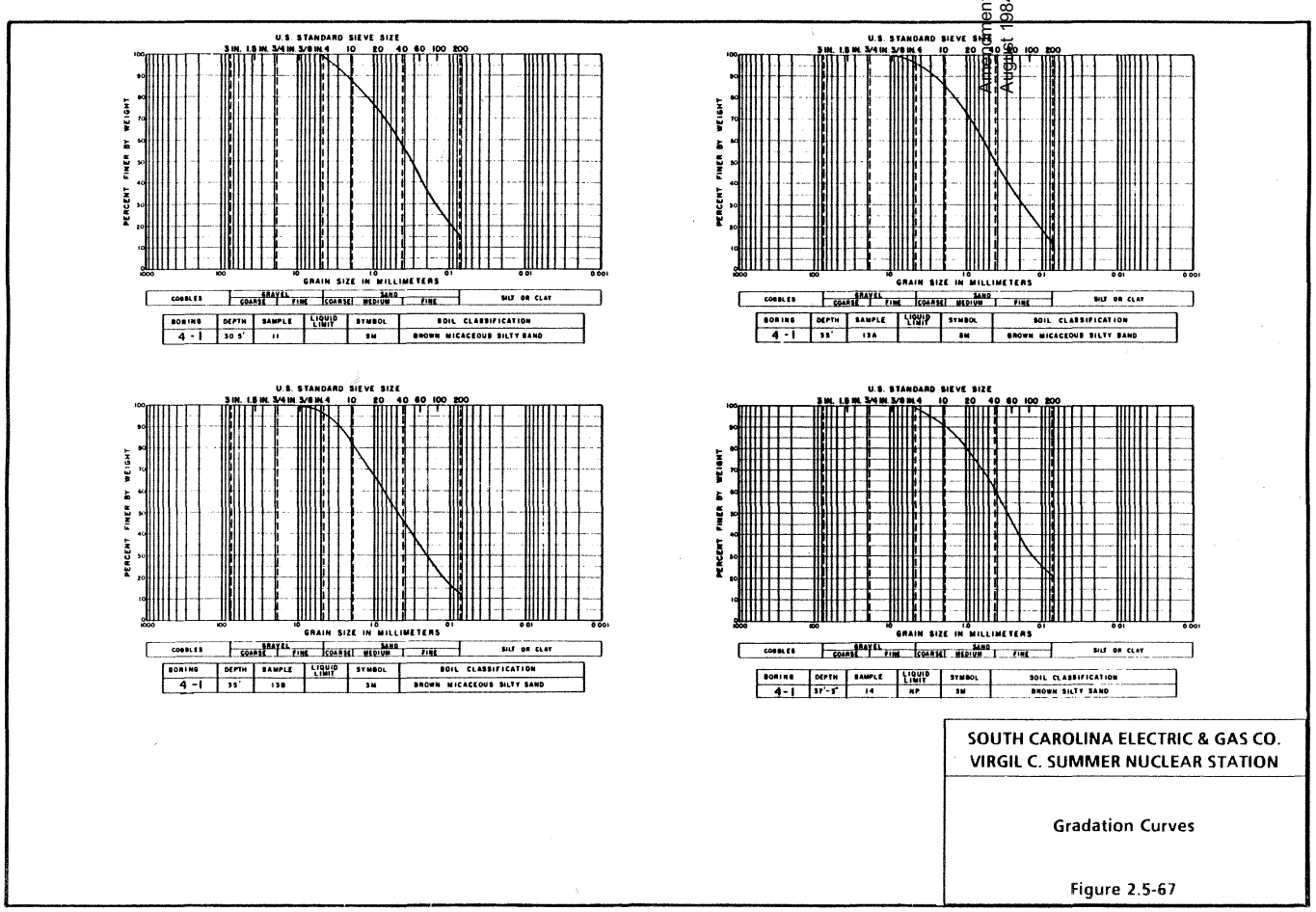


Figure 2.5-68
GRADATION CURVES

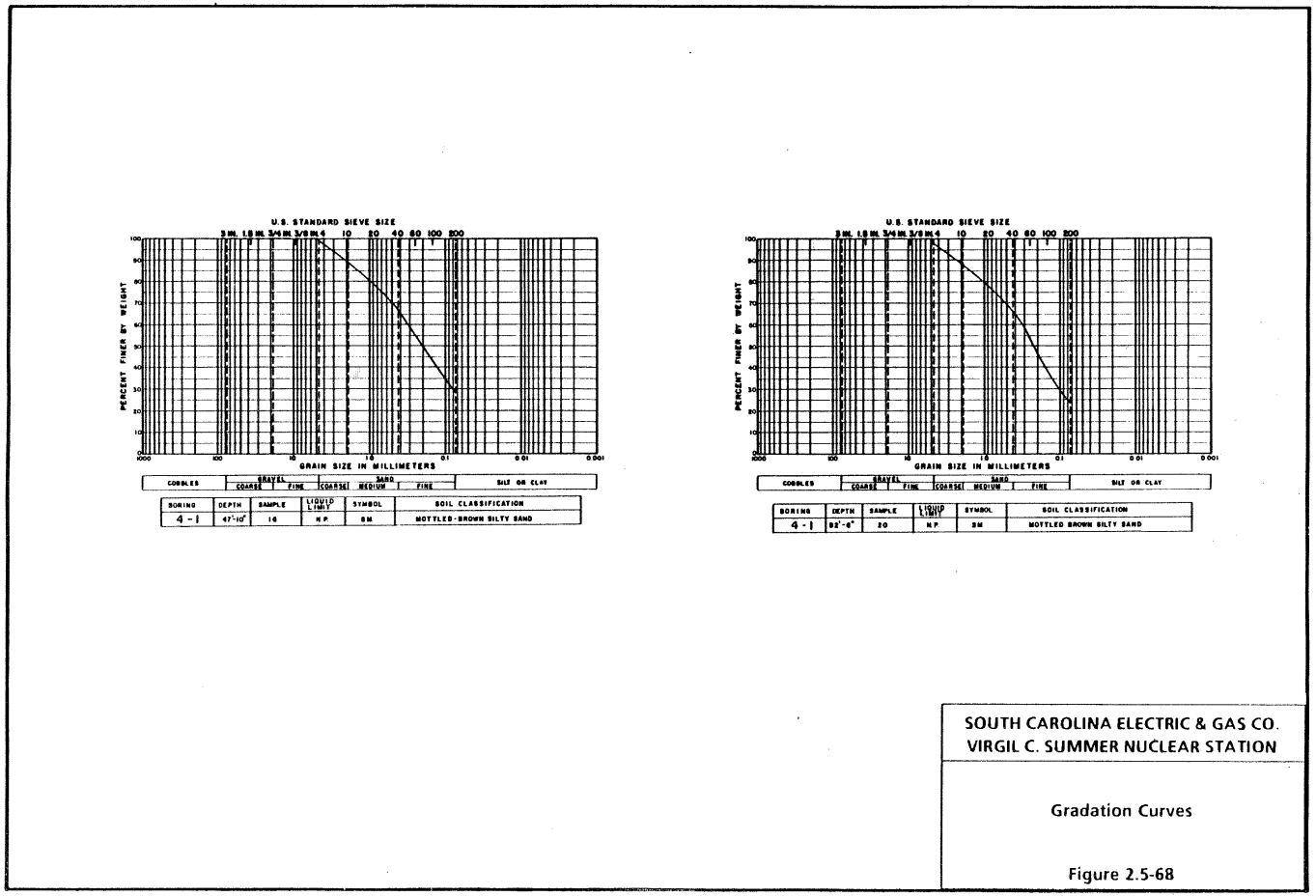


Figure 2.5-69
GRADATION CURVES

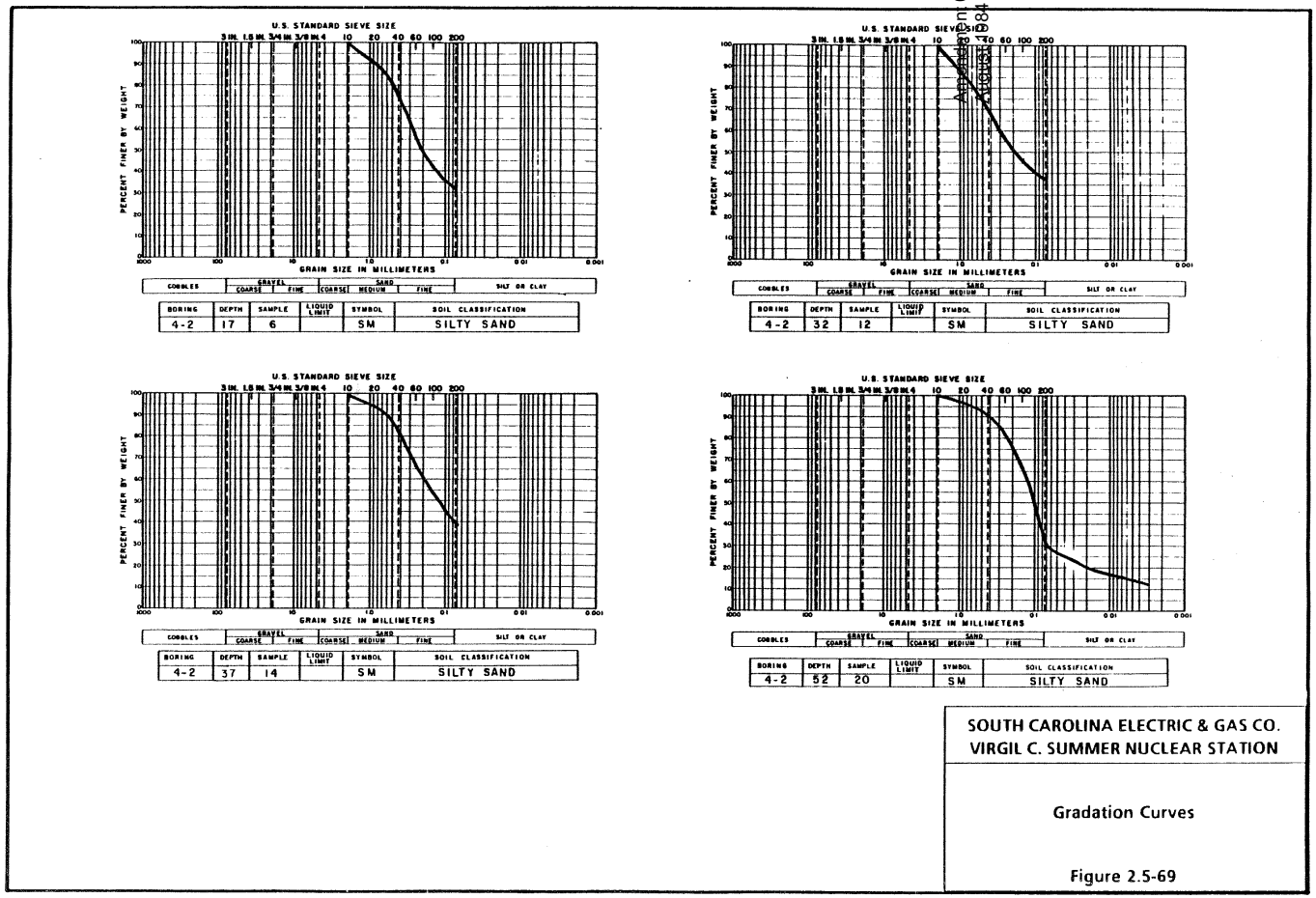
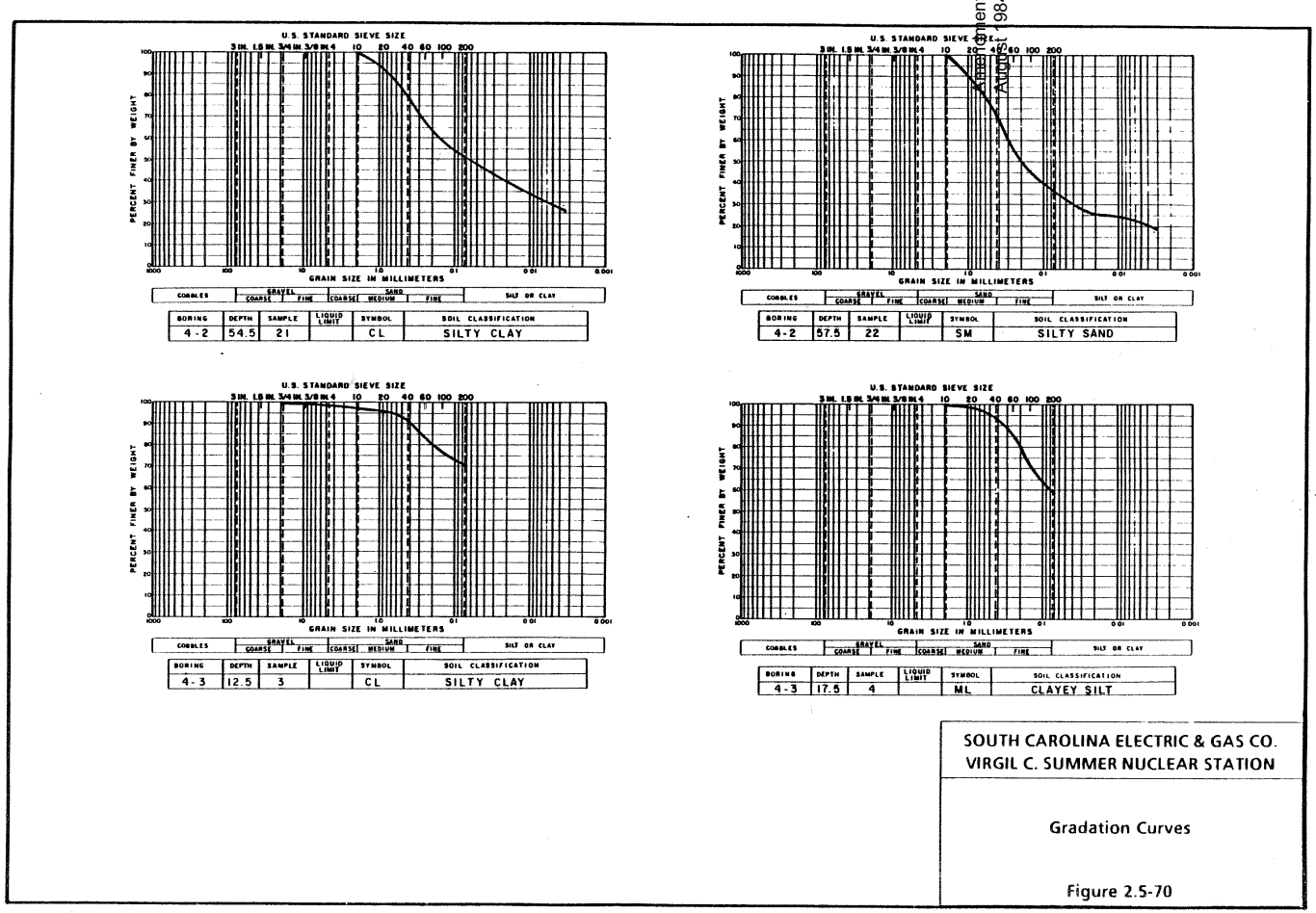


Figure 2.5-70
GRADATION CURVES



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August 1984

Figure 2.5-71
GRADATION CURVES

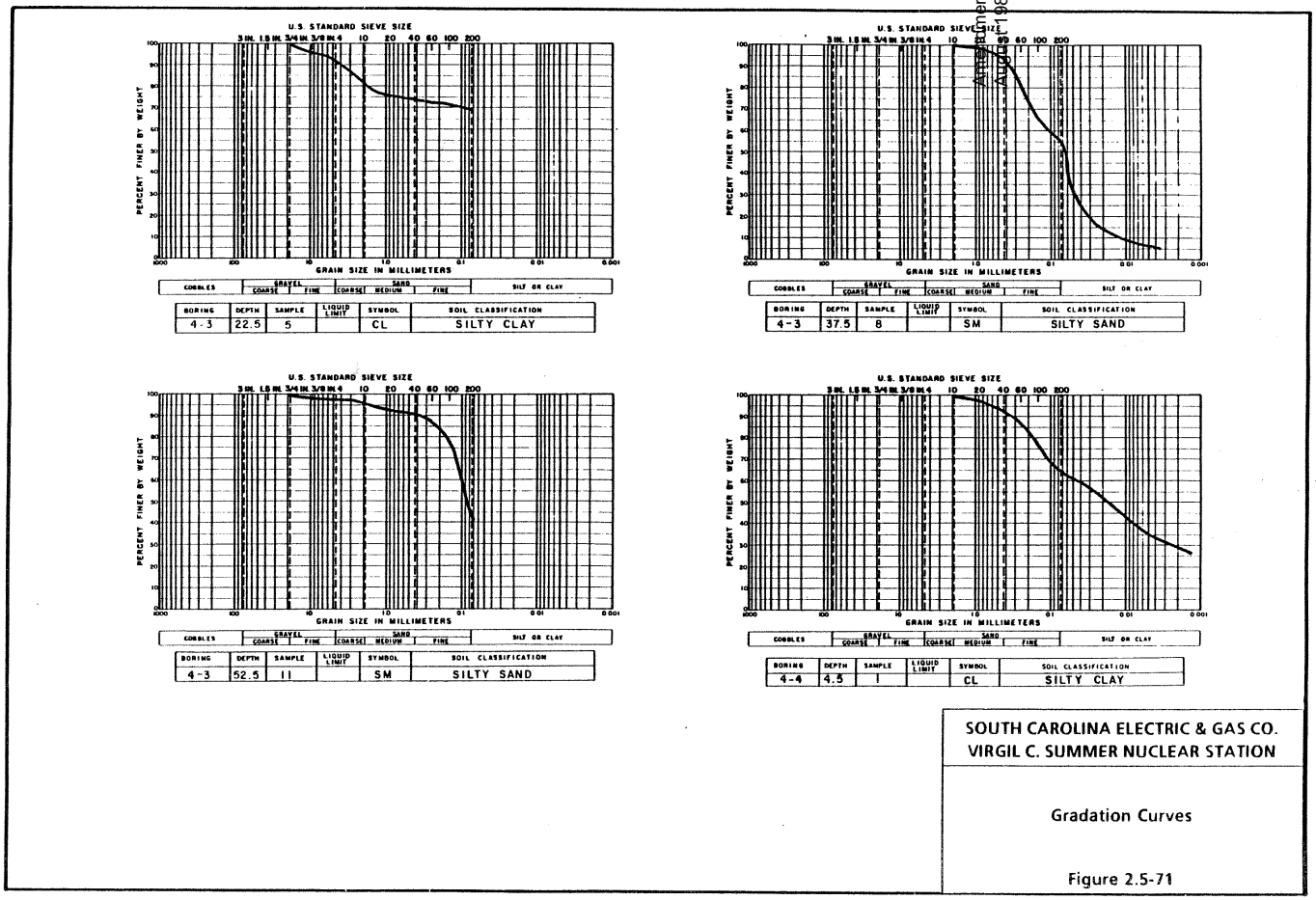

Figure 2.5-72
GRADATION CURVES

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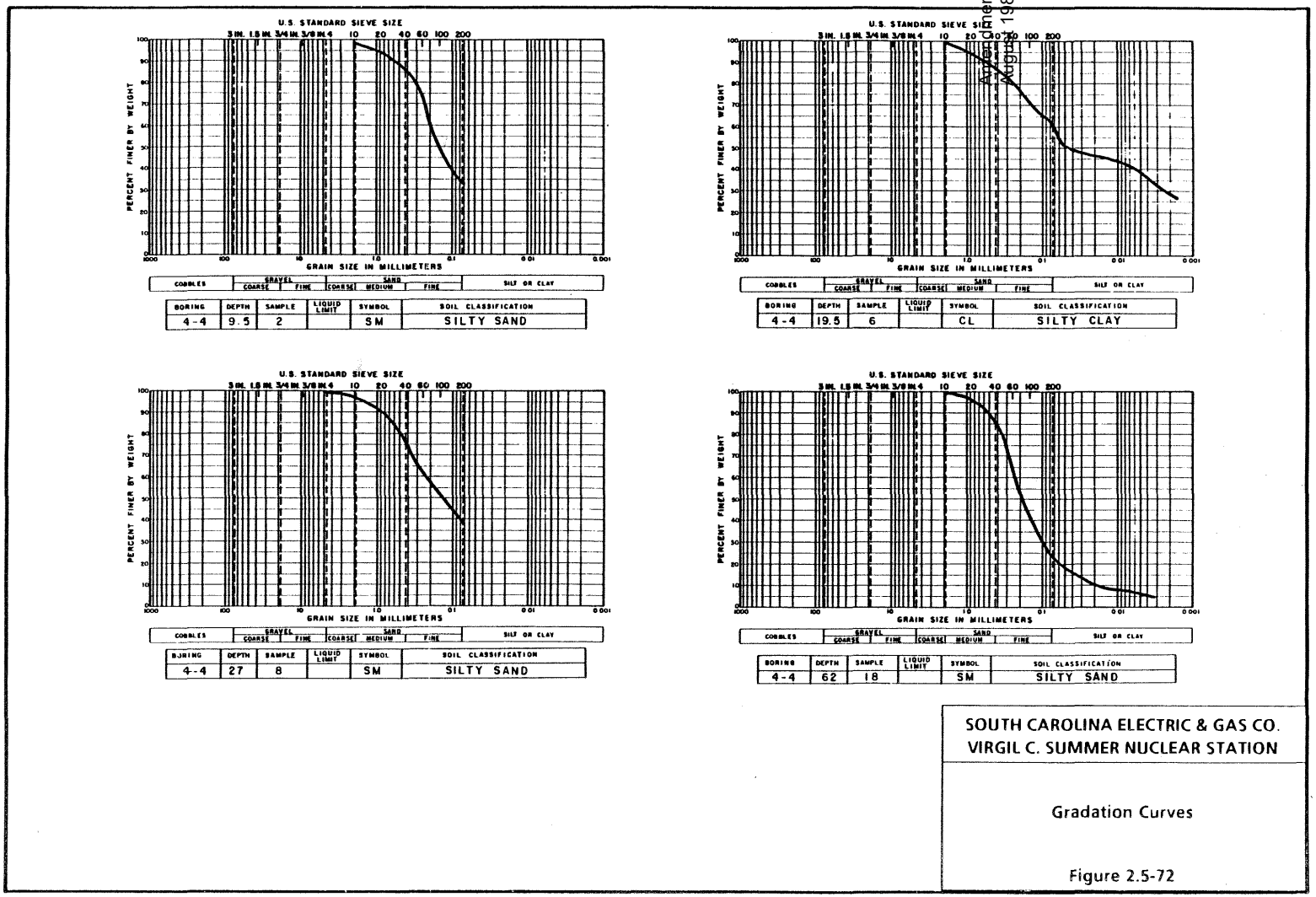

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Gradation Curves

Figure 2.5-72

Figure 2.5-73
GRADATION CURVES

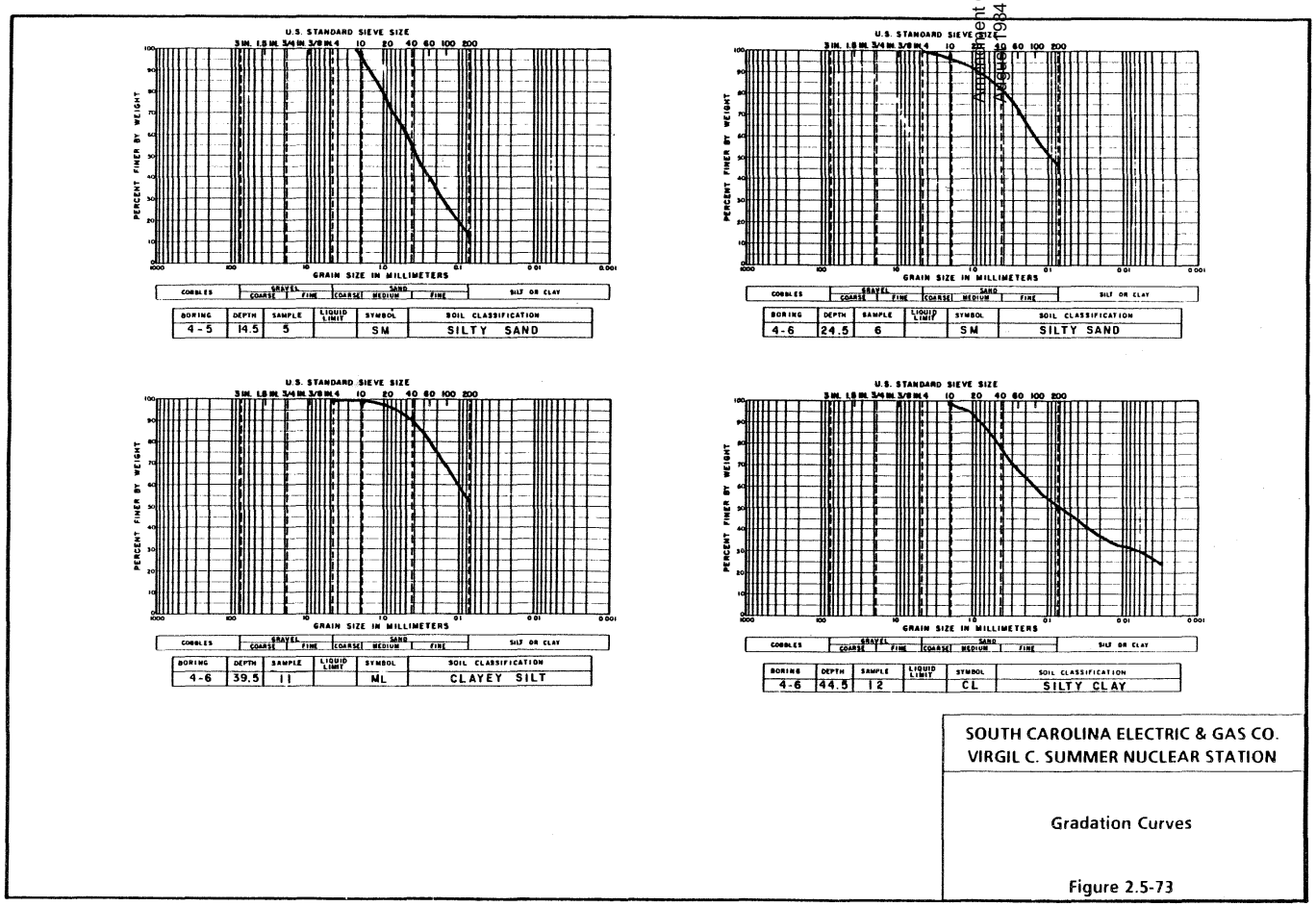

Figure 2.5-74
GRADATION CURVES

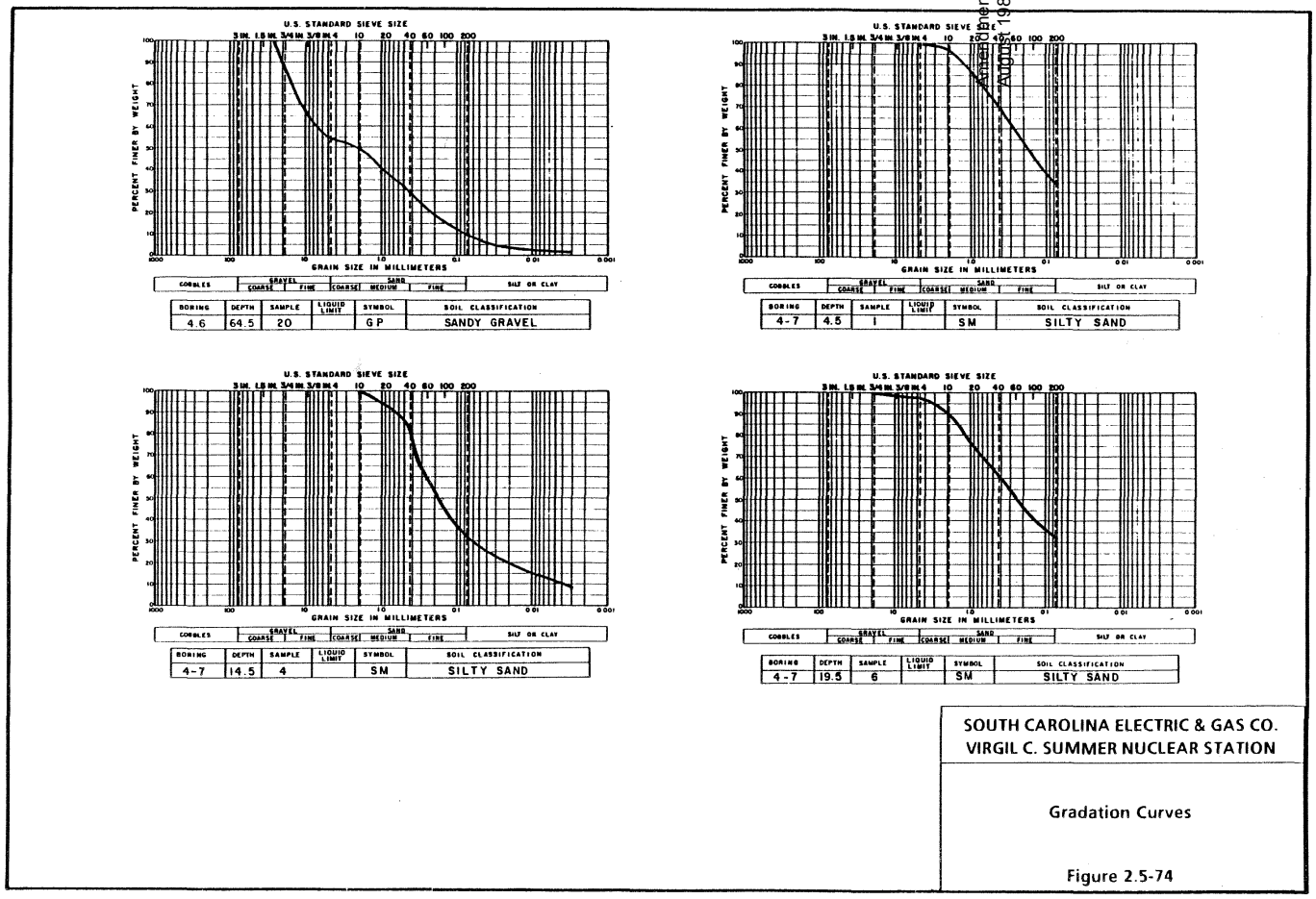

Figure 2.5-75
GRADATION CURVES

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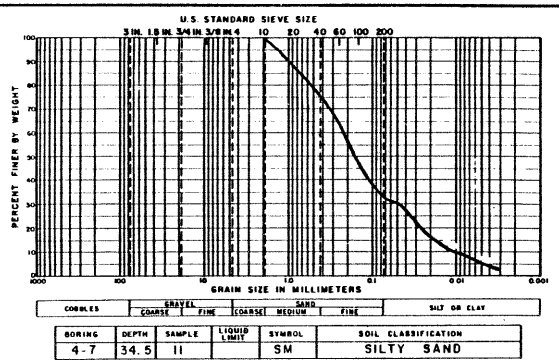
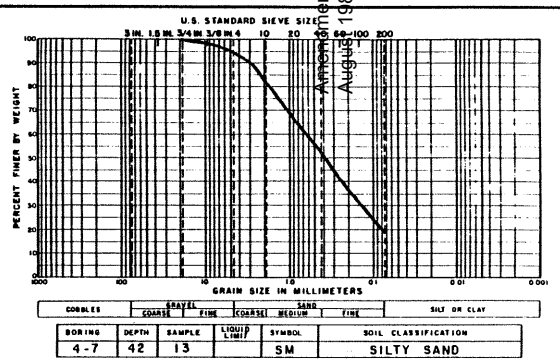
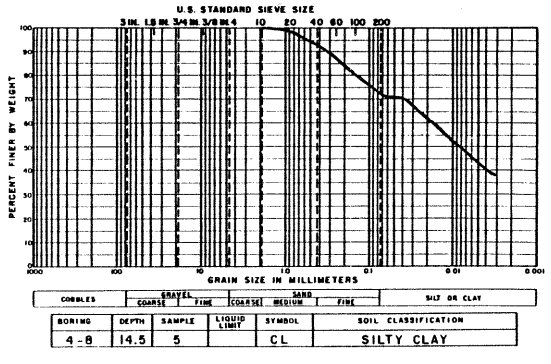


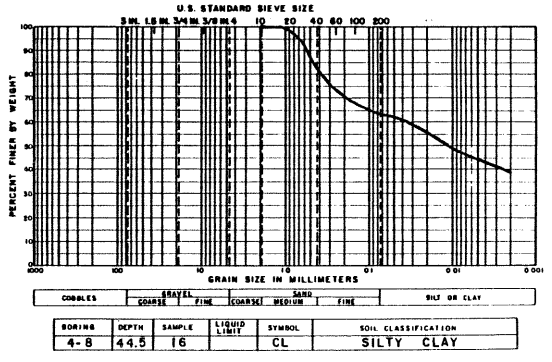
BORING	DEPTH	SAMPLE	LIQUID LIMIT	SYMBOL	SOIL CLASSIFICATION
4-7	34.5	11		SM	SILTY SAND



BORING	DEPTH	SAMPLE	LIQUID LIMIT	SYMBOL	SOIL CLASSIFICATION
4-7	42	13		SM	SILTY SAND



BORING	DEPTH	SAMPLE	LIQUID LIMIT	SYMBOL	SOIL CLASSIFICATION
4-8	14.5	5		CL	SILTY CLAY



BORING	DEPTH	SAMPLE	LIQUID LIMIT	SYMBOL	SOIL CLASSIFICATION
4-8	44.5	16		CL	SILTY CLAY

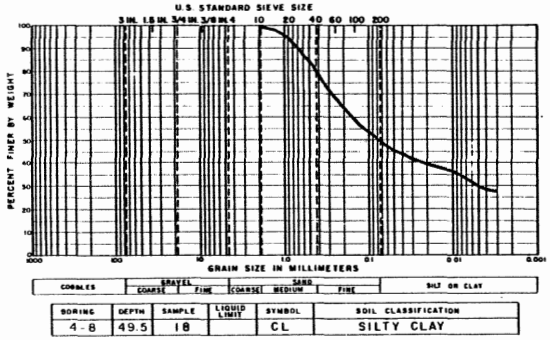
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Gradation Curves

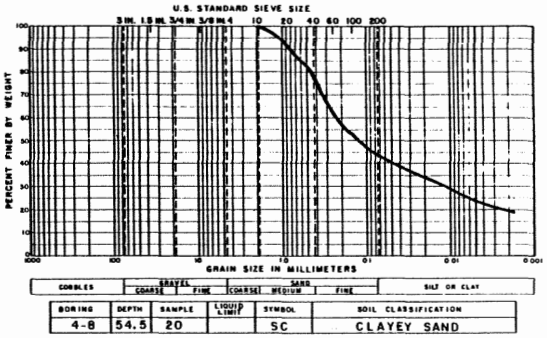
Figure 2.5-75

Figure 2.5-76

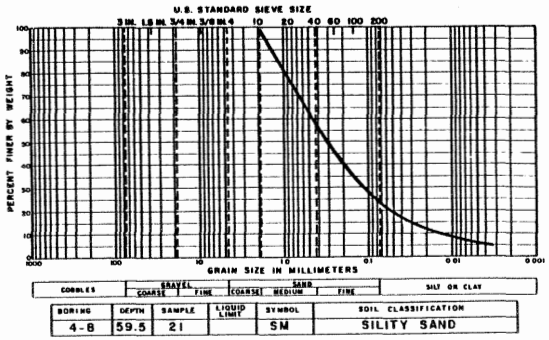
GRADATION CURVES



BORING	DEPTH	SAMPLE	LIQUID LIMIT	SYMBOL	SOIL CLASSIFICATION
4-8	49.5	18		CL	SILTY CLAY



BORING	DEPTH	SAMPLE	LIQUID LIMIT	SYMBOL	SOIL CLASSIFICATION
4-8	54.5	20		SC	CLAYEY SAND



BORING	DEPTH	SAMPLE	LIQUID LIMIT	SYMBOL	SOIL CLASSIFICATION
4-8	59.5	21		SM	SILITY SAND

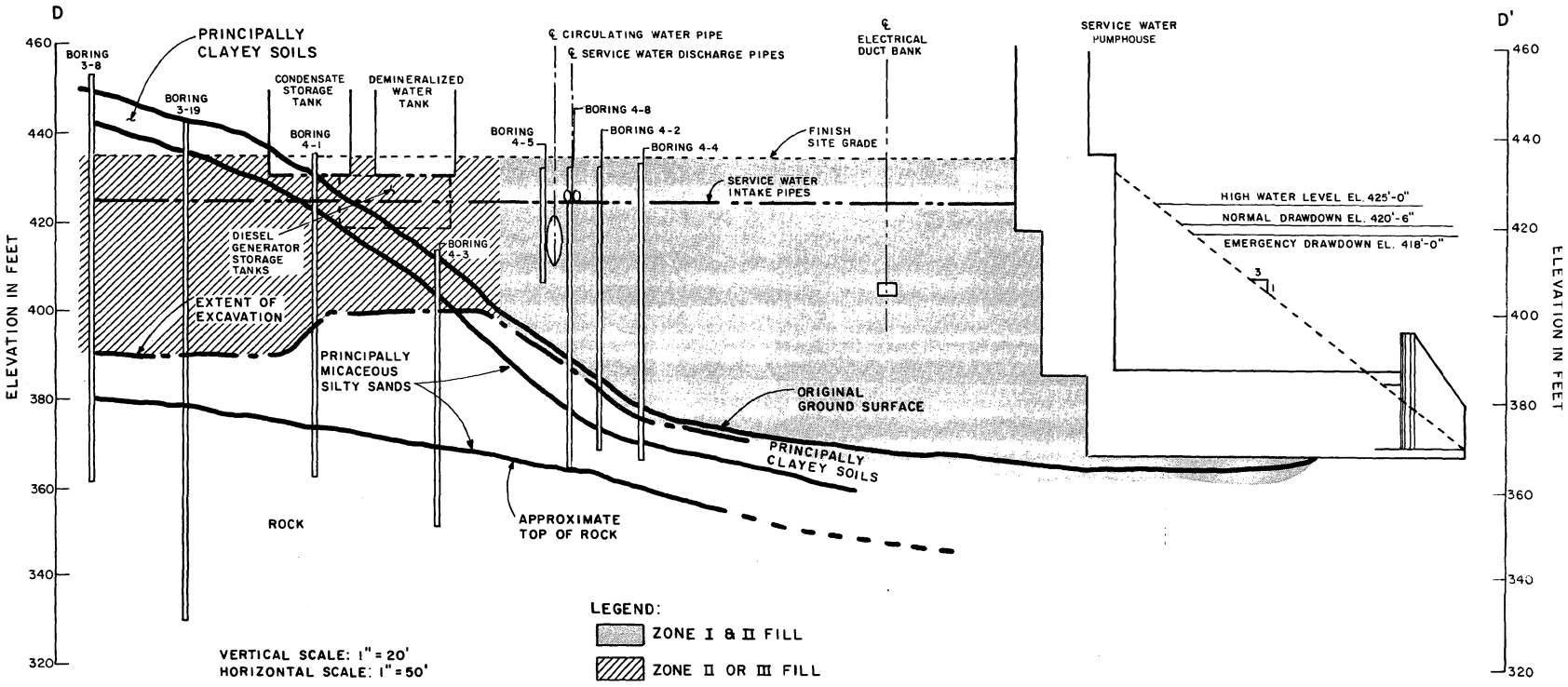
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Gradation Curves

Figure 2.5-76

Figure 2.5-80

CROSS SECTION D - D'



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Cross Section D - D'
Figure 2.5-80

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Figure 2.5-81

CROSS SECTION E- E'

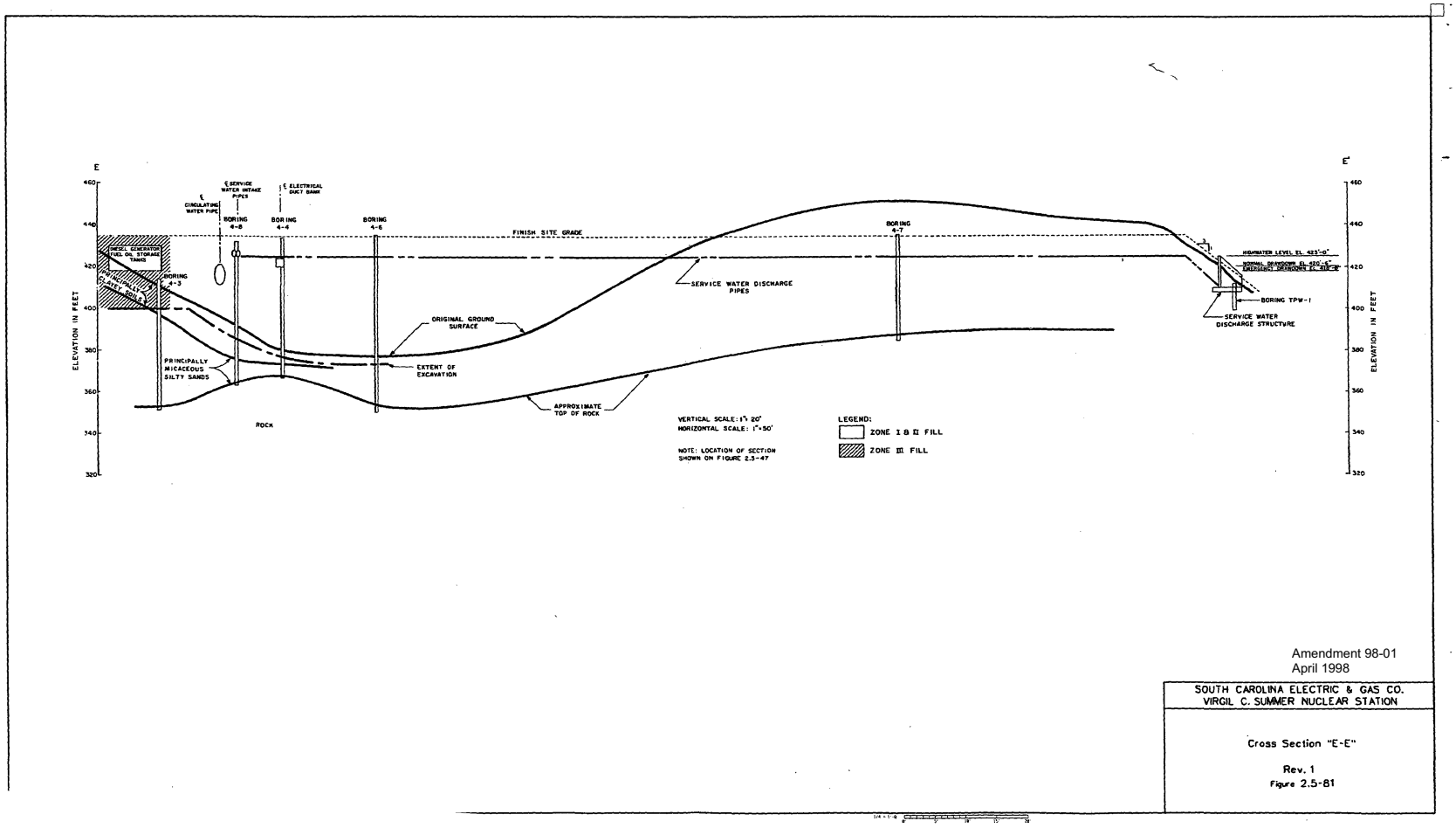

Figure 2.5-82

CROSS SECTION F - F'

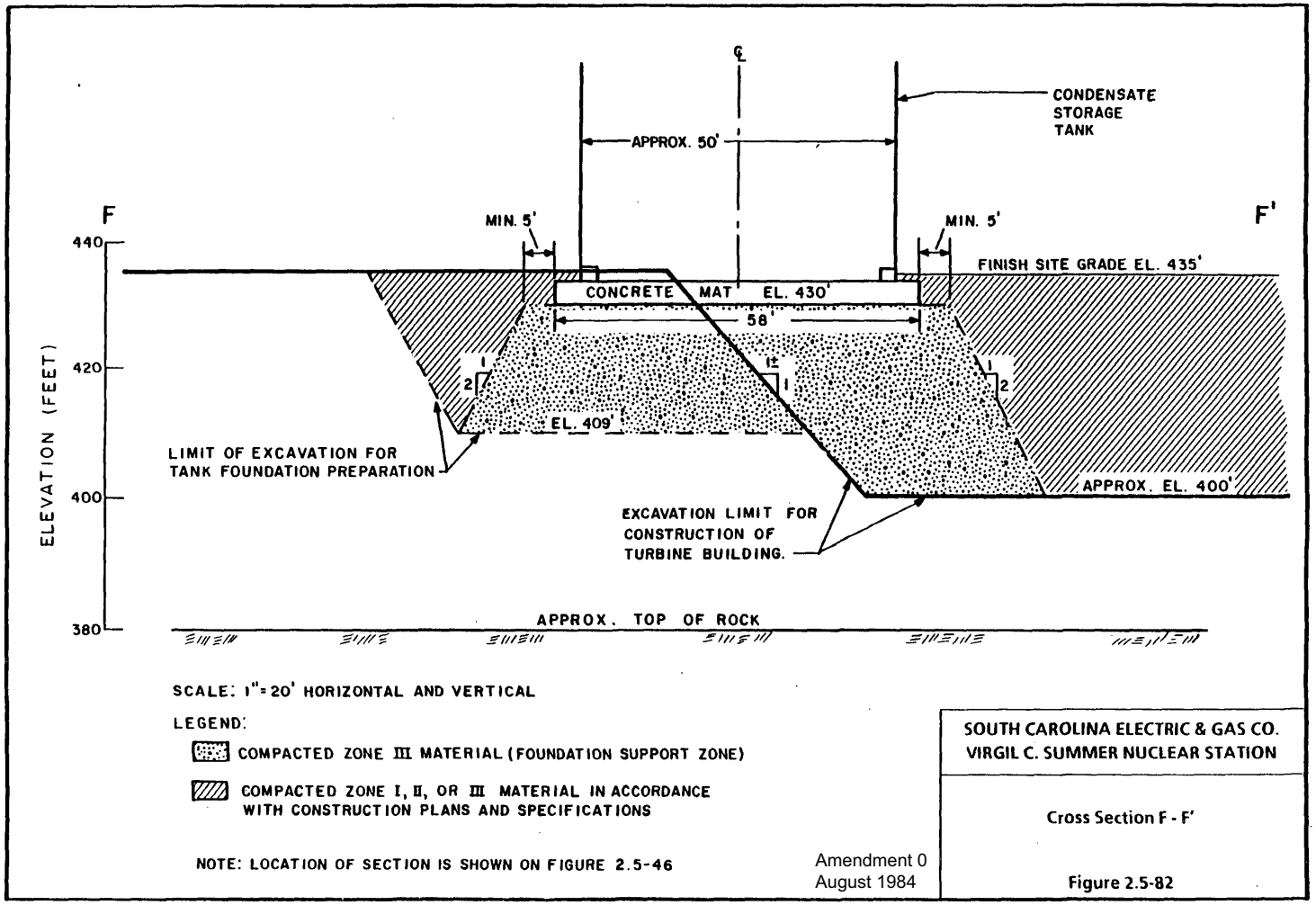

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Figure 2.5-83

UNIFIED SOIL CLASSIFICATION SYSTEM AND KEY TO SAMPLE TEST DATA

P■ INDICATES UNDISTURBED SAMPLE WITH 3 INCH O.D. SHELBY TUBE HYDRAULICALLY PUSHED

P☒ INDICATES DISTURBED SAMPLE WITH 3 INCH O.D. SHELBY TUBE HYDRAULICALLY PUSHED

■ INDICATES UNDISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER (3.25 INCHES O.D., 2.42 INCHES I.D. SPLIT SPOON SAMPLER)

☒ INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER

*◪ INDICATES DISTURBED SAMPLE WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)

◪ INDICATES DISTURBED SAMPLE WITH 2 INCH O.D. SAMPLER (NOT STANDARD PENETRATION TEST)

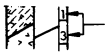
□ INDICATES SAMPLE ATTEMPT WITH NO RECOVERY

27■ INDICATES NUMBER OF BLOWS REQUIRED TO DRIVE DAMES & MOORE OR STANDARD PENETRATION SAMPLER 1 FOOT. SAMPLER DRIVING ENERGY IS DESCRIBED ON EACH BORING LOG.

TW■ INDICATES UNDISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED

TW☒ INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED

TW□ INDICATES NO RECOVERY WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED



INDICATES GENERALIZED ROCK PROPERTY INDICATOR (DETAILED DESCRIPTION PRESENTED IN SECTION 2.5.4.4.1)

1. RELATIVELY MASSIVE FRESH ROCK
2. RELATIVELY MODERATELY WEATHERED AND/OR MODERATELY JOINTED
3. RELATIVELY HIGHLY WEATHERED AND/OR HIGHLY JOINTED

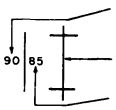
-ROCK IDENTIFICATION-

GRANODIORITE

MIGMATITE OF GRANODIORITE COMPOSITION

CONTACT BRECCIA MIGMATITE

MIGMATITE OF GNEISSIC COMPOSITION

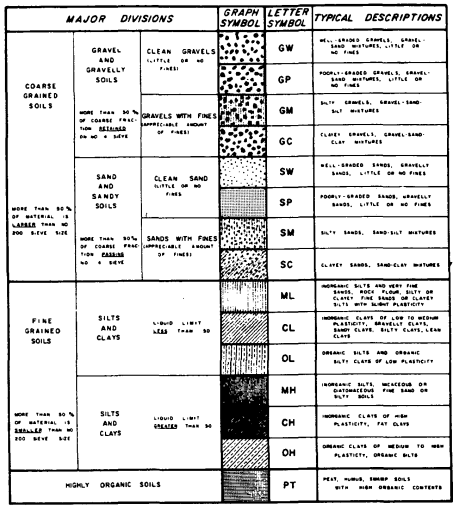


INDICATES PER CENT CORE RECOVERY = $\frac{\text{LENGTH OF CORE}}{\text{LENGTH OF RUN}}$ x 100

INDICATES LENGTH OF CORE RUN

INDICATES ROCK QUALITY DESIGNATION (RQD)

$$(RQD) = \frac{\text{SUM OF CORE SEGMENTS } \geq 4 \text{ INCHES LONG}}{\text{LEGNTH OF RUN}} \times 100$$



MAJOR DIVISIONS			GRAPH SYMBOL	LETTER SYMBOL	TYPICAL DESCRIPTIONS
COARSE GRAINED SOILS (MORE THAN 50 % OF MATERIAL IS LARGER THAN NO 200 SIEVE SIZE)	GRAVEL AND GRAVELLY SOILS (MORE THAN 50 % OF COARSE FRACTION RETAINED ON NO 4 SIEVE)	CLEAN GRAVELS (LITTLE OR NO FINES)		GW	WELL-GRADED GRAVELS, GRAVEL-SAND MIXTURES, LITTLE OR NO FINES
				GP	POORLY-GRADED GRAVELS, GRAVEL-SAND MIXTURES, LITTLE OR NO FINES
		GRAVELS WITH FINES (APPRECIABLE AMOUNT OF FINES)		GM	SILTY GRAVELS, GRAVEL-SAND-SILT MIXTURES
				GC	CLAYEY GRAVELS, GRAVEL-SAND-CLAY MIXTURES
	SAND AND SANDY SOILS (MORE THAN 50% OF COARSE FRACTION PASSING NO 4 SIEVE)	CLEAN SAND (LITTLE OR NO FINES)		SW	WELL-GRADED SANDS, GRAVELLY SANDS, LITTLE OR NO FINES
				SP	POORLY-GRADED SANDS, GRAVELLY SANDS, LITTLE OR NO FINES
		SANDS WITH FINES (APPRECIABLE AMOUNT OF FINES)		SM	SILTY SANDS, SAND-SILT MIXTURES
				SC	CLAYEY SANDS, SAND-CLAY MIXTURES
FINE GRAINED SOILS (MORE THAN 50 % OF MATERIAL IS SMALLER THAN NO 200 SIEVE SIZE)	SILTS AND CLAYS (LIQUID LIMIT LESS THAN 50)			ML	INORGANIC SILTS AND VERY FINE SANDS, ROCK FLOUR, SILTY OR CLAYEY FINE SANDS OR CLAYEY SILTS WITH SLIGHT PLASTICITY
				CL	INORGANIC CLAYS OF LOW TO MEDIUM PLASTICITY, GRAVELLY CLAYS, SANDY CLAYS, SILTY CLAYS, LEAN CLAYS
				OL	ORGANIC SILTS AND ORGANIC SILTY CLAYS OF LOW PLASTICITY
	SILTS AND CLAYS (LIQUID LIMIT GREATER THAN 50)			MH	INORGANIC SILTS, MICACEOUS OR DIATOMACEOUS FINE SAND OR SILTY SOILS
				CH	INORGANIC CLAYS OF HIGH PLASTICITY, FAT CLAYS
				OH	ORGANIC CLAYS OF MEDIUM TO HIGH PLASTICITY, ORGANIC SILTS
HIGHLY ORGANIC SOILS				PT	PEAT, MUSKS, SWAMP SOILS WITH HIGH ORGANIC CONTENTS

SOIL CLASSIFICATION CHART

NOTES:

1. DUAL SYMBOLS ARE USED TO INDICATE BORDERLINE CLASSIFICATIONS.
2. WHEN SHOWN ON THE BORING LOGS, THE FOLLOWING TERMS ARE USED TO DESCRIBE THE CONSISTENCY OF COHESIVE SOILS AND THE RELATIVE COMPACTNESS OF COHESIONLESS SOILS.

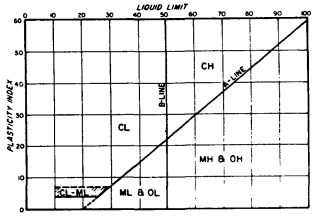
COHESIVE SOILS	(APPROXIMATE SHEARING STRENGTH IN KSF)	COHESIONLESS SOILS	
VERY SOFT	LESS THAN 25	VERY LOOSE	THESE ARE USUALLY BASED ON AN EXAMINATION OF SOIL SAMPLES, PENETRATION RESISTANCE, AND SOIL DENSITY DATA.
SOFT	0.25 TO 0.5	LOOSE	
MEDIUM STIFF	0.5 TO 1.0	MEDIUM DENSE	
STIFF	1.0 TO 2.0	DENSE	
VERY STIFF	2.0 TO 4.0	VERY DENSE	
HARD	GREATER THAN 4.0		

GRADATION CHART

MATERIAL SIZE	PARTICLE SIZE			
	LOWER LIMIT		UPPER LIMIT	
	MILLIMETERS	SIEVE SIZE#	MILLIMETERS	SIEVE SIZE#
CLAY SIZE			.005	
SILT SIZE	.005		.074	#200*
SAND				
FINE	.074	#200#	0.42	#40#
MEDIUM	0.42	#40#	2.00	#10#
COARSE	2.00	#10#	4.76	#4#
GRAVEL				
FINE	4.76	#4#	19.1	3/4" *
COARSE	19.1	3/4" *	76.2	3" *
COBBLES	76.2	3" *	304.8	12" *
BOULDERS	304.8	12" *	914.4	36" *

U.S. STANDARD *CLEAR SQUARE OPENINGS

PLASTICITY CHART



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VIRGIL C. SUMMER NUCLEAR STATION

Unified Soil Classification System and Key to Sample Test Data

Figure 2.5-83

Figure 2.5-84
SOIL SAMPLER TYPE U

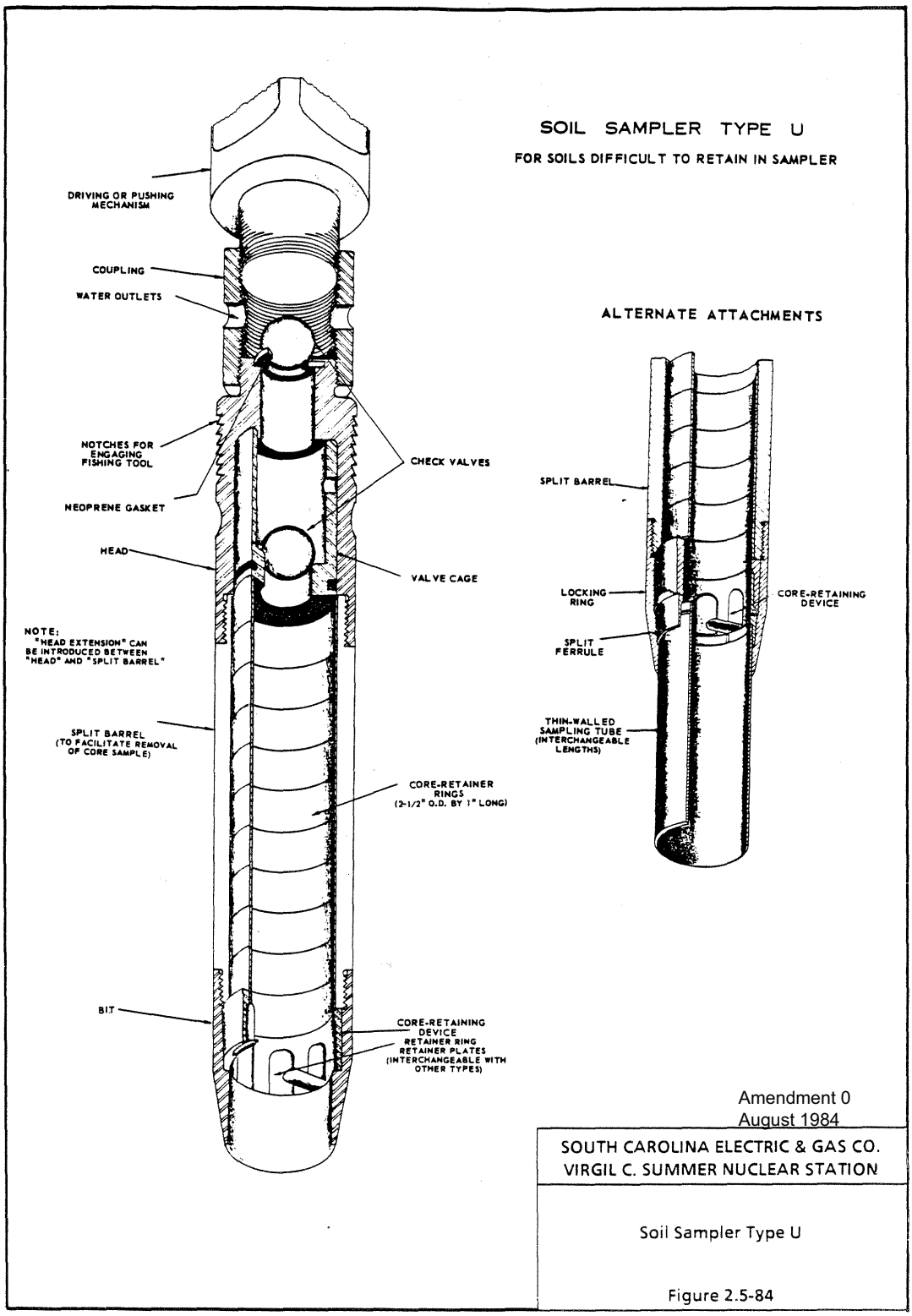

Figure 2.5-85

EMPIRICAL CORRELATION - BLOW COUNT AND SOIL CHARACTERISTICS

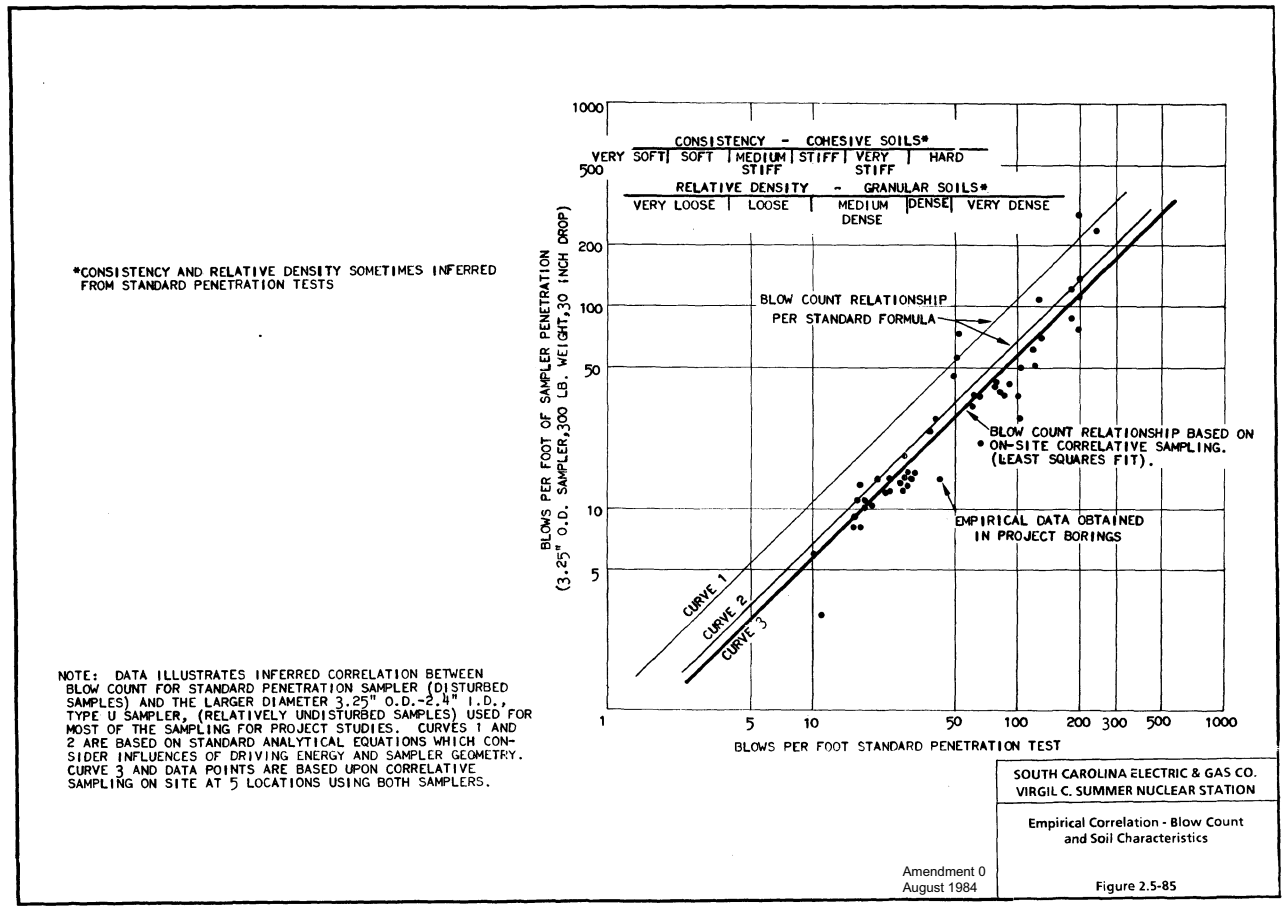

Figure 2.5-86
COMPARATIVE CONSOLIDATION TEST DATA - VIRGINIA SITE

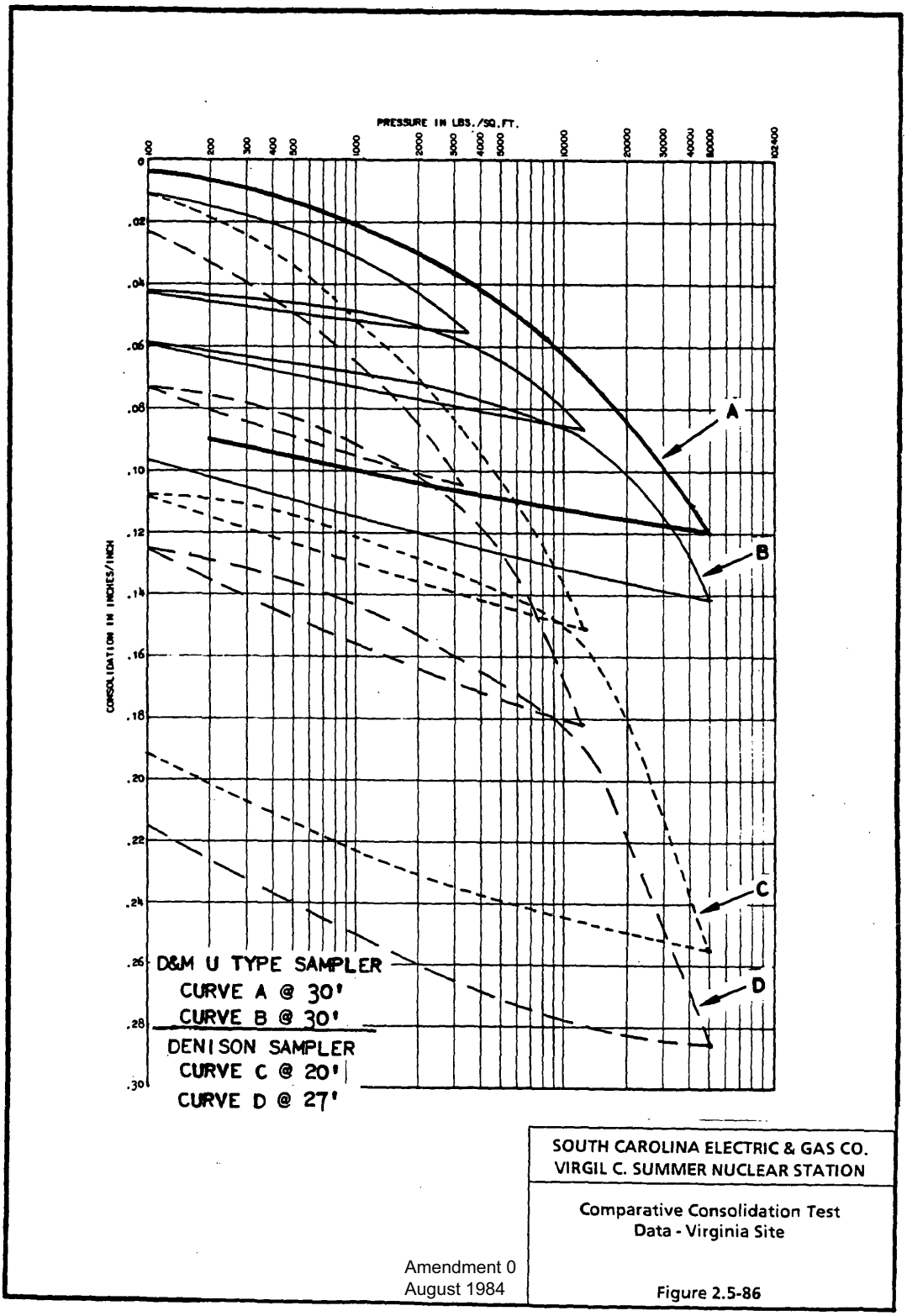

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Figure 2.5-87
COMPARATIVE CONSOLIDATION TEST DATA - VIRGINIA SITE

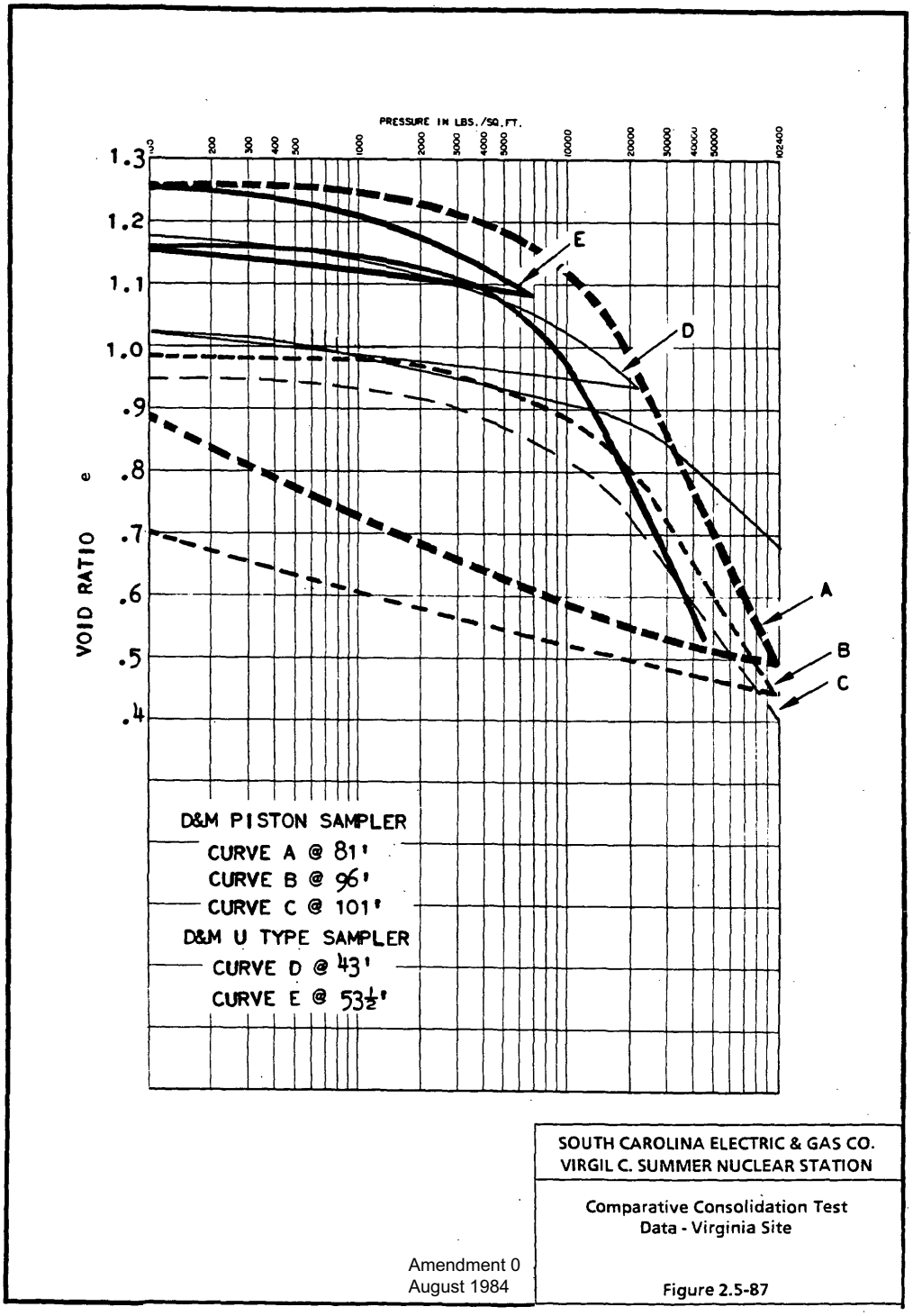
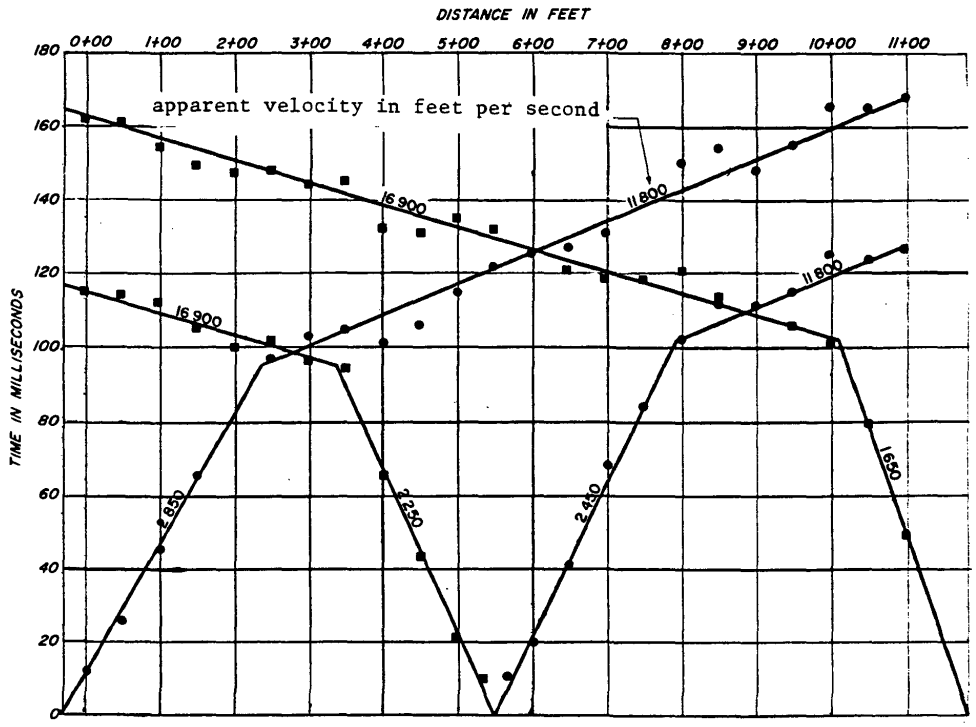


Figure 2.5-88
SEISMIC INFRACTION LINE 1



Note: times corrected to assumed horizontal grade, elevation 482 feet

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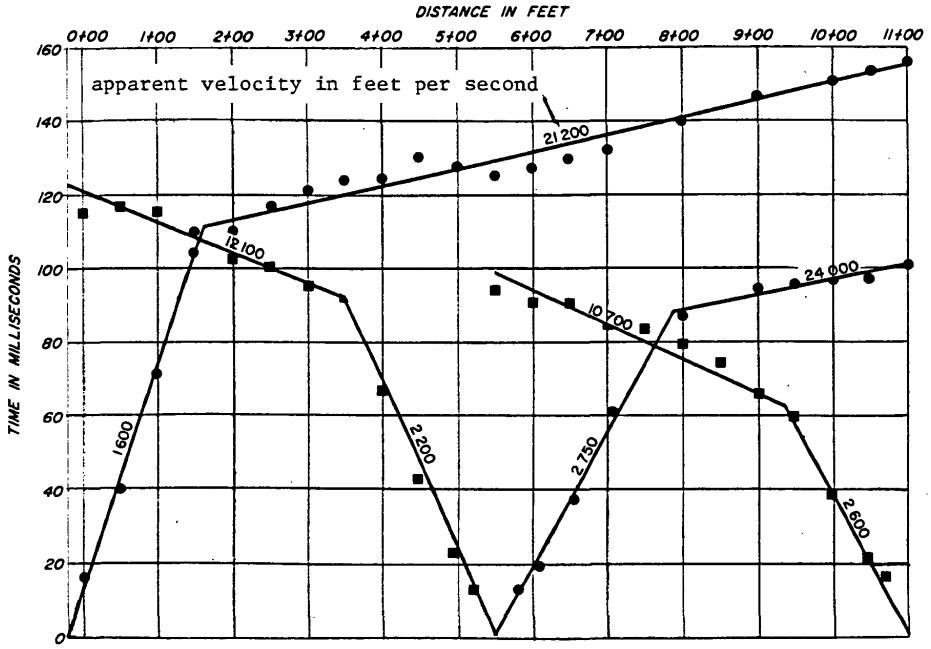
VIRGIL C. SUMMER NUCLEAR STATION

Seismic Infraction Line 1

Figure 2.5-88

Figure 2.5-89

SEISMIC INFRACTION LINE 2



Note: times corrected to assumed horizontal grade, elevation 482 feet

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Seismic Infraction Line 2

Figure 2.5-89

Figure 2.5-90
EVALUATION OF POTENTIAL FOR LIQUEFACTION OF SAPROLITE

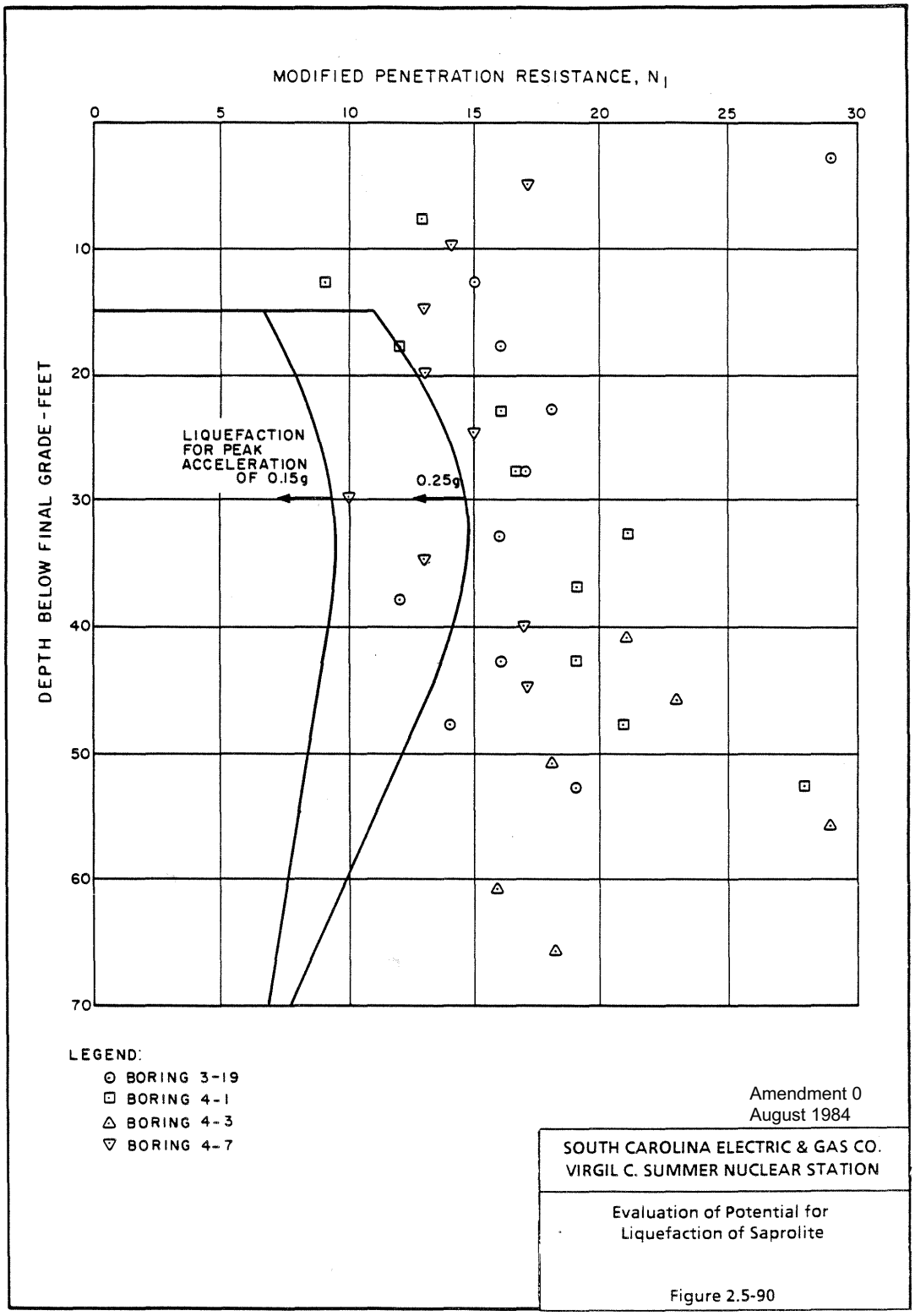
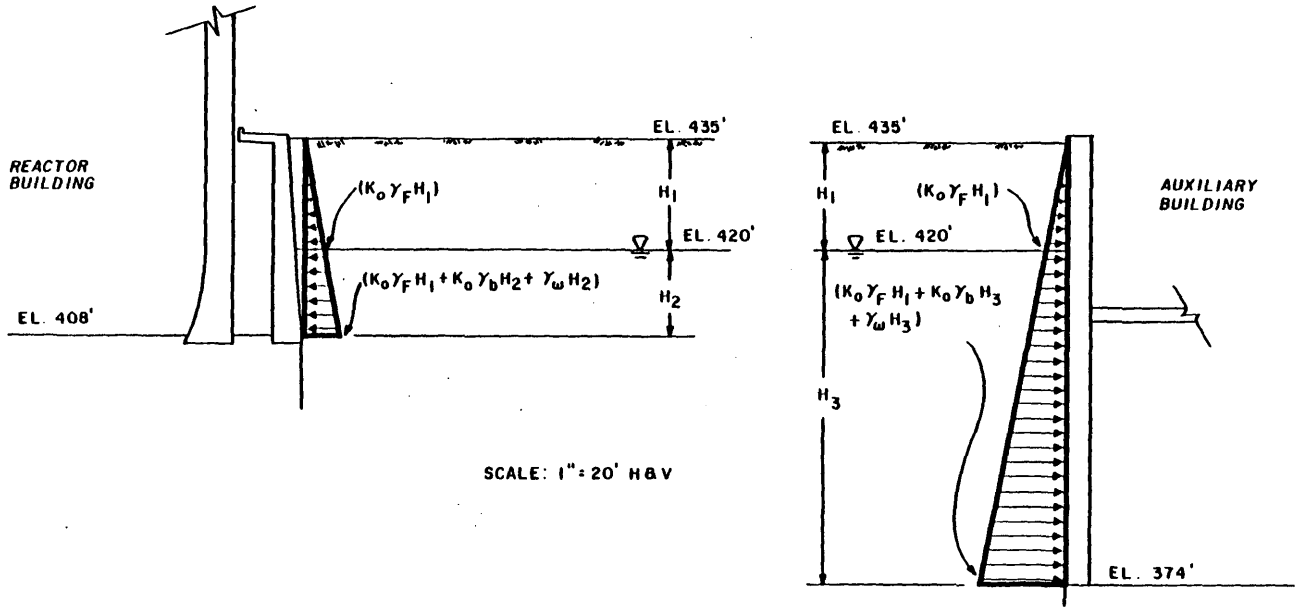


Figure 2.5-90a

Figure 2.5-90a

STATIC LATERAL EARTH PRESSURE DISTRIBUTION DIAGRAM FOR TYPICAL RIGID WALLS



LEGEND:

K_o = COEFFICIENT OF EARTH PRESSURE AT REST
γ_F = UNIT WEIGHT OF BACKFILL
γ_b = BUOYANT UNIT WEIGHT OF BACKFILL
γ_ω = UNIT WEIGHT OF WATER

REFERENCE FSAR FIGURE 3.8-68 (NO SCALE)

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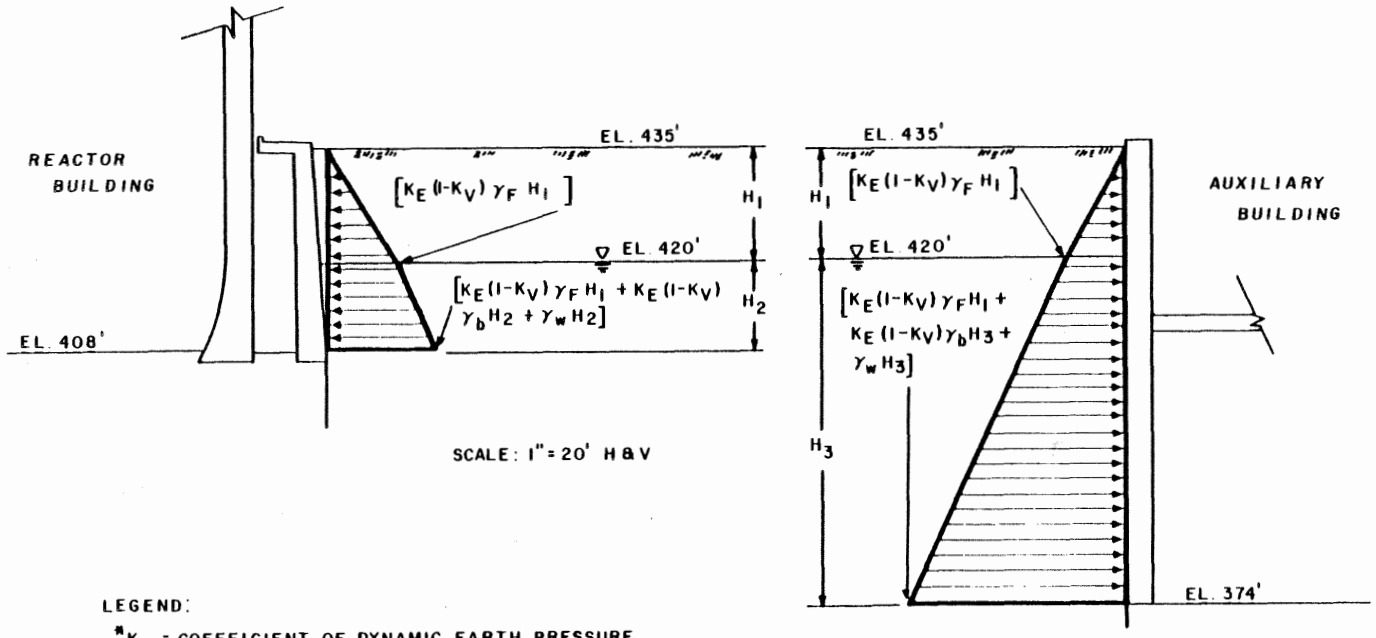
Static Lateral Earth Pressure Distribution Diagram for Typical Rigid Walls

Figure 2.5-90a

Figure 2.5-90b

DYNAMIC LATERAL EARTH PRESSURE DISTRIBUTION DIAGRAMS FOR TYPICAL RIGID WALLS



LEGEND:

*K_E = COEFFICIENT OF DYNAMIC EARTH PRESSURE

K_V = VERTICAL GROUND ACCELERATION/g

γ_F = UNIT WEIGHT OF BACKFILL

γ_b = BUOYANT UNIT WEIGHT OF BACKFILL

γ_w = UNIT WEIGHT OF WATER

*EVALUATED BASED ON MONONOBE-OKABE APPROACH AS MODIFIED BY KAPILA (FSAR, 2.5.4.10.5)

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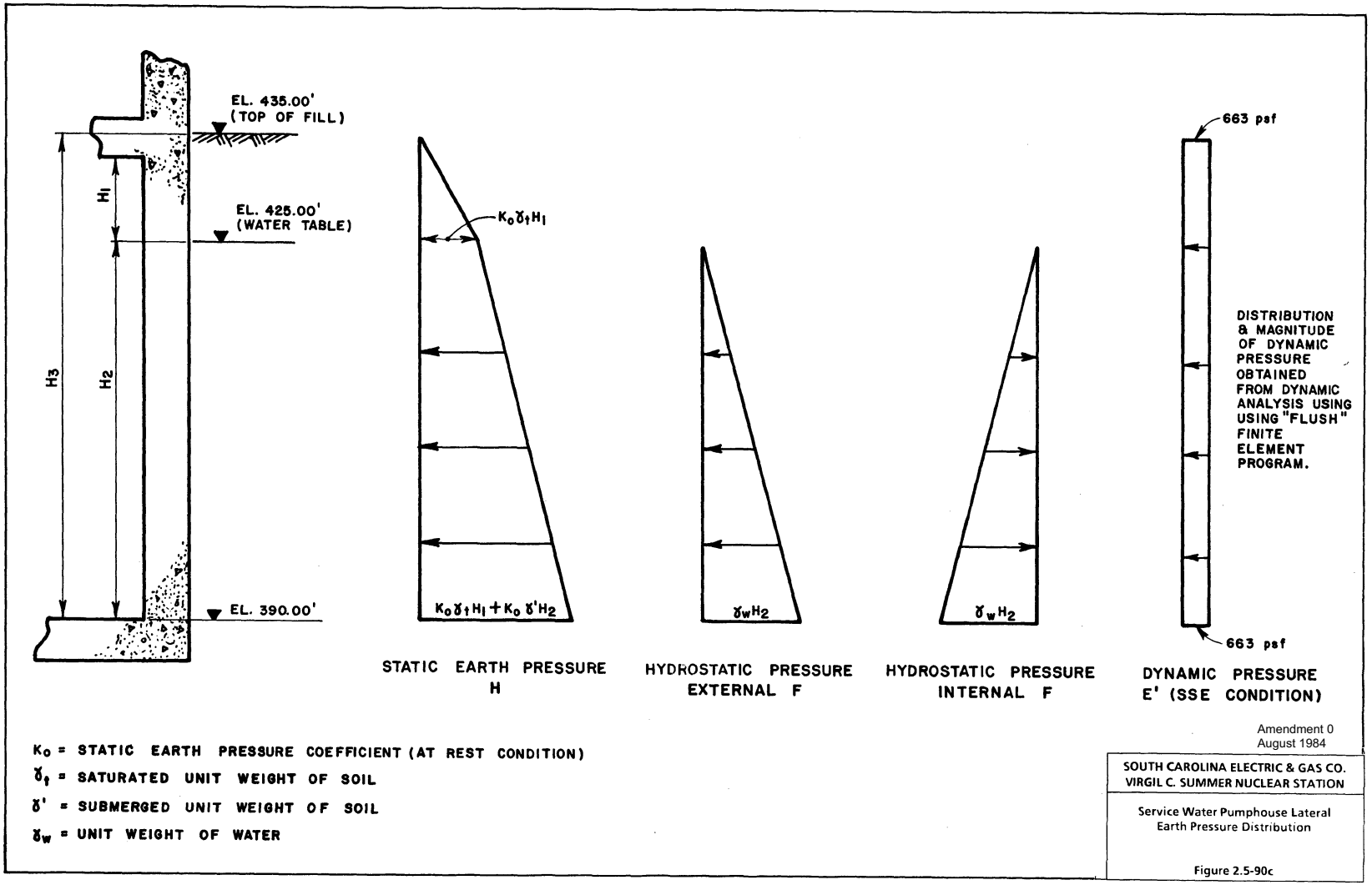
VIRGIL C. SUMMER NUCLEAR STATION

Dynamic Lateral Earth Pressure Distribution Diagrams for Typical Rigid Walls

Figure 2.5-90b

Figure 2.5-90c

SERVICE WATER PUMPHOUSE LATERAL EARTH PRESSURE DISTRIBUTION



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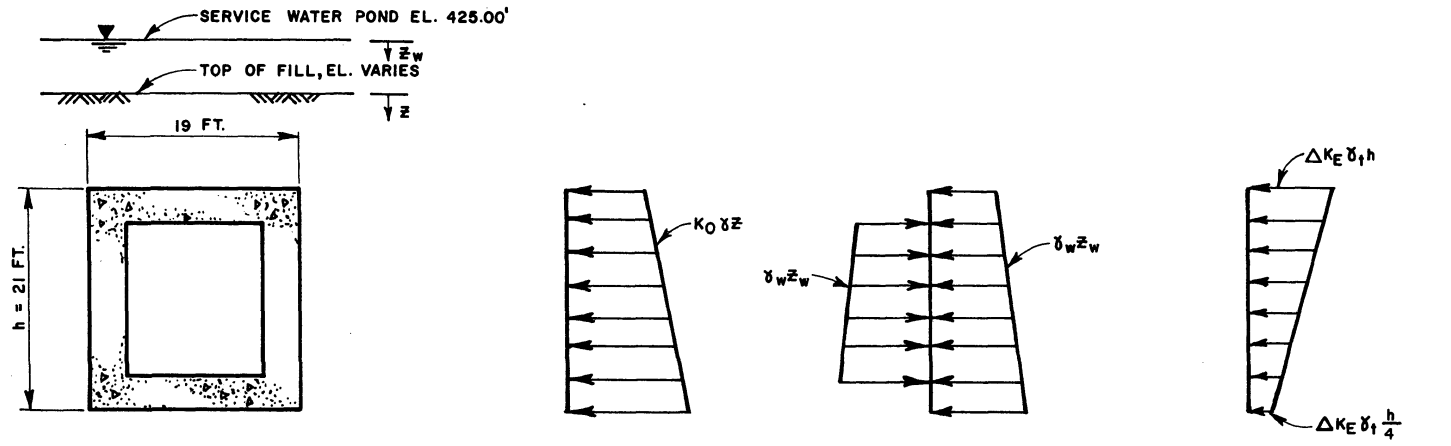
VIRGIL C. SUMMER NUCLEAR STATION

Service Water Pumphouse Lateral
Earth Pressure Distribution

Figure 2.5-90c

Figure 2.5-90d

SERVICE WATER INTAKE STRUCTURE
LATERAL EARTH PRESSURE DISTRIBUTION



SERVICE WATER INTAKE STRUCTURE

STATIC EARTH PRESSURE H

INTERNAL AND EXTERNAL HYDROSTATIC PRESSURE F

DYNAMIC EARTH PRESSURE E'

K_O = STATIC EARTH PRESSURE COEFFICIENT FOR AT-REST CONDITIONS

ΔK_E = DYNAMIC PRESSURE COEFFICIENT (EVALUATED USING SEED-WHITMAN METHOD)

γ_m = MOIST UNIT WEIGHT OF SOIL

γ_t = SATURATED UNIT WEIGHT OF SOIL

γ_b = SUBMERGED UNIT WEIGHT OF SOIL

γ_w = UNIT WEIGHT OF WATER

γ = γ_m FOR END OF CONSTRUCTION CONDITION & γ_b FOR OPERATING CONDITIONS

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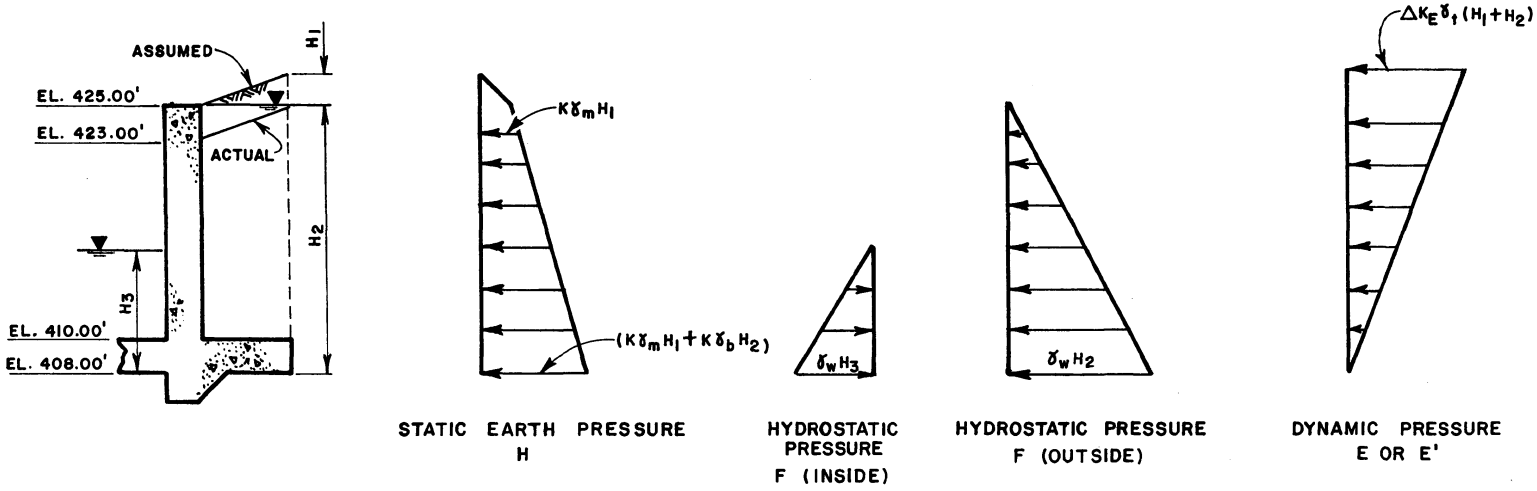
VIRGIL C. SUMMER NUCLEAR STATION

Service Water Intake Structure Lateral Earth Pressure Distribution

Figure 2.5-90d

Figure 2.5-90e

SERVICE WATER DISCHARGE STRUCTURE
LATERAL EARTH PRESSURE DISTRIBUTION



K = STATIC EARTH PRESSURE COEFFICIENT = K_O FOR AT-REST CONDITION AND K_A FOR ACTIVE CONDITION

ΔK_E = DYNAMIC PRESSURE COEFFICIENT = $(K^*_{OE} - K_O)$ AT REST CONDITION AND $(K^*_{AE} - K_E)$ ACTIVE CONDITION

γ_m = MOIST UNIT WEIGHT OF SOIL

γ_t = SATURATED UNIT WEIGHT OF SOIL

γ_w = UNIT WEIGHT OF WATER

* EVALUATION BASED ON MONONOBE-OKABE APPROACH.

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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Service Water Discharge Structure
Lateral Earth Pressure
Distribution

Figure 2.5-90e

Figure 2.5-91

SITE AND BORING PLAN
SERVICE WATER POND

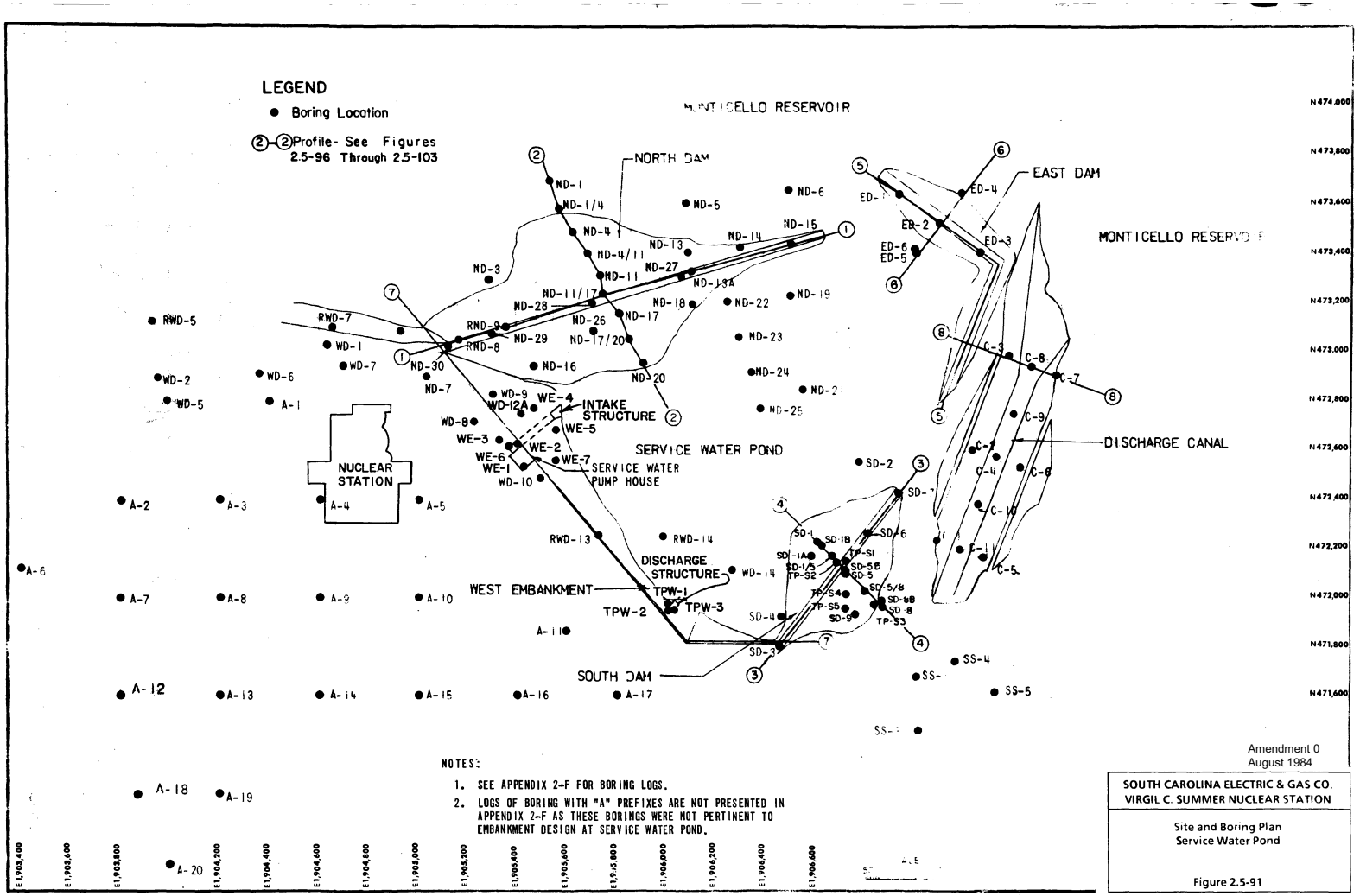
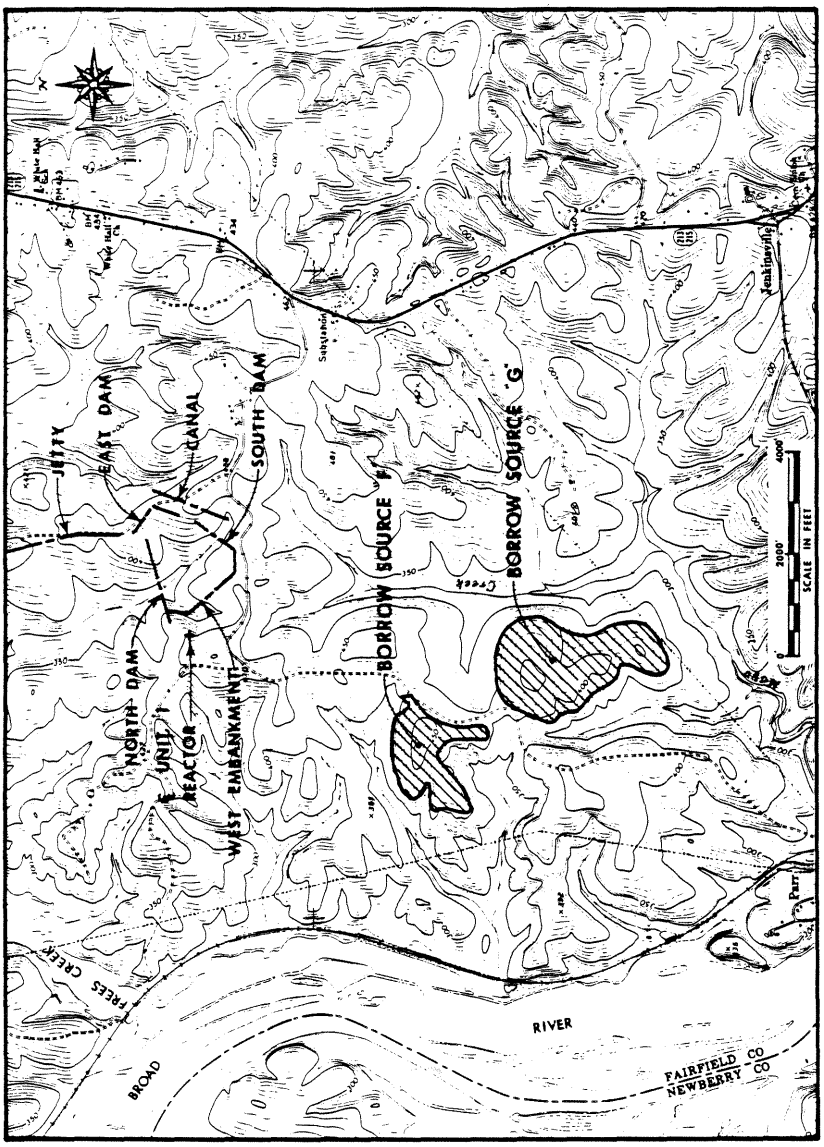


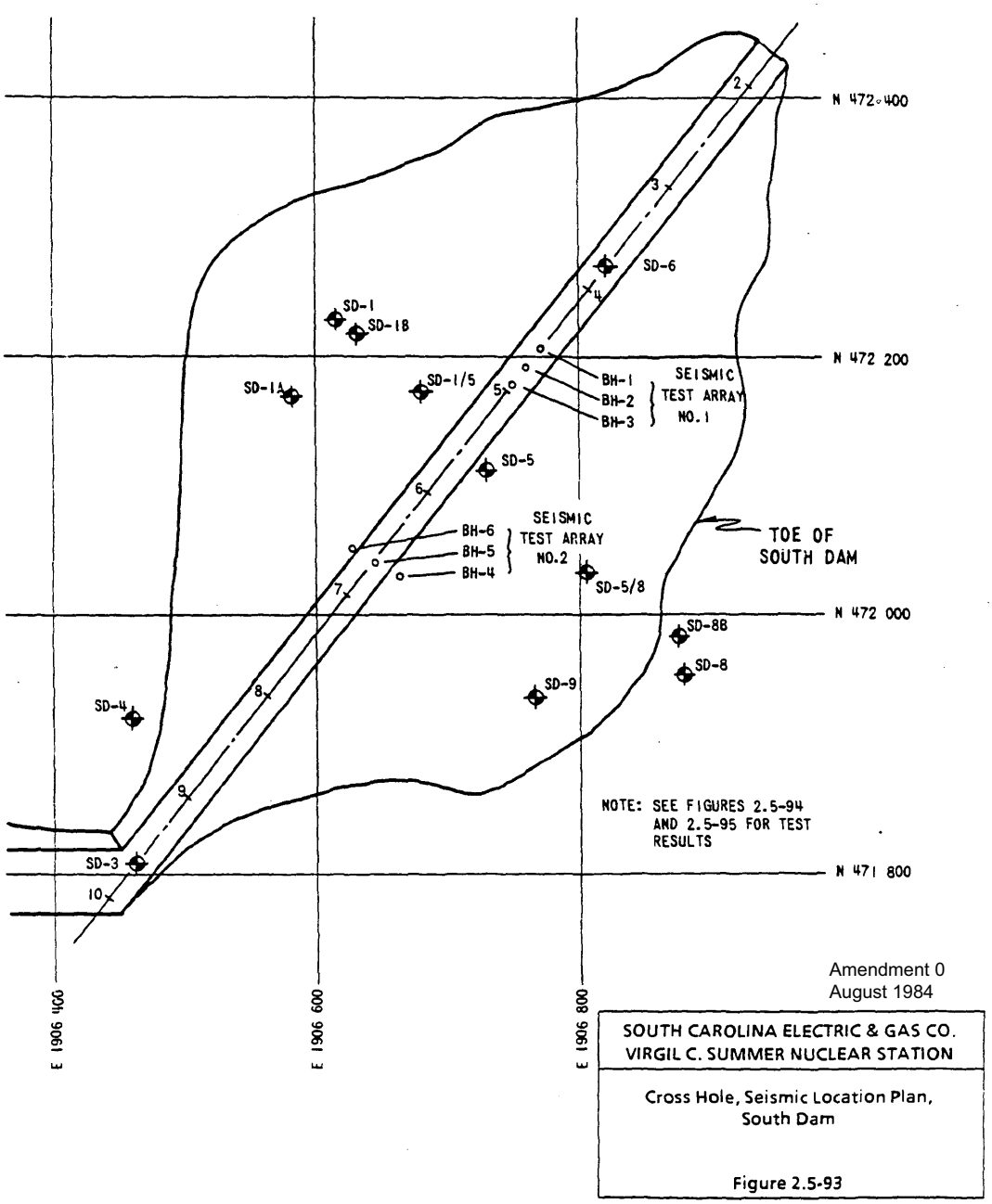
Figure 2.5-92
LOCATION PLAN BORROW SOURCES F AND G



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Location Plan Borrow Sources F and G Figure 2.5-92

Amendment 0
August 1984

Figure 2.5-93
CROSS HOLE SEISMIC LOCATION PLAN, SOUTH DAM



Amendment 0
August 1984

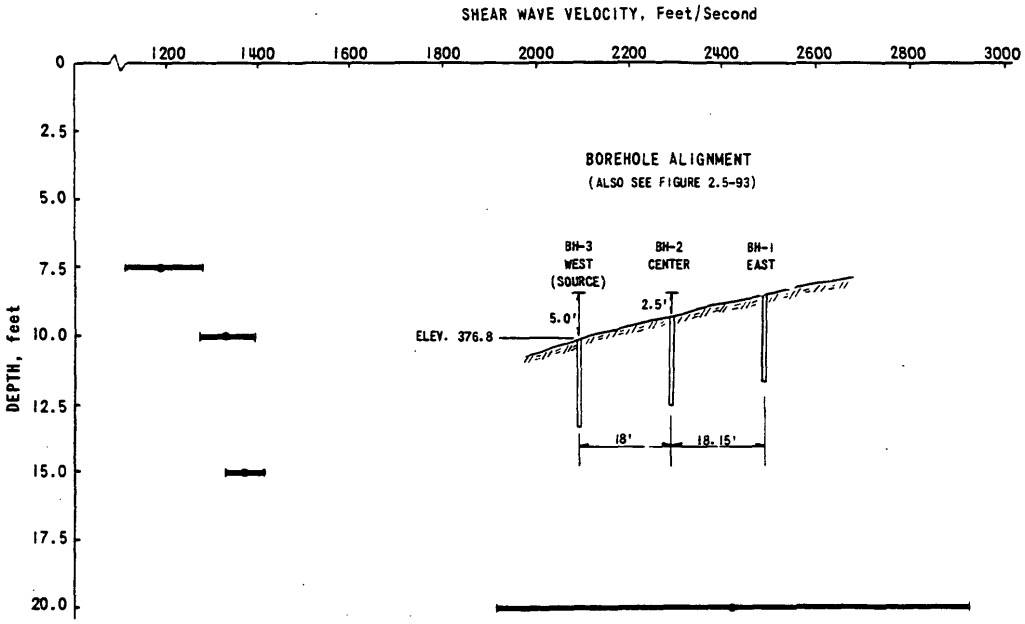
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Cross Hole, Seismic Location Plan, South Dam

Figure 2.5-93

Figure 2.5-94

SHEAR WAVE VELOCITIES TEST ARRAY NO. 1



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August 1984

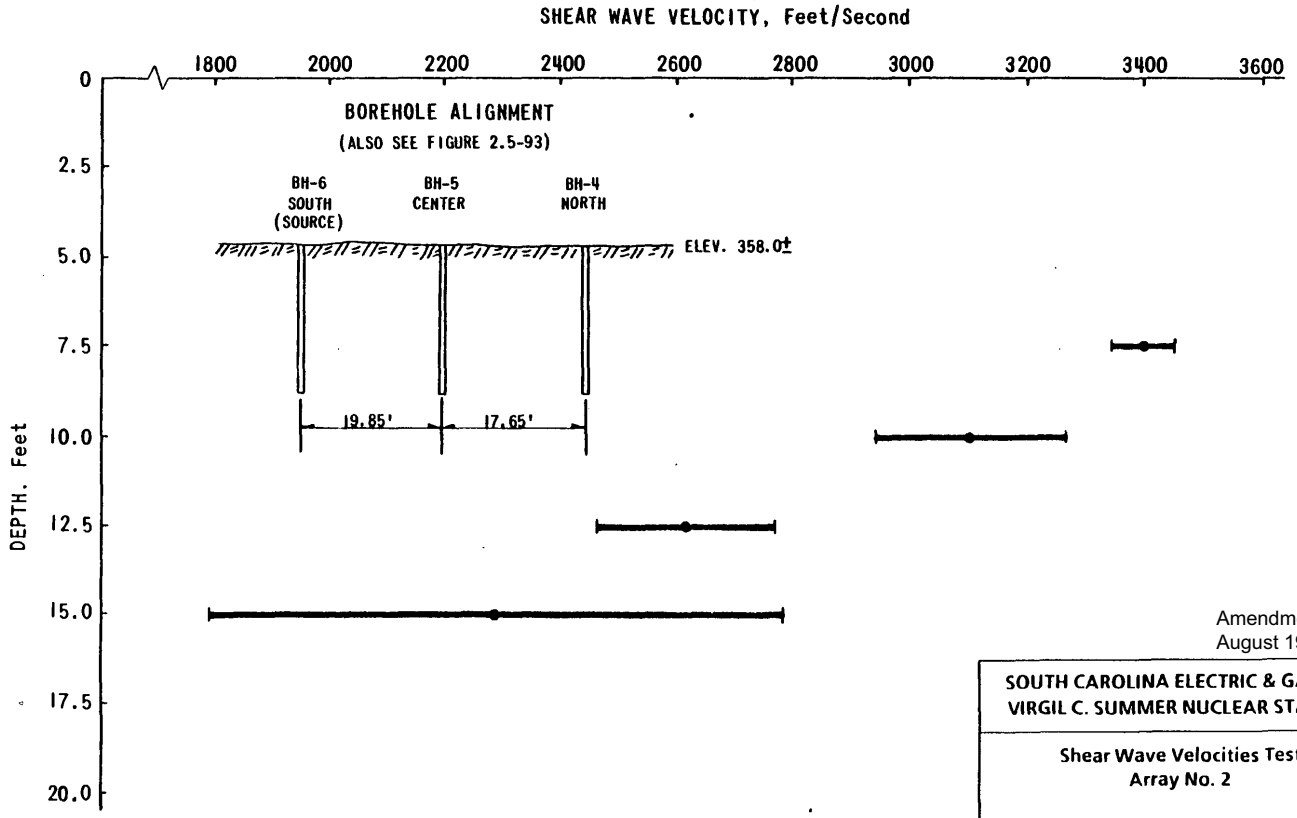
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Shear Wave Velocities Test
Array No. 1

Figure 2.5-94

Figure 2.5-95

SHEAR WAVE VELOCITIES TEST ARRAY NO. 1

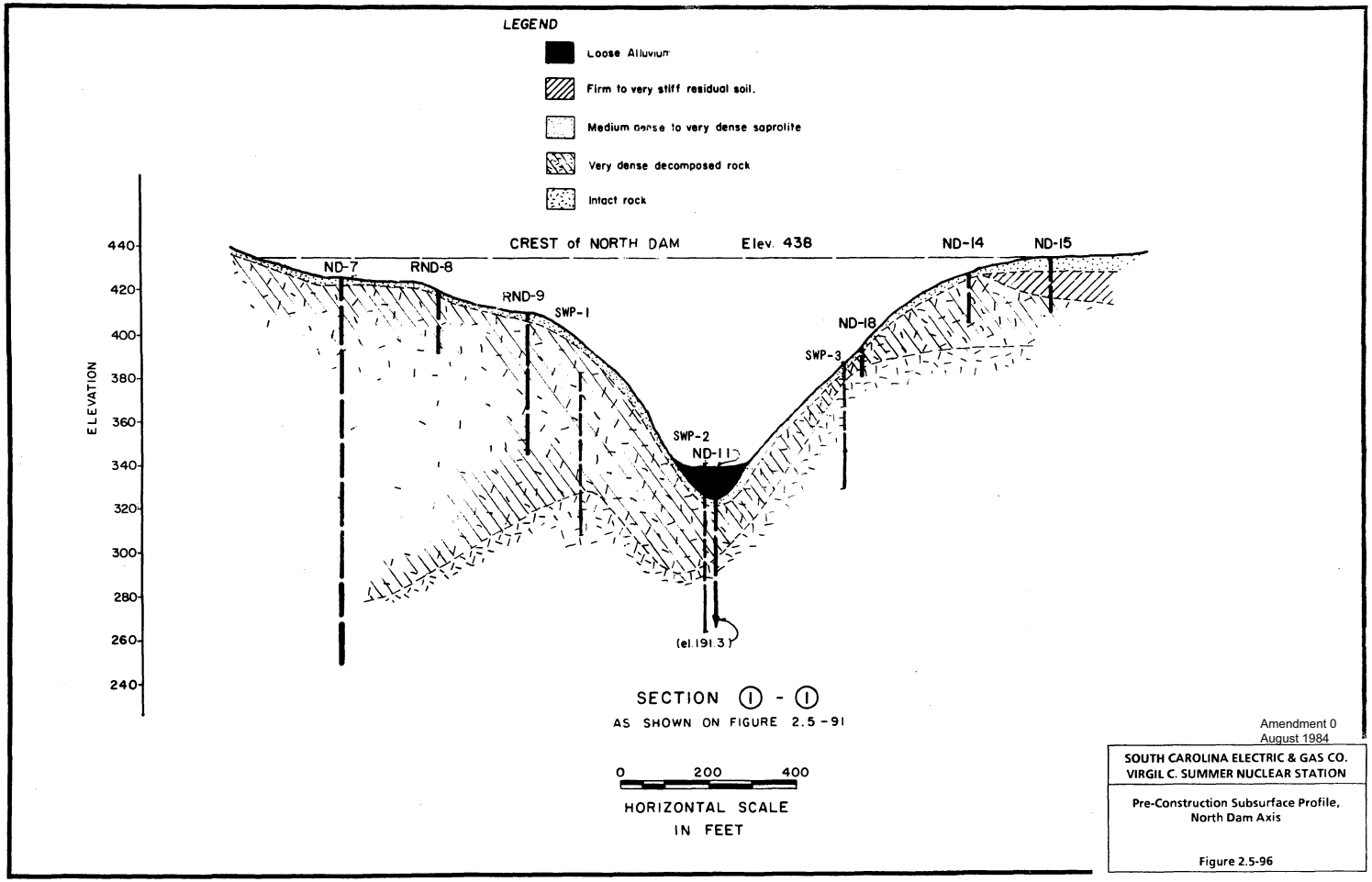


Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Shear Wave Velocities Test Array No. 2
Figure 2.5-95

Figure 2.5-96

SHEAR WAVE VELOCITIES TEST
ARRAY NO. 2



Amendment 0
August 1984

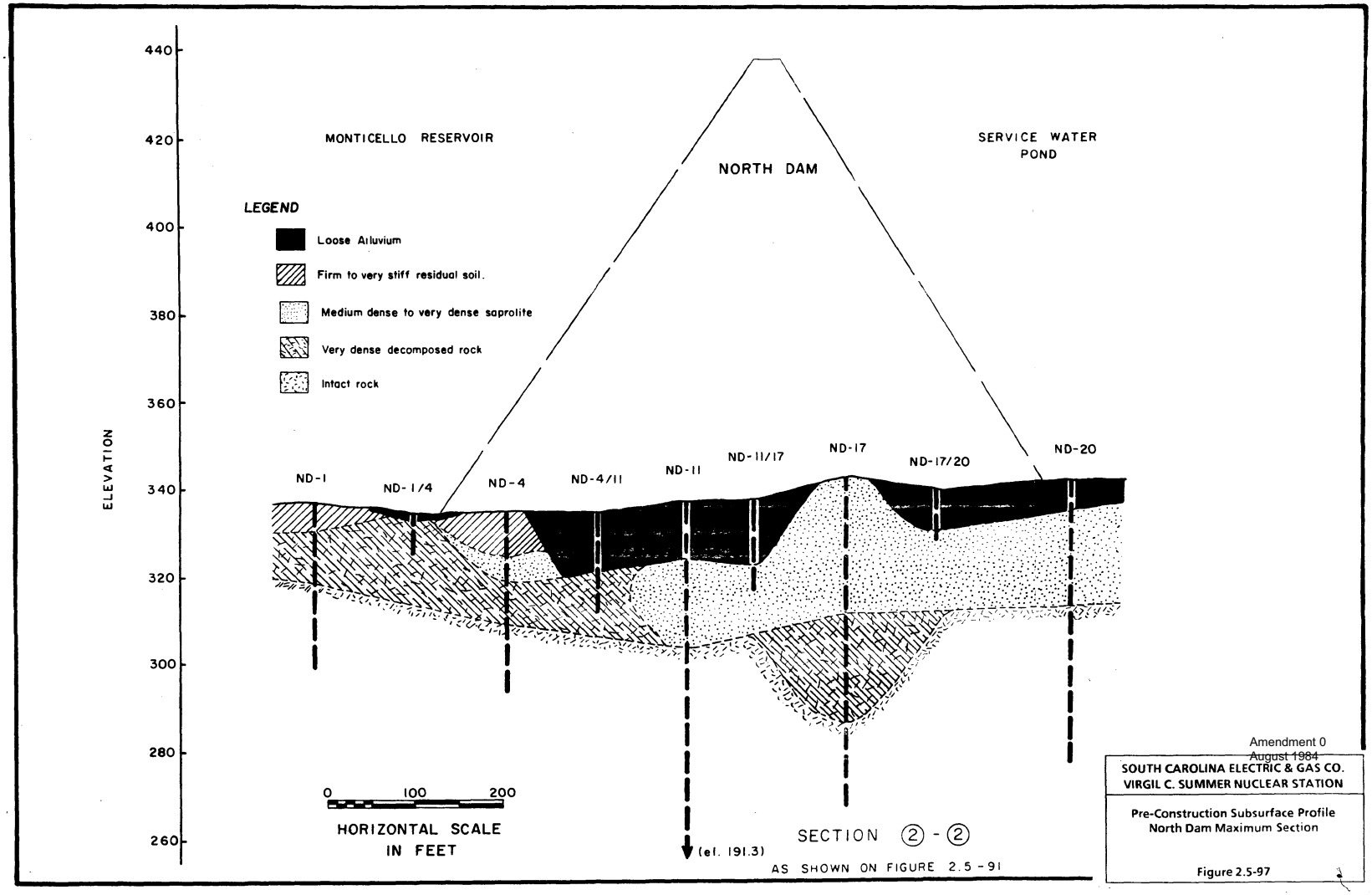
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Pre-Construction Subsurface Profile,
North Dam Axis

Figure 2.5-96

Figure 2.5-97

PRE-CONSTRUCTION SUBSURFACE PROFILE, NORTH DAM AXIS



Amendment 0
August 1984

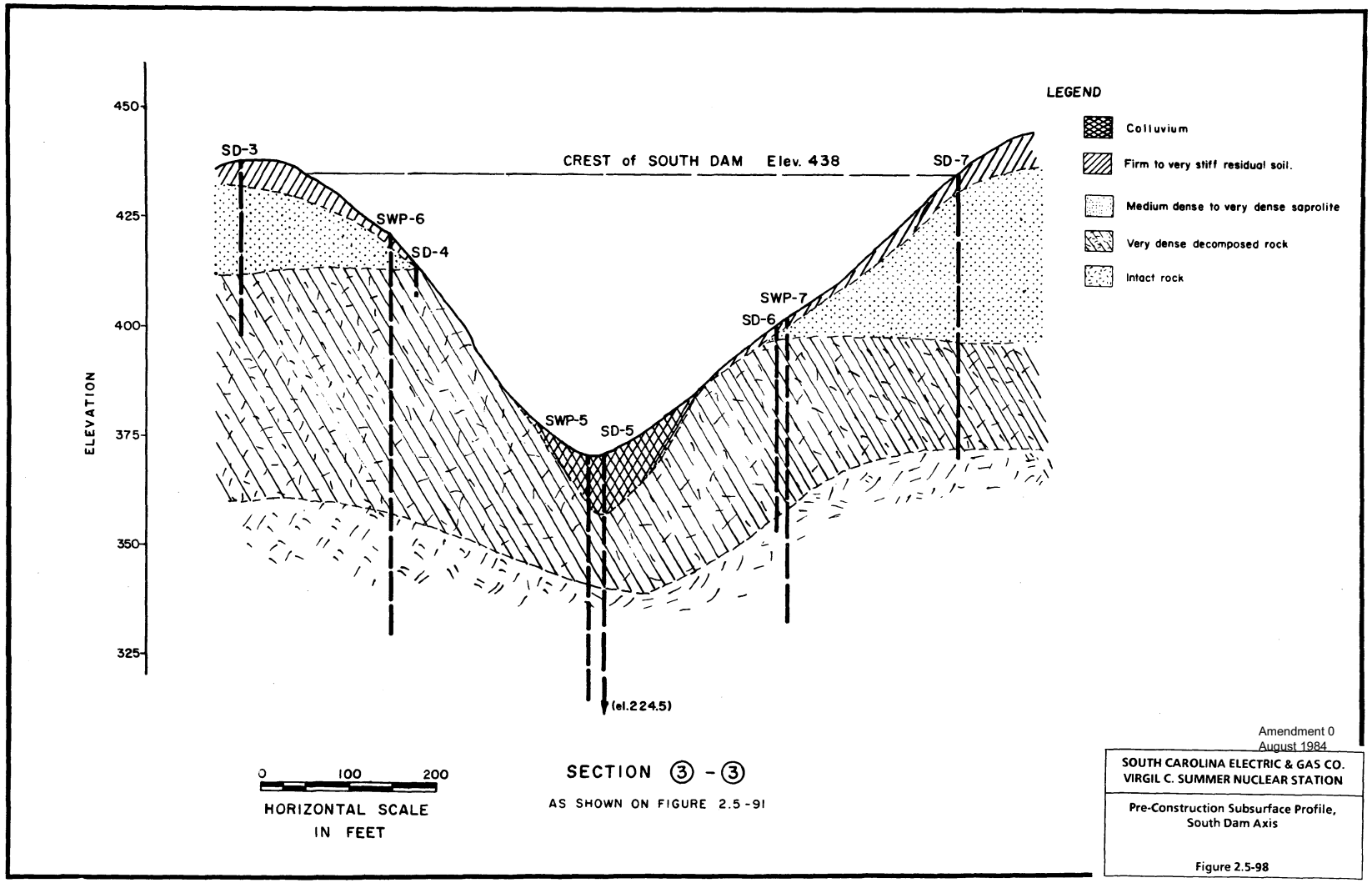
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Pre-Construction Subsurface Profile
North Dam Maximum Section

Figure 2.5-97

Figure 2.5-98

PRE-CONSTRUCTION SUBSURFACE PROFILE NORTH DAM MAXIMUM SECTION



Amendment 0
August 1984

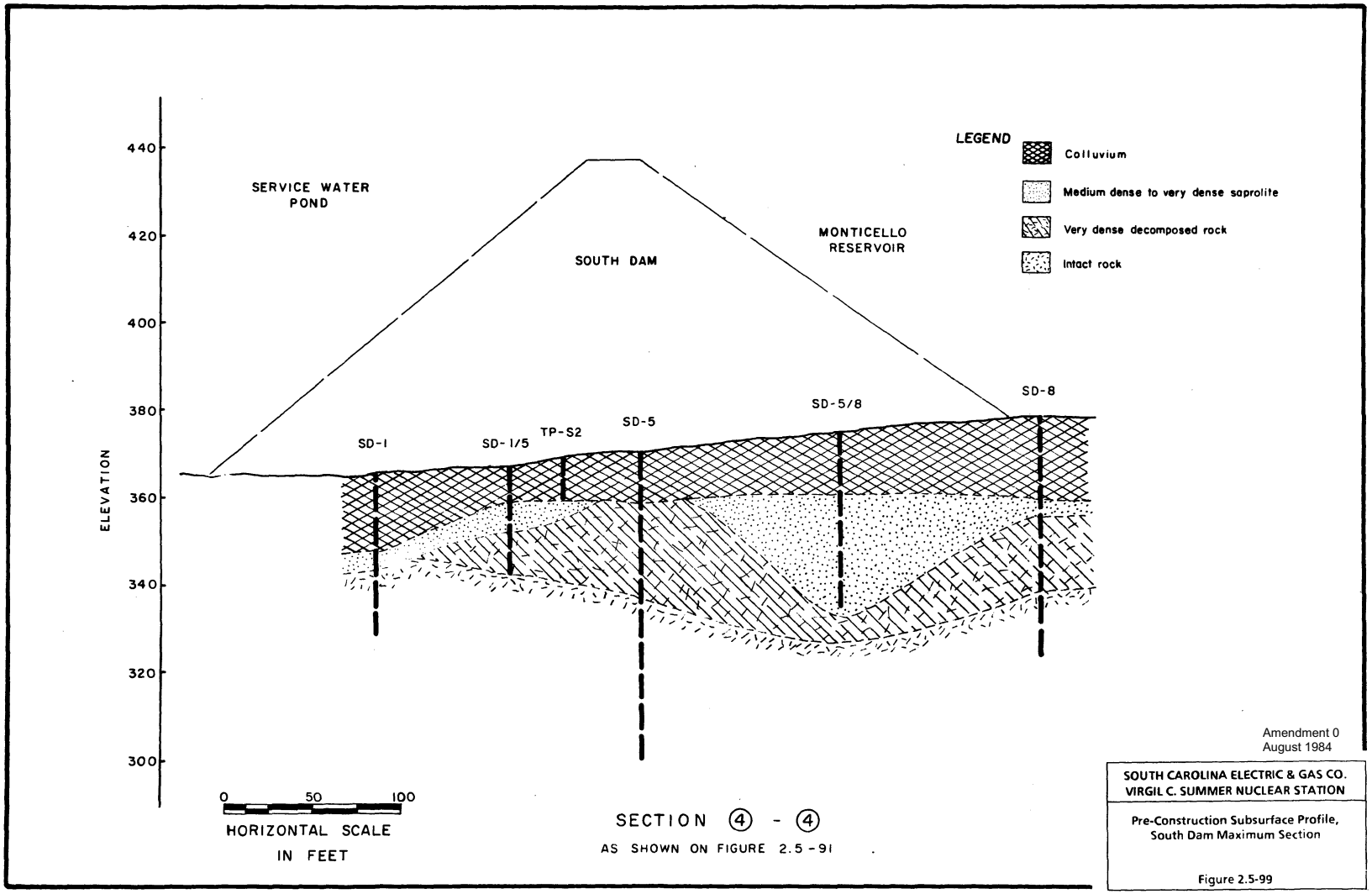
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Pre-Construction Subsurface Profile, South Dam Axis

Figure 2.5-98

Figure 2.5-99

PRE-CONSTRUCTION SUBSURFACE PROFILE, SOUTH DAM AXIS



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Pre-Construction Subsurface Profile, South Dam Maximum Section

Figure 2.5-99

Figure 2.5-100

PRE-CONSTRUCTION SUBSURFACE PROFILE, SOUTH DAM MAXIMUM SECTION

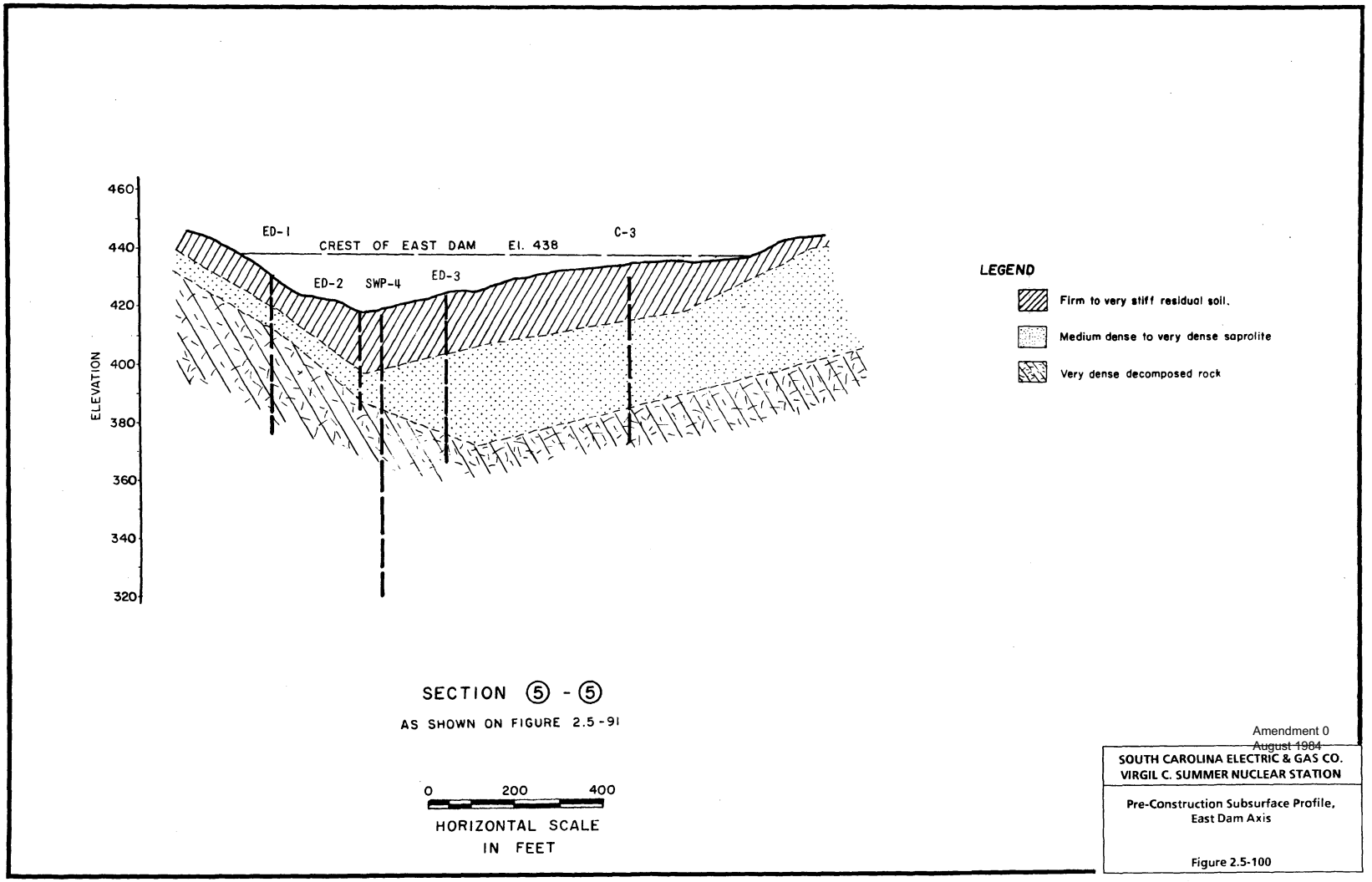


Figure 2.5-101

PRE-CONSTRUCTION SUBSURFACE PROFILE, EAST DAM AXIS

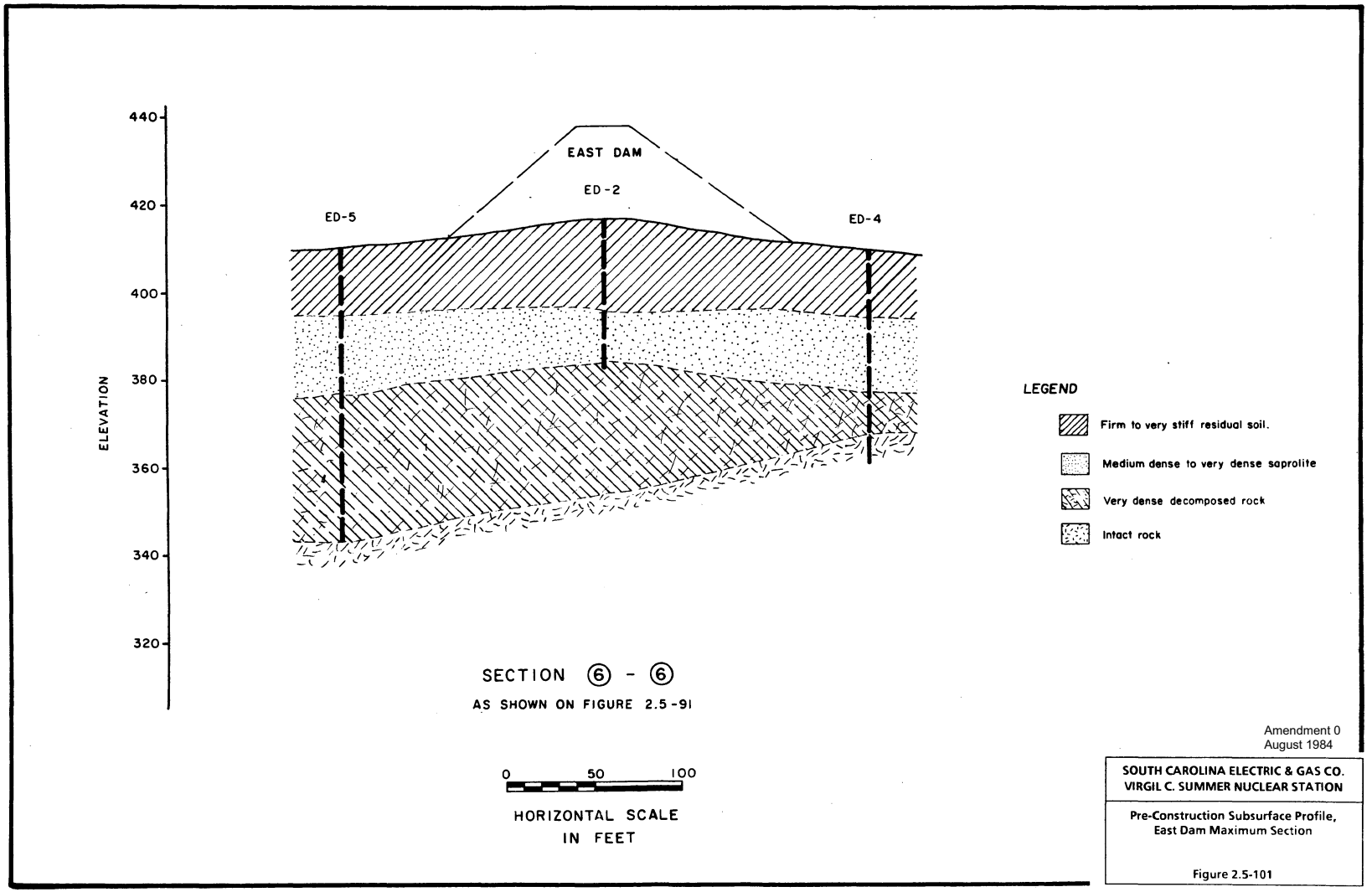


Figure 2.5-102

PRE-CONSTRUCTION SUBSURFACE PROFILE, EAST DAM MAXIMUM SECTION

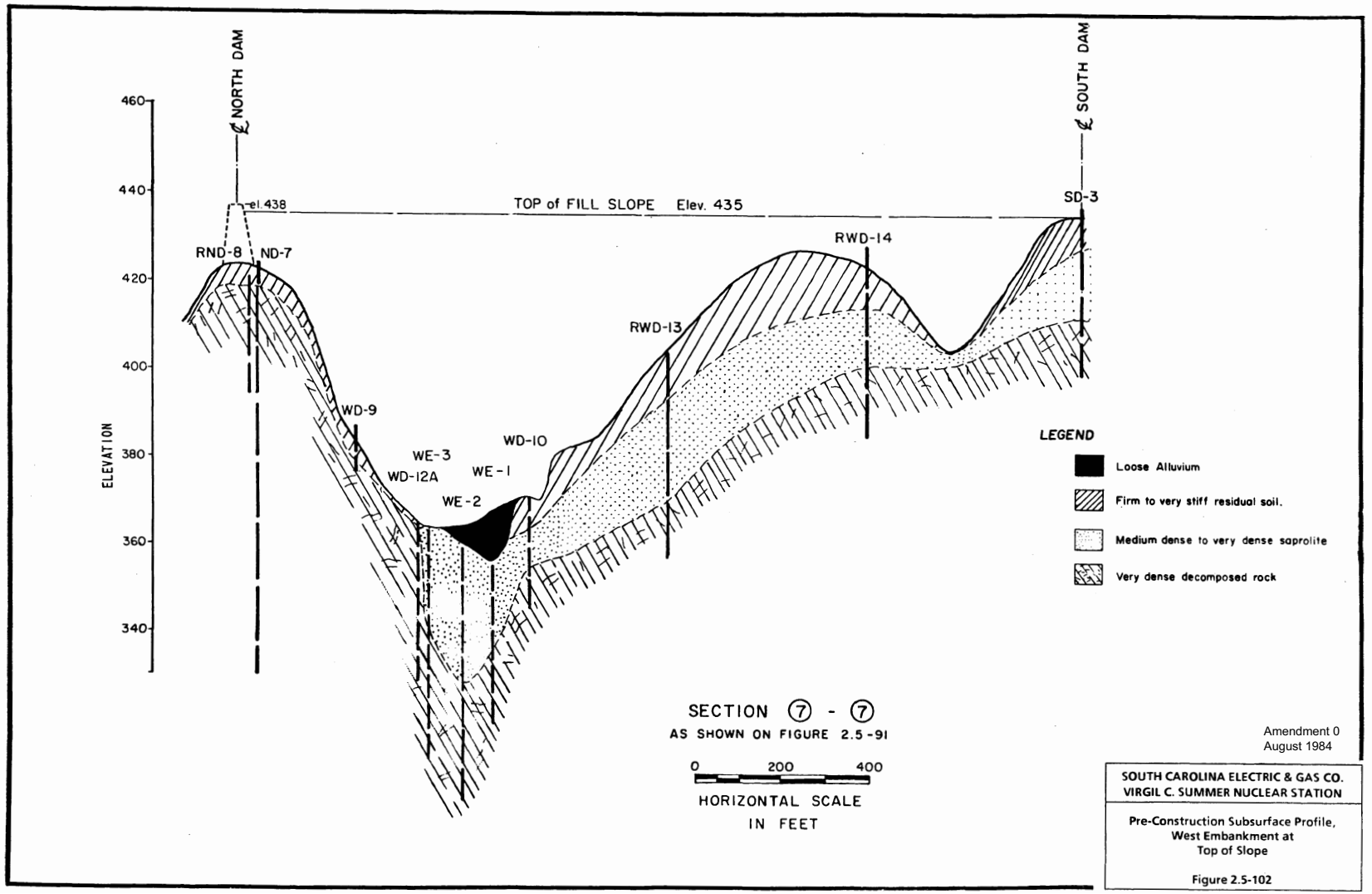
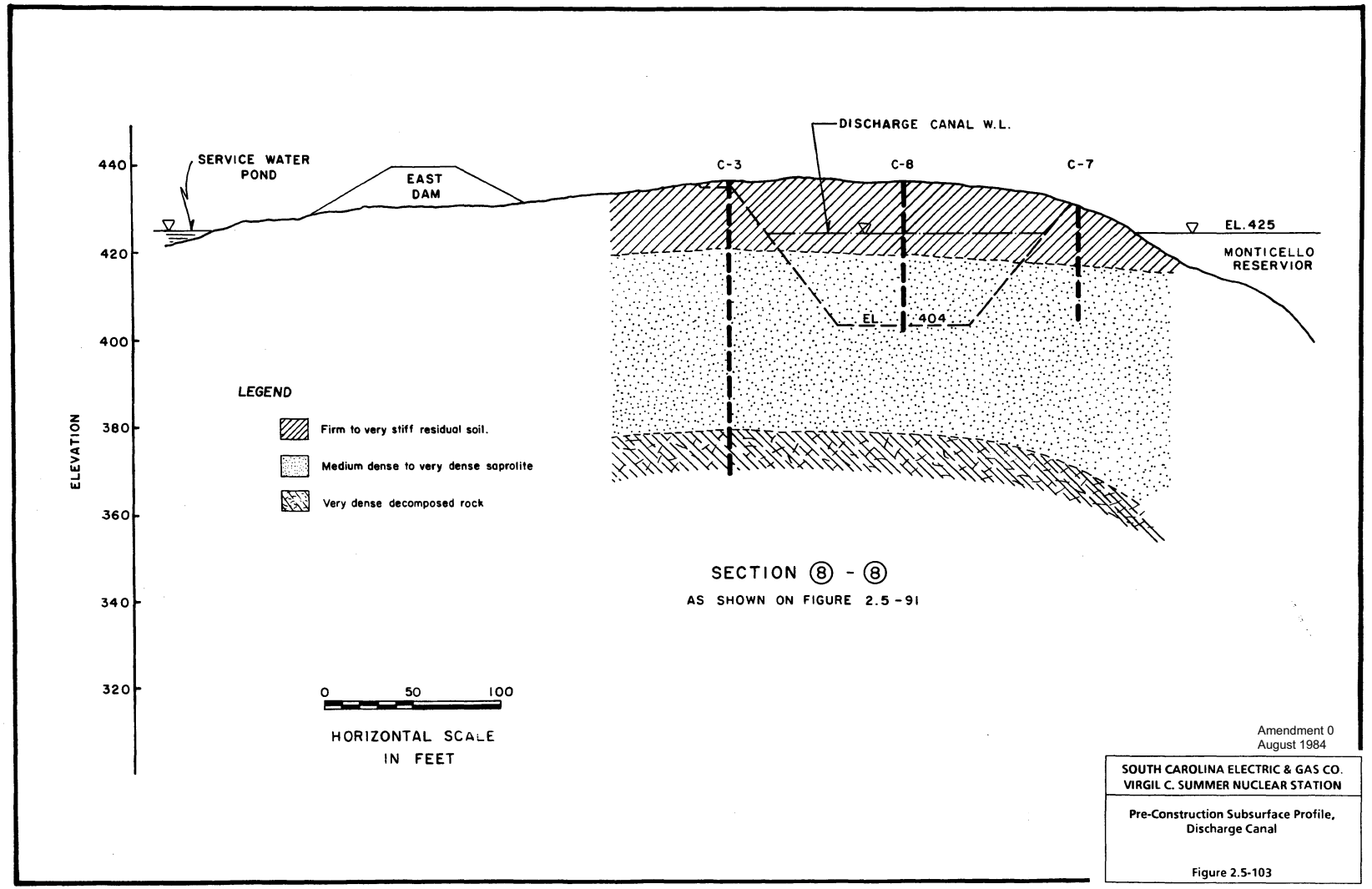


Figure 2.5-103

PRE-CONSTRUCTION PROFILE,
WEST EMBANKMENT AT TOP OF SLOPE

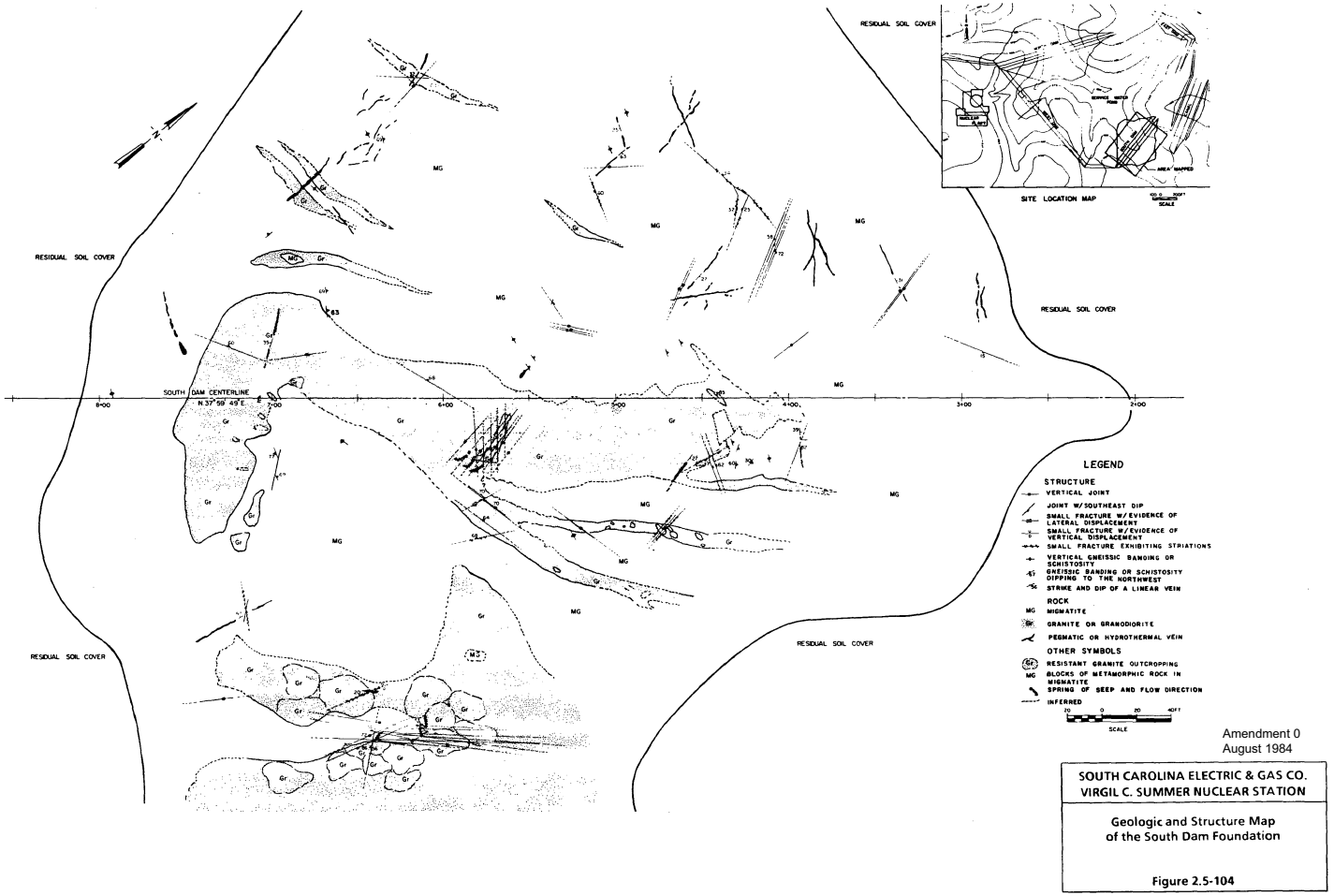


Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Pre-Construction Subsurface Profile, Discharge Canal
Figure 2.5-103

Figure 2.5-104

PRE-CONSTRUCTION SUBSURFACE PROFILE, DISCHARGE CANAL



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Geologic and Structure Map
of the South Dam Foundation

Figure 2.5-104

Figure 2.5-105

GEOLOGIC STRUCTURE MAP
OF THE SOUTH DAM FOUNDATION

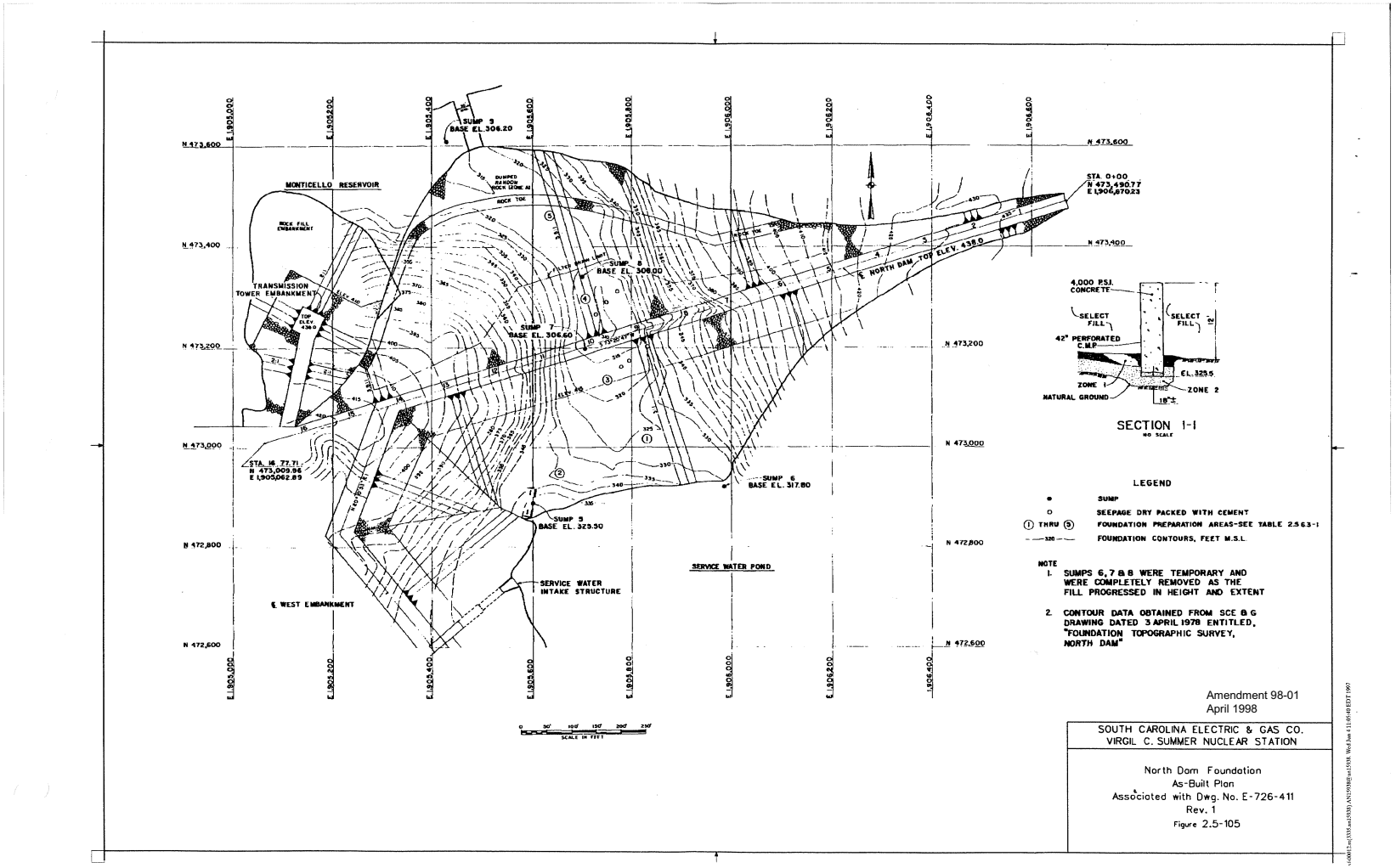
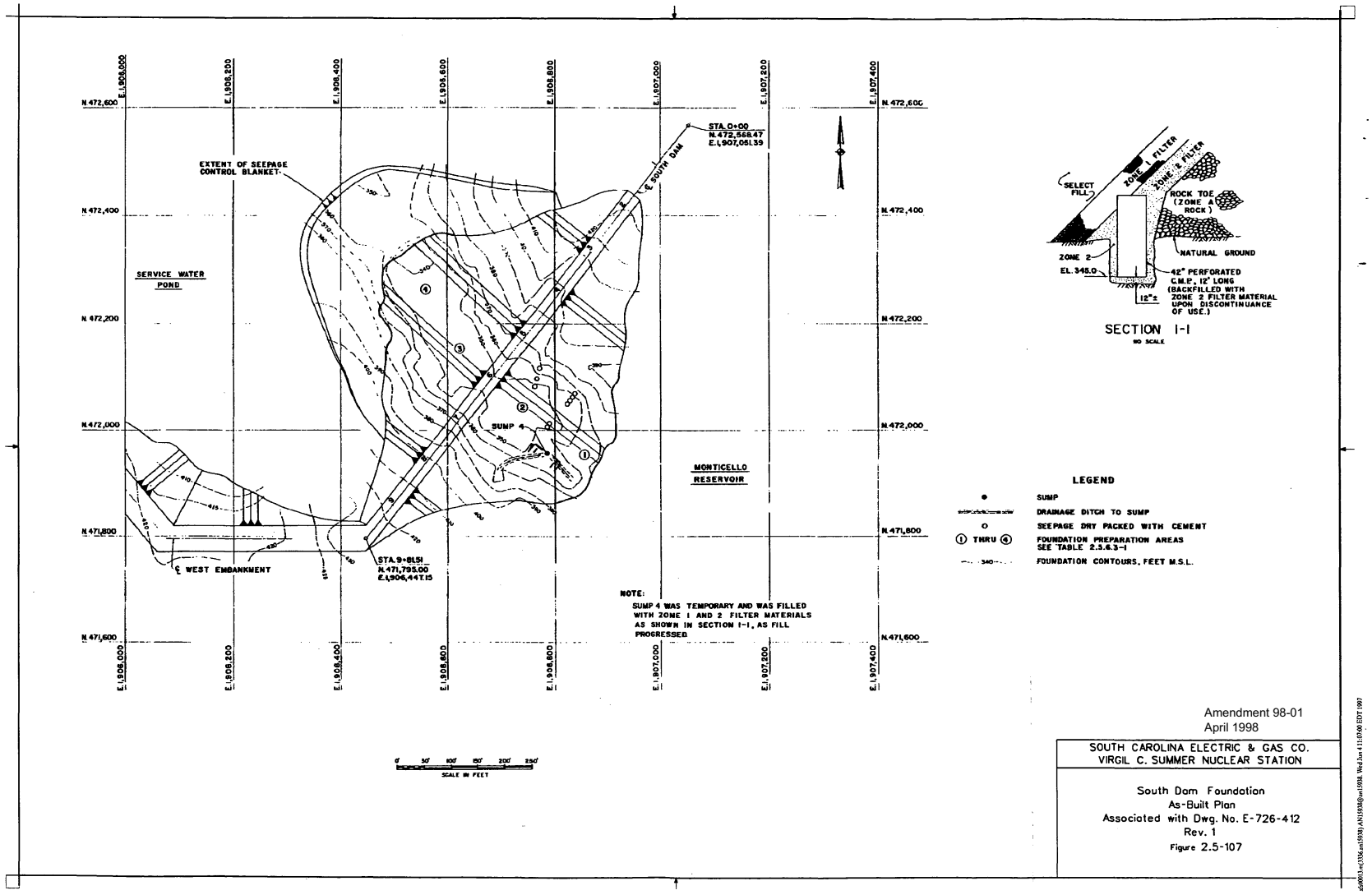


Figure 2.5-107

NORTH DAM FOUNDATION
AS-BUILT PLAN



Amendment 98-01
April 1998

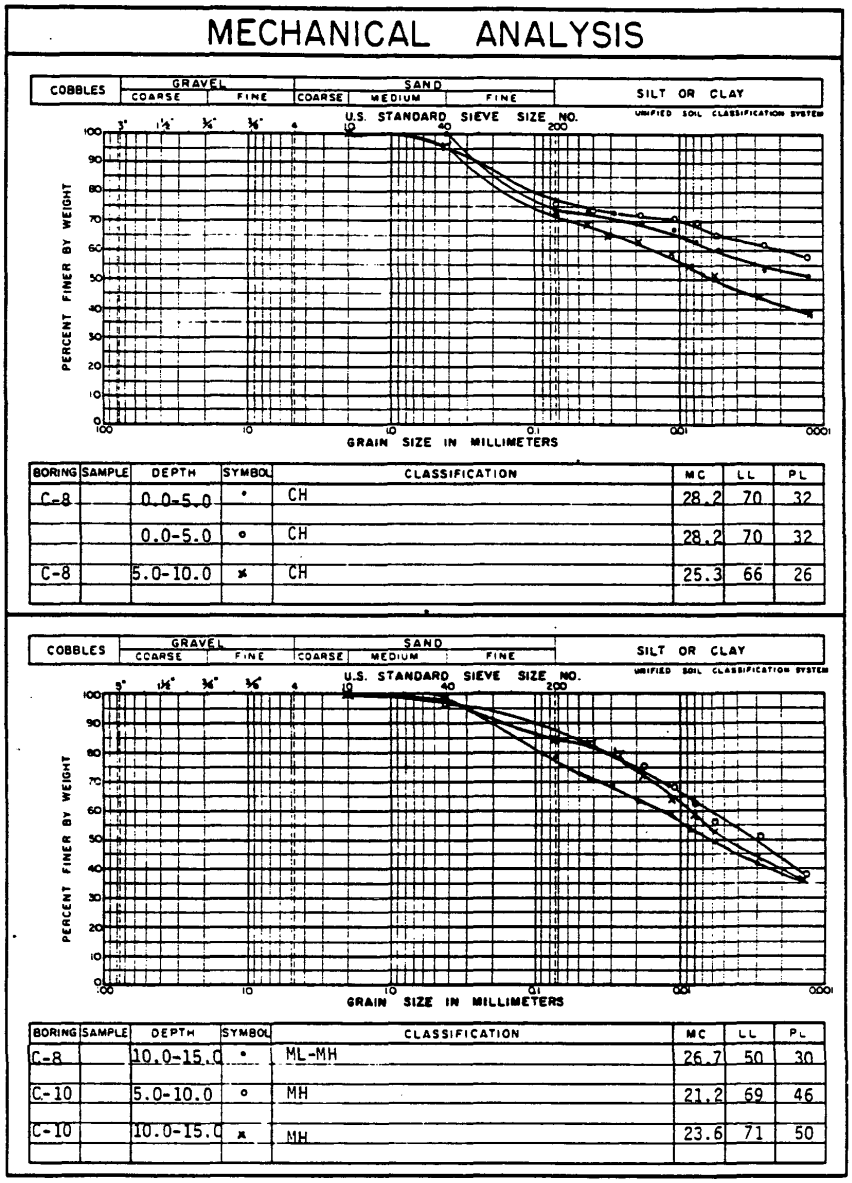
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

South Dam Foundation
As-Built Plan
Associated with Dwg. No. E-726-412
Rev. 1
Figure 2.5-107

Figure 2.5-108
DRAWING E-726-413
FSAR FIGURE REFERENCE

Figure 2.5-109
DRAWING E-726-416
FSAR FIGURE REFERENCE

Figure 2.5-110
GRAIN SIZE DISTRIBUTION CURVES
OF FOUNDATION SOILS (SHEET 1 OF 4)



BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
C-8		0.0-5.0	•	CH	28.2	70	32
		0.0-5.0	o	CH	28.2	70	32
C-8		5.0-10.0	x	CH	25.3	66	26

BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
C-8		10.0-15.0	•	ML-MH	26.7	50	30
C-10		5.0-10.0	o	MH	21.2	69	46
C-10		10.0-15.0	x	MH	23.6	71	50

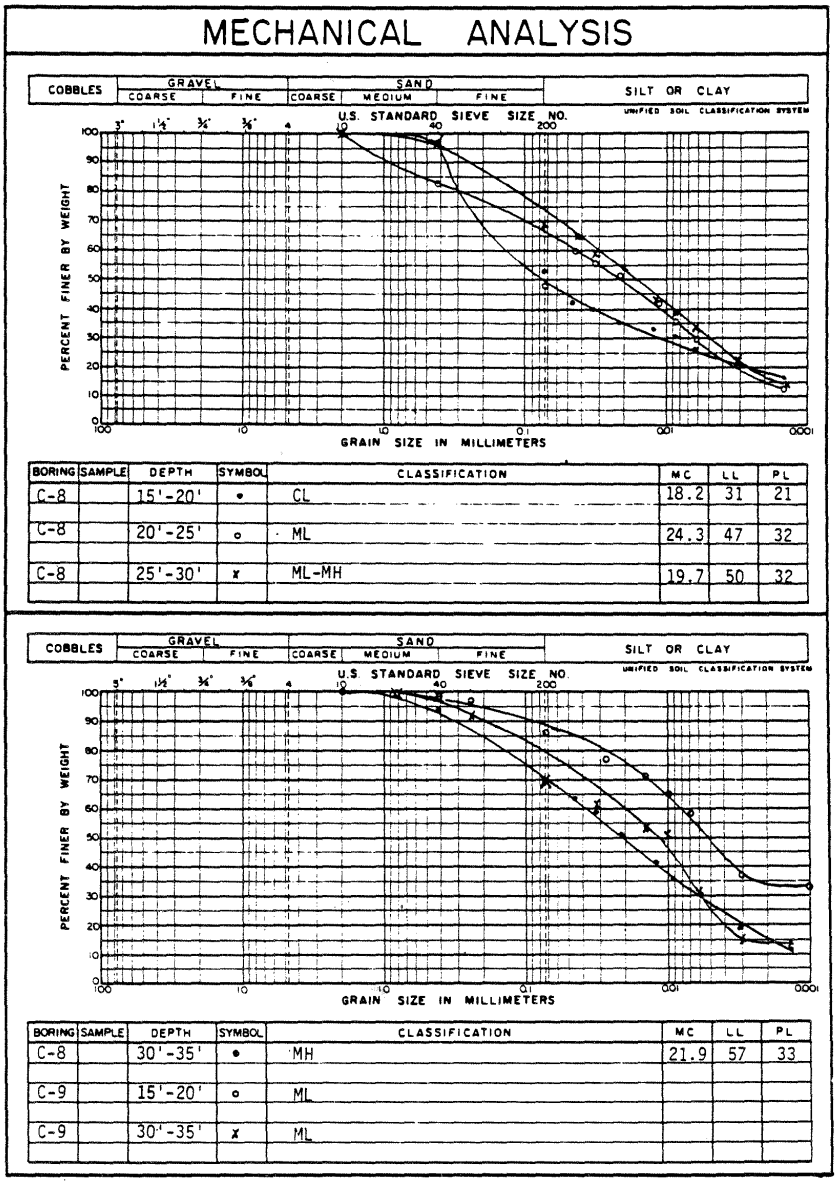
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
of Foundation Soils
(Sheet 1 of 4)

Figure 2.5-110

Amendment 0
August 1984

Figure 2.5-110
GRAIN SIZE DISTRIBUTION CURVES
OF FOUNDATION SOILS (SHEET 2 OF 4)



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

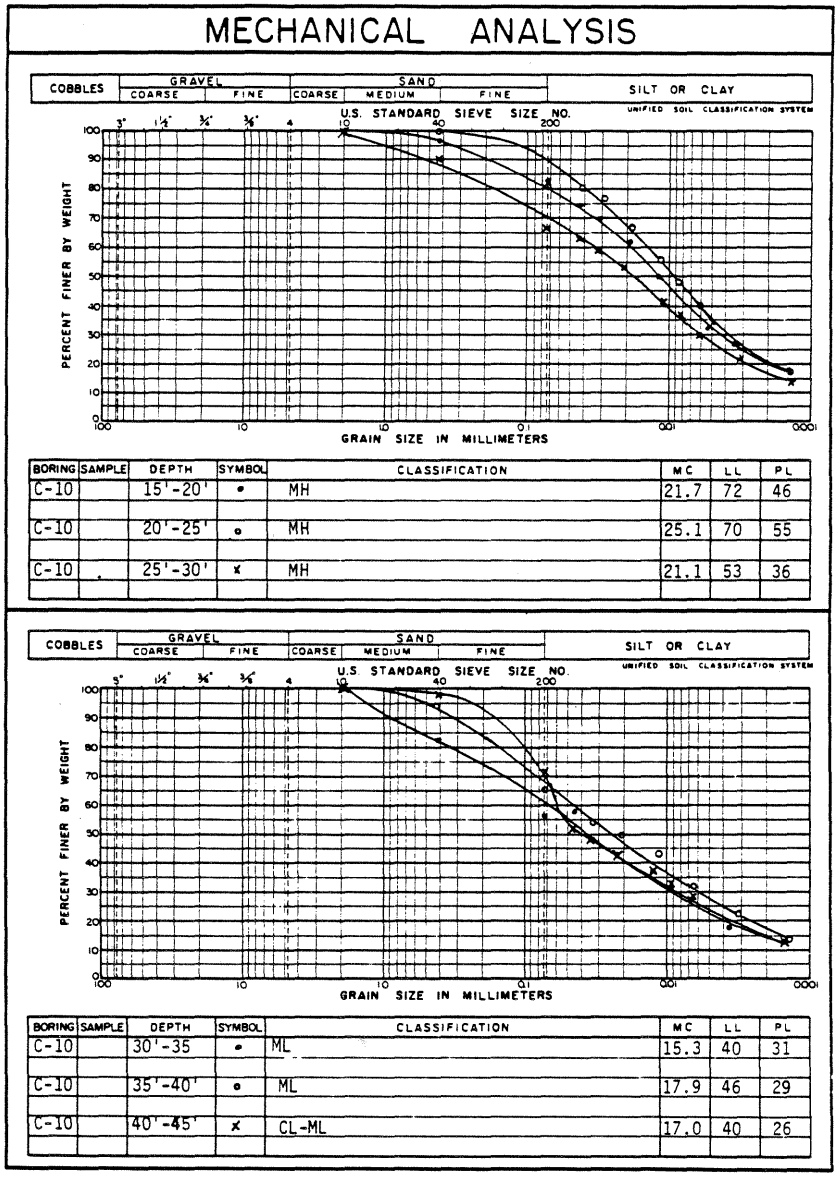
Grain Size Distribution Curves
of Foundation Soils
(Sheet 2 of 4)

Figure 2.5-110

Amendment 0
August 1984

Figure 2.5-110

GRAIN SIZE DISTRIBUTION CURVES OF FOUNDATION SOILS (SHEET 3 OF 4)



BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
C-10		15'-20'	•	MH	21.7	72	46
C-10		20'-25'	o	MH	25.1	70	55
C-10		25'-30'	x	MH	21.1	53	36

BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
C-10		30'-35	•	ML	15.3	40	31
C-10		35'-40'	o	ML	17.9	46	29
C-10		40'-45'	x	CL-ML	17.0	40	26

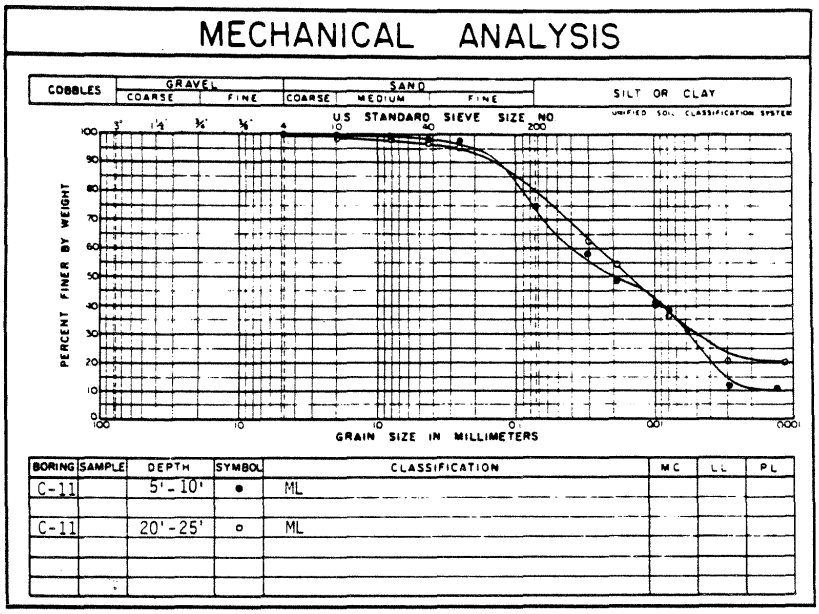
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves of Foundation Soils (Sheet 3 of 4)

Figure 2.5-110

Amendment 0
August 1984

Figure 2.5-110
GRAIN SIZE DISTRIBUTION CURVES OF FOUNDATION SOILS (SHEET 4 OF 4)



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves of Foundation Soils
(Sheet 4 of 4)

Figure 2.5-110

Figure 2.5-111
UNCONFINED COMPRESSION TEST
RESULTS ON FOUNDATION SOILS (SHEET 1 OF 9)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

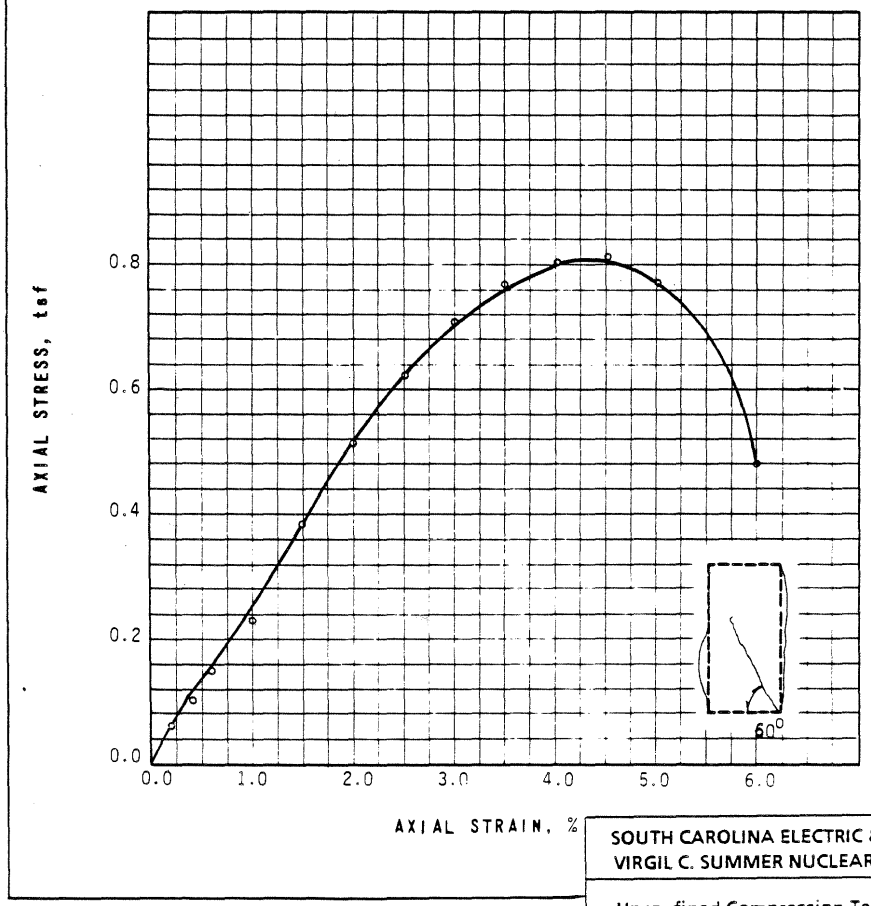
Boring No. ED-2 Sample No. S-1 Depth 2.0 - 4.0 Ft.

Description Red brown clayey silt (ML)

Moisture Content 27.3 % Dry Density 88.6 pcf

Liquid Limit 47 % Plastic Limit 36 %

Maximum Axial Stress 0.812 tsf @ 4.5 % Strain



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Foundation Soils
(Sheet 1 of 9)

Figure 2.5-111

Amendment 0
August 1984

Figure 2.5-111
UNCONFINED COMPRESSION TEST
RESULTS ON FOUNDATION SOILS (SHEET 2 OF 9)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

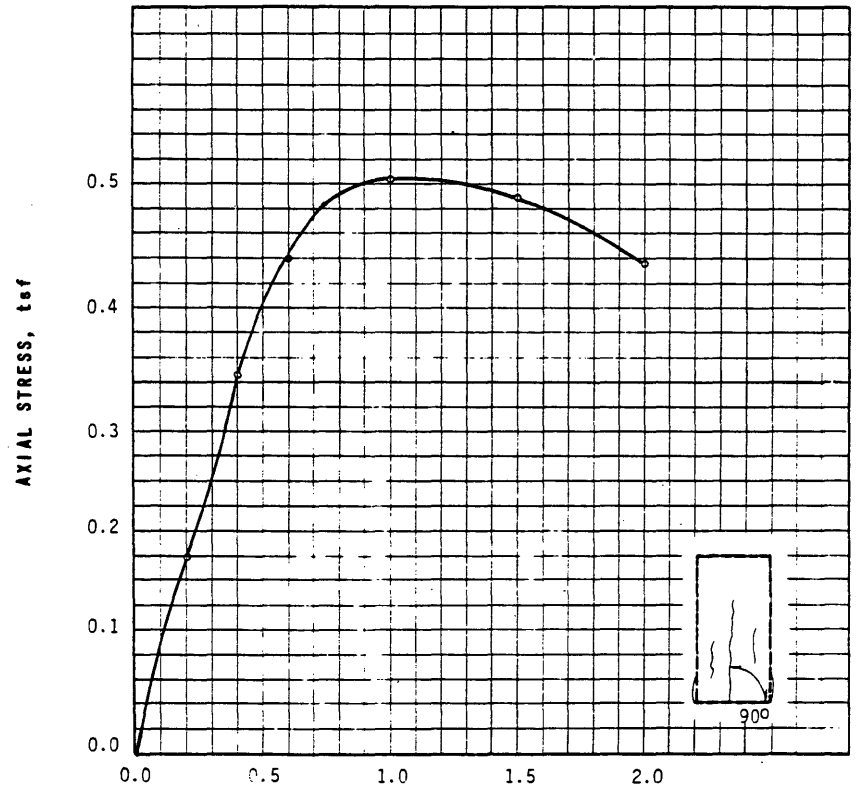
Boring No. ED-2 Sample No. S-3 Depth 7.0 - 9.5 Ft.

Description Red clayey silt (MH)

Moisture Content 42.9 % Dry Density 78.83 pcf

Liquid Limit 60 % Plastic Limit 51 %

Maximum Axial Stress 0.464 tsf @ 1.0 % Strain



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Foundation Soils
(Sheet 2 of 9)

Figure 2.5-111

Amendment 0
August 1984

Figure 2.5-111
UNCONFINED COMPRESSION TEST
RESULTS ON FOUNDATION SOILS (SHEET 3 OF 9)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

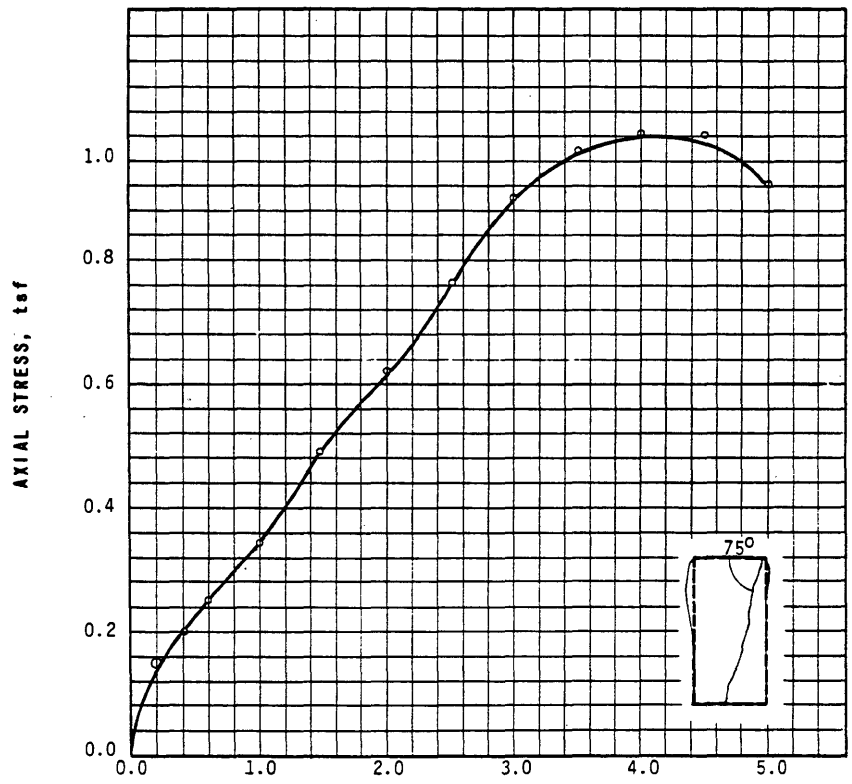
Boring No. WD-6 Sample No. S-1 Depth 2.0 - 4.2 Ft.

Description Red micaceous rooty fine sandy clayey silt (MH)

Moisture Content 32.1 % Dry Density 87.8 pcf

Liquid Limit 54 % Plastic Limit 37 %

Maximum Axial Stress 1.038 tsf @ 4.0 % Strain



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Foundation Soils
(Sheet 3 of 9)

Figure 2.5-111

Amendment 0
August 1984

Figure 2.5-111
UNCONFINED COMPRESSION TEST
RESULTS ON FOUNDATION SOILS (SHEET 4 OF 9)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

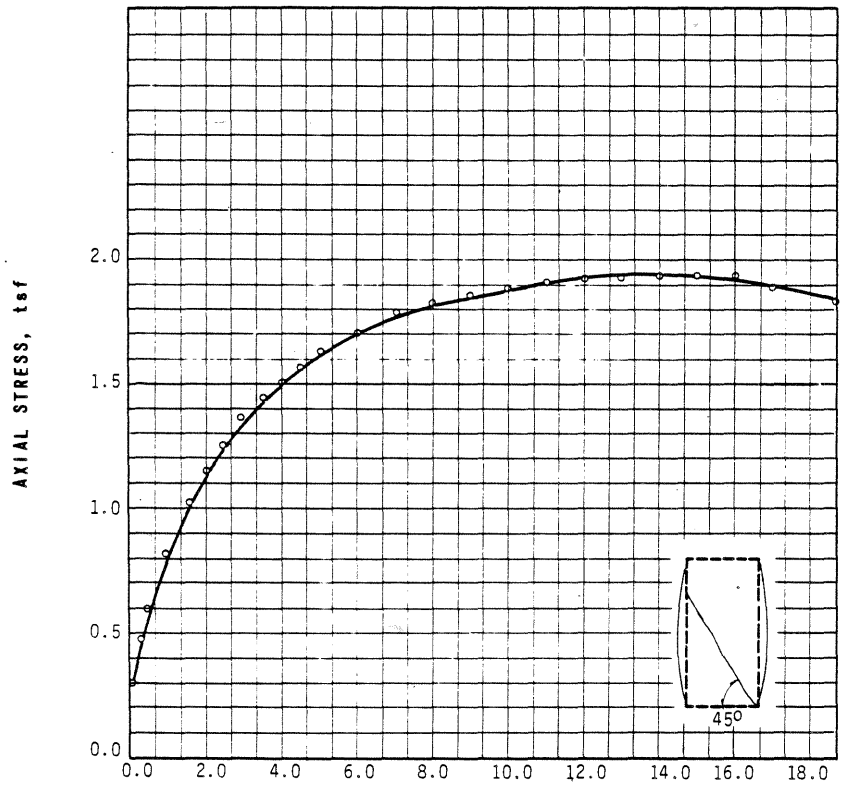
Boring No. WD-8 Sample No. S-1 Depth 2.0 - 4.8 Ft.

Description Red-brown micaceous sandy silty clay (some roots) (CH)

Moisture Content 32.7 % Dry Density 88.9 pcf

Liquid Limit 58 % Plastic Limit 24 %

Maximum Axial Stress 1.94 tsf @ 14.0 % Strain



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Foundation Soils
(Sheet 4 of 9)

Figure 2.5-111

Amendment 0
August 1984

Figure 2.5-111
UNCONFINED COMPRESSION TEST
RESULTS ON FOUNDATION SOILS (SHEET 5 OF 9)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

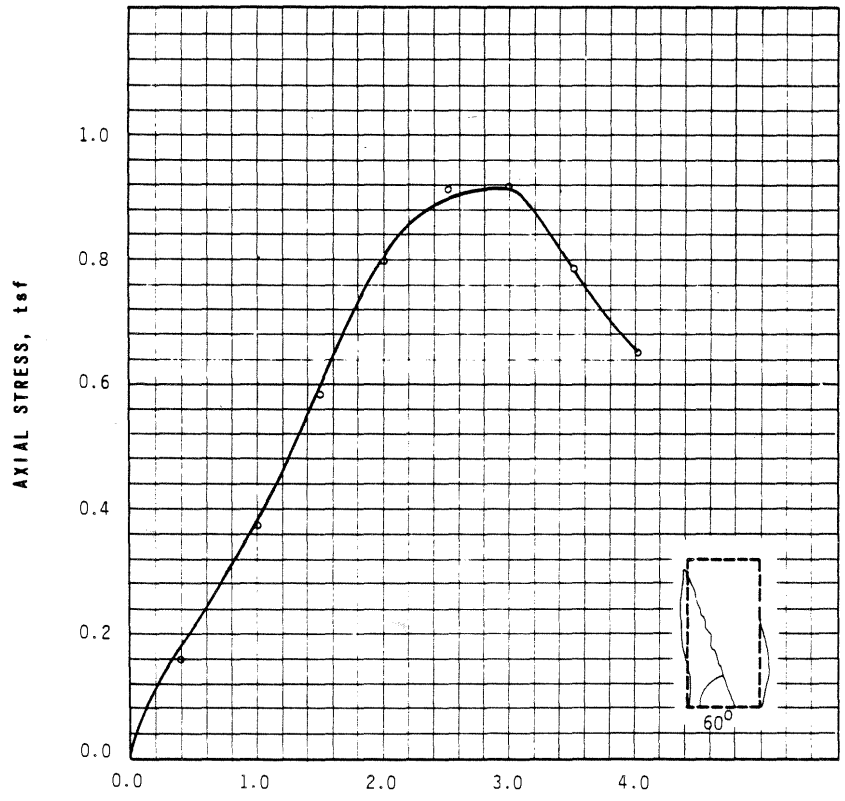
Boring No. SS-1 Sample No. S-1 Depth 2.0 - 3.9 Ft.

Description Red clayey silt with root inclusions (MH)

Moisture Content 36.1 % Dry Density 83.5 pcf

Liquid Limit 55 % Plastic Limit 43 %

Maximum Axial Stress 0.917 tsf @ 3.0 % Strain



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Foundation Soils
(Sheet 5 of 9)

Figure 2.5-111

Amendment 0
August 1984

Figure 2.5-111
UNCONFINED COMPRESSION TEST
RESULTS ON FOUNDATION SOILS (SHEET 6 OF 9)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

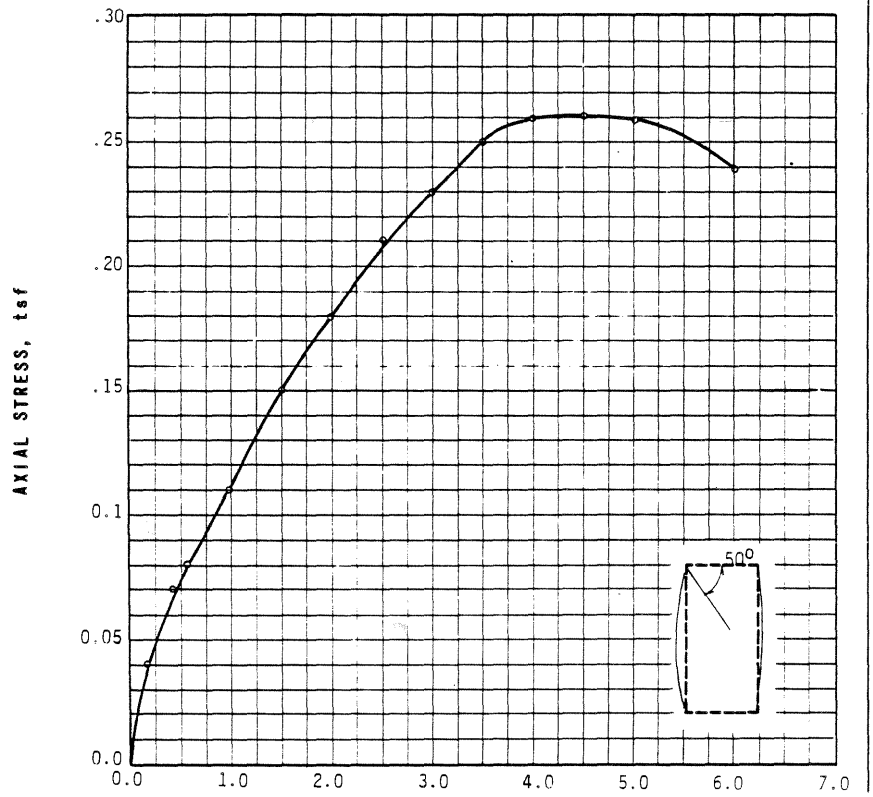
Boring No. SS-5 Sample No. S-2 Depth 10.0- 12.5 Ft.

Description Red-brown micaceous fine sandy clayey silt (MH)

Moisture Content 44.0 % Dry Density 72.1 pcf

Liquid Limit 59 % Plastic Limit 40 %

Maximum Axial Stress 0.26 tsf @ 4.0 % Strain



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Foundation Soils
(Sheet 6 of 9)

Figure 2.5-111

Amendment 0
August 1984

Figure 2.5-111
UNCONFINED COMPRESSION TEST
RESULTS ON FOUNDATION SOILS (SHEET 7 OF 9)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

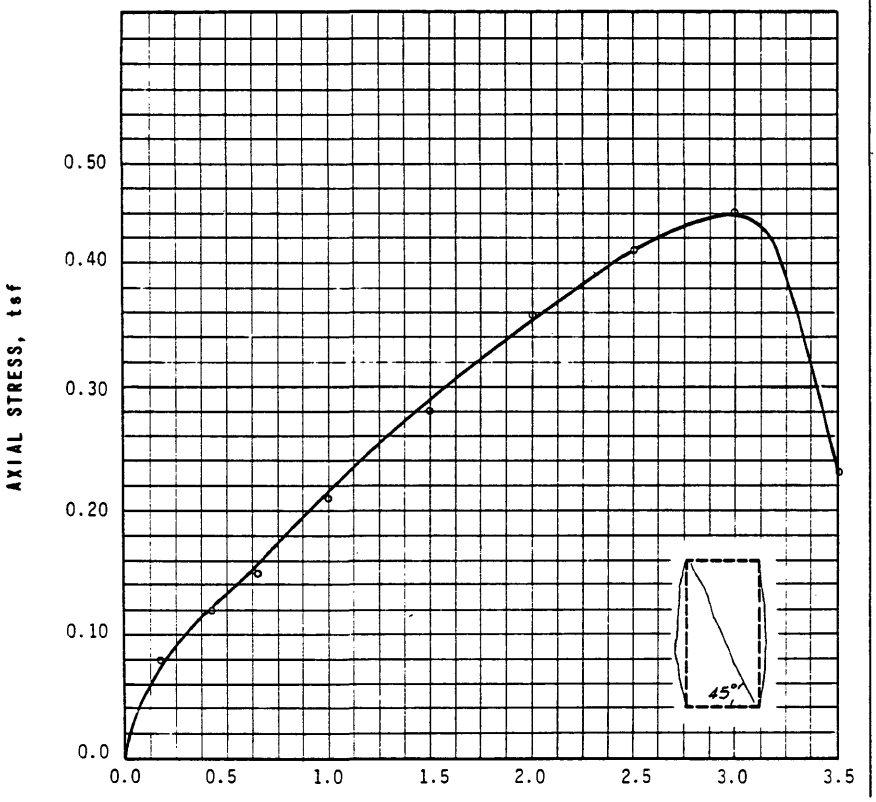
Boring No. SS-5 Sample No. S-3 Depth 18.0 - 20.6 Ft.

Description Light red-brown highly micaceous clayey sandy silt (ML)

Moisture Content 24.5 % Dry Density 91.1 pcf

Liquid Limit 42 % Plastic Limit 42 %

Maximum Axial Stress 0.44 tsf @ 3.0 % Strain



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Foundation Soils
(Sheet 7 of 9)

Figure 2.5-111

Amendment 0
August 1984

Figure 2.5-111

UNCONFINED COMPRESSION TEST
RESULTS ON FOUNDATION SOILS (SHEET 8 OF 9)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

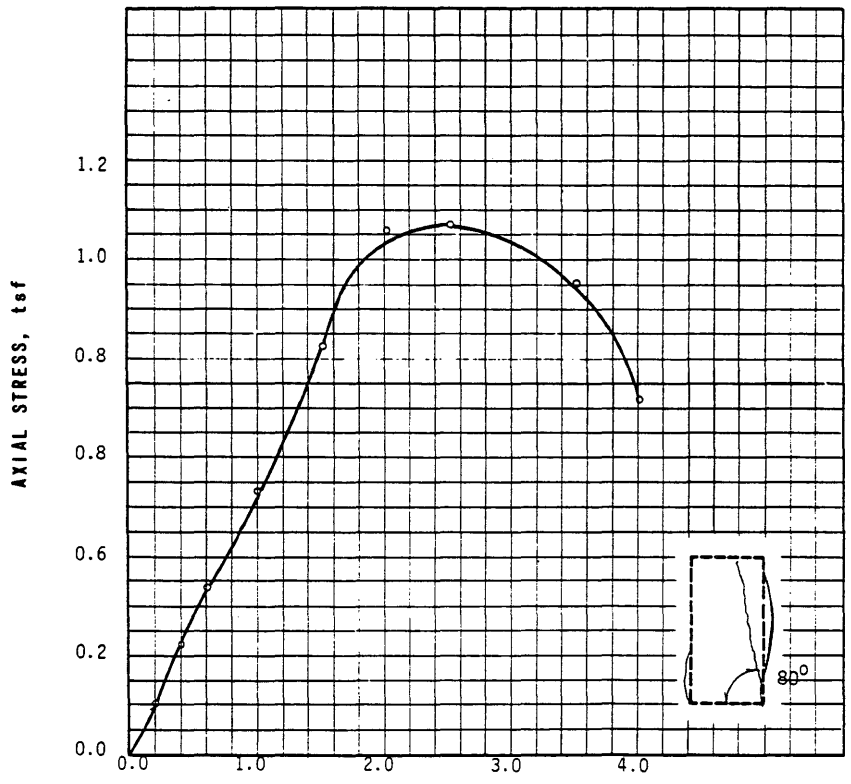
Boring No. C-3 Sample No. S-1 Depth 2.0 - 4.0 Ft.

Description Red silty clay (CL)

Moisture Content 22.9 % Dry Density 102.0 pcf

Liquid Limit 49 % Plastic Limit 20 %

Maximum Axial Stress 1.067 tsf @ 2.5 % Strain



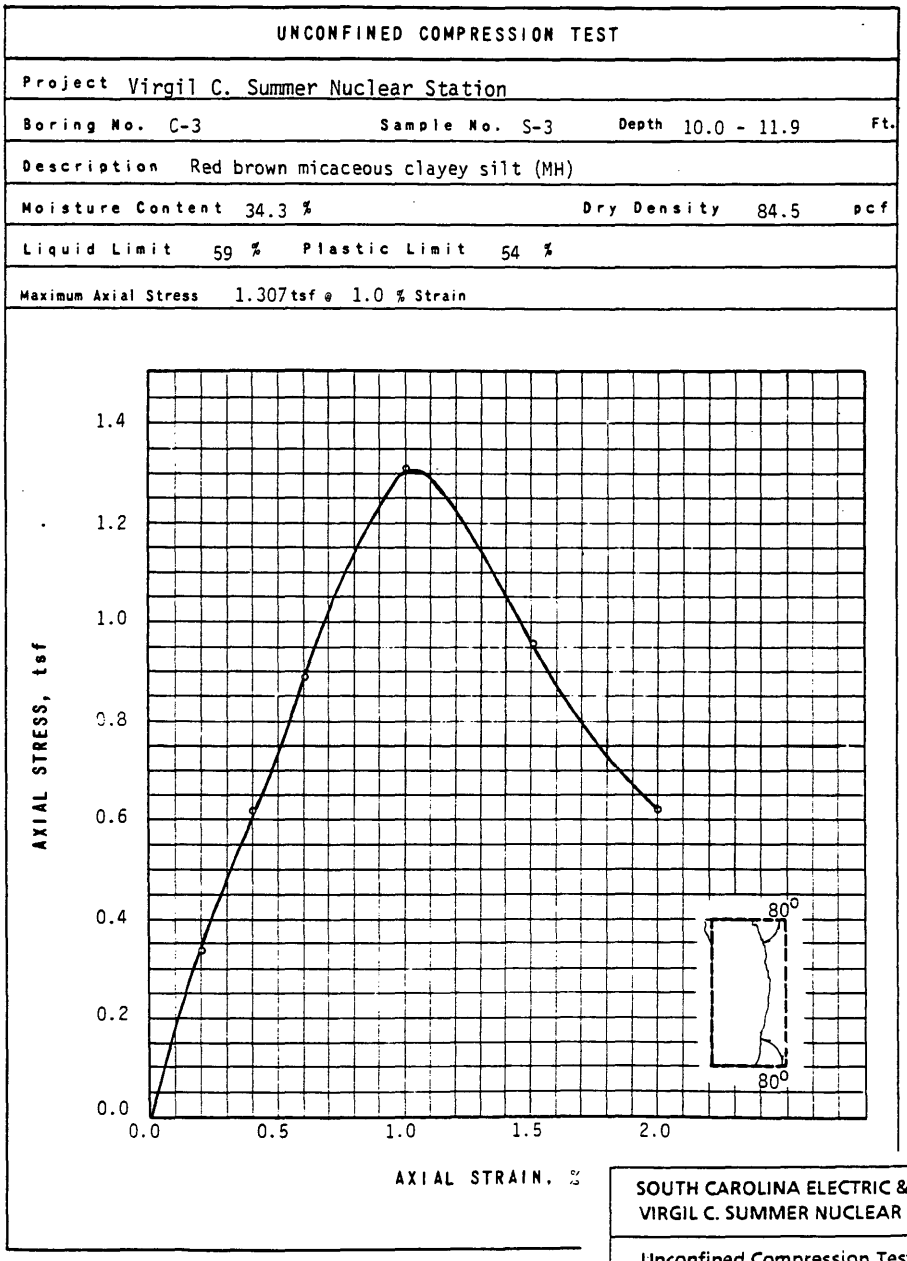
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Foundation Soils
(Sheet 8 of 9)

Figure 2.5-111

Amendment 0
August 1984

Figure 2.5-111
UNCONFINED COMPRESSION TEST
RESULTS ON FOUNDATION SOILS (SHEET 9 OF 9)



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Foundation Soils
(Sheet 9 of 9)

Figure 2.5-111

Amendment 0
August 1984

Figure 2.5-112

UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 1 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

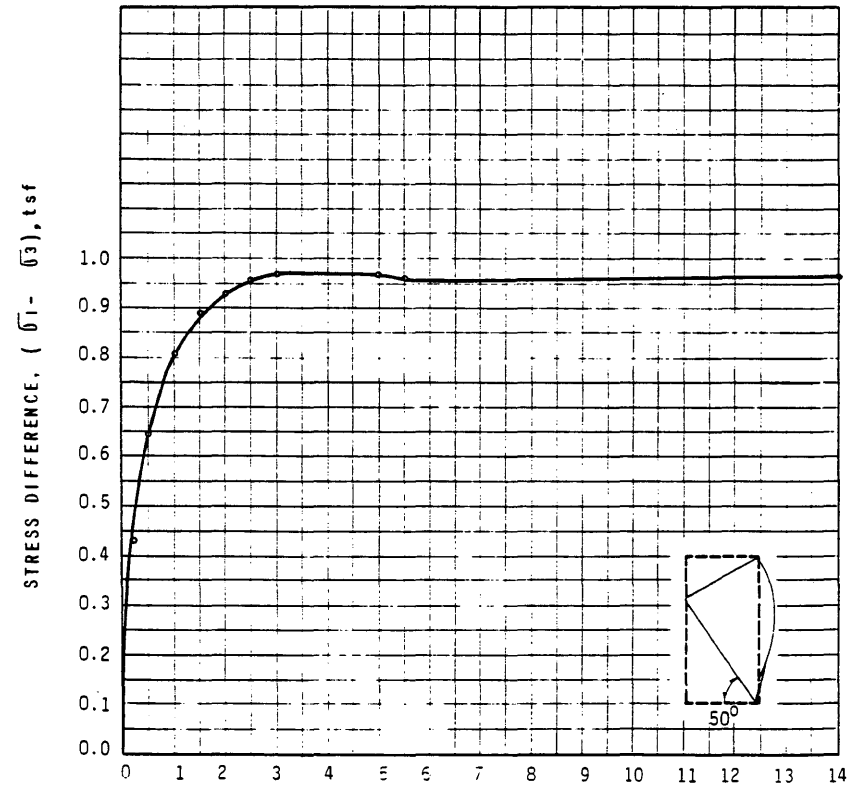
Boring No. SD-9B Sample No. ST-1 Depth 4.0 - 6.5 Ft

Description Red-brown fine sandy clayey silt (ML)

Moisture Content 29.0 % (after saturation) Dry Density 87.5 pcf

Liquid Limit 38 % Plastic Limit 26 % Relative Density - %

$(\sigma_1 - \sigma_3)$ max.= 0.97 tsf at 3.0 % Strain Chamber Pressure, σ_c = 17 psi



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 1 of 13)

Figure 2.5-112

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Figure 2.5-112
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 2 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

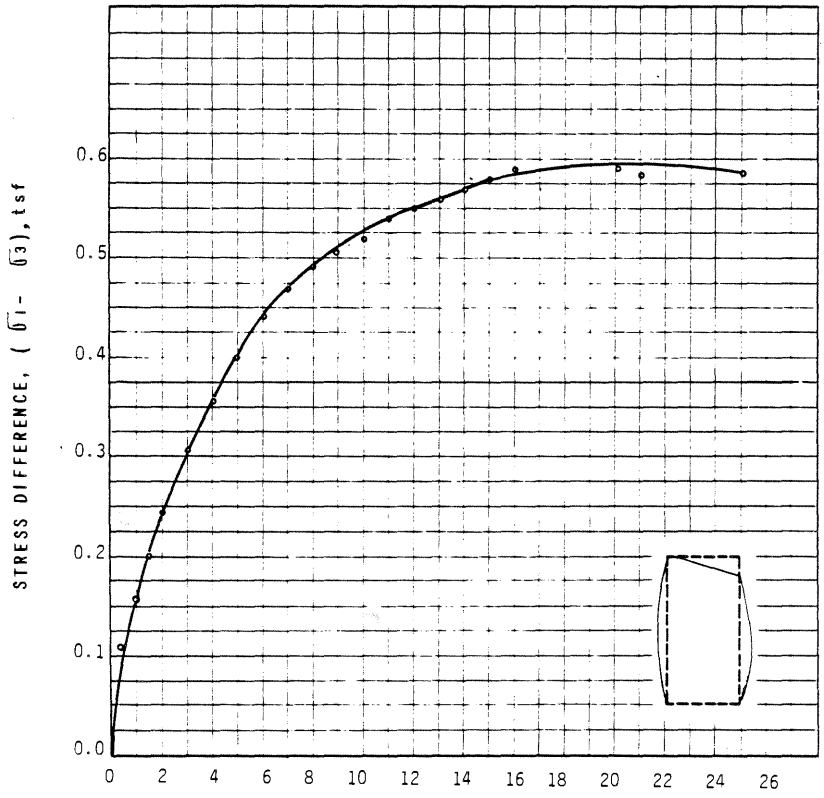
Boring No. SD-9B Sample No. ST-2 Depth 7.0 - 9.5 Ft

Description Red brown clayey silty medium to fine sand, trace coarse sand (SM-SC)

Moisture Content 24.1 % (after saturation) Dry Density 99.9 pcf

Liquid Limit 26 % Plastic Limit 19 % Relative Density - %

$(\sigma_1 - \sigma_3)$ max.= 0.59 tsf at 16.0 % Strain Chamber Pressure, σ_c = 17 psi



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 2 of 13)

Figure 2.5-112

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Figure 2.5-112
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 3 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

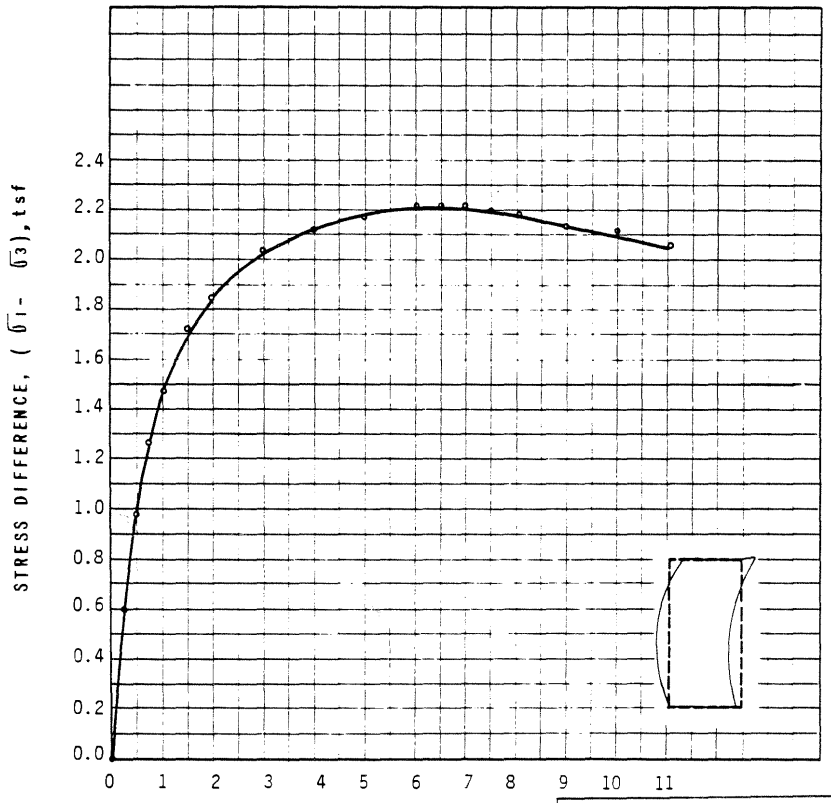
Boring No. SD-9B Sample No. ST-3 Depth 10.0-12.5 Ft

Description Mottled gray and brown clayey silty medium to fine sand (SM)

Moisture Content 14.8 % (after saturation) Dry Density 110.8 pcf

Liquid Limit 21 % Plastic Limit 17 % Relative Density - %

$(\sigma_1 - \sigma_3)$ max.= 2.2 tsf at 6.0 % Strain Chamber Pressure, σ_c = 17 psi



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 3 of 13)

Figure 2.5-112

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Figure 2.5-112
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 4 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

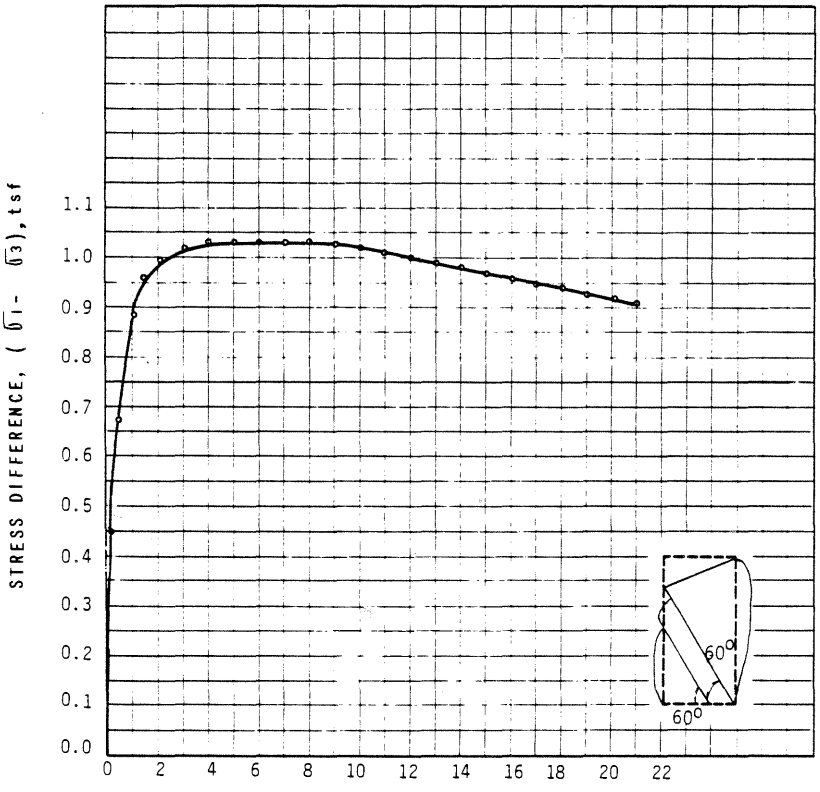
Boring No. SD-9D Sample No. ST-1 Depth 4.0 - 6.5 Ft

Description Dark brown sandy silty clay, trace roots (CL)

Moisture Content 23.8 % (after saturation) Dry Density 95.6 pcf

Liquid Limit 31 % Plastic Limit 20 % Relative Density - %

$(\sigma_1 - \sigma_3)$ max.= 1.03 tsf at 4.0 % Strain Chamber Pressure, σ_c = 17 psi



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 4 of 13)

Figure 2.5-112

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Figure 2.5-112
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 5 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

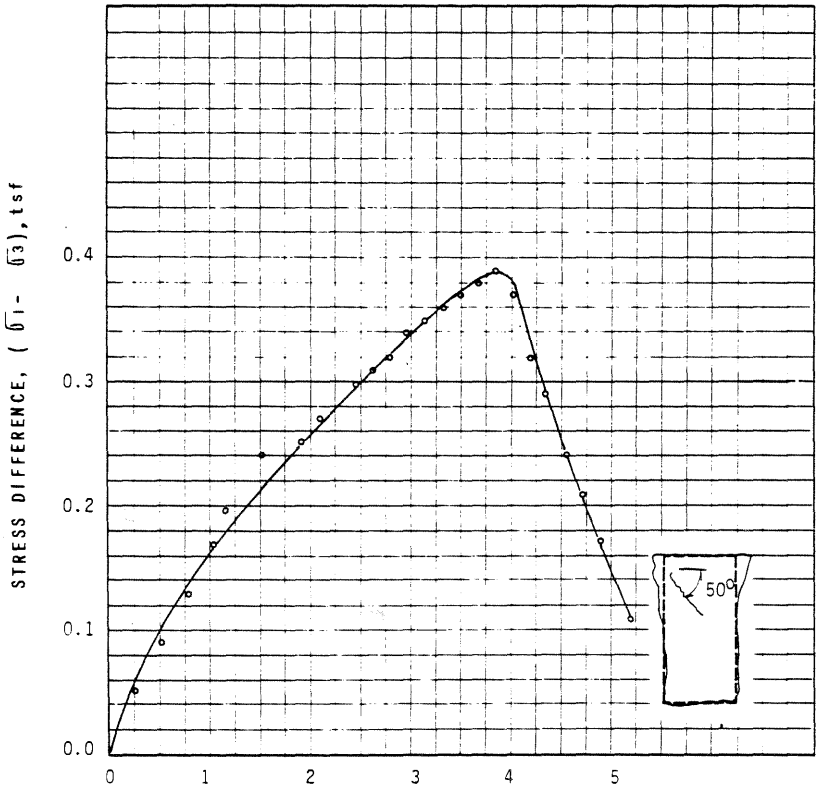
Boring No. ED-2 Sample No. S-7 Depth 17.0 - 19.5 Ft

Description Red-brown micaceous clayey silt, trace fine sand (MH)

Moisture Content 56.0 % (after saturation) Dry Density 67.5 pcf

Liquid Limit 54 % Plastic Limit 48 % Relative Density - %

$(\sigma_1 - \sigma_3)$ max.= 0.39 tsf at 3.85 % Strain Chamber Pressure, σ_c = 1.35 tsf



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 5 of 13)

Figure 2.5-112

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Figure 2.5-112

UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 6 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

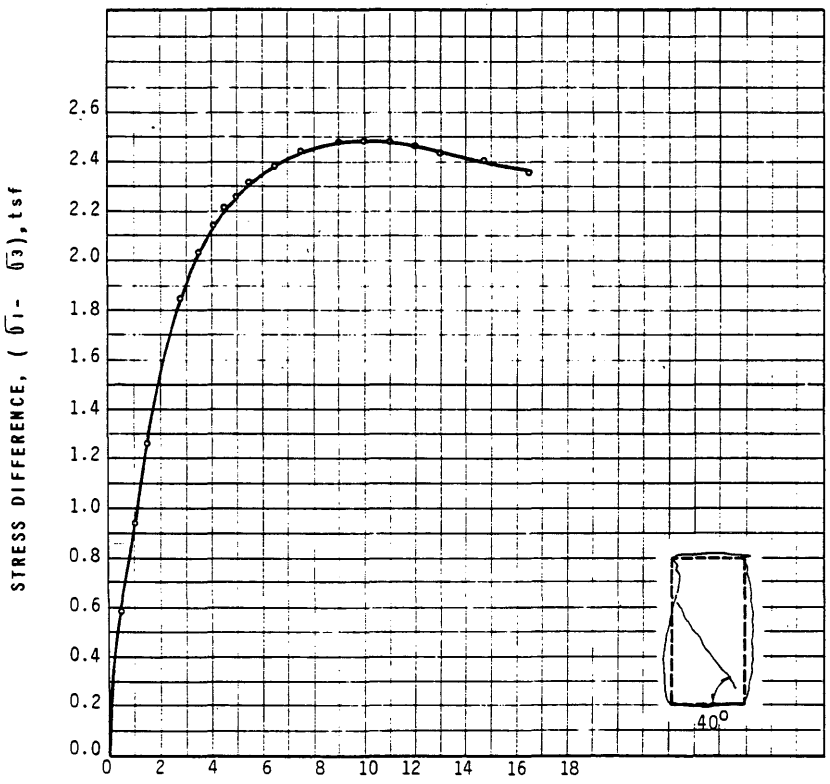
Boring No. ED-2 Sample No. S-11 Depth 27.0 - 29.1 Ft

Description Brown micaceous clayey sandy silt (ML-MH)

Moisture Content 33.8 % (after saturation) Dry Density 87.3 pcf

Liquid Limit 40 % Plastic Limit 40 % Relative Density - %

$(\sigma_1 - \sigma_3)$ max.= 2.49 tsf at 10.5 % Strain Chamber Pressure, σ_c = 1.65 tsf



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 6 of 13)

Figure 2.5-112

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Figure 2.5-112
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 7 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

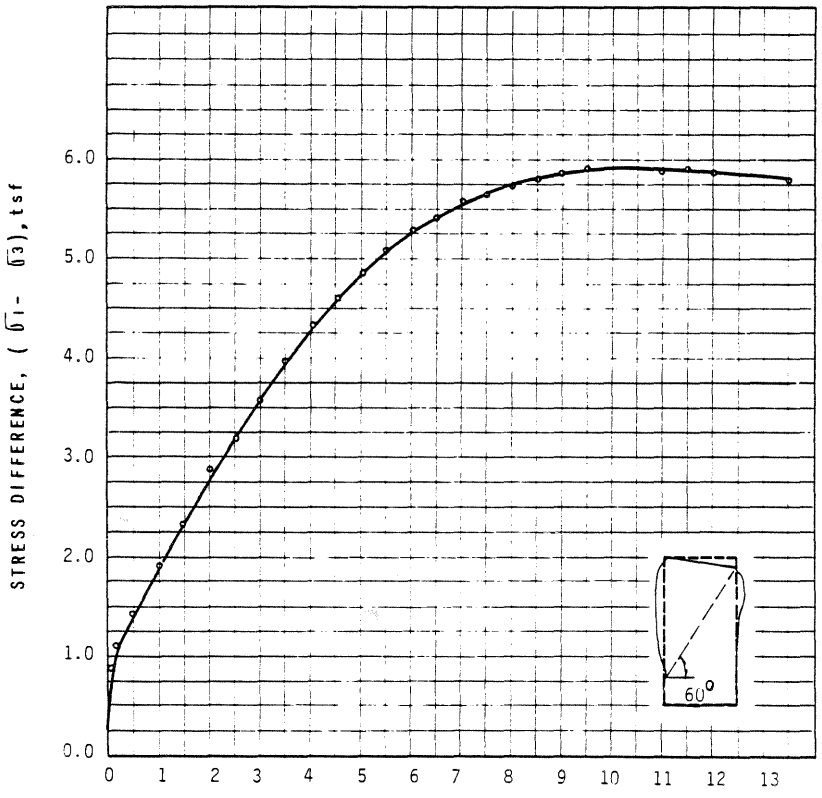
Boring No. WD-6 Sample No. S-3 Depth 10.0-12.5 Ft

Description Red-brown micaceous clayey silty sand (SM)

Moisture Content 23.0 % (after saturation) Dry Density 99.9 pcf

Liquid Limit 37 % Plastic Limit NP % Relative Density - %

$(\sigma_1 - \sigma_3)$ max.= 5.92 tsf at 10.5 % Strain Chamber Pressure, σ_c= 0.6 tsf



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 7 of 13)

Figure 2.5-112

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Figure 2.5-112
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 8 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

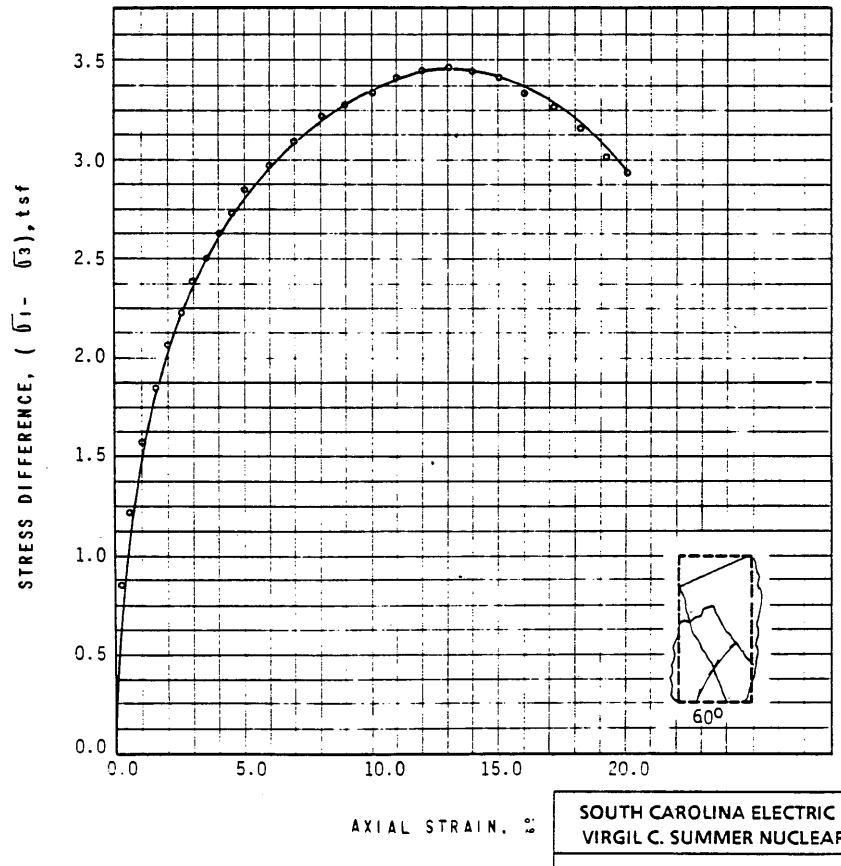
Boring No. WD-6 Sample No. S-5 Depth 18.0-20.2 Ft

Description Gray brown micaceous very fine sandy silt (ML)

Moisture Content 32.3 % (after saturation) Dry Density 85.9 pcf

Liquid Limit 36 % Plastic Limit NP % Relative Density - %

$(\bar{\sigma}_1 - \bar{\sigma}_3)$ max.= 3.45 tsf at 13.0 % Strain Chamber Pressure, $\bar{\sigma}_c$ = 1.10 tsf



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 8 of 13)

Figure 2.5-112

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Figure 2.5-112

UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 9 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

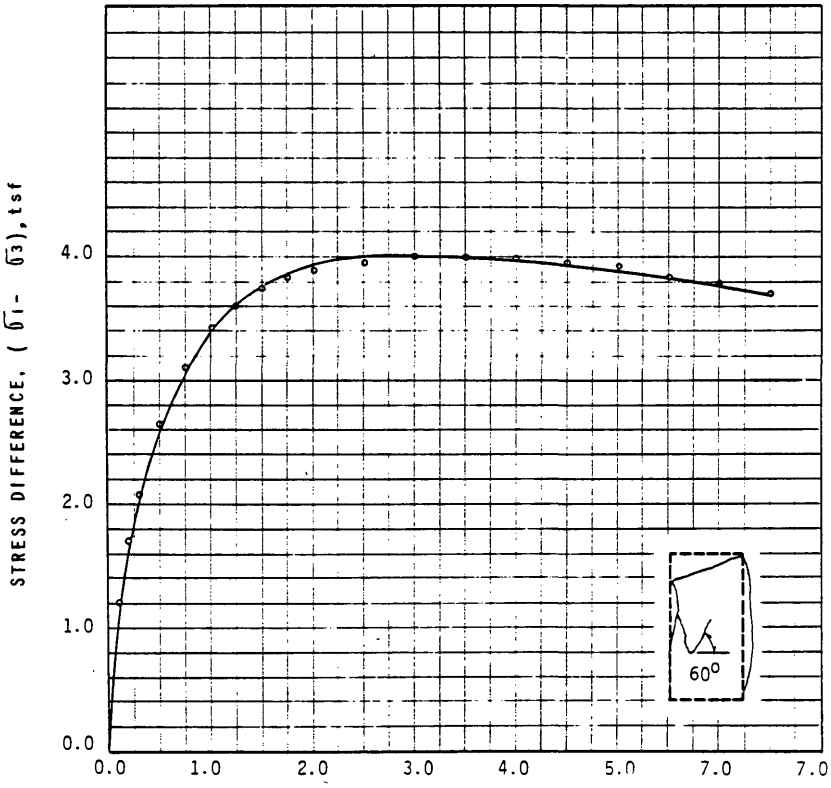
Boring No. WD-8 Sample No. S-3 Depth 10.0 - 11.8 Ft

Description Red brown micaceous sandy clayey silt (ML)

Moisture Content 30.9 % (after saturation) Dry Density 88.9 pcf

Liquid Limit 45 % Plastic Limit NP % Relative Density - %

$(\bar{\sigma}_1 - \bar{\sigma}_3)$ max.= 4.0 tsf at 3.0 % Strain Chamber Pressure, $\bar{\sigma}_c$ = 2.85 tsf



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 9 of 13)

Figure 2.5-112

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Figure 2.5-112
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 10 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

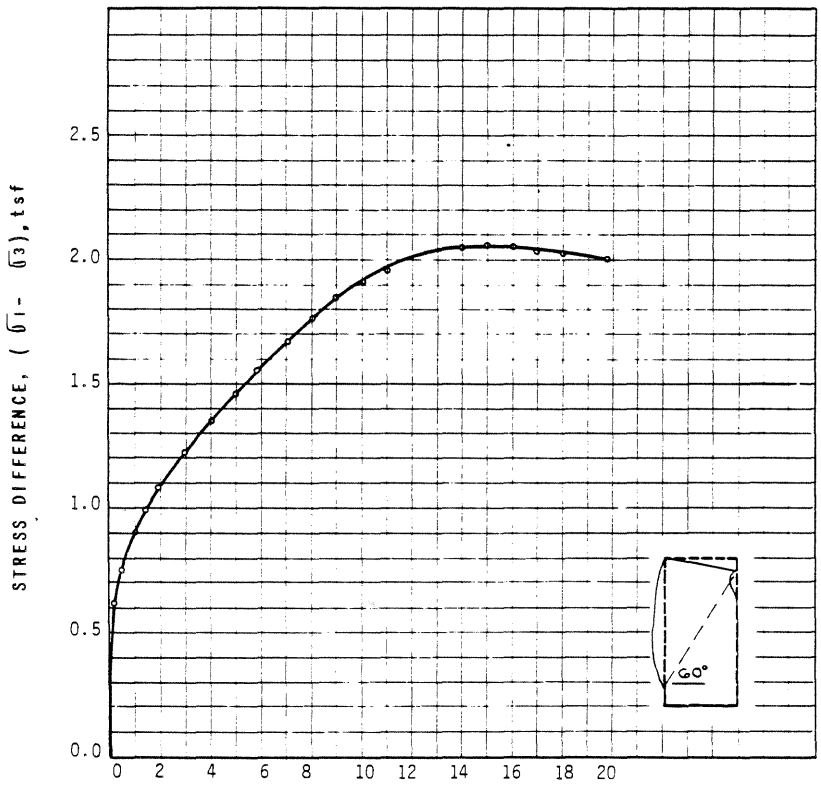
Boring No. SS-4 Sample No. S-3 Depth 10.0 - 12.0 Ft

Description Light brown fine sandy silt (ML)

Moisture Content 31.1 % (after saturation) Dry Density 80.1 pcf

Liquid Limit 40 % Plastic Limit NP % Relative Density - %

$(\sigma_1 - \sigma_3)$ max.= 2.08 tsf at 15.0 % Strain Chamber Pressure, σ_c = 0.94 tsf



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 10 of 13)

Figure 2.5-112

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Figure 2.5-112
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 11 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

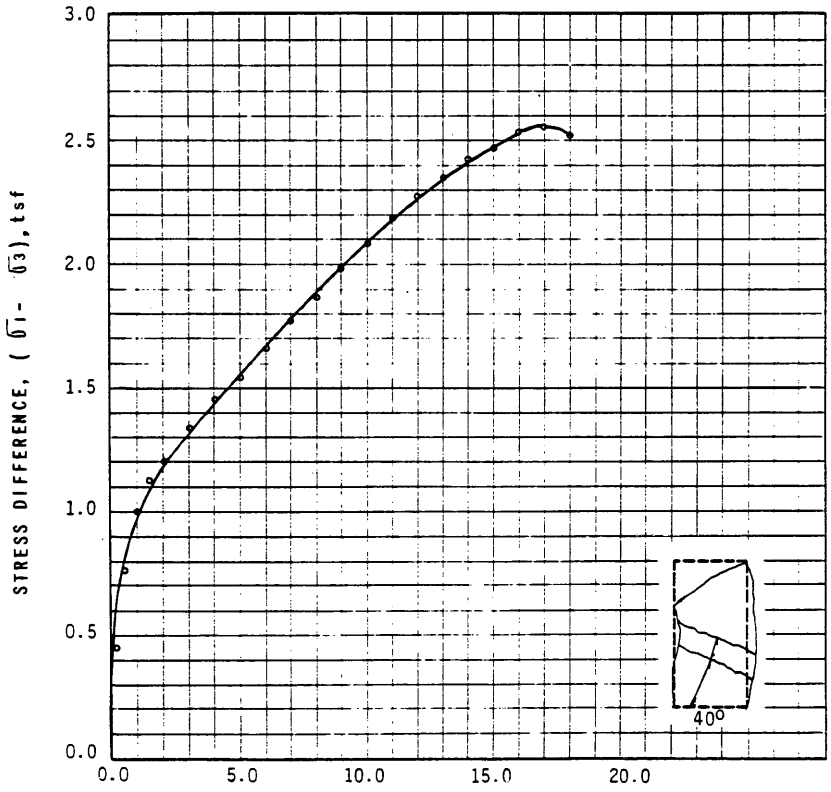
Boring No. SS-4 Sample No. S-5 Depth 18.0 - 20.3 Ft

Description Gray and brown micaceous very fine sandy silt (ML)

Moisture Content 26.9 % (after saturation) Dry Density 93.8 pcf

Liquid Limit 31 % Plastic Limit NP % Relative Density - %

$(\bar{\sigma}_1 - \bar{\sigma}_3)$ max.= 2.54 tsf at 16.5 % Strain Chamber Pressure, $\bar{\sigma}_c$= 1.29 tsf



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 11 of 13)

Figure 2.5-112

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Figure 2.5-112
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 12 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

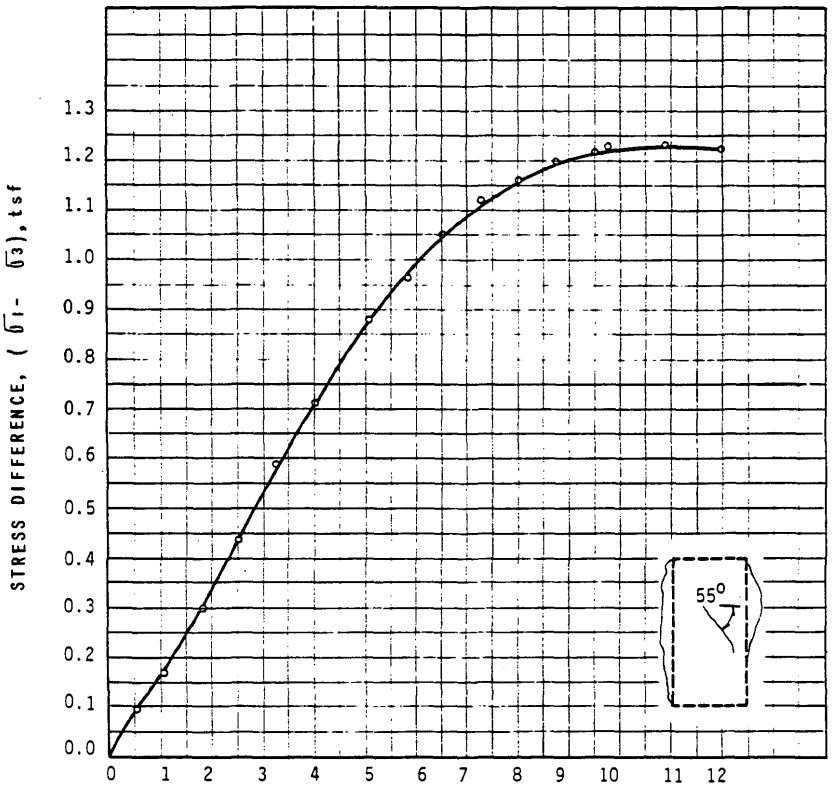
Boring No. C-3 Sample No. S-5 Depth 18.0 - 20.4 Ft

Description Red-brown micaceous clayey silt, trace fine sand (MH)

Moisture Content 44.7 % (after saturation) Dry Density 81.3 pcf

Liquid Limit 53 % Plastic Limit 19 % Relative Density %

$(\sigma_1 - \sigma_3)$ max.= 1.24 tsf at 10.9 % Strain Chamber Pressure, σ_c = 0.6 tsf



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 12 of 13)

Figure 2.5-112

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Figure 2.5-112

UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 13 OF 13)

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

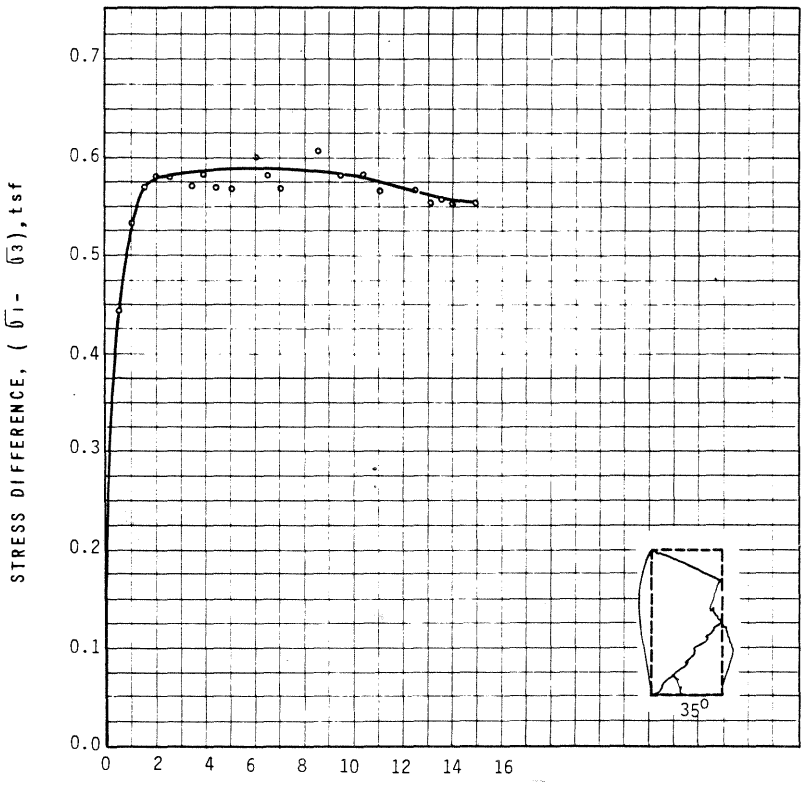
Boring No. C-5 Sample No. S-3 Depth 7.0 - 9.5 Ft

Description Red-brown silty clayey sand and sandy clayey silt (SM-ML)

Moisture Content 34.9 % (after saturation) Dry Density 74.5 pcf

Liquid Limit 32 % Plastic Limit 25 % Relative Density - %

$(\bar{\sigma}_1 - \bar{\sigma}_3)$ max.= 0.58 tsf at 7.0 % Strain Chamber Pressure, $\bar{\sigma}_c$ = 0.6 tsf



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Unconsolidated-Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 13 of 13)

Figure 2.5-112

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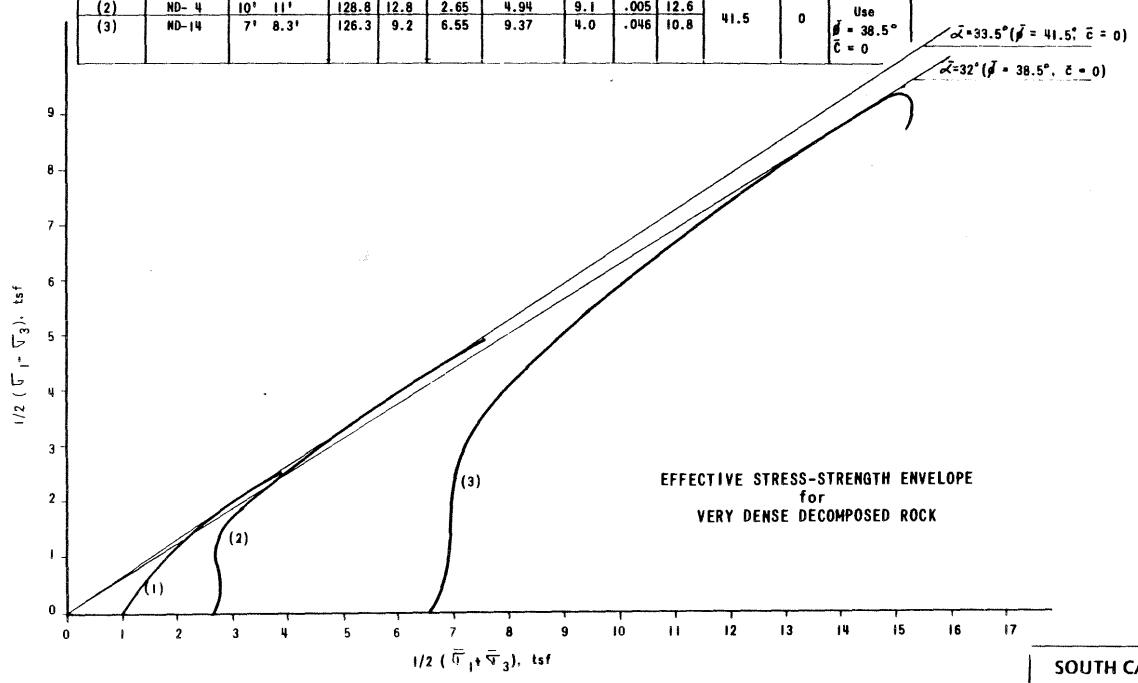
Figure 2.5-113

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 1 OF 3)

TEST No.	BORING No.	SAMPLE DEPTH (Ft.)	γ_d (pcf)	W_n (%)	$\bar{\sigma}_c$ (tsf)	$\frac{(\sigma_1-\sigma_3)_{max}}{2}$ (tsf)	ϵ_f (%)	A_f	W_f (%)	$\bar{\phi}$ (degrees)	$\bar{c}$ (psf)	REMARKS
(1)	ND-14	12' 13.7'	125.2	6.7	1.00	4.25	6.4	.136	7.5	38.5	0	For Design
(2)	ND- 4	10' 11'	128.8	12.8	2.65	4.94	9.1	.005	12.6	41.5	0	Use
(3)	ND-14	7' 8.3'	126.3	9.2	6.55	9.37	4.0	.046	10.8			$\bar{\phi}$ = 38.5° $\bar{c}$ = 0



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Isotropically Consolidated, Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 1 of 3)

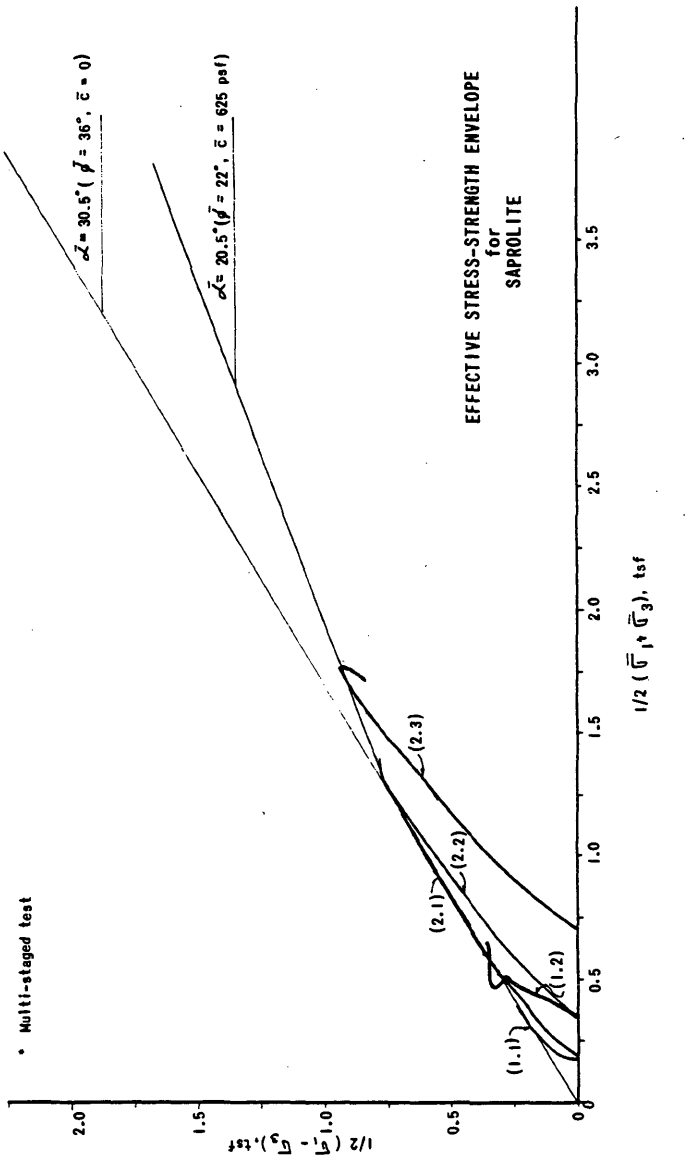
Figure 2.5-113

Figure 2.5-113

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 2 OF 3)

TEST No.	BORING No.	SAMPLE DEPTH (Ft.)	γ_d (pcf)	W_0 (%)	$\bar{\sigma}_c$ (tsf)	$\left(\frac{\sigma_1-\sigma_3}{2}\right)_{max}$ (tsf)	ϵ_f (%)	A_f	W_f (%)	$\bar{\phi}$ (degrees)	$\bar{c}$ (psf)	REMARKS
(1.1) ~ (1.2) *	C-5	17' ~ 19.3'	87.3	36.5	0.18	0.21	4.2	.074	32.0	36	0	For Design Use
					0.36	0.37	6.4	-.091				
(2.1) ~ (2.3) *	C-5	17' ~ 19.3'	97.8	23.0	0.18	0.67	8.1	-.203	25.4	36	0	$\bar{\phi}$ = 36° $\bar{c}$ = 0
					0.36	0.79	5.3	-.130		22	625	
					0.72	0.94	4.8	-.057				

* Multi-staged test



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Isotropically Consolidated, Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 2 of 3)

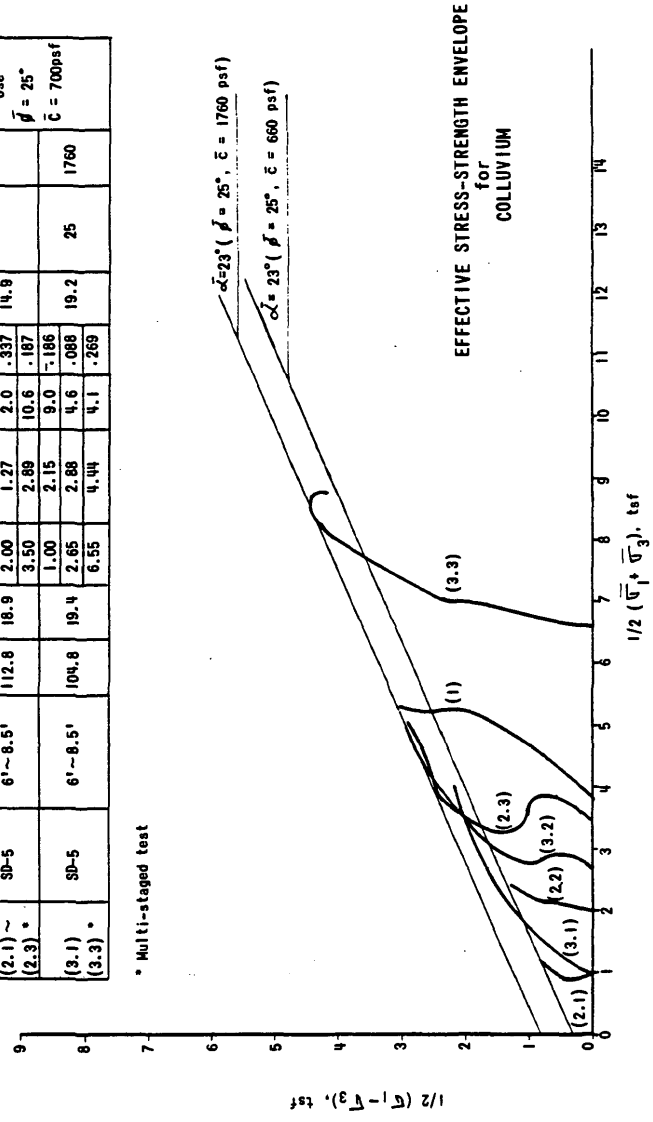
Figure 2.5-113

Figure 2.5-113

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON FOUNDATION SOILS (SHEET 3 OF 3)

TEST No.	BORING No.	SAMPLE DEPTH (Ft.)	γ_d (pcf)	W_n (%)	$\bar{\sigma}_c$ (tsf)	$\frac{S_u}{\frac{(\bar{\sigma}_1-\bar{\sigma}_3)_{max}}{2}}$ (tsf)	ϵ_f (%)	A_f	W_f (%)	$\bar{\phi}$ (degrees)	$\bar{c}$ (psf)	REMARKS
(1)	SD-5	6'~8.5'	109.3	20.9	3.88	3.03	5.4	.263	24.2	25	660	For Design Use $\bar{\phi}$ = 25° $\bar{c}$ = 700psf
(2.1)~(2.3) *	SD-5	6'~8.5'	112.8	18.9	1.00	0.80	2.1	.390	14.9			
					2.00	1.27	2.0	.337				
					3.50	2.89	10.6	.187				
(3.1)~(3.3) *	SD-5	6'~8.5'	104.8	19.4	1.00	2.15	9.0	.186	19.2	25	1760	
					2.65	2.88	4.6	.088				
					6.55	4.44	4.1	.269				

* Multi-staged test



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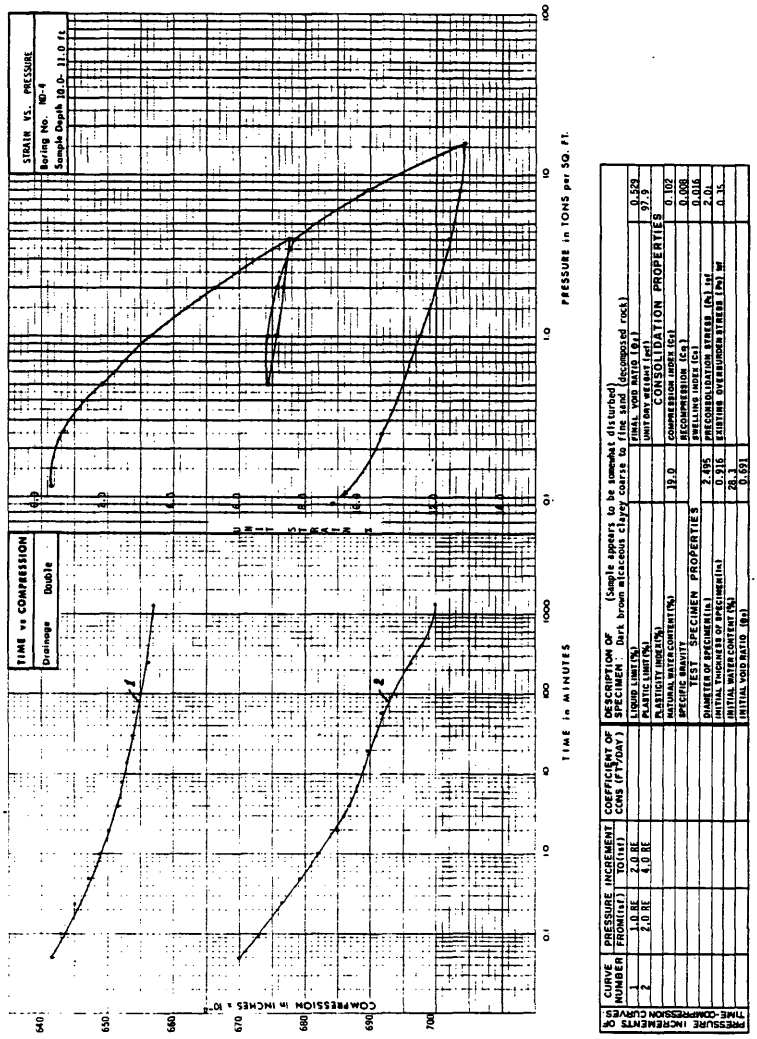
Isotropically Consolidated, Undrained Triaxial Compression Test Results On Foundation Soils (Sheet 3 of 3)

Figure 2.5-113

Figure 2.5-114
CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 1 OF 13)



CURVE NUMBER	PRESSURE INCREMENT PSF(Kg/cm²)	TOTAL TIME	COEFFICIENT OF CONSOLIDATION (ft²/DAY)
1	1.0 RE	2.0 RE	
2	2.0 RE	4.0 RE	

PRESSURE INCREMENTS OF TIME-COMPRESSION CURVES

DESCRIPTION OF SPECIMEN (Sample appears to be somewhat disturbed) (dark brown micaceous clayey coarse to fine sand (decomposed rock)

LIQUID LIMIT (%)	
PLASTIC LIMIT (%)	
PLASTICITY INDEX (%)	
NATURAL WATER CONTENT (%)	18.0
SPECIFIC GRAVITY	
TEST SPECIMEN PROPERTIES	
DIAMETER OF SPECIMEN (in.)	2.495
INITIAL THICKNESS OF SPECIMEN (in.)	0.916
INITIAL WATER CONTENT (%)	20.3
INITIAL VOID RATIO (e₀)	0.691
INITIAL UNIT DRY WEIGHT (pcf)	97.9
CONSOLIDATION PROPERTIES	
COMPRESSION INDEX (Cc)	0.102
RECOMPRESSION (Cr)	0.008
SWELLING INDEX (Cs)	0.016
PRECONSOLIDATION STRESS (σc) tsf	2.01
SATURATED OVERBURDEN STRESS (σo) tsf	0.35
	0.529

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Consolidation Test Results On
Foundation Soil
(Sheet 1 of 13)

Figure 2.5-114

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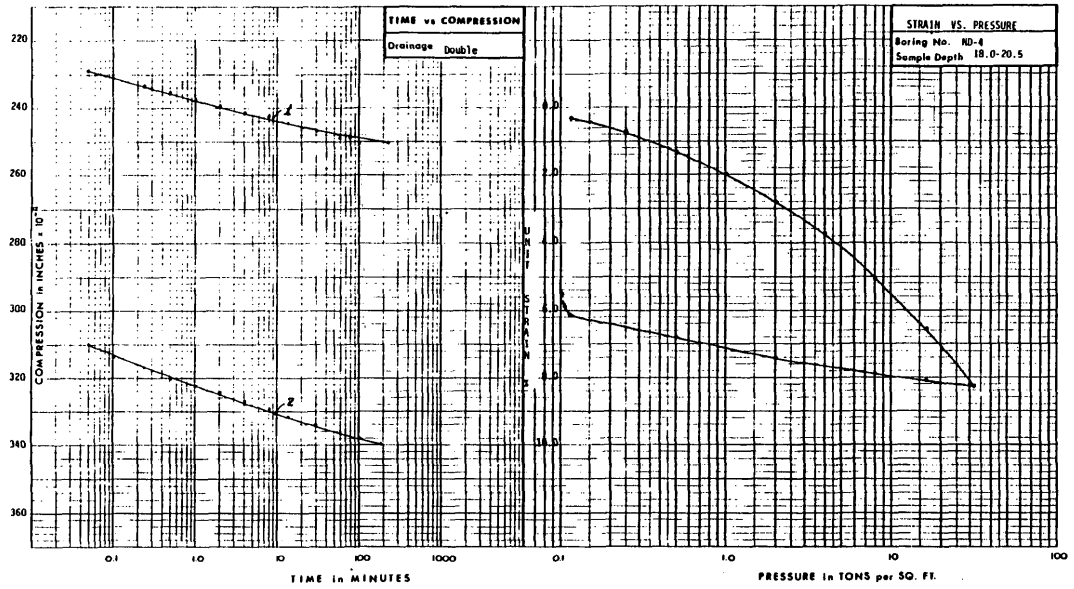
Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 2 OF 13)



PRESSURE INCREMENTS OF TIME-COMPRESSION CURVES

CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS. (FT²/DAY)
1	1.0	2.0	
2	2.0	4.0	

DESCRIPTION OF SPECIMEN: Dark brown micaceous clayey coarse fo fine sand (decomposed rock)

LIQUID LIMIT(%)		FINAL VOID RATIO (ef)	0.293
PLASTIC LIMIT(%)		UNIT DRY WEIGHT (pcf)	119.7
PLASTICITY INDEX(%)		CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT(%)	15.4	COMPRESSION INDEX (Cc) (Unit strain basis)	0.058
SPECIFIC GRAVITY	2.64	RECOMPRESSION (Cr) " " "	
TEST SPECIMEN PROPERTIES		SWELLING INDEX (Cs) " " "	0.009
DIAMETER OF SPECIMEN(in.)	2.486	PRECONSOLIDATION STRESS (Pc) tsf	4.0±
INITIAL THICKNESS OF SPECIMEN(in.)	0.926	EXISTING OVERBURDEN STRESS (Po) tsf	0.75
INITIAL WATER CONTENT (%)	15.0		
INITIAL VOID RATIO (eo)	0.377		

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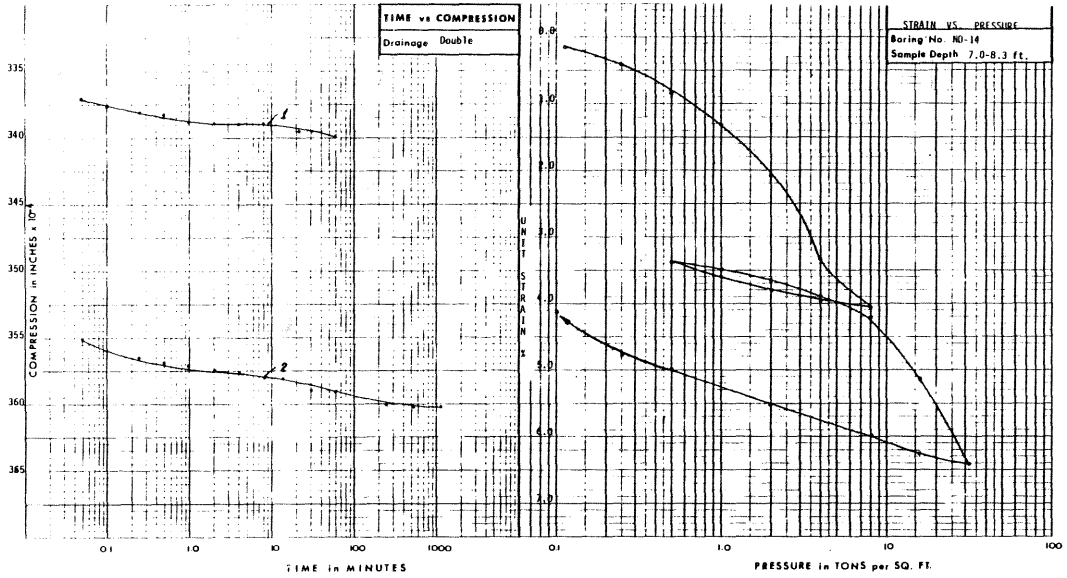
Consolidation Test Results On Foundation Soil (Sheet 2 of 13)

Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 3 OF 13)



PRESSURE INCREMENTS OF TIME-COMPRESSION CURVES	CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS (FT^2/DAY)
	1	1.0 RE	2.0 RE	
	2	2.0 RE	4.0 RE	

DESCRIPTION OF SPECIMEN: Brown micaceous sandy clay (decomposed rock)			
LIQUID LIMIT (%)		FINAL VOID RATIO (e_f)	0.270
PLASTIC LIMIT (%)		UNIT DRY WEIGHT (pcf)	126.6
PLASTICITY INDEX (%)		CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT (%)	8.8	COMPRESSION INDEX (Cc)(Unit strain basis)	0.037
SPECIFIC GRAVITY		RECOMPRESSION (Cr) " " "	0.006
TEST SPECIMEN PROPERTIES		SWELLING INDEX (Cs) " " "	0.008
DIAMETER OF SPECIMEN (in.)	2.495	PRECONSOLIDATION STRESS (P_c) tsf	3.0±
INITIAL THICKNESS OF SPECIMEN (in.)	0.931	EXISTING OVERBURDEN STRESS (P_o) tsf	0.55
INITIAL WATER CONTENT (%)	7.9		
INITIAL VOID RATIO (e_o)	0.311		

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Consolidation Test Results On
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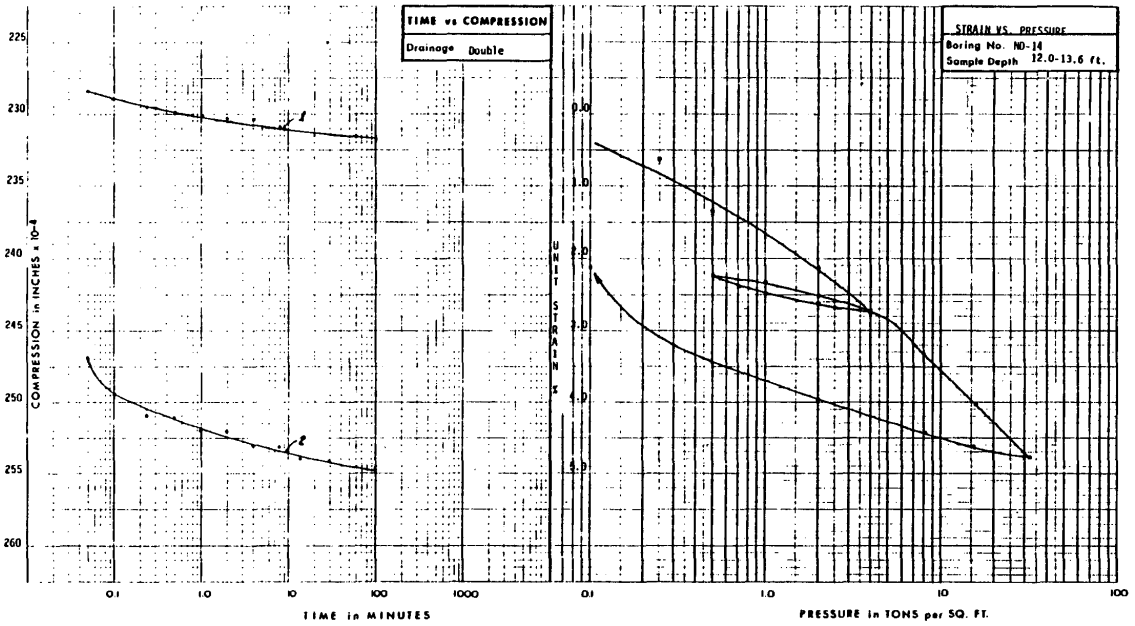
(Sheet 3 of 13)

Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 4 OF 13)



PRESSURE INCREMENTS OF TIME-COMPRESSION CURVES	CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS. (FT^2/DAY)
	1	1.0 RE	2.0 RE	
	2	2.0 RE	4.0 RE	

DESCRIPTION OF SPECIMEN: Light brown micaceous decomposed rock

LIQUID LIMIT (%)		FINAL VOID RATIO (e_f)	0.042
PLASTIC LIMIT (%)		UNIT DRY WEIGHT (pcf)	140.1
PLASTICITY INDEX (%)		CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT (%)	5.6	COMPRESSION INDEX (C_c)(Unit strain basis)	0.024
SPECIFIC GRAVITY	2.66	RECOMPRESSION (C_R)	0.006
TEST SPECIMEN PROPERTIES		SWELLING INDEX (C_s)	0.009
DIAMETER OF SPECIMEN (in.)	2.495	PRECONSOLIDATION STRESS (P_c) tsf	4.0±
INITIAL THICKNESS OF SPECIMEN (in.)	0.930	EXISTING OVERBURDEN STRESS (P_o) tsf	0.9
INITIAL WATER CONTENT (%)	1.9		
INITIAL VOID RATIO (e_o)	0.185		

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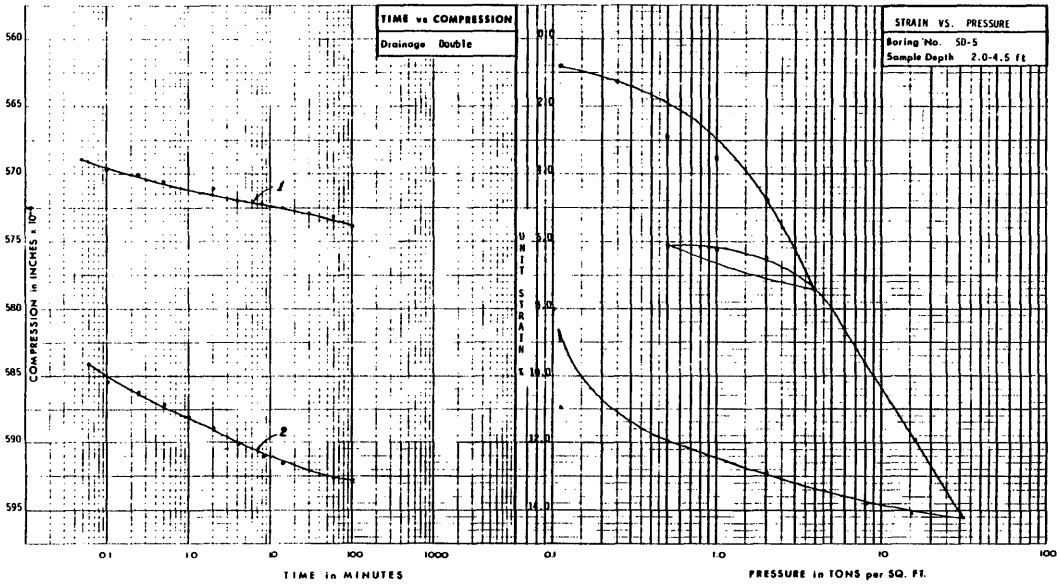
Consolidation Test Results On Foundation Soil (Sheet 4 of 13)

Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 5 OF 13)



PRESSURE INCREMENTS OF TIME-COMPRESSION CURVES	CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS (FT²/DAY)
	1	0.5 u	1.0 RE	
	2	1.0 RE	2.0 RE	

DESCRIPTION OF SPECIMEN: Red brown micaceous sandy silty clay, trace organic matter (CL-ML)

LIQUID LIMIT (%)	23.0	FINAL VOID RATIO (@ t)	0.398
PLASTIC LIMIT (%)	15.0	UNIT DRY WEIGHT (pcf)	110.6
PLASTICITY INDEX (%)	8.0	CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT (%)	17.2	COMPRESSION INDEX (Cc)(Unit strain basis)	0.080
SPECIFIC GRAVITY	2.67	RECOMPRESSION (Cr) " " "	0.007
TEST SPECIMEN PROPERTIES		SWELLING INDEX (Cs) " " "	0.016
DIAMETER OF SPECIMEN (in.)	2.495	PRECONSOLIDATION STRESS (Pc) tsf	1.0±
INITIAL THICKNESS OF SPECIMEN (in.)	0.915	EXISTING OVERBURDEN STRESS (Po) tsf	0.7±
INITIAL WATER CONTENT (%)	18.4		
INITIAL VOID RATIO (@ t)	0.507		

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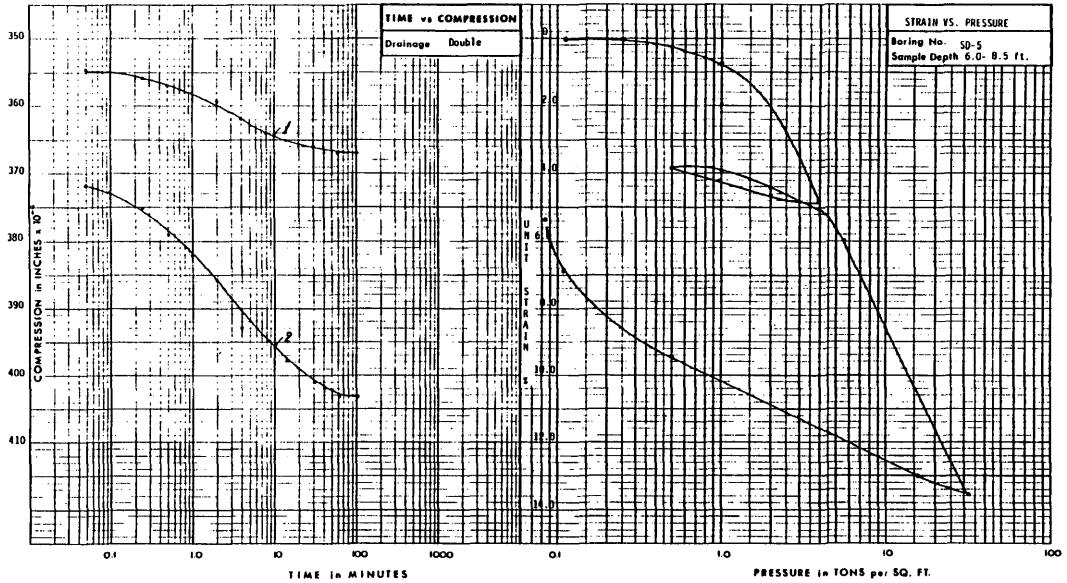
Consolidation Test Results On Foundation Soil (Sheet 5 of 13)

Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 6 OF 13)



PRESSURE INCREMENTS OF TIME-COMPRESSION CURVES	CURVE NUMBER	PRESSURE INCREMENT FROM(tsf.)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS. (FT^2/DAY)
	1	1.5 UN	1.0 RE	
	2	1.0 RE	2.0 RE	

DESCRIPTION OF SPECIMEN: Dark gray micaceous sandy clay

LIQUID LIMIT (%)		FINAL VOID RATIO (e_f)	0.638
PLASTIC LIMIT (%)		UNIT DRY WEIGHT (pcf)	99.0
PLASTICITY INDEX (%)		CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT (%)	21.6	COMPRESSION INDEX (C_c) (Unit strain basis)	0.100
SPECIFIC GRAVITY	2.67	RECOMPRESSION (C_R) " " "	0.015
TEST SPECIMEN PROPERTIES		SWELLING INDEX (C_s) " " "	0.023
DIAMETER OF SPECIMEN (in.)	2.495	PRECONSOLIDATION STRESS (P_c) tsf	2.01
INITIAL THICKNESS OF SPECIMEN (in.)	0.919	EXISTING OVERBURDEN STRESS (P_o) tsf	0.23
INITIAL WATER CONTENT (%)	24.3		
INITIAL VOID RATIO (e_o)	0.683		

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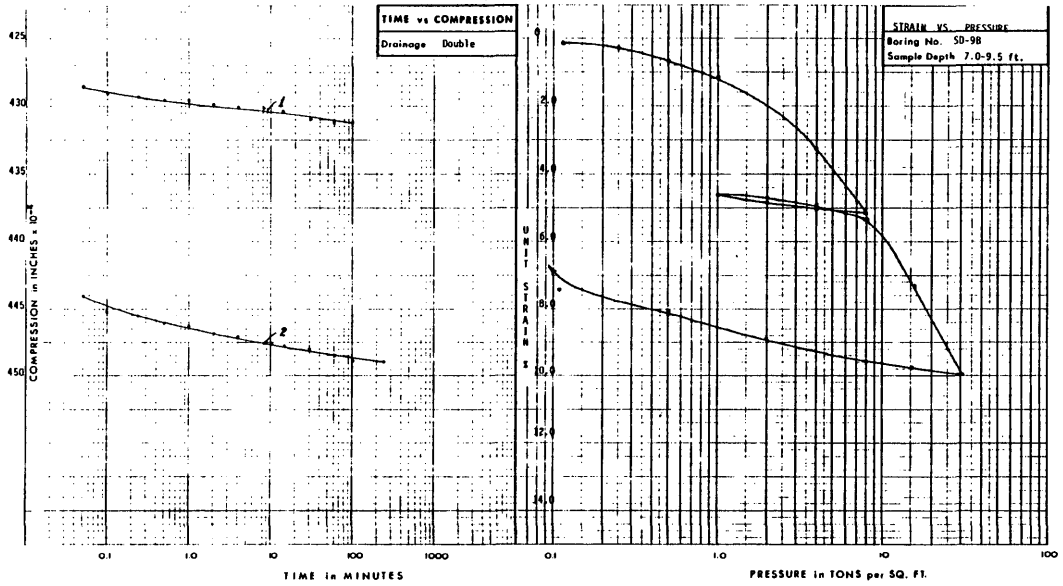
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Results On Foundation Soil (Sheet 6 of 13)

Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 7 OF 13)



PRESSURE INCREMENTS OF TIME-COMPRESSION CURVES

CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS. (FT²/DAY)
1	1.0 u	2.0 RE	
2	2.0 RE	4.0 RE	

DESCRIPTION OF SPECIMEN: Red-brown clayey silty sand, trace coarse sand and roots (ML)

LIQUID LIMIT(%)	26.0	FINAL VOID RATIO (ef)	0.46
PLASTIC LIMIT(%)	19.0	UNIT DRY WEIGHT (pcf)	106.1
PLASTICITY INDEX(%)	7.0	CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT(%)	19.7	COMPRESSION INDEX (Cc)(Unit strain basis)	0.080
SPECIFIC GRAVITY		RECOMPRESSION (Cr)	0.007
TEST SPECIMEN PROPERTIES		SWELLING INDEX (Cs) " "	0.013
DIAMETER OF SPECIMEN(in)	2.495	PRECONSOLIDATION STRESS (Pc) tsf	5.01
INITIAL THICKNESS OF SPECIMEN(in)	.915	EXISTING OVERBURDEN STRESS (Po) tsf	0.29
INITIAL WATER CONTENT (%)	19.7		
INITIAL VOID RATIO (ei)	0.57		

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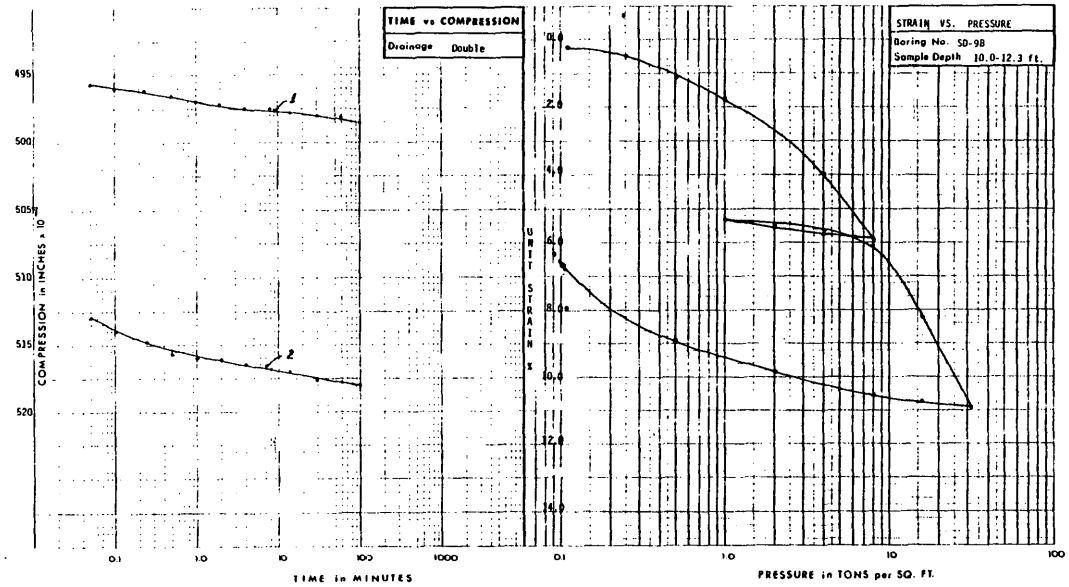
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Results On
Foundation Soil
(Sheet 7 of 13)

Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 8 OF 13)



PRESSURE INCREMENTS OF TIME-COMPRESSION CURVES	CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS (FT²/DAY)
	1	1.0 u	2.0 RE	
	2	2.0 RE	4.0 RE	

DESCRIPTION OF SPECIMEN: Brownish gray clayey silty sand, trace roots (ML)

TEST SPECIMEN PROPERTIES		CONSOLIDATION PROPERTIES	
LIQUID LIMIT (%)	21.0	FINAL VOID RATIO (e_f)	.60
PLASTIC LIMIT (%)	17.0	UNIT DRY WEIGHT (pcf)	109.5
PLASTICITY INDEX (%)	4.0		
NATURAL WATER CONTENT (%)	14.3	COMPRESSION INDEX (C_c) (Unit strain basis)	0.084
SPECIFIC GRAVITY		RECOMPRESSION (C_R)	0.007
		SWELLING INDEX (C_s)	0.015
DIAMETER OF SPECIMEN (in.)	2.495	PRECONSOLIDATION STRESS (P_c) tsf	5.0±
INITIAL THICKNESS OF SPECIMEN (in.)	.915	EXISTING OVERBURDEN STRESS (P_o) tsf	0.42
INITIAL WATER CONTENT (%)	14.2		
INITIAL VOID RATIO (e_o)	.50		

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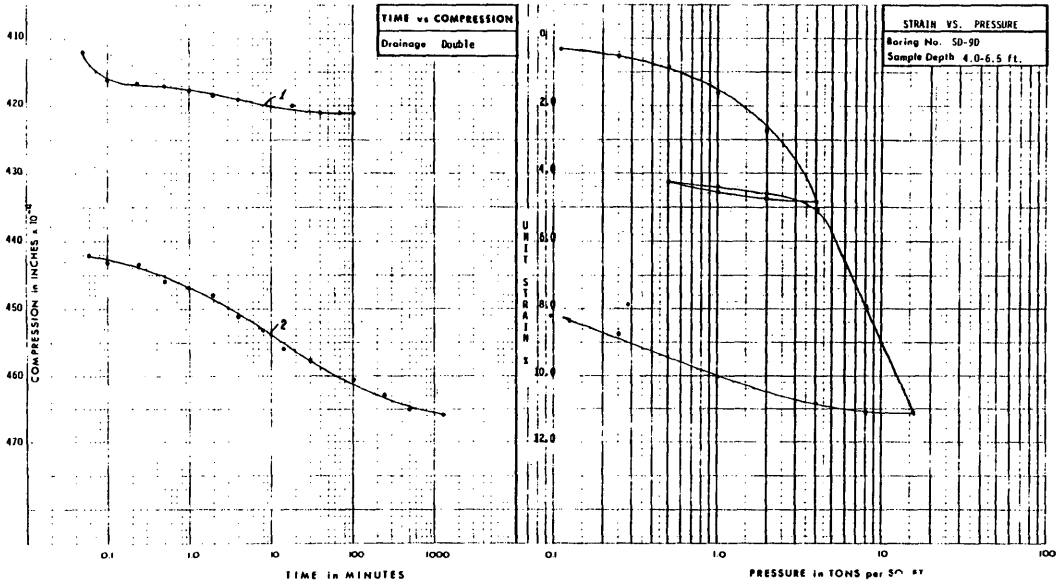
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Results On Foundation Soil (Sheet 8 of 13)

Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 9 OF 13)



PRESSURE INCREMENTS OF TIME COMPRESSION CURVES	CURVE NUMBER	PRESSURE INCREMENT FROM (tsf)	PRESSURE INCREMENT TO (tsf)	COEFFICIENT OF CONS (FT²/DAY)
	1	1.0 RE	2.0 RE	
	2	2.0 RE	4.0 RE	

DESCRIPTION OF SPECIMEN: Dark brown sandy silty clay, trace roots (CL)			
LIQUID LIMIT (%)	31.0	FINAL VOID RATIO (e_f)	0.54
PLASTIC LIMIT (%)	20.0	UNIT DRY WEIGHT (pcf)	98.9
PLASTICITY INDEX (%)	11.0	CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT (%)	23.1	COMPRESSION INDEX (C_c) (Unit strain basis)	0.009
SPECIFIC GRAVITY	2.66	RECOMPRESSION (C_R)	0.008
TEST SPECIMEN PROPERTIES		SWELLING INDEX (C_s)	0.016
DIAMETER OF SPECIMEN (in)	2.495	PRECONSOLIDATION STRESS (P_c) tsf	0.41
INITIAL THICKNESS OF SPECIMEN (in)	.916	EXISTING OVERBURDEN STRESS (P_o) tsf	0.26
INITIAL WATER CONTENT (%)	23.1		
INITIAL VOID RATIO (e_o)	.68		

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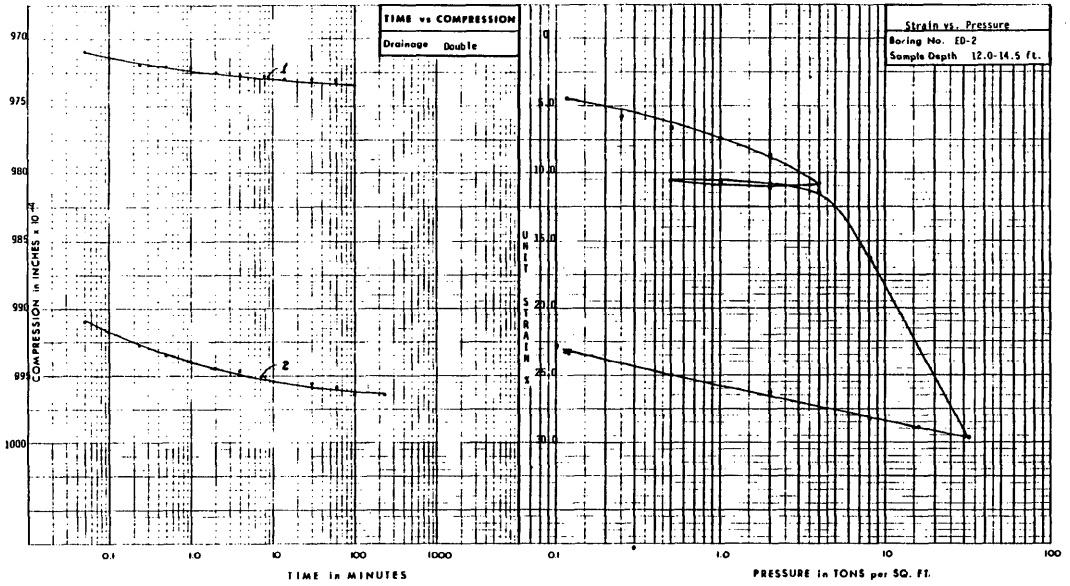
Consolidation Test Results On Foundation Soil (Sheet 9 of 13)

Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 10 OF 13)



PRESSURE INCREMENTS OF TIME COMPRESSION CURVES	CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS (FT²/DAY)
	1	0.5 u	1.0 RE	
	2	1.0 RE	2.0 RE	

DESCRIPTION OF SPECIMEN: Red-brown micaceous sandy silty clay becoming sandy clayey silt (MH)

LIQUID LIMIT(%)	65.0	FINAL VOID RATIO (e_f)	0.982
PLASTIC LIMIT(%)	58.0	UNIT DRY WEIGHT (pcf)	69.8
PLASTICITY INDEX(%)	7.0	CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT(%)	51.0	COMPRESSION INDEX (C_c) (Unit strain basis)	0.23
SPECIFIC GRAVITY	- -	RECOMPRESSION (C_R) " " "	0.007
TEST SPECIMEN PROPERTIES		SWELLING INDEX (C_s)	0.026
DIAMETER OF SPECIMEN(in.)	2.835	PRECONSOLIDATION STRESS (P_c) tsf	5.01
INITIAL THICKNESS OF SPECIMEN(in.)	0.915	EXISTING OVERBURDEN STRESS (P_o) tsf	0.75
INITIAL WATER CONTENT (%)	49.5		
INITIAL VOID RATIO (e_o)	1.390		

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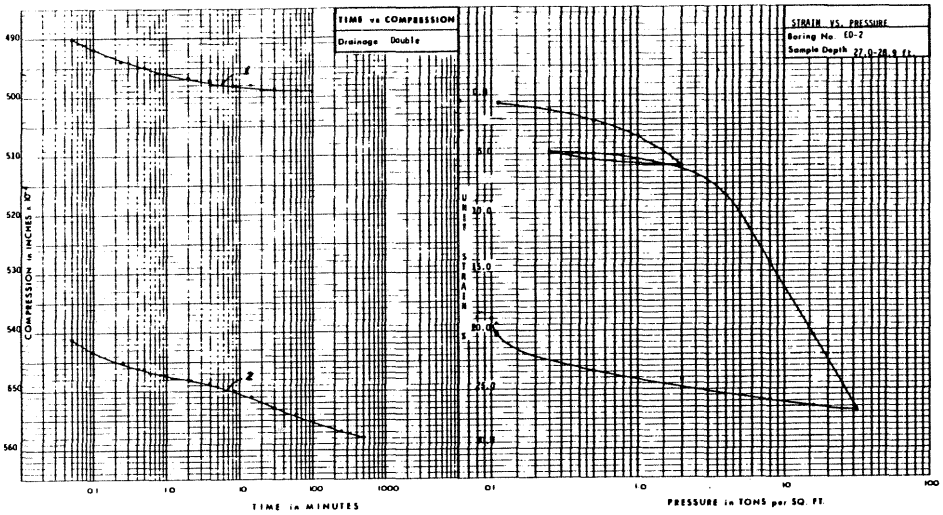
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Results On Foundation Soil (Sheet 10 of 13)

Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 11 OF 13)



PRESSURE INCREMENTS OF TIME COMPRESSION CURVES	CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS (FT²/DAY)
	1	¼ RE	1.0 RE	
	2	1.0 RE	2.0 RE	

DESCRIPTION OF SPECIMEN: Brown gray micaceous clayey silty fine sand (SM-SW)

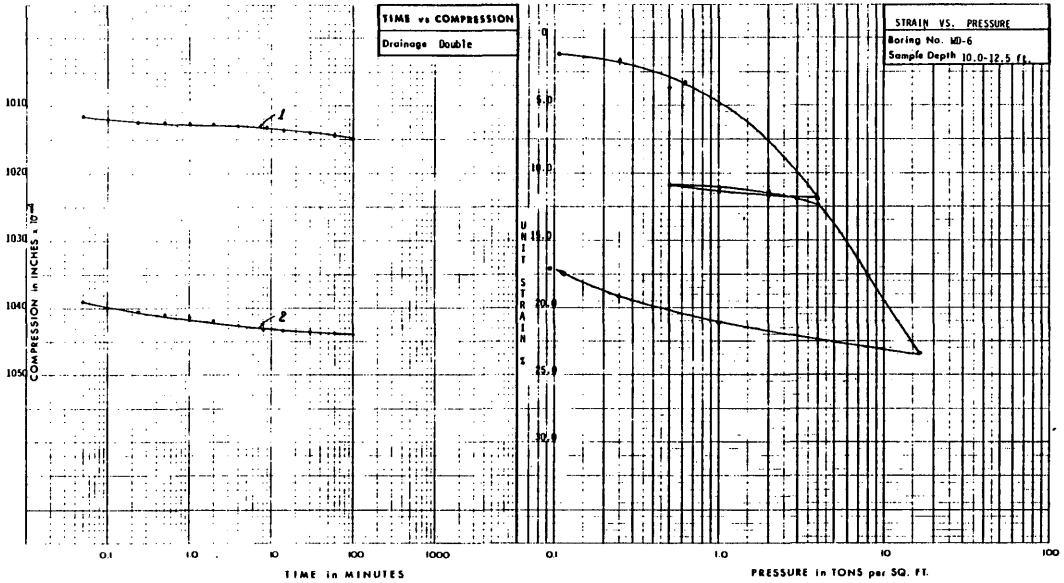
LIQUID LIMIT(%)	45.0
PLASTIC LIMIT(%)	45.0
PLASTICITY INDEX(%)	NP
NATURAL WATER CONTENT(%)	36.9
SPECIFIC GRAVITY	2.67
TEST SPECIMEN PROPERTIES	
DIAMETER OF SPECIMEN(in)	2.495
INITIAL THICKNESS OF SPECIMEN(in)	0.915
INITIAL WATER CONTENT (%)	36.1
INITIAL VOID RATIO (e₀)	1.14

FINAL VOID RATIO (e_f)	0.725
UNIT DRY WEIGHT (pcf)	78.1
CONSOLIDATION PROPERTIES	
COMPRESSION INDEX (C_c) (Unit strain basis)	0.215
RECOMPRESSION (C_R) " " "	0.012
SWELLING INDEX (C_s)	0.021
PRECONSOLIDATION STRESS (P_c) tsf	1.0±
EXISTING OVERBURDEN STRESS (P_o) tsf	1.57

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Consolidation Test Results On Foundation Soil (Sheet 11 of 13) Figure 2.5-114

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 12 OF 13)



PRESSURE INCREMENTS OF TIME COMPRESSION CURVES

CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS (FT²/DAY)
1	0.5 N	1.0 RE	
2	1.0 RE	2.0 RE	

DESCRIPTION OF SPECIMEN: Red-brown micaceous fine sandy clayey silt changing to clayey silty sand with more mica (ML-MH)

LIQUID LIMIT (%)	37.0	FINAL VOID RATIO (e_f)	.55
PLASTIC LIMIT (%)	37.0	UNIT DRY WEIGHT (pcf)	78.1
PLASTICITY INDEX (%)	NP	CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT (%)	22.6	COMPRESSION INDEX (Cc) (Unit strain basis)	0.19
SPECIFIC GRAVITY	2.69	RECOMPRESSION (Cq) " " "	0.013
TEST SPECIMEN PROPERTIES		SWELLING INDEX (Cs)	0.025
DIAMETER OF SPECIMEN (in.)	2.495	PRECONSOLIDATION STRESS (P_c) tsf	2.0±
INITIAL THICKNESS OF SPECIMEN (in)	.516	EXISTING OVERBURDEN STRESS (P_o) tsf	0.55
INITIAL WATER CONTENT (%)	22.6		
INITIAL VOID RATIO (e_o)	1.15		

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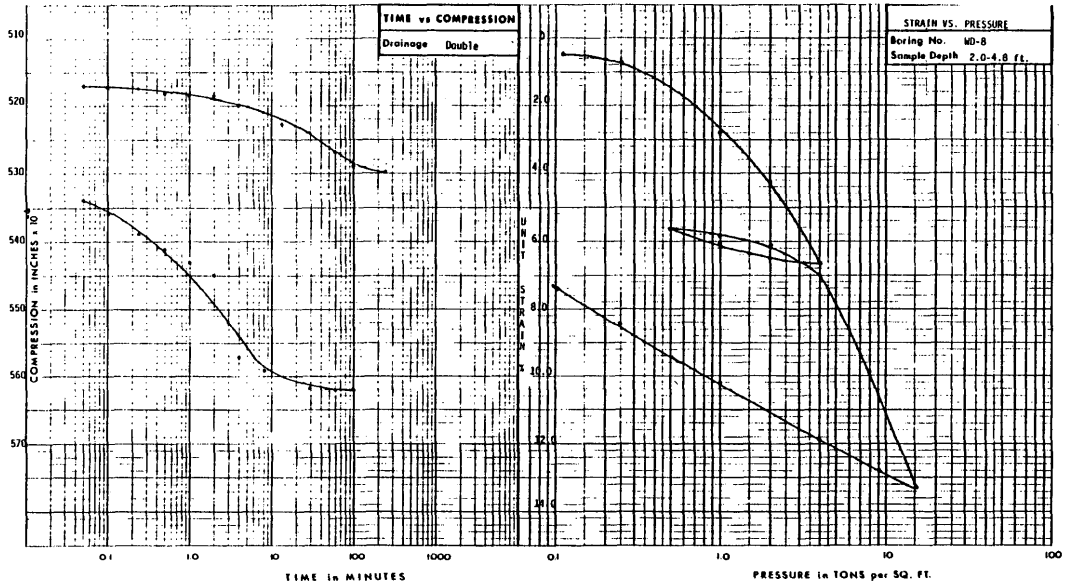
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Results On Foundation Soil (Sheet 12 of 13)

Figure 2.5-114

CONSOLIDATED TEST RESULTS ON FOUNDATION SOIL (SHEET 13 OF 13)



PRESSURE INCREMENTS OF THE CONSOLIDATION CURVES	CURVE NUMBER	PRESSURE INCREMENT FROM(tsf)	PRESSURE INCREMENT TO(tsf)	COEFFICIENT OF CONS (FT²/DAY)
	1	0.5 u	1.0 RE	
	2	1.0 RE	2.0 RE	

DESCRIPTION OF SPECIMEN: Red-brown micaceous sandy silty clay

LIQUID LIMIT (%)	-	FINAL VOID RATIO (e_f)	.86
PLASTIC LIMIT (%)	-	UNIT DRY WEIGHT (pcf)	84.0
PLASTICITY INDEX (%)		CONSOLIDATION PROPERTIES	
NATURAL WATER CONTENT (%)	36	COMPRESSION INDEX (C_c) (Unit strain basis)	0.12
SPECIFIC GRAVITY	2.6	RECOMPRESSION (C_R) " " "	0.013
TEST SPECIMEN PROPERTIES		SWELLING INDEX (C_s)	0.028
DIAMETER OF SPECIMEN (in.)	2.495	PRECONSOLIDATION STRESS (P_c) tsf	2.0
INITIAL THICKNESS OF SPECIMEN (in.)	.916	EXISTING OVERBURDEN STRESS (P_o) tsf	0.12
INITIAL WATER CONTENT (%)	36		
INITIAL VOID RATIO (e_0)	.98		

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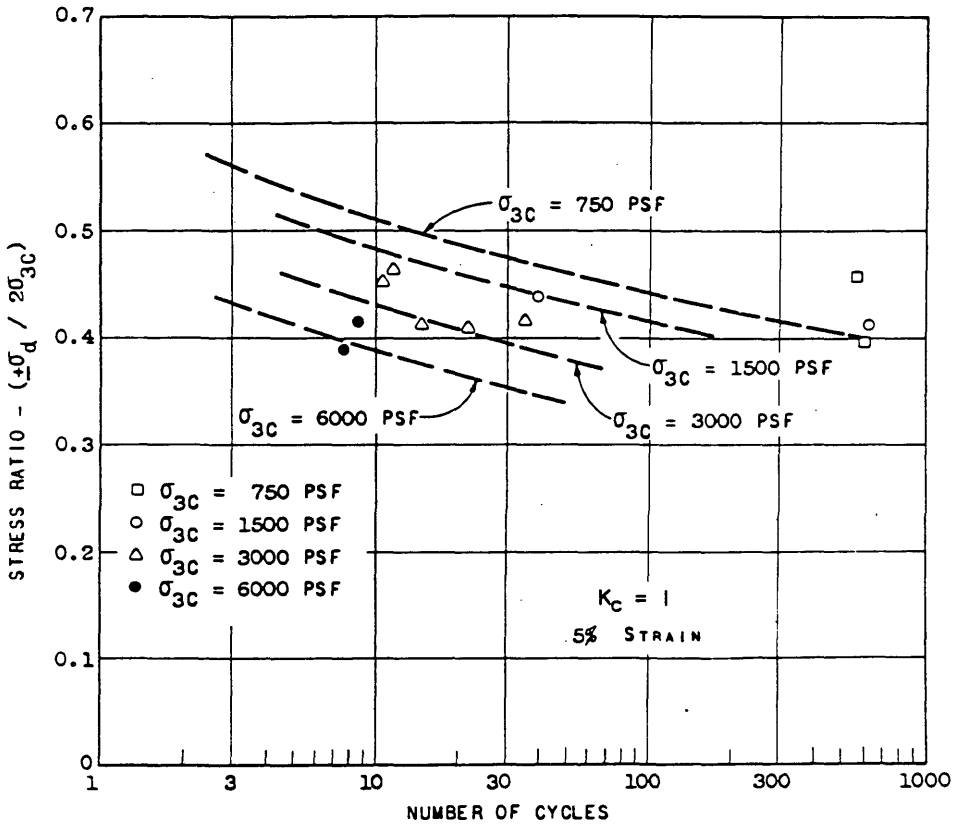
VIRGIL C. SUMMER NUCLEAR STATION

Consolidation Test Results On Foundation Soil (Sheet 13 of 13)

Figure 2.5-114

Figure 2.5-115
CYCLIC TRIAXIAL TEST RESULTS FOR UNDISTRIBUTED SAMPLES OF COLLUVIUM



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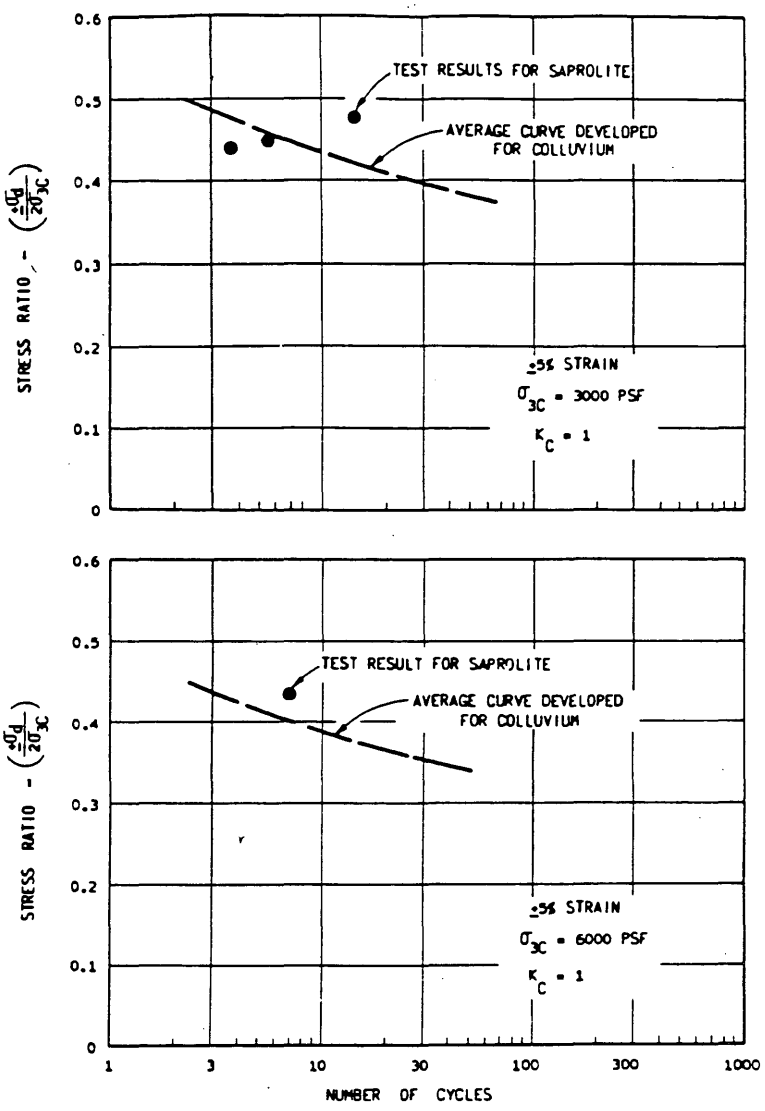
VIRGIL C. SUMMER NUCLEAR STATION

Cyclic Triaxial Test Results for
Undisturbed Samples of Colluvium

Figure 2.5-115

Figure 2.5-116

CYCLIC TRIAXIAL TEST RESULTS FOR UNDISTURBED SAMPLES OF SAPROLITE



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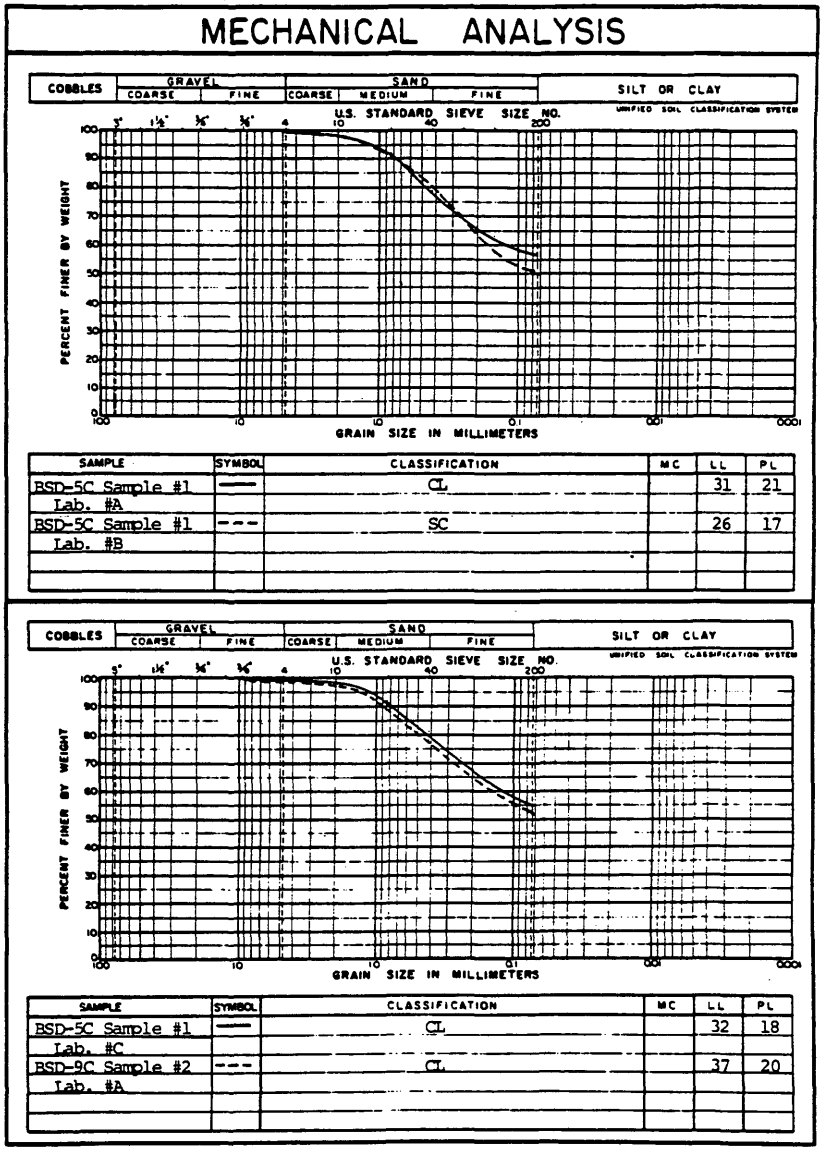
Cyclic Triaxial Test Results for Undisturbed Samples of Saprolite Figure 2.5-116

Figure 2.5-117

PHYSICAL PROPERTIES OF COLLUVIAL CYCLIC TRIAXIAL TEST SAMPLES (SHEET 1 OF 3)



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Physical Properties Of Colluvial Cyclic Triaxial Test Samples (Sheet 1 of 3) Figure 2.5-117

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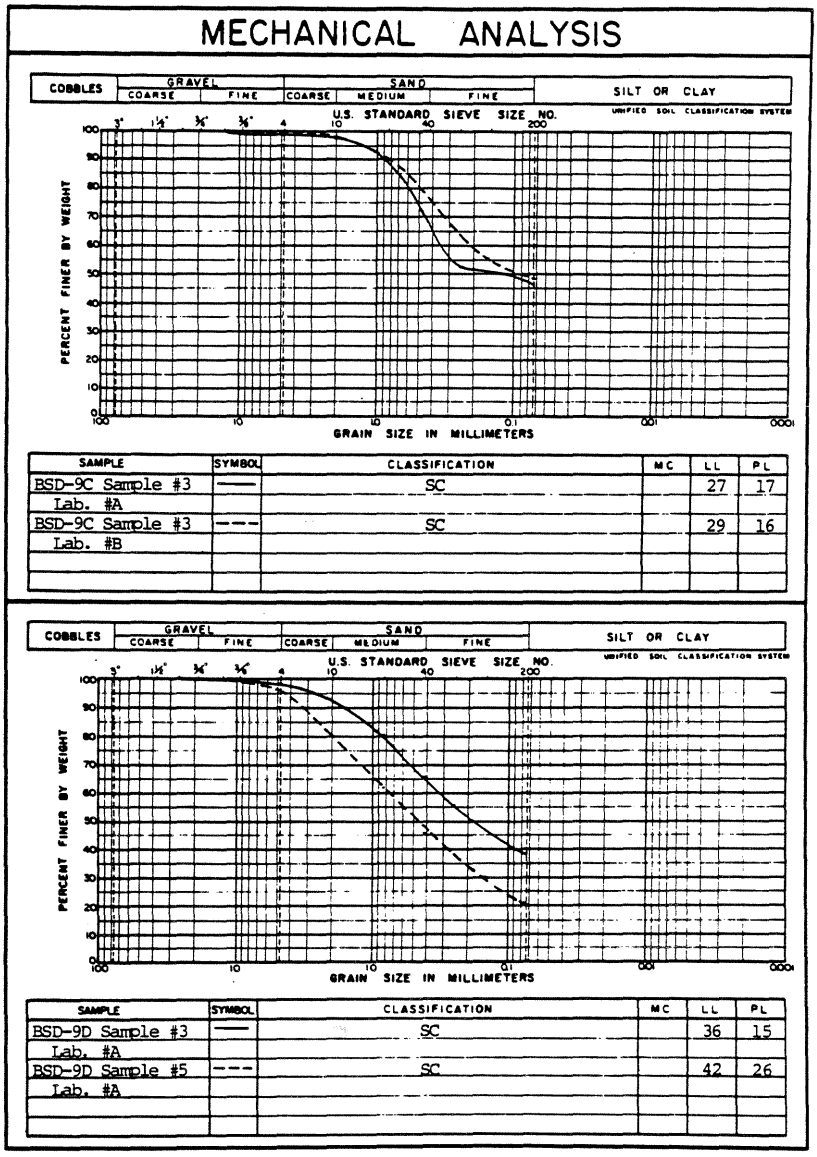
Figure 2.5-117

PHYSICAL PROPERTIES OF COLLUVIAL CYCLIC TRIAXIAL TEST SAMPLES (SHEET 2 OF 3)



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Physical Properties Of Colluvial
Cyclic Triaxial Test Samples
(Sheet 2 of 3)

Figure 2.5-117

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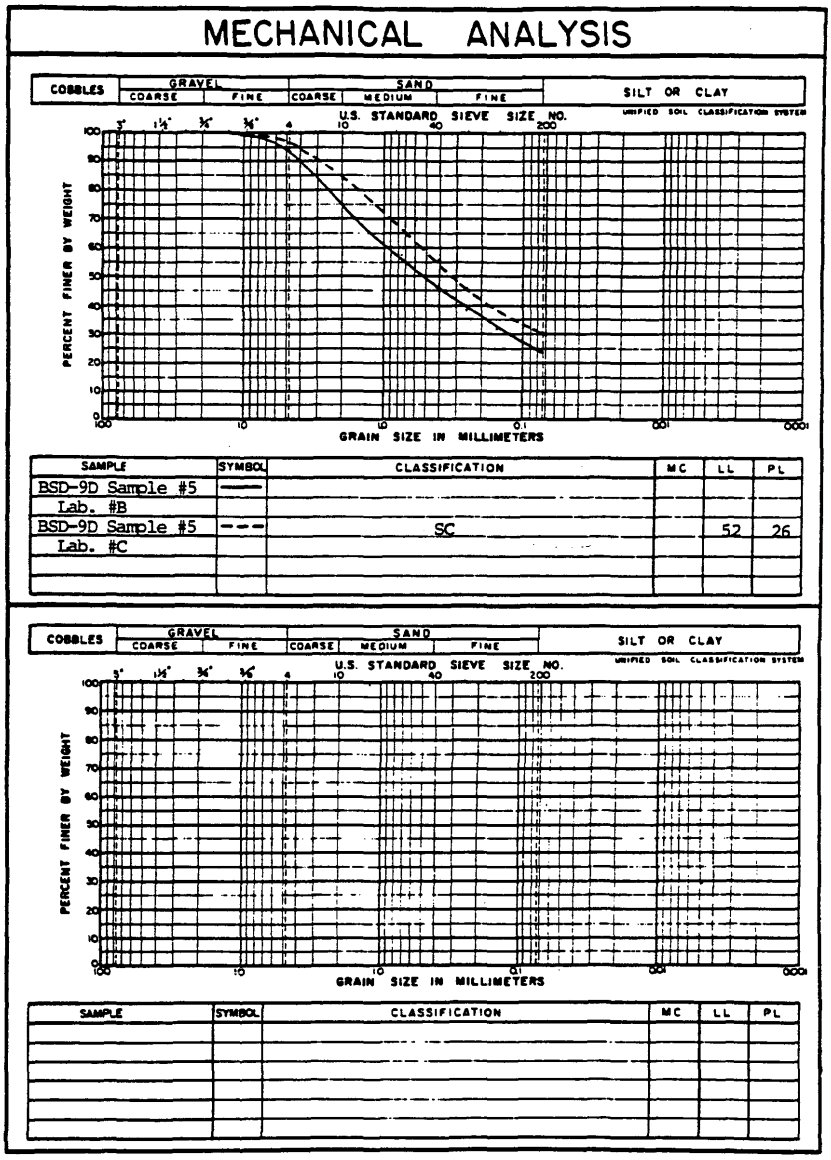
Figure 2.5-117

PHYSICAL PROPERTIES OF COLLUVIAL CYCLIC TRIAXIAL TEST SAMPLES (SHEET 3 OF 3)



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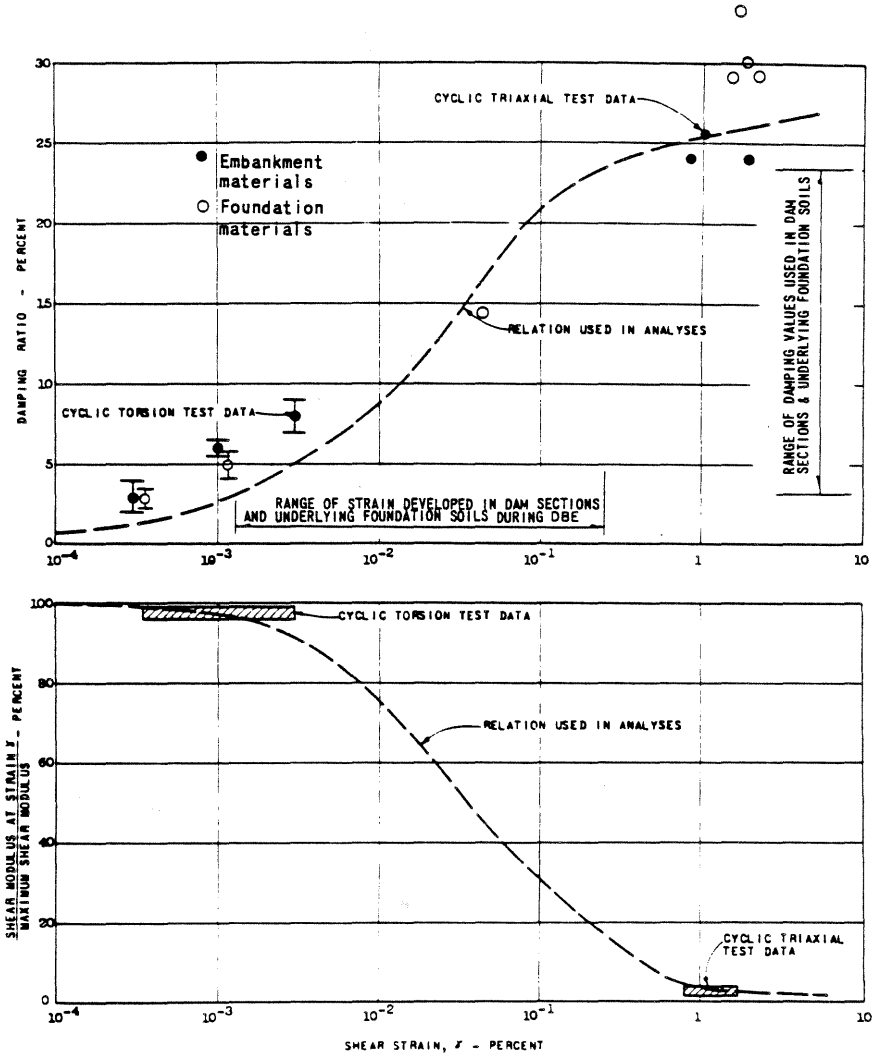
Physical Properties Of Colluvial Cyclic Triaxial Test Samples (Sheet 3 of 3) Figure 2.5-117

Figure 2.5-118
VARIATIONS OF DAMPING AND SHEAR MODULI USED IN DESIGN



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Variations of Damping and Shear Moduli Used in Desgn
Figure 2.5-118

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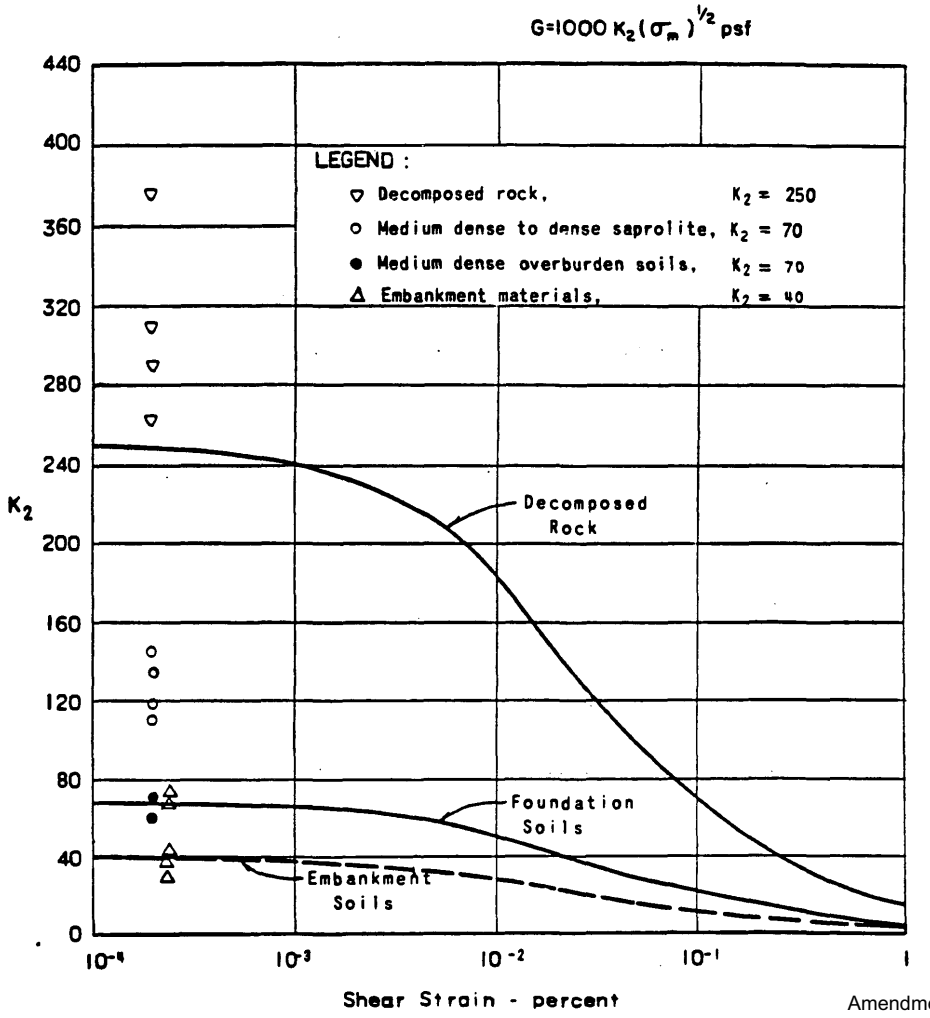
Figure 2.5-119

SHEAR MODULUS K_2 PARAMETER VS. SHEAR STRAIN



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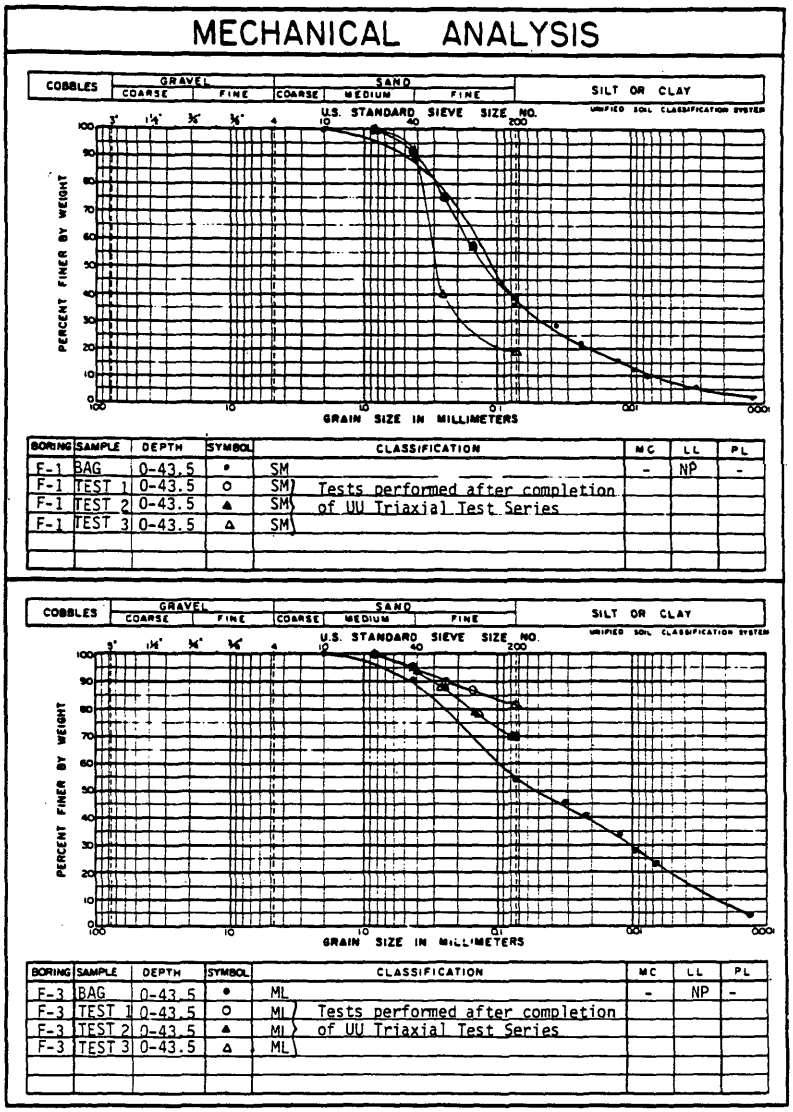
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Shear Modulus K_2 Parameter
Vs. Shear Strain

Figure 2.5-119

Figure 2.5-120

GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 1 OF 17)



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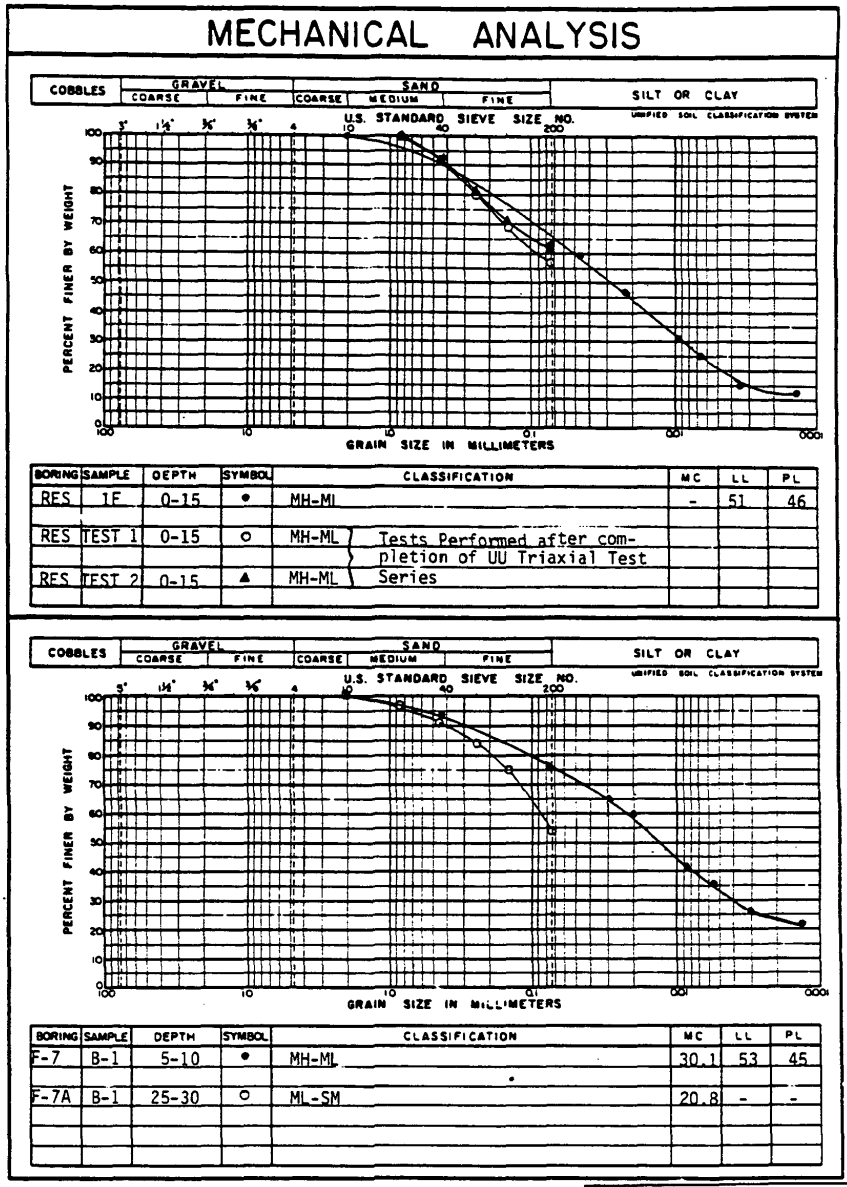
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 1 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES
OF BORROW SOIL (SHEET 2 OF 17)



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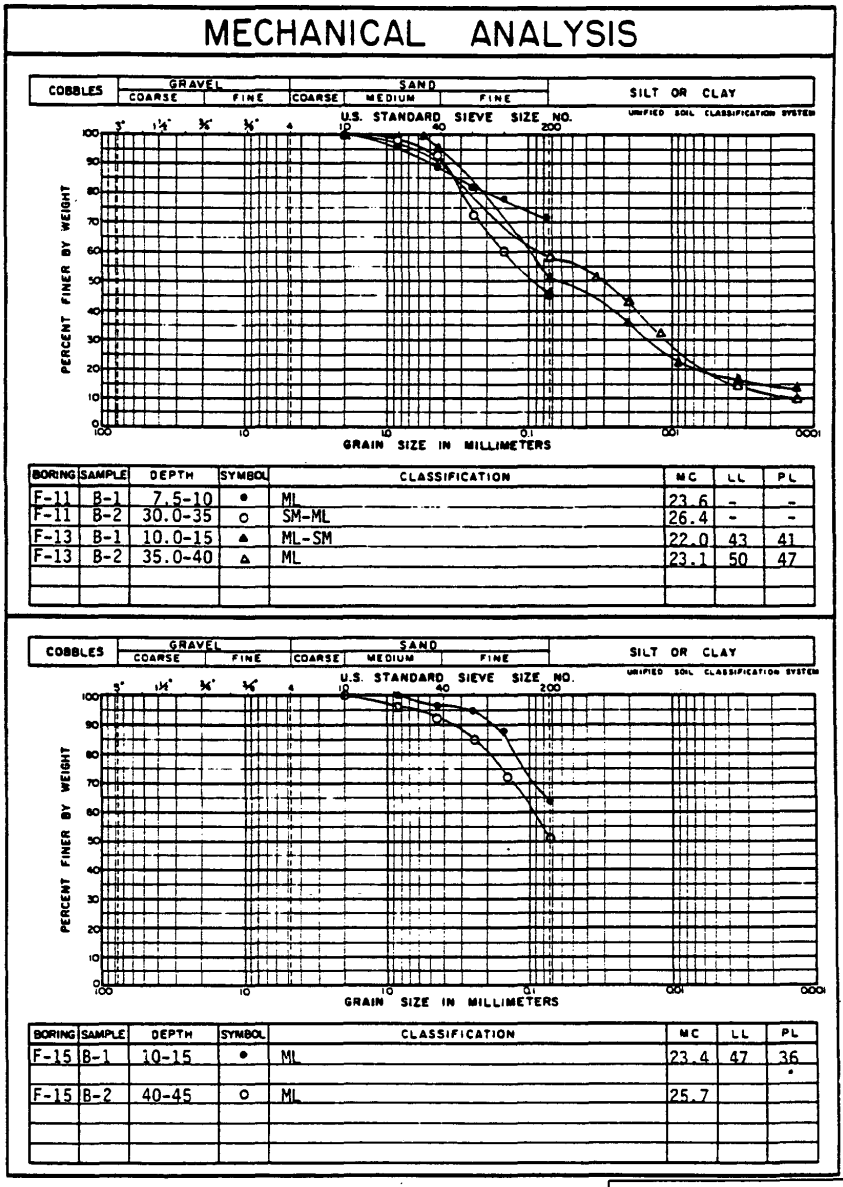
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 2 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 3 OF 17)



BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
F-11	B-1	7.5-10	●	ML	23.6	-	-
F-11	B-2	30.0-35	○	SM-ML	26.4	-	-
F-13	B-1	10.0-15	▲	ML-SM	22.0	43	41
F-13	B-2	35.0-40	△	ML	23.1	50	47

BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
F-15	B-1	10-15	●	ML	23.4	47	36
F-15	B-2	40-45	○	ML	25.7		

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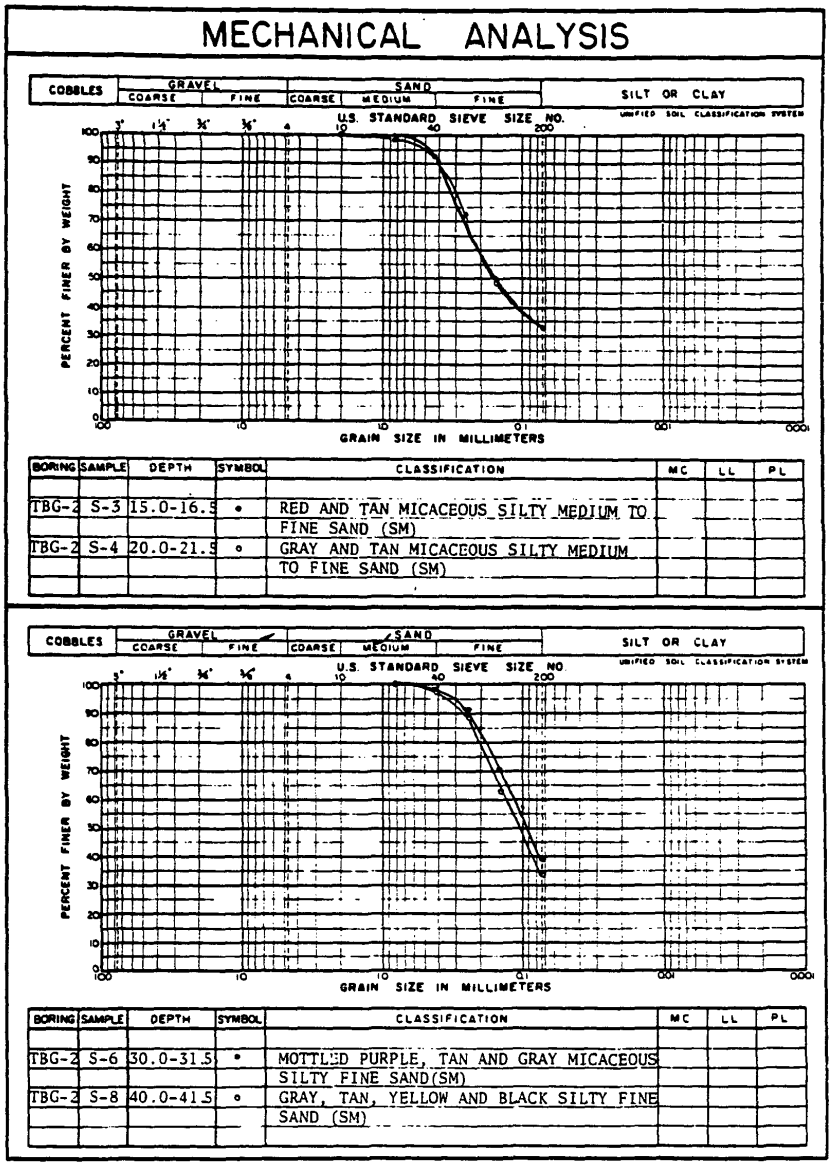
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 3 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 4 OF 17)



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VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 4 of 17)

Figure 2.5-120

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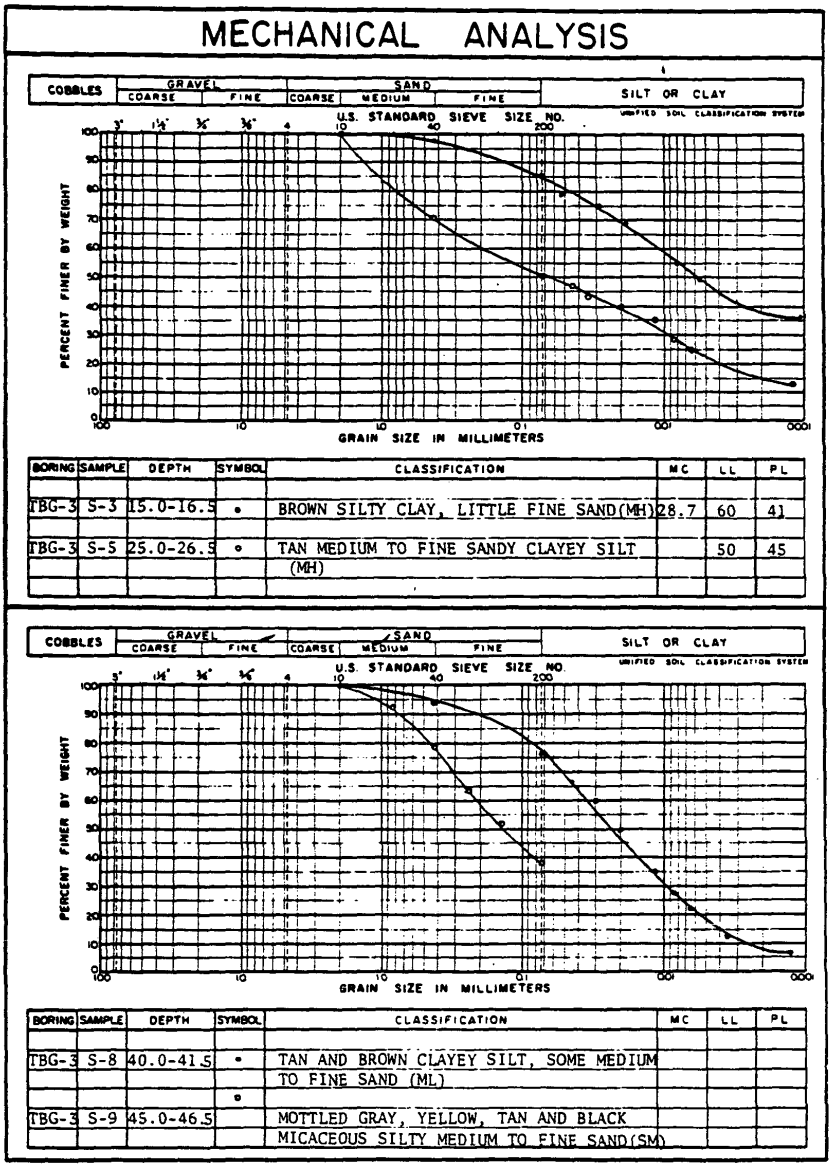
Figure 2.5-120

GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 5 OF 17)



BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
TBG-3	S-3	15.0-16.5	•	BROWN SILTY CLAY, LITTLE FINE SAND(MH)	28.7	60	41
TBG-3	S-5	25.0-26.5	○	TAN MEDIUM TO FINE SANDY CLAYEY SILT (MH)		50	45

BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
TBG-3	S-8	40.0-41.5	•	TAN AND BROWN CLAYEY SILT, SOME MEDIUM TO FINE SAND (ML)			
TBG-3	S-9	45.0-46.5	○	MOTTLED GRAY, YELLOW, TAN AND BLACK MICACEOUS SILTY MEDIUM TO FINE SAND(SM)			

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SOUTH CAROLINA ELECTRIC & GAS CO.
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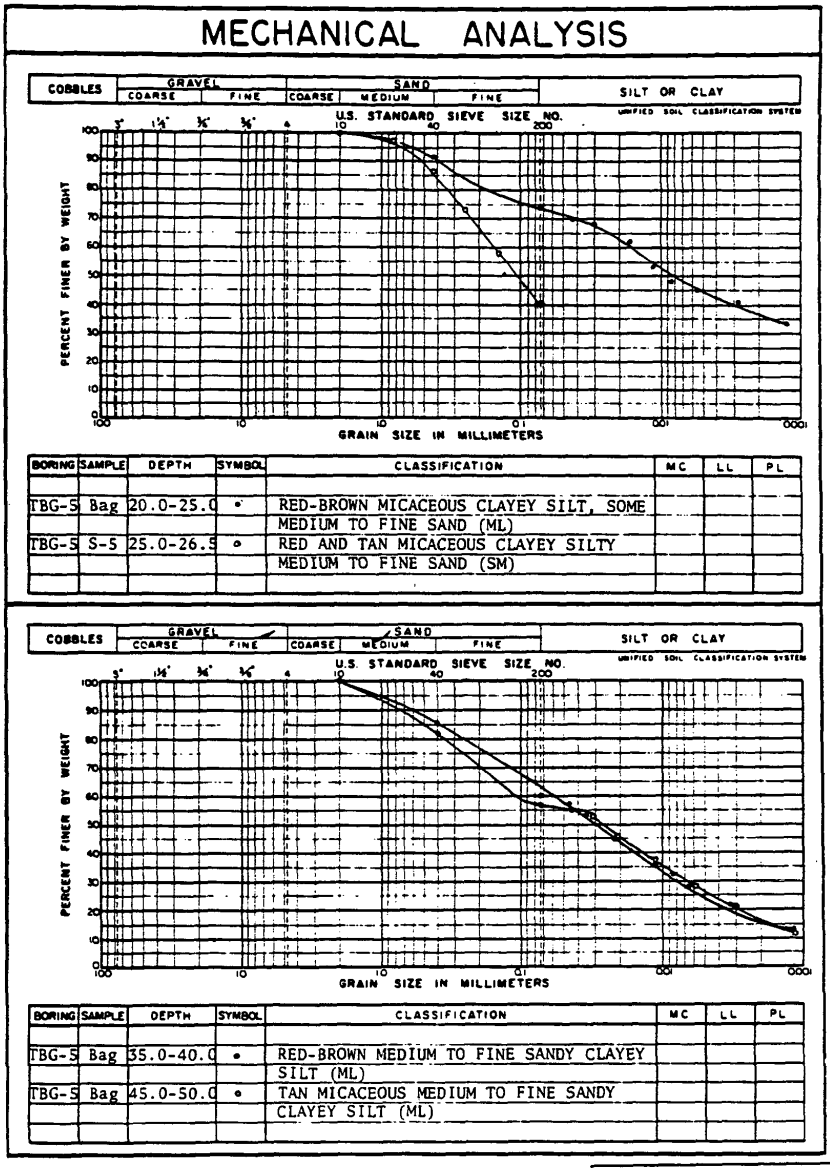
Grain Size Distribution Curves
Of Borrow Soil
(Sheet 5 of 17)

Figure 2.5-120

Figure 2.5-120

GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 6 OF 17)



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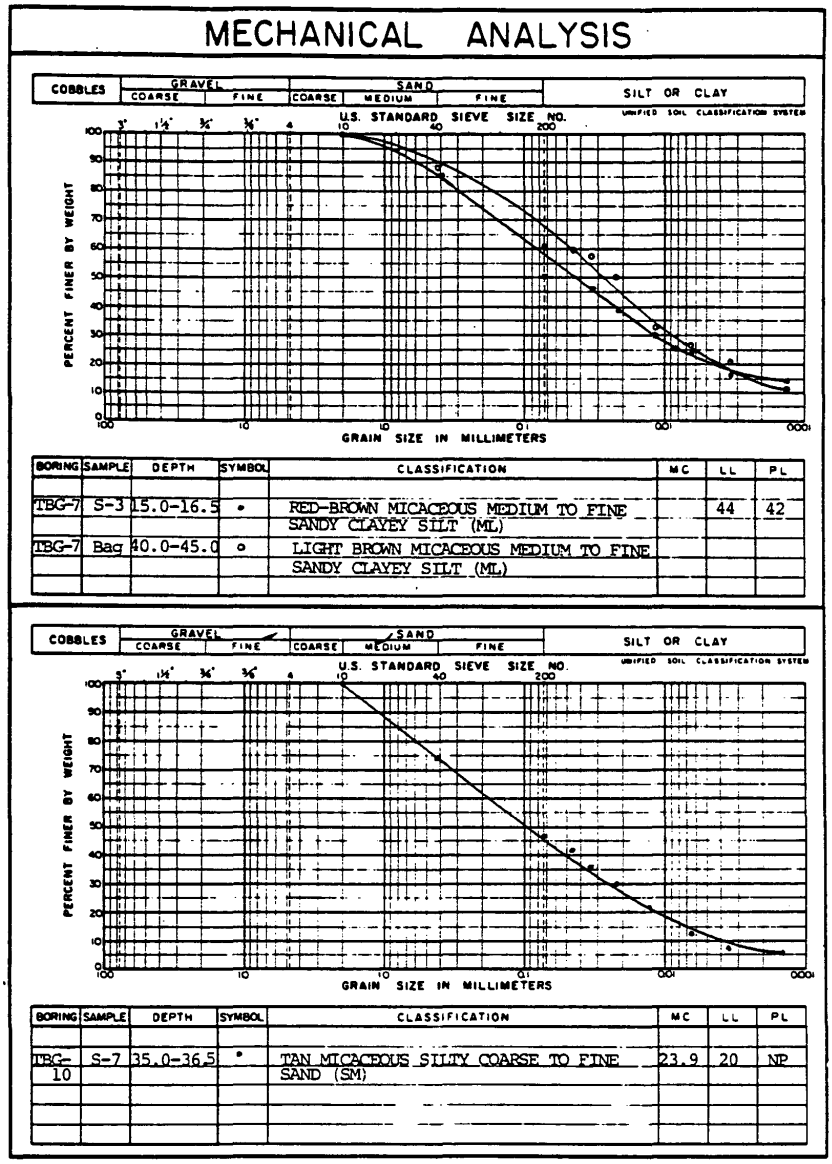
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 6 of 17)

Figure 2.5-120

Figure 2.5-120

GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 7 OF 17)



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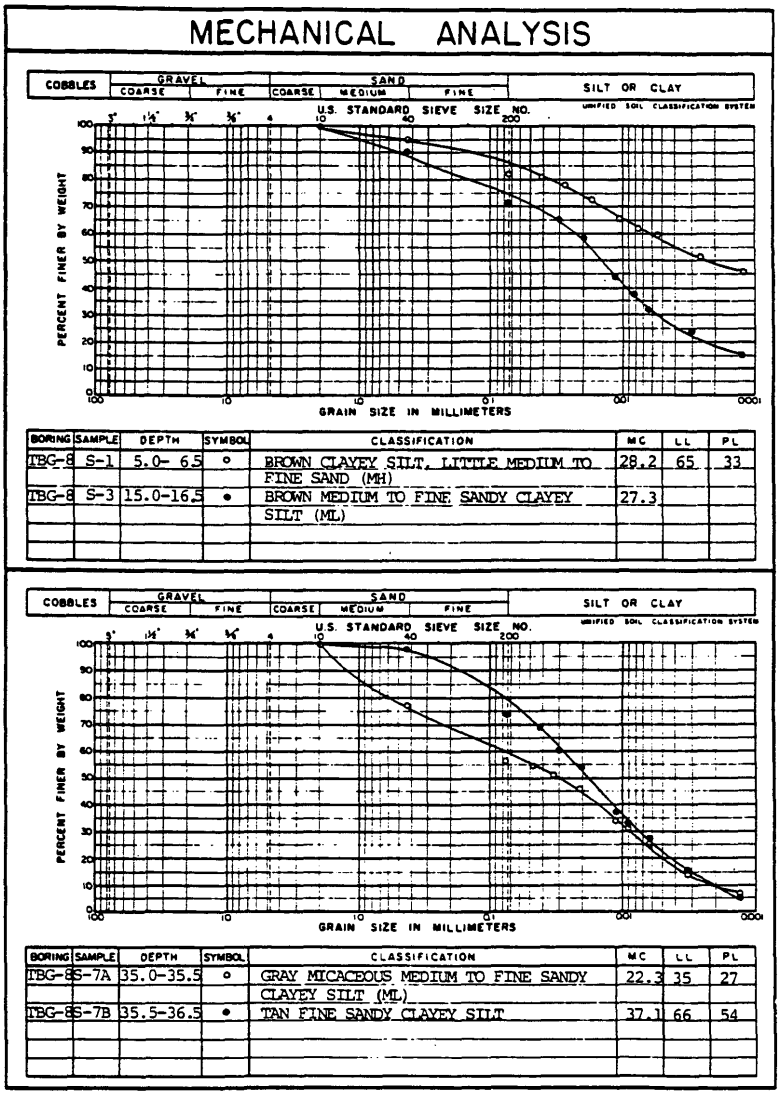
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 7 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 8 OF 17)



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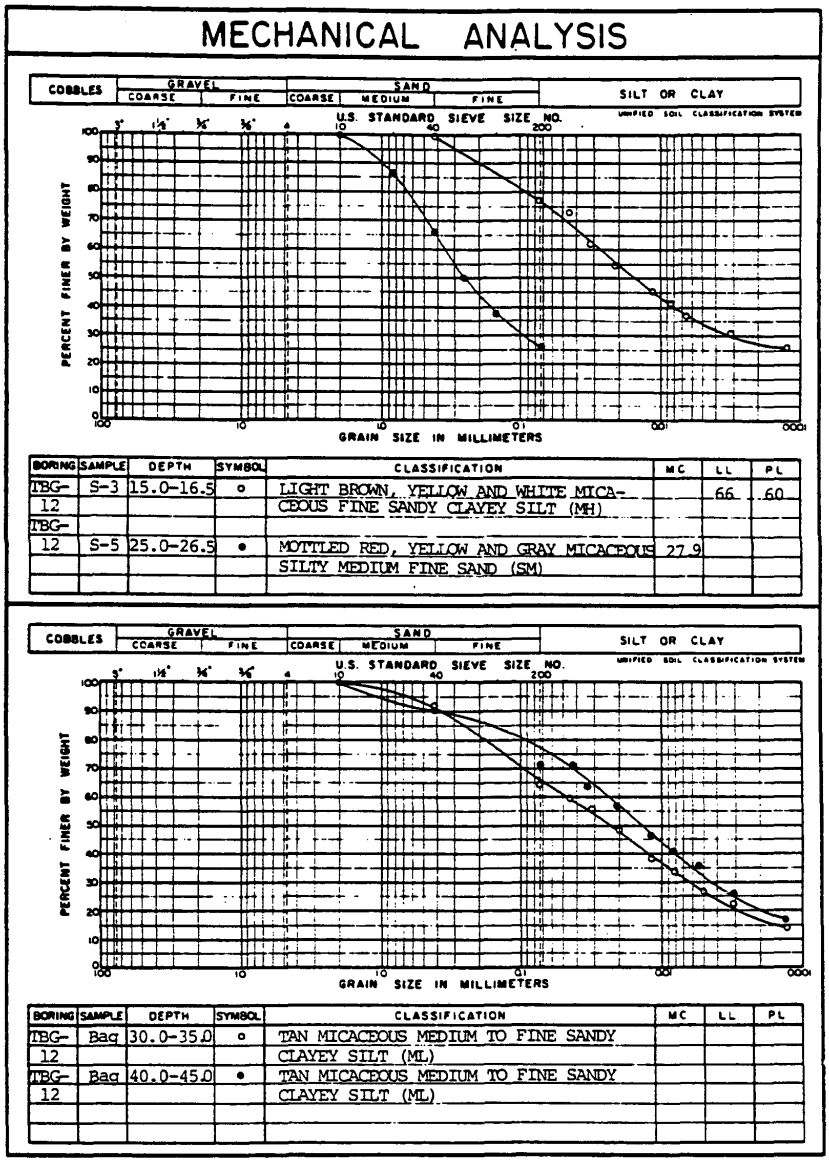
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 8 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 9 OF 17)



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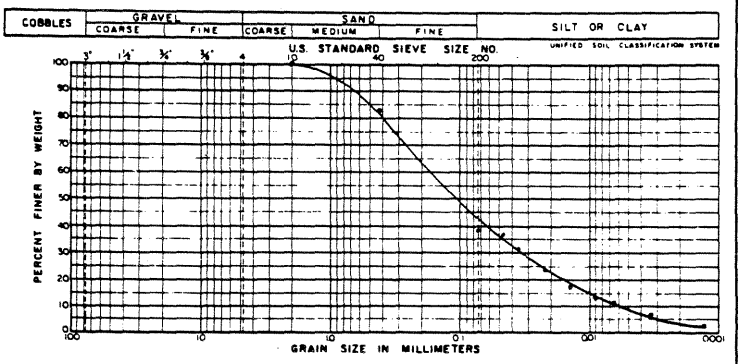
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 9 of 17)

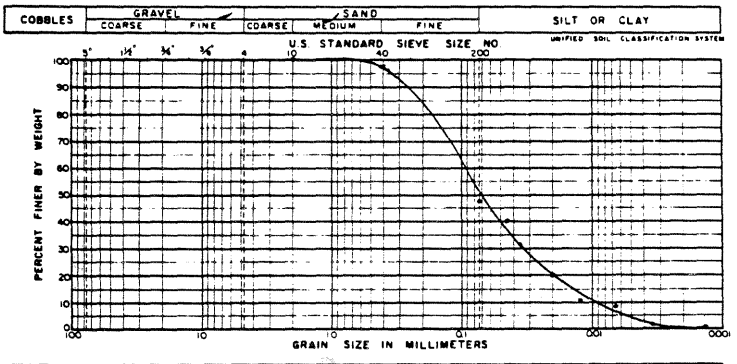
Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 10 OF 17)

MECHANICAL ANALYSIS



BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
TBG-14	S-3	20.0-21.5	•	RED, TAN AND YELLOW MICACEOUS SILTY MEDIUM TO FINE SAND (SM)		52	42



BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
TBG-14	S-8	40.0-41.5	•	GREEN-BROWN AND DARK BROWN MICACEOUS SILTY FINE SAND			

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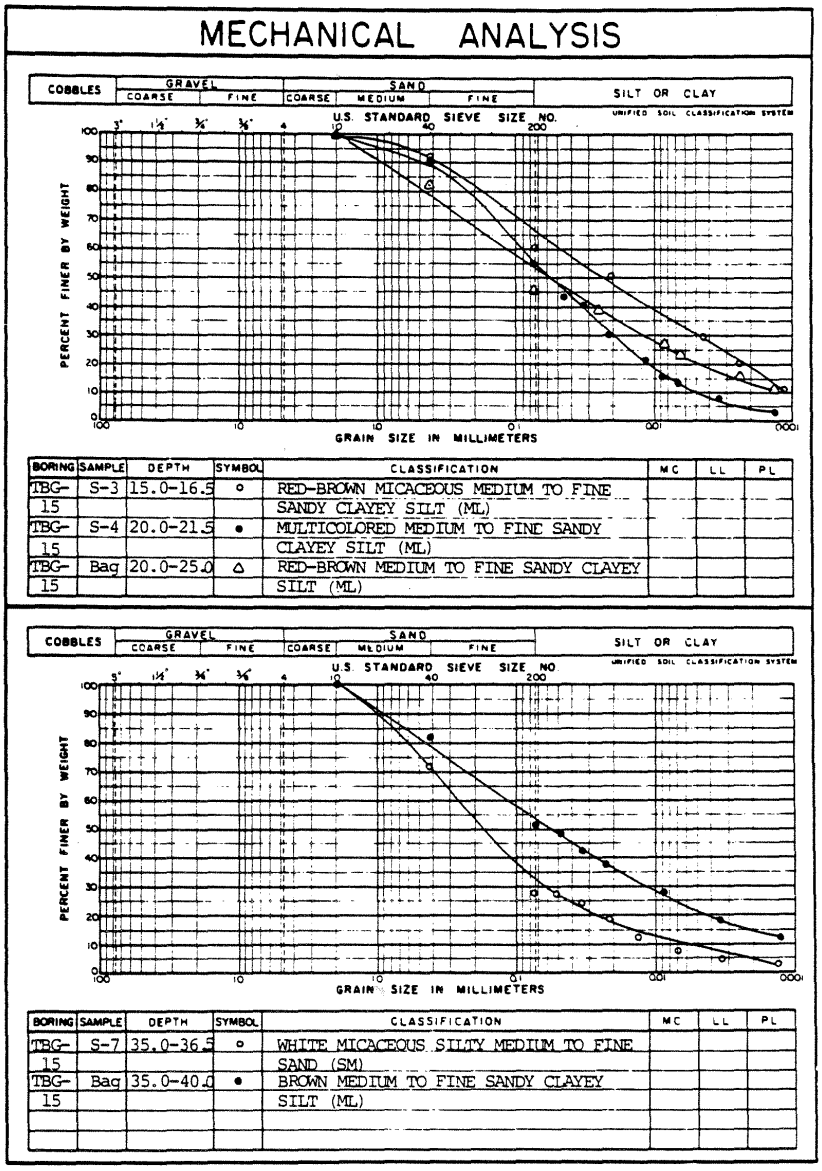
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 10 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 11 OF 17)



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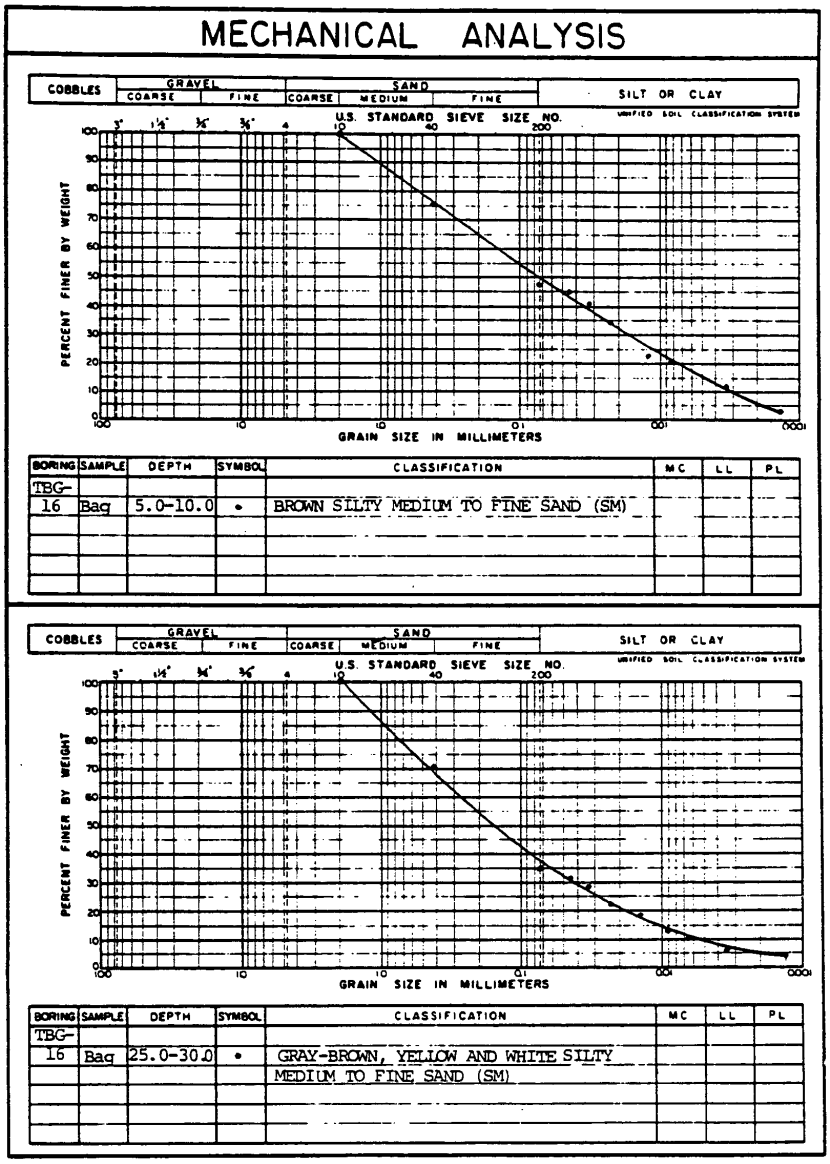
Grain Size Distribution Curves
Of Borrow Soil
(Sheet 11 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 12 OF 17)



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SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
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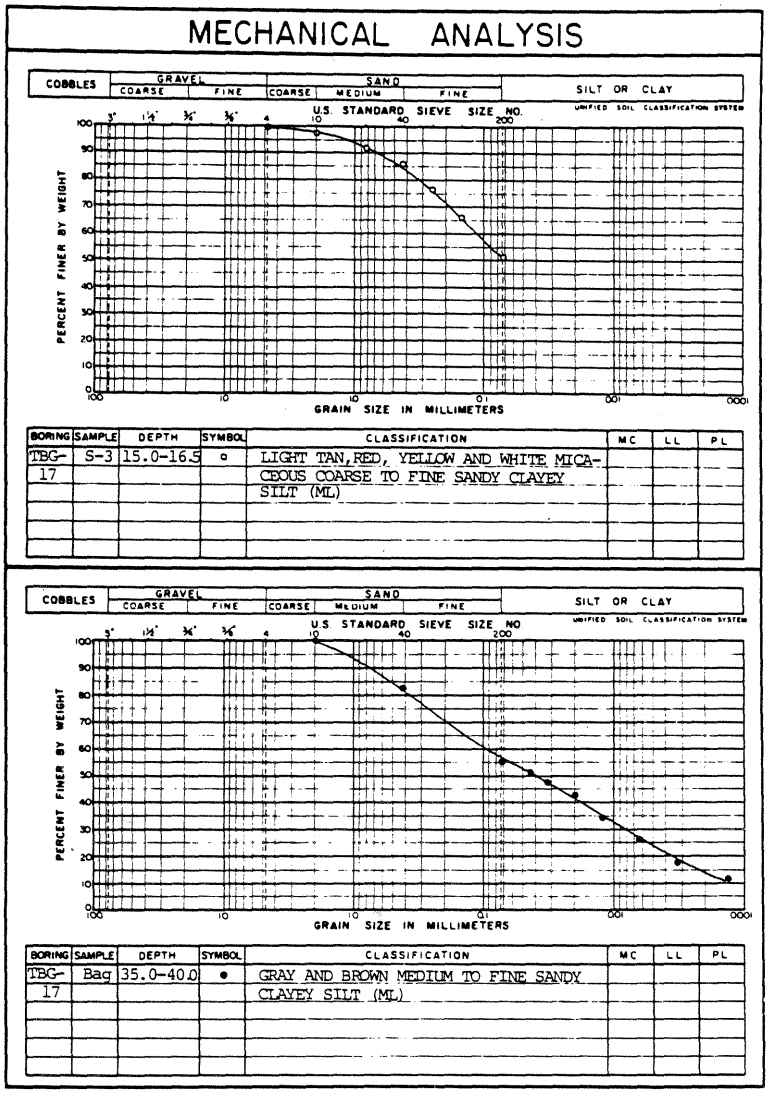
Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 13 OF 17)



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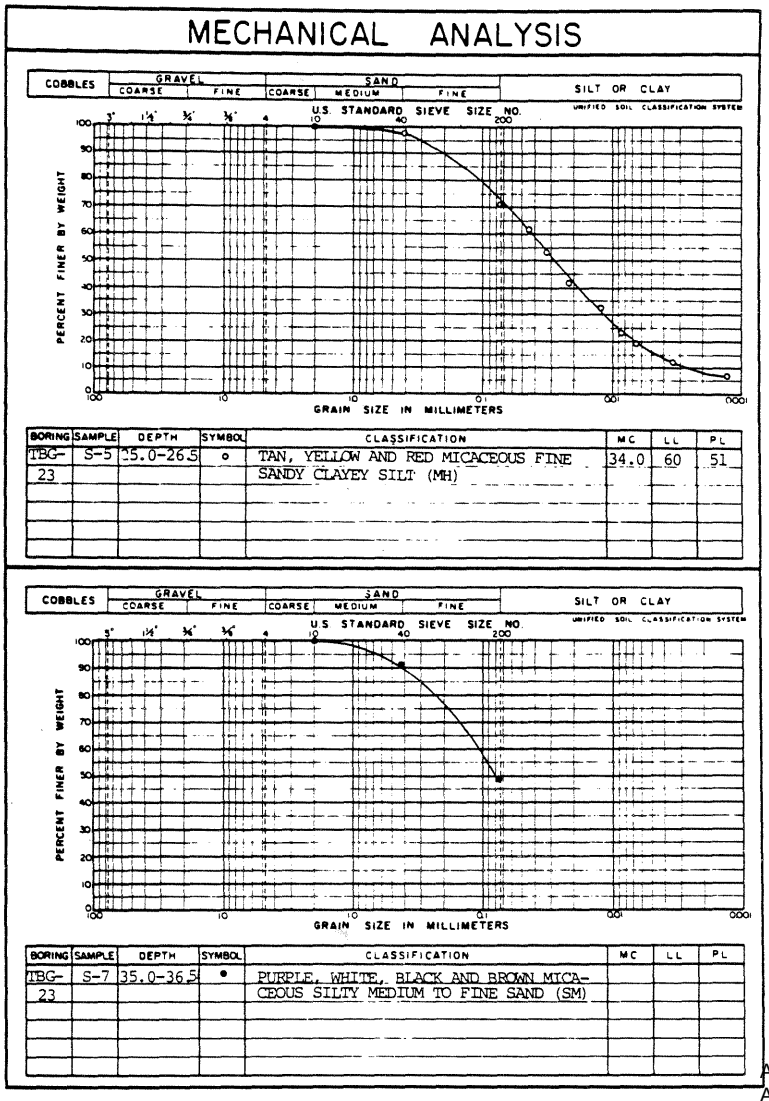
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 13 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 14 OF 17)



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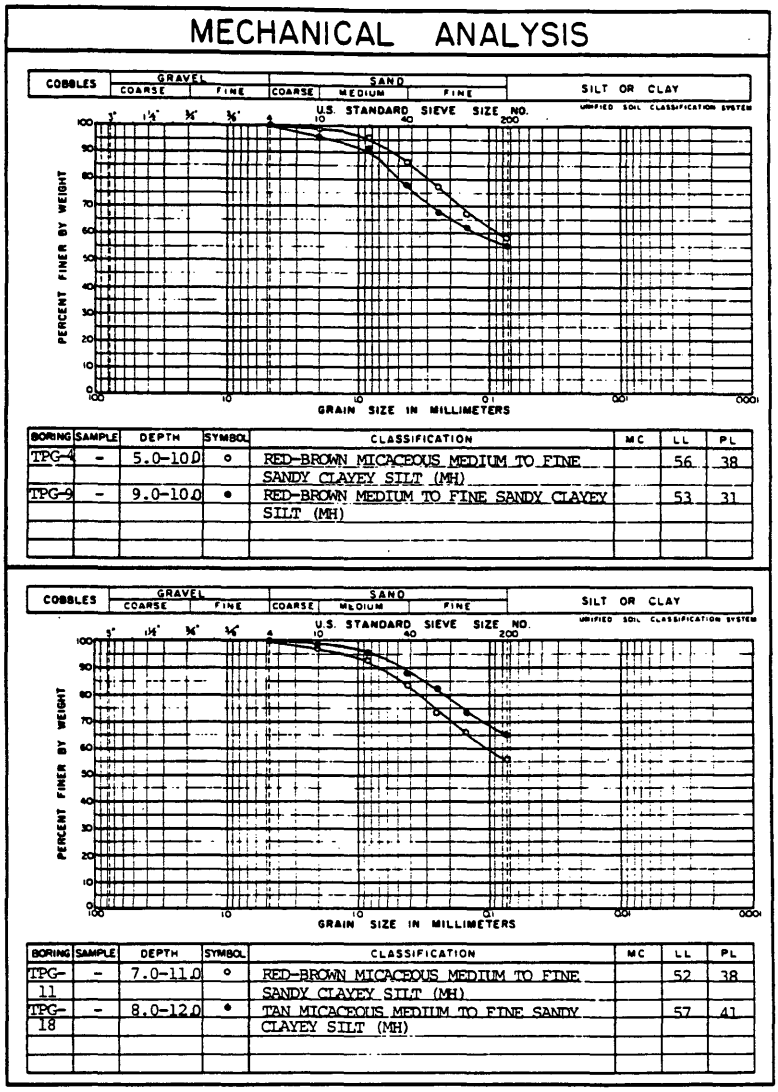
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 14 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 15 OF 17)



BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
TPG-4	-	5.0-10.0	○	RED-BROWN MICACEOUS MEDIUM TO FINE SANDY CLAYEY SILT (MH)		56	38
TPG-9	-	9.0-10.0	●	RED-BROWN MEDIUM TO FINE SANDY CLAYEY SILT (MH)		53	31

BORING	SAMPLE	DEPTH	SYMBOL	CLASSIFICATION	MC	LL	PL
TPG-11	-	7.0-11.0	○	RED-BROWN MICACEOUS MEDIUM TO FINE SANDY CLAYEY SILT (MH)		52	38
TPG-18	-	8.0-12.0	●	TAN MICACEOUS MEDIUM TO FINE SANDY CLAYEY SILT (MH)		57	41

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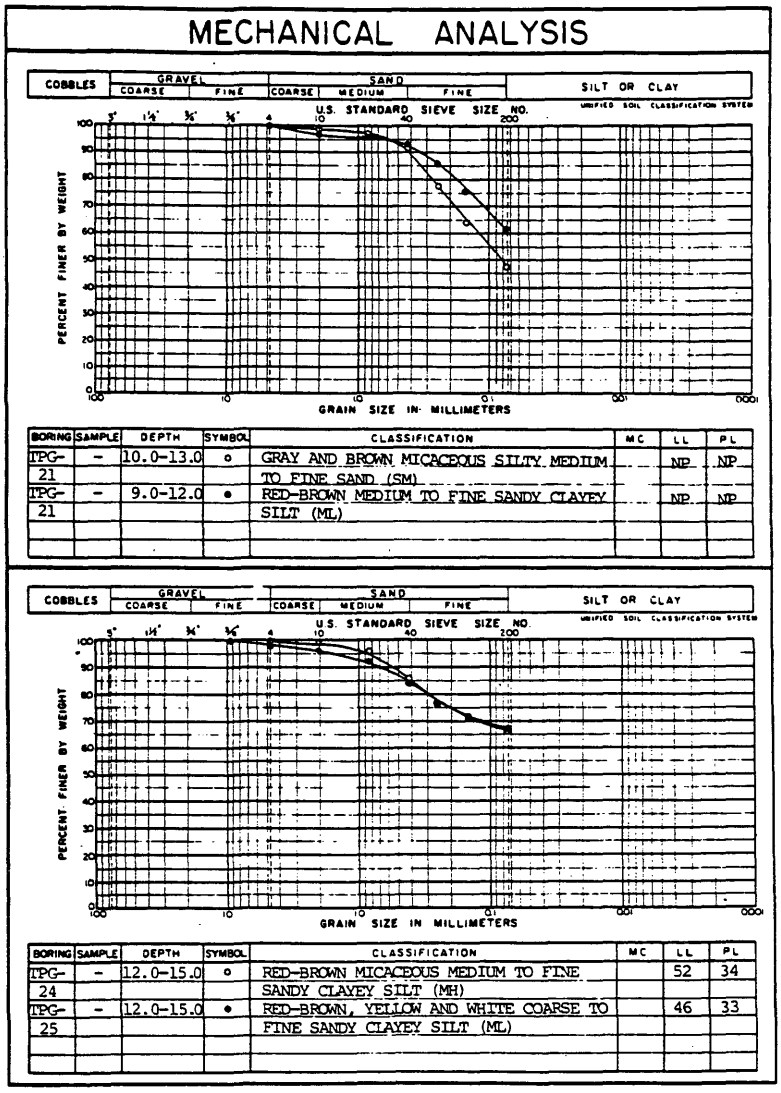
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 15 of 17)

Figure 2.5-120

Figure 2.5-120
GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 16 OF 17)



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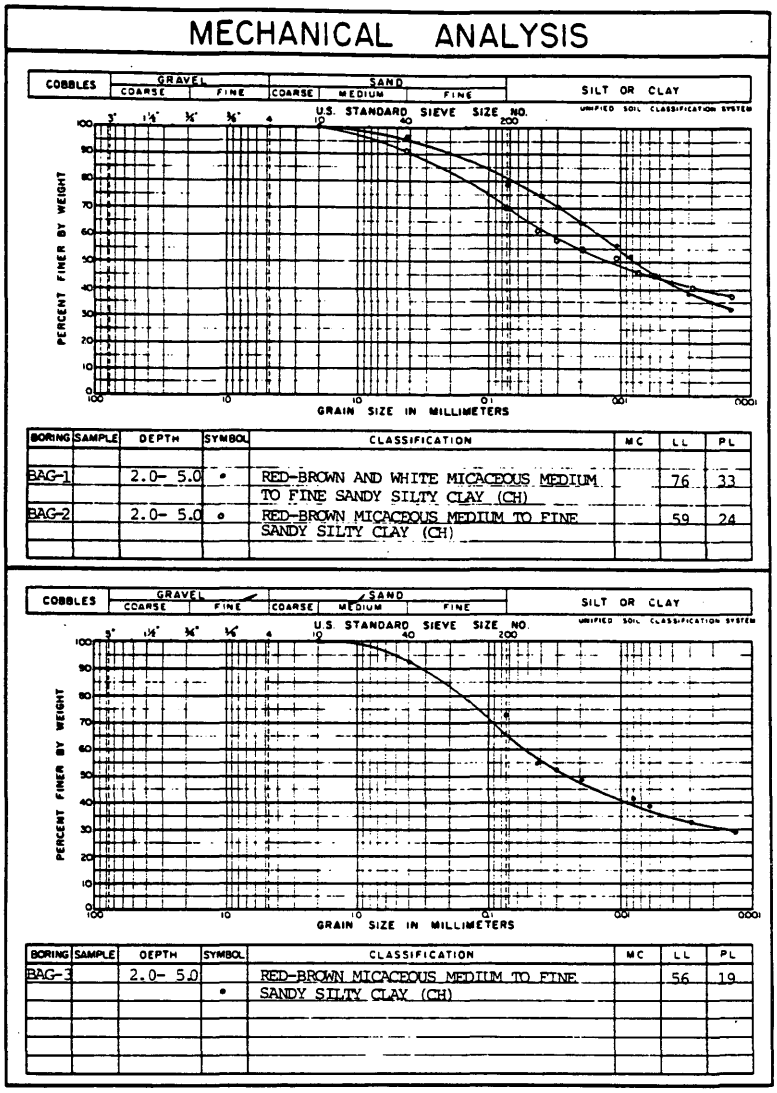
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 16 of 17)

Figure 2.5-120

Figure 2.5-120

GRAIN SIZE DISTRIBUTION CURVES OF BORROW SOIL (SHEET 17 OF 17)



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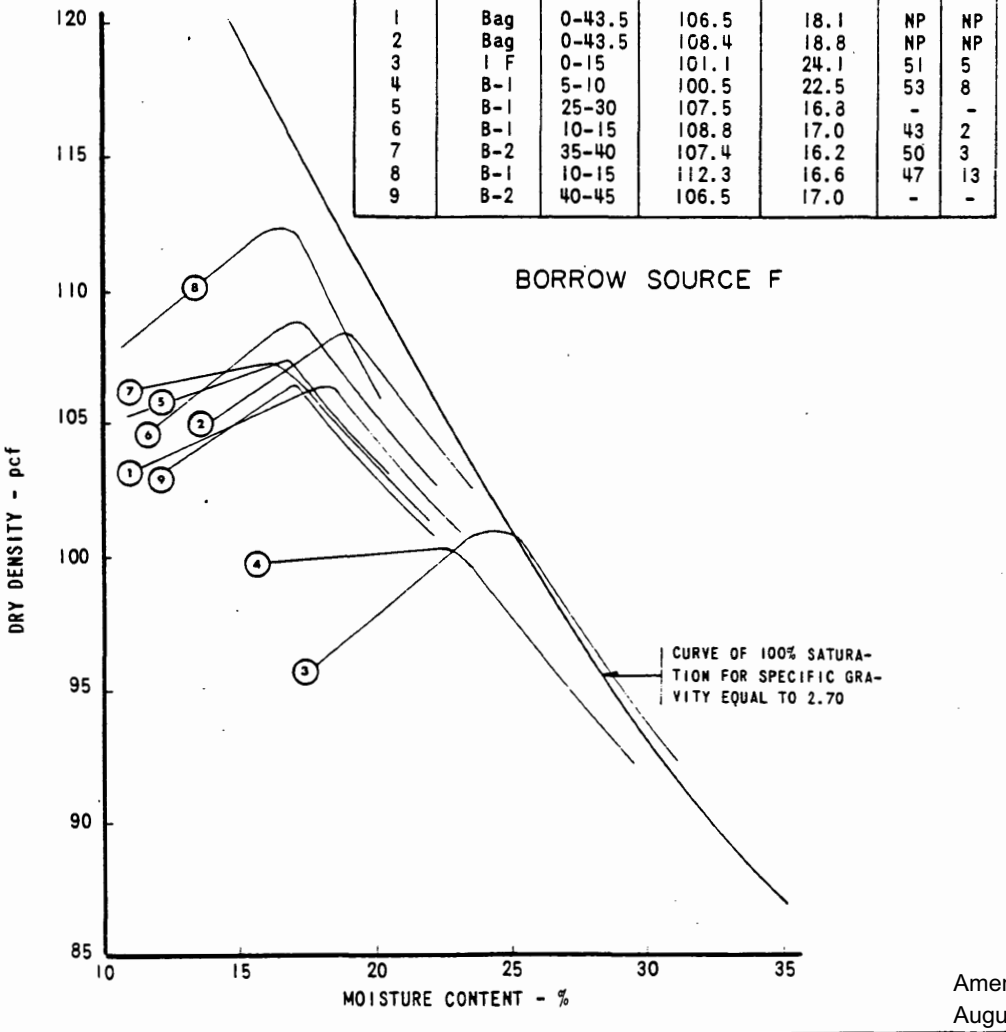
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution Curves
Of Borrow Soil
(Sheet 17 of 17)

Figure 2.5-120

Figure 2.5-121
COMPACTION TEST RESULTS FOR BORROW SOURCE F

CURVE NO.	SAMPLE NO.	DEPTH (Ft)	MAX. DRY DENSITY (pcf)	OPTIMUM MOISTURE CONTENT (%)	LL (%)	PI (%)
1	Bag	0-43.5	106.5	18.1	NP	NP
2	Bag	0-43.5	108.4	18.8	NP	NP
3	1 F	0-15	101.1	24.1	51	5
4	B-1	5-10	100.5	22.5	53	8
5	B-1	25-30	107.5	16.8	-	-
6	B-1	10-15	108.8	17.0	43	2
7	B-2	35-40	107.4	16.2	50	3
8	B-1	10-15	112.3	16.6	47	13
9	B-2	40-45	106.5	17.0	-	-



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SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

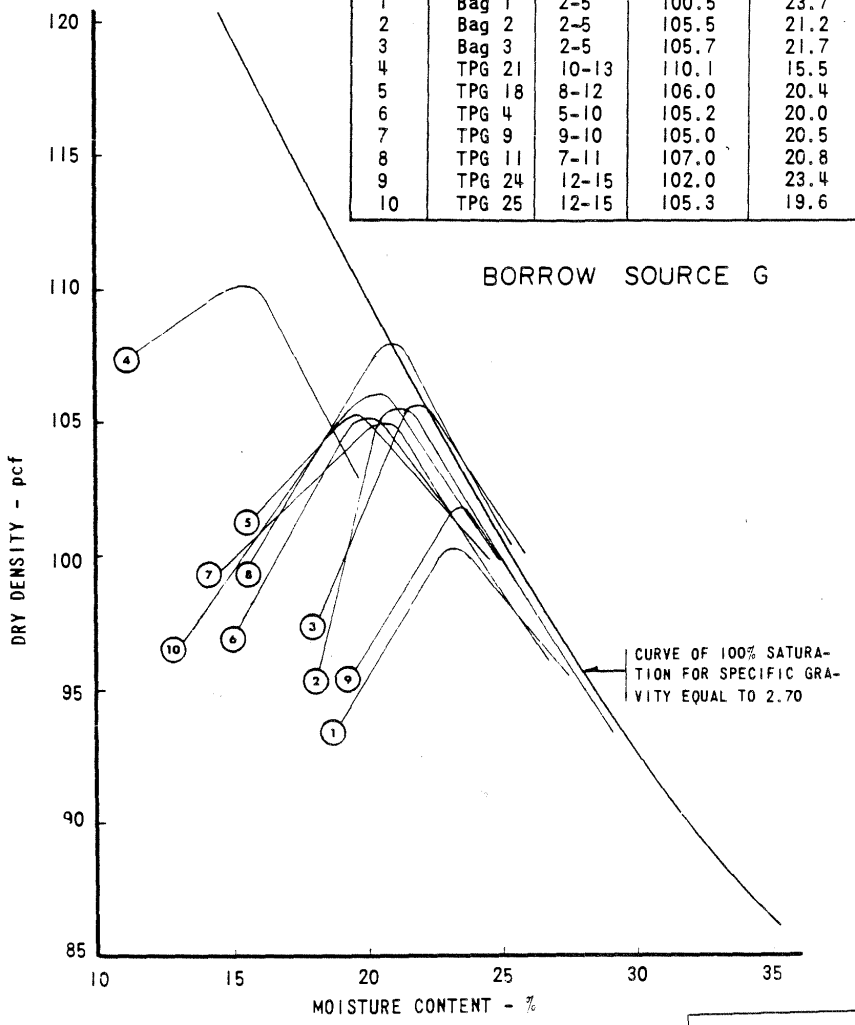
Compaction Test Results for
Borrow Source F

Figure 2.5-121

Figure 2.5-122

COMPACTION TEST RESULTS FOR BORROW SOURCE G

CURVE NO.	SAMPLE NO.	DEPTH (Ft)	MAX. DRY DENSITY (pcf)	OPTIMUM MOISTURE CONTENT (%)	LL (%)	PI (%)
1	Bag 1	2-5	100.5	23.7	76	33
2	Bag 2	2-5	105.5	21.2	59	24
3	Bag 3	2-5	105.7	21.7	56	19
4	TPG 21	10-13	110.1	15.5	66	17
5	TPG 18	8-12	106.0	20.4	57	26
6	TPG 4	5-10	105.2	20.0	66	17
7	TPG 9	9-10	105.0	20.5	73	35
8	TPG 11	7-11	107.0	20.8	60	18
9	TPG 24	12-15	102.0	23.4	75	30
10	TPG 25	12-15	105.3	19.6	58	23



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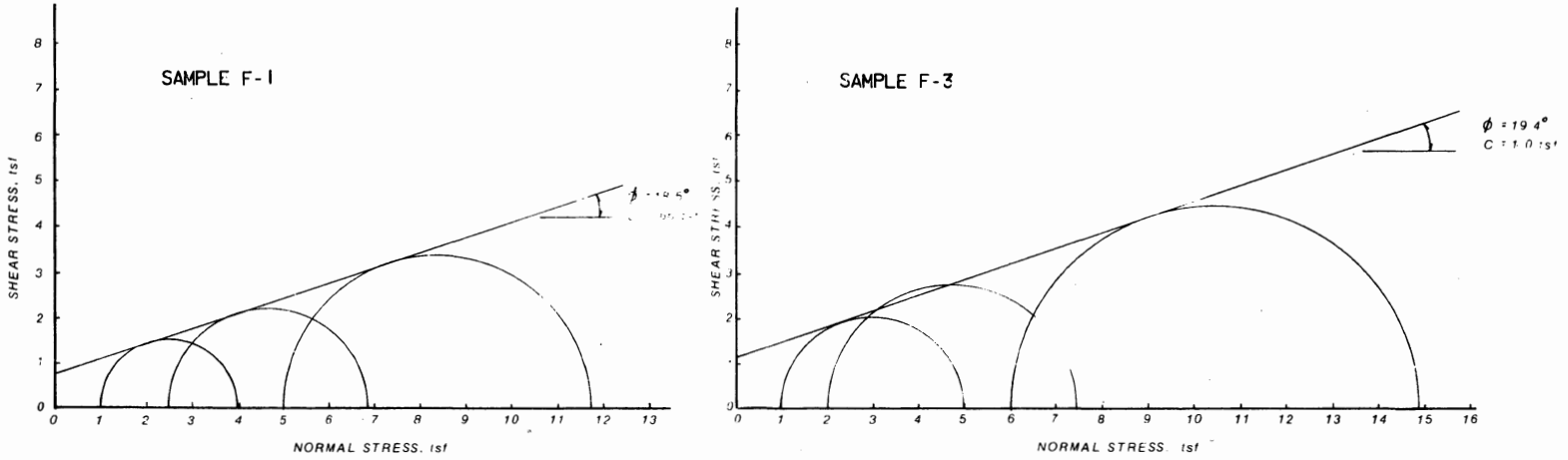
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Compaction Test Results for
Borrow Source G

Figure 2.5-122

Figure 2.5-123

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON BORROW SOIL (SHEET 1 OF 2)



TEST No.	BORING No.	DEPTH Feet	DRY DEN. pcf	MOISTURE %	PERCENT COMPACTION	CONFINING PRES. tsf	STRAIN %
1	F-1	Auger	95.5	21.9	89.7	1.08	4.6
2	-"-	Bag	95.5	22.2	89.7	2.52	4.7
3	-"-	Sample	96.0	22.5	90.1	5.04	4.6
4	F-3	0 -43.5'	98.1	21.5	90.4	1.00	3.3
5	-"-	—"—	97.5	22.3	89.8	2.00	3.8
6	-"-	—"—	97.5	22.3	89.8	6.00	4.0

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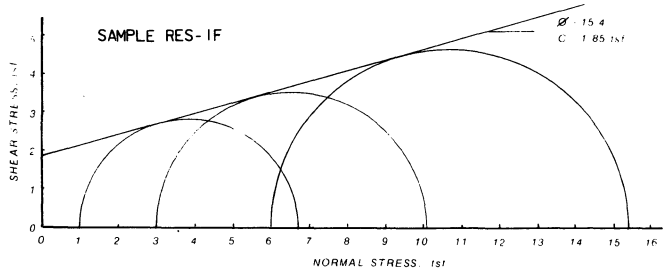
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

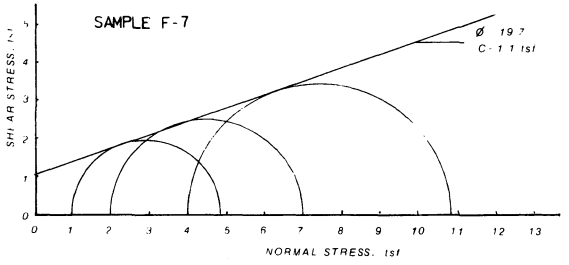
Unconsolidated Undrained Triaxial Compression Test Results On Borrow Soil (Sheet 1 of 2)

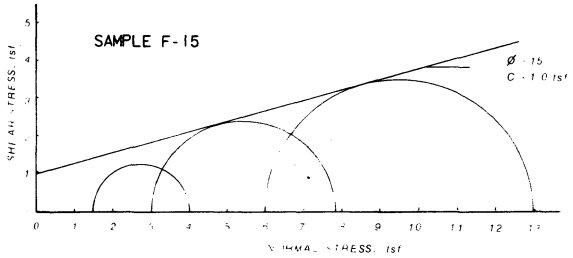
Figure 2.5-123

Figure 2.5-123

UNCONSOLIDATED UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON BORROW SOIL (SHEET 2 OF 2)







TEST No.	BORING No.	DEPTH Feet	DRY DENS. pcf	MOISTURE %	PERCENT COMPACTION	CONFINING PRES. tsf	STRAIN %
7	Residual	0 -15'	91.8	27.4	90.4	1.0	2.5
8	-"-	-"-	93.0	25.7	93.0	3.0	2.6
9	-"-	-"-	92.8	26.8	91.4	6.0	3.2
10	F-7	5'-10'	91.2	26.1	90.6	1.0	2.8
11	-"-	-"-	91.2	26.1	90.6	2.0	3.2
12	-"-	-"-	89.9	27.9	89.3	4.0	3.2
13	F-15	40'-45'	94.6	22.1	88.8	1.5	3.8
14	-"-	-"-	95.1	21.5	89.2	3.0	3.1
15	-"-	-"-	94.8	21.6	89.0	6.0	3.6

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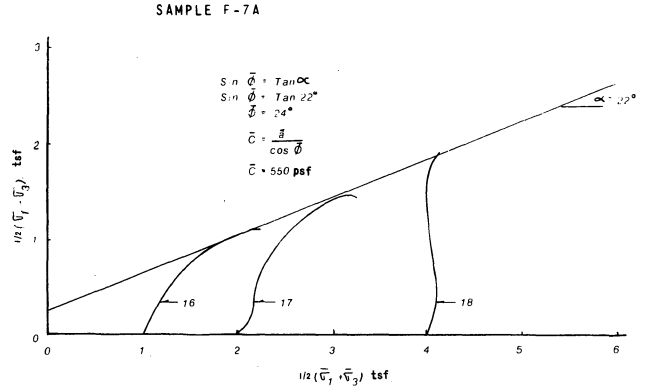
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

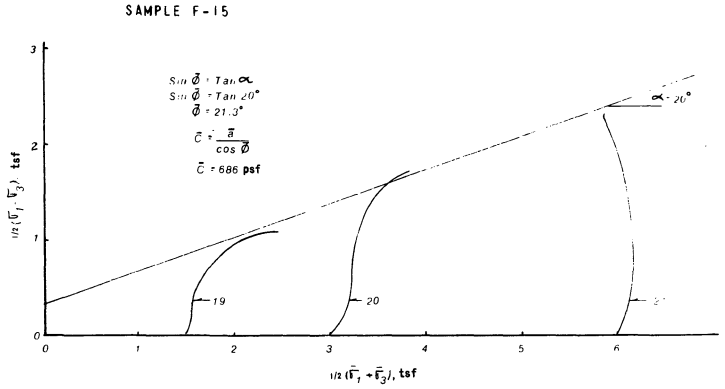
Unconsolidated Undrained Triaxial Compression Test Results On Borrow Soil (Sheet 2 of 2)

Figure 2.5-123

Figure 2.5-124

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON BORROW SOILS (SHEET 1 OF 2)





TEST No.	BORE No.	SAMPLE No.	DEPTH Feet	MOISTURE %	DRY DENS. pcf	COMPACTION %	$(\bar{\sigma}_1 - \bar{\sigma}_3)$ Max. tsf	ϵ_f %	Δ_f	$\bar{\phi}$	$\bar{C}$ psf
16	F-7A	B-1	25'-30'	20.6	96.0	89.4	2.20	7.0	-.02	24°	550
17	—"—	—"—	—"—	20.6	96.9	90.2	2.89	9.0	.08		
18	—"—	—"—	—"—	20.5	97.1	90.3	3.81	7.0	.46		
19	F-13	B-2	35'-40'	18.7	97.0	90.2	2.22	11.0	.06	21°	700
20	—"—	—"—	—"—	19.0	97.3	90.5	3.46	8.0	.26		
21	—"—	—"—	—"—	18.6	97.8	91.0	4.60	8.0	.54		

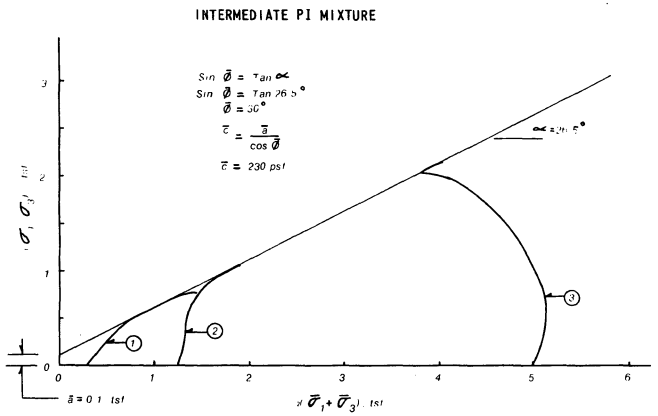
Amendment 0
August 1984

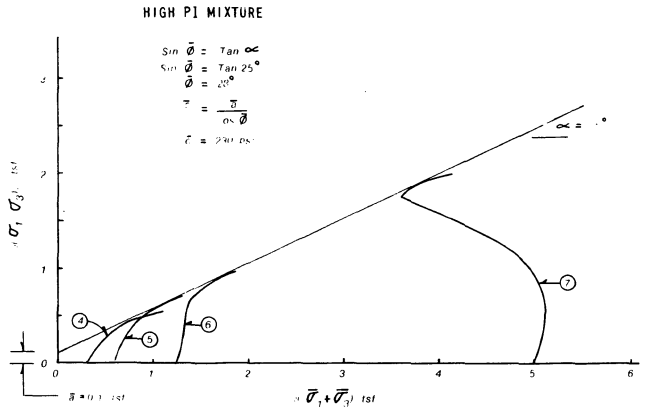
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Isotropically Consolidated, Undrained
Triaxial Compression Test Results
On Borrow Soils
(Sheet 1 of 2)
Figure 2.5-124

Figure 2.5-124

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TEST RESULTS ON BORROW SOILS (SHEET 2 OF 2)





TEST NO.	LL	PL	PI	MOISTURE CONTENT (%)	DRY DENSITY (pcf)	COMPACTION (%)	$\bar{\sigma}_c$ (tsf)	$\frac{1}{2}(\sigma_1 - \sigma_3)$ Max. (tsf)	ϵ_f (%)	$\bar{\phi}$ (deg)	$\bar{c}$ (psf)
①	62	40	22	21.8	95.1	90.0	600	0.78	14.0	30	230
②	58	35	23	22.0	94.5	89.8	2500	1.08	20.0		
③	62	37	25	21.3	95.0	90.0	10000	2.13	17.0		
④	67	39	28	25.3	91.6	89.8	600	0.58	15.0		230
⑤	66	36	30	25.1	91.9	90.1	1200	0.84	18.7		
⑥	67	37	30	24.8	93.4	91.6	2500	0.96	17.0		
⑦	55	30	25	25.9	92.6	90.8	10000	1.99	19.0		

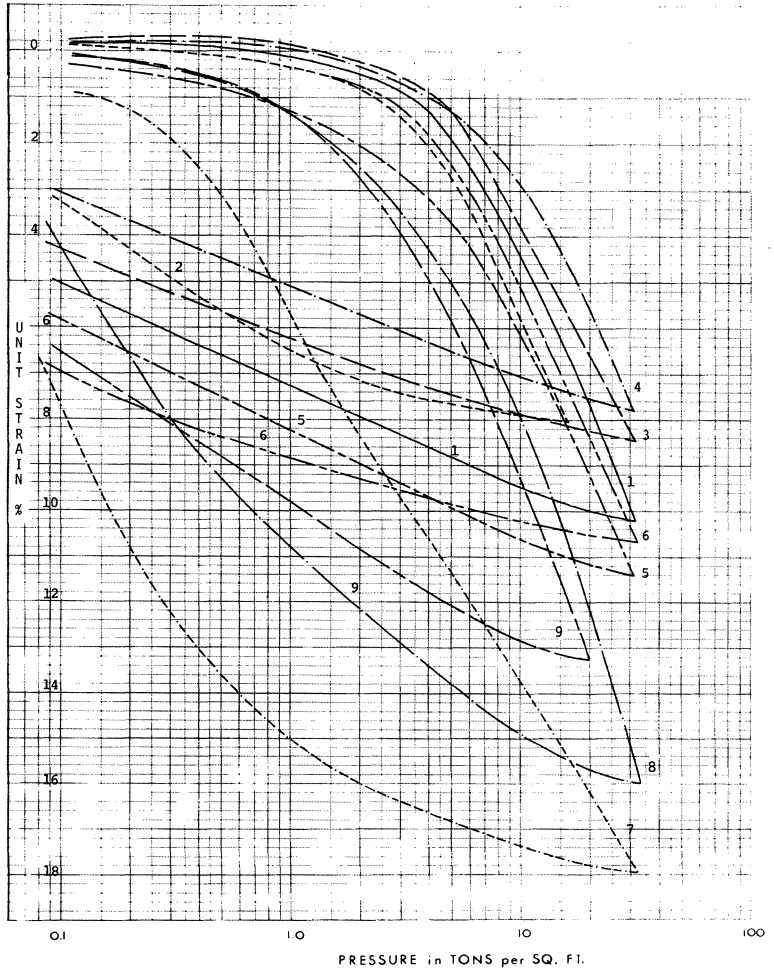
Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Isotropically Consolidated, Undrained
Triaxial Compression Test Results
On Borrow Soils
(Sheet 2 of 2)
Figure 2.5-124

Figure 2.5-125

CONSOLIDATION TEST RESULTS ON BORROW SOILS

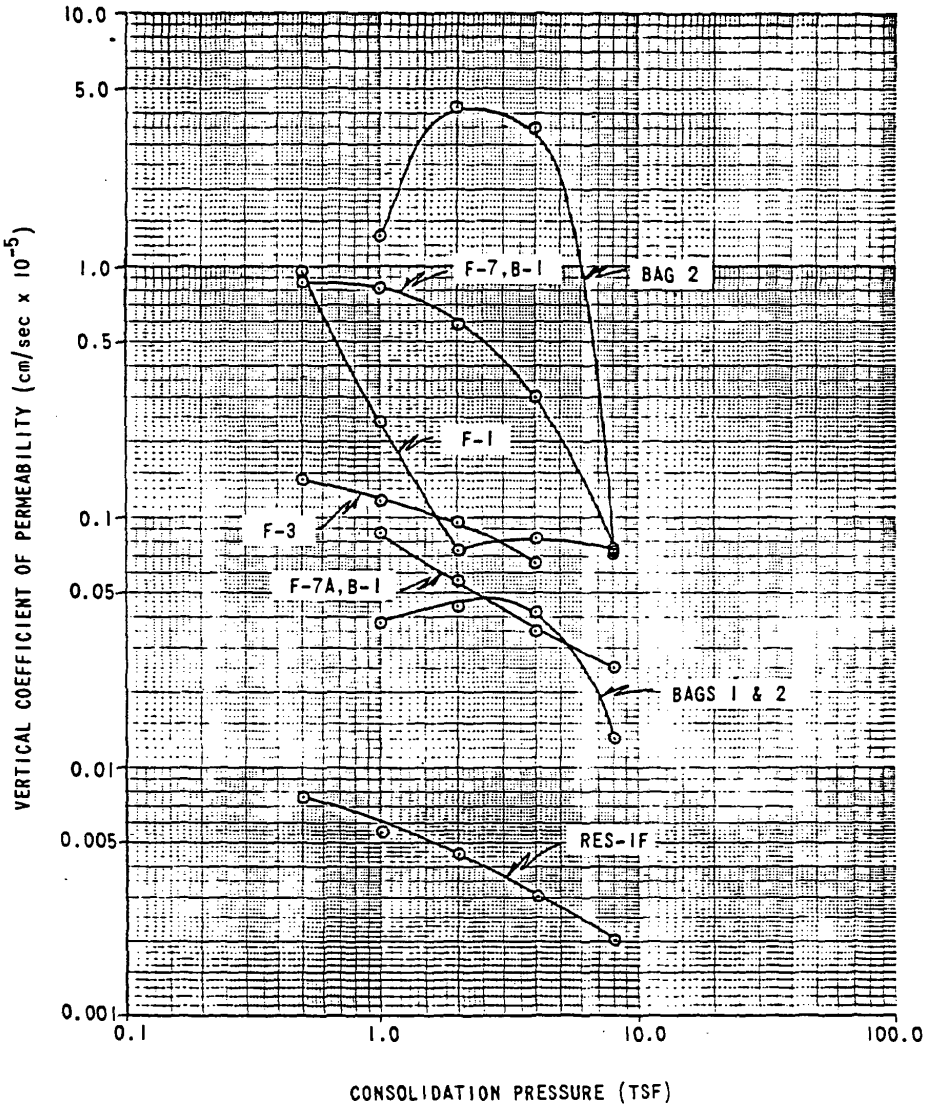


Symbol	Test No.	Borrow Source	Sample Identification	Dry Density (%)	Moisture Content (%)	Liquid Limit (%)	Plastic Limit (%)	Plasticity Index (%)
———	1	G	Bags 1 & 2	94.5	25.0	63	36	27
- - - - -	2	G	Bag 2	96.6	22.2	64	38	26
— — —	3	G	Bag 2	97.9	21.6	64	38	26
— — —	4	G	Bags 1 & 2	96.5	24.8	63	36	27
— · — · —	5	F	Res - 1F	93.4	27.3	51	46	5
— · — · —	6	F	F-7, B-1	90.7	25.0	53	45	8
- - - - -	7	F	F-1	96.1	21.4	NP	-	-
———	8	F	F-3	96.5	21.7	NP	-	-
———	9	F	B-7A, B-1	95.3	20.8	-	-	-

Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Consolidation Test Results on Borrow Soils Figure 2.5-125

Figure 2.5-126
PERMEABILITY TEST RESULTS ON BORROW SOILS

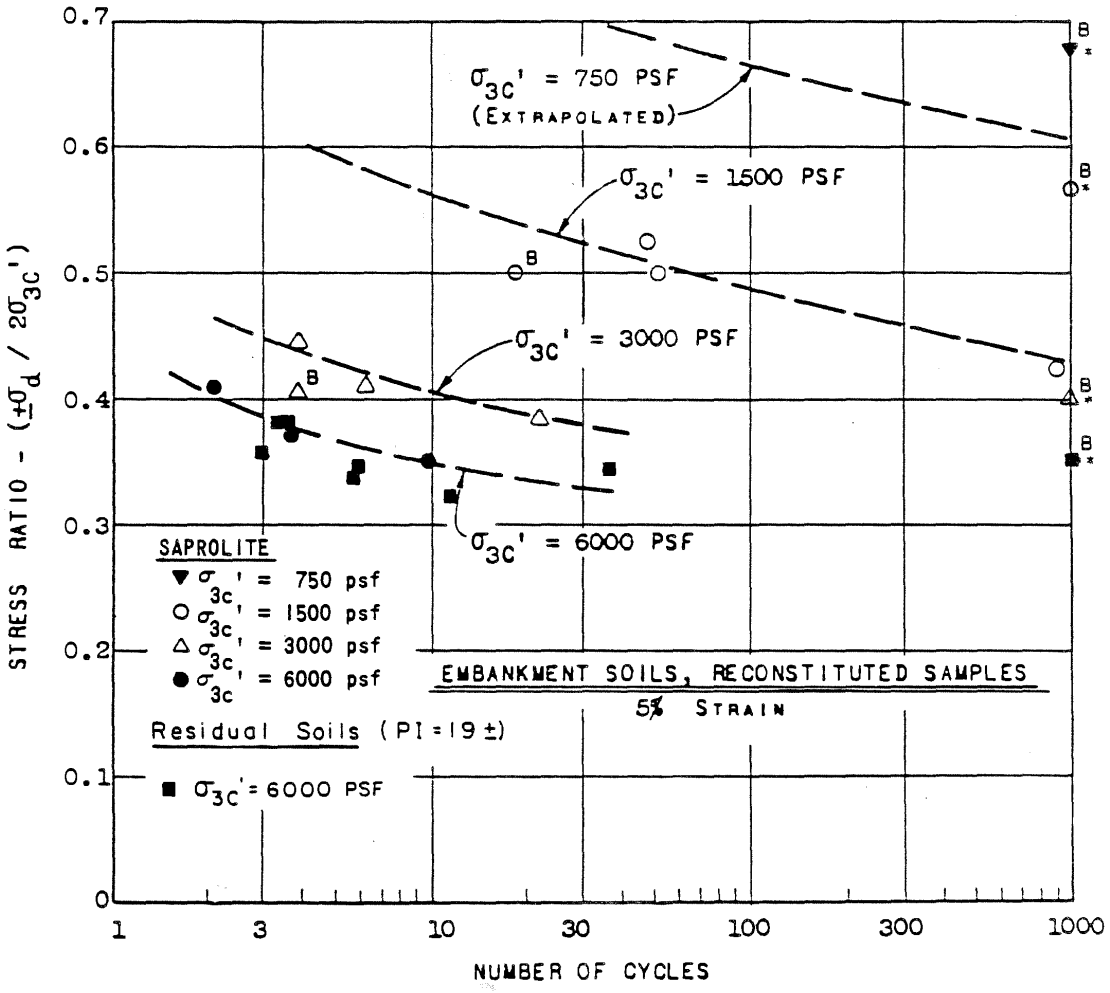


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Permeability Test Results on Borrow Soils
Figure 2.5-126

Amendment 0
August 1984

Figure 2.5-127

CYCLE TRIAXIAL TEST RESULTS FOR EMBANKMENT SOILS ($K_C = 1$)



NOTES: B INDICATES BLOCK SAMPLE

* INDICATES SAMPLE DID NOT FAIL AFTER 1000 CYCLES

Amendment 0
August 1984

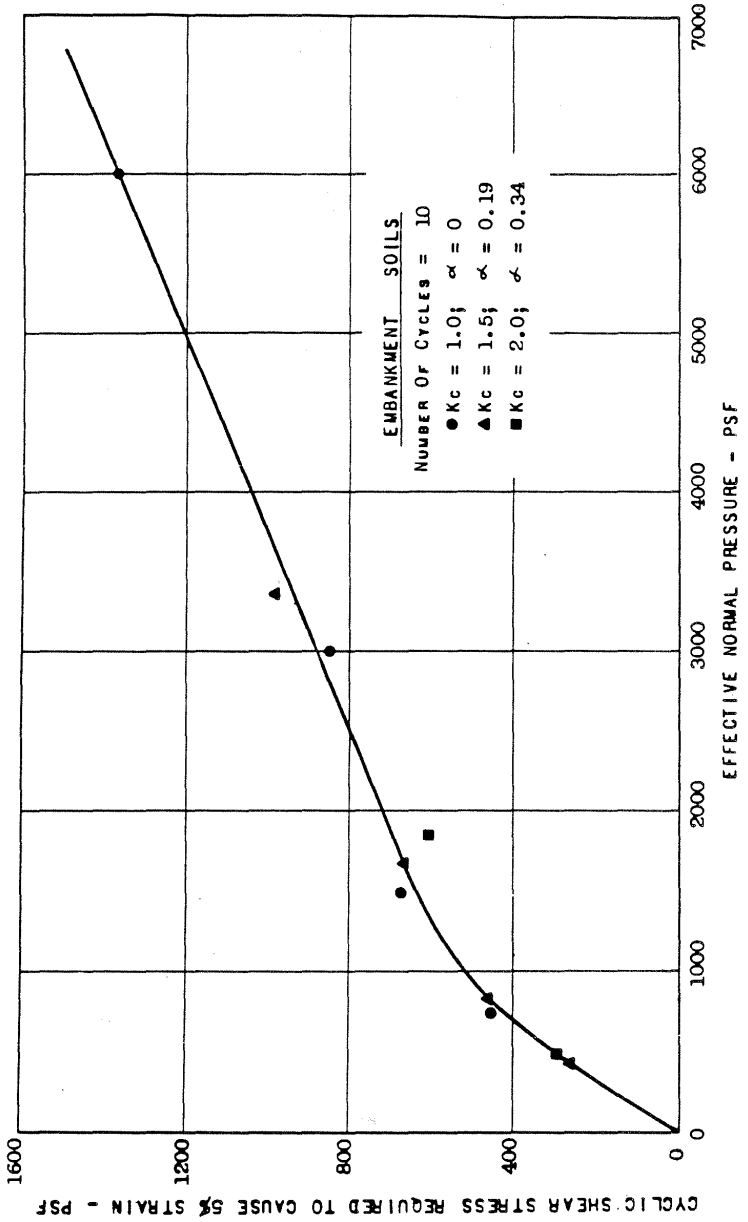
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Cycle Triaxial Test Results for Embankment Soils (K_c = 1)

Figure 2.5-127

Figure 2.5-128

STRESSES REQUIRED TO CAUSE
5% STRAIN IN 10 CYCLES FOR EMBANKMENT SOILS

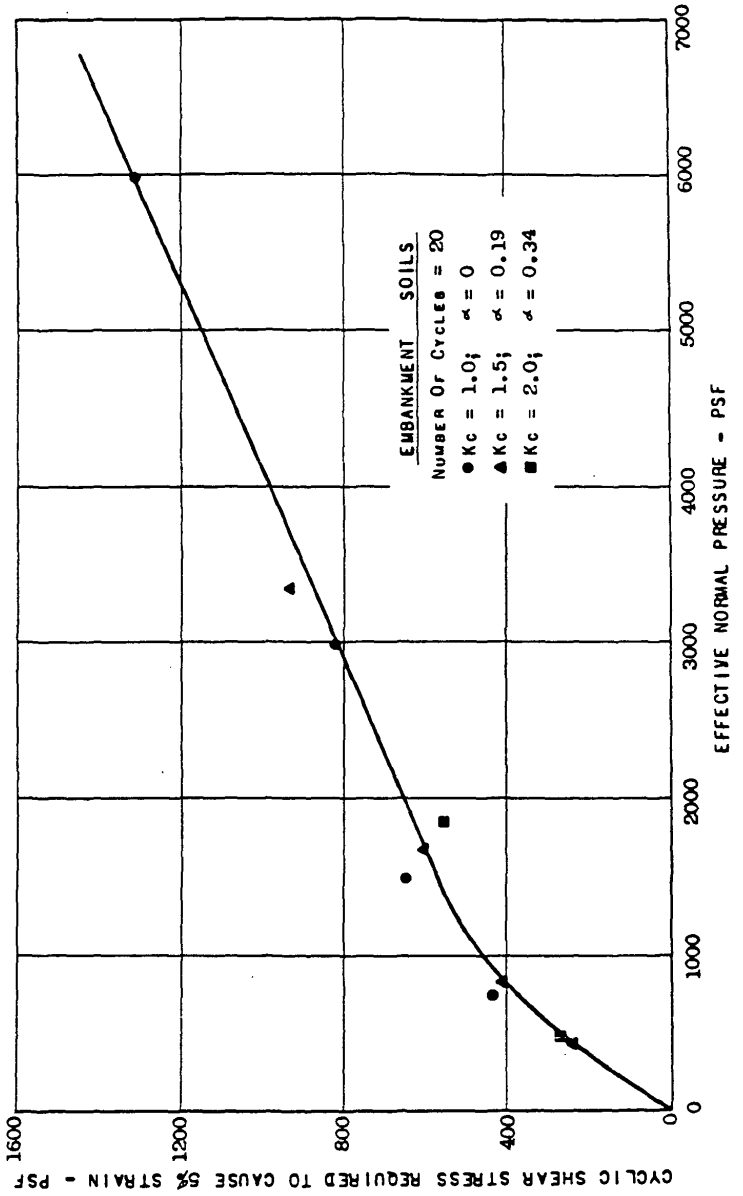


Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Stresses Required to Cause 5% Strain in 10 Cycles for Embankment Soils
Figure 2.5-128

Figure 2.5-129

STRESSES REQUIRED TO CAUSE
5% STRAIN IN 20 CYCLES FOR EMBANKMENT SOILS

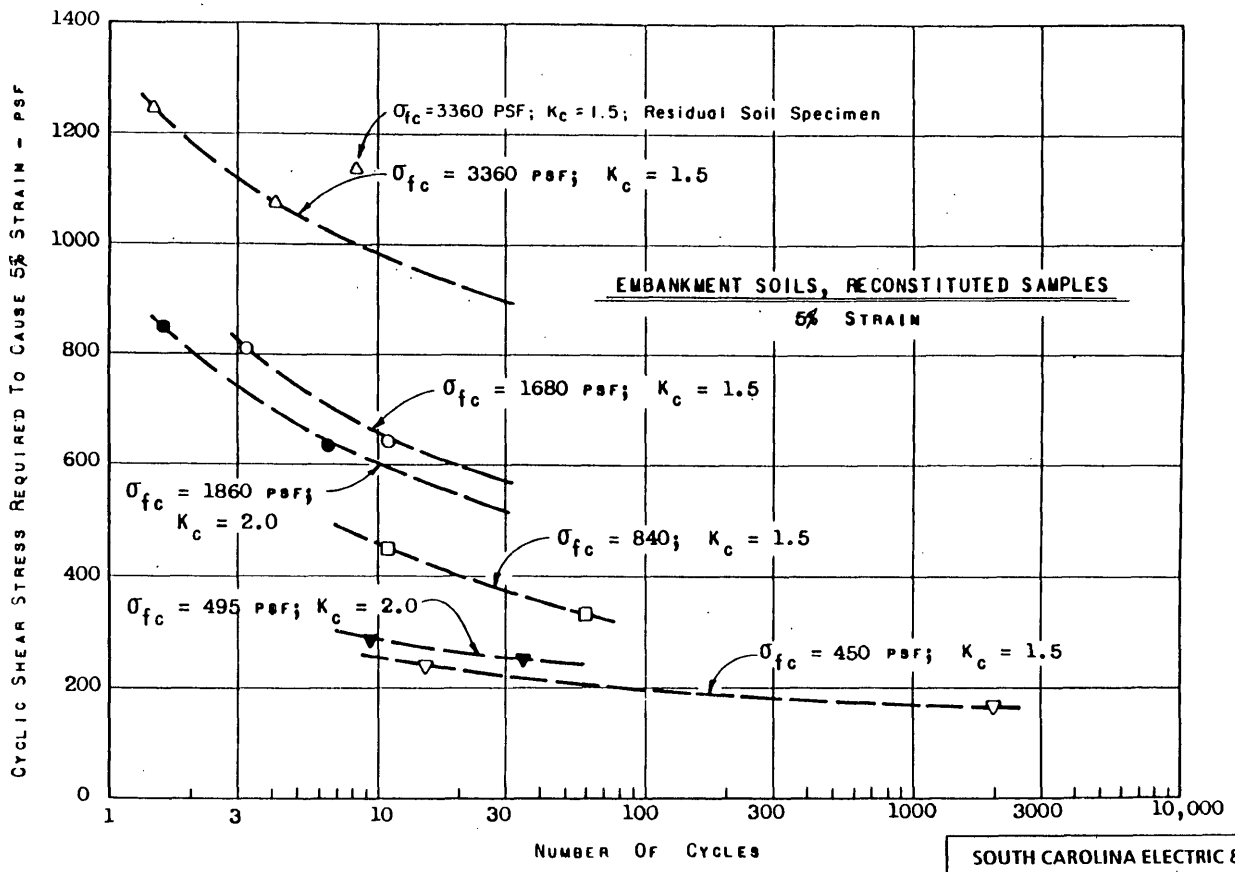


Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Stresses Required to Cause 5% Strain in 20 Cycles for Embankment Soils Figure 2.5-129

Figure 2.5-130

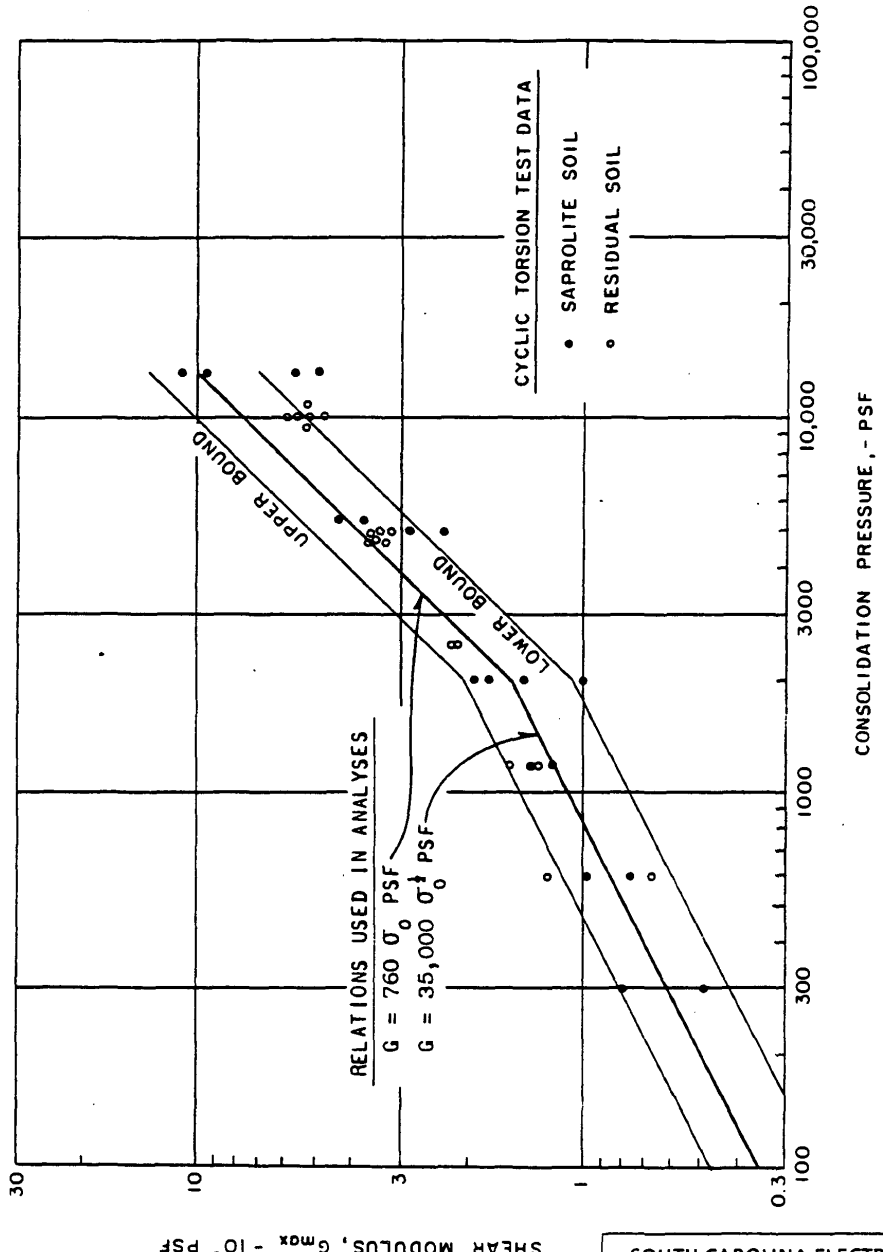
CYCLIC TRIAXIAL TEST RESULTS FOR EMBANKMENT SOILS ($K_C > 1$)



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Cyclic Triaxial Test Results For Embankment Soils ($k_c > 1$)
Figure 2.5-130

Amendment 0
August 1984

Figure 2.5-131
SHEAR MODULUS VALUES AT VERY LOW STRAIN LEVELS FOR EMBANKMENT SOILS

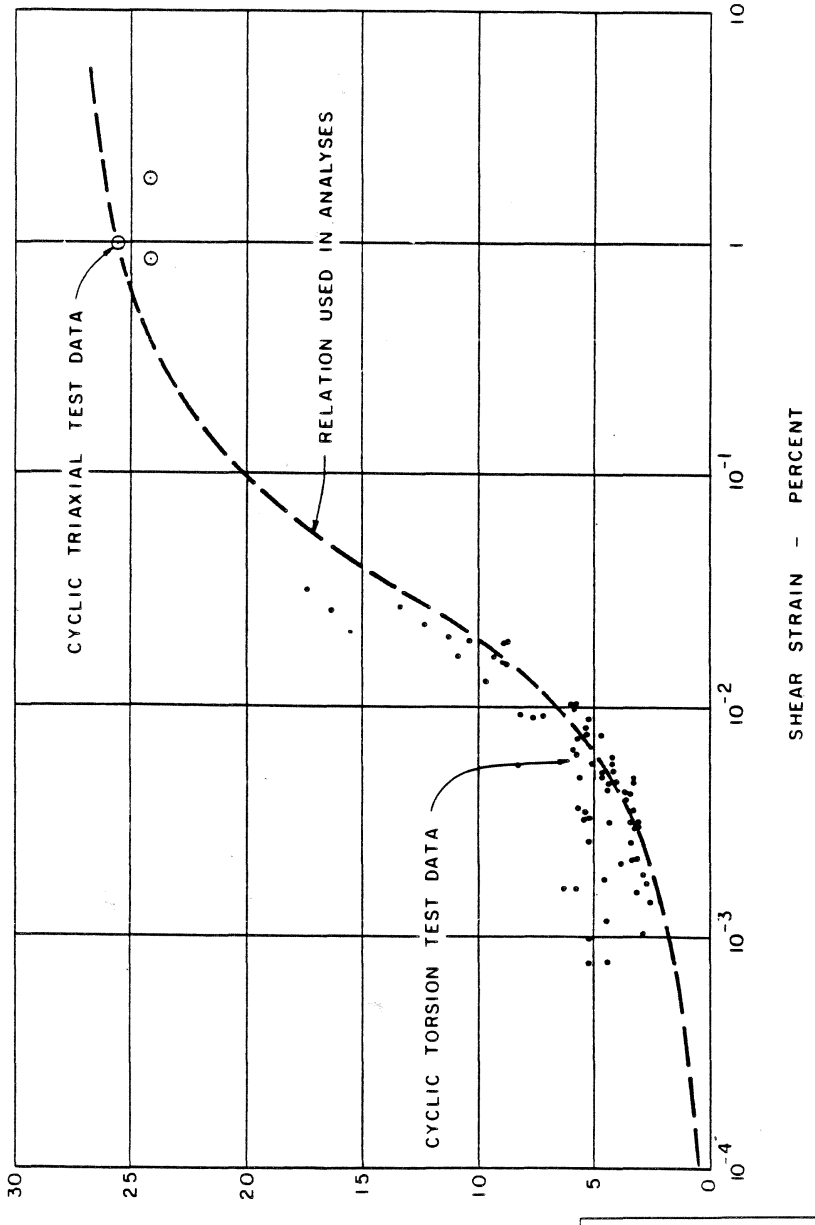


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Shear Modulus Values at Very Low Strain Levels for Embankment Soils
Figure 2.5-131

Amendment 0
August 1984

Figure 2.5-132

VARIATION OR DAMPING VALUES AS A FUNCTION OF STRAIN FOR EMBANKMENT SOILS



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

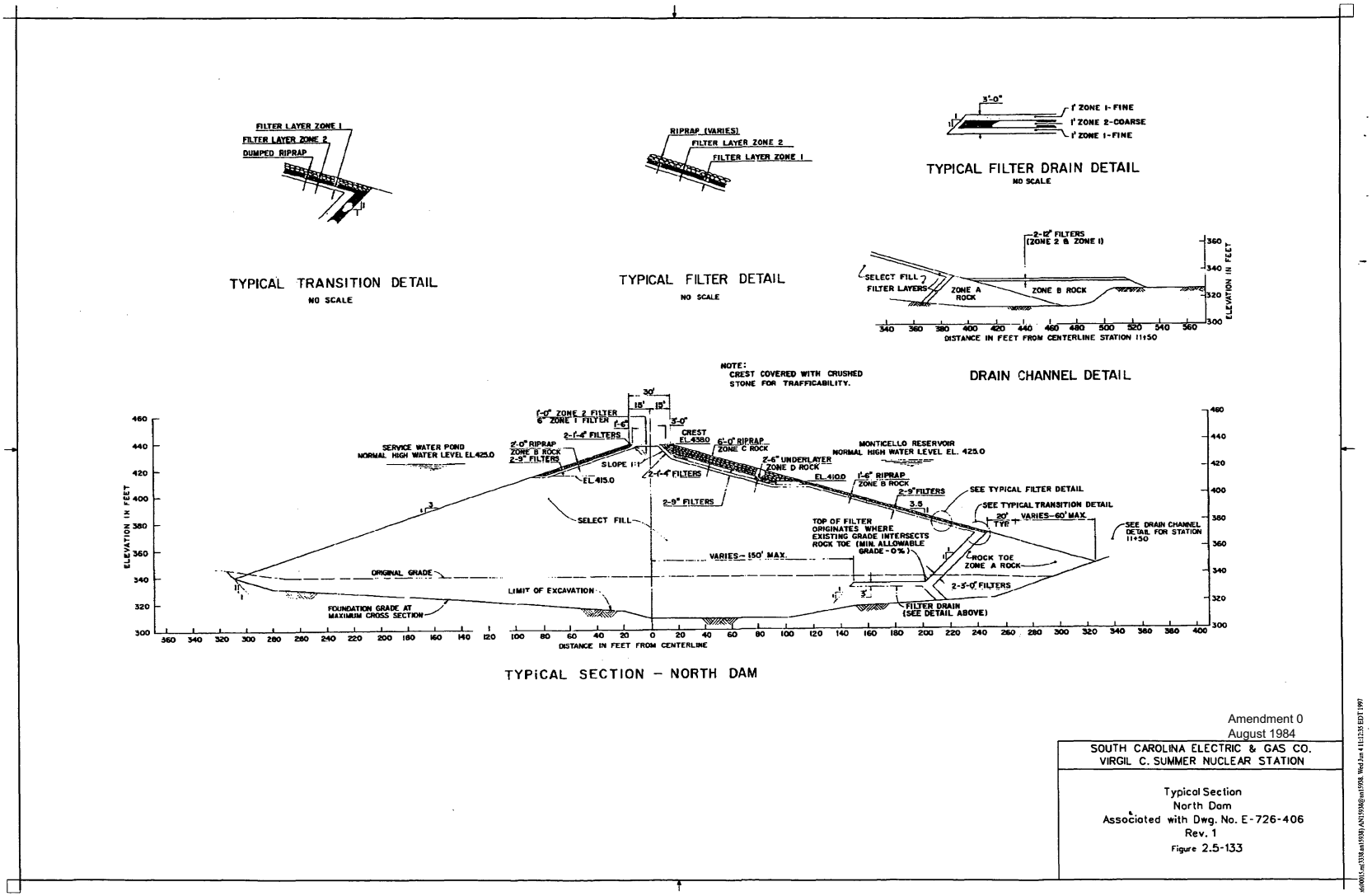
Variation or Damping Values as a Function of Strain for Embankment Soils

Figure 2.5-132

Figure 2.5-133

TYPICAL SECTION NORTH DAM

ASSOCIATED WITH DWG. NO. E - 726 - 406



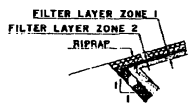
Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Typical Section
North Dam
Associated with Dwg. No. E-726-406
Rev. 1
Figure 2.5-133

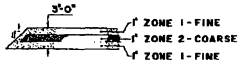
Figure 2.5-134

TYPICAL SECTION SOUTH DAM
ASSOCIATED WITH DWG. NO. E - 726 - 406

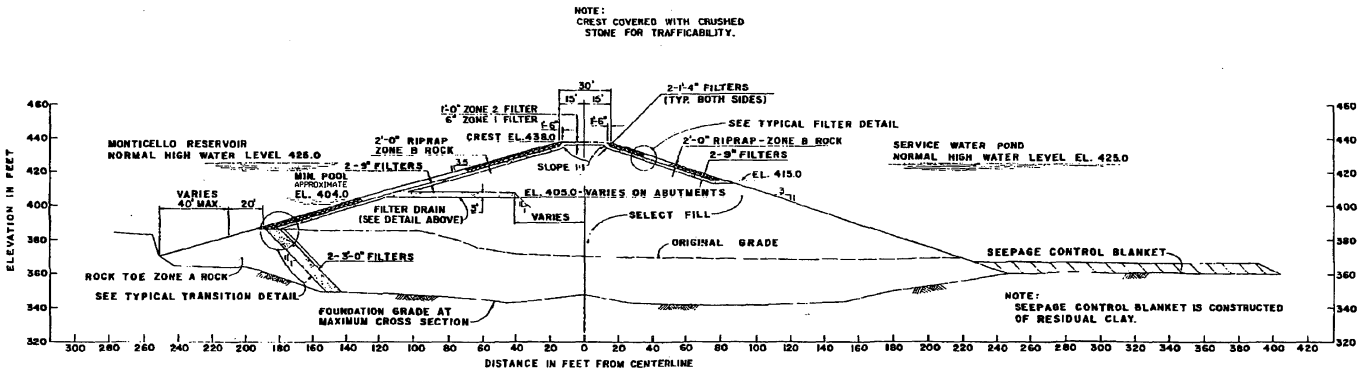


TYPICAL TRANSITION DETAIL
NO SCALE

TYPICAL FILTER DETAIL
NO SCALE



TYPICAL FILTER DRAIN DETAIL
NO SCALE



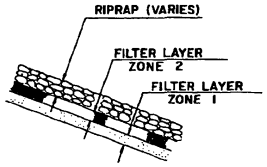
TYPICAL SECTION - SOUTH DAM

Amendment 98-01
April 1998

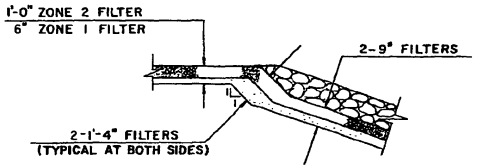
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Section South Dam Associated with Dwg. No. E-726-406 Rev. 1 Figure 2.5-134

Figure 2.5-135

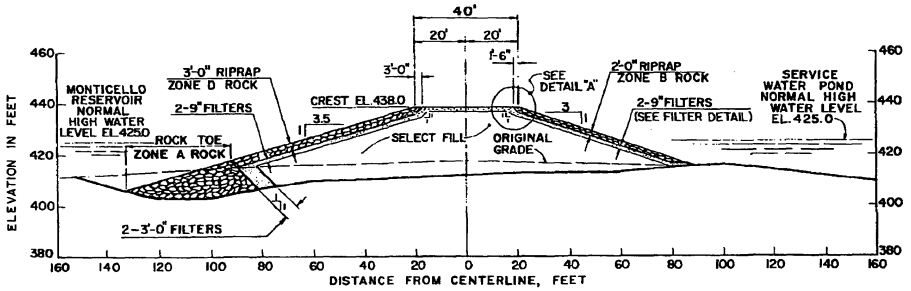
TYPICAL SECTION EAST DAM
ASSOCIATED WITH DWG. NO. E - 726 - 407



TYPICAL FILTER DETAIL
NO SCALE



DETAIL "A"
NO SCALE



TYPICAL SECTION—EAST DAM

Amendment 98-01
April 1998

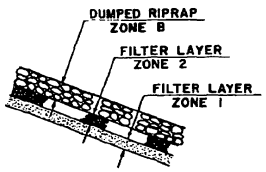
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Typical Section
East Dam
Associated with Dwg. No. E-726-407
Rev. 1
Figure 2.5-135

Amendment 98-01

Figure 2.5-136

TYPICAL SECTION WEST DAM
ASSOCIATED WITH DWG. NO. E - 726 - 407



TYPICAL FILTER DETAIL
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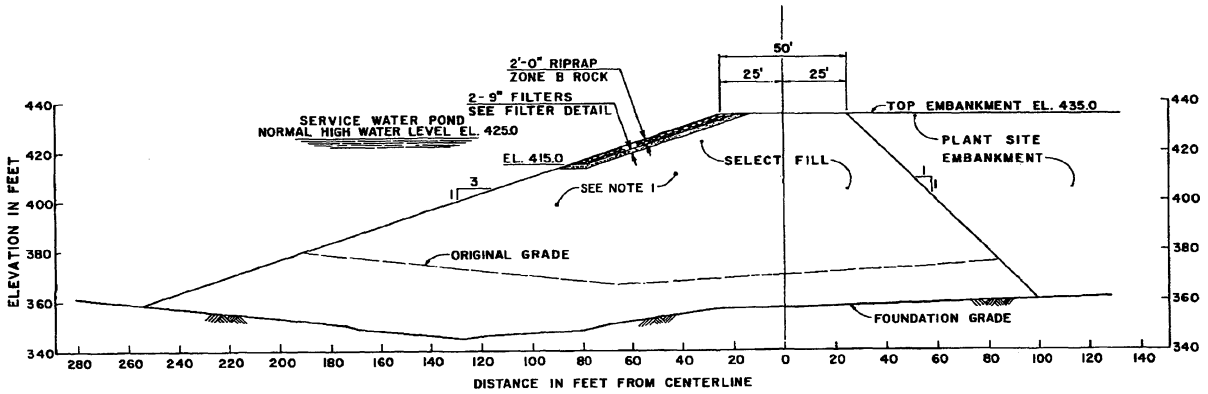


TYPICAL SECTION - WEST EMBANKMENT

Amendment 98-01
April 1998

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Section West Embankment Associated with Dwg. No. E-726-407 Rev. 1 Figure 2.5-136

Amendment 98-01
April 1998

Figure 2.5-137
PHOTOGRAPH OF DRAINAGE BLANKET - NORTH DAM

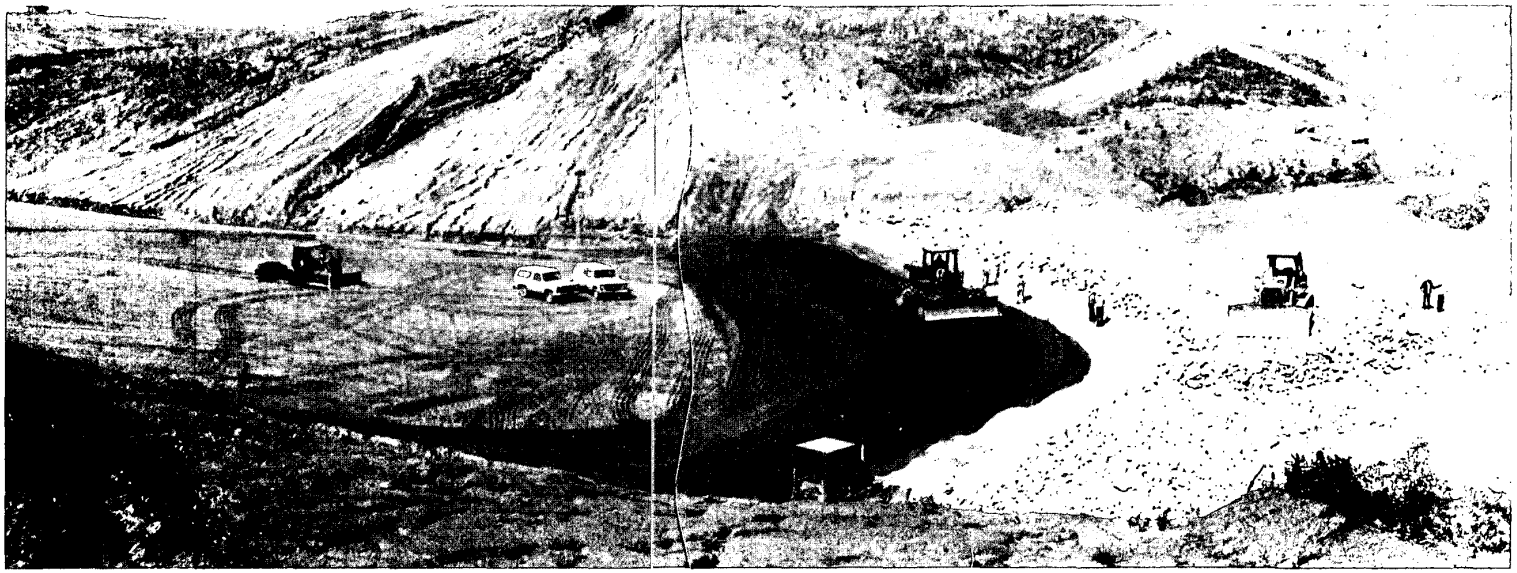
Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Photograph Of Drainage
Blanket - North Dam

Figure 2.5-137

Figure 2.5-138
PHOTOGRAPH OF ROCK TOE CONSTRUCTION - SOUTH DAM

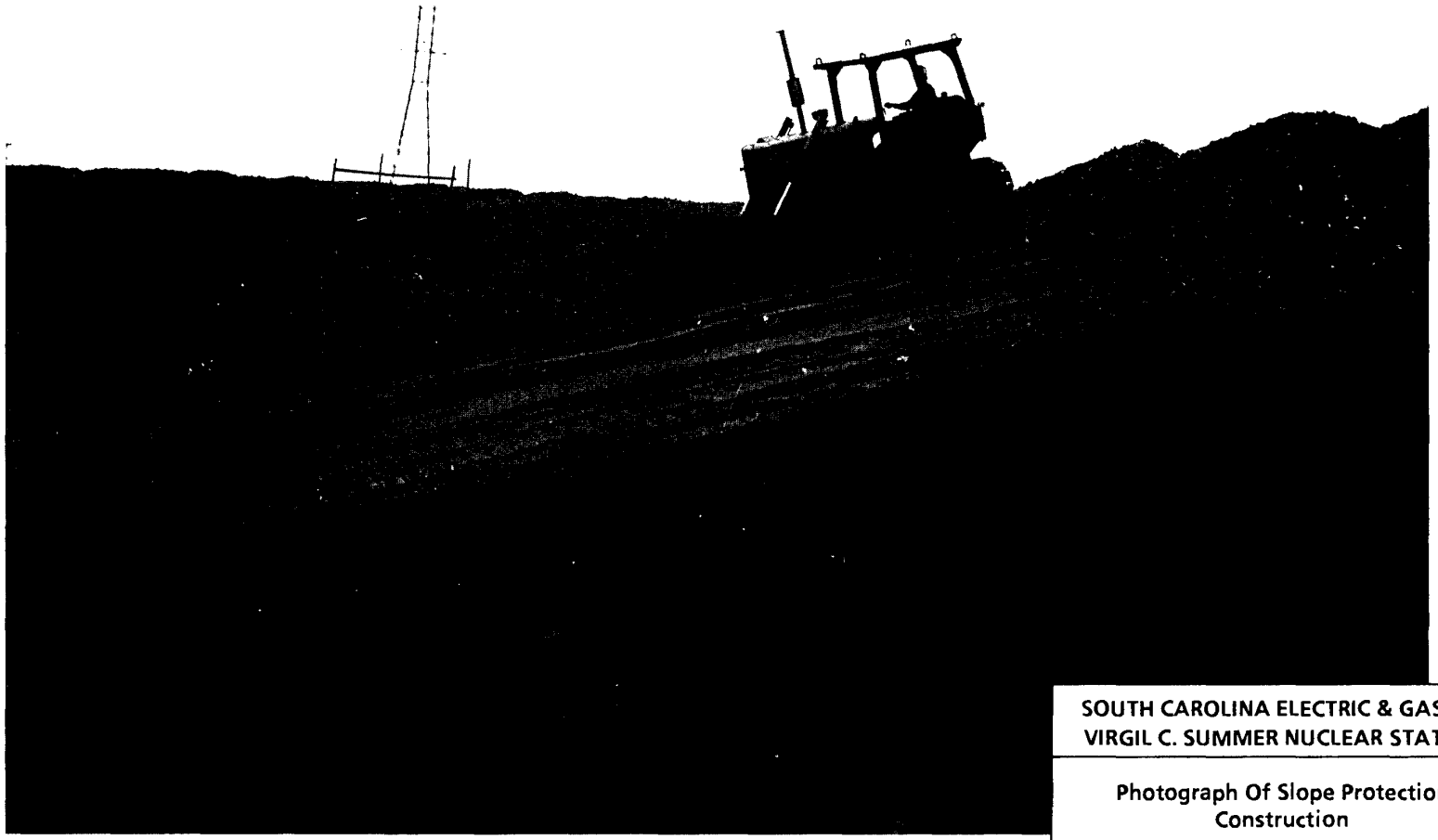


Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Photograph Of Rock Toe Construction - South Dam Figure 2.5-138

Figure 2.5-139

PHOTOGRAPH OF SLOPE PROTECTION CONSTRUCTION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Photograph Of Slope Protection Construction
Figure 2.5-139

Amendment 0
August 1984

Figure 2.5-140

CALCULATED POST-CONSTRUCTION SETTLEMENT AND TENSILE STRAIN NORTH DAM

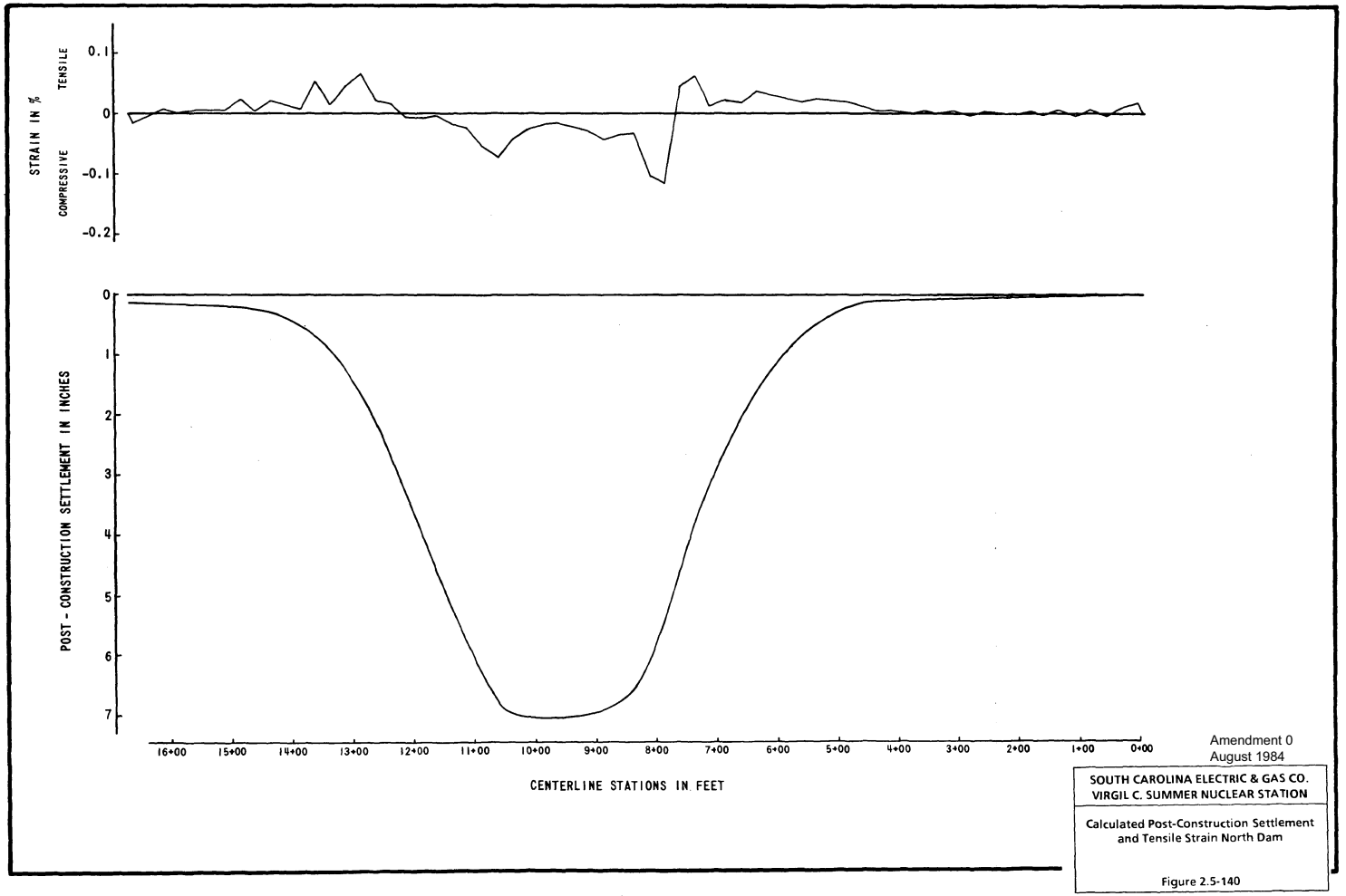
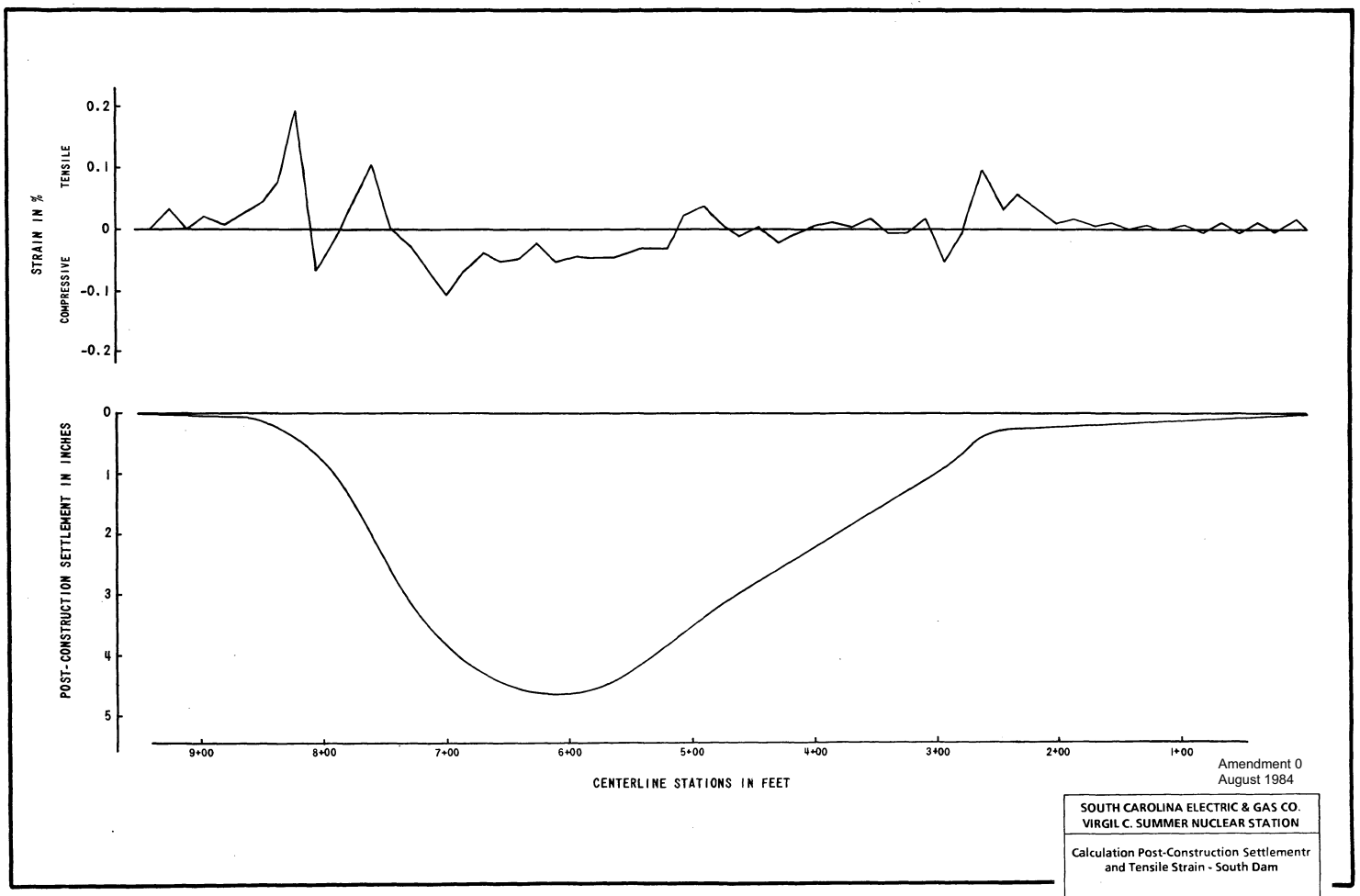


Figure 2.5-141

CALCULATION POST-CONSTRUCTION SETTLEMENT AND TENSILE STRAIN - SOUTH DAM



Amendment 0
August 1984

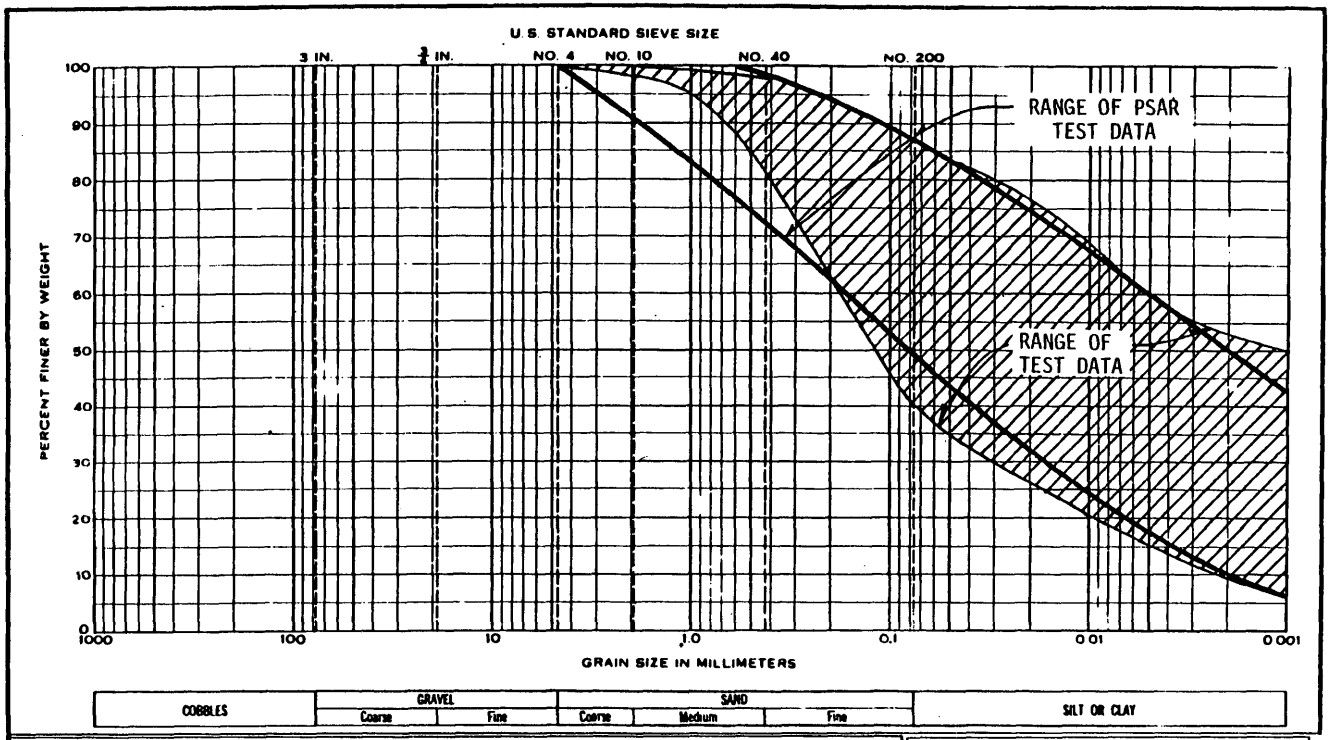
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Calculation Post-Construction Settlementr and Tensile Strain - South Dam

Figure 2.5-141

Figure 2.5-142

SUMMARY OF CONSTRUCTION CONTROL
GRADATION TEST - SELECT FILL (SHEET 1 OF 4)



SELECT FILL MATERIALS

SUMMARY OF 45 GRADATION TESTS
FROM THE NORTH DAM

Amendment 0
August 1984

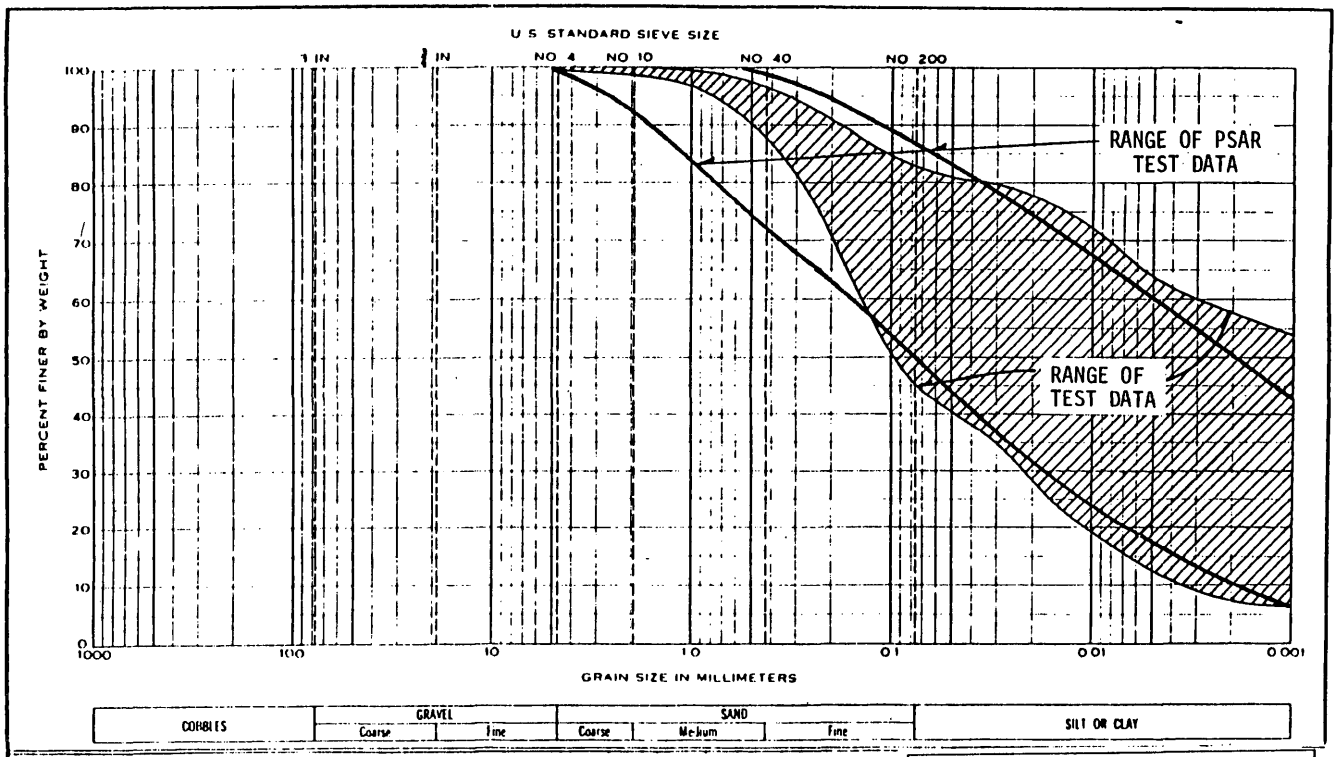
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary Of Construction Control
Gradation Tests - Select Fill
(Sheet 1 of 4)

Figure 2.5-142

Figure 2.5-142

SUMMARY OF CONSTRUCTION CONTROL
GRADATION TEST - SELECT FILL (SHEET 2 OF 4)



SELECT FILL MATERIALS

SUMMARY OF 24 GRADATION TESTS
FROM THE SOUTH DAM

Amendment 0
August 1984

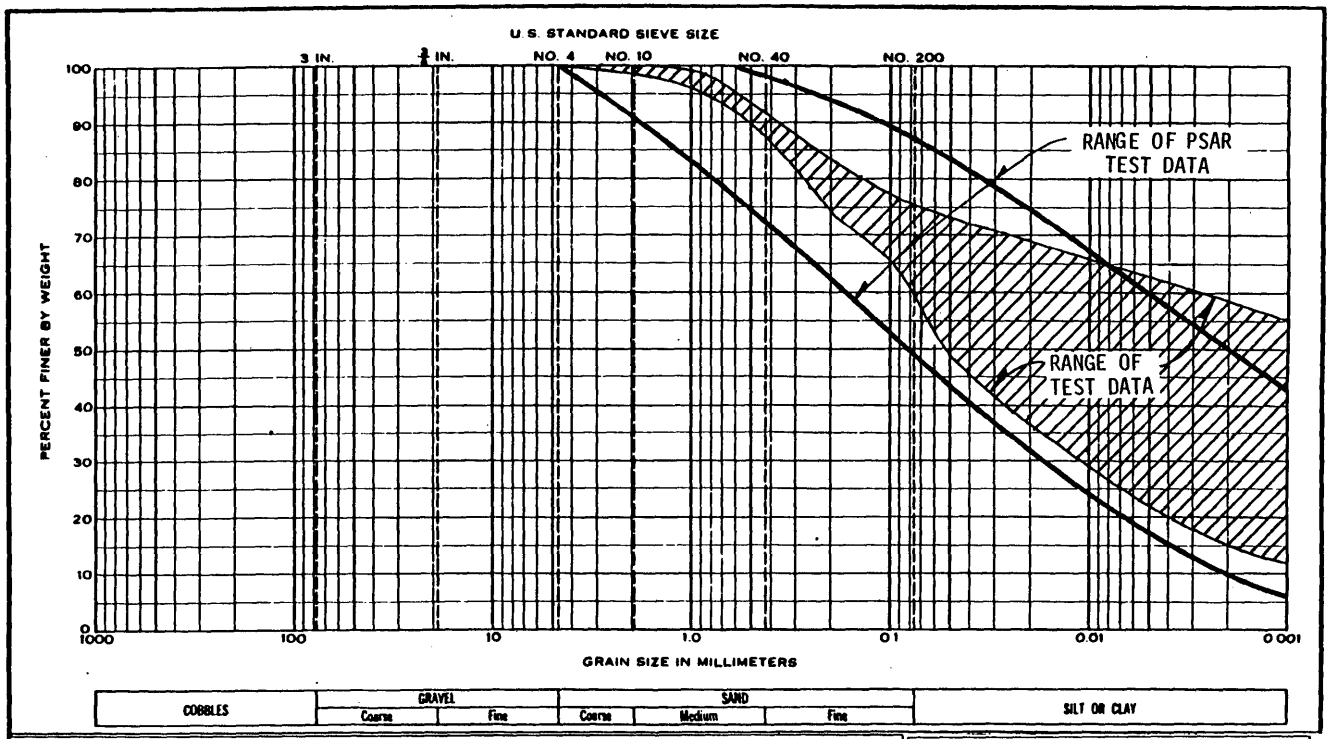
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary Of Construction Control
Gradation Tests - Select Fill
(Sheet 2 of 4)

Figure 2.5-142

Figure 2.5-142

SUMMARY OF CONSTRUCTION CONTROL
GRADATION TEST - SELECT FILL (SHEET 3 OF 4)



SELECT FILL MATERIALS

SUMMARY OF 8 GRADATION TESTS
FROM THE EAST DAM

Amendment 0
August 1984

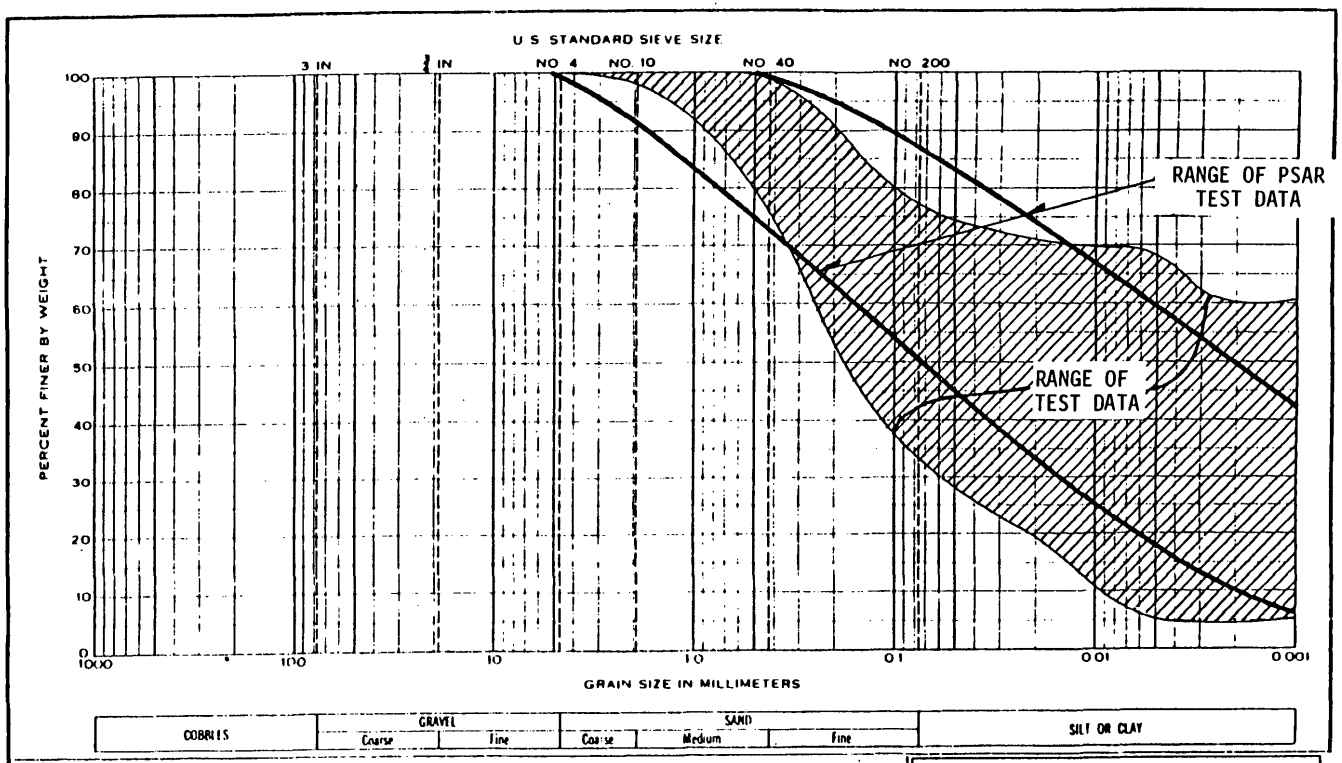
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary Of Construction Control
Gradation Tests - Select Fill
(Sheet 3 of 4)

Figure 2.5-142

Figure 2.5-142

SUMMARY OF CONSTRUCTION CONTROL
GRADATION TEST - SELECT FILL (SHEET 4 OF 4)



SELECT FILL MATERIALS

SUMMARY OF 43 GRADATION TESTS
FROM THE WEST EMBANKMENT

Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary Of Construction Control
Gradation Tests - Select Fill
(Sheet 4 of 4)

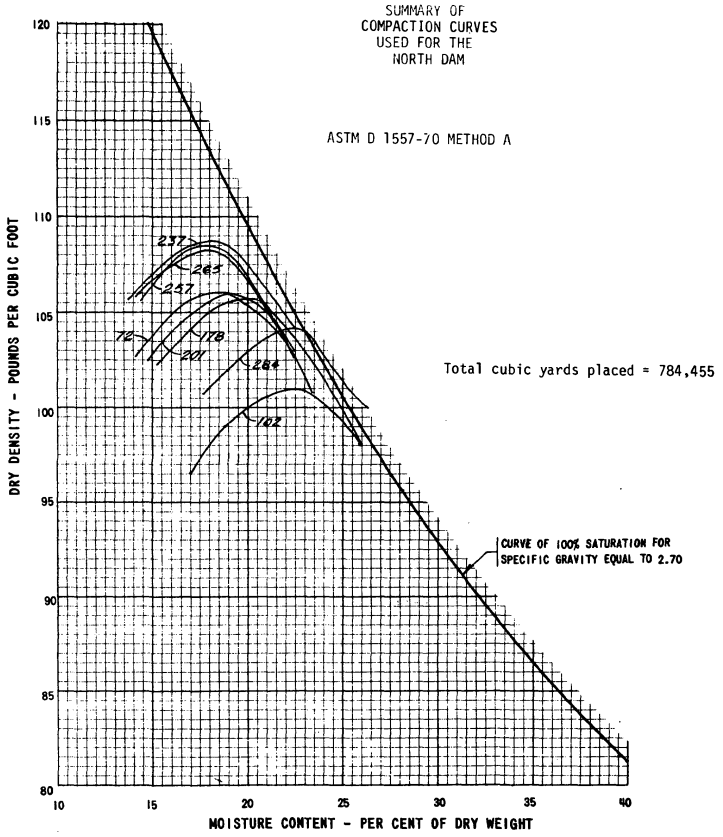
Figure 2.5-142

Figure 2.5-143

SUMMARY OF CONSTRUCTION CONTROL COMPACTION CURVES - SELECT FILL (SHEET 1 OF 4)

Curve No.	γ_{dmax} (pcf)	Opt. m/c %	No. of samples compared	% of total cu. yds. placed
51	108.0	17.4	1	<1
57	102.5	19.3	10	2
66	97.1	26.1	1	<1
67	100.7	23.8	3	<1
68	100.6	25.5	15	3
72	106.0	18.5	73	13
85	103.0	22.5	1	<1
91	104.2	22.1	14	3
94	113.2	17.5	2	<1
96	100.5	24.5	1	<1
98	101.5	23.0	4	1
102	101.0	23.0	29	5
104	104.4	22.4	3	<1
105	105.5	21.3	23	4
114	98.9	20.7	1	<1
123	107.2	18.2	2	<1
145	106.9	19.3	3	<1
146	106.7	19.4	10	2
162	105.7	19.0	6	1
167	105.9	18.5	19	3
178	105.7	20.0	25	5
192	104.5	20.0	8	1
193	105.5	19.5	18	3
198	106.1	17.0	17	3
201	106.0	19.0	94	17
237	108.7	17.7	31	6
257	108.5	17.9	30	6
265	108.3	18.0	51	9
279	109.5	15.8	10	2
284	104.4	22.7	28	5
293	107.9	19.4	11	2

NOTE: Only compaction curves representing 5% or more of total fill volume are shown.



Amendment 0
August 1984

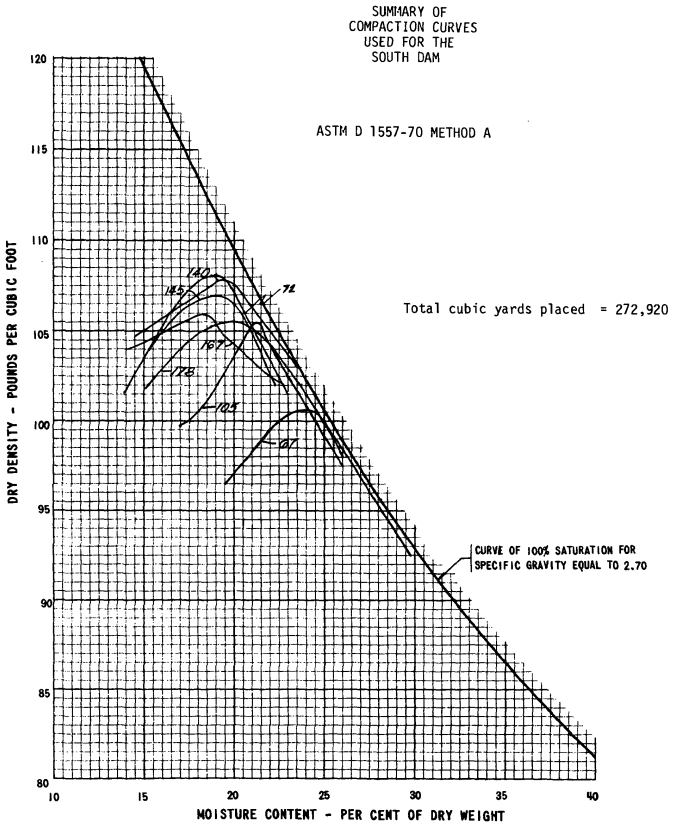
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Summary Of Construction Control Compaction Curves - Select Fill (Sheet 1 of 4) Figure 2.5-143

Figure 2.5-143

SUMMARY OF CONSTRUCTION CONTROL COMPACTION CURVES - SELECT FILL (SHEET 2 OF 4)

Curve No.	γ_{dmax} (pcf)	Opt. m/c %	No. of samples compared	% of total cu. yds. placed
67	100.7	23.8	10	5
68	100.6	25.5	1	<1
69	101.0	24.2	4	2
72	106.0	18.5	46	22
74	99.0	27.0	9	4
82	102.1	23.3	2	1
85	103.0	22.5	4	2
91	104.2	22.1	5	2
98	101.5	23.0	7	3
102	101.0	23.0	9	4
104	104.4	22.4	4	2
105	105.5	21.3	30	15
115	104.6	17.7	1	<1
140	107.9	19.3	10	5
145	106.9	19.3	20	10
146	106.7	19.4	9	4
162	105.8	19.0	5	2
167	105.9	18.5	13	6
178	105.7	20.0	13	6
179	109.5	17.0	1	<1
193	105.5	19.5	1	<1

NOTE: Only compaction curves representing 5% or more of total fill volume are shown.



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary Of Construction Control Compaction Curves - Select Fill (Sheet 2 of 4)

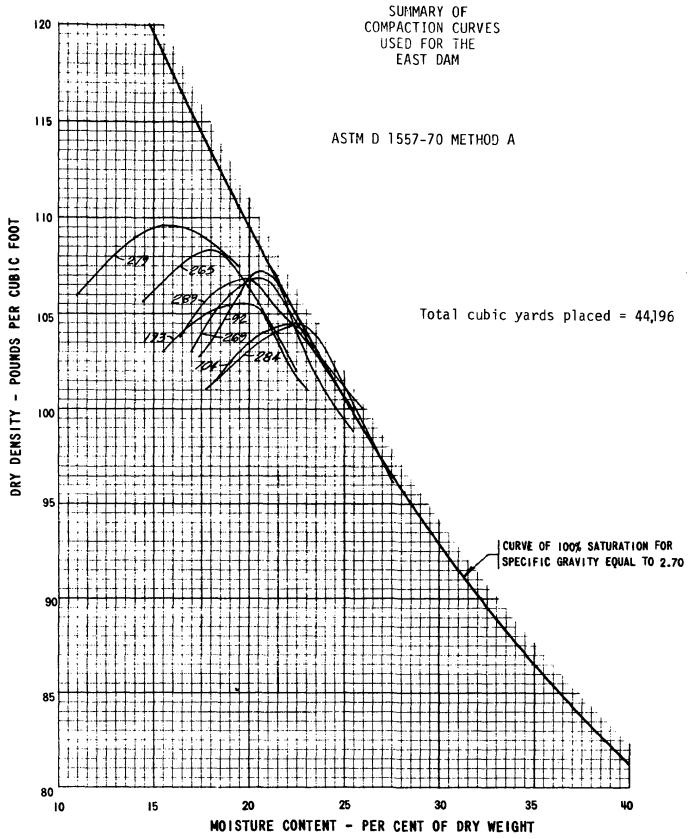
Figure 2.5-143

Figure 2.5-143

SUMMARY OF CONSTRUCTION CONTROL COMPACTION CURVES - SELECT FILL (SHEET 3 OF 4)

Curve No.	γ_{dmax} (pcf)	opt. m/c %	No. of samples compared	% of total cu. yds. placed
92	107.2	20.5	3	8
104	104.4	22.4	5	13
193	105.5	19.5	3	8
252	109.2	17.5	2	5
265	108.3	18.0	4	10
269	106.8	20.3	2	5
279	109.5	15.8	4	10
284	104.4	22.7	13	33
289	106.8	19.7	3	8

NOTE: Only compaction curves representing 5% or more of total fill volume are shown.



Amendment 0
August 1984

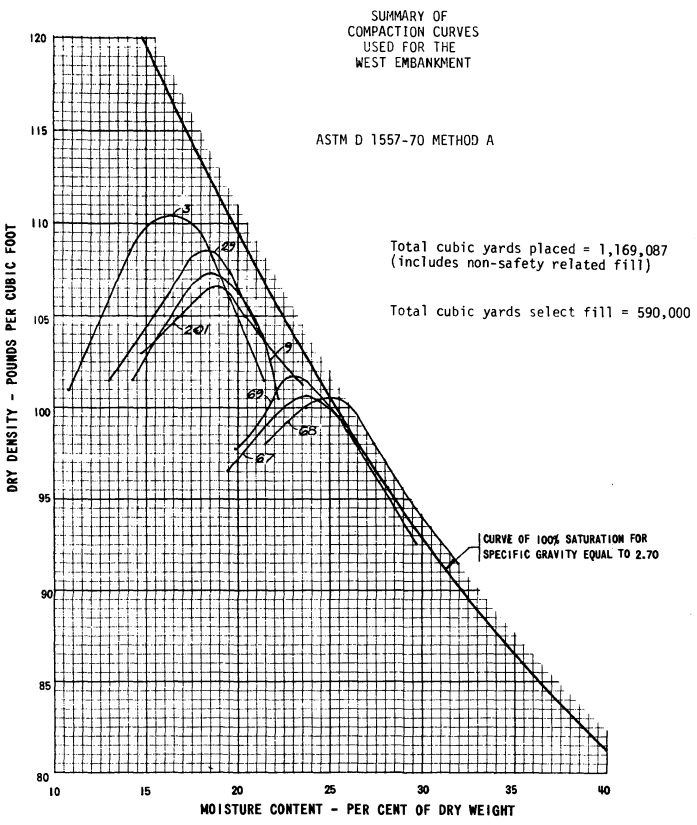
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Summary Of Construction Control Compaction Curves - Select Fill (Sheet 3 of 4) Figure 2.5-143

Figure 2.5-143

SUMMARY OF CONSTRUCTION CONTROL COMPACTION CURVES - SELECT FILL (SHEET 4 OF 4)

Curve No.	γ_{dmax} (pcf)	Opt. m/c %	No. of samples compared	% of total cu. yds. placed
A	107.0	17.2	3	1
1	116.3	12.5	1	<1
2	117.1	12.5	1	<1
3	110.4	16.8	52	13
4	114.6	13.6	1	<1
6	114.4	13.5	1	<1
7	108.9	17.4	2	<1
9	107.3	18.6	22	6
10	106.4	17.0	10	3
11	108.5	15.0	2	<1
28	109.9	14.1	4	1
29	108.6	18.5	19	5
67	100.7	23.8	58	15
68	100.6	25.5	28	7
69	101.0	24.2	25	6
72	106.0	18.5	2	<1
74	99.0	27.0	1	<1
85	103.0	22.5	1	<1
91	104.2	22.1	7	2
92	107.2	20.5	4	1
96	100.5	24.5	3	1
102	101.0	23.0	1	<1
104	104.4	22.4	3	1
178	105.7	20.0	17	4
193	105.5	19.5	4	1
200	107.7	17.0	3	1
201	106.6	19.0	45	12
237	108.7	17.7	6	2
257	108.5	17.9	14	4
262	110.8	16.8	4	1
265	108.3	18.0	14	4
279	109.5	15.8	5	2
282	112.4	16.2	1	<1
283	107.8	19.5	3	1
284	104.4	22.7	9	2
289	106.9	19.7	7	2
293	107.9	19.4	3	1

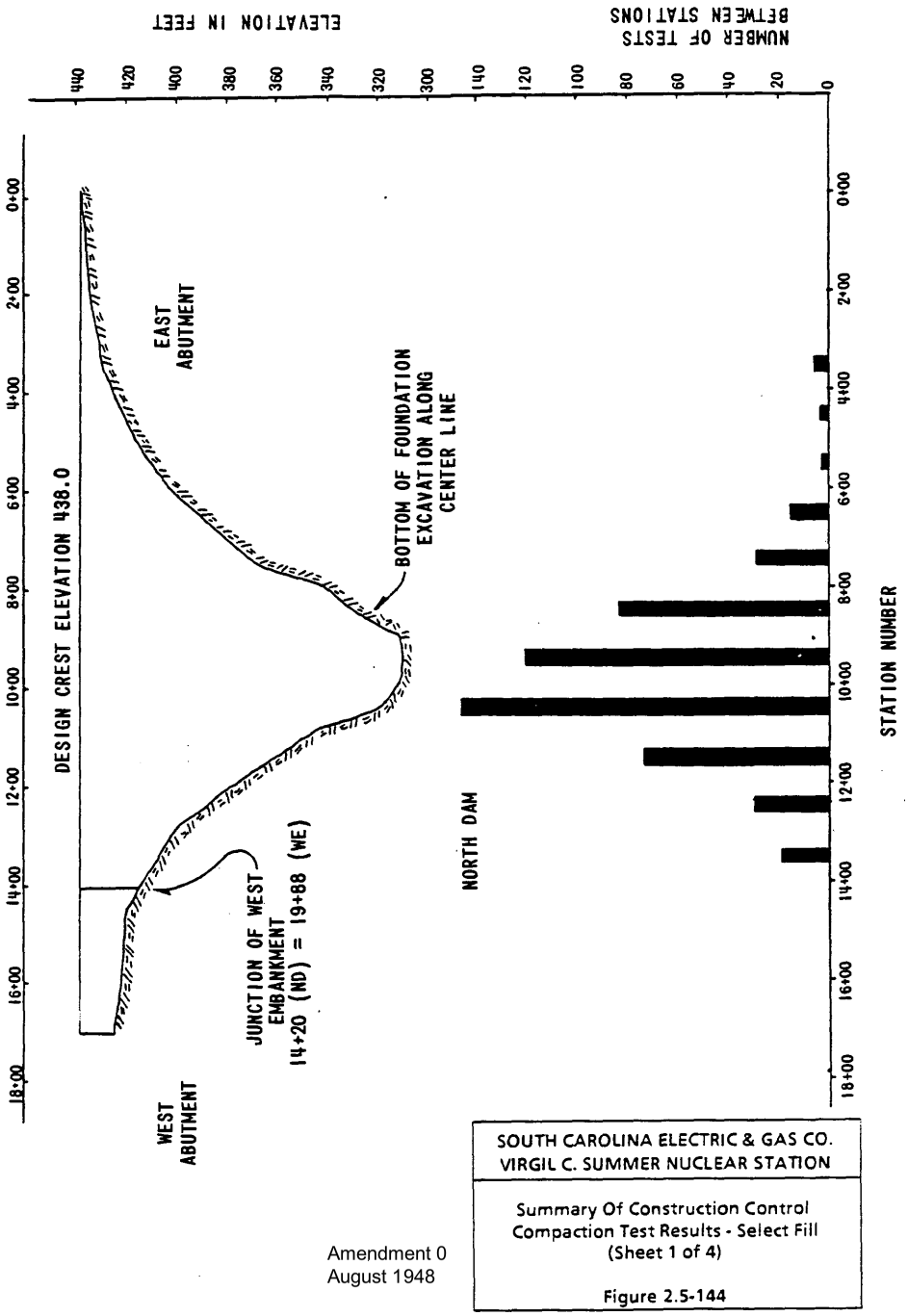
NOTE: Only compaction curves representing 5% or more of total fill volume are shown.



Amendment 0
August 1984

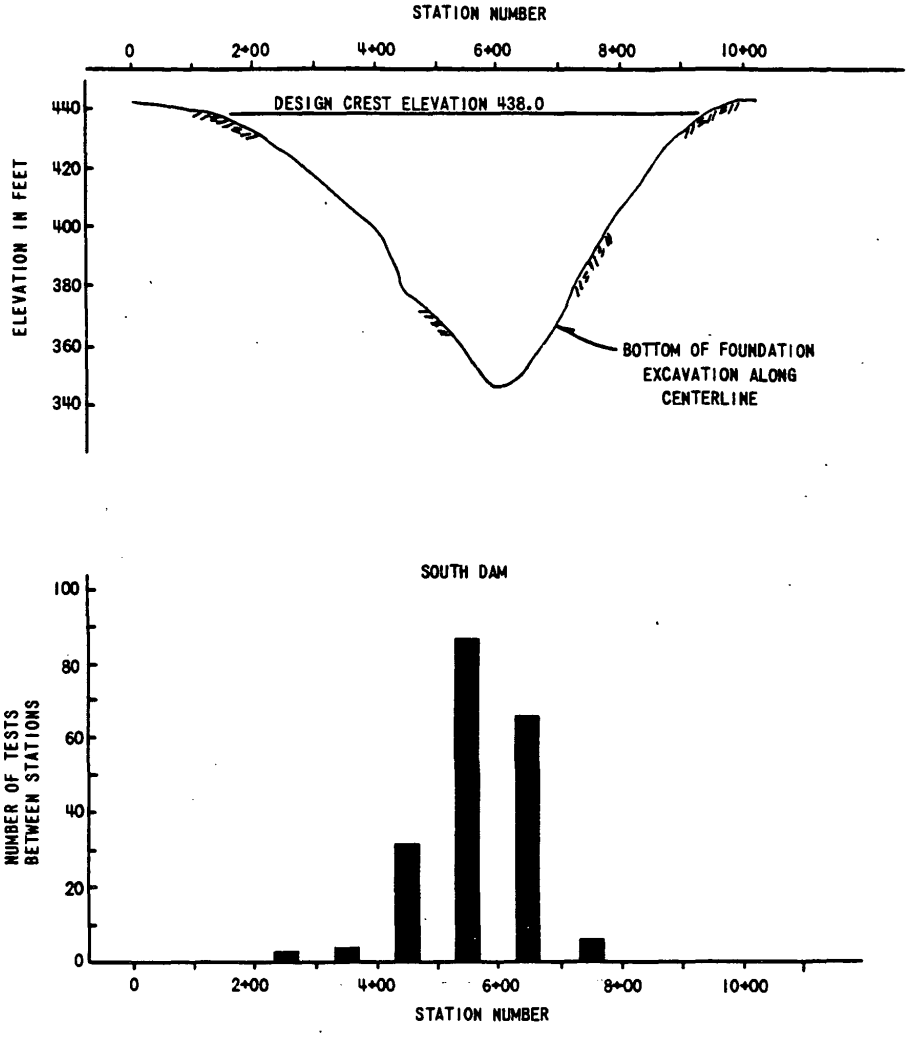
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Summary Of Construction Control Compaction Curves - Select Fill (Sheet 4 of 4) Figure 2.5-143

Figure 2.5-144
SUMMARY OF CONSTRUCTION
CONTROL COMPACTION TEST RESULTS - SELECT FILL
(SHEET 1 OF 4)



Amendment 0
August 1948

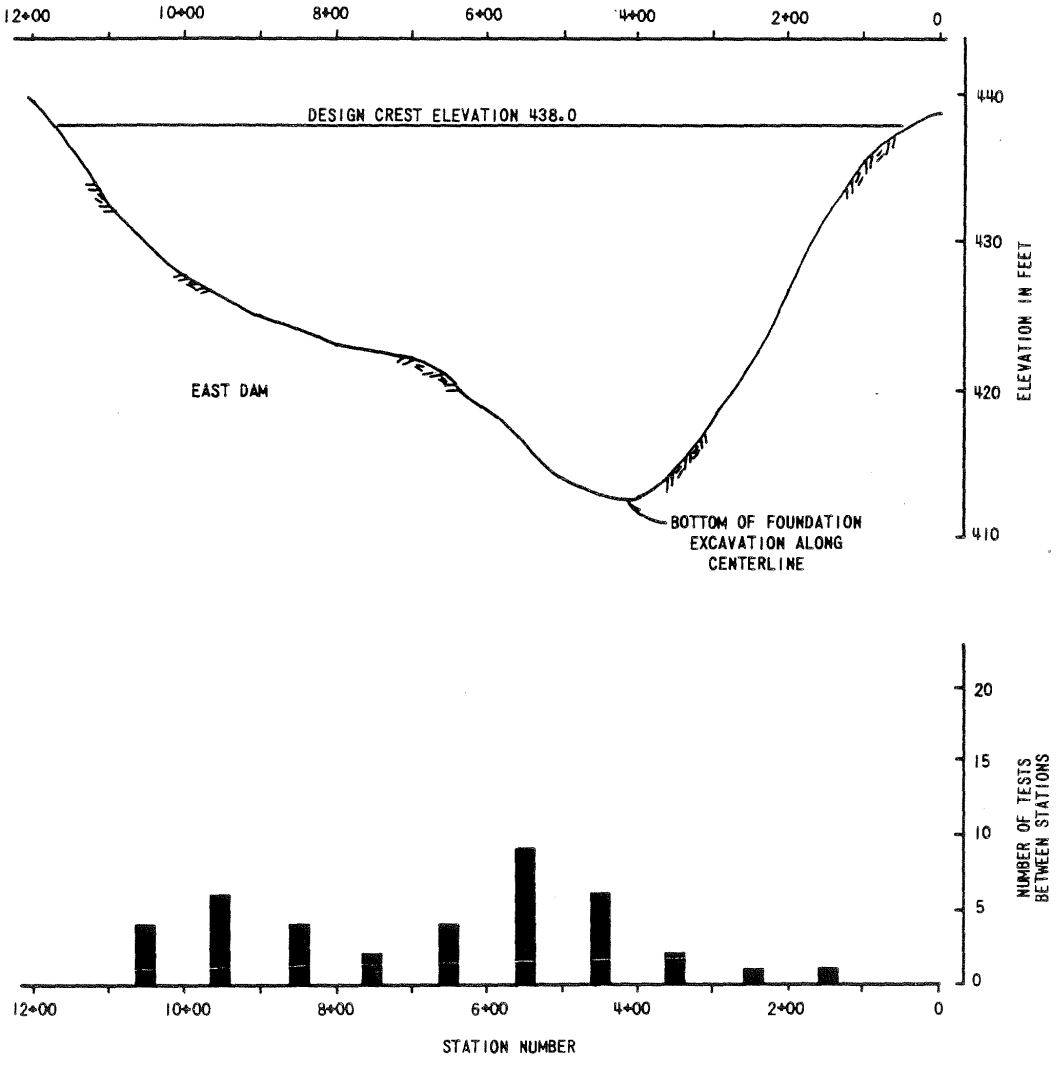
Figure 2.5-144
SUMMARY OF CONSTRUCTION CONTROL COMPACTION TEST RESULTS - SELECT FILL (SHEET 2 OF 4)



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Summary Of Construction Control Compaction Test Results - Select Fill (Sheet 2 of 4) Figure 2.5-144

Amendment 0
August 1984

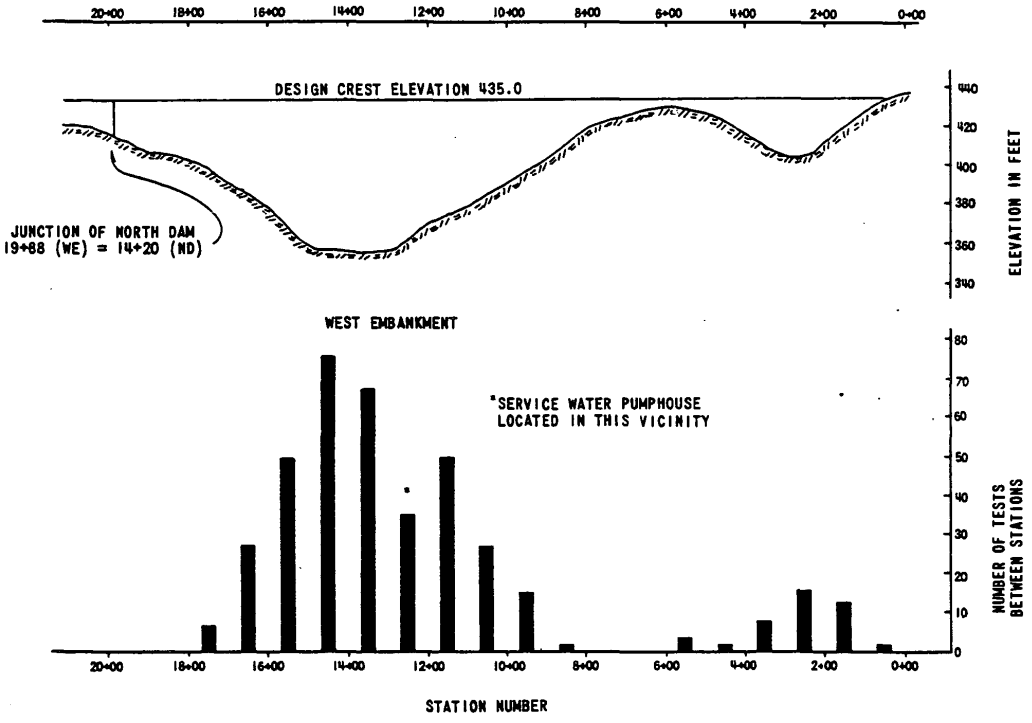
Figure 2.5-144
SUMMARY OF CONSTRUCTION CONTROL COMPACTION TEST RESULTS - SELECT FILL (SHEET 3 OF 4)



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Summary Of Construction Control Compaction Test Results - Select Fill (Sheet 3 of 4) Figure 2.5-144

Amendment 0
August 1984

Figure 2.5-144
SUMMARY OF CONSTRUCTION
CONTROL COMPACTION TEST RESULTS - SELECT FILL
(SHEET 4 OF 4)

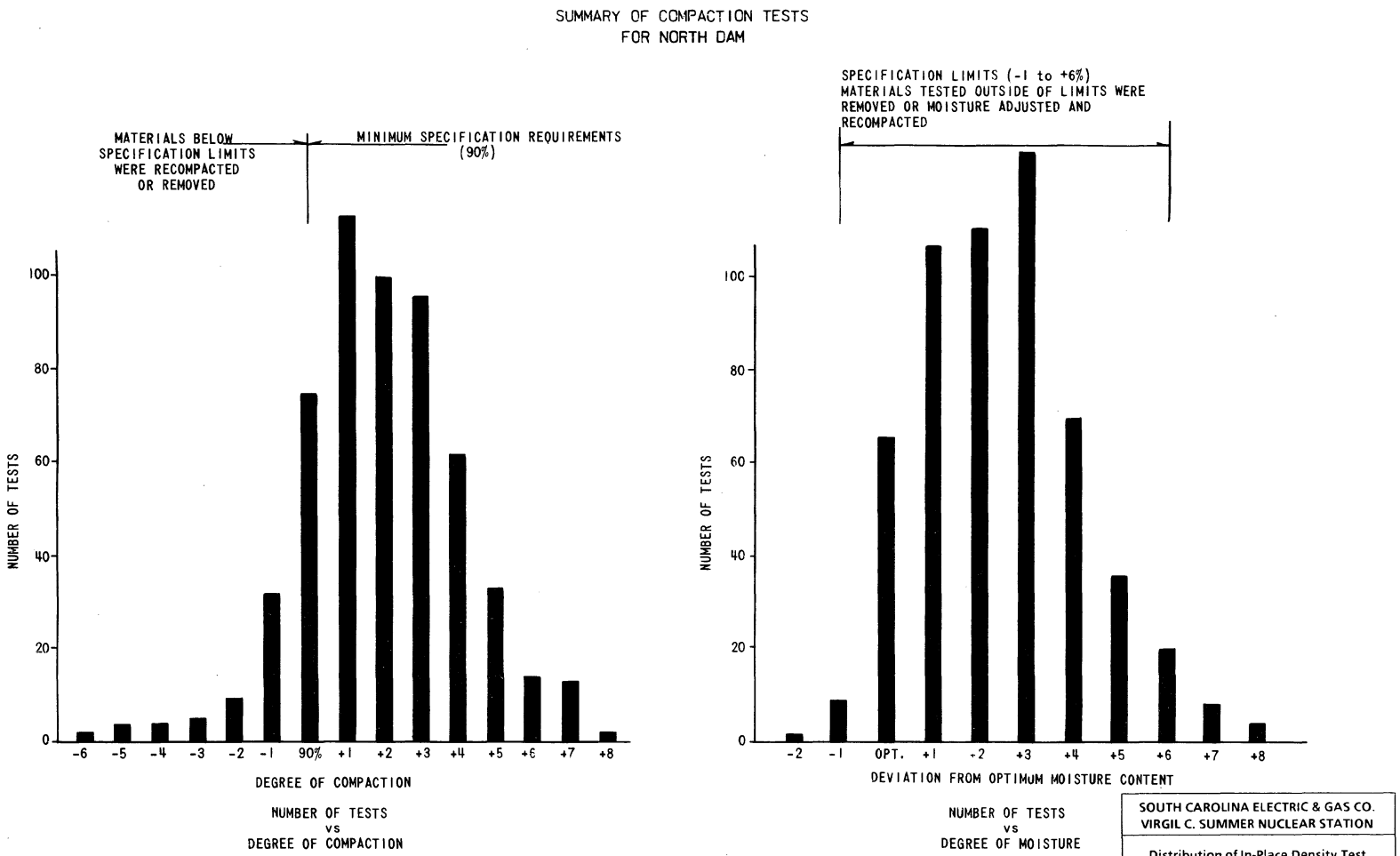


Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Summary Of Construction Control Compaction Test Results - Select Fill (Sheet 4 of 4) Figure 2.5-144

Figure 2.5-145

DISTRIBUTION OF IN-PLACE DENSITY TEST LOCATIONS - SELECT FILL (SHEET 1 OF 4)

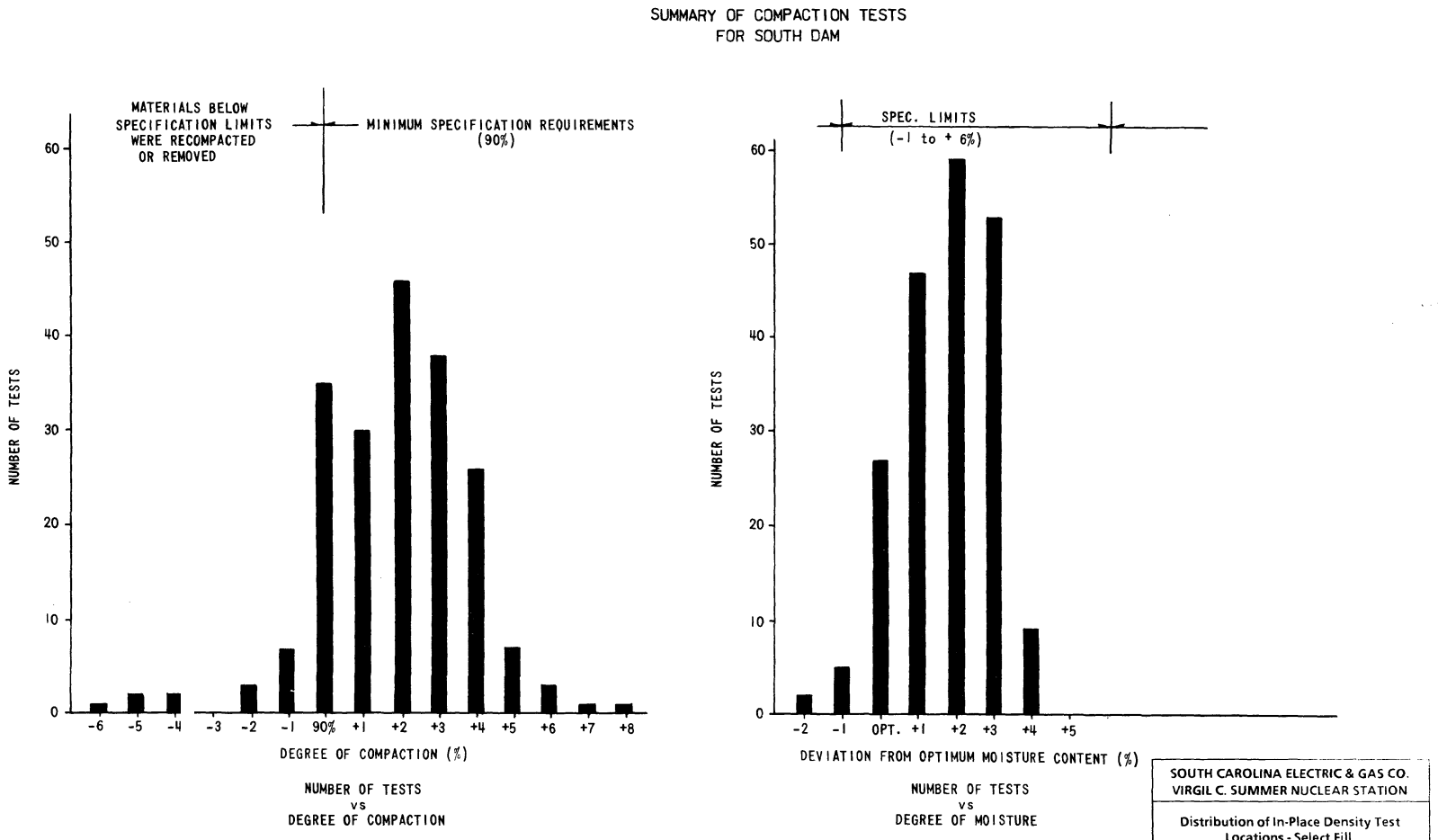


Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Distribution of In-Place Density Test Locations - Select Fill (Sheet 1 of 4) Figure 2.5-145

Figure 2.5-145

DISTRIBUTION OF IN-PLACE
DENSITY TEST LOCATIONS - SELECT FILL (SHEET 2 OF 4)



Amendment 0
August 1984

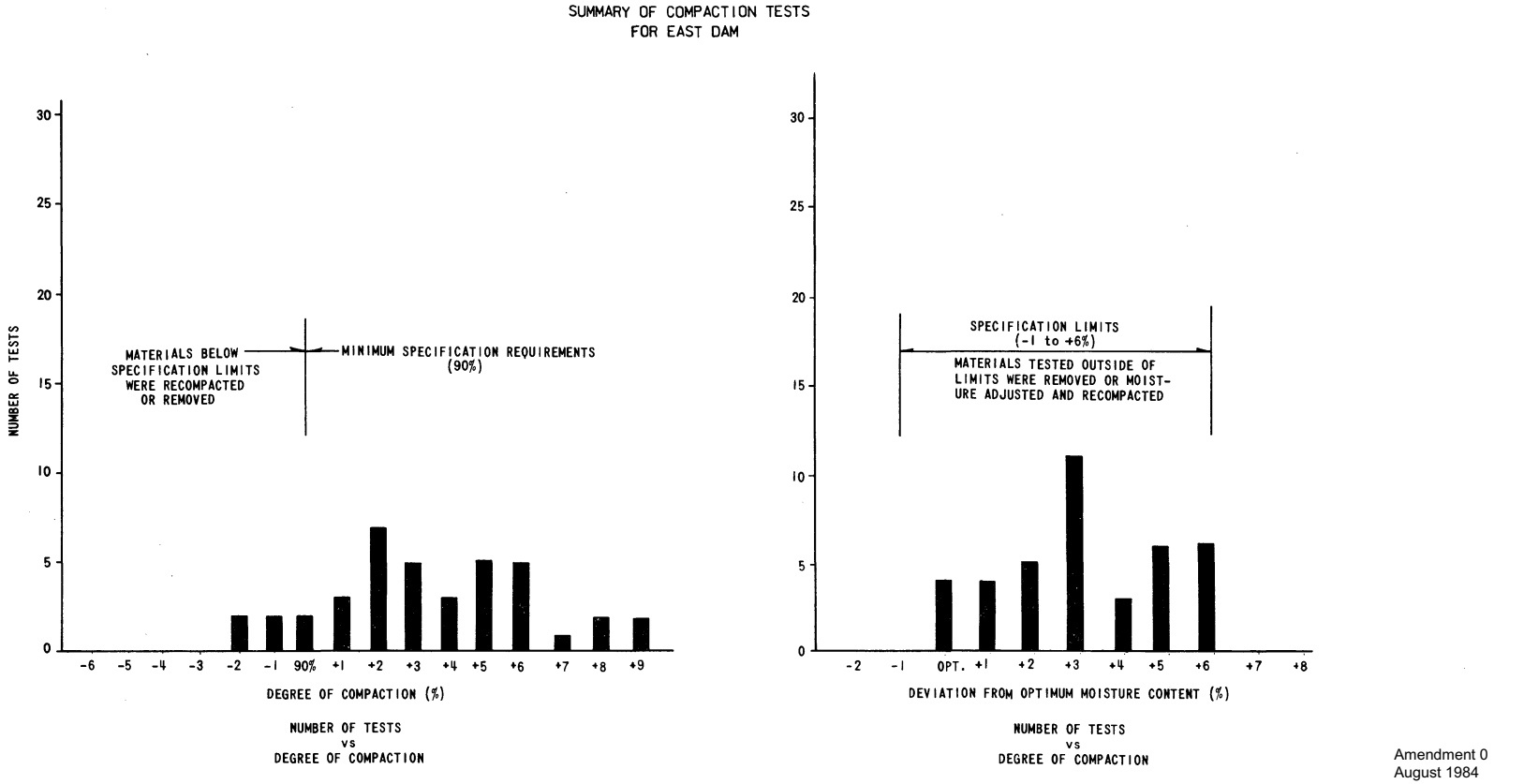
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Distribution of In-Place Density Test Locations - Select Fill (Sheet 2 of 4)

Figure 2.5-145

Figure 2.5-145

DISTRIBUTION OF IN-PLACE
DENSITY TEST LOCATIONS - SELECT FILL (SHEET 3 OF 4)



Amendment 0
August 1984

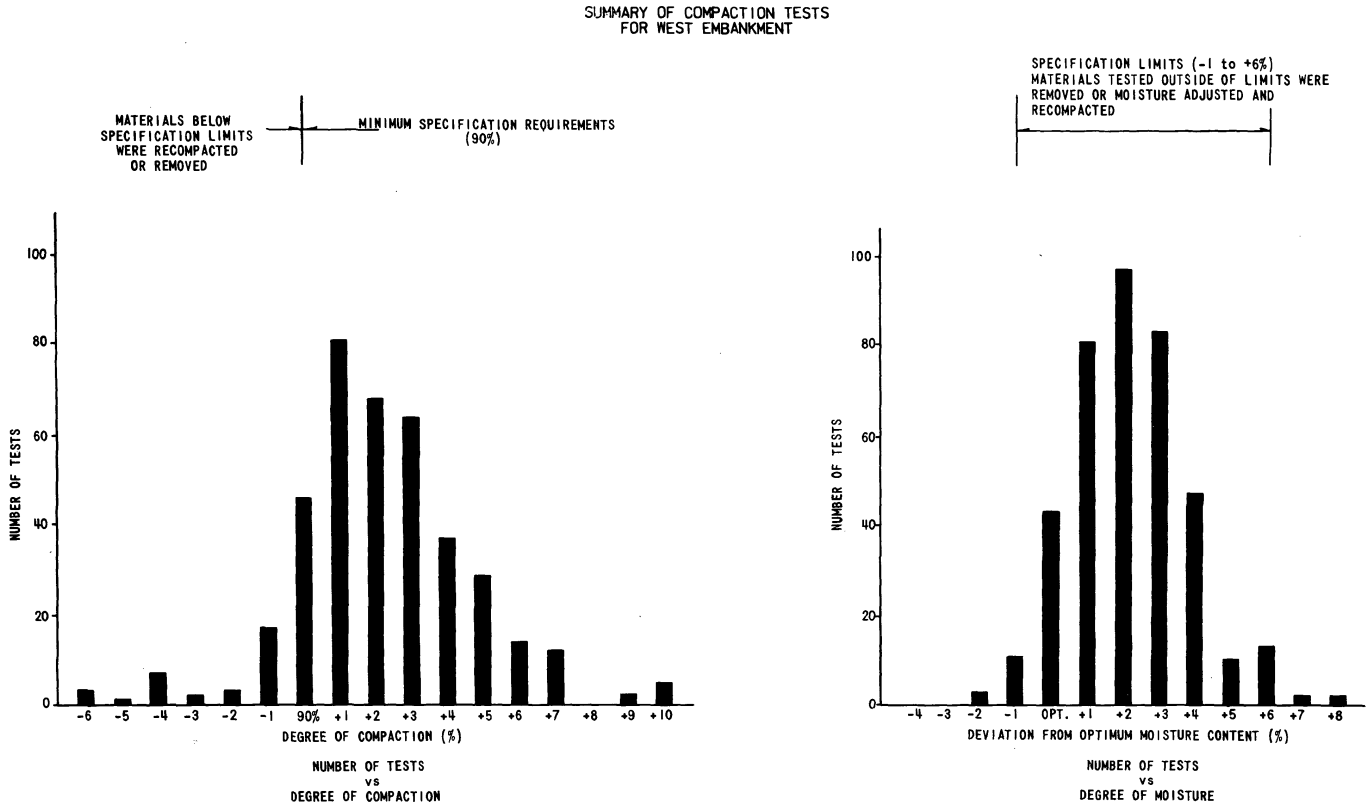
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Distribution of In-Place Density Test Locations - Select Fill (Sheet 3 of 4)

Figure 2.5-145

Figure 2.5-145

DISTRIBUTION OF IN-PLACE DENSITY TEST LOCATIONS - SELECT FILL (SHEET 4 OF 4)

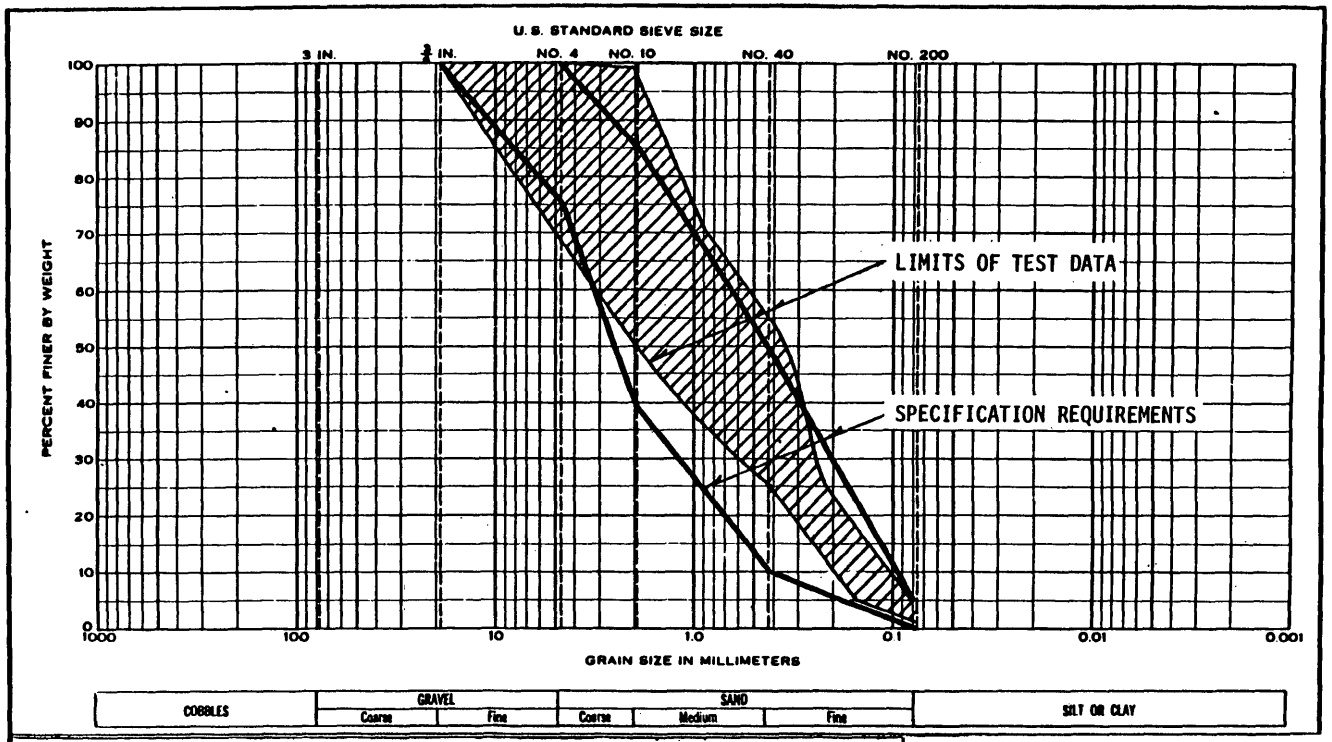


Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Distribution of In-Place Density Test Locations - Select Fill (Sheet 4 of 4) Figure 2.5-145

Figure 2.5-146

SUMMARY OF CONSTRUCTION CONTROL
GRADATION TESTS - ZONE 1 FILTER MATERIAL



ZONE 1 FILTER

SUMMARY OF EIGHTY-THREE GRADATION TESTS
REPRESENTING 32,151 CUBIC YARDS OF MATERIAL.

Amendment 0
August 1984

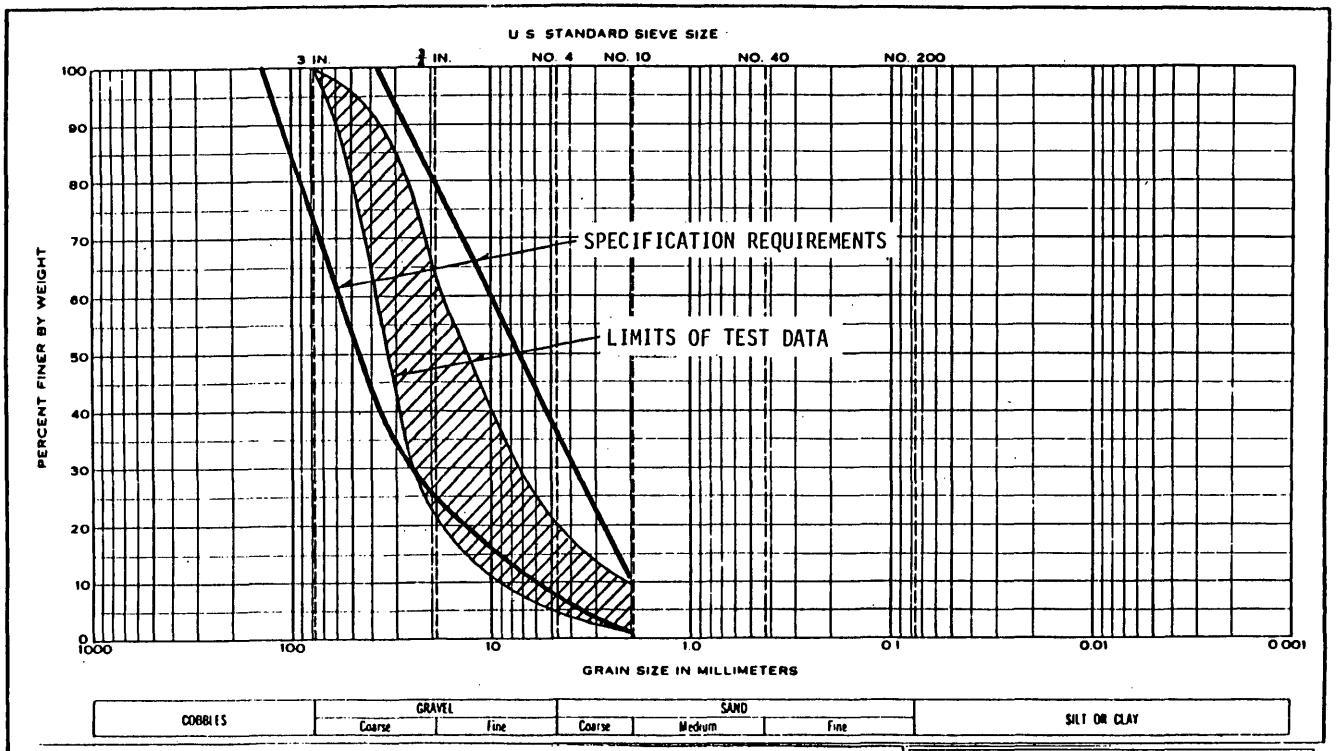
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary of Construction Control
Gradation Tests - Zone 1
Filter Material

Figure 2.5-146

Figure 2.5-147

SUMMARY OF CONSTRUCTION CONTROL
GRADATION TESTS - ZONE 2 FILTER MATERIAL



ZONE 2 FILTER

SUMMARY OF 150 GRADATION TESTS REPRESENTING
35,858 CUBIC YARDS OF MATERIAL

Amendment 0
August 1984

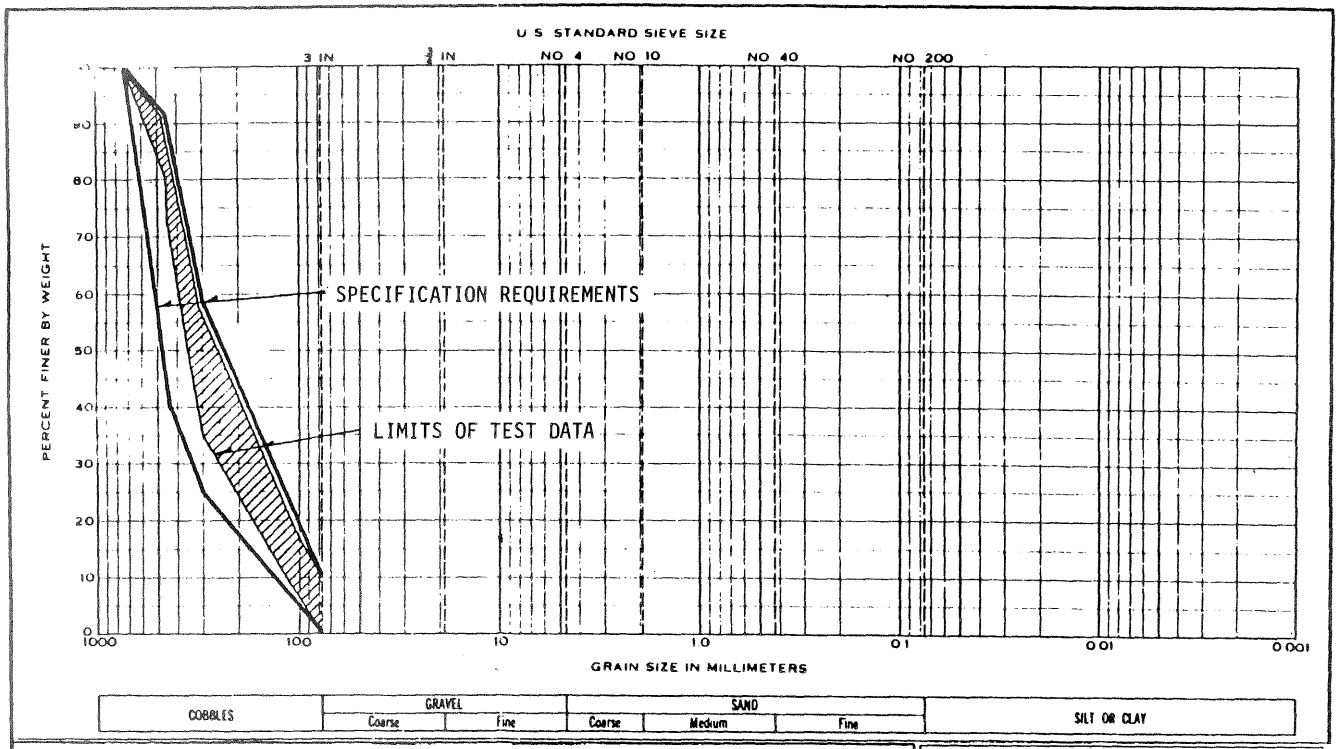
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary of Construction Control Gradation Tests - Zone 2 Filter Material

Figure 2.5-147

Figure 2.5-148

SUMMARY OF CONSTRUCTION CONTROL GRADATION TESTS - ZONE A ROCK



ZONE A RIPRAP

SUMMARY OF NINE GRADATION TESTS REPRESENTING
42,636 CUBIC YARDS OF MATERIAL

Amendment 0
August 1984

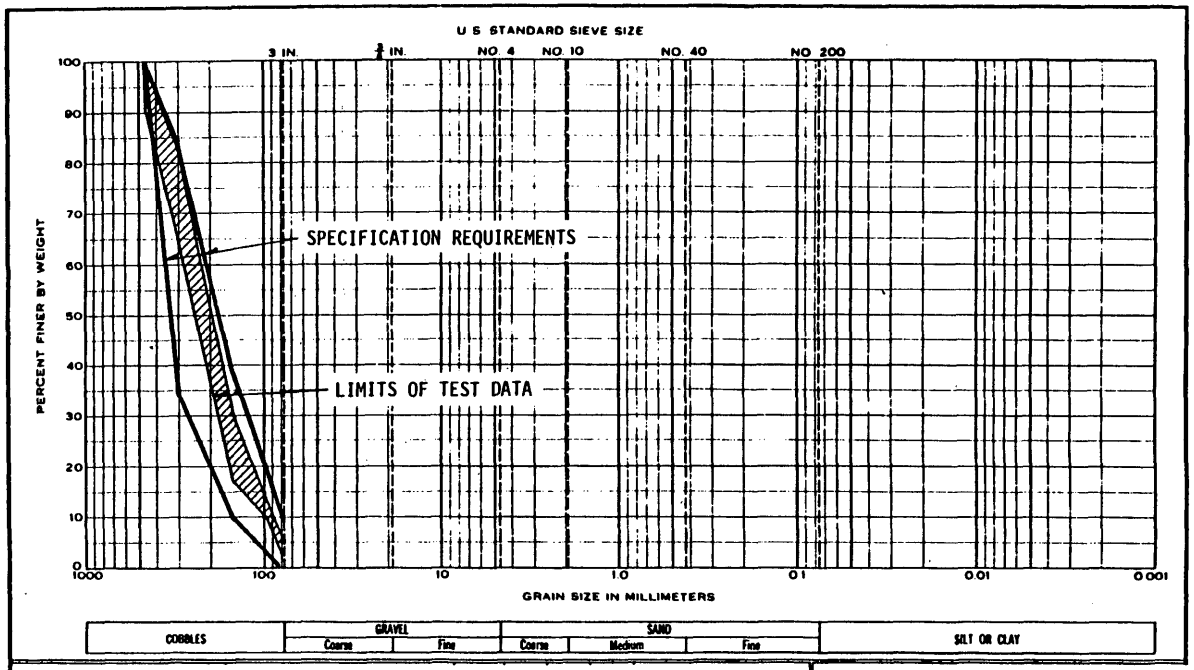
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary of Construction Control
Gradation Tests - Zone A Rock

Figure 2.5-148

Figure 2.5-149

SUMMARY OF CONSTRUCTION CONTROL
GRADATION TESTS - ZONE B ROCK
(SHEET 1 OF 3)



ZONE B RIPRAP

SUMMARY OF THREE GRADATION TESTS REPRESENTING
36,000 CUBIC YARDS OF MATERIAL
(INCLUDES DATA THROUGH JUNE, 1976)

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

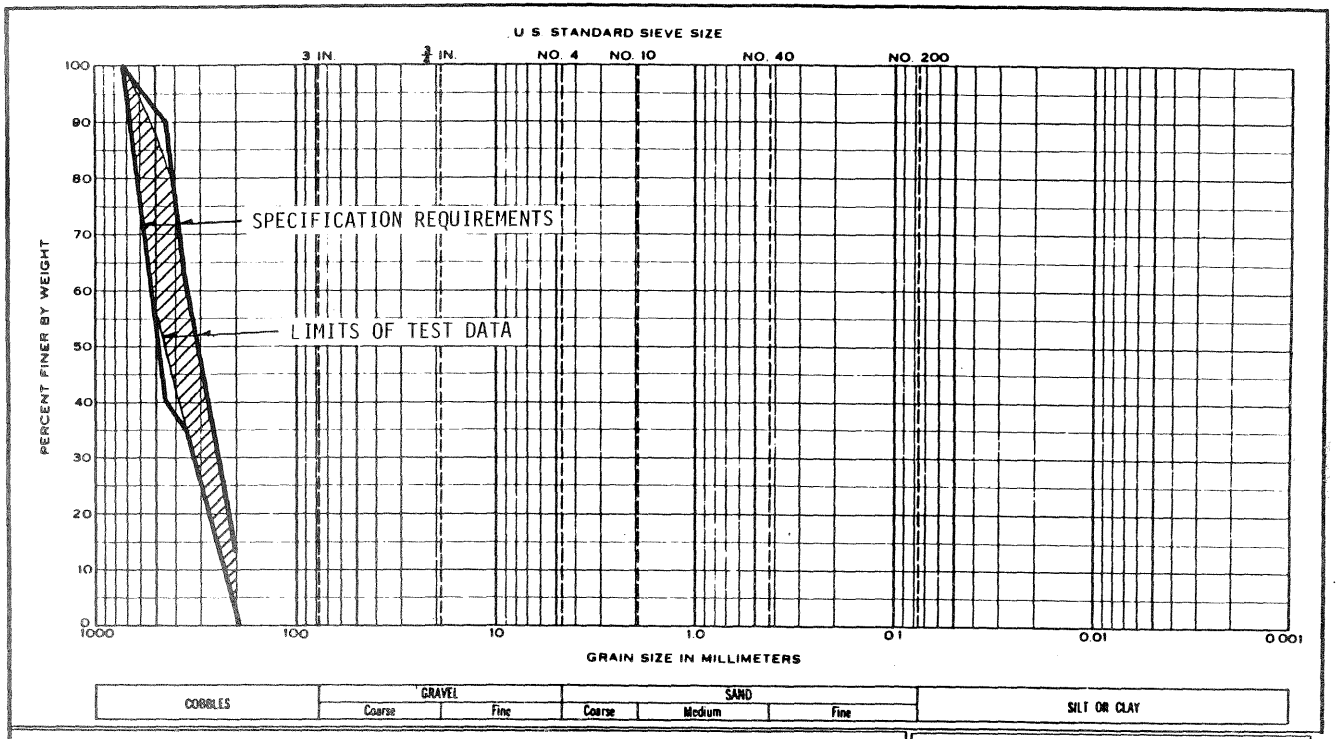
Summary Of Construction Control
Gradation Tests - Zone B Rock
(Sheet 1 of 3)

Figure 2.5-149

Amendment 0
August 1984

Figure 2.5-149

SUMMARY OF CONSTRUCTION CONTROL
GRADATION TESTS - ZONE D ROCK (SHEET 2 OF 3)



ZONE D RIPRAP
Summary of 5 Gradation Tests
Representing 20186 Cubic Yards

GRADATION CURVES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary Of Construction Control
Gradation Tests - Zone D Rock
(Sheet 2 of 3)

Figure 2.5-149

Figure 2.5-149

SUMMARY OF CONSTRUCTION CONTROL GRADATION TESTS - ZONE C ROCK (SHEET 3 OF 3)

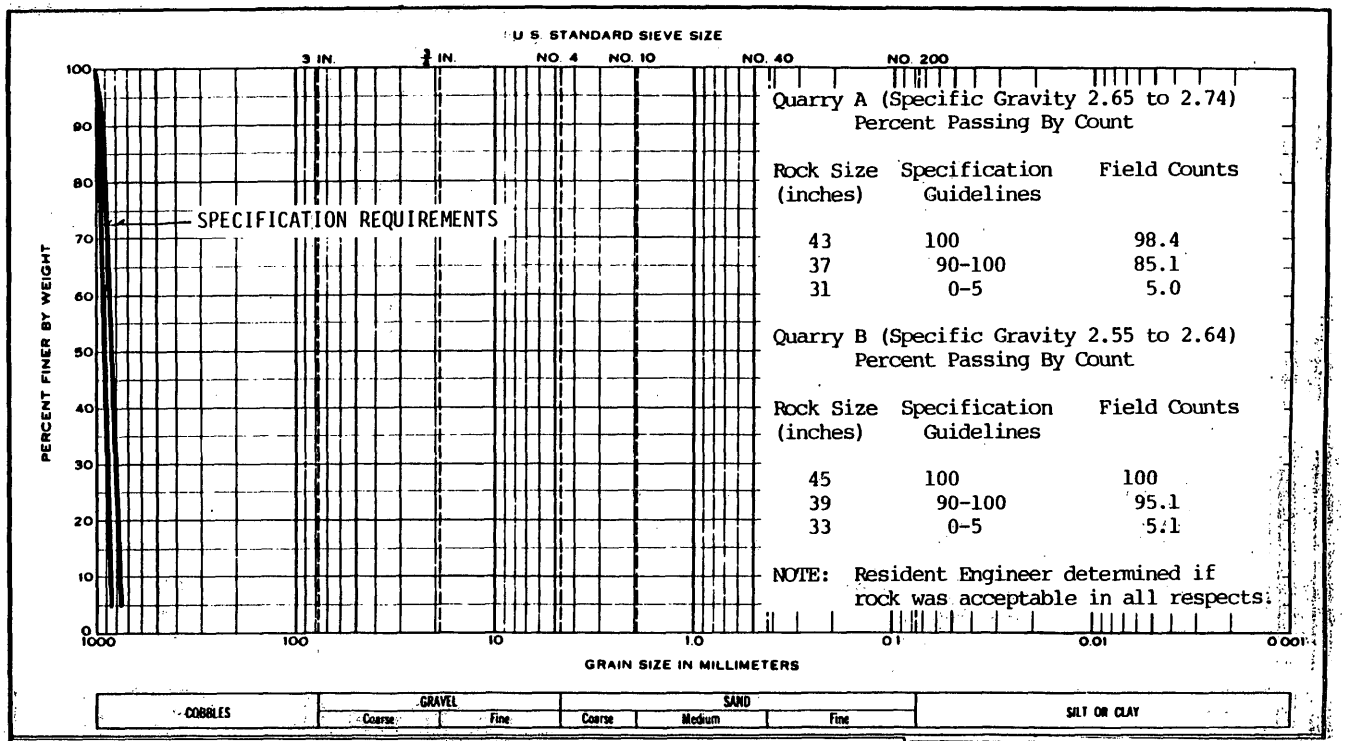
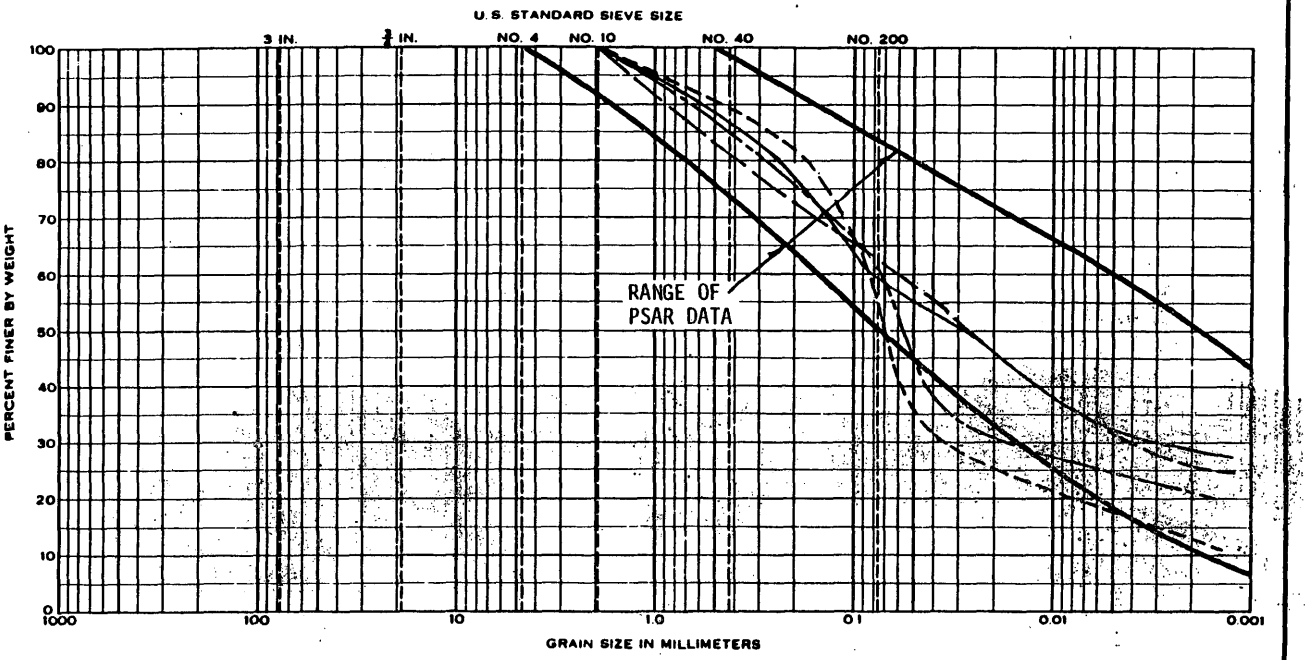


Figure 2.5-150

GRAIN SIZE DISTRIBUTION CURVES - BLOCK SAMPLES
(SHEET 1 OF 8)



Sample No.	Elev or Depth	Classification	NatWC	LL	PL	PI	SYMBOL
UDS- 1	-	ML	29.5	43	33	10	
UDS- 2	-	ML	22.2	43	33	10	
UDS- 3	-	ML	23.2	42	34	8	
UDS- 4	-	ML-SM	20.3	41	37	4	

GRADATION CURVES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

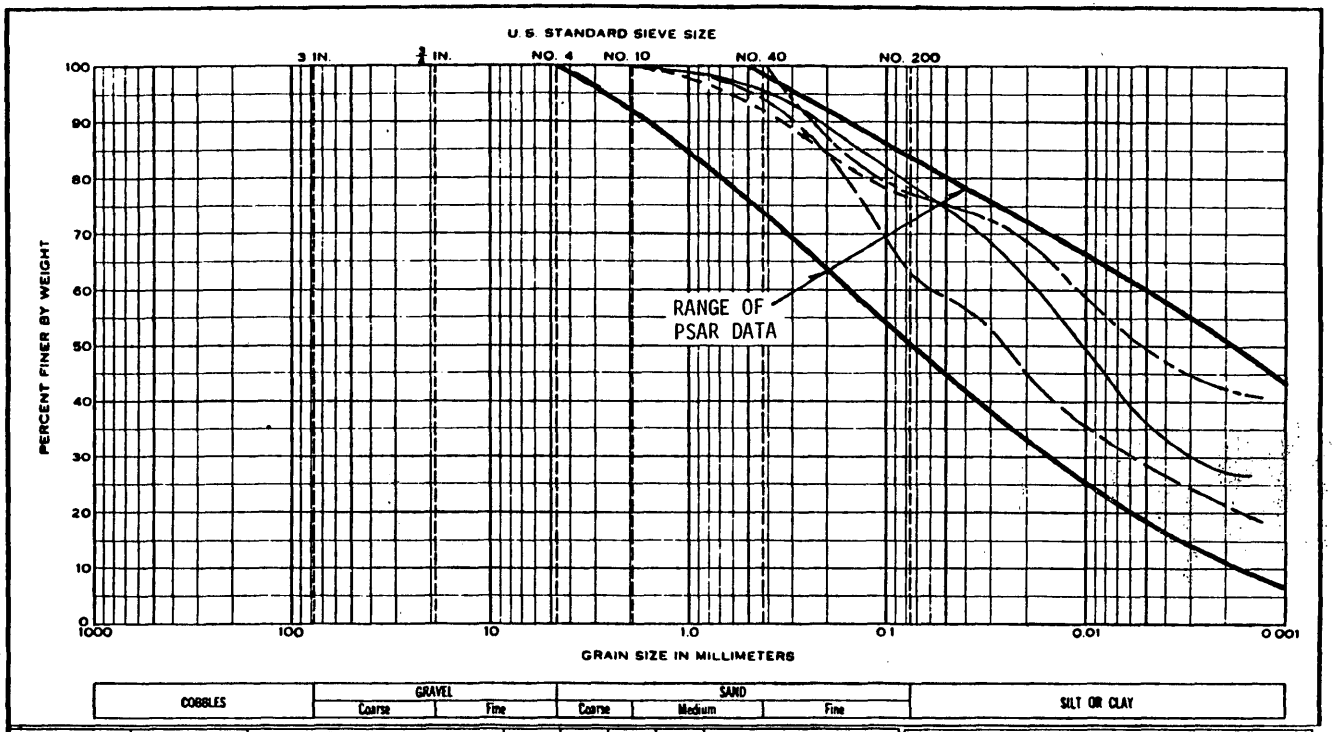
Grain Size Distribution
Curves - Block Samples
(Sheet 1 of 8)

Figure 2.5-150

Amendment 0
August 1984

Figure 2.5-150

GRAIN SIZE DISTRIBUTION
CURVES - BLOCK SAMPLES (SHEET 2 OF 8)



Sample No.	Elev or Depth	Classification	NatWC	LL	PL	PI	SYMBOL
UDS- 5	-	MH	27.0	59	46	13	
UDS- 7	-	MH	24.7	59	34	25	
UDS- 9	-	MH	24.3	69	43	26	
UDS-11	-	MH	24.3	61	43	18	

GRADATION CURVES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution
Curves - Block Samples
(Sheet 2 of 8)

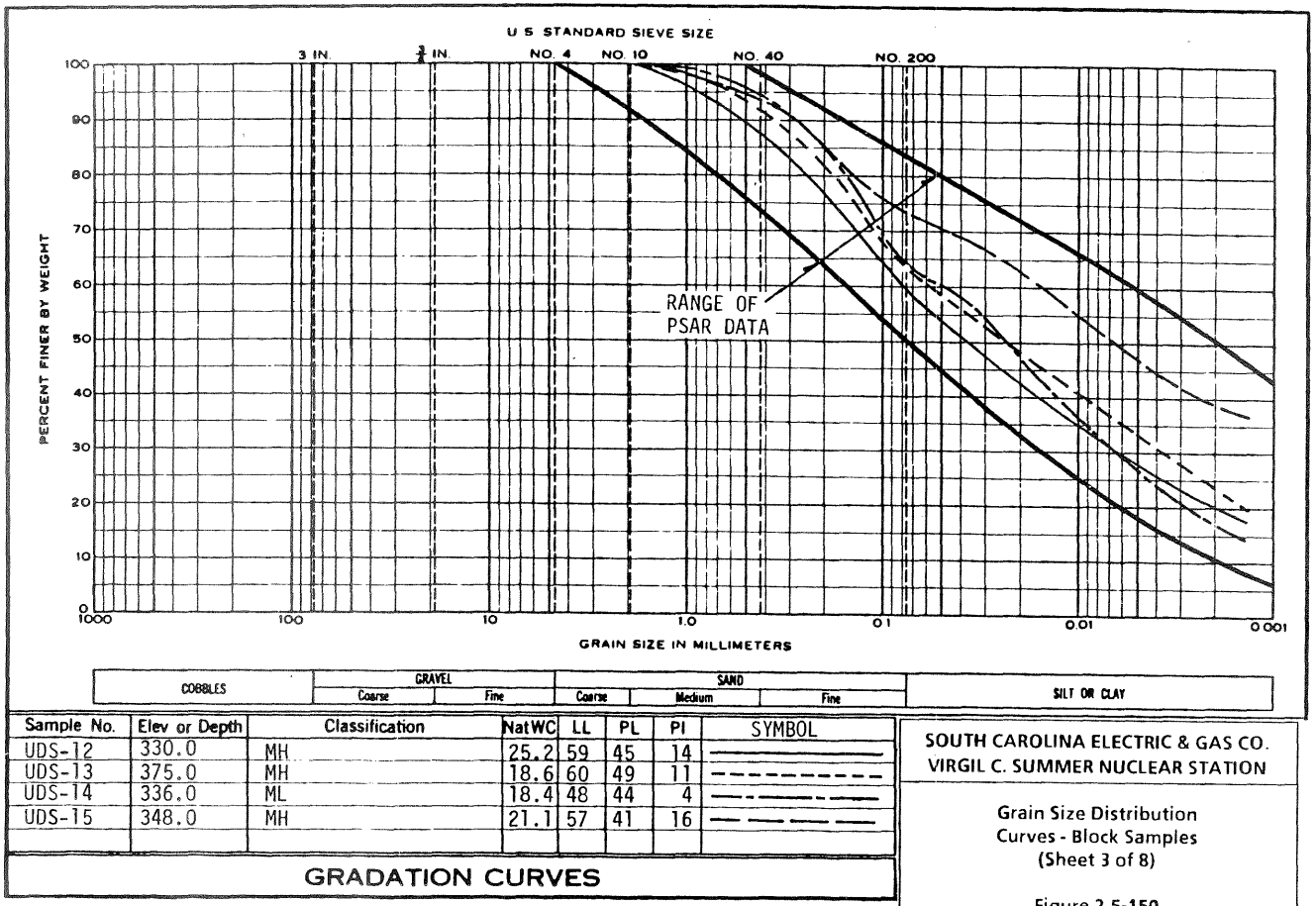
Figure 2.5-150

Amendment 0
August 1984

Figure 2.5-150

GRAIN SIZE DISTRIBUTION

CURVES - BLOCK SAMPLES (SHEET 3 OF 8)



Sample No.	Elev or Depth	Classification	NatWC	LL	PL	PI	SYMBOL
UDS-12	330.0	MH	25.2	59	45	14	
UDS-13	375.0	MH	18.6	60	49	11	
UDS-14	336.0	ML	18.4	48	44	4	
UDS-15	348.0	MH	21.1	57	41	16	

GRADATION CURVES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

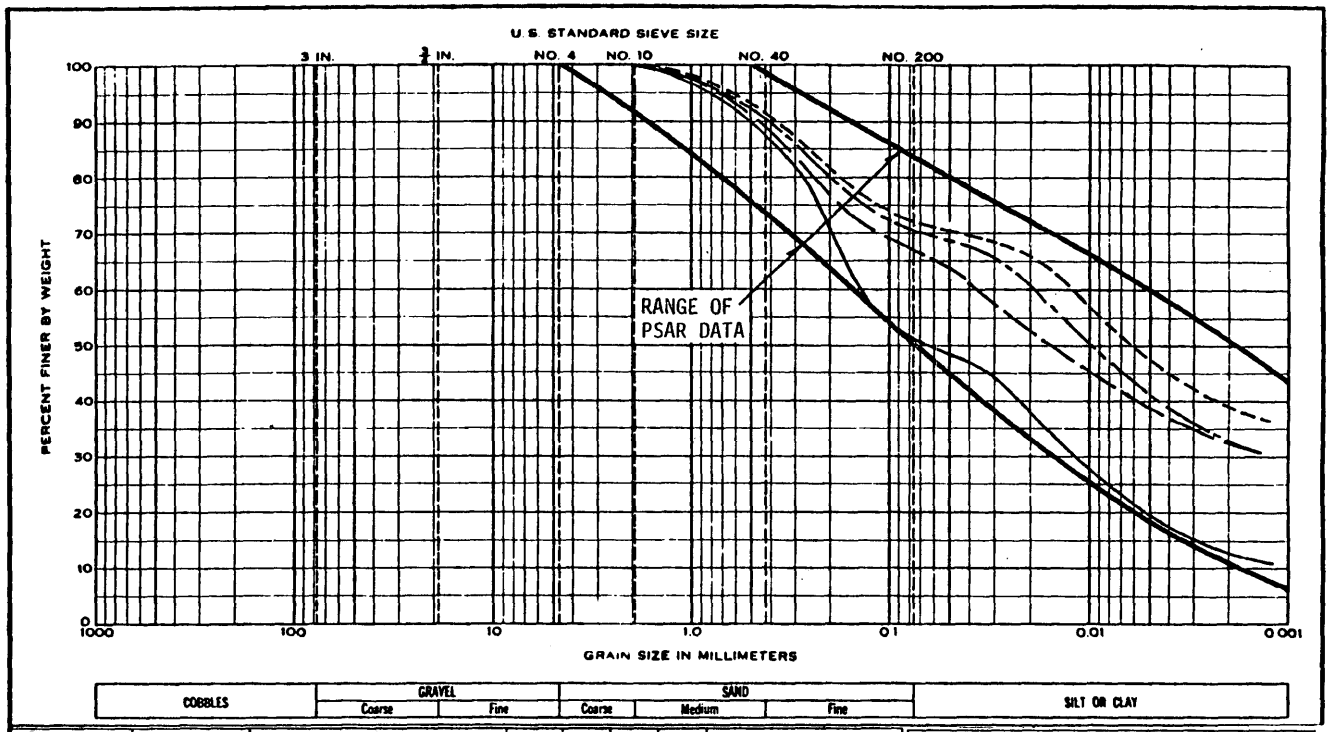
Grain Size Distribution
Curves - Block Samples
(Sheet 3 of 8)

Figure 2.5-150

Amendment 0
August 1984

Figure 2.5-150

GRAIN SIZE DISTRIBUTION
CURVES - BLOCK SAMPLES (SHEET 4 OF 8)



Sample No.	Elev or Depth	Classification	NatWC	LL	PL	PI	SYMBOL
UDS-17	391	ML-SM	19.1	NP	NP	-	
UDS-18	402	MH	22.7	68	44	24	
UDS-19	344	MH	22.0	52	45	7	
UDS-20	407	MH-CH	25.2	60	32	28	

GRADATION CURVES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

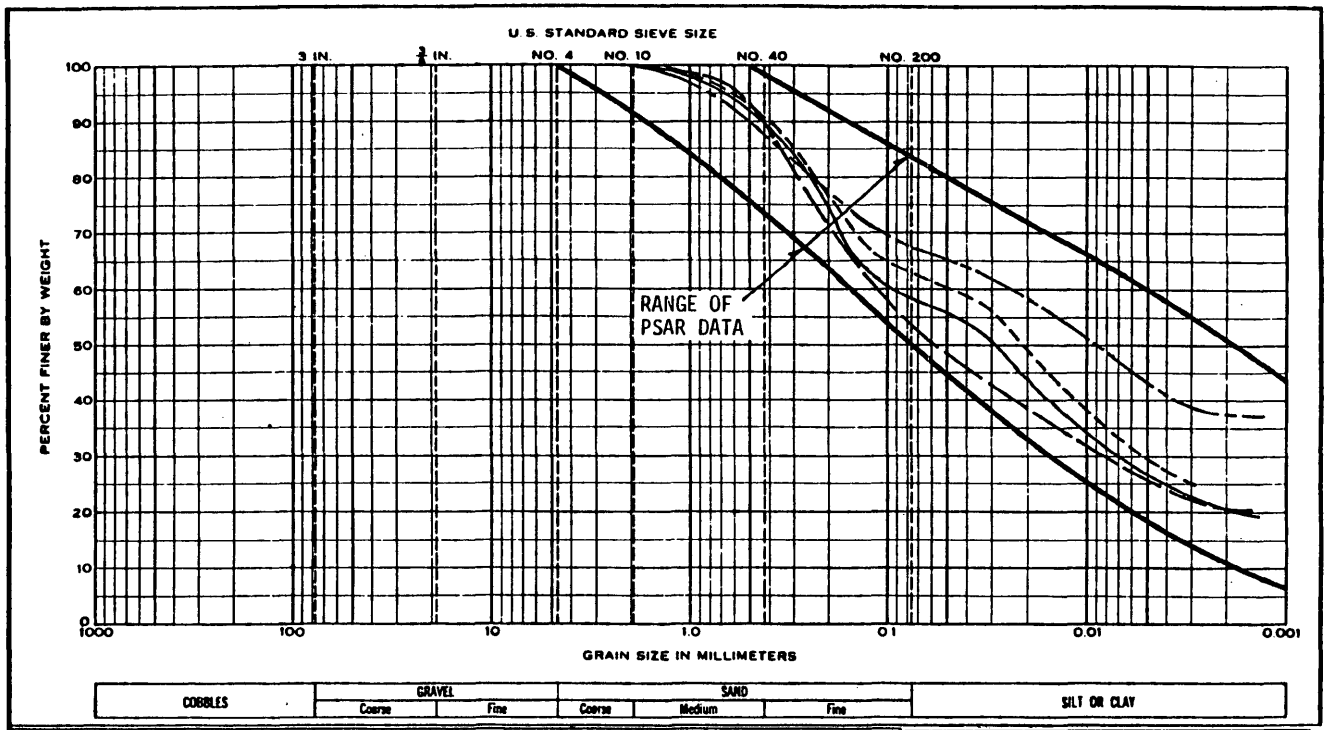
Grain Size Distribution
Curves - Block Samples
(Sheet 4 of 8)

Figure 2.5-150

Amendment 0
August 1984

Figure 2.5-150

GRAIN SIZE DISTRIBUTION
CURVES - BLOCK SAMPLES (SHEET 5 OF 8)



Sample No.	Elev or Depth	Classification	NatWC	LL	PL	PI	SYMBOL
UDS-21	363	ML	--	49	41	8	
UDS-22	N/A	ML	24	44	39	5	
UDS-24	422	ML	22	NP	NP	-	
UDS-26	369	ML-SM	20	47	34	13	

GRADATION CURVES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

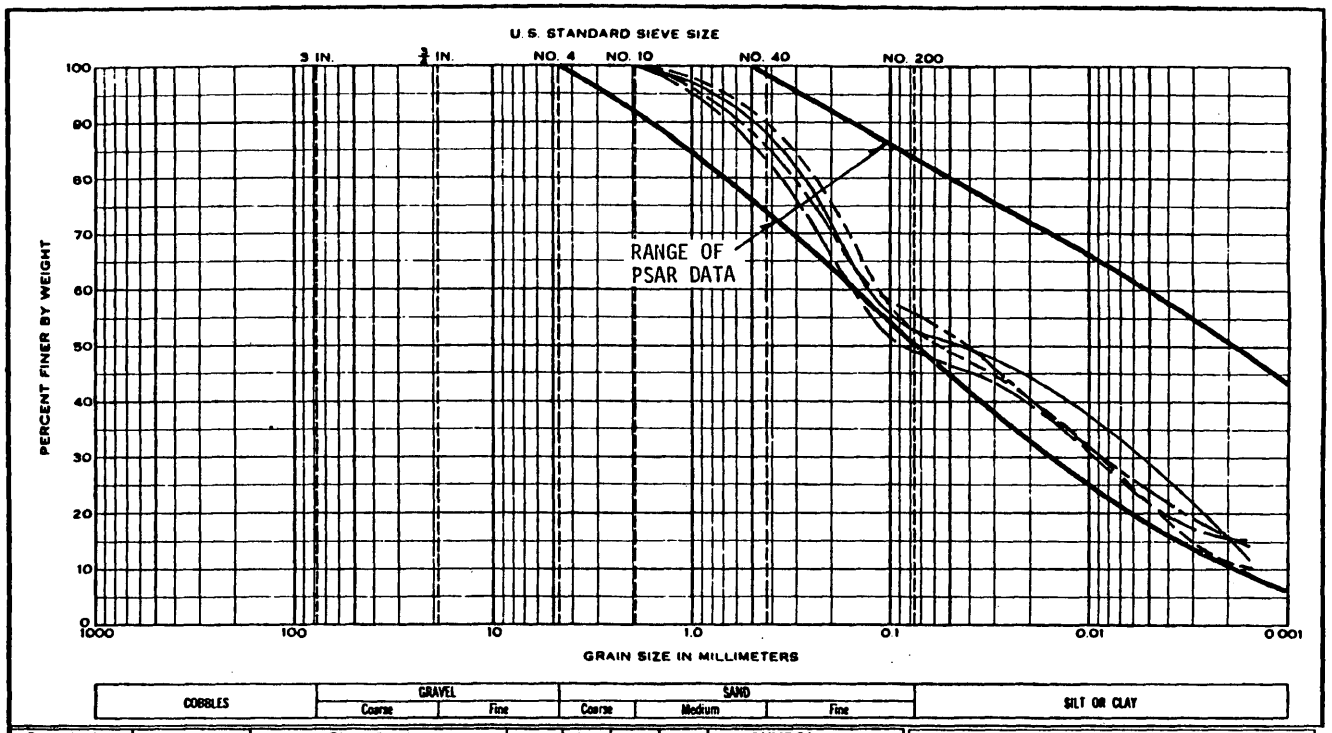
Grain Size Distribution
Curves - Block Samples
(Sheet 5 of 8)

Figure 2.5-150

Amendment 0
August 1984

Figure 2.5-150

GRAIN SIZE DISTRIBUTION
CURVES - BLOCK SAMPLES (SHEET 6 OF 8)



Sample No.	Elev or Depth	Classification	NatWC	LL	PL	PI	SYMBOL
UDS-28	N/A	ML-SM	21	NP	NP	-	
UDS-30	379	ML-MH	21	51	44	7	
UDS-31	381	ML-MH	-	54	41	13	
UDS-33	N/A	ML	19	NP	NP	-	

GRADATION CURVES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

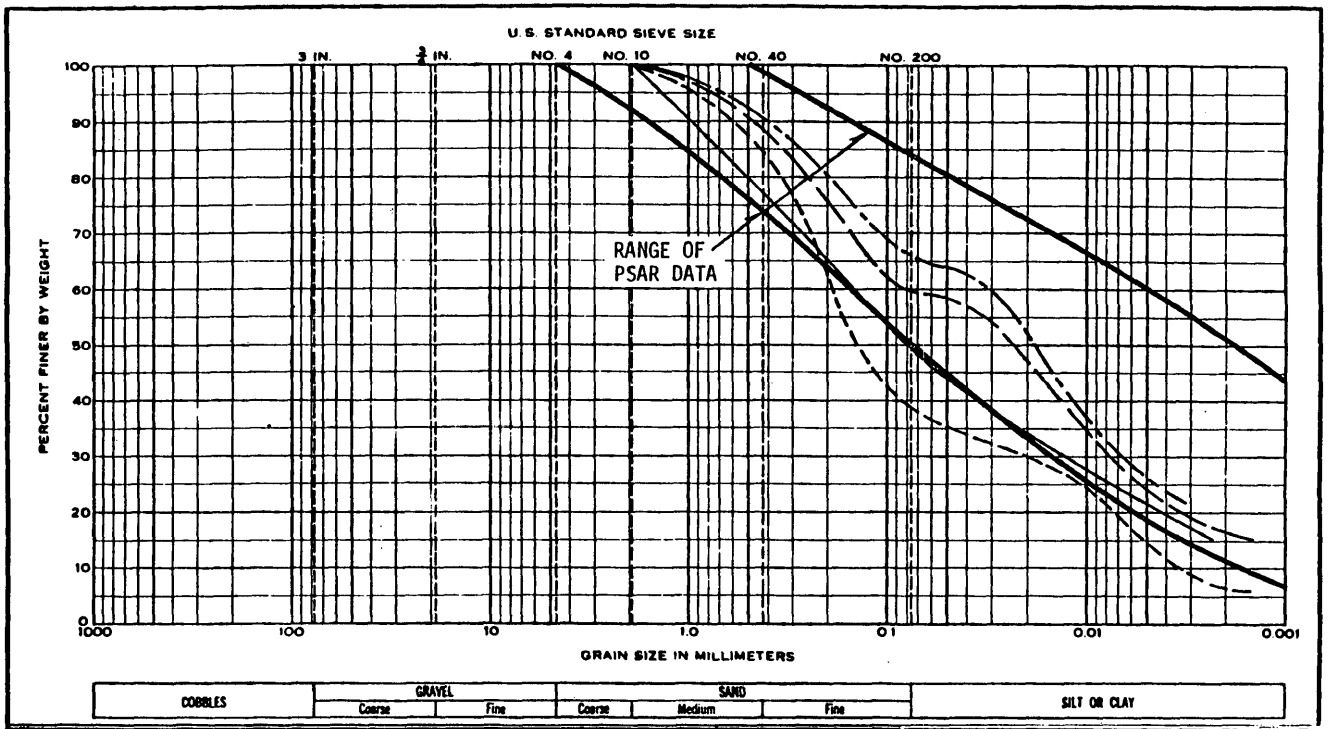
Grain Size Distribution
Curves - Block Samples
(Sheet 6 of 8)

Figure 2.5-150

Amendment 0
August 1984

Figure 2.5-150

GRAIN SIZE DISTRIBUTION
CURVES - BLOCK SAMPLES (SHEET 7 OF 8)



Sample No.	Elev or Depth	Classification	Nat WC	LL	PL	PI	SYMBOL
UDS-34	N/A	SM	20	NP	NP	-	
UDS-36	416	SM-ML	23	NP	NP	-	
UDS-37	384	ML	21	NP	NP	-	
UDS-44	408	ML	19	43	36	7	

GRADATION CURVES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution
Curves - Block Samples
(Sheet 7 of 8)

Figure 2.5-150

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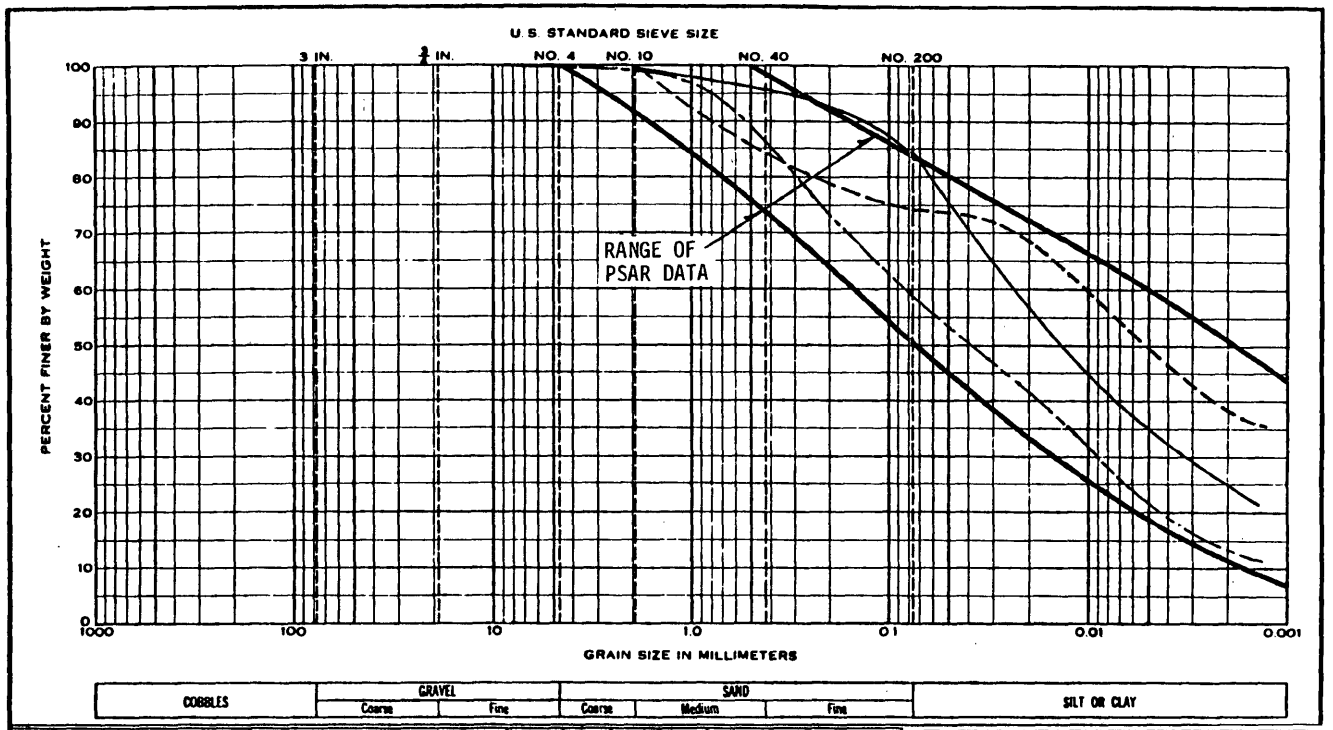
Figure 2.5-150

GRAIN SIZE DISTRIBUTION
CURVES - BLOCK SAMPLES (SHEET 8 OF 8)



Sample No.	Elev or Depth	Classification	Nat WC	LL	PL	PI	SYMBOL
UDS-48	431	MH	27	55	48	7	
UDS-49	430	MH	24	57	44	13	
UDS-38	394	MH	20	52	44	8	

GRADATION CURVES

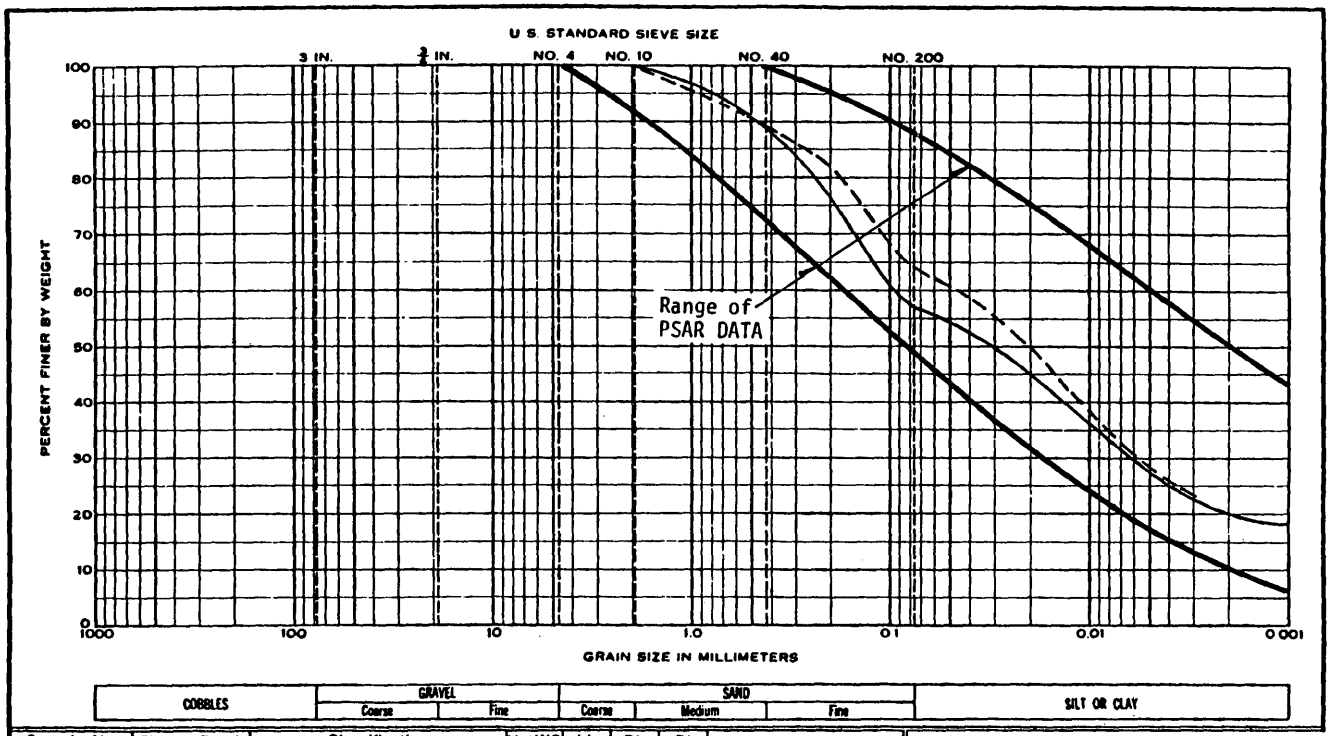
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution
Curves - Block Samples
(Sheet 8 of 8)

Figure 2.5-150

Figure 2.5-150a

GRAIN SIZE DISTRIBUTION CURVES - BORROW SOURCE G



Sample No.	Elev or Depth	Classification	Nat WC	LL	PL	PI
UDS-21	N/A	ML	25.1	49	41	8
UDS-22	N/A	ML	23.5	44	39	5

GRADATION CURVES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Grain Size Distribution
Curves - Borrow Source G

Figure 2.5-150a

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Figure 2.5-151

UNCONFIRMED COMPRESSION TEST RESULTS ON BLOCK SAMPLES (SHEET 1 OF 2)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

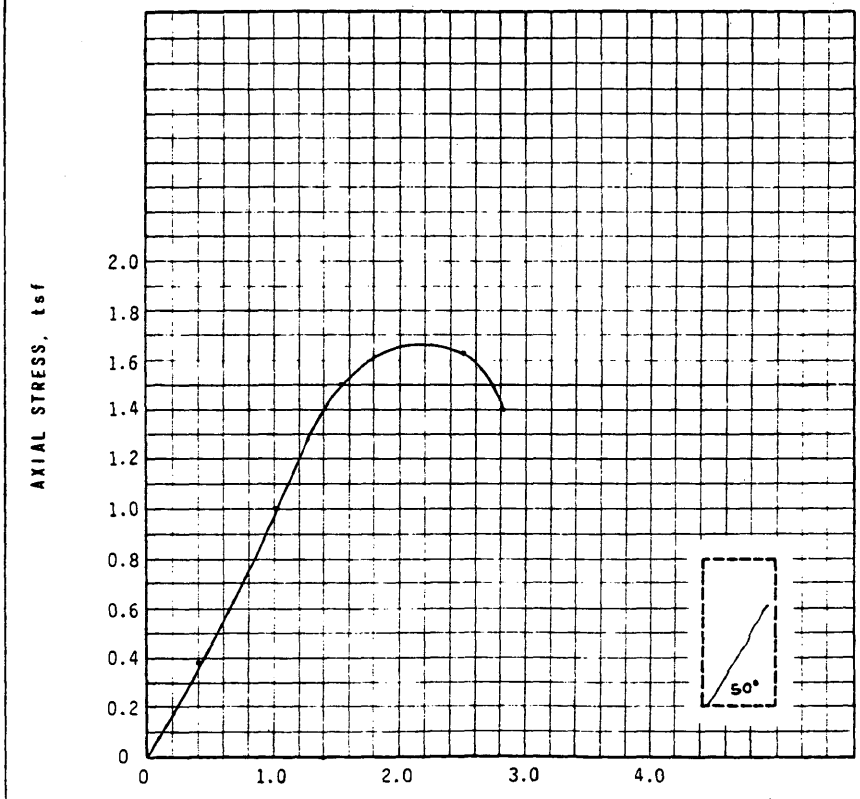
Block No. UDS-2 Coord. N 472,591 E 1,905,450 Elev. 383

Description Red-brown micaceous decomposed sandy silt (ML)

Moisture Content 23.2 % Dry Density 89.9 pcf

Liquid Limit 43 % Plastic Limit 33 %

Maximum Axial Stress 1.695 tsf @ 2.0 % Strain



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Block Samples
(Sheet 1 of 2)

Figure 2.5-151

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Figure 2.5-151
UNCONFIRMED COMPRESSION TEST RESULTS ON BLOCK SAMPLES (SHEET 2 OF 2)

UNCONFINED COMPRESSION TEST

Project Virgil C. Summer Nuclear Station

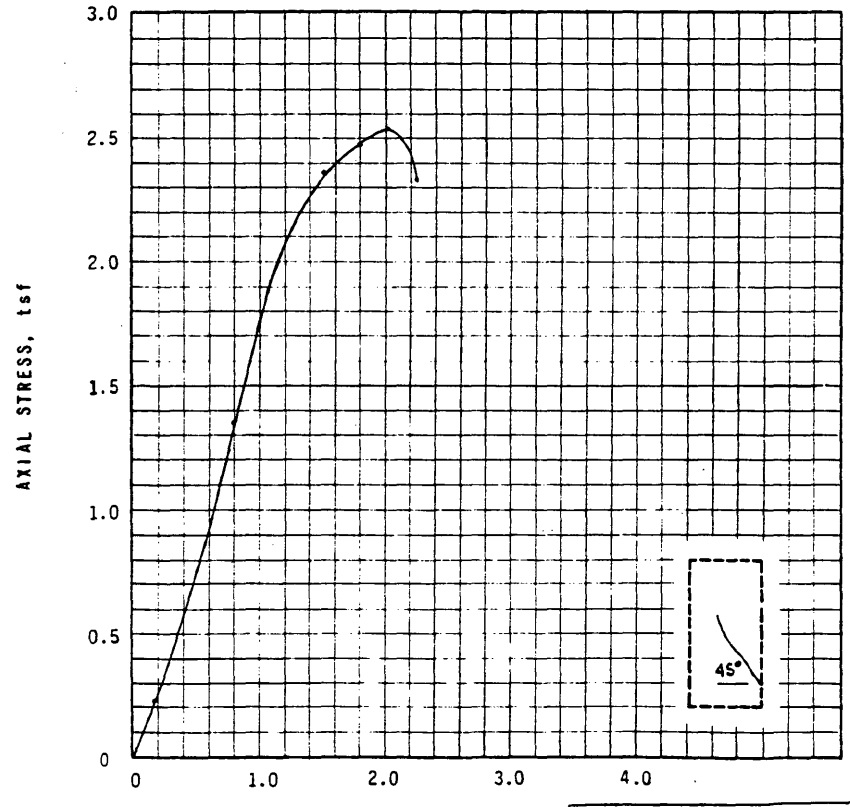
Block No. UDS-4 Coord. N 472,745 E 1,905,425 Elev. 390

Description Red-brown micaceous decomposed sandy silt (ML)

Moisture Content 21.2 % Dry Density 93.6 pcf

Liquid Limit 41 % Plastic Limit 37 %

Maximum Axial Stress 2.5 tsf @ 2.0 % Strain



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconfined Compression Test Results
On Block Samples
(Sheet 2 of 2)

Figure 2.5-151

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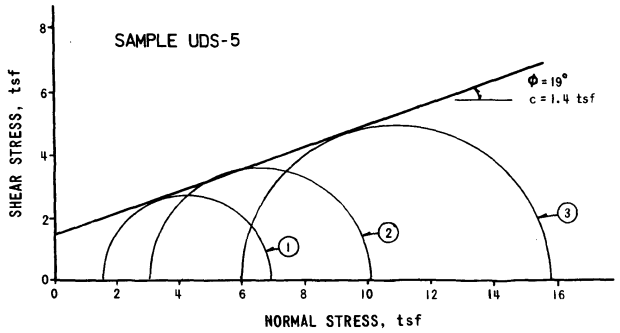
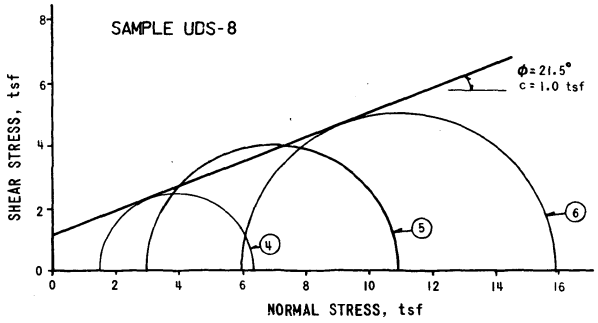
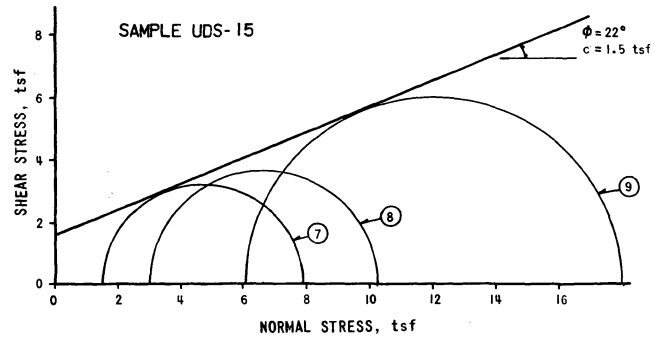
Figure 2.5-152

UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST ON BLOCK SAMPLES (SHEET 1 OF 4)





TEST NO.	SAMPLE NO.	LOCATION	DRY DENSITY (pcf)	MOISTURE CONTENT (%)	PERCENT COMP.	CONFINING PRESSURE (tsf)	STRAIN (%)
①	UDS-5	NORTH DAM	92.4	27.5	89.0	1.50	16.0
②	UDS-5	NORTH DAM	91.7	28.7	88.3	3.00	15.0
③	UDS-5	NORTH DAM	92.7	28.0	89.3	6.00	18.0
④	UDS-8	NORTH DAM	88.0	23.2	87.4	1.50	5.0
⑤	UDS-8	NORTH DAM	92.9	25.1	92.3	3.00	5.0
⑥	UDS-8	NORTH DAM	96.8	23.6	96.2	6.00	5.0
⑦	UDS-15	NORTH DAM	91.8	21.1	91.2	2.00	15.0
⑧	UDS-15	NORTH DAM	86.5	21.1	85.9	3.00	17.0
⑨	UDS-15	NORTH DAM	94.9	21.1	94.2	6.00	15.0



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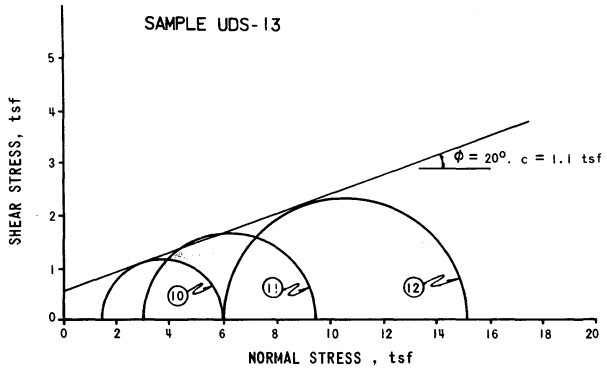
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

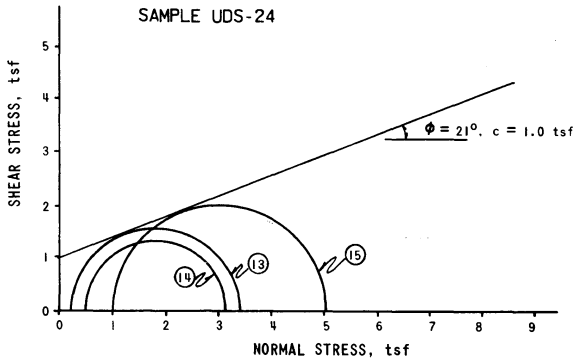
Unconsolidated-Undrained Triaxial Compression Test On Block Samples (Sheet 1 of 4)

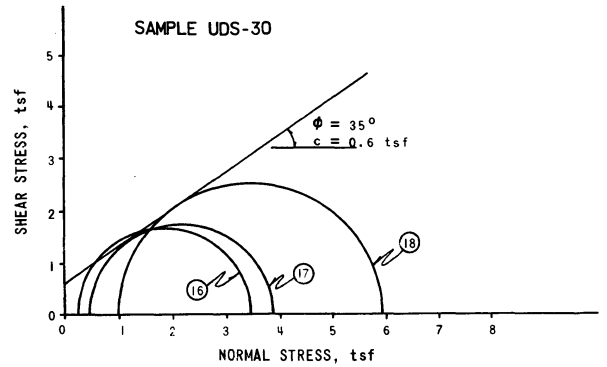
Figure 2.5-152

Figure 2.5-152

UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST ON BLOCK SAMPLES (SHEET 2 OF 4)







TEST NO.	SAMPLE NO.	LOCATION	DRY DENSITY (pcf)	MOISTURE CONTENT (%)	PERCENT COMP.	CONFINING PRESSURE (tsf)	STRAIN (%)
10	UDS-13	SOUTH DAM	91.2	18.8	86.0	1.5	16.5
11	UDS-13		86.1	18.6	81.2	3.0	22.0
12	UDS-13		86.1	18.6	81.2	6.0	19.0
13	UDS-24	SOUTH DAM	91.8	22.3	86.8	0.25	1.78
14	UDS-24		83.1	22.9	78.6	0.50	8.05
15	UDS-24		87.1	20.4	82.4	1.00	6.03
16	UDS-30	NORTH DAM	93.7	20.1	86.6	0.25	4.5
17	UDS-30		92.2	21.5	85.2	0.50	3.5
18	UDS-30		91.7	21.0	84.8	1.00	5.0

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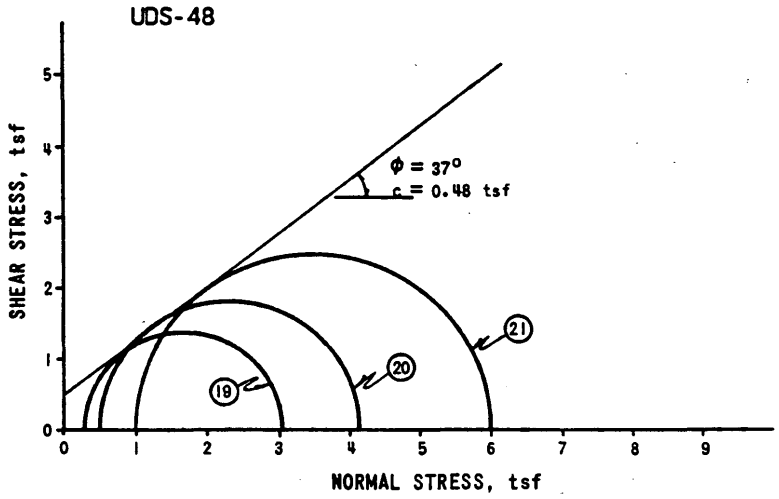
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconsolidated-Undrained Triaxial Compression Test On Block Samples
(Sheet 2 of 4)

Figure 2.5-152

Figure 2.5-152
UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST ON BLOCK SAMPLES (SHEET 3 OF 4)



TEST NO.	SAMPLE NO.	LOCATION	DRY DENSITY (pcf)	MOISTURE CONTENT (%)	PERCENT COMP.	CONFINING PRESSURE (tsf)	STRAIN (%)
(19)	UDS-48		95.9	25.4	91.9	0.25	3.57
(20)	UDS-48	EAST DAM	96.9	25.6	92.8	0.50	3.93
(21)	UDS-48		95.4	25.5	91.4	1.00	8.75

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconsolidated-Undrained Triaxial Compression Test On Block Samples (Sheet 3 of 4)

Figure 2.5-152

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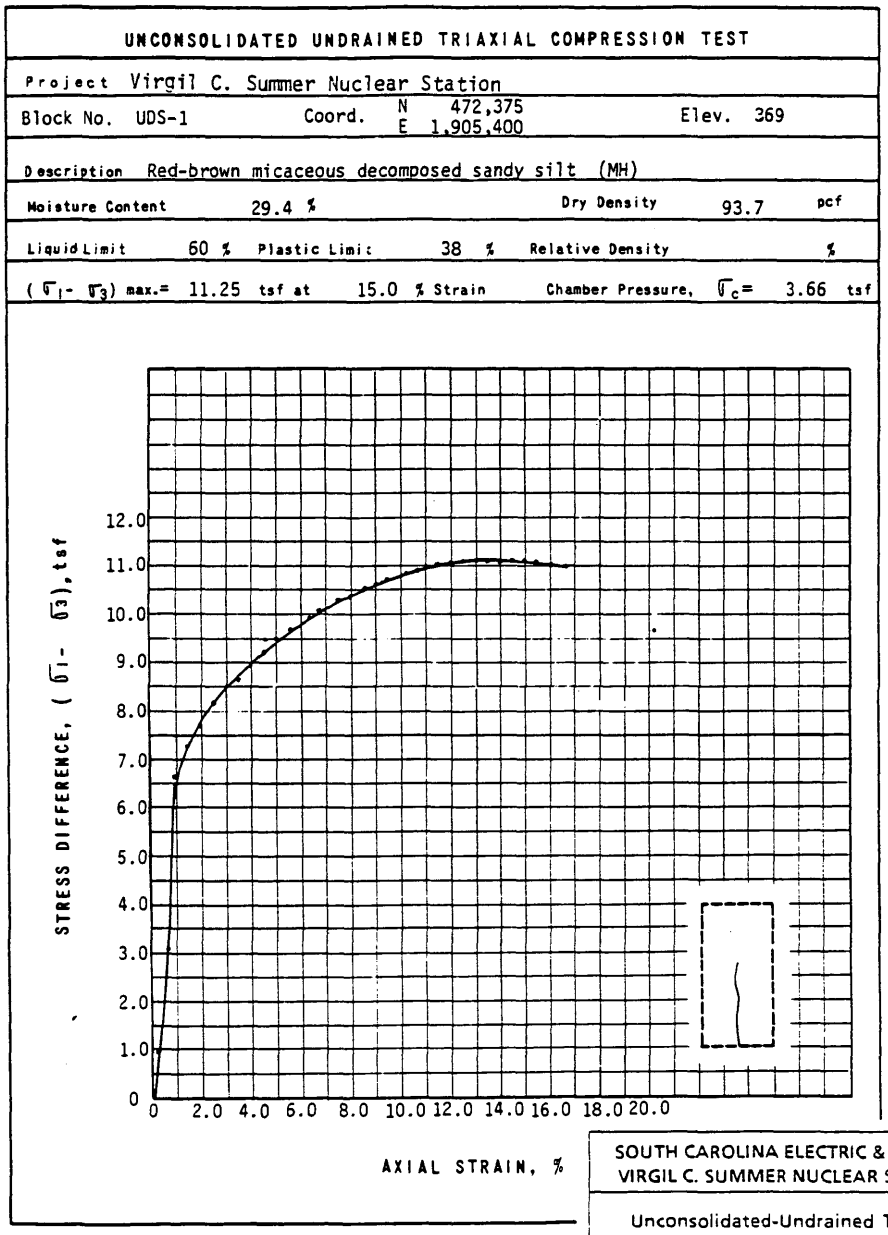
August 1984

Figure 2.5-152

UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TEST ON BLOCK SAMPLES (SHEET 4 OF 4)



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Unconsolidated-Undrained Triaxial Compression Test On Block Samples (Sheet 4 of 4)

Figure 2.5-152

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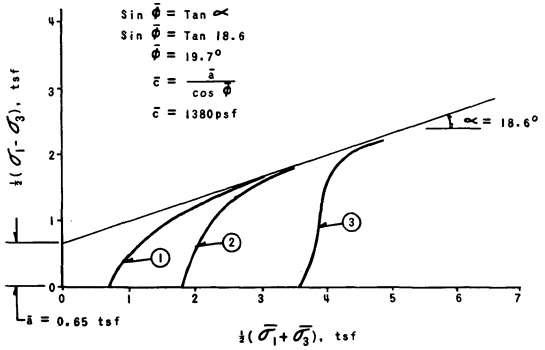
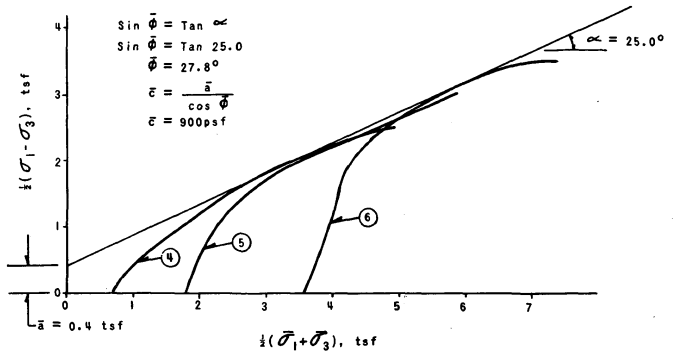
Figure 2.5-153

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TESTS ON BLOCK SAMPLES (SHEET 1 OF 7)





TEST NO.	BLOCK NO.	LOCATION	LL	PL	MOISTURE CONTENT (%)	DRY DENSITY (pcf)	$\bar{\sigma}_c$ (tsf)	$\frac{1}{2}(\sigma_1 - \sigma_3)_{max}$ (tsf)	ϵ_f (%)	$\bar{\Phi}$ (deg)	$\bar{c}$ (psf)
①	UDS-1	WEST EMBANK	60	38	29.8	91.4	0.72	1.62	13.0	18.8	1520
②	UDS-1				24.1	91.5	1.80	1.78	12.5		
③	UDS-1				23.8	93.0	3.60	2.21	13.6		
④	UDS-3	WEST EMBANK	45	35	22.3	101.5	0.72	2.56	14.2	25.2	1104
⑤	UDS-3				22.5	102.0	1.80	3.00	15.4		
⑥	UDS-3				22.6	101.5	3.60	3.58	17.5		

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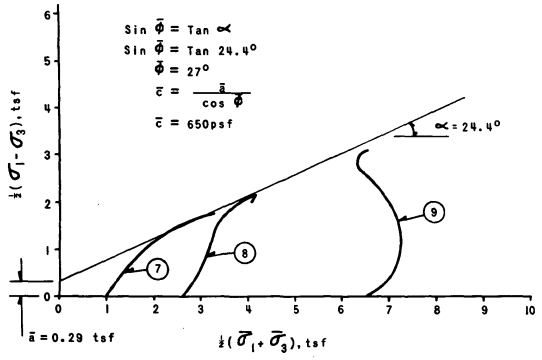
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

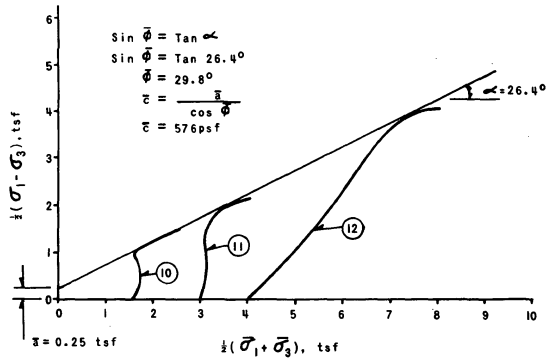
Isotropically Consolidated, Undrained Triaxial Compression Tests On Block Samples (Sheet 1 of 7)

Figure 2.5-153

Figure 2.5-153

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TESTS ON BLOCK SAMPLES (SHEET 2 OF 7)





TEST NO.	BLOCK NO.	LOCATION	LL	PL	MOISTURE CONTENT (%)	DRY DENSITY (%)	$\bar{\sigma}_c$ (tsf)	$\frac{1}{2}(\sigma_1 - \sigma_3)_{max}$ (tsf)	ϵ_f (%)	$\bar{\Phi}$ (deg)	$\bar{c}$ (psf)
⑦	UDS-A	WEST EMBANK	NP	NP	19.9	98.5	1.0	1.82	23.0	26.4	670
⑧	UDS-A				19.4	97.8	2.65	2.21	12.5		
⑨	UDS-A				22.3	92.3	6.55	3.15	13.0		
⑩	UDS-9	WEST EMBANK	69	43	23.3	97.2	1.5	1.52	20.0	31	600
⑪	UDS-9				22.5	97.2	3.0	2.20	20.0		
⑫	UDS-9				24.3	99.6	4.0	4.15	7.0		

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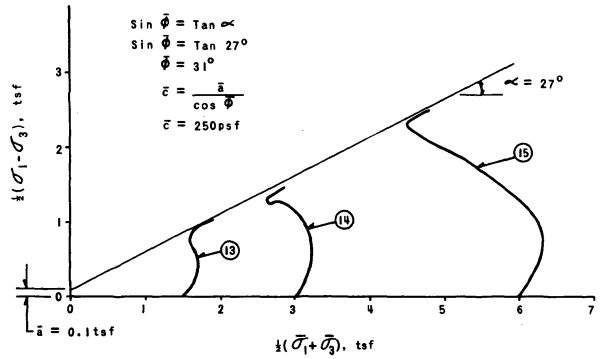
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

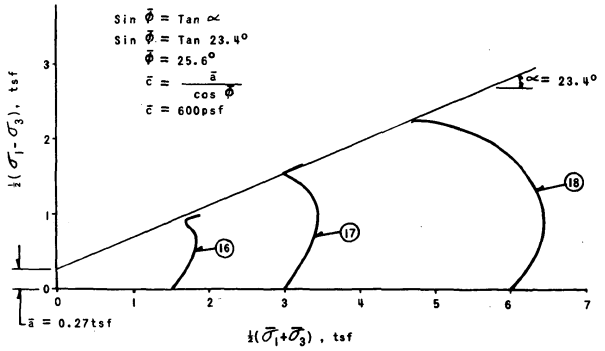
Isotropically Consolidated, Undrained Triaxial Compression Tests On Block Samples (Sheet 2 of 7)

Figure 2.5-153

Figure 2.5-153

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TESTS ON BLOCK SAMPLES (SHEET 3 OF 7)





TEST NO.	BLOCK NO.	LOCATION	LL	PL	MOISTURE CONTENT (%)	DRY DENSITY (pcf)	$\bar{\sigma}_c$ (tsf)	$\frac{1}{2}(\sigma_1-\sigma_3)_{max}$ (tsf)	ϵ_f (%)	$\bar{\Phi}$ (deg)	$\bar{c}$ (psf)
(13)	UDS-11	SOUTH DAM	61	43	24.1	89.2	1.5	1.04	12.8	31	250
(14)	UDS-11				24.4	90.0	3.0	1.28	8.0		
(15)	UDS-11				25.4	90.1	6.0	2.48	14.0		
(16)	UDS-12	NORTH DAM	59	45	24.6	83.5	1.5	0.98	17.0	25.6	600
(17)	UDS-12				26.4	95.8	3.0	1.67	17.0		
(18)	UDS-12				24.2	96.8	6.0	2.28	8.0		

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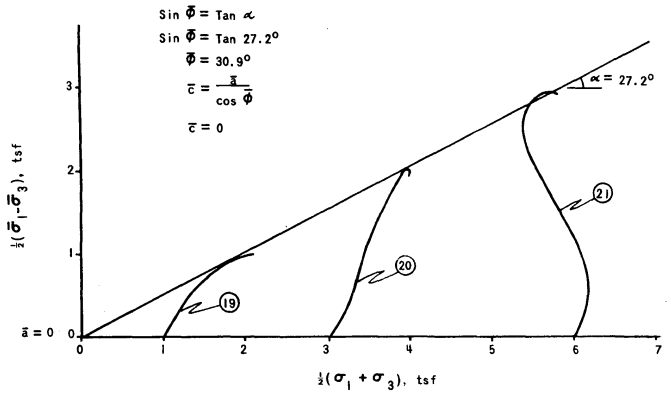
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

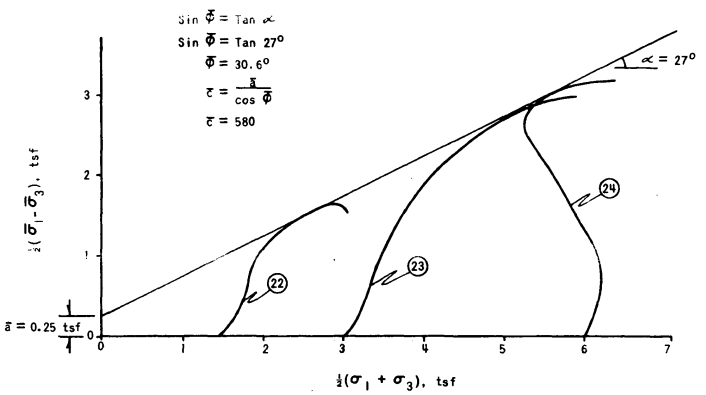
Isotropically Consolidated, Undrained Triaxial Compression Tests On Block Samples (Sheet 3 of 7)

Figure 2.5-153

Figure 2.5-153

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TESTS ON BLOCK SAMPLES (SHEET 4 OF 7)





TEST NO.	BLOCK NO.	LOCATION	LL	PL	MOISTURE CONTENT (%)	DRY DENSITY (pcf)	$\bar{\sigma}_c$ (tsf)	$\frac{1}{2}(\bar{\sigma}_1 - \bar{\sigma}_3)_{max}$ (tsf)	ϵ_f (%)	$\bar{\Phi}$ (deg)	$\bar{c}$ (psf)
(19)	UDS-17	SOUTH DAM	NP	NP	19.1	89.4	1.0	1.01	8.00	30.9	0
(20)	UDS-17				18.5	91.4	3.0	2.03	7.00		
(21)	UDS-17				16.7	90.4	6.0	2.96	15.00		
(22)	UDS-18	SOUTH DAM	68	44	19.0	95.7	1.5	1.64	11.45	30.0	580
(23)	UDS-18				23.7	94.2	3.0	2.99	9.53		
(24)	UDS-18				22.3	100.0	6.0	3.20	23.40		

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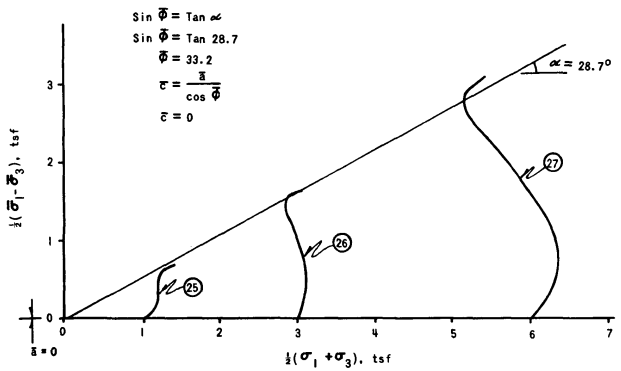
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Isotropically Consolidated, Undrained Triaxial Compression Tests On Block Samples (Sheet 4 of 7)

Figure 2.5-153

Figure 2.5-153

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TESTS ON BLOCK SAMPLES (SHEET 5 OF 7)



TEST NO.	BLOCK NO.	LOCATION	LL	PL	MOISTURE CONTENT (%)	DRY DENSITY (pcf)	$\bar{\sigma}_c$ (tsf)	$\frac{1}{2}(\bar{\sigma}_1 - \bar{\sigma}_3)_{max}$ (tsf)	ϵ_f (%)	$\bar{\Phi}$ (deg)	$\bar{c}$ (psf)
(25)	UDS-19	NORTH DAM	52	45	22.0	86.9	1.00	0.71	12.00	33.2	0
(26)	UDS-19				22.0	93.3	3.00	1.62	10.00		
(27)	UDS-19				22.2	87.2	6.00	3.11	15.00		

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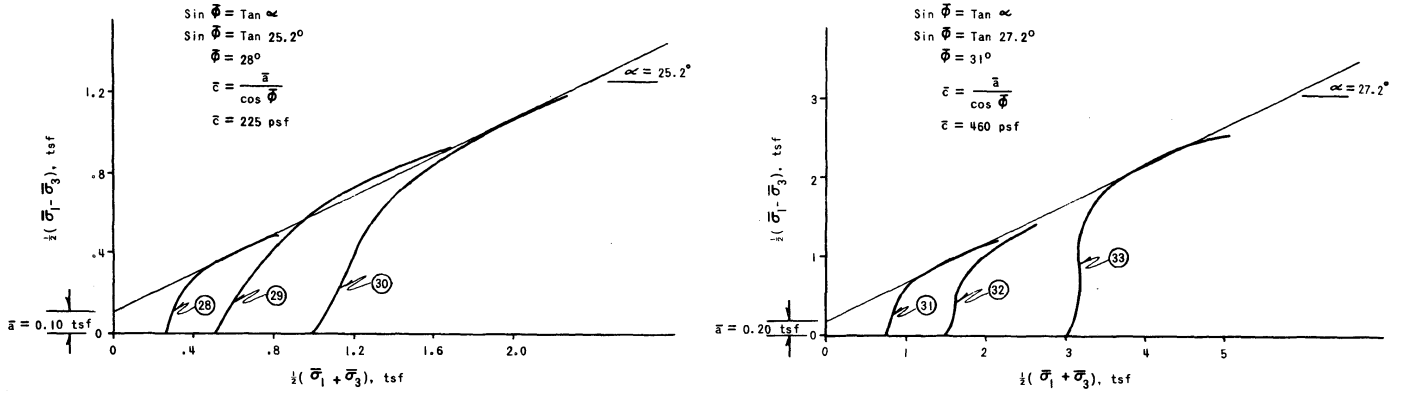
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Isotropically Consolidated, Undrained Triaxial Compression Tests On Block Samples (Sheet 5 of 7)

Figure 2.5-153

Figure 2.5-153

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TESTS ON BLOCK SAMPLES (SHEET 6 OF 7)



TEST NO.	BLOCK NO.	LOCATION	LL	PL	MOISTURE CONTENT (%)	DRY DENSITY (pcf)	$\bar{\sigma}_c$ (tsf)	$\frac{1}{2}(\bar{\sigma}_1 - \bar{\sigma}_3)_{max}$ (tsf)	ϵ_f (%)	$\bar{\Phi}$ (deg)	$\bar{c}$ (psf)
(28)	UDS-31	NORTH DAM	54	41	19.1	98.8	0.25	.497	7.57	28	225
(29)	UDS-31				18.9	98.7	0.50	.960	13.30		
(30)	UDS-31				19.2	97.7	1.00	1.183	15.88		
(31)	UDS-37	NORTH DAM	NP	NP	20.2	93.3	0.75	1.22	14.52	31	460
(32)	UDS-37				21.2	92.7	1.50	1.30	11.40		
(33)	UDS-37				19.9	98.2	3.00	2.56	14.85		

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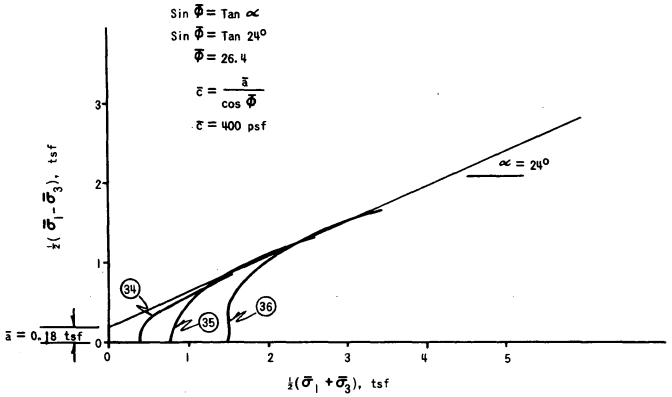
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Isotropically Consolidated, Undrained Triaxial Compression Tests On Block Samples (Sheet 6 of 7)

Figure 2.5-153

Figure 2.5-153

ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION TESTS ON BLOCK SAMPLES (SHEET 7 OF 7)



TEST NO.	BLOCK NO.	LOCATION	LL	PL	MOISTURE CONTENT (%)	DRY DENSITY (pcf)	$\bar{\sigma}_c$ (tsf)	$\frac{1}{2}(\bar{\sigma}_1 - \bar{\sigma}_3)_{max}$ (tsf)	ϵ_f (%)	$\bar{\Phi}$ (deg)	$\bar{c}$ (psf)
(34)	UDS-44	NORTH DAM	43	36	17.6	97.8	0.37	0.84	11.10		
(35)	UDS-44				18.4	99.0	0.75	1.32	16.51	26.4	400
(36)	UDS-44				18.8	100.5	1.50	1.67	13.86		

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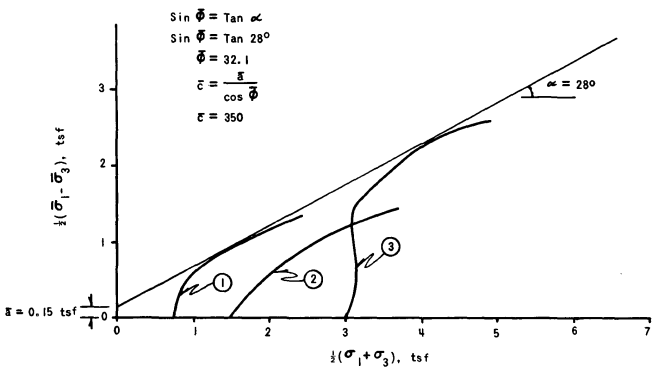
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

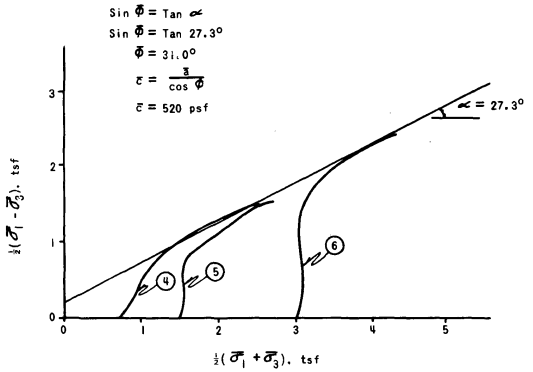
Isotropically Consolidated, Undrained Triaxial Compression Tests On Block Samples (Sheet 7 of 7)

Figure 2.5-153

Figure 2.5-153a

CIU TEST ON BLOCK SAMPLES AT HIGH MOISTURE CONTENT





TEST NO.	BLOCK NO.	LOCATION	LL	PL	MOISTURE CONTENT (%)	DRY DENSITY (pcf)	$\bar{\sigma}_c$ (tsf)	$\frac{1}{2}(\bar{\sigma}_1 - \bar{\sigma}_3)_{max}$ (tsf)	ϵ_f (%)	$\bar{\Phi}$ (deg)	$\bar{c}$ (psf)
①	UDS-21	TEST FILL	49	41	24.6	93.8	0.75	1.35	14.40	32.1	350
②	UDS-21				25.6	92.5	1.50	1.47	14.68		
③	UDS-21				25.2	92.8	3.00	2.65	13.50		
④	UDS-22	TEST FILL	44	39	23.4	93.7	0.75	1.63	16.29	31	520
⑤	UDS-22				23.7	93.4	1.50	1.51	9.04		
⑥	UDS-22				23.4	92.5	3.00	2.39	9.59		

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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

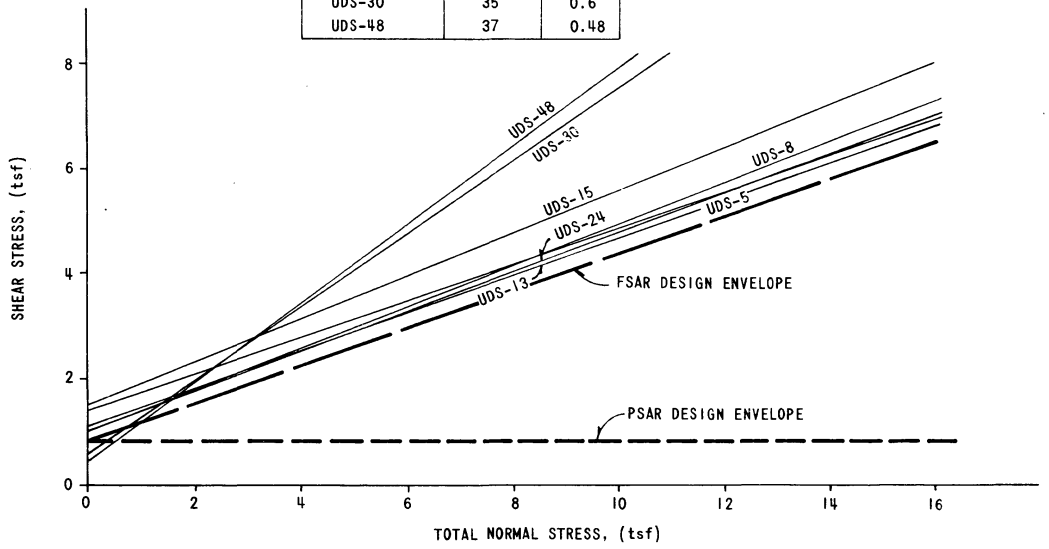
$\overline{CIU}$ Tests on Block Samples at High Moisture Content

Figure 2.5-153a

Figure 2.5-154

SUMMARY OF UNCONSOLIDATED-UNDRAINED TRIAXIAL COMPRESSION TESTS ON BLOCK SAMPLES

SAMPLE NO.	ϕ (deg)	c (tsf)
FSAR DESIGN ENVELOPE	20	0.8
PSAR DESIGN ENVELOPE	0	0.8
UDS-5	19	1.4
UDS-8	21.5	1.0
UDS-13	20	1.1
UDS-15	22	1.5
UDS-24	21	1.0
UDS-30	35	0.6
UDS-48	37	0.48



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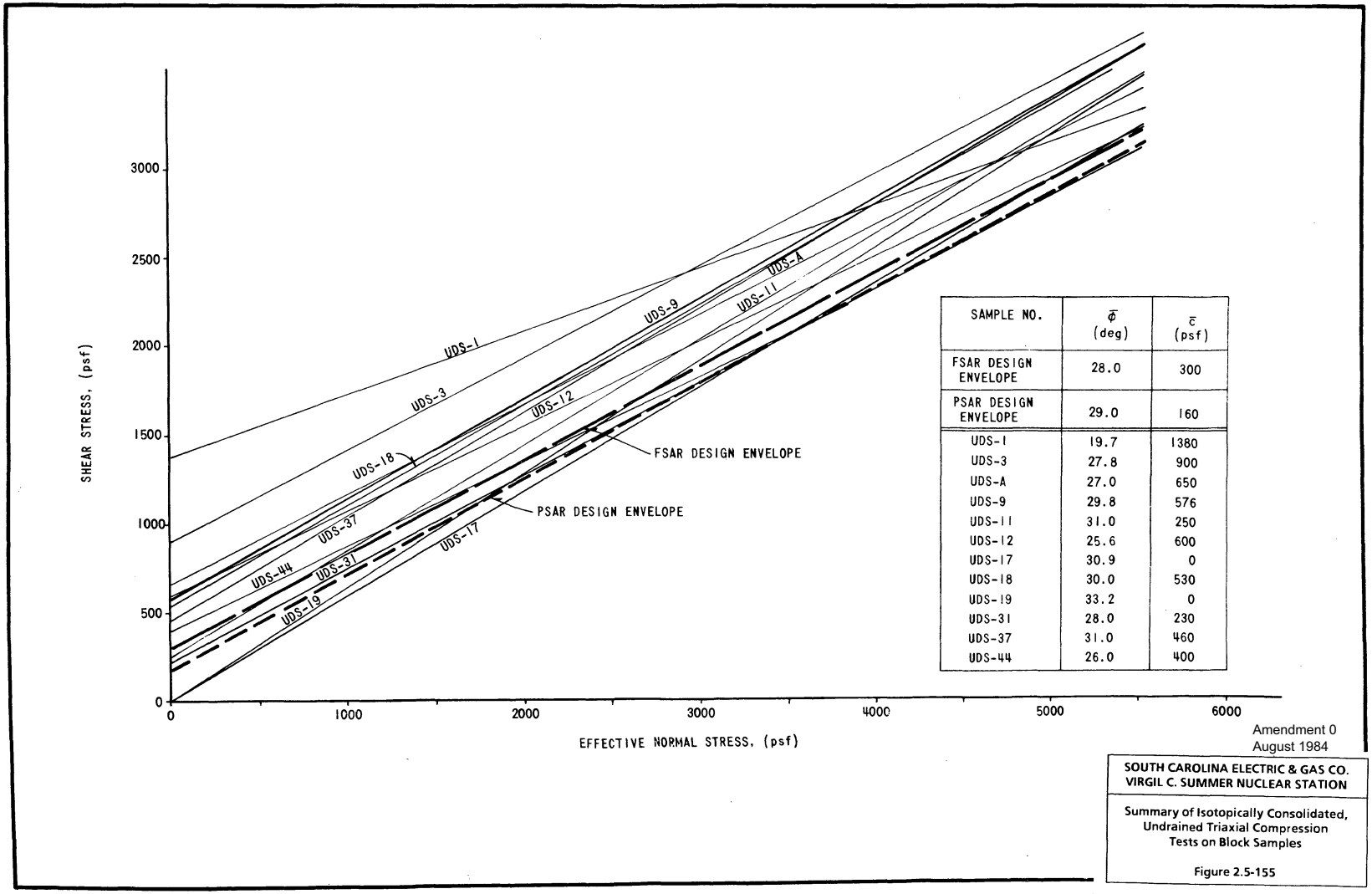
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary of Unconsolidated-Undrained Triaxial Compression Tests on Block Samples

Figure 2.5-154

Figure 2.5-155

SUMMARY OF ISOTROPICALLY CONSOLIDATED, UNDRAINED TRIAXIAL COMPRESSION ON BLOCK SAMPLES



SAMPLE NO.	$\bar{\phi}$ (deg)	$\bar{c}$ (psf)
FSAR DESIGN ENVELOPE	28.0	300
PSAR DESIGN ENVELOPE	29.0	160
UDS-1	19.7	1380
UDS-3	27.8	900
UDS-A	27.0	650
UDS-9	29.8	576
UDS-11	31.0	250
UDS-12	25.6	600
UDS-17	30.9	0
UDS-18	30.0	530
UDS-19	33.2	0
UDS-31	28.0	230
UDS-37	31.0	460
UDS-44	26.0	400

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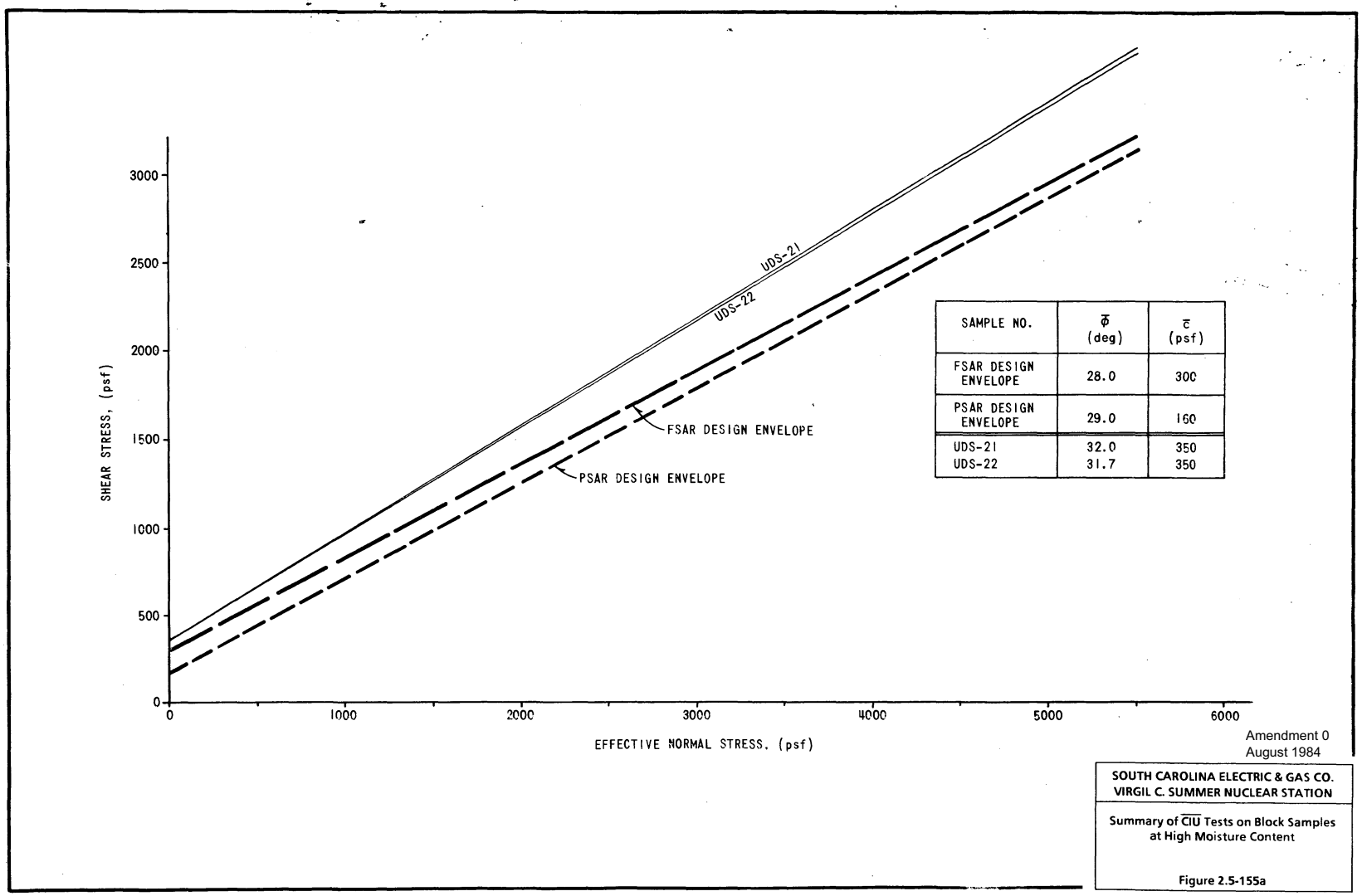
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary of Isotopically Consolidated, Undrained Triaxial Compression Tests on Block Samples

Figure 2.5-155

Figure 2.5-155a

SUMMARY OF CIU TESTS ON BLOCK SAMPLE AT HIGH MOISTURE CONTENT



SAMPLE NO.	$\bar{\Phi}$ (deg)	$\bar{c}$ (psf)
FSAR DESIGN ENVELOPE	28.0	300
PSAR DESIGN ENVELOPE	29.0	160
UDS-21	32.0	350
UDS-22	31.7	350

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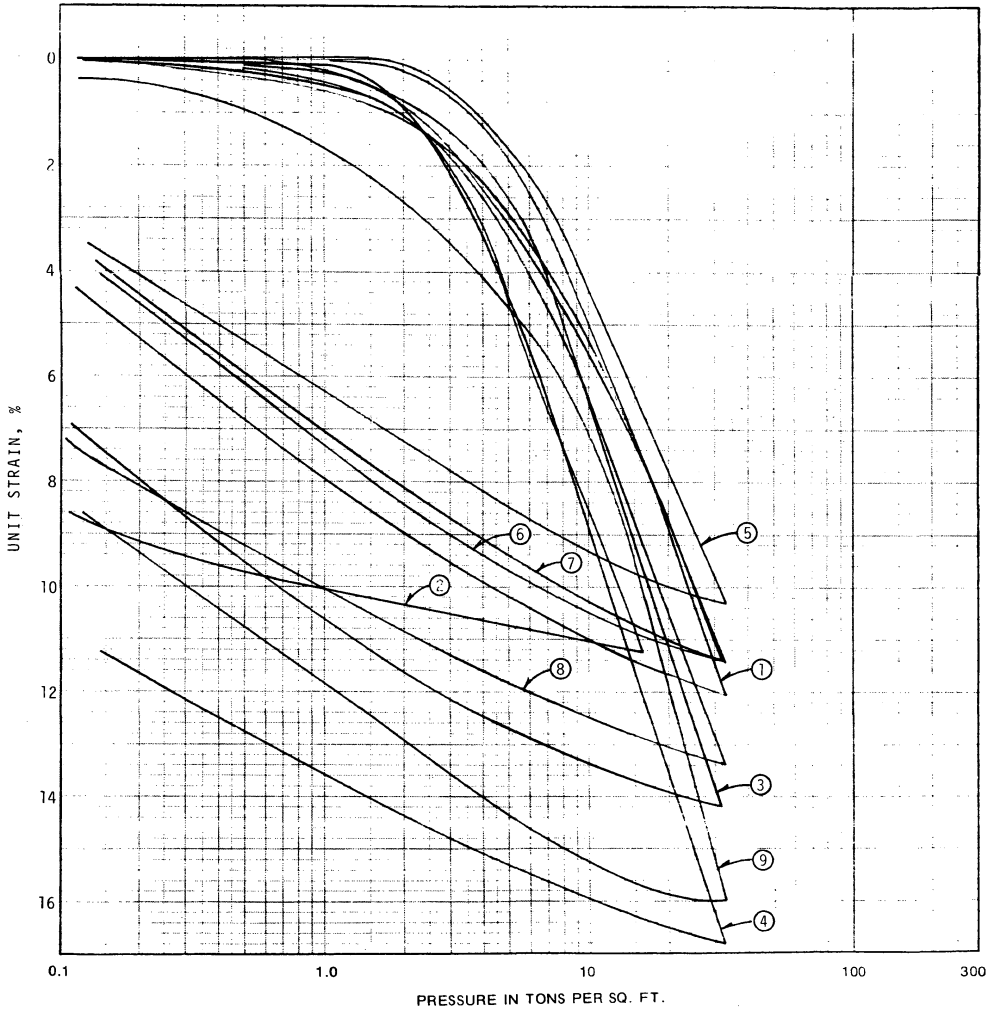
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary of $\overline{CIU}$ Tests on Block Samples at High Moisture Content

Figure 2.5-155a

Figure 2.5-156

SUMMARY OF CONSOLIDATION TEST RESULTS - NORTH DAM (SHEET 1 OF 4)



CURVE NUMBER	BLOCK SAMPLE NUMBER	ELEVATION	INITIAL DRY DENSITY (pcf)	INITIAL M/C %	LIQUID LIMIT %	PLASTIC LIMIT %	INITIAL VOID RATIO
①	UDS-5V	338	93.3	27.0	59	46	0.890
②	UDS-8V	342	110.3	22.8	47	42	0.887
③	UDS-12V	330	89.3	25.2	59	45	0.930
④	UDS-12H	330	92.7	25.2	59	45	1.085
⑤	UDS-15V	348	92.7	22.1	57	41	0.828
⑥	UDS-15H	348	93.5	21.6	57	41	0.824
⑦	UDS-19V	344	90.8	22.4	52	45	0.760
⑧	UDS-19H	344	97.1	22.2	52	45	0.782
⑨	UDS-31V	331	95.1	21.6	54	41	0.771

(1) V = Sample cut horizontally through the block.

H = Sample cut vertically through the block.

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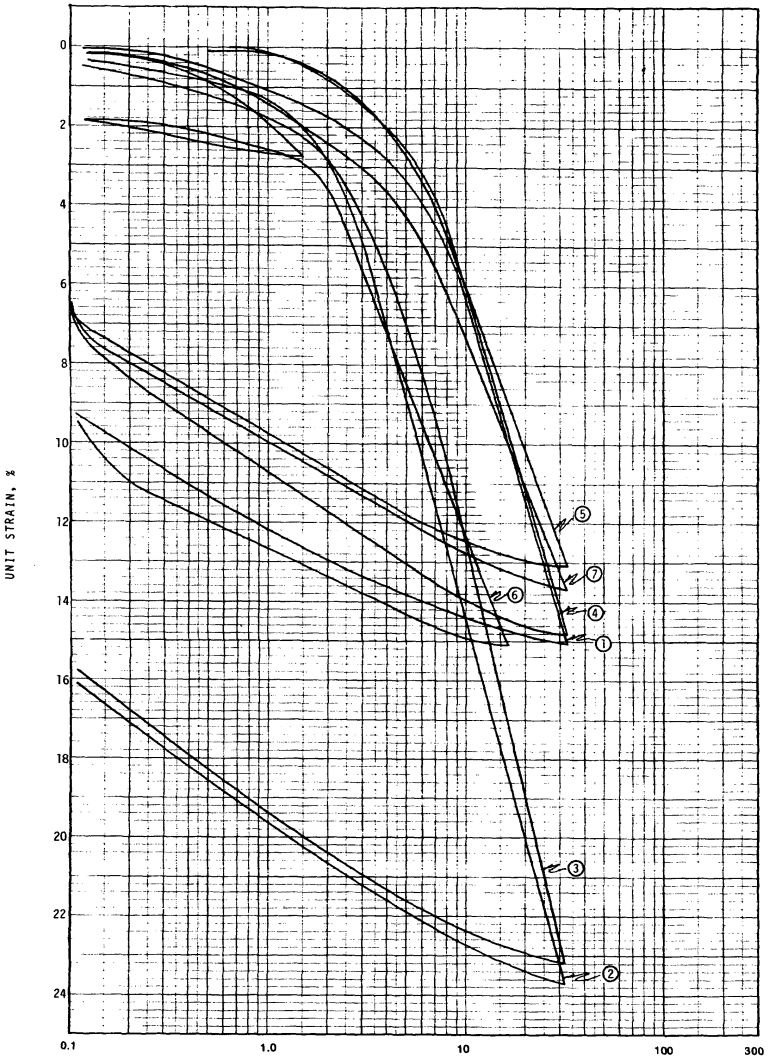
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Summary Of Consolidation Test Results - North Dam (Sheet 1 of 4) Figure 2.5-156

Figure 2.5-156

SUMMARY OF CONSOLIDATION TEST RESULTS - SOUTH DAM (SHEET 2 OF 4)



CURVE NUMBER	BLOCK SAMPLE NUMBER (1)	ELEVATION	INITIAL DRY DENSITY (pcf)	INITIAL M/C %	LIQUID LIMIT %	PLASTIC LIMIT %	INITIAL VOID RATIO
①	UDS-11V	365	91.1	21.8	61	18	0.901
②	UDS-13V	375	85.7	17.7	66	49	1.025
③	UDS-13H	375	89.7	17.1	60	49	0.993
④	UDS-17V	391	93.5	18.7	NP	NP	0.822
⑤	UDS-17H	391	96.3	19.1	NP	NP	0.769
⑥	UDS-20V	407	85.8	24.7	60	32	0.967
⑦	UDS-24V	422	91.2	24.4	NP	NP	0.849

(1) V = Sample cut horizontally through the block with loads applied vertically.

H = Sample cut vertically through the block with loads applied horizontally.

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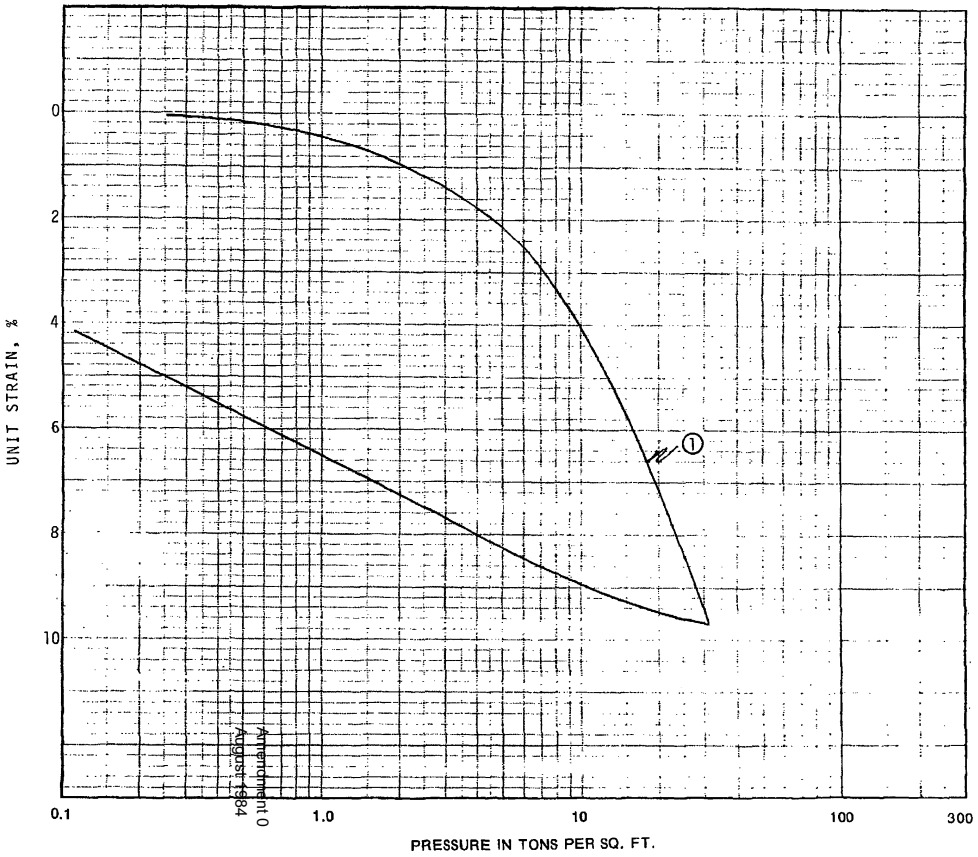
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Summary Of Consolidation Test Results - South Dam (Sheet 2 of 4) Figure 2.5-156

Figure 2.5-156

SUMMARY OF CONSOLIDATION TEST RESULTS - EAST DAM (SHEET 3 OF 4)



CURVE NUMBER	BLOCK SAMPLE NUMBER	ELEVATION	INITIAL DRY DENSITY (pcf)	INITIAL M/C	LIQUID LIMIT	PLASTIC LIMIT	INITIAL VOID RATIO
①	UDS-48 V	431	94.0	26.4	55	48	0.818

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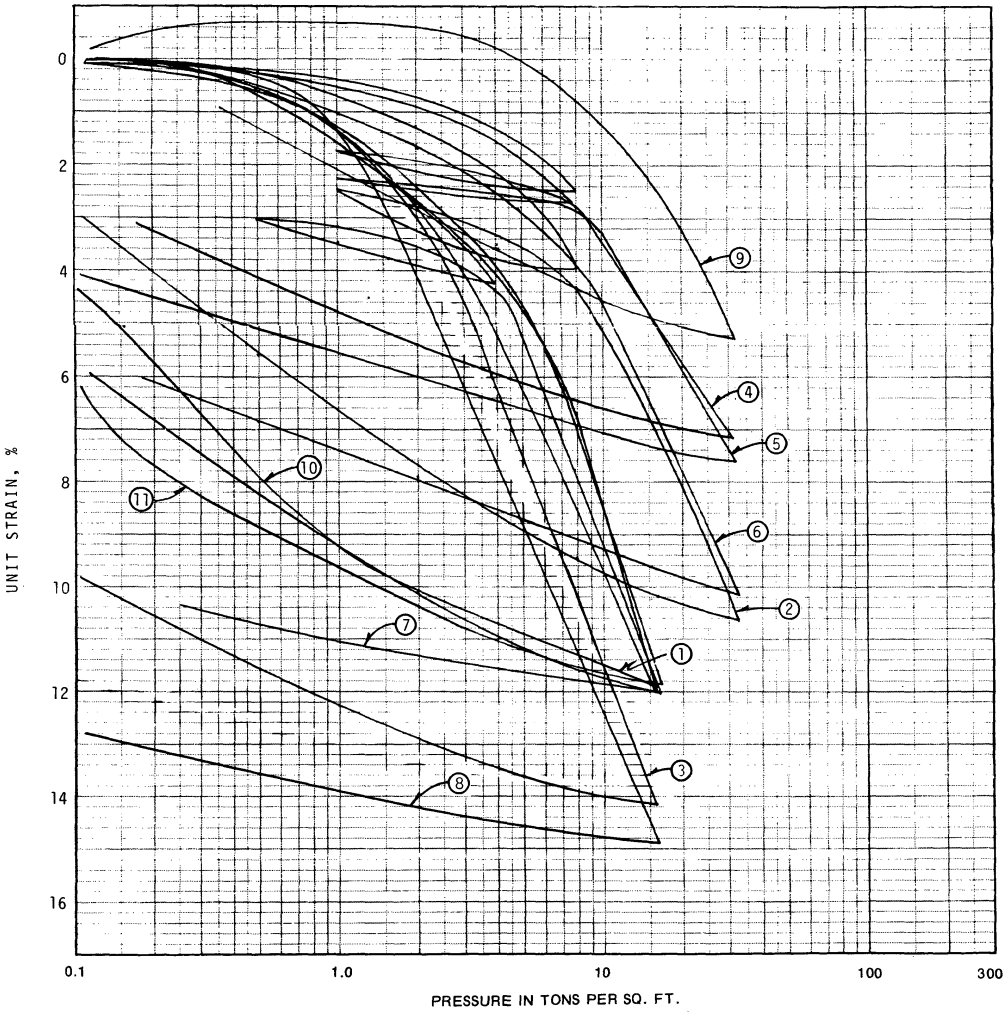
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Summary Of Consolidation
Test Results - East Dam
(Sheet 3 of 4)

Figure 2.5-156

Figure 2.5-156

SUMMARY OF CONSOLIDATION
TEST RESULTS - WEST EMBANKMENT SHEET 4 OF 4)



CURVE NUMBER	BLOCK SAMPLE NUMBER	ELEVATION	INITIAL DRY DENSITY (pcf)	INITIAL M/C %	LIQUID LIMIT %	PLASTIC LIMIT %	INITIAL VOID RATIO
①	UDS-AV	385	94.0	23.4	NP	NP	0.797
②	UDS-1V	369	87.6	29.5	60	38	0.882
③	UDS-2V	383	89.9	22.2	43	33	0.863
④	UDS-3V	384	96.4	23.2	42	34	0.729
⑤	UDS-3H	384	97.8	24.1	45	35	0.704
⑥	UDS-4V	390	93.6	20.3	41	37	0.733
⑦	UDS-7V	400	86.0	24.7	59	34	0.958
⑧	UDS-7H	400	82.2	23.6	51	35	1.056
⑨	UDS-9V	421	97.3	24.3	69	43	0.843
⑩	UDS-36V	416	89.9	23.3	NP	NP	0.895
⑪	UDS-36H	416	89.2	22.6	NP	NP	0.905

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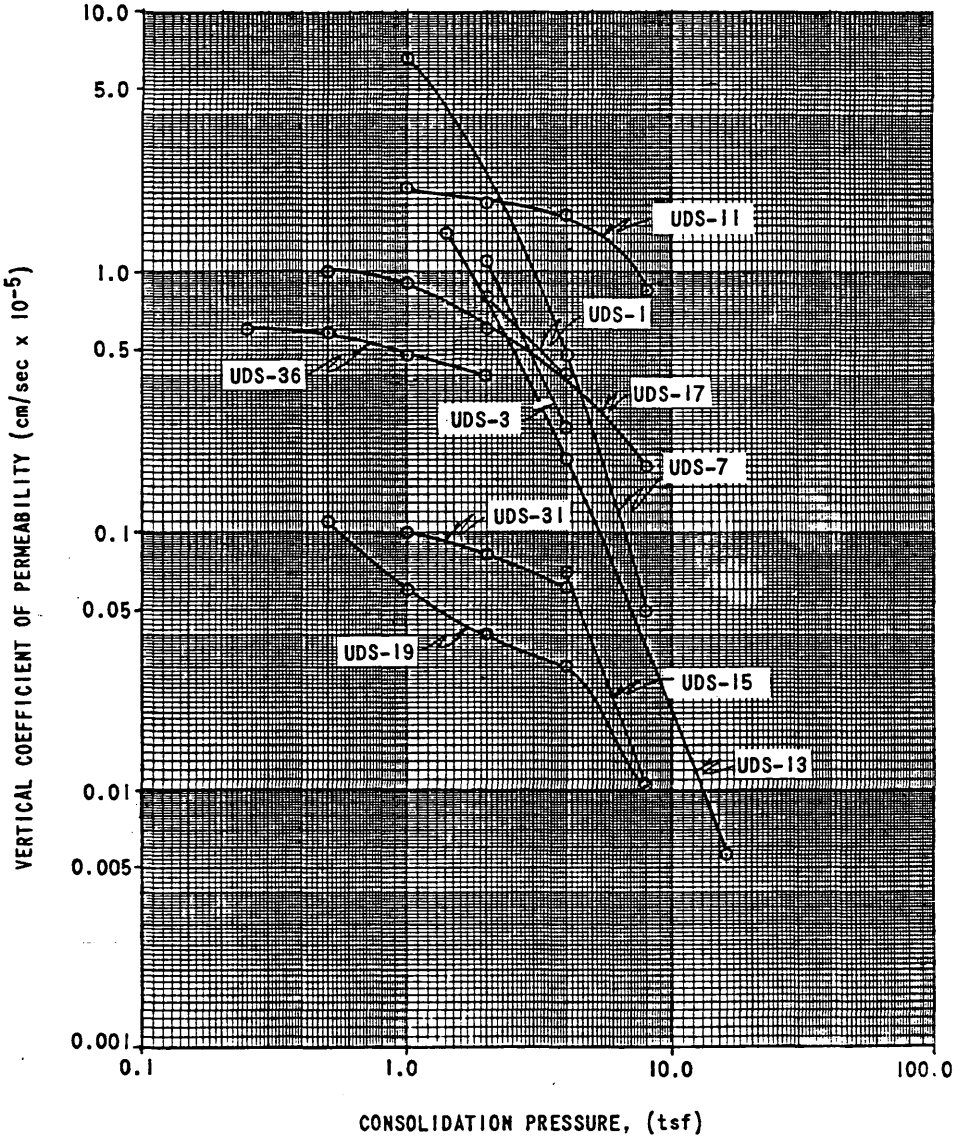
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Summary Of Consolidation Test Results - West Embankment (Sheet 4 of 4) Figure 2.5-156

Figure 2.5-157

VERTICAL PERMEABILITY TEST RESULTS ON BLOCK SAMPLES



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VIRGIL C. SUMMER NUCLEAR STATION

Vertical Permeability Test Results on Block Samples

Figure 2.5-157

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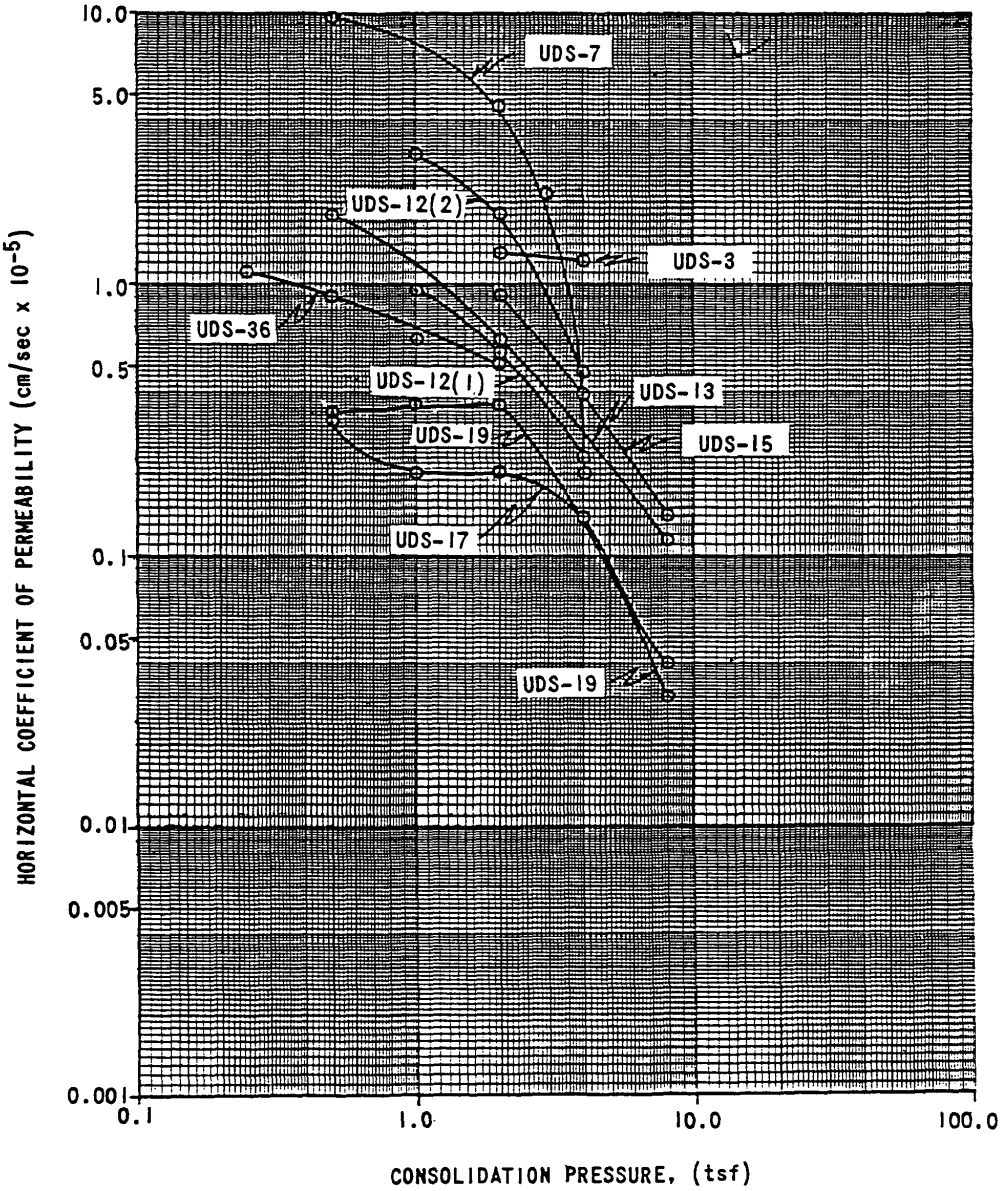
Figure 2.5-158
HORIZONTAL PERMEABILITY TEST RESULTS ON BLOCK SAMPLES



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VIRGIL C. SUMMER NUCLEAR STATION

Horizontal Permeability Test Results on Block Samples

Figure 2.5-158

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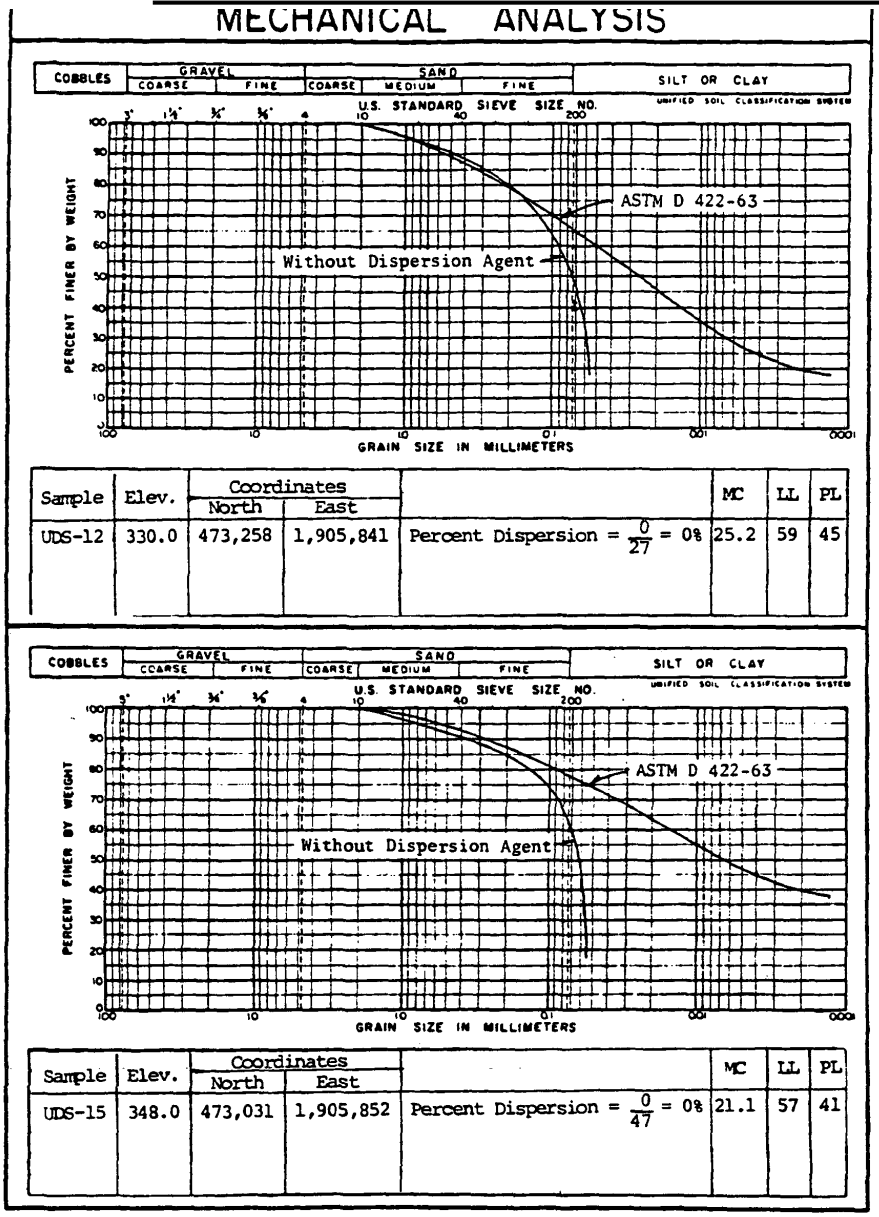
Figure 2.5-159

TYPICAL SOIL CONSERVATION SERVICE
DISPERSION TEST RESULTS ON BLOCK SAMPLES



Sample	Elev.	Coordinates North	Coordinates East		MC	LL	PL
UDS-12	330.0	473,258	1,905,841	Percent Dispersion = $\frac{0}{27}$ = 0%	25.2	59	45

Sample	Elev.	Coordinates North	Coordinates East		MC	LL	PL
UDS-15	348.0	473,031	1,905,852	Percent Dispersion = $\frac{0}{47}$ = 0%	21.1	57	41

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Soil Conservation Service Dispersion Test Results on Block Samples Figure 2.5-159

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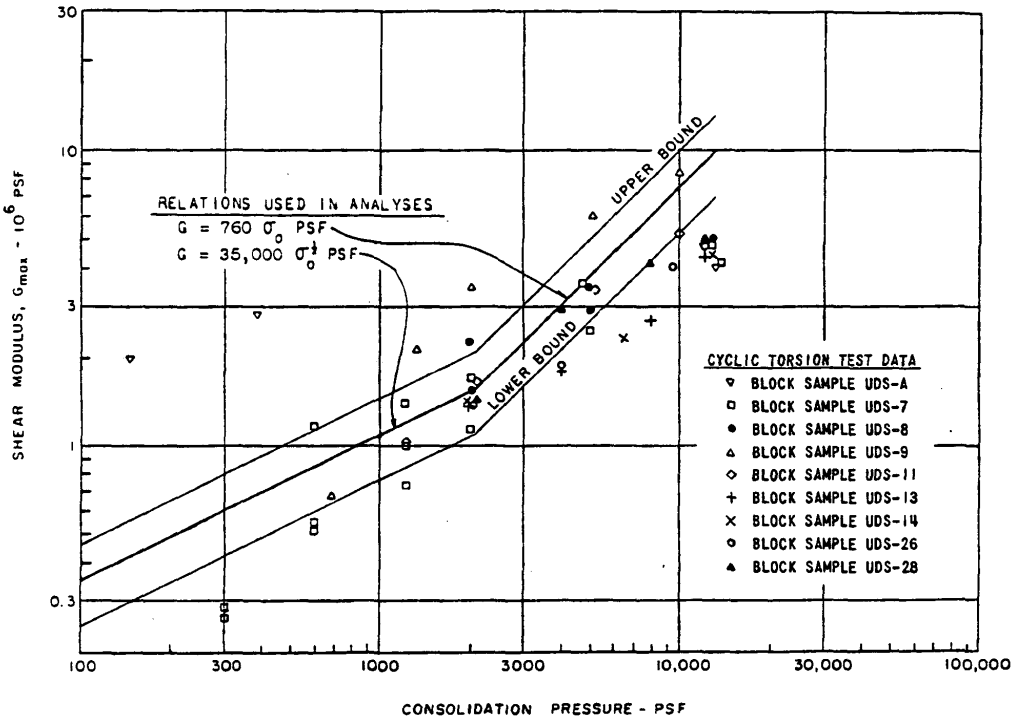
Figure 2.5-160

SHEAR MODULUS VALUES AT VERY LOW STRAIN LEVELS FOR BLOCK SAMPLES



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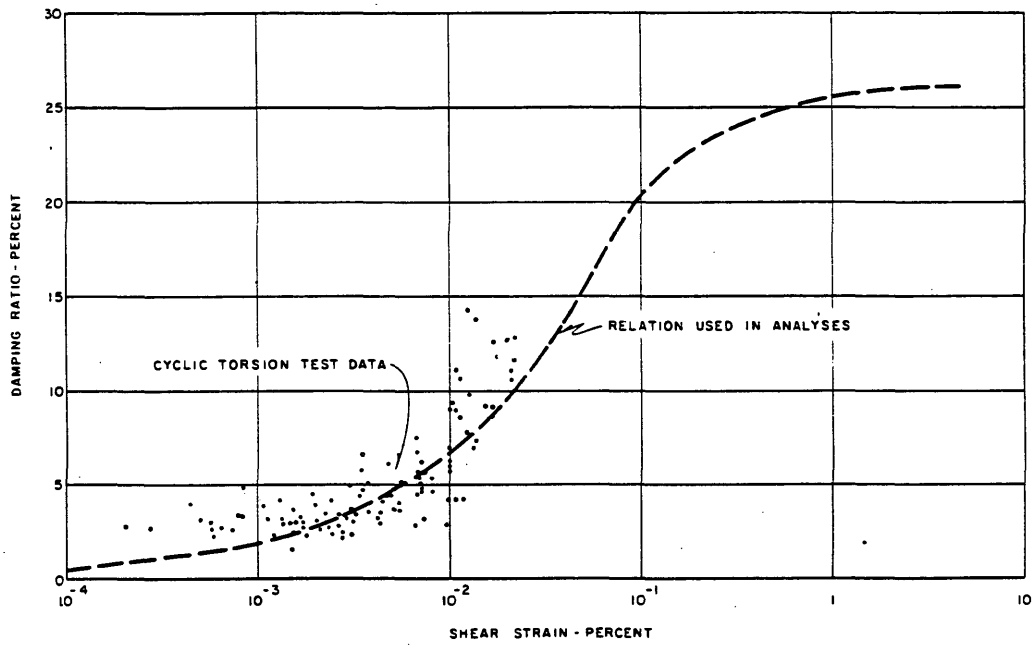
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Shear Modulus Values at Very Low Strain Levels for Block Samples Figure 2.5-160

Figure 2.5-160a

VARIATION OF DAMPING VALUES AS A FUNCTION OF STRAIN FOR BLOCK SAMPLES



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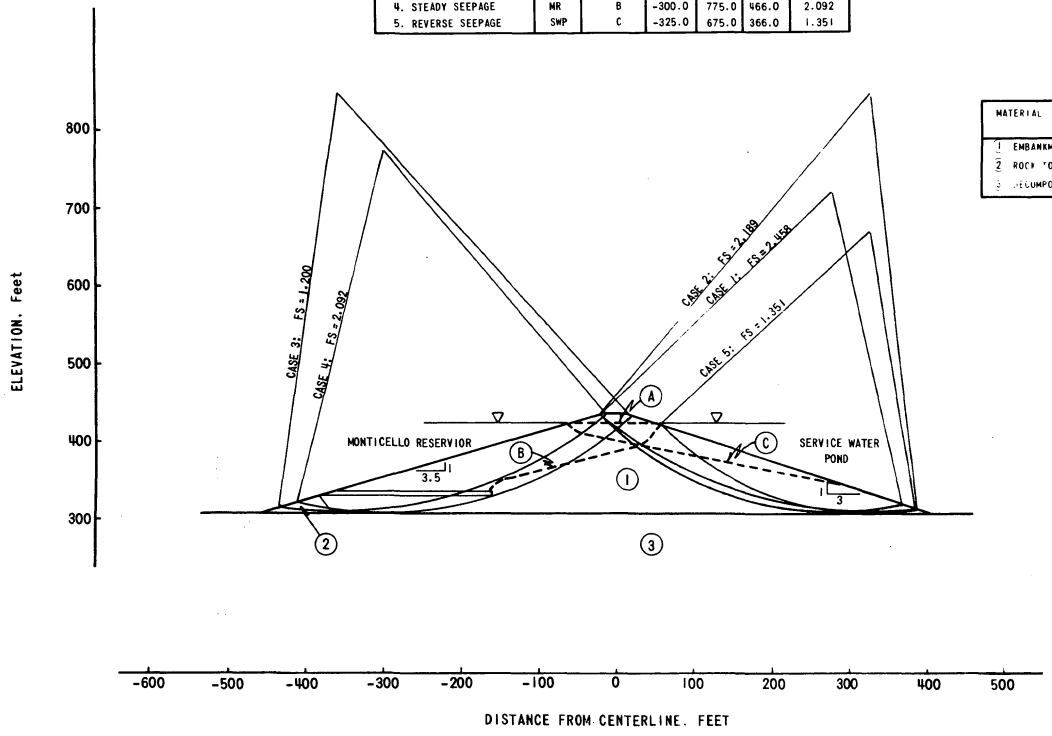
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Variation of Damping Values as a Function of Strain for Block Samples Figure 2.5-160a

Figure 2.5-161

STATIC STABILITY ANALYSIS NORTH DAM

CASE	SLOPE	PHREATIC LINE	X	Y	R	FACTOR OF SAFETY
1. END OF CONSTRUCTION	SWP	--	275.0	725.0	416.0	2.458
2. SUBMERGED	SWP	A	325.0	850.0	541.0	2.189
3. SUDDEN DRAWDOWN	MR	A	-350.0	850.0	541.0	1.200
4. STEADY SEEPAGE	MR	B	-300.0	775.0	466.0	2.092
5. REVERSE SEEPAGE	SWP	C	-325.0	675.0	366.0	1.351



MATERIAL	γ_t (pcf)	Cu (psf)	Φ_u (deg)	$\bar{c}$ (psf)	$\bar{\Phi}$ (deg)
1 EMBANKMENT	119	1600	20	300	28
2 ROCK TOE	135	0	35	0	35
3 DECOMPOSED CRYSTALLINE ROCK	138	3000	0	0	38.5

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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Static Stability Analysis
North Dam

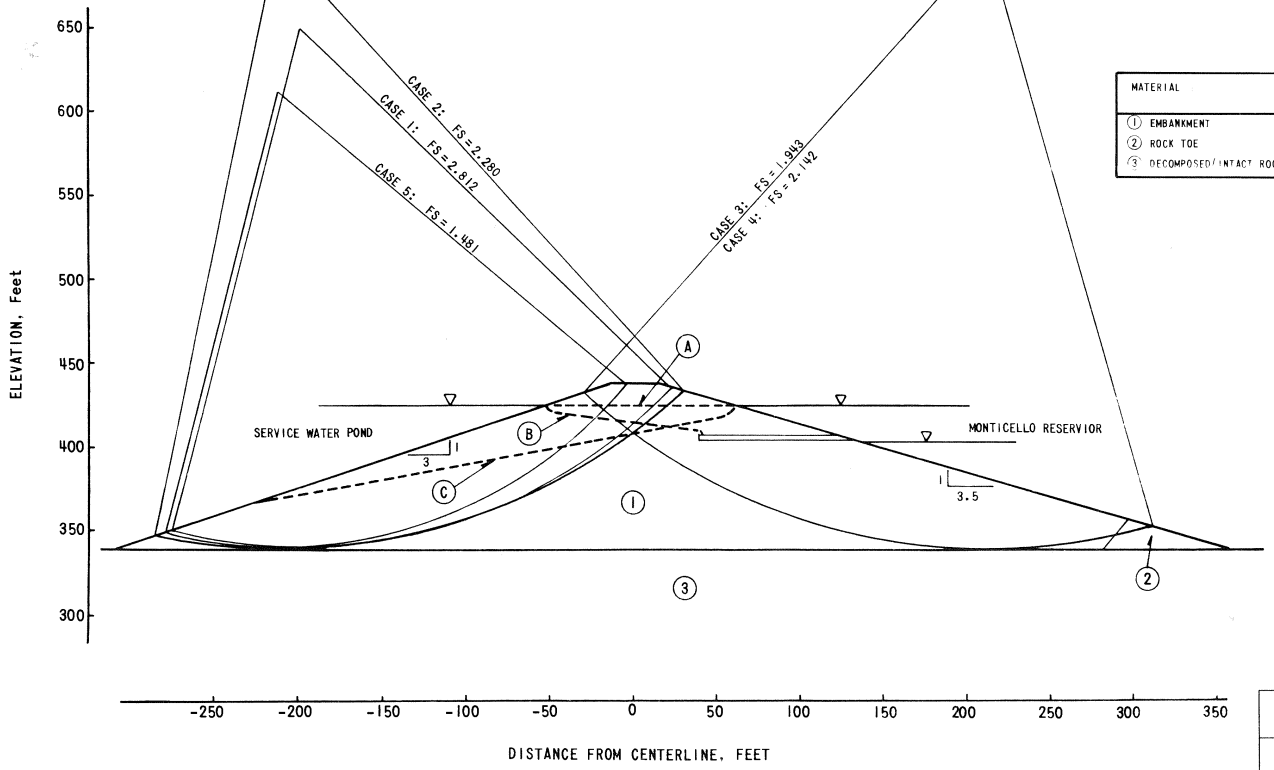
Figure 2.5-161

Figure 2.5-162

STATIC STABILITY ANALYSIS SOUTH DAM

CASE	SLOPE	PHREATIC LINE	X	Y	R	FACTOR OF SAFETY
1. END OF CONSTRUCTION	SWP	--	-200.0	650.0	310.0	2.812
2. SUBMERGED	SWP	A	-225.0	700.0	360.0	2.280
3. SUDDEN DRAWDOWN	MR	A	225.0	700.0	360.0	1.943
4. STEADY SEEPAGE	MR	B	225.0	700.0	360.0	2.142
5. REVERSE SEEPAGE	SWP	C	-225.0	625.0	285.0	1.481

MATERIAL	γ_t (pcf)	Cu (psf)	ϕ_u (deg)	c (psf)	ϕ (deg)
(1) EMBANKMENT	119	1600	20	300	28
(2) ROCK TOE	135	0	35	0	35
(3) DECOMPOSED/INTACT ROCK	138	3000	0	-	-



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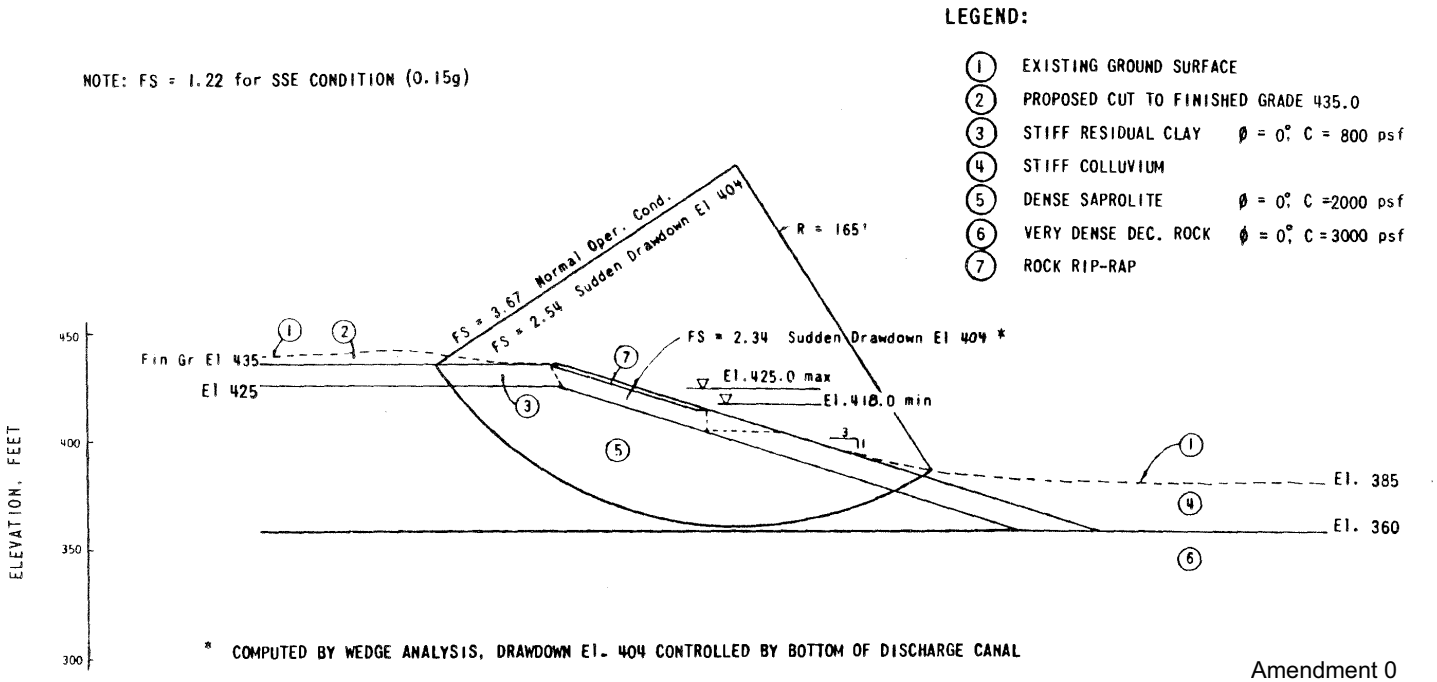
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Static Stability Analysis
South Dam

Figure 2.5-162

Figure 2.5-163

STABILITY ANALYSIS OF SLOPE NEAR SOUTH DAM ABUTMENT



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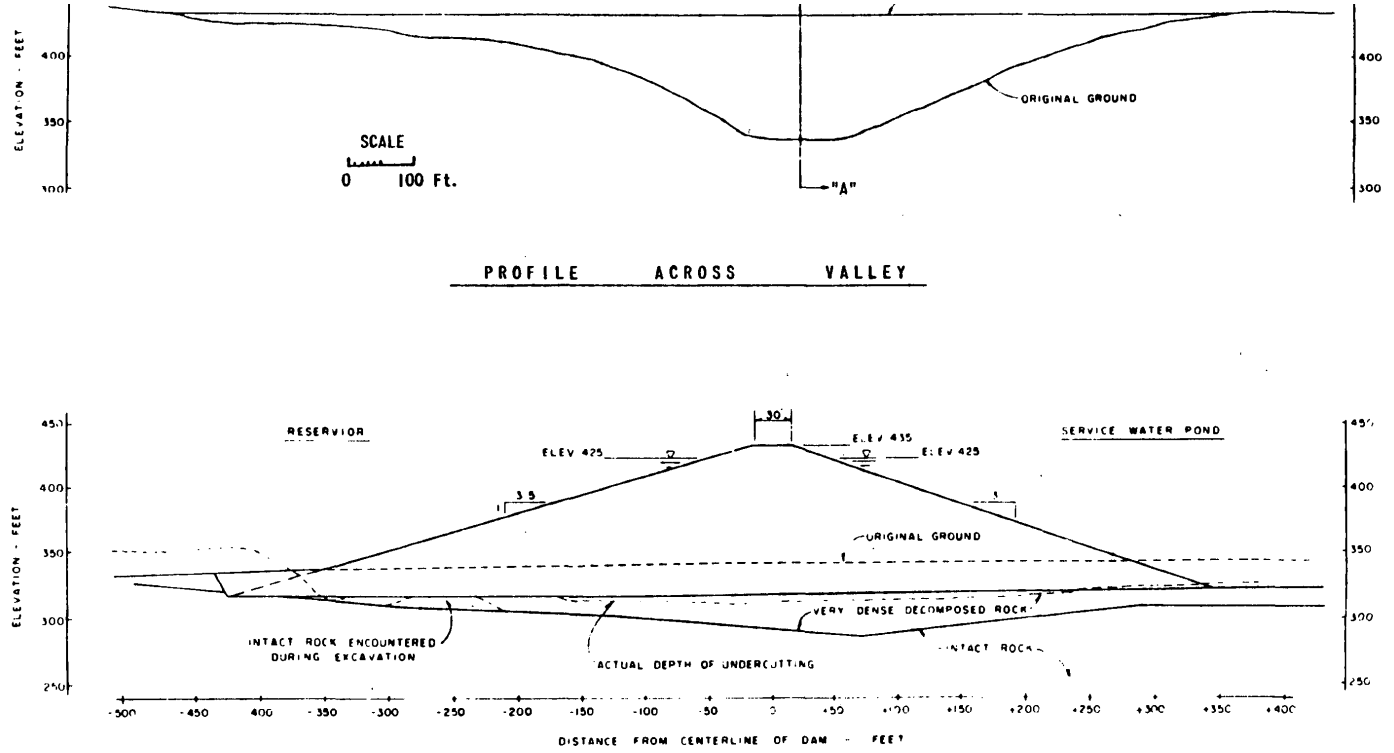
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Stability Analysis Natural Slope Near South Dam Abutment
Figure 2.5-163

Figure 2.5-164

PROFILE ACROSS VALLEY AND MAXIMUM SECTION ANALYZED FOR SEISMIC STABILITY - NORTH DAM



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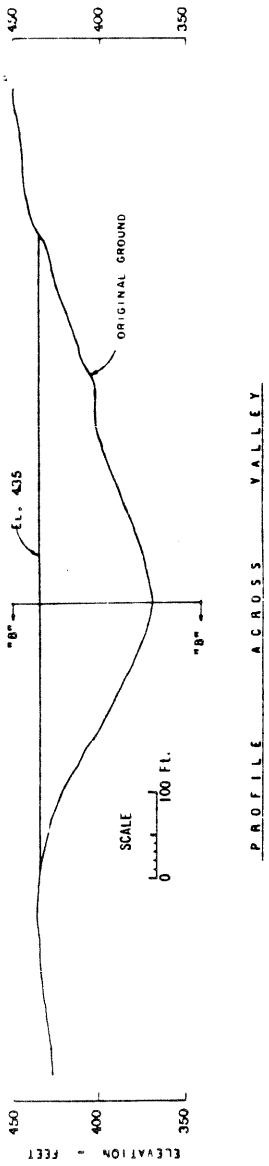
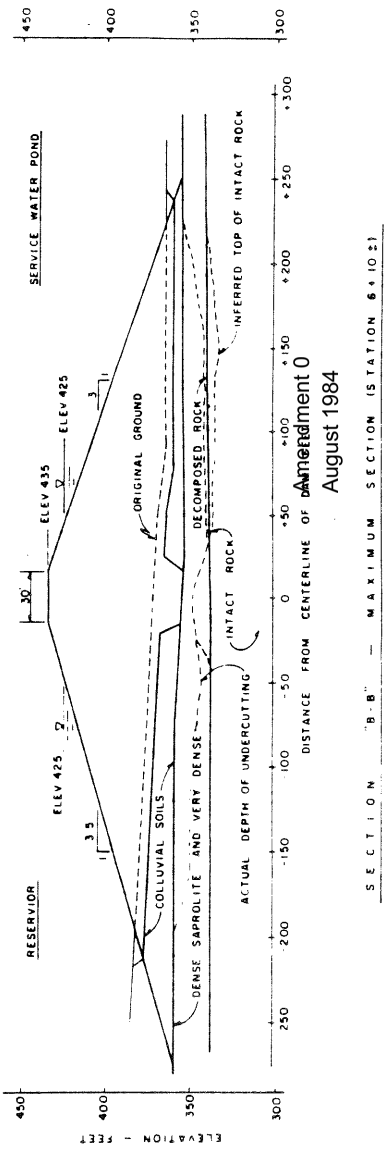
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Profile Across Valley and Maximum Section Analyzed for Seizmic Stability- North Dam Figure 2.5-164

Figure 2.5-165

PROFILE ACROSS VALLEY AND MAXIMUM SECTION ANALYZED FOR SEISMIC STABILITY - SOUTH DAM





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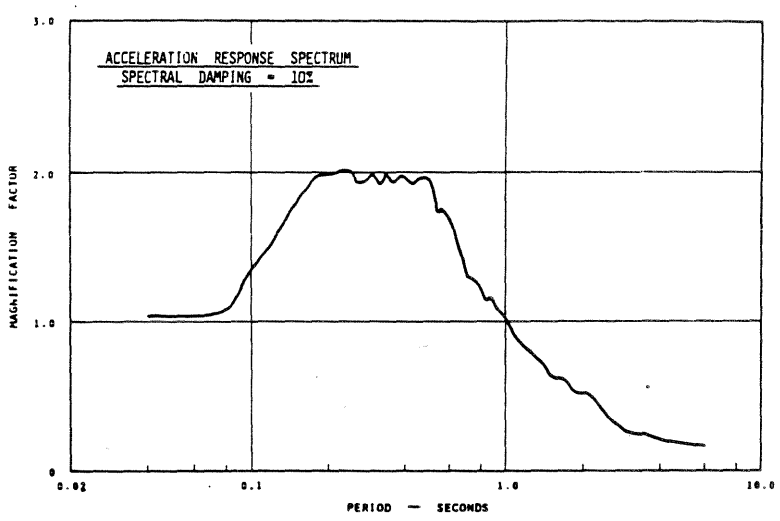
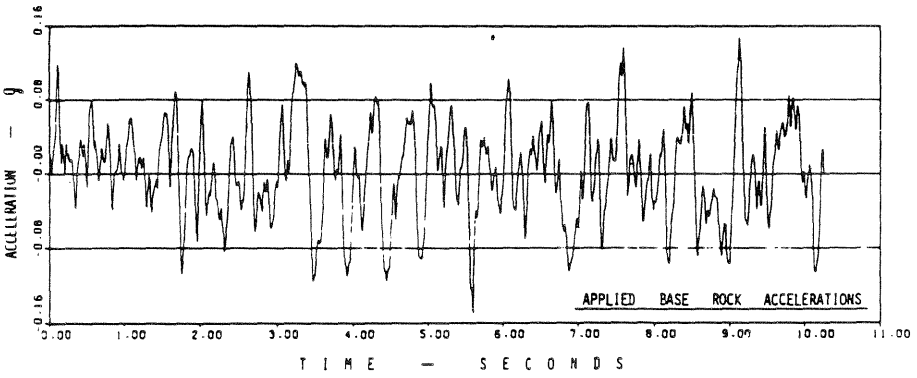
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Profile Across Valley and Maximum Section Analyzed for Seizmic Stability- South Dam Figure 2.5-165

Figure 2.5-166
TIME HISTORY AND RESPONSE SPECTRUM FOR APPLIED BASE ROCK MOTION





SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Time History and Response Spectrum for Applied Base Rock Motion

Figure 2.5-166

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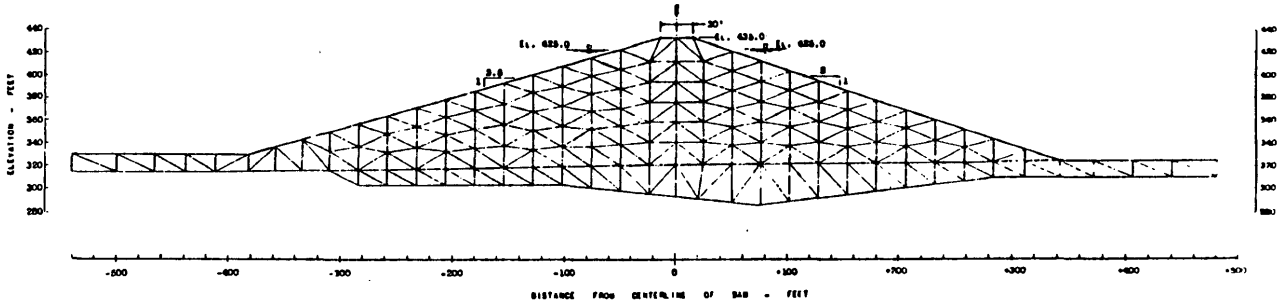
August 1984

Figure 2.5-167

FINITE ELEMENT REPRESENTATION - MAXIMUM SECTION NORTH DAM



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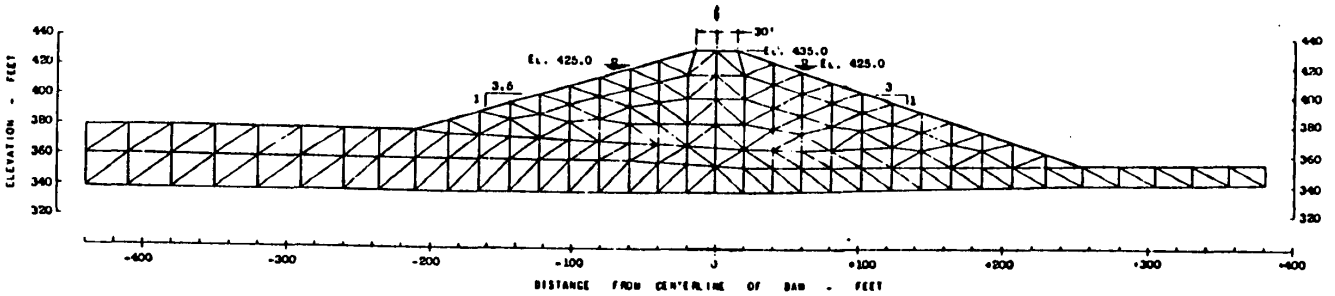
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Finite Element Representation - Maximum Section North Dam
Figure 2.5-167

Figure 2.5-168

FINITE ELEMENT REPRESENTATION - MAXIMUM SECTION SOUTH DAM



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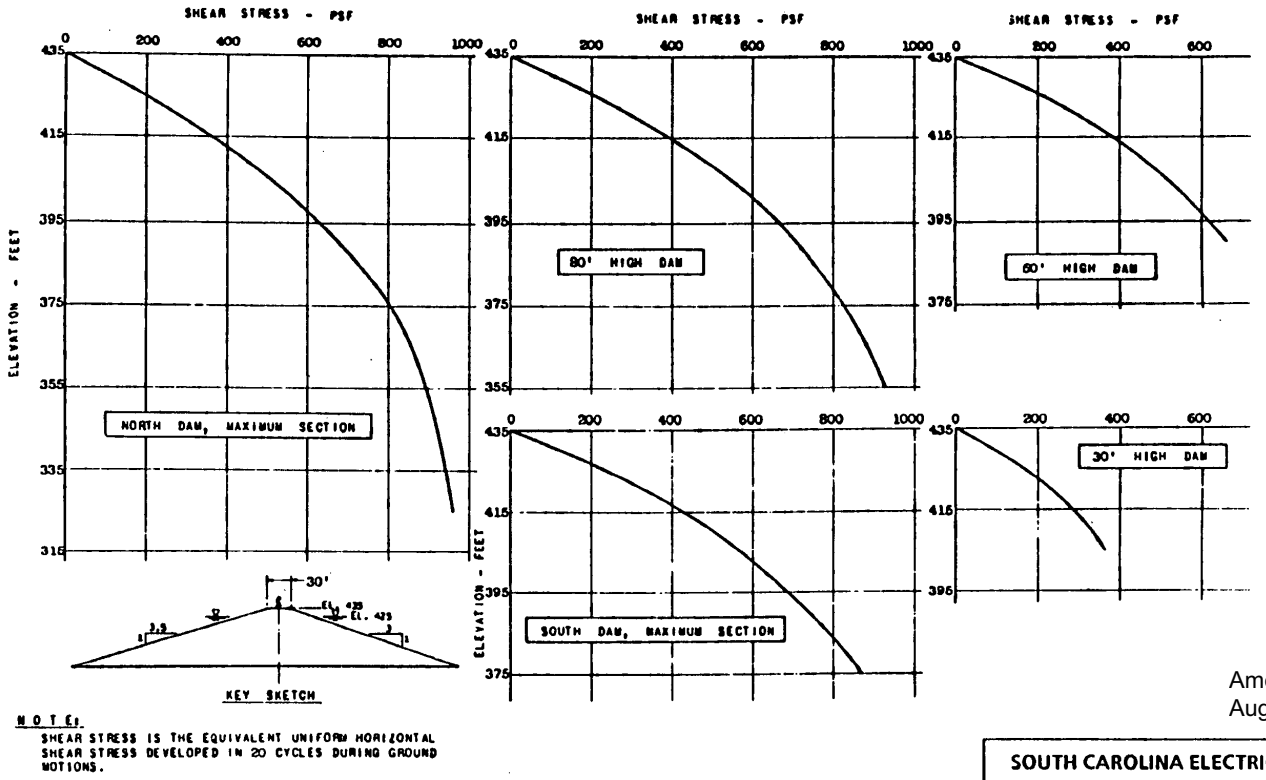
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Finite Element Representation - Maximum Section South Dam Figure 2.5-168

Figure 2.5-169

SHEAR STRESS VARIATION ALONG CENTERLINE DURING SSE



NOTES:
SHEAR STRESS IS THE EQUIVALENT UNIFORM HORIZONTAL SHEAR STRESS DEVELOPED IN 20 CYCLES DURING GROUND MOTIONS.

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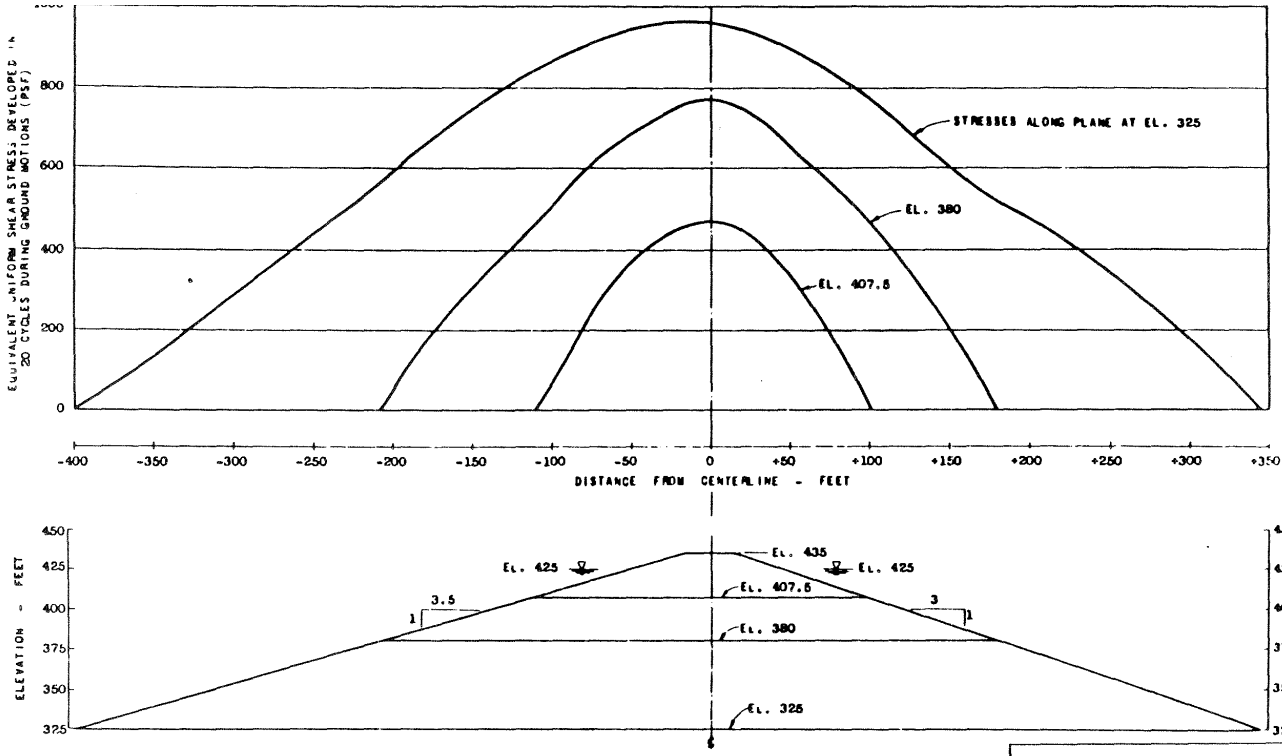
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Shear Stress Variation Along Centerline During SSE
Figure 2.5-169

Figure 2.5-170

SHEAR STRESS DEVELOPED ALONG TYPICAL HORIZONTAL PLANES DURING SSE- MAXIMUM SECTION ANALYZED - NORTH DAM



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Shear Stresses Developed Along Typical Horizontal Planes During SSE - Maximum Section Analyzed - North Dam Figure 2.5-170

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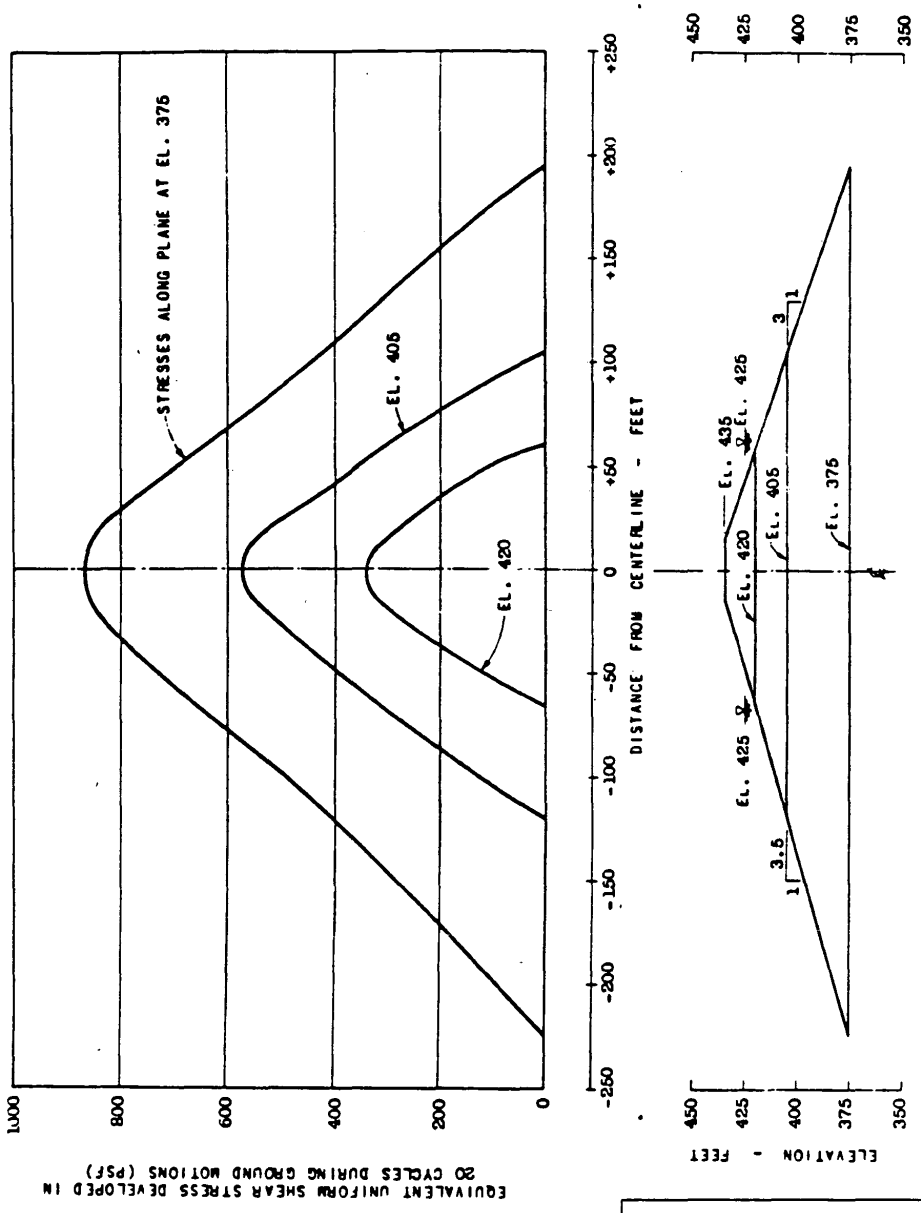
Figure 2.5-171

SHEAR STRESSES DEVELOPED ALONG TYPICAL HORIZONTAL PLANES DURING SSE - MAXIMUM SECTION ANALYZED SOUTH DAM



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Shear Stresses Developed Along Typical Horizontal Planes During SSE - Maximum Section Analyzed South Dam Figure 2.5-171

Figure 2.5-172

SHEAR STRESSES DEVELOPED ALONG TYPICAL HORIZONTAL PLANES DURING SSE - 80 FOOT HIGH DAM

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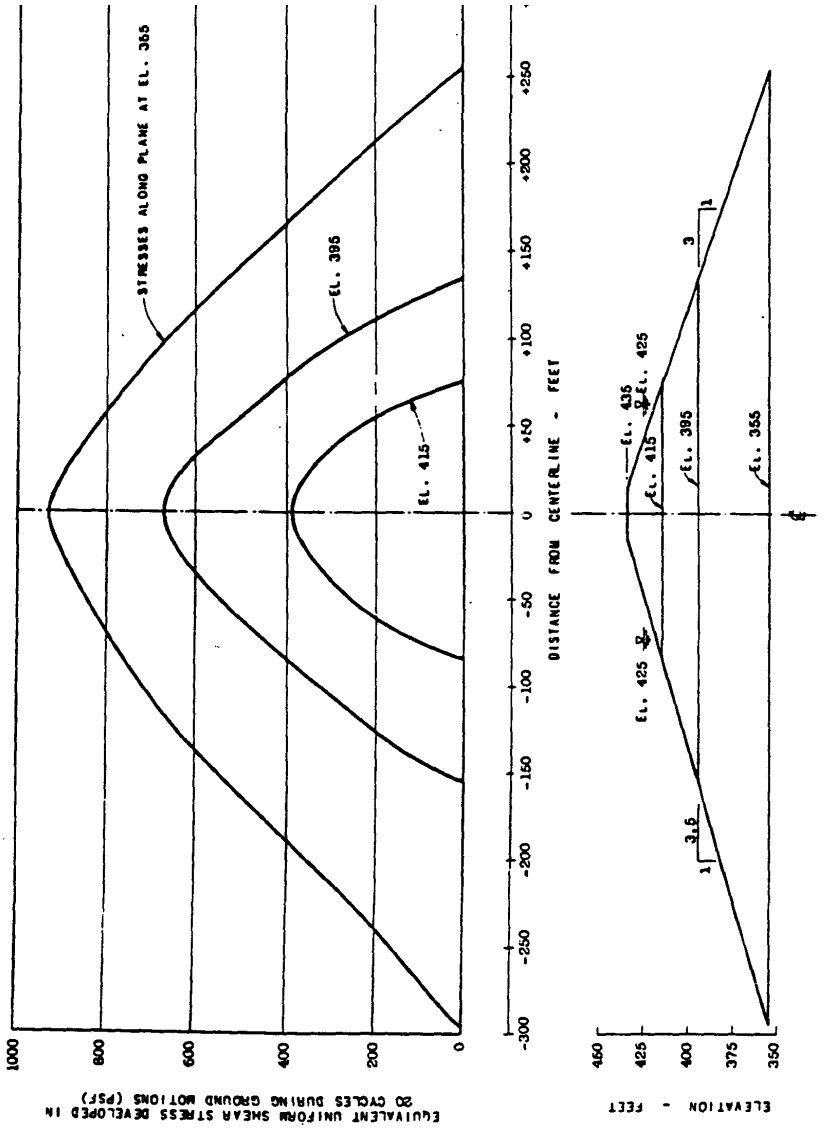
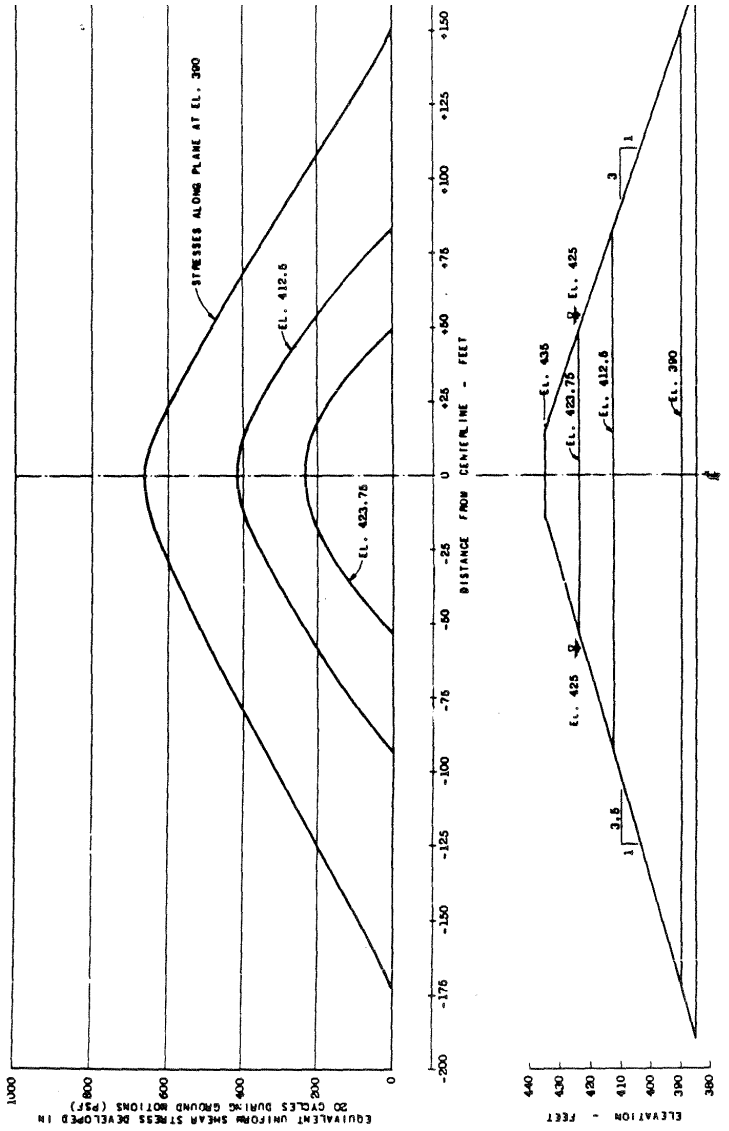


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Shear Stresses Developed Along Typical Horizontal Planes During SSE - 80 Foot High Dam Figure 2.5-172

Figure 2.5-173

SHEAR STRESSES DEVELOPED ALONG TYPICAL HORIZONTAL PLANES DURING SSE - 50 FOOT HIGH DAM



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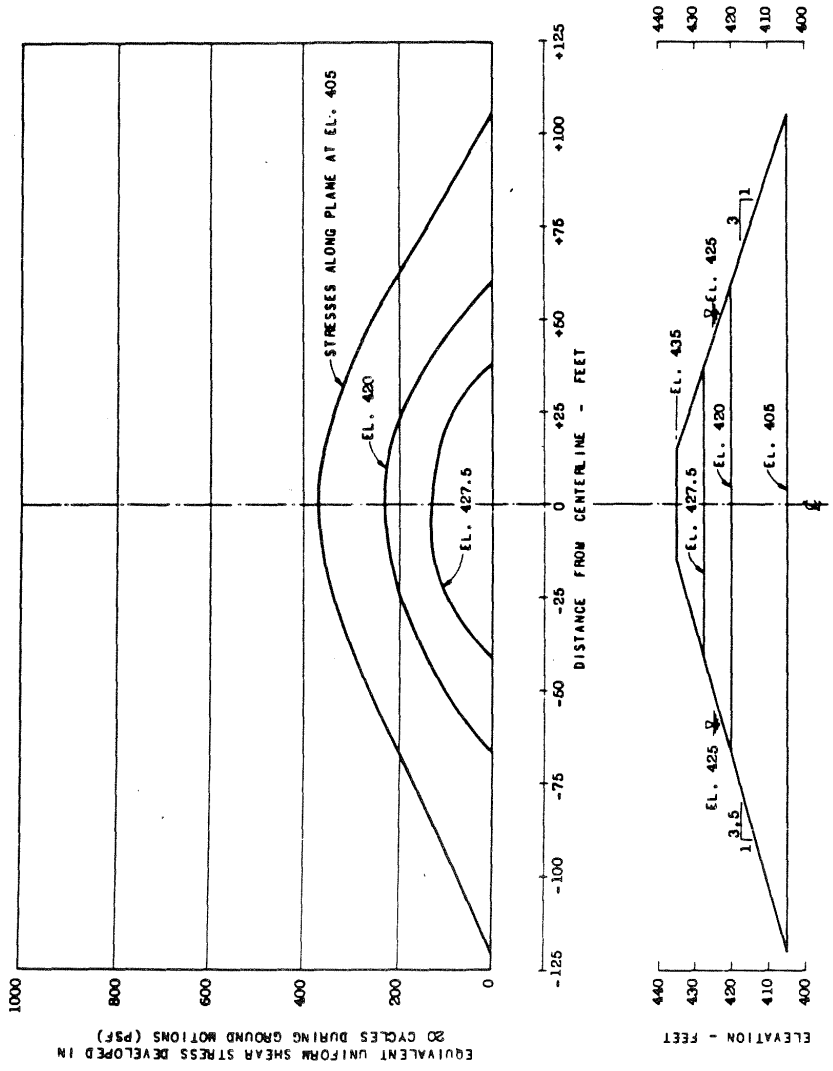
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Shear Stresses Developed Along Typical Horizontal Planes During SSE - 50 Foot High Dam Figure 2.5-173

Figure 2.5-174

SHEAR STRESSES DEVELOPED ALONG TYPICAL HORIZONTAL PLANES DURING SSE - 30 FOOT HIGH DAM



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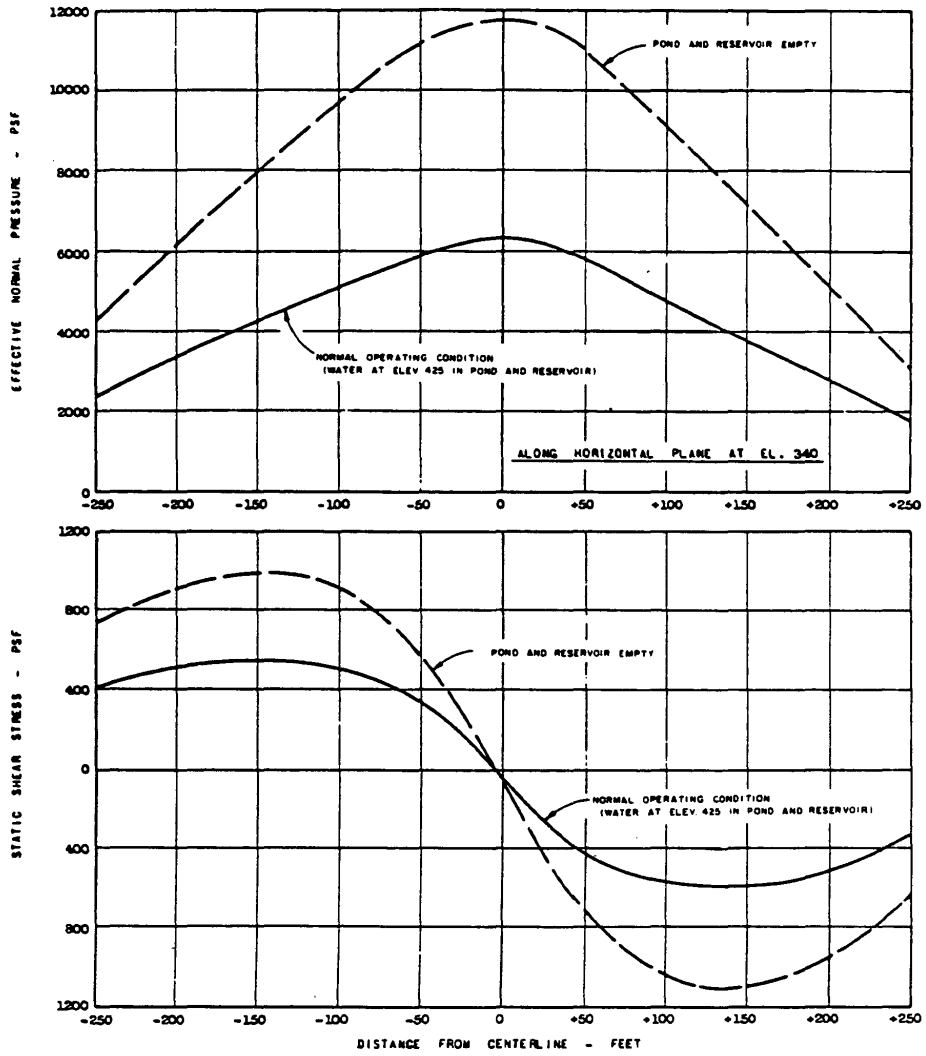
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Shear Stresses Developed Along Typical Horizontal Planes During SSE - 30 Foot High Dam Figure 2.5-174

Figure 2.5-175

TYPICAL STATIC STRESSES FOR NORMAL OPERATING CONDITION AND FOR POND AND RESERVOIR EMPTY - MAXIMUM SECTION ANALYZED, NORTH DAM



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Static Stresses for Normal Operating Condition and for Pond and Reservoir Empty - Maximum Section Analyzed, North Dam Figure 2.5-175

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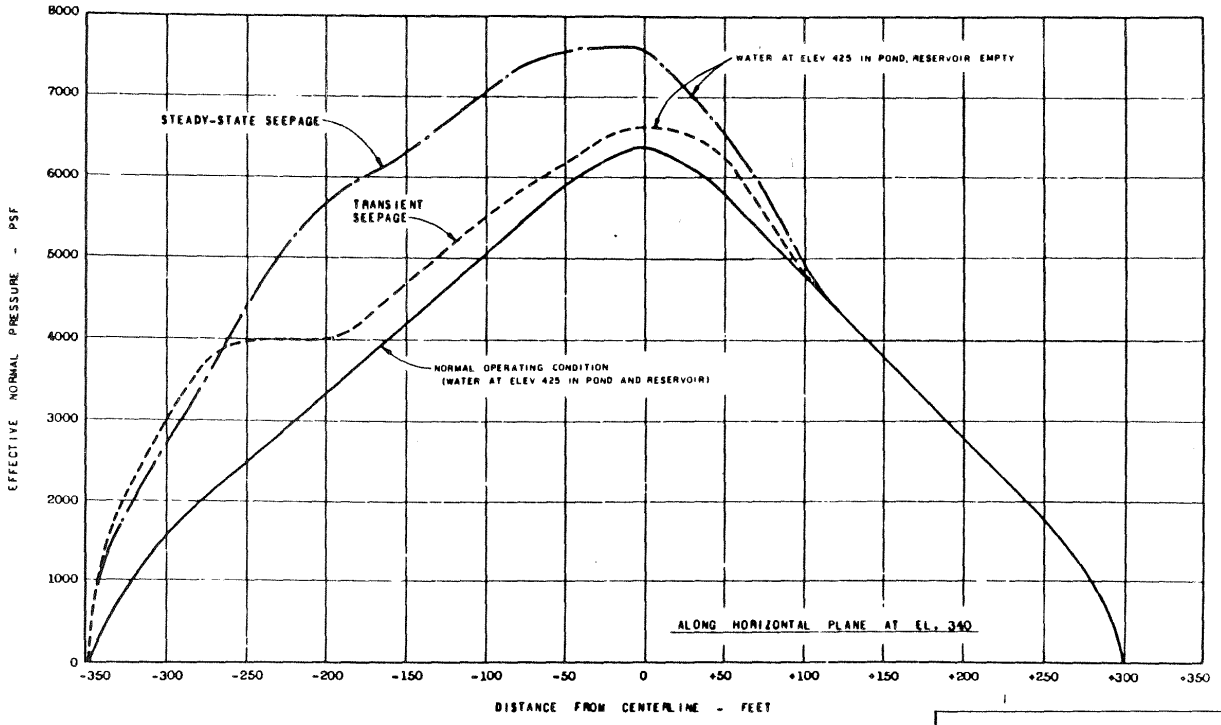
Figure 2.5-176

TYPICAL STRESSES FROM NORMAL OPERATING CONDITIONS AND FOR WATER AT ELEV. 425.0 IN POND WITH RESERVOIR EMPTY - MAX. SECTION ANALYZED, NORTH DAM



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Static Stresses from Normal Operating Conditions and for Water at Elev. 425.0 in Pond with Reservoir Empty - Max. Section Analyzed, North Dam Figure 2.5-176

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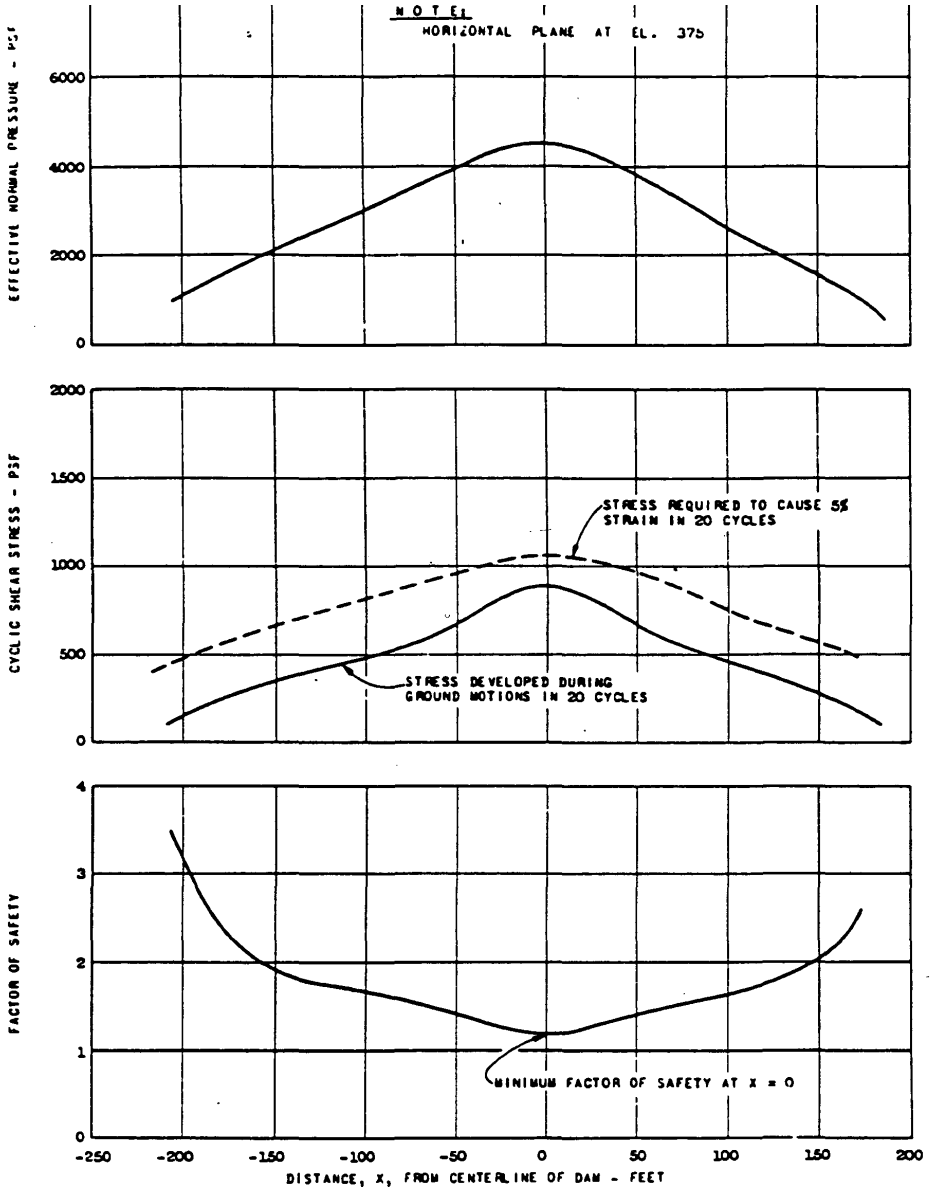
Figure 2.5-177

FAILURE POTENTIAL ALONG TYPICAL HORIZONTAL PLANE - MAXIMUM SECTION ANALYZED, SOUTH DAM



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Failure Potential Along Typical Horizontal Plane - Maximum Section Analyzed, South Dam Figure 2.5-177

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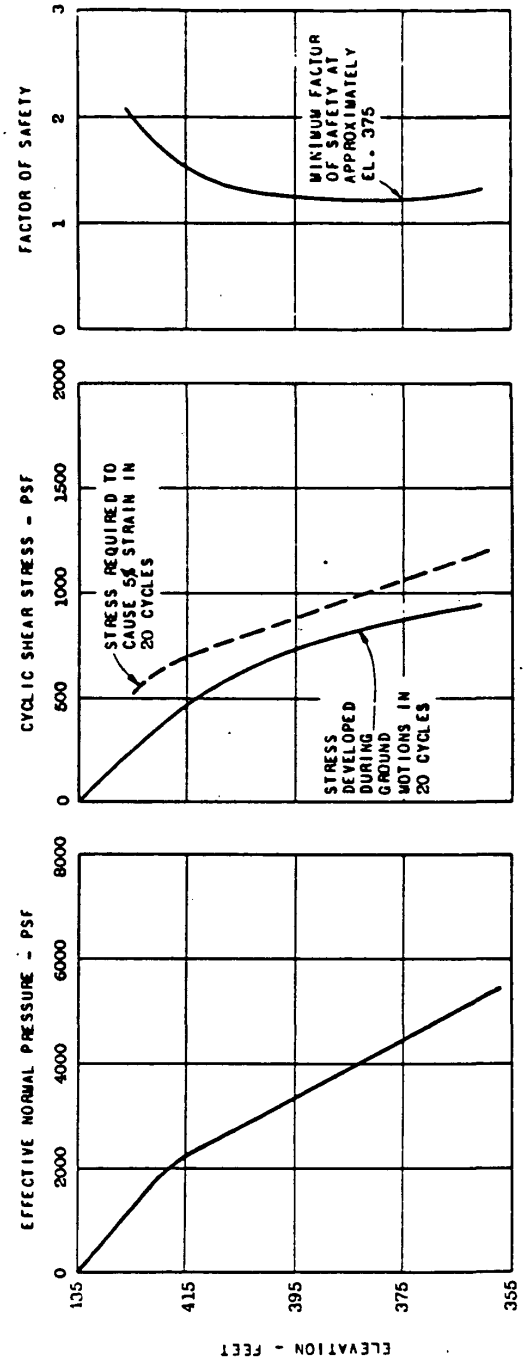
Figure 2.5-178
FAILURE POTENTIAL ALONG CENTERLINE - MAXIMUM SECTION ANALYZED, SOUTH DAM



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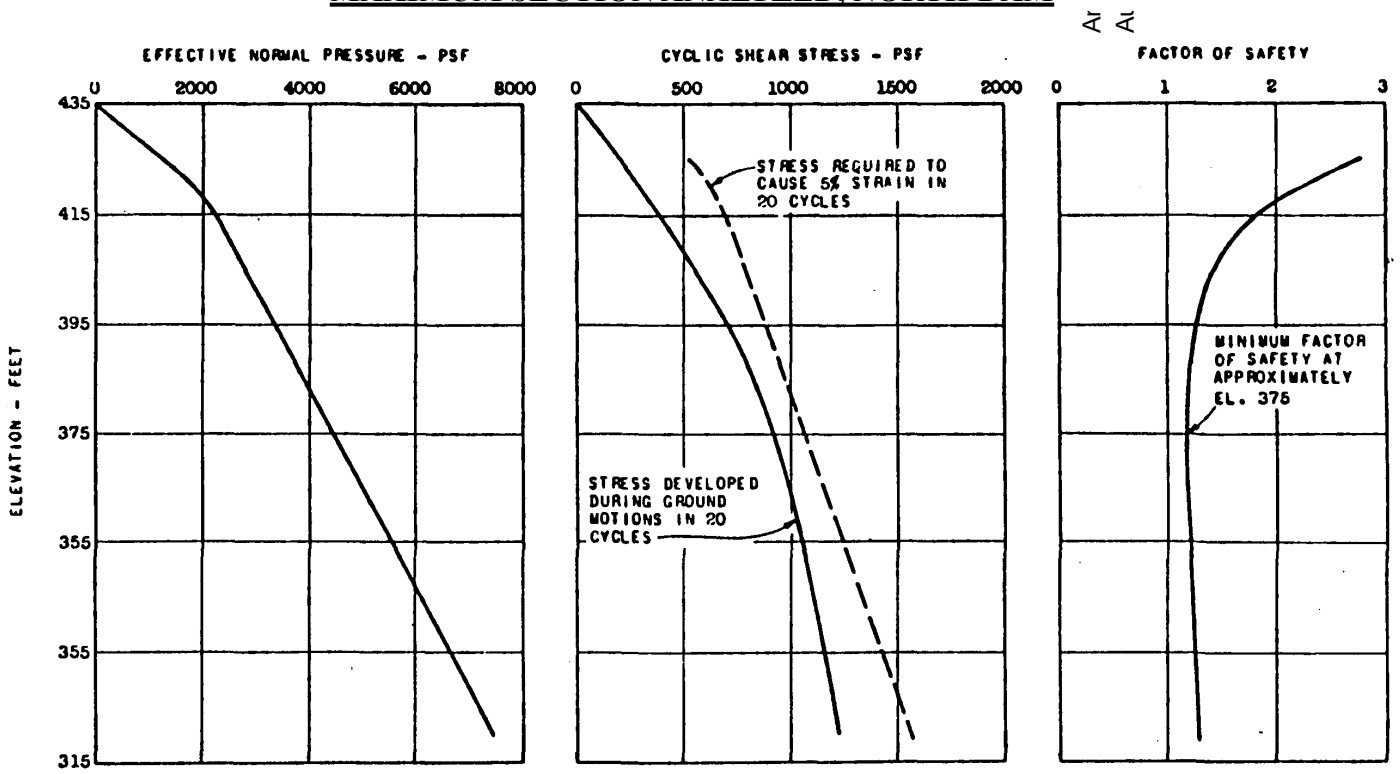
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Failure Potential Along Centerline - Maximum Section Analyzed, South Dam

Figure 2.5-178

Figure 2.5-179

FAILURE POTENTIAL ALONG CENTERLINE - MAXIMUM SECTION ANALYZED, NORTH DAM



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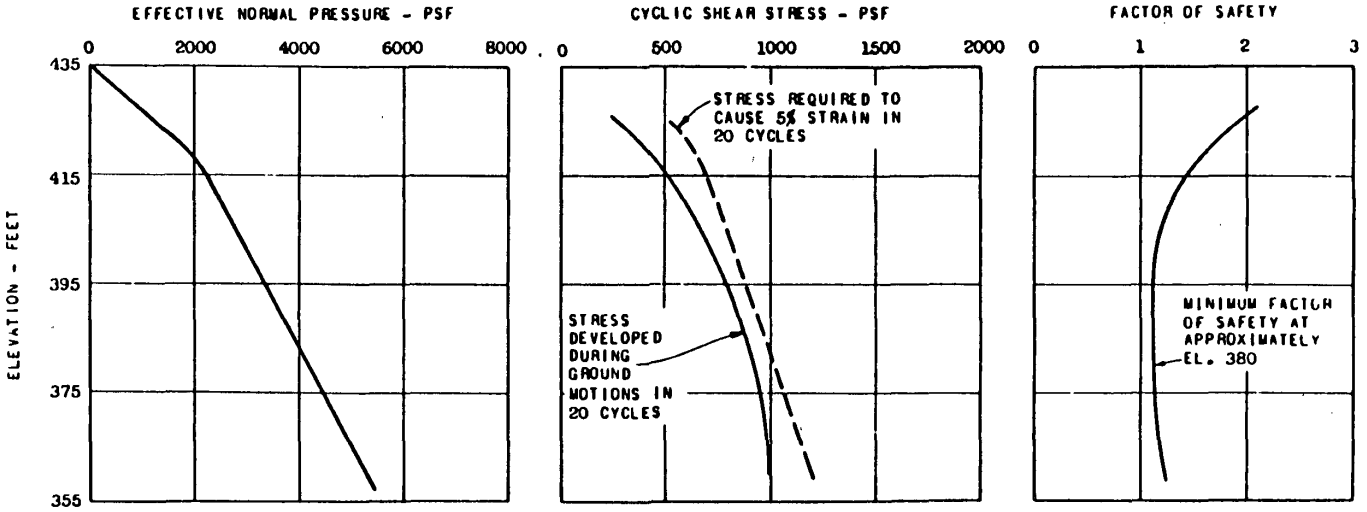
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Failure Potential Along Centerline - Maximum Section Analyzed, North Dam Figure 2.5-179

Figure 2.5-180

FAILURE POTENTIAL ALONG CENTERLINE - USING UPPER BOUND ON PROBABLE MODULUS VALUES - MAXIMUM SECTION ANALYZED, SOUTH DAM



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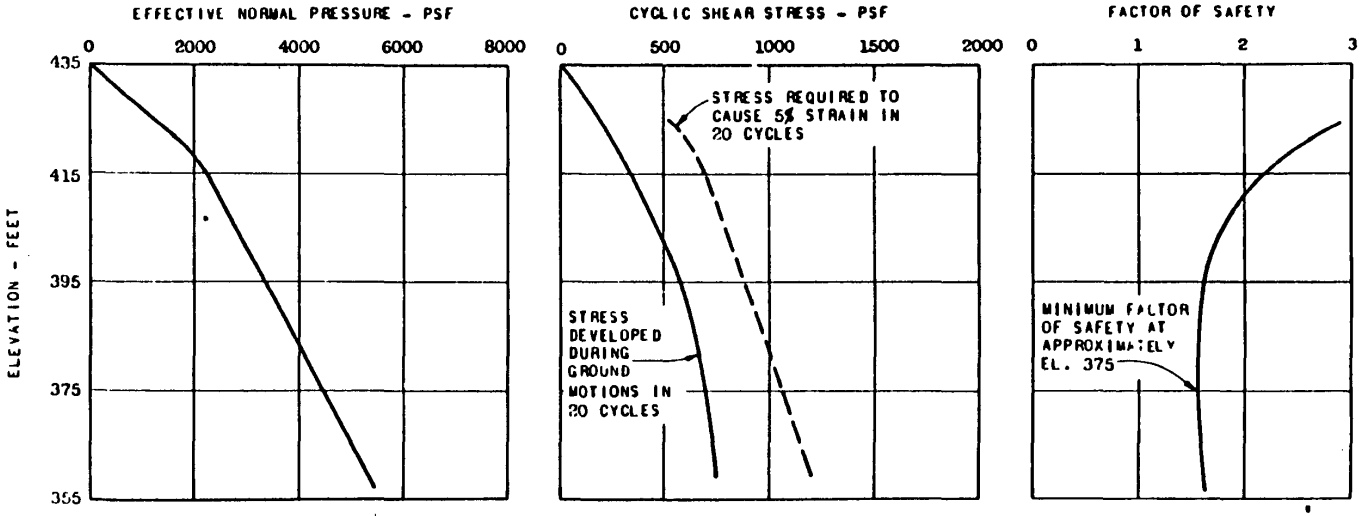
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Failure Potential Along Centerline Using Upper Bound on Probable Modulus Values - Maximum Section Analyzed, South Dam Figure 2.5-180

Figure 2.5-181

FAILURE POTENTIAL ALONG CENTERLINE USING LOWER BOUND ON PROBABLE MODULUS VALUES - MAXIMUM SECTION ANALYZED, SOUTH DAM



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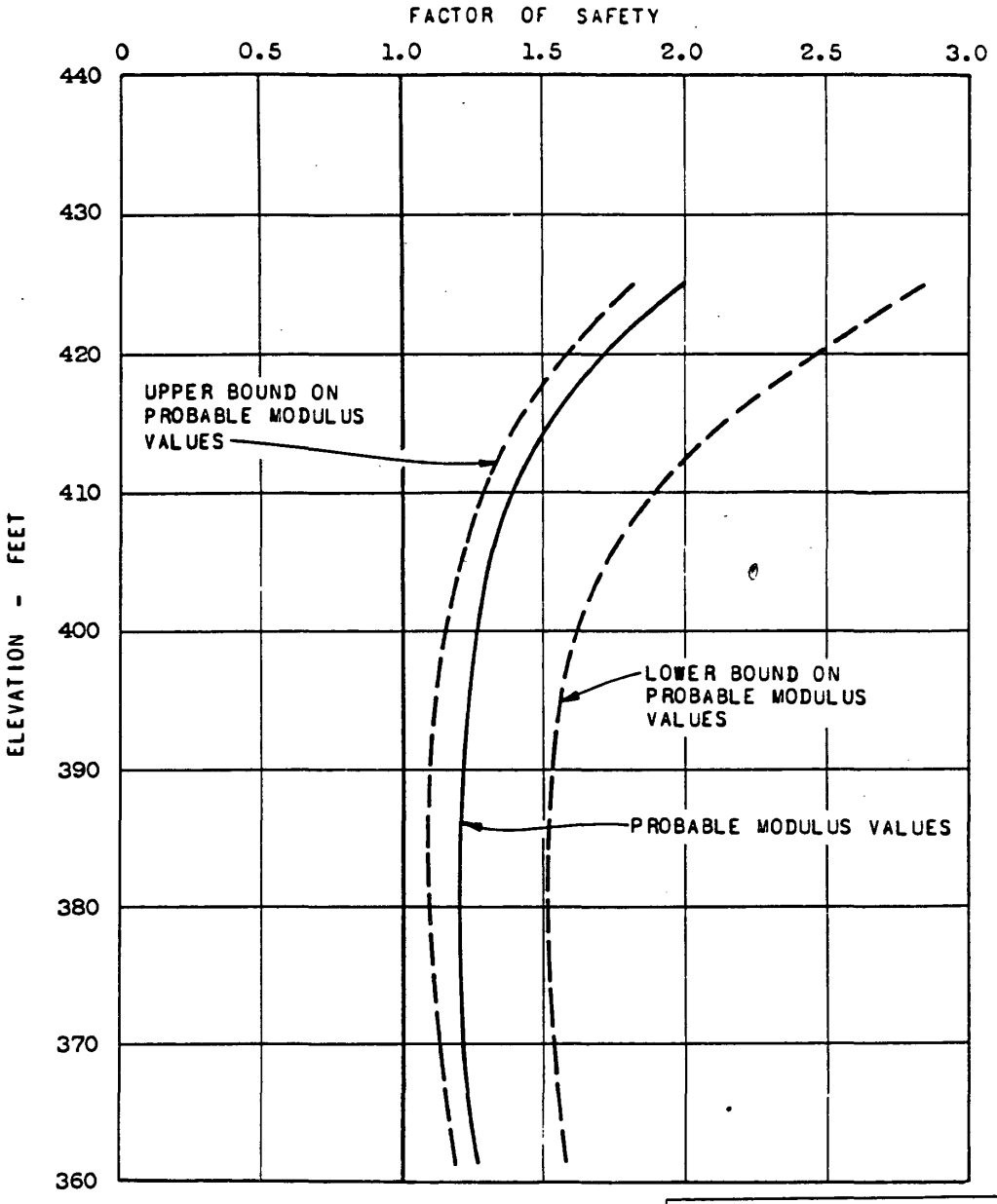
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Failure Potential Along Centerline Using Lower Bound on Probable Modulus Values - Maximum Section Analyzed, South Dam Figure 2.5-181

Figure 2.5-182

EFFECTS OF VARIATION IN MODULUS VALUES ON FAILURE POTENTIAL - MAXIMUM SECTION ANALYZED, SOUTH DAM



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Effects of Variation in Modulus Values on Failure Potential - Maximum Section Analyzed, South Dam

Figure 2.5-182

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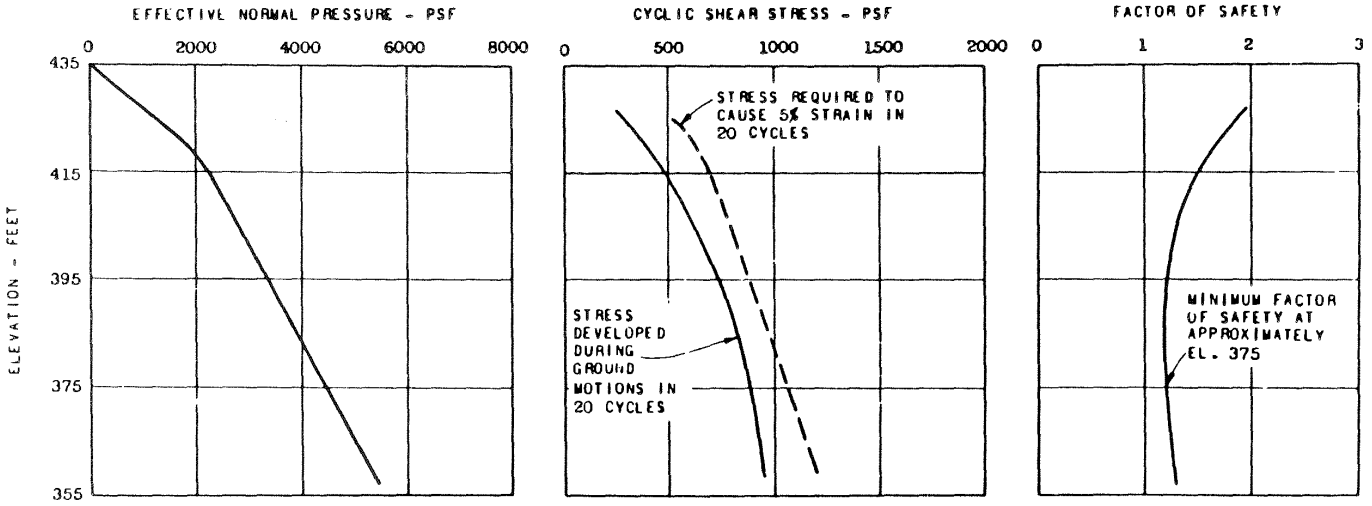
Figure 2.5-183

FAILURE POTENTIAL ALONG CENTERLINE USING LOWER BOUND ON DAMPING VALUES - MAXIMUM SECTION ANALYZED - SOUTH DAM



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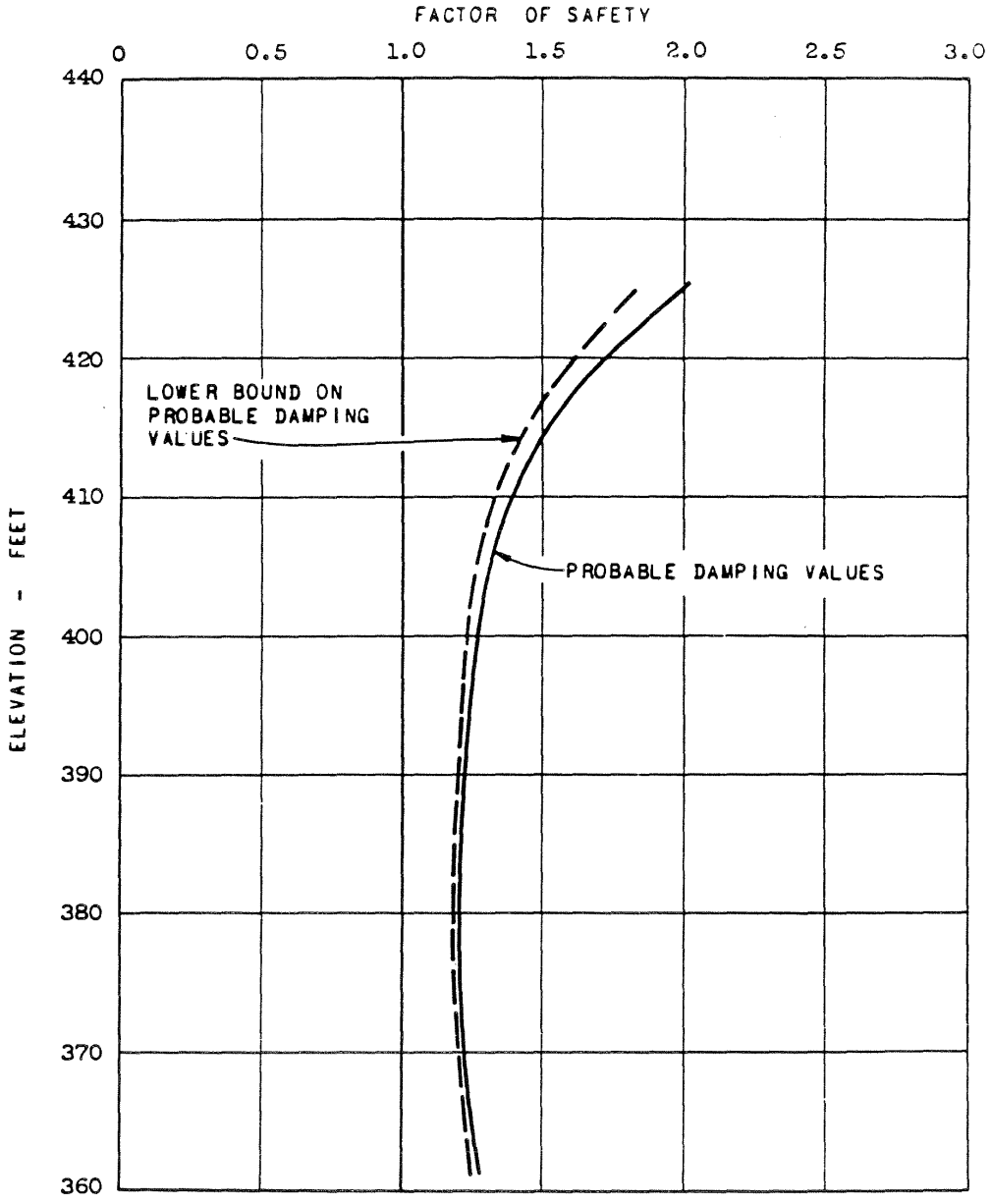
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Failure Potential Along Centerline Using Lower Bound on Damping Values - Maximum Section Analyzed, South Dam Figure 2.5-183

Figure 2.5-184

EFFECTS OF VARIATION IN DAMPING VALUES ON FAILURE POTENTIAL - MAXIMUM SECTION ANALYZED, SOUTH DAM



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Effects of Variation in Damping Values on Failure Potential - Maximum Section Analyzed, South Dam Figure 2.5-184

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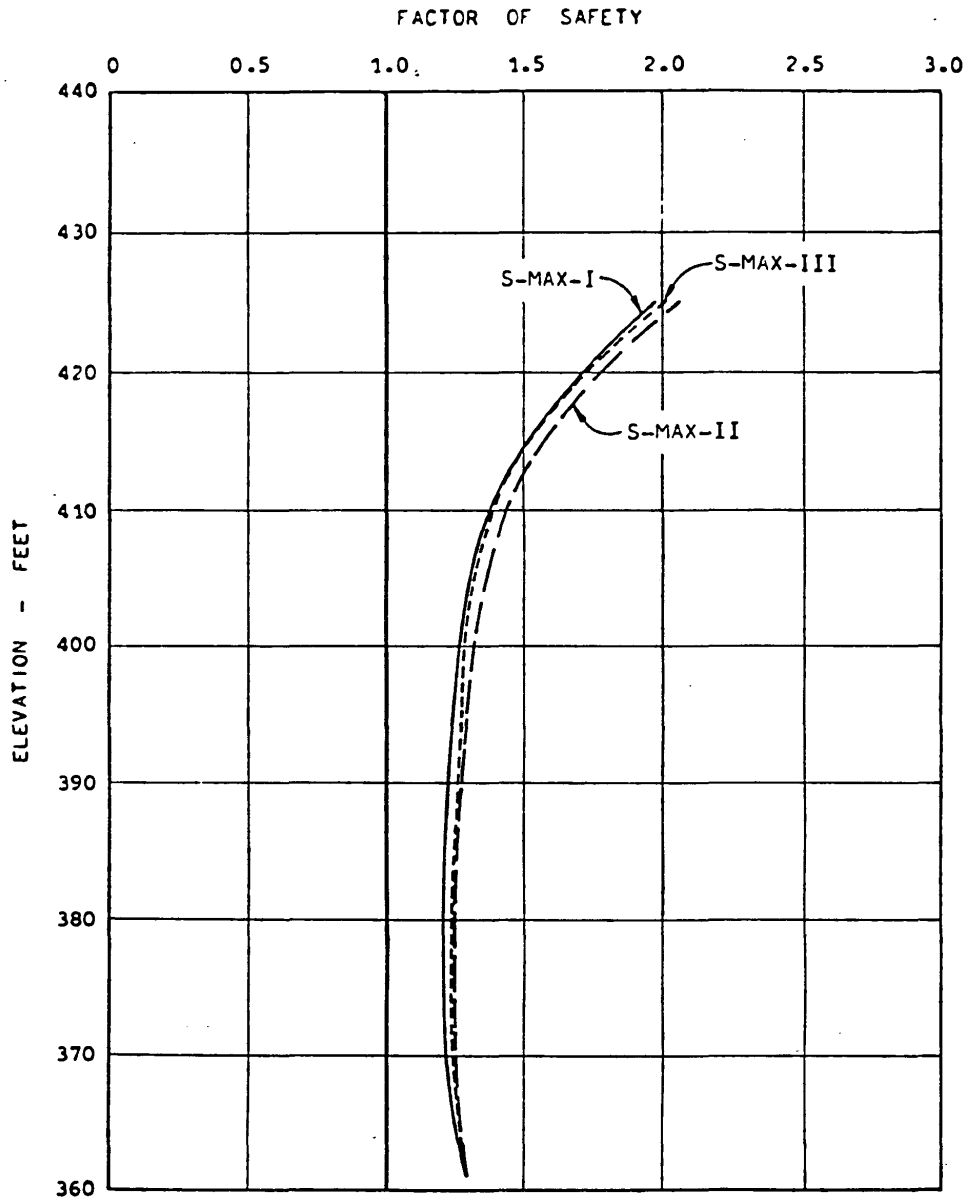
Figure 2.5-185

EFFECTS OF VARIATION IN MODULUS VALUES OF THE FOUNDATION STRATA ON FAILURE POTENTIAL - MAXIMUM SECTION ANALYZED, SOUTH DAM



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Effects of Variation in Modulus Values of the Foundation Strata on Failure Potential - Maximum Section Analyzed , South Dam
Figure 2.5-185

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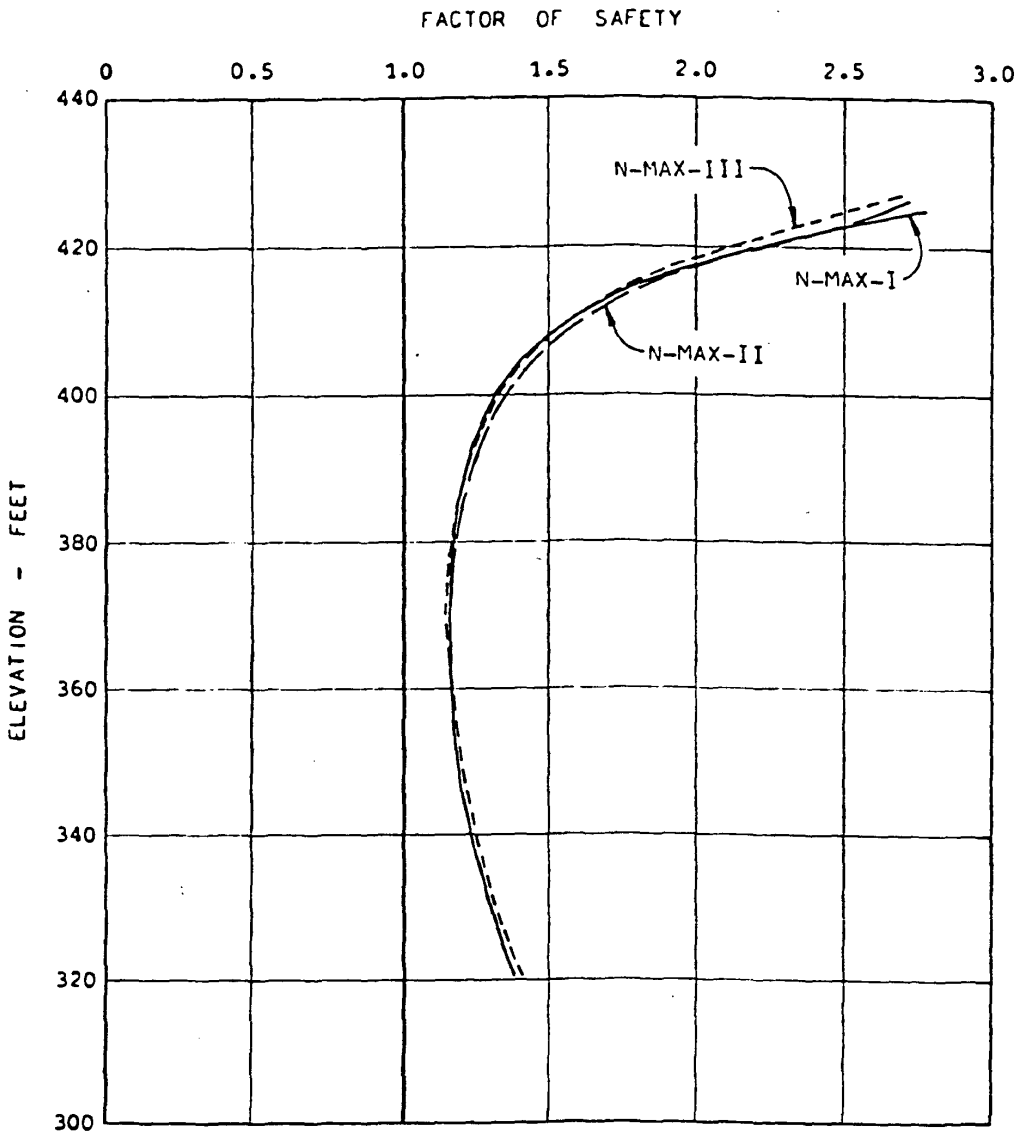
Figure 2.5-186

EFFECTS OF VARIATION IN MODULUS VALUES OF THE WEATHERED ROCK ON FAILURE POTENTIAL - MAXIMUM SECTION ANALYZED, NORTH DAM



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Effects of Variation in Modulus Values of the Weathered Rock on Failure Potential - Maximum Section Analyzed , North Dam

Figure 2.5-186

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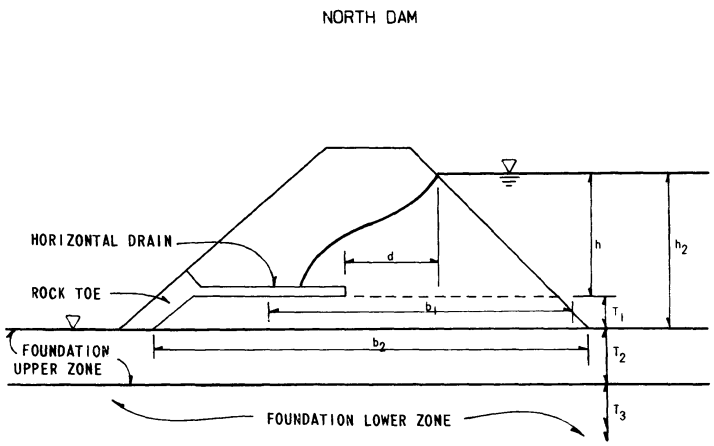
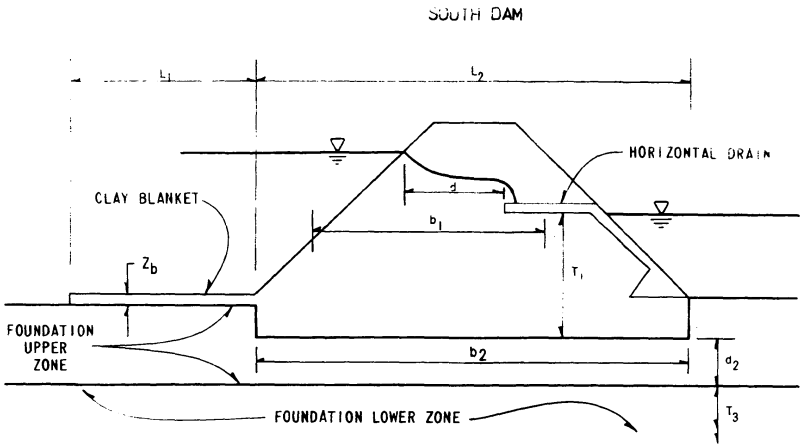
Figure 2.5-187

SCHEMATIC DEFINITION OF GEOMETRICAL PARAMETERS USED IN SEEPAGE ANALYSIS



NOTE: IN SECTION 2.5.6.6.3, USE:

1) h and d with Eq (1) for seepage through embankment above drain
2) h, T_1 and b_1 with Eq (2) for seepage through embankment below drain
3) h_2, T_2 and b_2 with Eq (2) for seepage through foundation upper zone
4) h_2, T_3 and b_2 with Eq (4) for seepage through foundation lower zone



NOTE: IN SECTION 2.5.6.6.3, USE:

1) h and d with Eq (1) for seepage through embankment above drain
2) h, T_1 and b_1 with Eq (2) for seepage through embankment below drain
3) h, d_2, L_1 and L_2 with Eq (5) for seepage through foundation upper zone protected with clay blanket
4) h, T_3 and b_2 with Eq (4) for seepage through foundation lower zone

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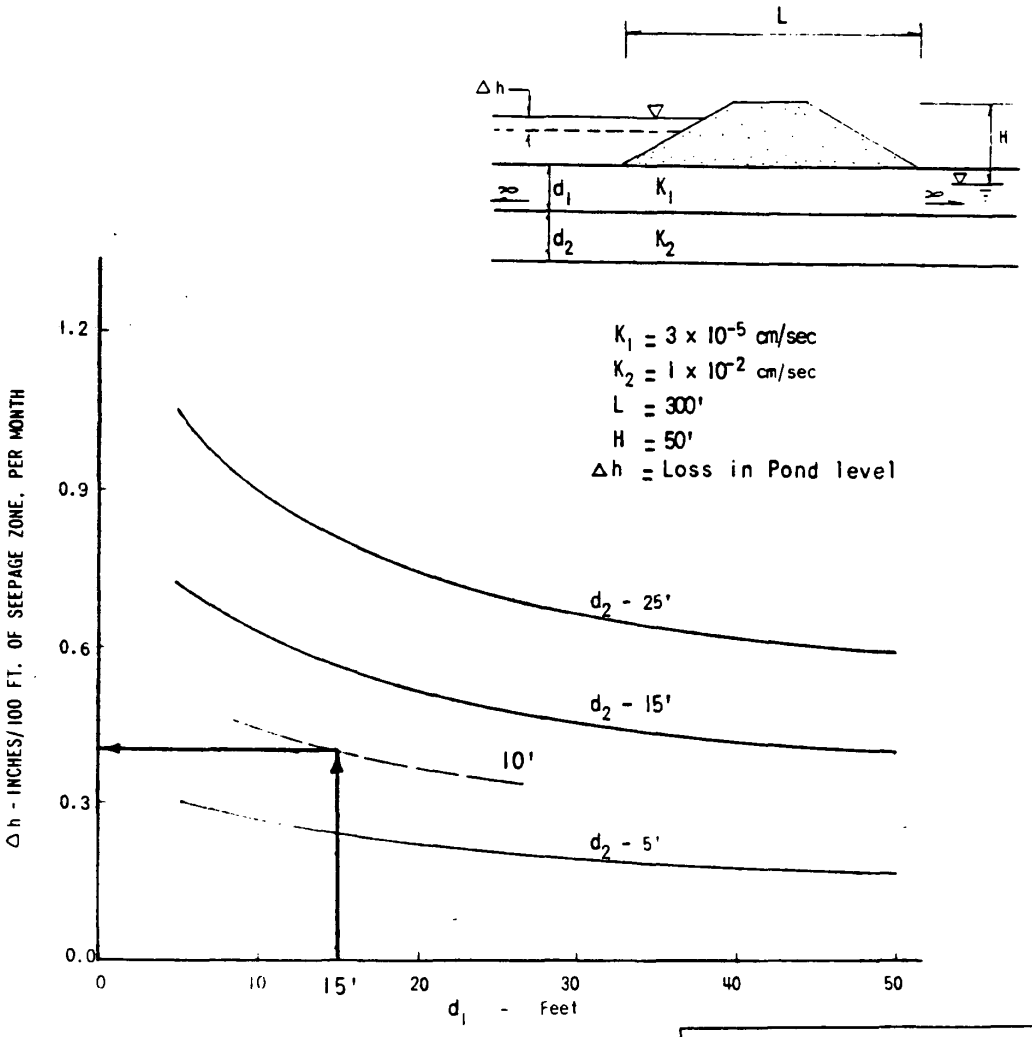
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Schematic Definition of Geometrical Parameters Used in Seepage Analysis

Figure 2.5-187

Figure 2.5-188

ESTIMATED LOSS IN POND LEVEL DUE TO HIGH PERMEABILITY FOUNDATION ZONE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Estmated Loss in Pond Level Due to High Permeability Foundation Zone Figure 2.5-188

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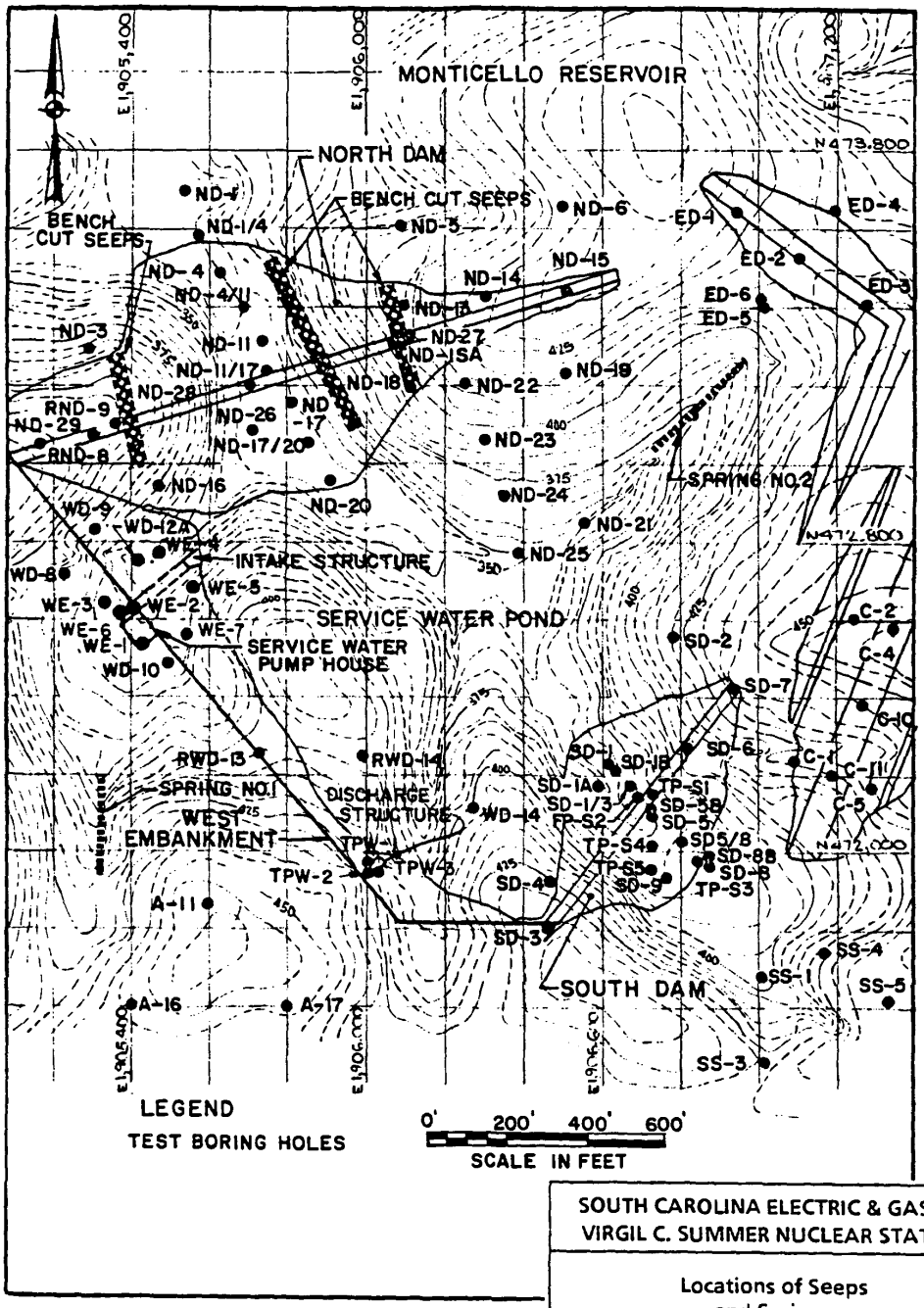
Figure 2.5-189

LOCATIONS OF SEEPS AND SPRINGS



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VIRGIL C. SUMMER NUCLEAR STATION

Locations of Seeps and Springs

Figure 2.5-189

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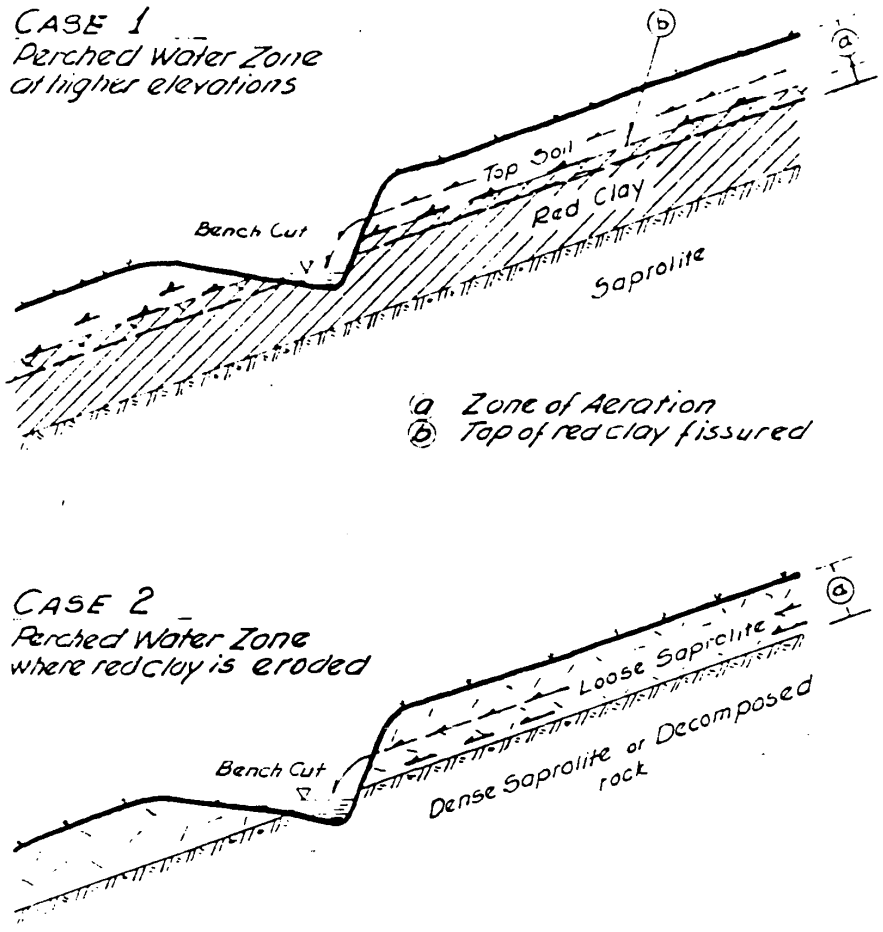
Figure 2.5-190
SEEPAGE AT BENCH CUTS



(Case 2 is the most common case at lower elevations)

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Seepage at Bench Cuts
Figure 2.5-190

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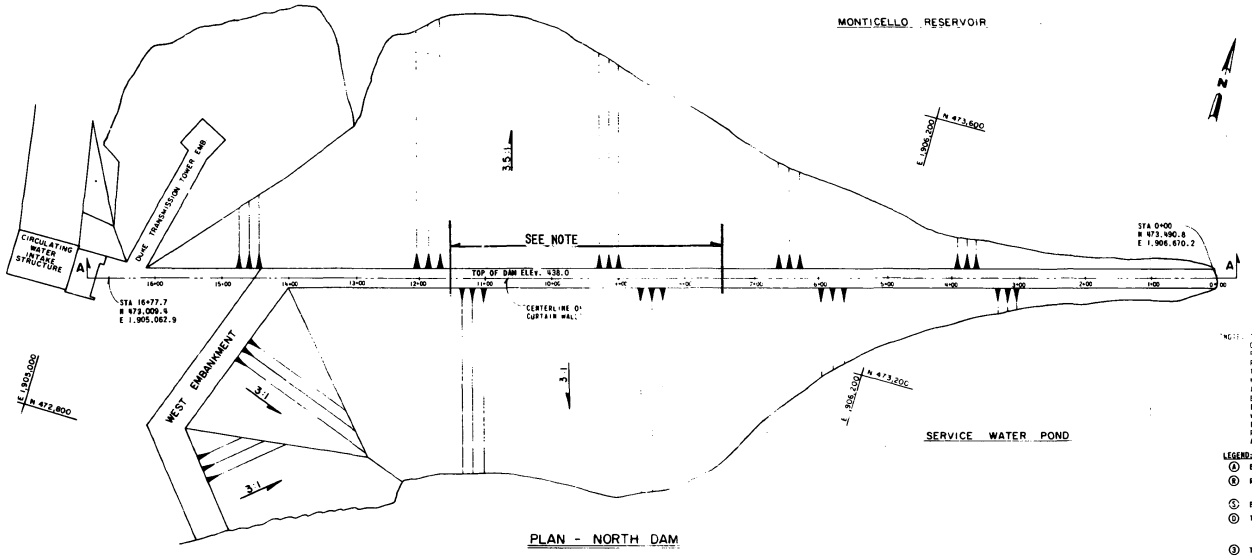
Figure 2.5-191

GROUT CURTAIN PLAN AND PROFILE



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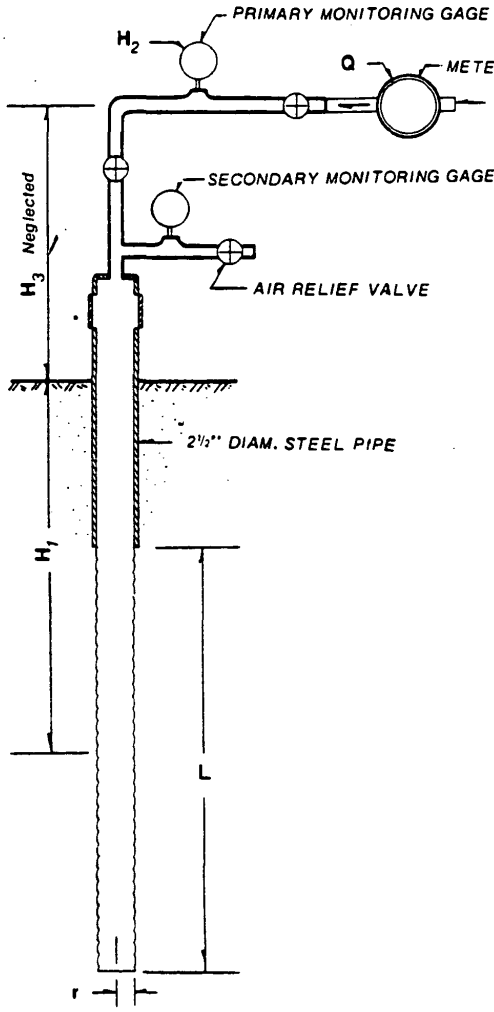
VIRGIL C. SUMMER NUCLEAR STATION

Grout Curtain Plan and Profile

Figure 2.5-191

Figure 2.5-192

WATER PRESSURE TESTING APPARATUS



PERMEABILITY COMPUTATION

$K = 0.0108 \frac{Q}{LH} \times \text{Log}_e \frac{L}{r}$

K = Permeability (cm/sec)

Q = Inflow rate (GPM)

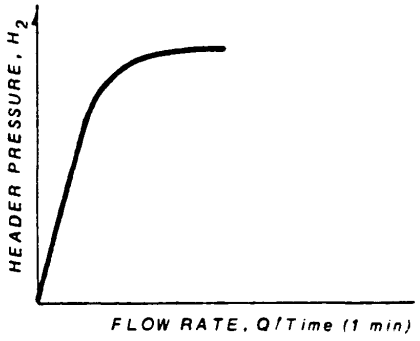
L = Length of Test Section (ft)

H = Pressure Head (ft)

r = Radius of Hole (ft)

NOTE: Total Head, $H = H_1 + H_2$

PROCEDURE USED TO PLOT PRESSURE vs FLOW RATE



NOT TO SCALE

SCHEMATIC of WATER PRESSURE TESTING APPARATUS

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Water Pressure Testing Apparatus Figure 2.5-192

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Figure 2.5-193

CIRCULATING GROUT SYSTEM

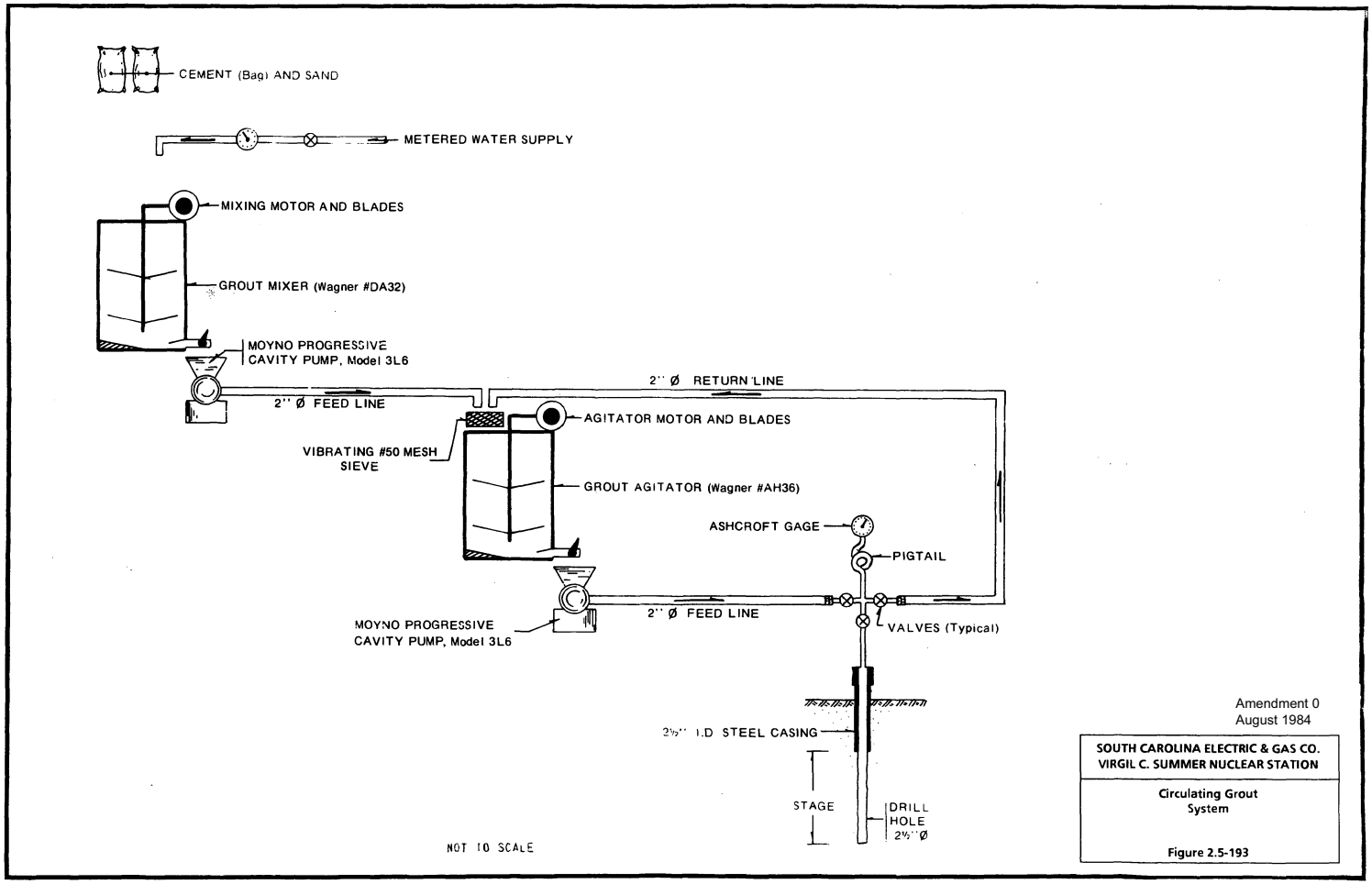
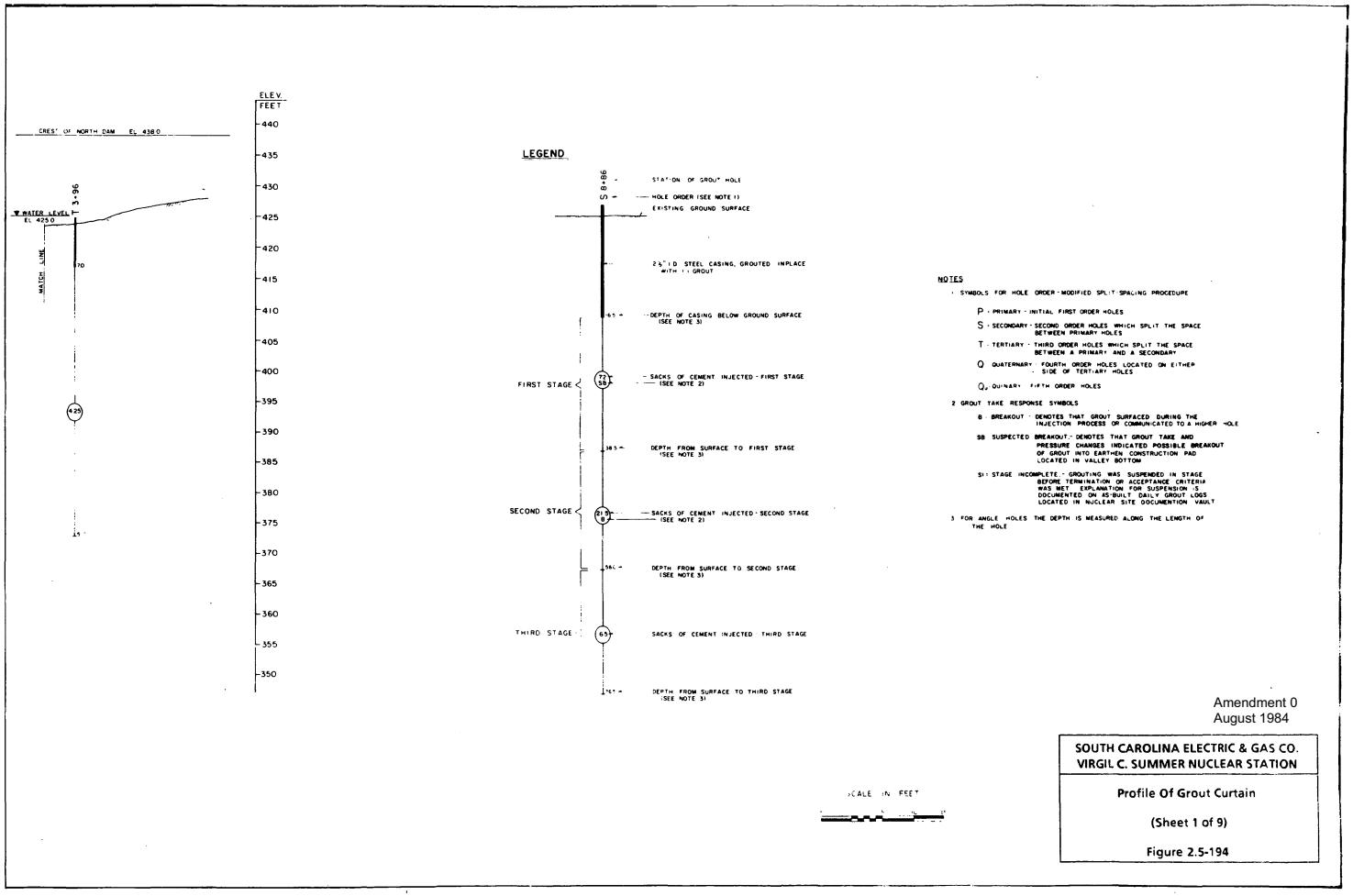


Figure 2.5-194

PROFILE OF GROUT CURTAIN

(SHEET 1 OF 9)



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SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Profile Of Grout Curtain (Sheet 1 of 9) Figure 2.5-194

Figure 2.5-194

PROFILE OF GROUT CURTAIN

(SHEET 2 OF 9)

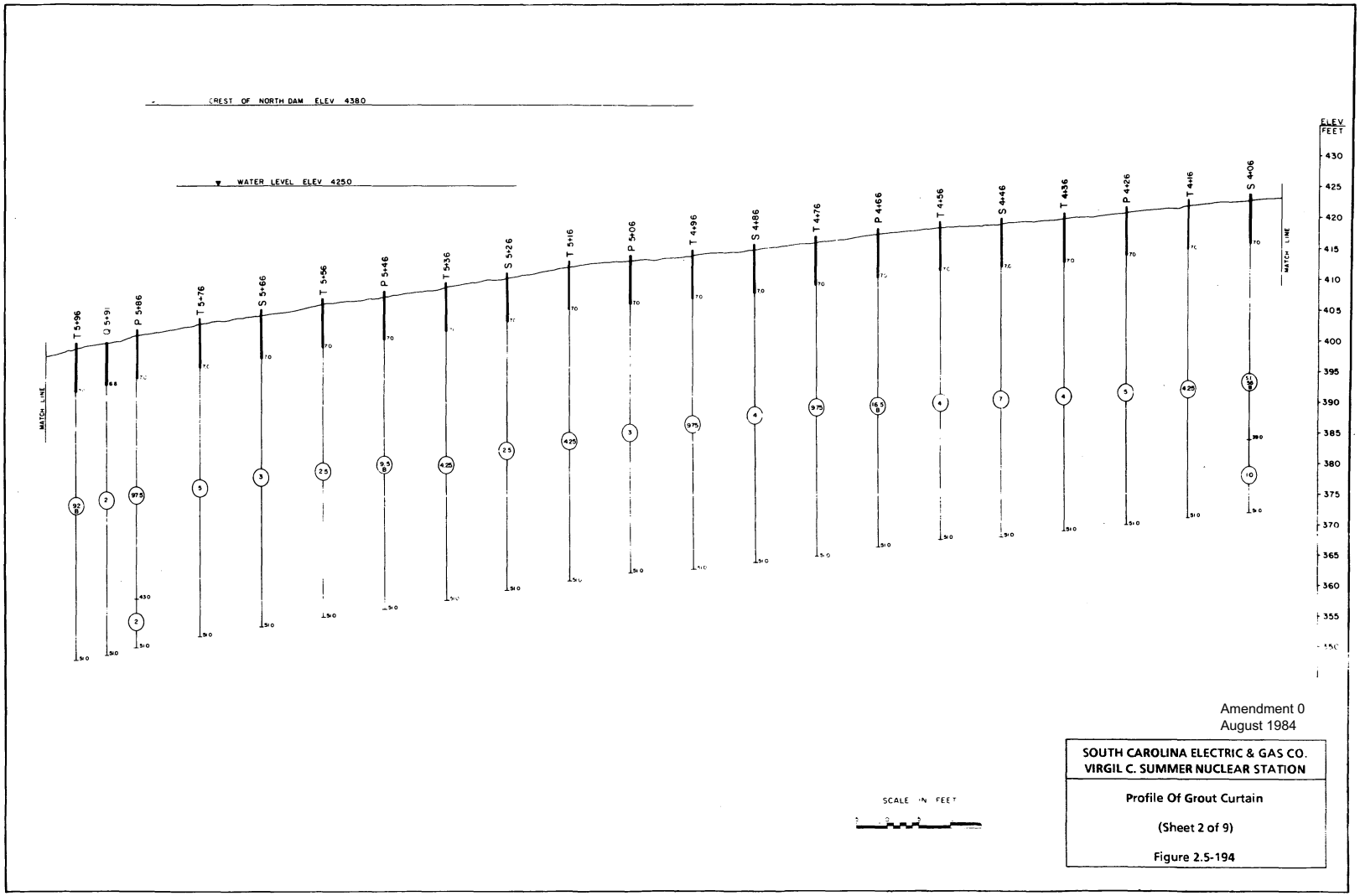

Figure 2.5-194

PROFILE OF GROUT CURTAIN

(SHEET 3 OF 9)

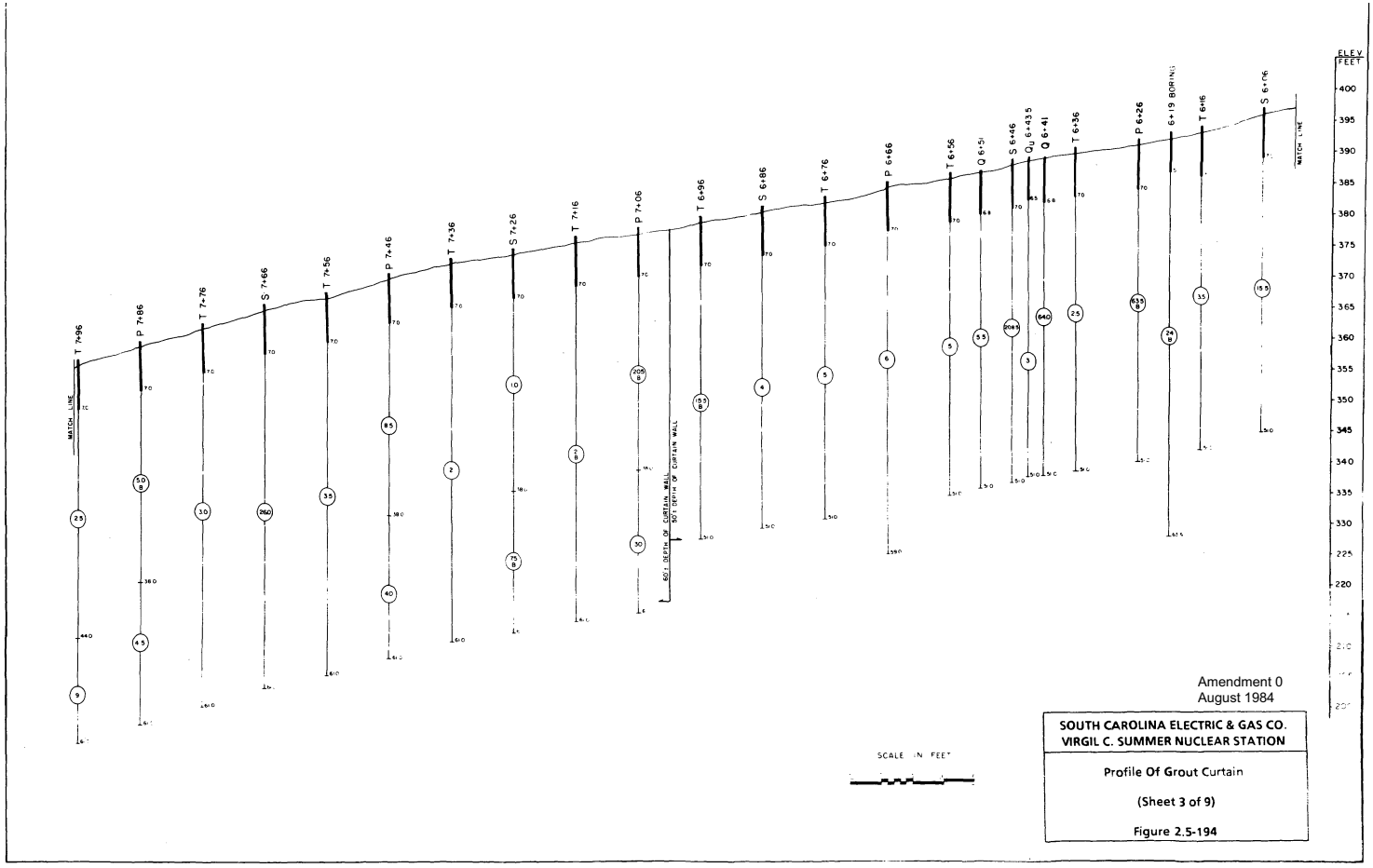

Figure 2.5-194

PROFILE OF GROUT CURTAIN

(SHEET 4 OF 9)

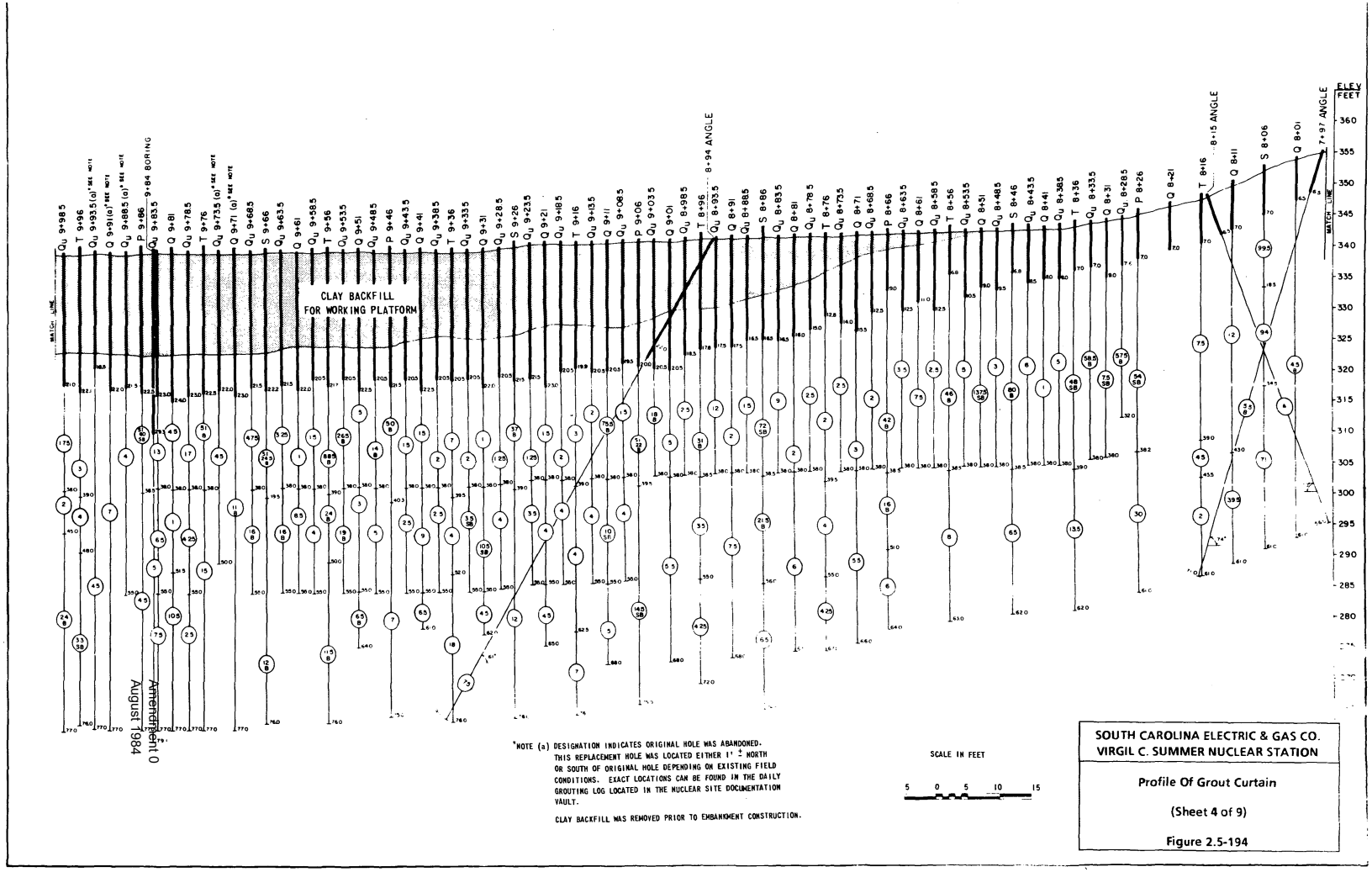

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Figure 2.5-194

PROFILE OF GROUT CURTAIN

(SHEET 5 OF 9)

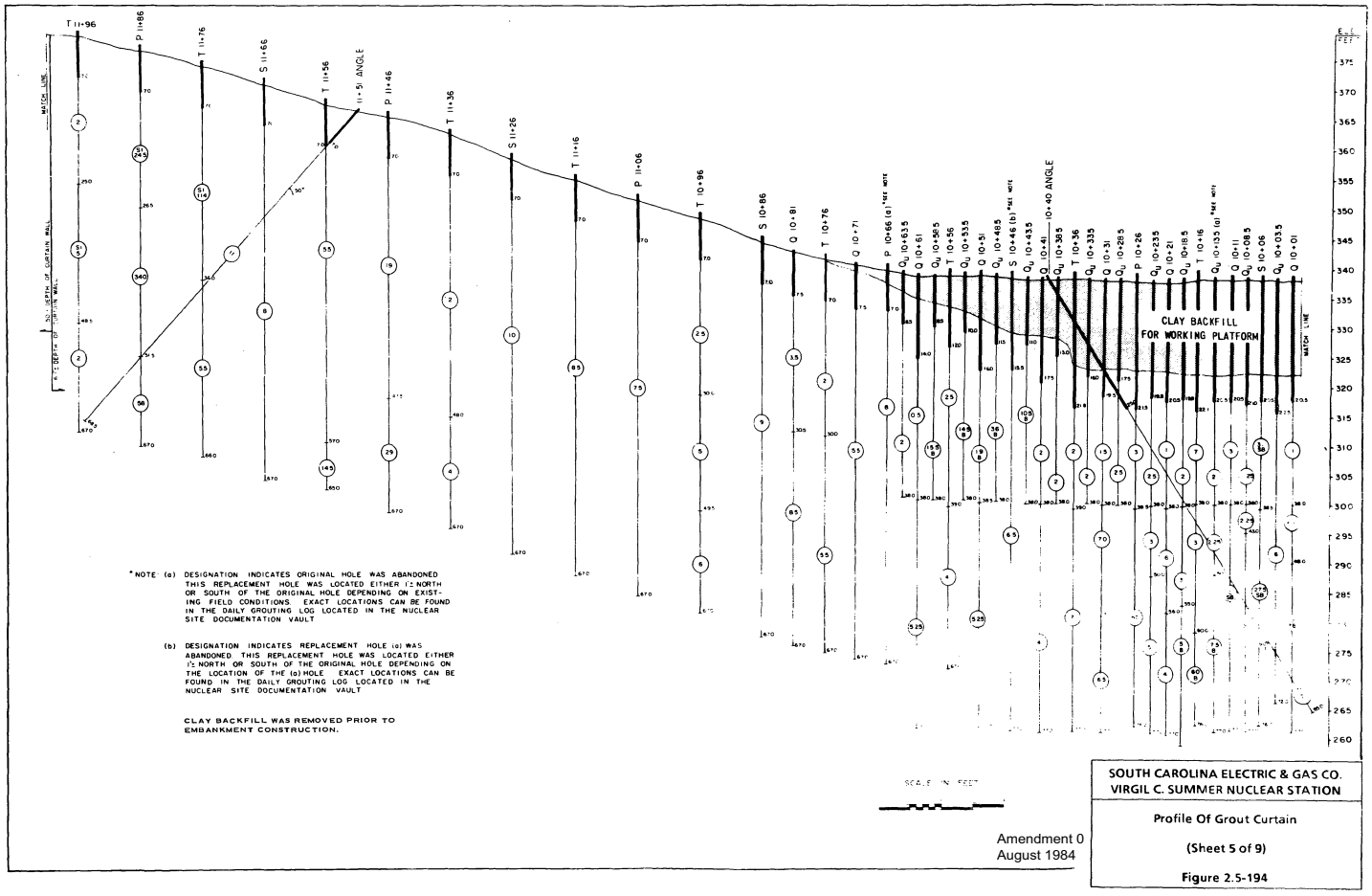

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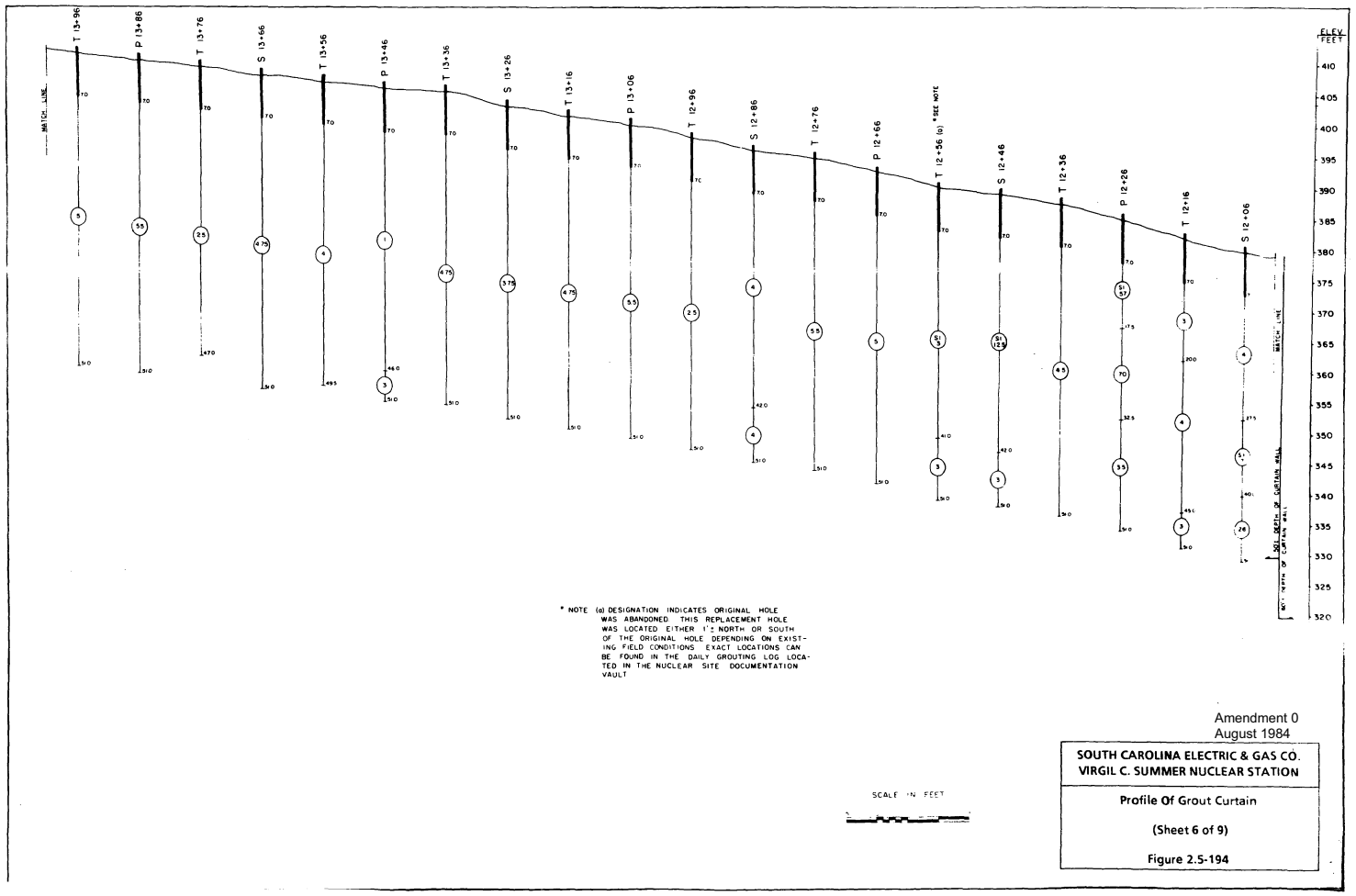
Figure 2.5-194

PROFILE OF GROUT CURTAIN

(SHEET 6 OF 9)



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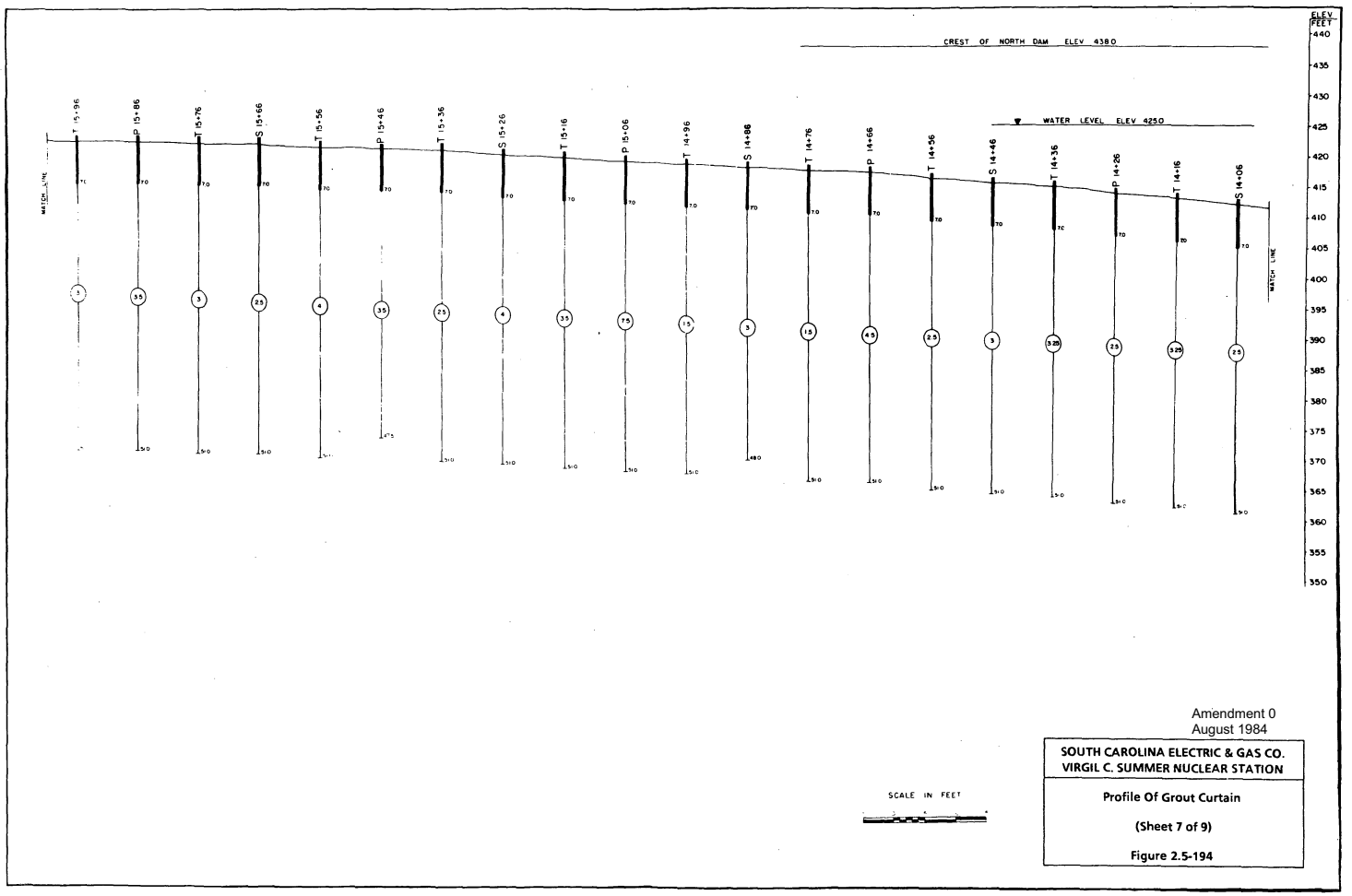
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Profile Of Grout Curtain
(Sheet 6 of 9)
Figure 2.5-194

Figure 2.5-194

PROFILE OF GROUT CURTAIN

(SHEET 7 OF 9)



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SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Profile Of Grout Curtain (Sheet 7 of 9) Figure 2.5-194

Figure 2.5-194
PROFILE OF GROUT CURTAIN
(SHEET 8 OF 9)

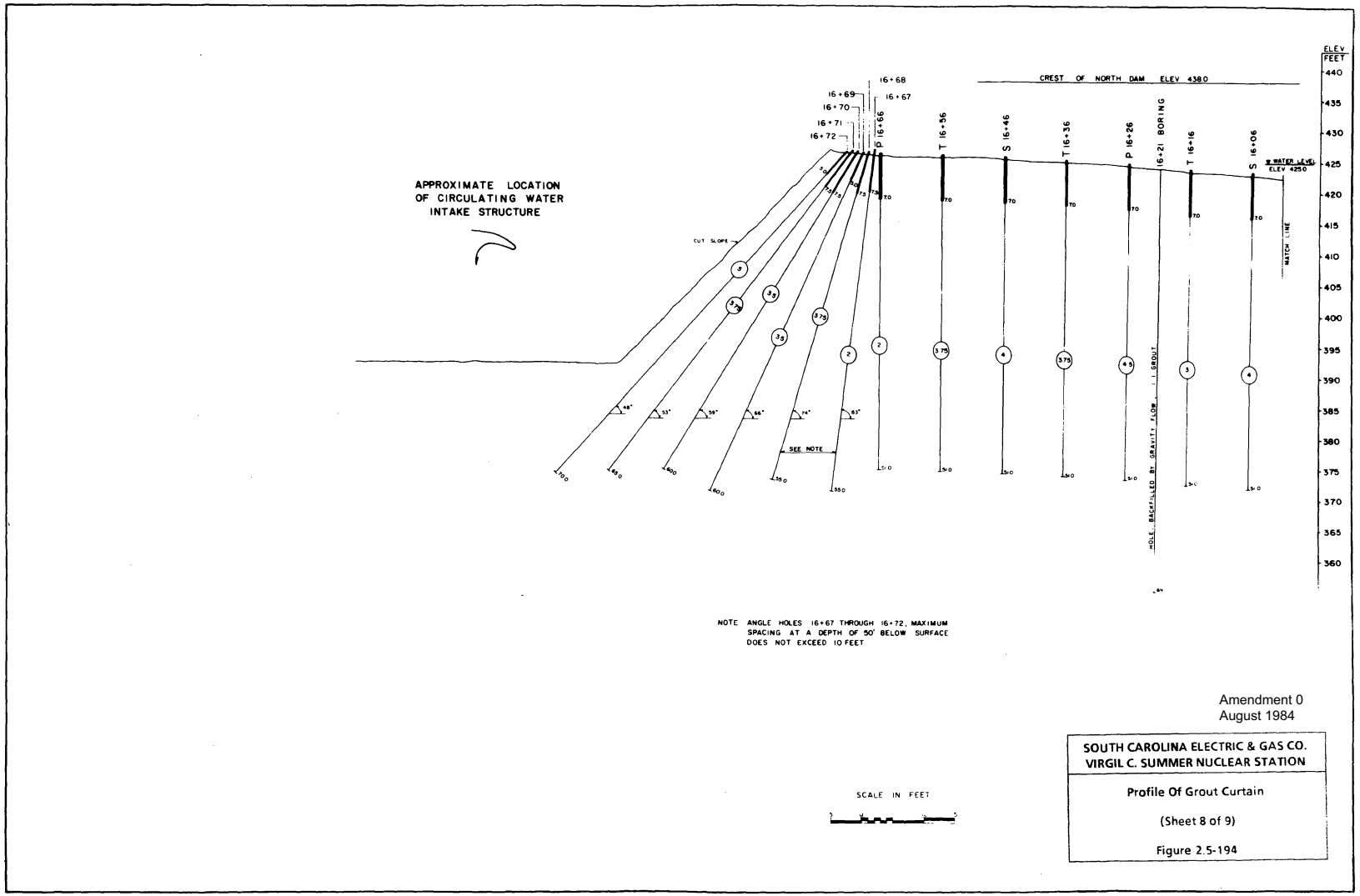


Figure 2.5-194

PROFILE OF GROUT CURTAIN
(SHEET 9 OF 9)

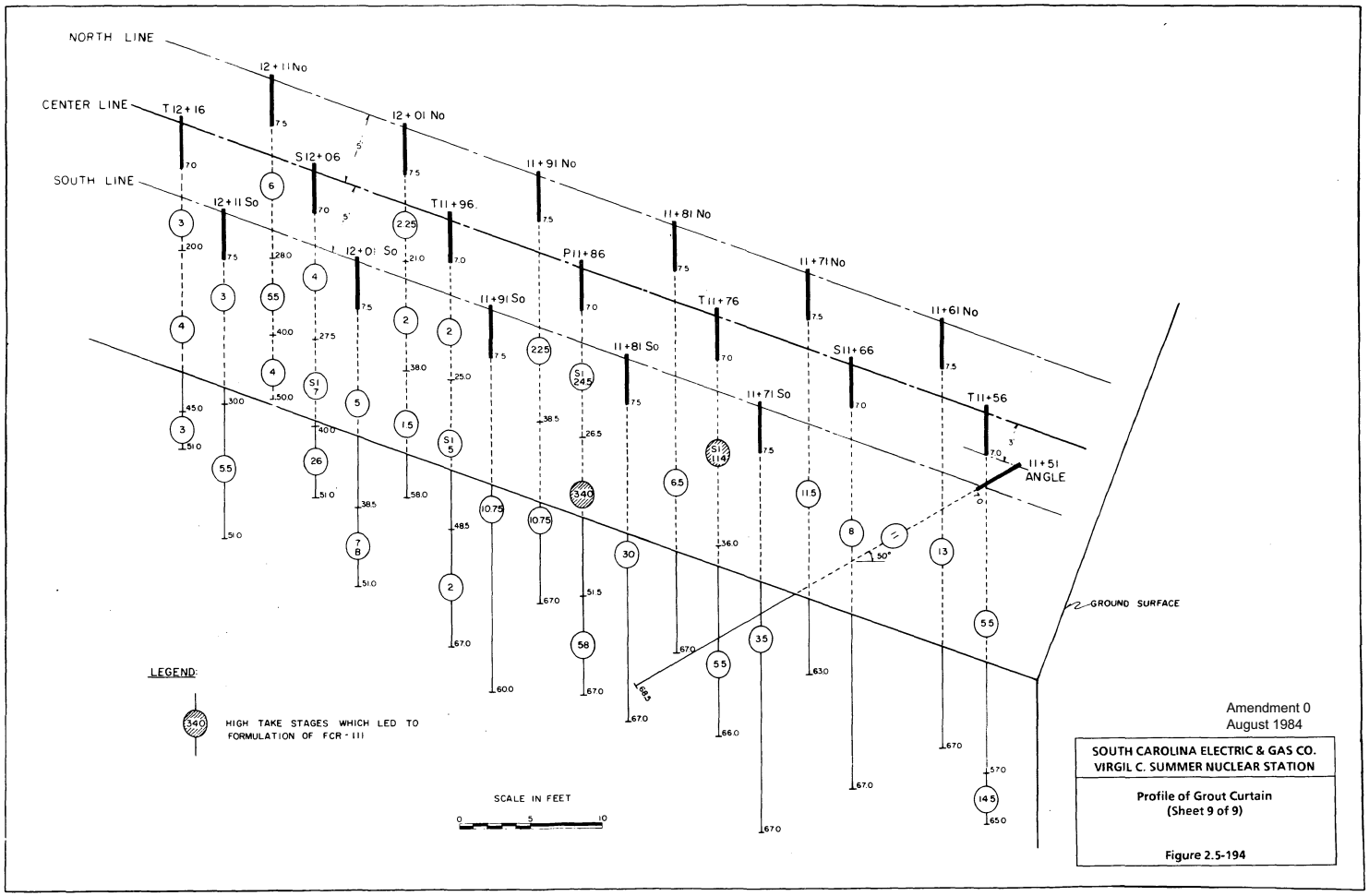
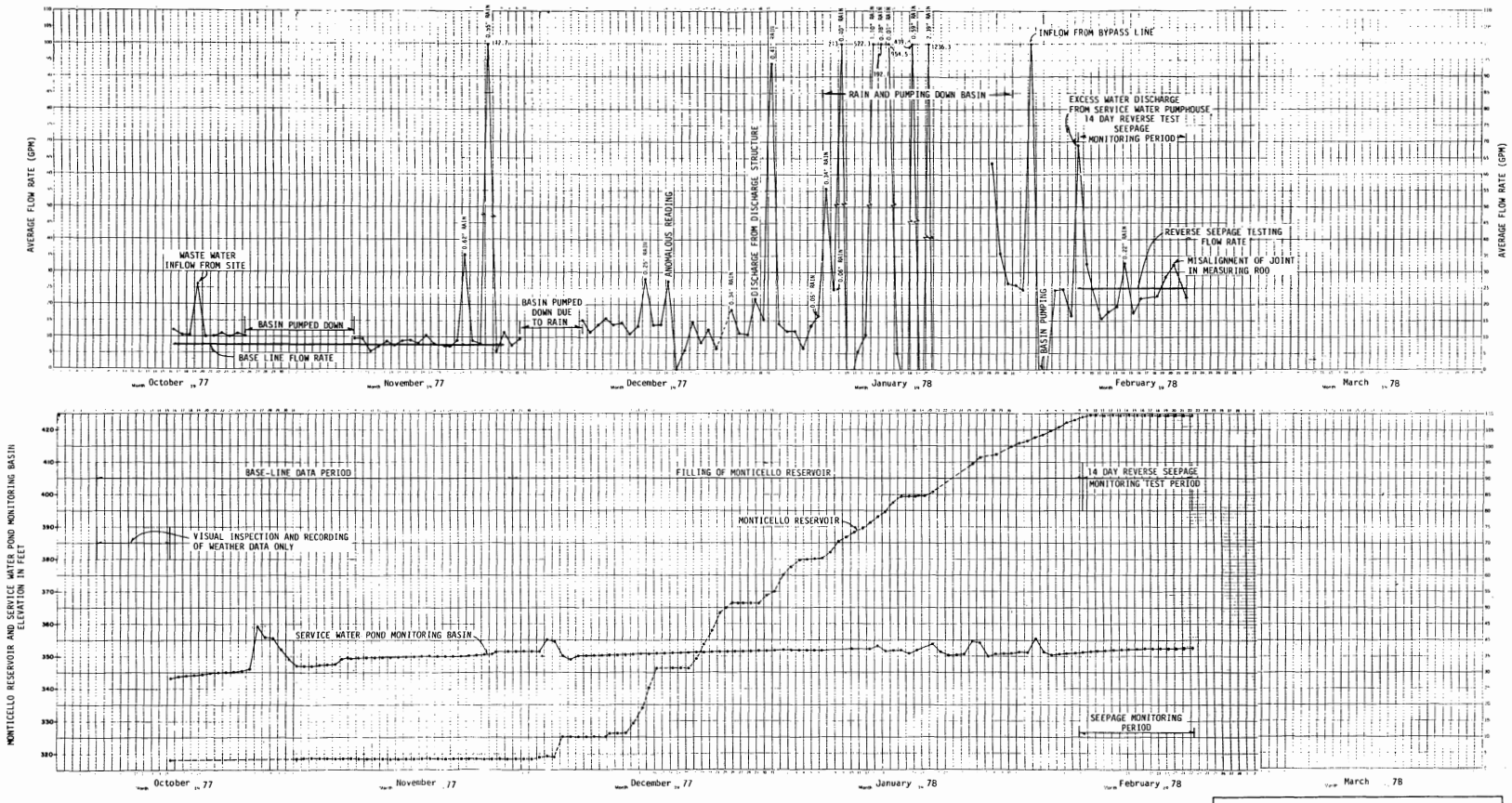


Figure 2.5-194a

REVERSE SEEPAGE TESTING FLOW RATES



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

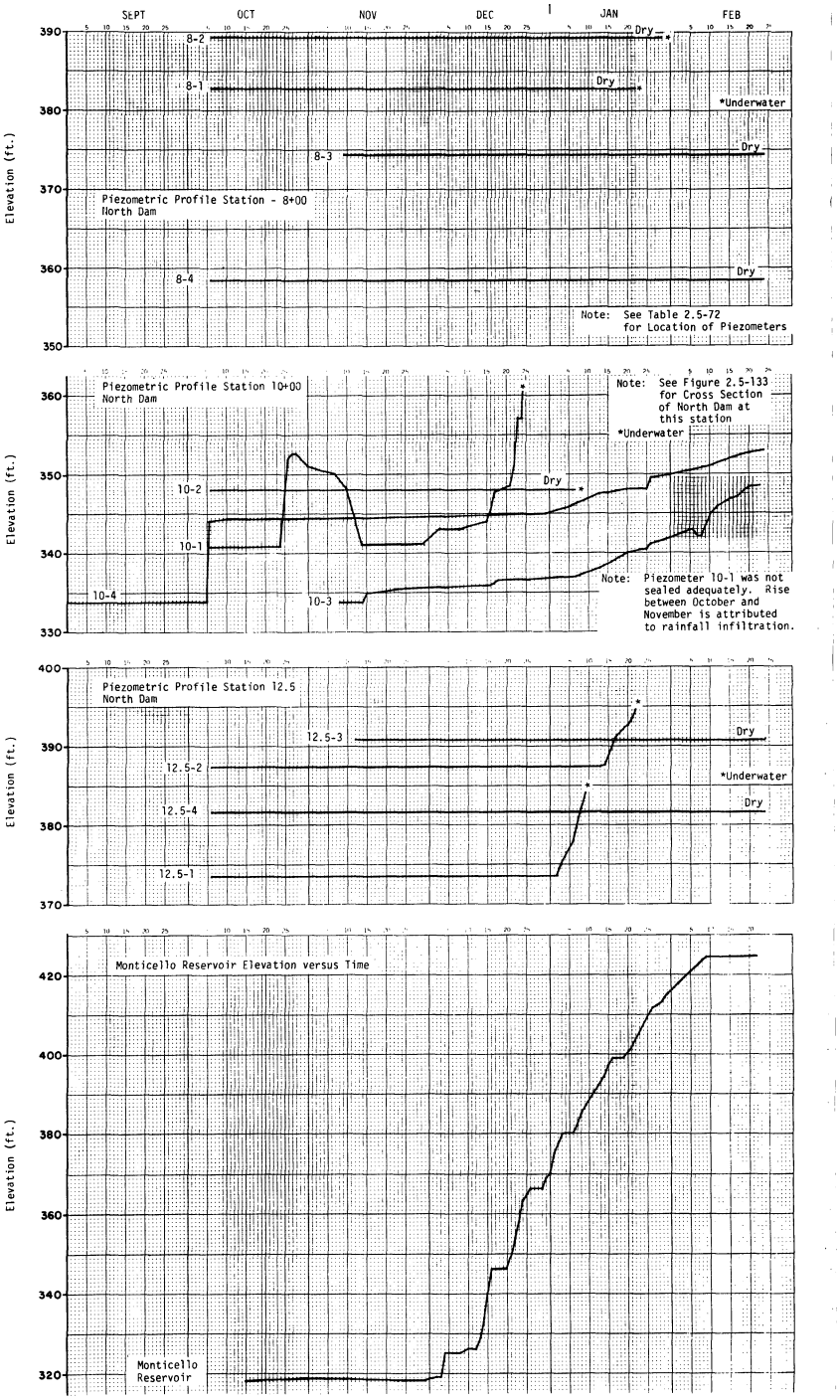
Reverse Seepage Testing
Flow Rates

Figure 2.5-194a

Amendment 0
August 1984

Figure 2.5-194b

PIEZOMETRIC LEVELS DURING REVERSE SEEPAGE TESTING



Amendment 0
August 1984

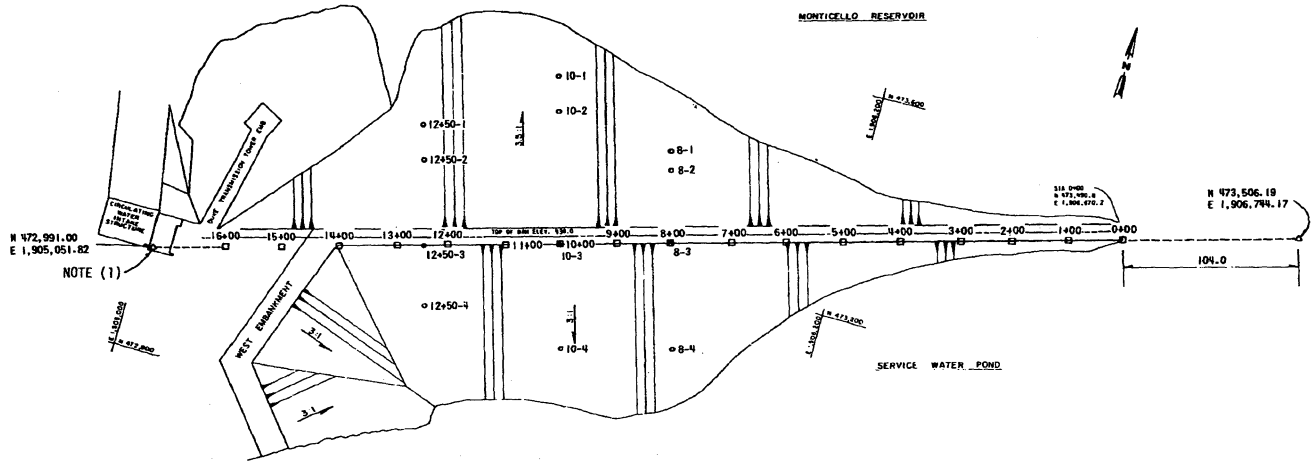
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Piezometric Levels During Reverse Seepage Testing

Figure 2.5-194b

Figure 2.5-195

INSTRUMENTATION LOCATION PLAN FOR NORTH DAM



NOTE (1) Reference point is located on Circulation Water Intake Structure which is founded on rock

(2) Monument 16+00 removed due to construction of guard tower

LEGEND:

- ○ PIEZOMETER
- □ ELEVATION AND ALIGNMENT MONUMENT
- △ REFERENCE ALIGNMENT MONUMENT

Amendment 98-01
April 1998

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

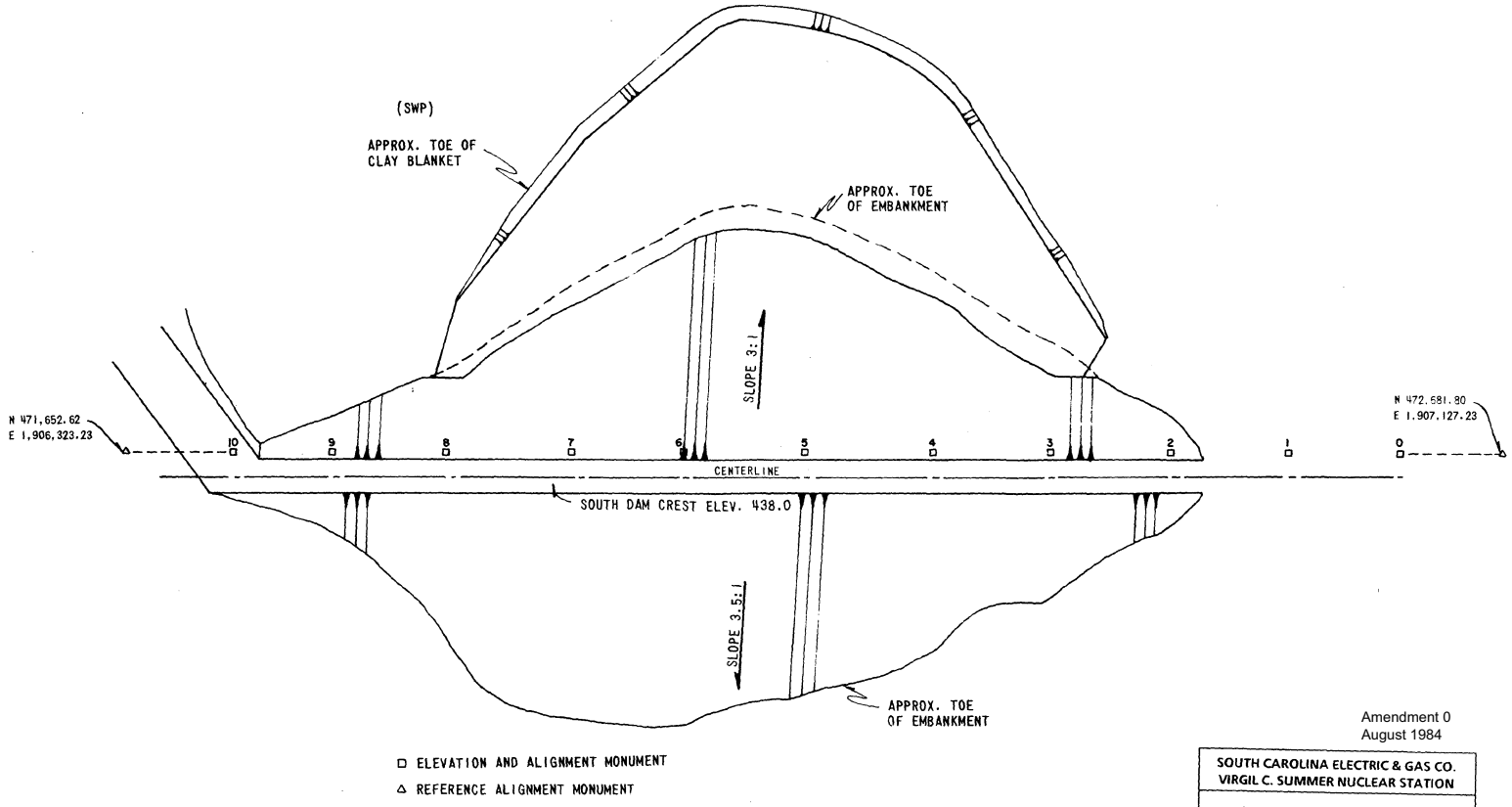
Instrumentation Location Plan
for North Dam

Rev. 1
Figure 2.5-195

Amendment 98-01
April 1998

Figure 2.5-195a

INSTRUMENTATION LOCATION PLAN FOR SOUTH DAM

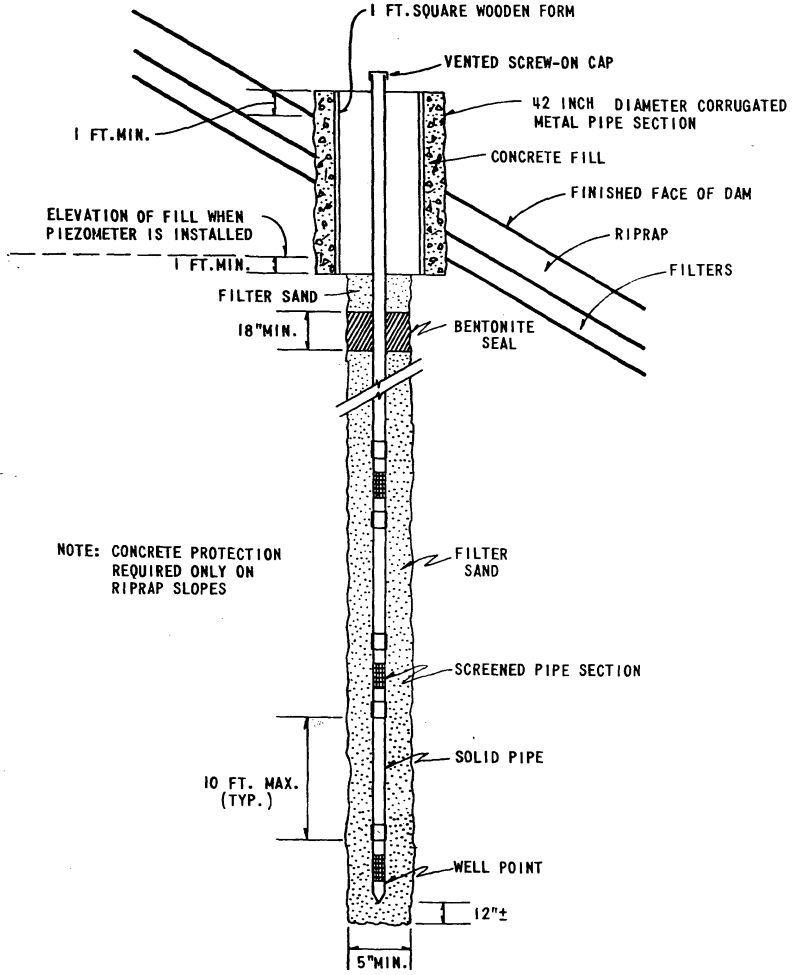


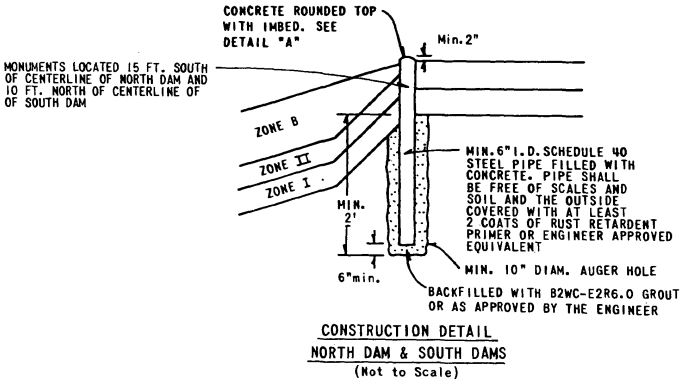
Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Instrumentation Location Plan for South Dam
Figure 2.5-195a

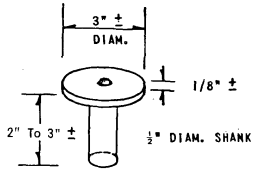
Figure 2.5-196

INSTRUMENTATION DETAILS





CONSTRUCTION DETAIL
NORTH DAM & SOUTH DAMS
(Not to Scale)



EMBED & SEAL ROD INTO MONUMENT

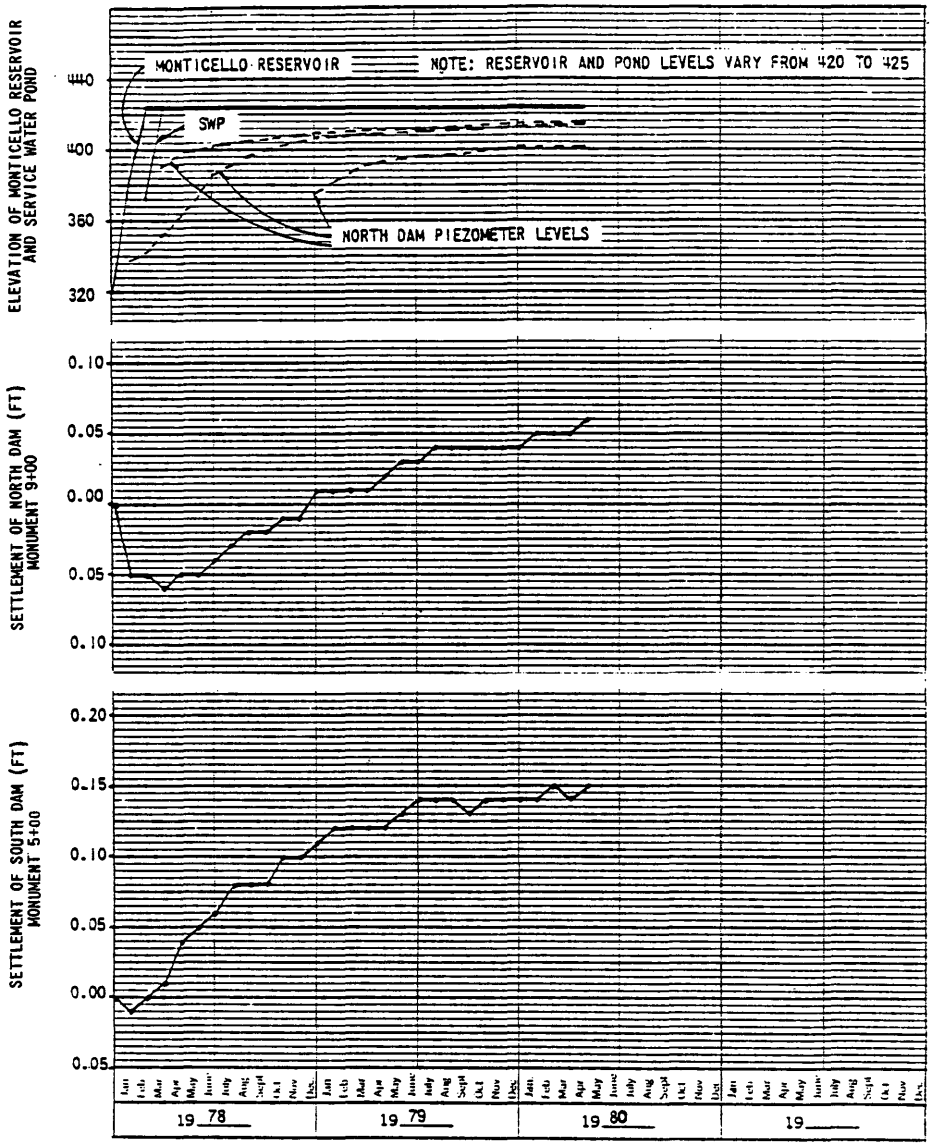
DETAIL A
(Not to Scale)

Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Instrumentation Details
Figure 2.5-196

Figure 2.5-196a

POST-CONSTRUCTION CREST SETTLEMENT
- MAXIMUM CROSS SECTION -
NORTH AND SOUTH DAMS

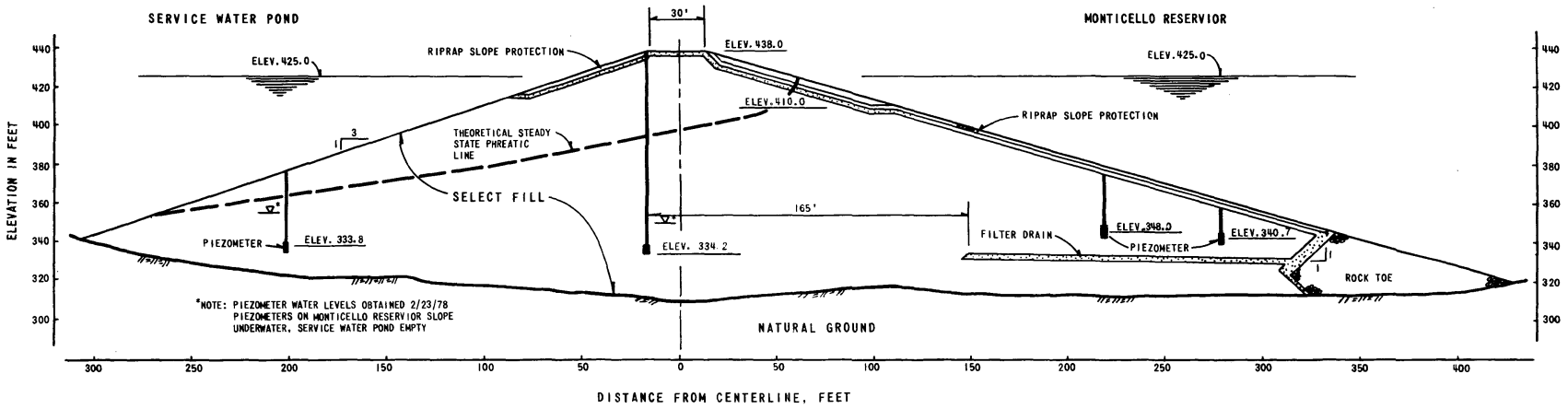


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Post-Contruction Crest Settlement - Maximum Cross Section - North and South Dams Figure 2.5-196a

Amendment 0
August 1984

Figure 2.5-197

TYPICAL CROSS SECTION FOR PIEZOMETER LOCATIONS STATION 10 + 00

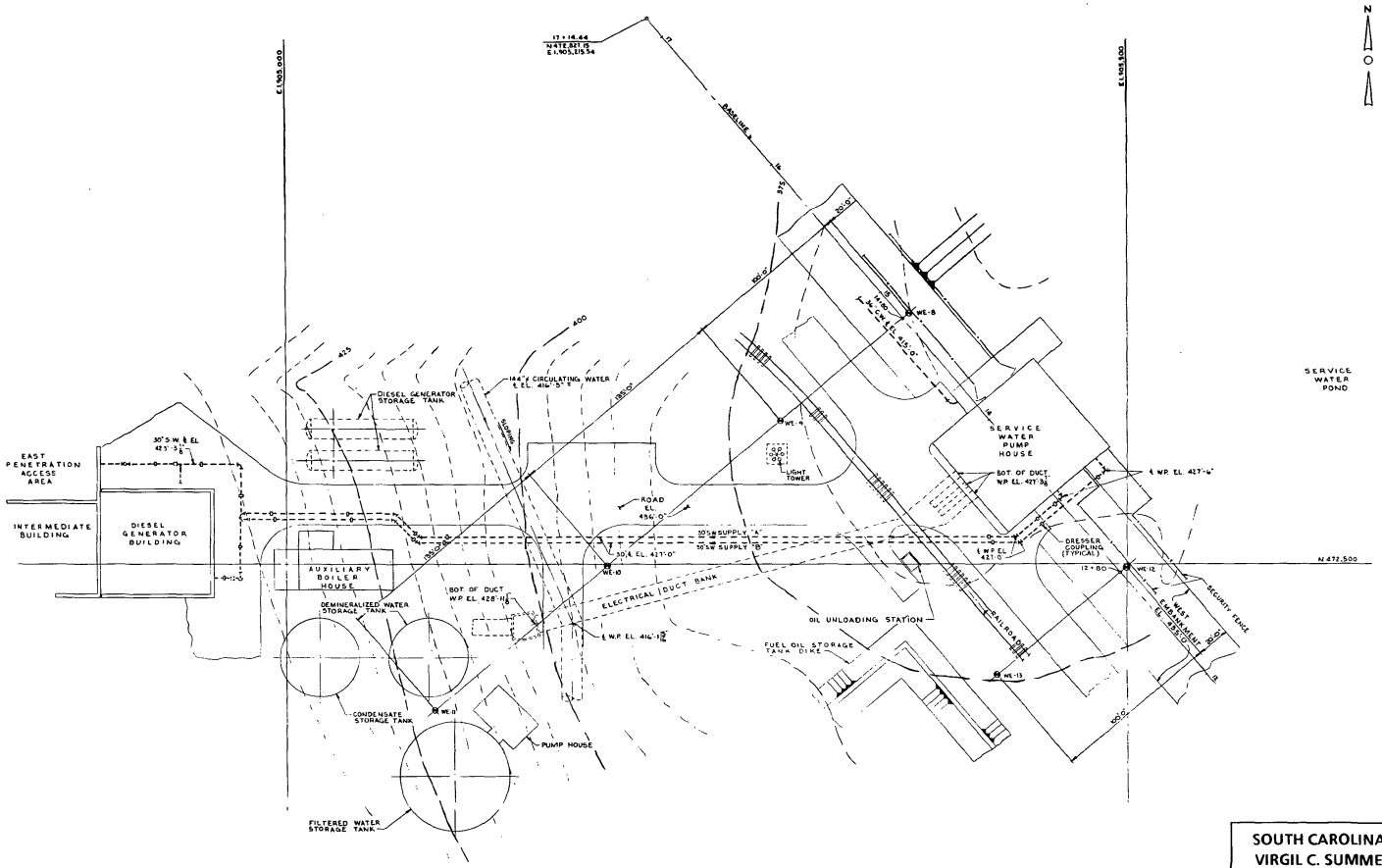


Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Cross Section for Piezometer Locations Station 10 + 00
Figure 2.5-197

Figure 2.5-197a

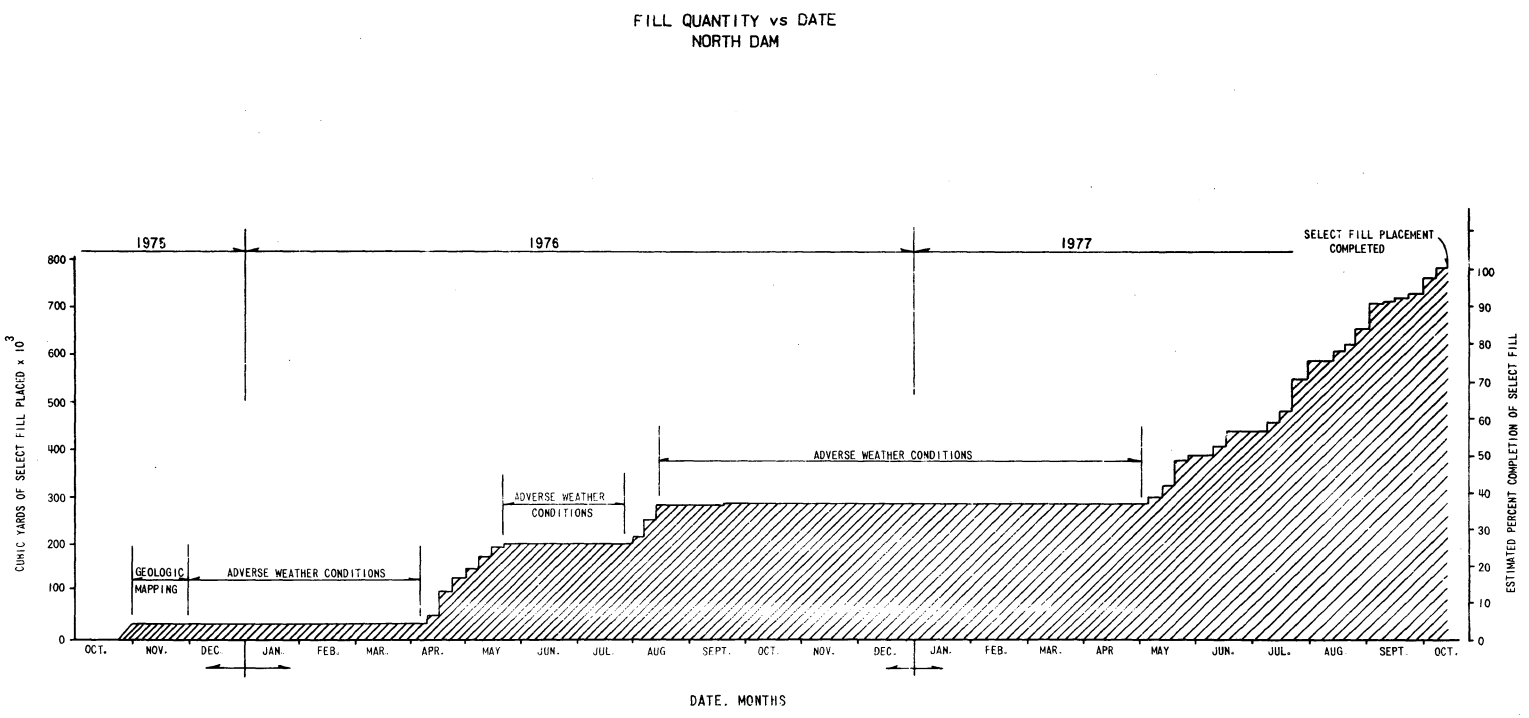
PIEZOMETER LOCATIONS IN VICINITY OF THE SERVICE WATER PUMPHOUSE



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Piezometer Locations in Vicintity of the Service Water Pumphouse
Figure 2.5-197a

Figure 2.5-198
FILL QUANTITY VS. DATE
(SHEET 1 OF 4)



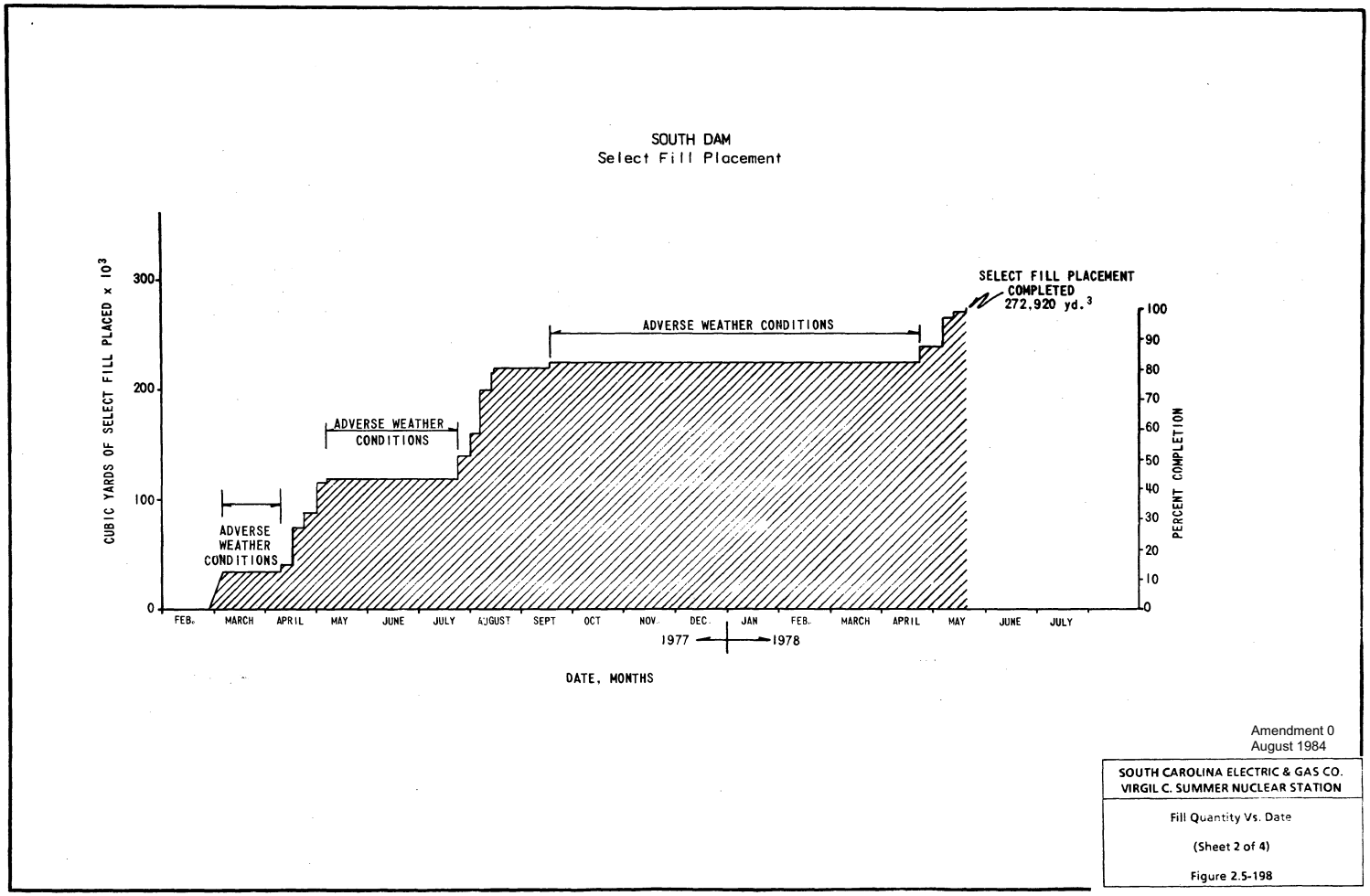
Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Fill Quantity Vs. Date
(Sheet 1 of 4)
Figure 2.5-198

Figure 2.5-198

FILL QUANTITY VS. DATE

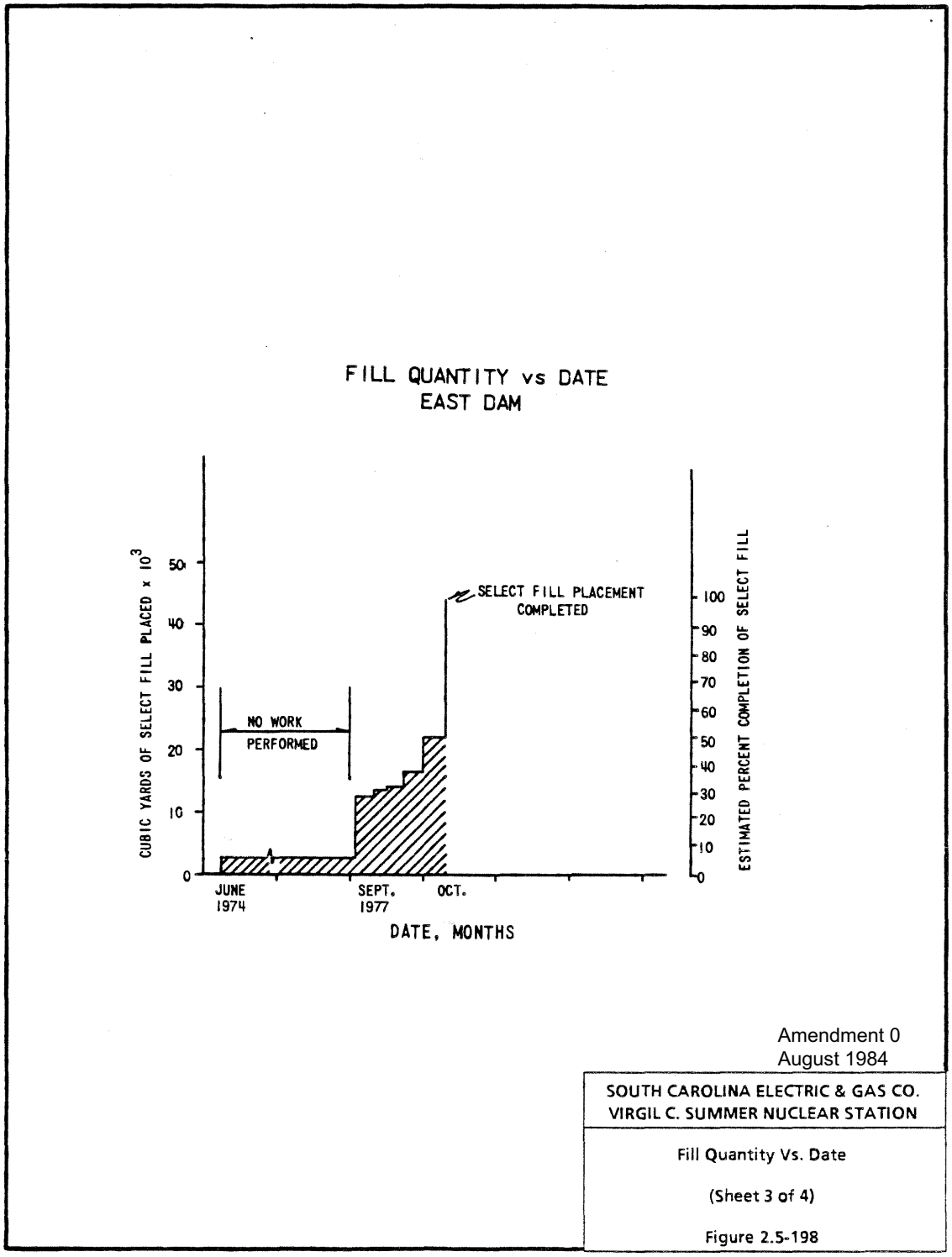
(SHEET 2 OF 4)



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Fill Quantity Vs. Date
(Sheet 2 of 4)
Figure 2.5-198

Figure 2.5-198
FILL QUANTITY VS. DATE
(SHEET 3 OF 4)



Amendment 0
August 1984

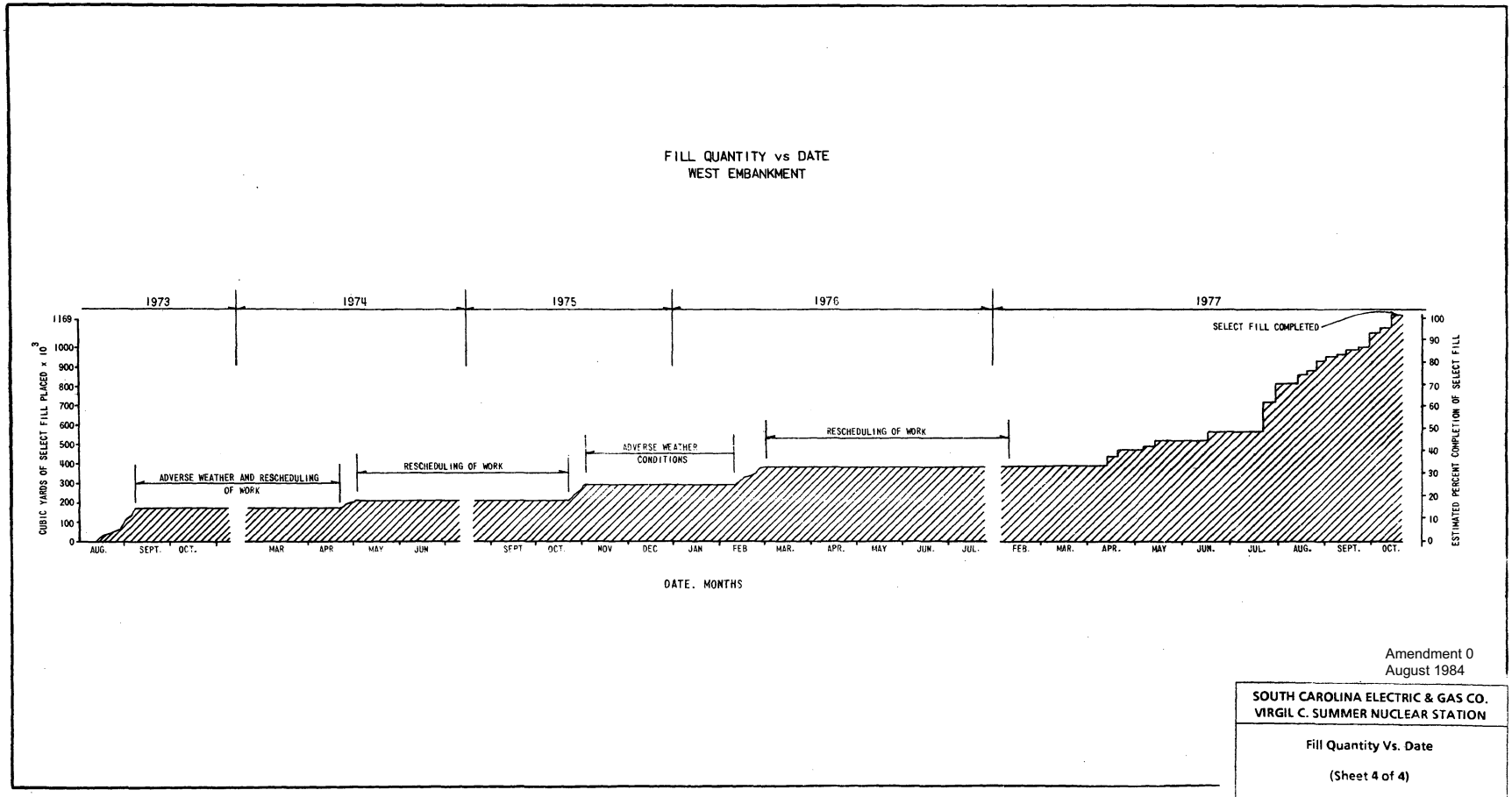
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Fill Quantity Vs. Date

(Sheet 3 of 4)

Figure 2.5-198

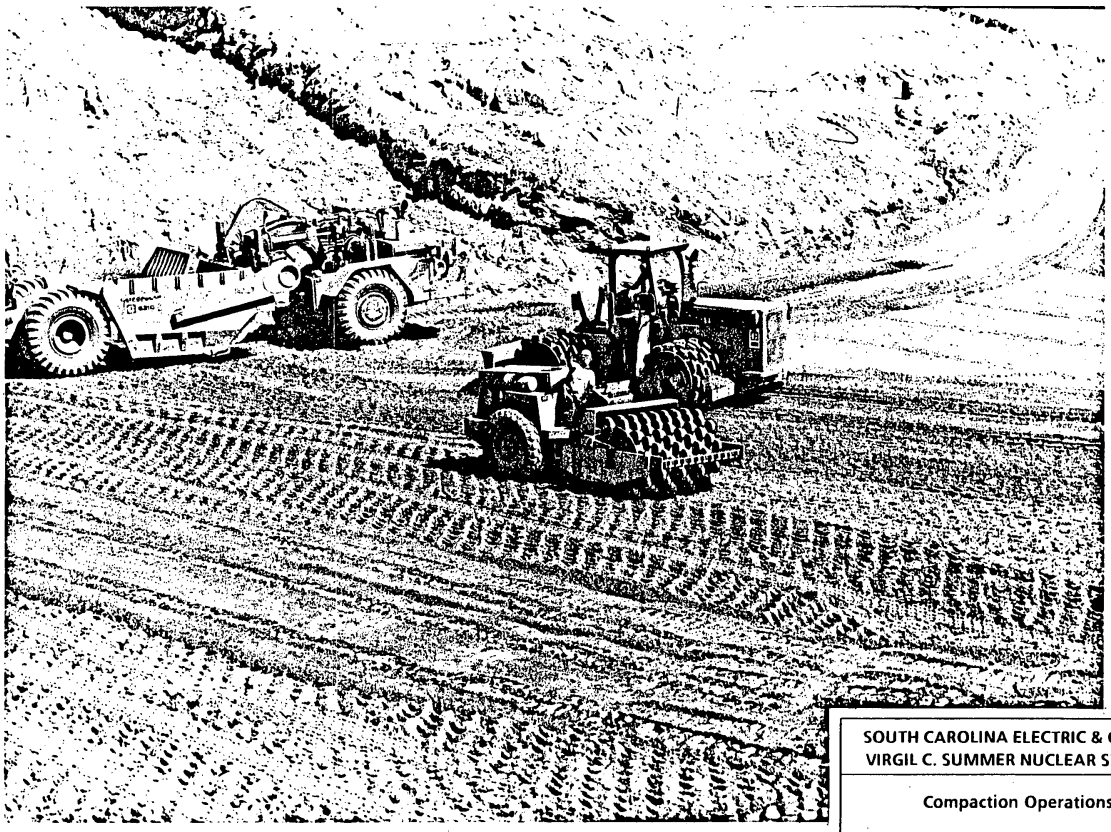
Figure 2.5-198
FILL QUANTITY VS. DATE
(SHEET 4 OF 4)



Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Fill Quantity Vs. Date
(Sheet 4 of 4)
Figure 2.5-198

Figure 2.5-199
COMPACTION OPERATIONS



SOUTH CAROLINA ELECTRIC & GA
VIRGIL C. SUMMER NUCLEAR STA
Compaction Operations
Figure 2.5-199

Amendment 0
August 1984

Appendix 2A
X-RAY DIFFRACTION ANALYSIS

X-RAY DIFFRACTION ANALYSIS

Paul C. Ragland
University of North Carolina

RESULTS

Sample No. 1:

Crystal concentrate collected from drusy lining of vug.

Result: Laumontite (a zeolite).

Sample No. 1-B:

Siliceous lining and fill material from same vug.

Result: alpha-quartz; in addition, three very small peaks that probably belong to a small quantity of montmorillonitic clay.

Sample No. 2:

Crystals scraped from thoroughly weathered vug lining.

Result: laumontite.

Sample No. 4:

Black vein deposit, probably wad.

Results: poorly crystallized kaolinite (as indicated by very broad teeth); alpha-quartz; one small peak in the region of the strongest feldspar piece; amorphous material, which is probably an iron-magnesium oxide (presence of amorphous material is indicated by very high background).

Sample No. 5:

White clay ridge vein deposit.

Results: moderately well crystallized kaolinite; minor alpha-quartz.

PROCEDURES

1. Crush each sample for 10 minutes in SPEX mixer mill.
2. Grind each sample for 10 minutes in a Fischer automatic mortar and pestle.
3. Scan each sample from 2 degrees to 50 degrees to theta on a Phillips X-ray difractometer at the following settings: Copper tube nickel filter, 35 kv, 19 milliamps: PAD: Window 15 volts, base level 3 volts, Scintillation counter at 900 volts; Scan speed: one degree a minute; time constant: 2; Rate meter: either 1 x 103 or 2 x 103 full scale.
4. Each sample was run in duplicate to verify all peak positions.
5. Identifications were made by referring to the standard ASTM powder diffraction data file and to the verification references given above. Positive identification of at least 10 peaks was considered necessary for definite mineral identification.2A

Verification References

Laumontite:

Bartl, H. and Fischer, K. F., 1967, Unterschung der Kristallsturktur des Zeilithes Laumontit: Nus, Jarb. Mineral. Monatshefte, pp. 33-42.

Alpha-Quartz:

Zachariasen, W. H., Tlettineger, H. A., 1965, Extension in Quartz: Acta Cryst., Vol. 18, pp. 710-714.

Kaolinite:

Drits, V. A., and Kashaez, A. A., 1960, an X-ray Study of a Single Crystal of Kaolinite: Soviet Physics - Crystaliography, Vol. 5, No. 2, pp. 207-210.

Appendix 2B

APPENDIX B RADIOMETRIC ANALYSIS, RUBIDIUM-STRONTIUM AGE DETERMINATION

RADIOMETRIC ANALYSIS, RUBIDIUM-STRONTIUM AGE DETERMINATION

Paul D. Fullagar
University of North Carolina

Method

Samples were analyzed to determine rubidium-strontium (Rb-Sr) radiometric ages using standard methods of sample preparation and analytical procedures. Naturally-occurring Rb and Sr are composed of the following isotopes:

Rb	Sr
Rb^{85}	Sr^{84}
Rb^{87}	Sr^{86}
	Sr^{87}
	Sr^{88}

Rb^{87} decays to Sr^{87} at a fixed and known rate. This Sr^{87} is called radiogenic Sr. The time (age) since crystallization or metamorphism of a mineral or rock can be determined by measuring the present concentrations of Rb^{87} and Sr^{87} and calculating or estimating the amounts of these isotopes initially present in the mineral.

The following equation is used for the age calculations:

$$(Sr^{87}/Sr^{86})N = (Sr^{87}/Sr^{86})0 + Rb^{87}/Sr^{86}\ (e^{\lambda t} - 1)$$

Where

$(Sr^{87}/Sr^{86})_N$ is the measured isotopic ratio,

$(Sr^{87}/Sr^{86})_O$ is the ratio at the time of crystallization (initial ratio) and is estimated for model ages or calculated when multiple samples are analyzed from the same rock unit (the age that results is called an isochron age),

Rb^{87}/Sr^{86} is measured,

e is the natural logarithm,

λ (lambda) is the Rb^{87} decay constant (1.39×10^{-11}/year) and
t is time or the age of the system.

An age is obtained by solving the equation for t. Each quantity in the age equation is expressed as a ratio to Sr^{86} since this is the form in which data is obtained from a mass spectrometer.

An age for a sample of igneous or metamorphic rock is normally interpreted as indicating the time of crystallization or formation of the rock. Biotite separated from the rock normally gives a minimum age because the radiometric clock for biotites is not set until the temperature of the mineral drops below approximately 200°C.

The isotopic and concentration analyses were made with a thermal ionization source mass spectrometer in the geochronology laboratories at the Geology Department of the University of North Carolina, Chapel Hill.

Sample Preparation

All samples were washed with distilled water to remove extraneous matter. A chip was cut from each sample and analyzed by X-ray fluorescence to obtain approximate Rb/Sr ratios. These ratios were used to

1. Select samples suitable for age determinations
2. Establish proper weight of sample to be dissolved for mass spectrometric analysis
3. Determine amount of Sr^{84} and Rb^{87} spike to be added to each sample for the purpose of measuring Sr and Rb concentrations.

Based on the approximate Rb/Sr ratio, sample NK 2.3 was not analyzed. The Rb/Sr ratio of about 0.4 was too low to permit calculation of a model age as an insignificant amount of radiogenic Sr would have accumulated in the rock. In general, Rb/Sr ratios must be at least 1.0 in order to calculate a meaningful model age.

Samples for age determinations were crushed in a jaw crusher and a split of the total or whole rock sample was taken for samples SC 2.2, SC 2.4 and NK 2.1. These whole rock samples were then processed for mass spectrometric analysis. The remaining rock samples were crushed further in a disk mill and sieved. The 20 to 40 mesh or 40 to 60 mesh fraction was passed through a magnetic separator to obtain a biotite (or biotite-chlorite) concentrate. With repeated pass-throughs, mineral separates of 98+% purity were obtained for all samples except NK 2.2 and SD 3.2; these samples are estimated to be 95% biotite-chlorite. A heavy liquid (methylene iodide) was used to help clean up the separate from NK 2.2. The impurities in the mineral separates are grains of feldspar and quartz. Their presence almost certainly has no effect on the ages obtained.

Spikes of Sr^{84} and Rb^{87} were added to each sample; the samples then were dissolved with hydrofluoric and sulfuric acids. Solutions were passed through cation exchange columns to concentrate Rb and Sr. The next step was analysis of the samples in the mass spectrometer.

Calculations

Model Ages. Model ages are obtained by using the previously given age equation and assuming a value for $(Sr^{87}/Sr^{86})_O$. The assumed value for these model age calculations is

0.7050. This value is the average of the values calculated (see below) for SC 2.4 (0.7045) and NK 2.1 (0.7055); since these samples are very similar to the other samples analyzed it is reasonable to use 0.705 except where noted under Results. Following is an example of model age calculation:

SC 2.1 Biotite

$$(Sr^{87}/Sr^{86})N = (Sr^{87}/Sr^{86})O + Rb^{87}/Sr^{86}\,(e^{\lambda t} - 1)$$

$$0.8617 = 0.7050 + 38.18 \quad \left(e^{(1.39 \times 10^{-11}/\text{year})t} - 1\right)$$

t = 295 ± 15 million years (m.y.)

The age uncertainty (± 15 m.y.) is an estimate based on our analytical precision.

Isochron Ages, There are two unknowns in the age equation, $(Sr^{87}/Sr^{86})_O$ and t. By analyzing two (or more) samples from the same rock unit it is possible to solve for both unknowns as they will be the same for each sample. This solving of simultaneous equations is tedious if done by hand and we use a standard computer program that is used by virtually all geochronology laboratories. This program was used for the two SC 2.4 samples and the two NK 2.1 samples.

Results

Location SC. Two biotites from unweathered samples (SC 2.1 Biotite, SC 2.3 Biotite) have model ages of 295 ±15 m.y. and 315 ± m.y., respectively (see data table). A biotite-chlorite sample and whole rock sample of hydrothermally altered SC 2.4 yield an isochron age of 299 ± 10 m.y. The close agreement between the ages of the unweathered and altered samples suggests one of two possibilities:

1. The alteration occurred about 300 m.y. ago, or
2. The alteration occurred more recently but did not affect the Rb-Sr chemistry and isotopic composition of the sample.

If petrographic study indicates a significant alteration and recrystallization, the alteration probably occurred about 300 m.y. ago. Whole rock sample SC 2.2, a microbreccia from a shear zone, has a model age of 345 + 70 m.y. The large error reflects the low radiogenic Sr content, or low $(Sr^{87}/Sr^{86})_N$ ratio for the sample. The ratio is 0.7164 which is quite closed to the assumed initial ratio of 0.7050. A small error in the $(Sr^{87}/Sr^{86})_N$ ratio produces a relatively large error in the age. The initial ratio could be greater than 0.7050 as a thermal or recrystallization event more recent than 345 m.y ago would be expected to raise the initial ratio; thus, the 345 m.y age for the microbreccia should be considered a maximum age.

Location SD. SD 3.3 Biotite is unweathered and has a 314 ± 15 m.y. age. Slightly altered biotite from weathered granodiorite (SD 3.1 Biotite) has an identical age of 317 ± 15 m.y. Thus, the degree of alteration exhibited by SD 3.1 Biotite was not sufficient to change the Rb- Sr age of biotite from this location. SD 3.2 Biotite-Chlorite has a model age of 358 ± 40

m.y. This age is probably best interpreted as a maximum age as the initial ratio could be higher that 0.705.

Location NJ. Biotite from unweathered granodiorite (NJ 1.1 Biotite) has a model age of 299 ± 15 m.y. which is essentially identical to the ages for the other unaltered samples (locations SC, SD and NK). These ages are best interpreted as minimum ages for the formation of the granodiorite.

Location NK. Samples of whole rock and biotite from unweathered granodiorite (NK 2.1 and NK 2.1 Biotite) have an isochron age of 292 ± 10 m.y. NK 2.2 Biotite-Chlorite has a model age of 521 ± 70 m.y. Again, because of the low $(Sr^{87}/SR^{86})_N$ ratio the error is large. Because the sample is altered, there is no assurance that the initial ratio is 0.7050; indeed, the fact that this model age is much greater than any age for unaltered samples indicates that this should be regarded as a maximum age.

Qualifications of Investigators

The analyses were performed by Dr. Paul D. Fullagar with the assistance of Dr. Michael L. Bottino. We each have over ten years experience in Rb-Sr geochronology. During this time we have authored or co-authored about 20 papers on geochronology which have been published in major scientific journals. In addition we have each presented over 20 geochronology papers at national and international meetings. All of our geochronology research has received financial support from the National Science Foundation. Virtually all of Fullagar's research for the last seven years has involved geochronology problems in the southeastern United States.

The laboratories in which the analyses were done are in the Geology Department at the University of North Carolina, Chapel Hill. These facilities were developed by and are supervised by Dr. Fullagar. The laboratories have been full operation for over three years, and during this time 600 rock and mineral samples have been analyzed to determine Rb-Sr ages.

ANALYTICAL DATA

SAMPLE	Sr^{86}/Sr^{88}	$(Sr^{87}/Sr^{86})N$	Rb ppm	Sr ppm	Rb/Sr	$Rb^{87}Sr^{86}$	Age, m.y
SC 2.1 Biotite	0.11960	0.8617	483.1	37.19	12.99	38.18	295 + 15*
SC 2.2	0.11977	0.7164	133.5	163.1	0.818	2.37	345 ± 70*
SC 2.3 Biotite	0.11961	0.8502	518.0	45.96	11.27	33.08	315 ± 15*
SC 2.4	0.11995	0.7079	89.39	316.3	0.283	0.818	299 ± 10
SC 2.4 Biotite-Chlorite	0.11928	0.7509	161.2	42.02	3.84	11.15	299 ± 10
SD 3.1 Biotite	0.11949	0.8457	450.8	41.49	10.86	31.88	317 ± 15*
SD 3.2 Biotite-Chlorite	0.11984	0.7254	94.12	66.67	1.41	4.09	358 ± 40*
SD 3.3 Biotite	0.11940	0.8691	502.8	39.41	12.76	37.52	314 ± 15*
NJ 1.1 Biotite	0.11963	0.9644	507.7	24.21	20.97	62.24	299 ± 15*
NK 2.1	0.12027	0.7088	108.2	388.4	0.279	0.807	292 ± 10
NK 2.1 Biotite	0.11978	1.3093	540.6	11.16	48.42	148.5	292 ± 10
NK 2.2 Biotite-Chlorite	0.11996	0.7218	73.24	91.91	0.797	2.31	521 ± 70*

* Model age, $(Sr^{87}/Sr^{86})_0$ assumed = 0.7050

Rb^{87} decay constant = 1.39×10^{-11}/year

Appendix 2C
RADIOMETRIC ANALYSIS, POTASSIUM-ARGON AGE DETERMINATION

(Insert Teledyne Isotopes pages)

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Isotopes Sample #	Your Sample #	Isotopic Age (m.y.)	scc $Ar^{40\ Rad}/gm\ x10^{-5}$	% Ar^{40} Rad	% K
KA73-390	SC 2.3		8.48	91	6.78
Biotite			8.56	91	6.88
		288±14	8.52		6.83
KA73-391	SD 3.1		6.97	79	6.37
			6.91	80	5.85
		264±16	6.94		6.11
KA73-392	SD 3.2		1.33	61	1.25
			1.36	65	1.18
		256±15	1.34		1.22
KA73-393	SD 3.3		7.87	87	6.13
Biotite			7.95	87	6.15
		297±18	7.91		6.14
KA73-394	NJ 1.1		9.07	94	7.26
Biotite			9.10	94	7.23
		290±17	9.09		7.25
KA73-395	NK 2.1		9.46	79	7.54
Biotite			9.53	79	7.50
		292±17	9.50		7.52

02-01

The constants used for the age calculations are: $\lambda_\beta = 4.72 \times 10^{-10}\ yr^{-1}$ λ_e = 0.585 x 10^{-10} yr^{-1} and K^{40} = 1.19 x 10^{-4} atom percent of natural potassium.

02-01

The error indicated for the reported ages consists of a summation of all analytical errors. Through past experience these errors generally amount to 1-3 percent. Therefore, we have selected the upper limit of our analytical error (3 percent) and use this number in calculating the analytical error in the isotopic ages for samples with sufficient radiogenic argon. As the volume of radiogenic argon or the potassium content decreases to 10^{-8} scc and less than 0.1% respectively, the size of the analytical error naturally increases. This is due to the inherent limitation of the instrumentation. In these cases errors are calculated in a manner similar to that of Cox and Dalrmple (J. Geophys. Res 72 (10) p. 2603-14).

02-01

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If you have any questions concerning these results or I can be of any further assistance to you, please do not hesitate to contact me. We look forward to being of continued service to you.

Very truly yours,

Todd M. Gates

TMG:11

Reformatted Per
Amendment 02-01

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TELEDYNE ISOTOPES

WESTWOOD LABORATORIES
50 VAN BUREN AVENUE
WESTWOOD, NEW JERSEY 07675
(201) 664-7070 TELESX 134475

10 January 1974

Mr. William Smith
Dames & Moore
Suite 200
455 East Paces Ferry Road
Atlanta, Georgia 30305

Dear Mr. Smith:

Subject: W. O. No. 3-9308-212

We have completed the analysis of your sample submitted for K/Ar age determination. The results are as follows:

Isotopes Sample #	Your Sample #	Isotopic Age (m.y.)	scc $Ar^{40\ Rad}/gm \times 10^{-5}$	% Ar^{40} Rad	% K
KA74-108	X-1		0.064	27	0.33
			0.059	25	0.34
		45±5	0.062		0.34
KA74-109	SH4		1.09	87	1.85
			1.11	88	1.89
		141±8	1.10		1.87
KA74-110	-		8.09	90	6.50
			8.14	90	6.50
		289±17	8.12		6.50

02-01

The constants used for the age calculations are $\lambda_\beta = 4.72 \times 10^{-10}\ yr^{-1}$ $\lambda_e = 0.585 \times 10^{-10}\ yr^{-1}$ and $K^{40} = 1.19 \times 10^{-4}$ atom percent of natural potassium.

02-01

The error indicated for the reported ages consists of a summation of all analytical errors. Through past experience these errors generally amount to 1-3 percent. Therefore, we have selected the upper limit of our analytical error (3 percent) and use this number in calculating the analytical error in the isotopic ages for samples with sufficient radiogenic argon. As the volume of radiogenic argon or the potassium content decreases to 10^{-8} scc and less than 0.1% respectively, the size of the analytical error naturally increases. This is due to the inherent limitation of the instrumentation. In these cases errors are calculated in a manner similar to that of Cox and Dalrymple (J.Geophys. Res 72 (10) p. 2603-14).

If you have any questions concerning these results or I can be of any further assistance to you, please do not hesitate to contact me. We look forward to being of continued service to you.

02-01

Very truly yours,

TMG:11

Todd M. Gates

Reformatted Per Amendment 02-01

Appendix 2D
IN SITU STRESS MEASUREMENTS BY THE OVERCORING TECHNIQUE

IN SITU STRESS MEASUREMENTS BY THE OVERCORING TECHNIQUE

Dale Stephenson
Dames & Moore

There are several methods available for measuring in situ stresses in rock, many of which are described in ASTM STP 429 Determination of Stress in Rock, A State-Of-the-Art Report, some of which involve the overcoring method. The one used in this investigation of the in situ rock stresses at the Virgil C. Summer Nuclear Station involved overcoring and was done using a borehole deformation gage similar to the one developed by the U. S. Bureau of Mines. A detailed description of the gage and theory involved can be found in reports by Obert (1962) or Merrill (1967). Where the measurements are made near the earth surface in vertical drill holes one stress direction is assumed vertical and due to gravity loading. The other two components of stress (termed secondary principal stresses) can be determined from a single overcoring observation. If three non-parallel holes are drilled and measurements made in them, the complete state of stress in the rock mass can be determined. Only a summary of the theory and method is presented here.

Using elastic theory, the solution of stresses and strains associated with a hole in an infinite plate subjected to a biaxial stress field can be determined. Therefore, if the strain or deformation of the hole in the plate can be measured the biaxial stresses (P',Q') can be calculated. For the condition of plane stress the diametral deformation Uis

$$U = \frac{d}{E}(P'+Q') + 2(P'-Q')\cos 2\theta \qquad (1)$$

and if the plate is in plane strain

$$U = \frac{d(1-\nu^2)}{E}(P'+Q') + 2(P'-Q')\cos 2\theta \qquad (2)$$

where d is the diameter of the hole and E and ν are elastic constants.

If the diametral deformations in three specified directions are measured at a point in a borehole in the rock, P', Q' and θ can be determined assuming the elastic constants are known. If the measurements of diametral deformation (U_1, U_2, U_3) are made at 60-degree intervals (angular deformation rosette) the magnitude and direction of the applied field can be determined from:

$$P' = \frac{E}{6d}\{(U_1+U_2+U_3) + (\sqrt{2}/2)[(U_1-U_2)^2+(U_2-U_3)^2+(U_3-U_1)^2]^{1/2}\} \qquad (3)$$

$$Q' = \frac{E}{6d}\{(U_1+U_2+U_3) - (\sqrt{2}/2)[(U_1-U_2)^2+(U_2-U_3)^2+(U_3-U_1)^2]^{1/2}\} \qquad (4)$$

$$\theta = 1/2\tan^{-1}\frac{\sqrt{3}(U_2-U_3)}{2U_1-U_2-U_3} \qquad (5)$$

where θ is measured from U_1 to P' in a counterclockwise direction. To use this mathematical procedure to determine the absolute stress in the rock an overcoring technique must be used.

The procedure as developed by the U. S. Bureau of Mines and used at the site is to first drill a small diameter (1 1/2 inch) hole into the bottom surface of a 6 inch diameter borehole. The borehole deformation gage is then placed in this hole, oriented to measure one of the deformations in a given direction such as north and an initial strain indicator reading made, S_1 (S_1, S_2, S_3). Next the section of rock is concentrically overcored using the 6 inch diameter diamond bit, thereby stress relieving the section of the rock containing the gage. Strain indicator readings are taken during the overcoring and after the rock core containing the gage as been completely stress relieved (there is no further drop in readings) a final value of readings S_2 (S'_1, S'_2, S'_3) is taken. The difference between the initial and final strain indicator readings can be related by a calibration factor to the deformation of the borehole. This procedure is illustrated in Figure 2D-1 where (a) is the overcoring technique and (b) is the response of the strain indicator.

The modulus of deformation of the rock is calculated using the scope of the pressure/deformation plot by means of the relationship

$$E = \frac{4ab^2}{(b^2 - a^2)} \frac{\Delta P}{U} \qquad (6)$$

where E is the modulus, a is the inner radius of the specimen, b is the outer radius, ΔP is the change in applied pressure, and U is the measured deformation of the inner hole. This is similar to the thick walled cylinder problem and the complete derivation is given in Obert and Duvall (1967).

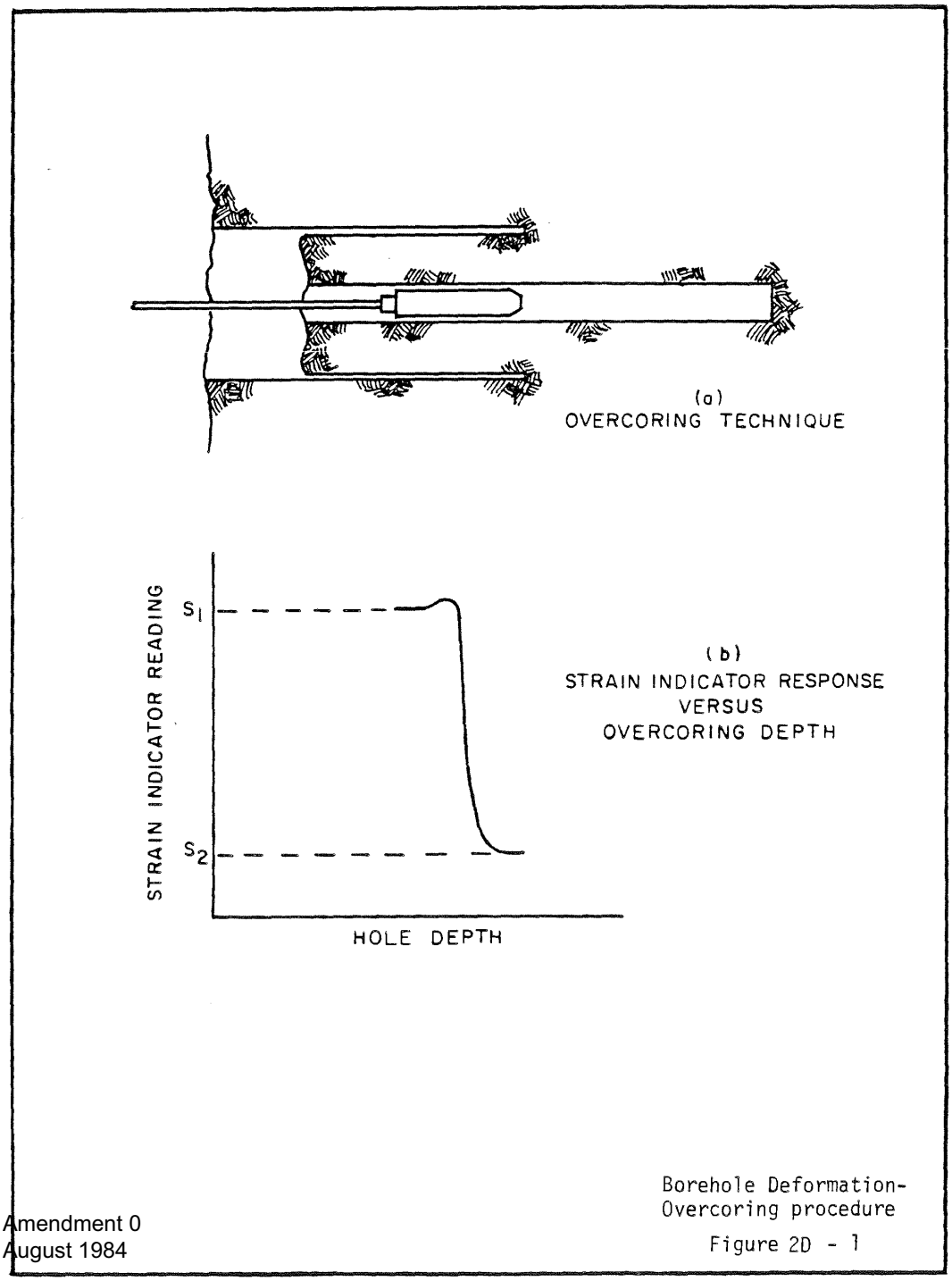
Each laboratory test of the specimen enables three separate directional moduli to be calculated, 60 degrees apart. To provide more data to examine the validity of assuming an isotropic modulus, laboratory tests are repeated with the borehole deformation gage rotated counterclockwise through 30 degrees with respect to field locations. If the rock is anisotropic, this can be taken into consideration in the calculation of the in situ stresses.

The results of the field test showing plots of deformation versus depth are given in Figures 2.D-1 through 2.D-6.

Dale Stephenson

Dames & Moore

Figure 2.D-1
BOREHOLE DEFORMATION
OVERCORING PROCEDURE



Borehole Deformation-
Overcoring procedure
Figure 2D - 1

Amendment 0
August 1984

Figure 2.D-2
IN SITU STRESS TEST
BORING OC - 1 TEST 2

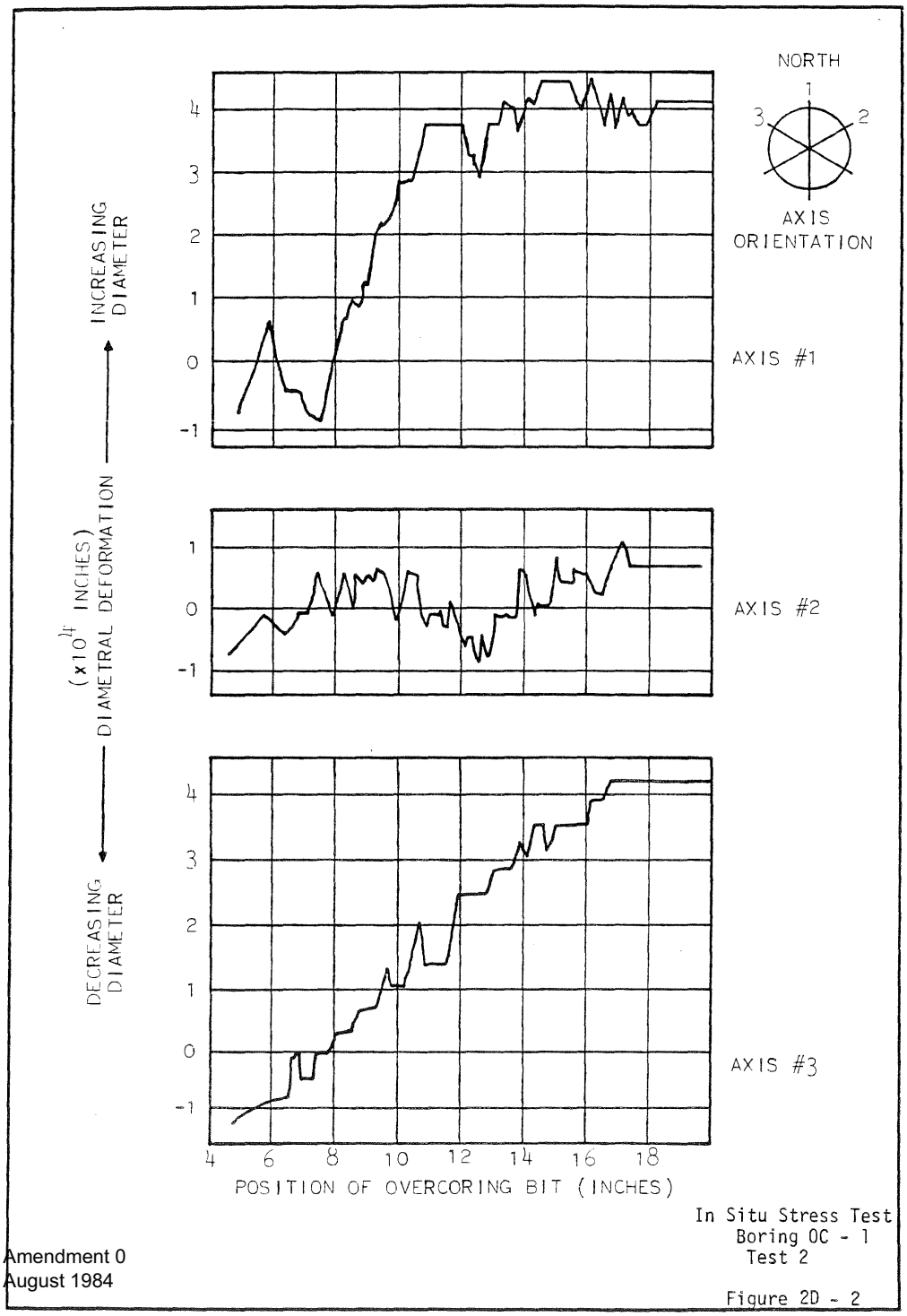


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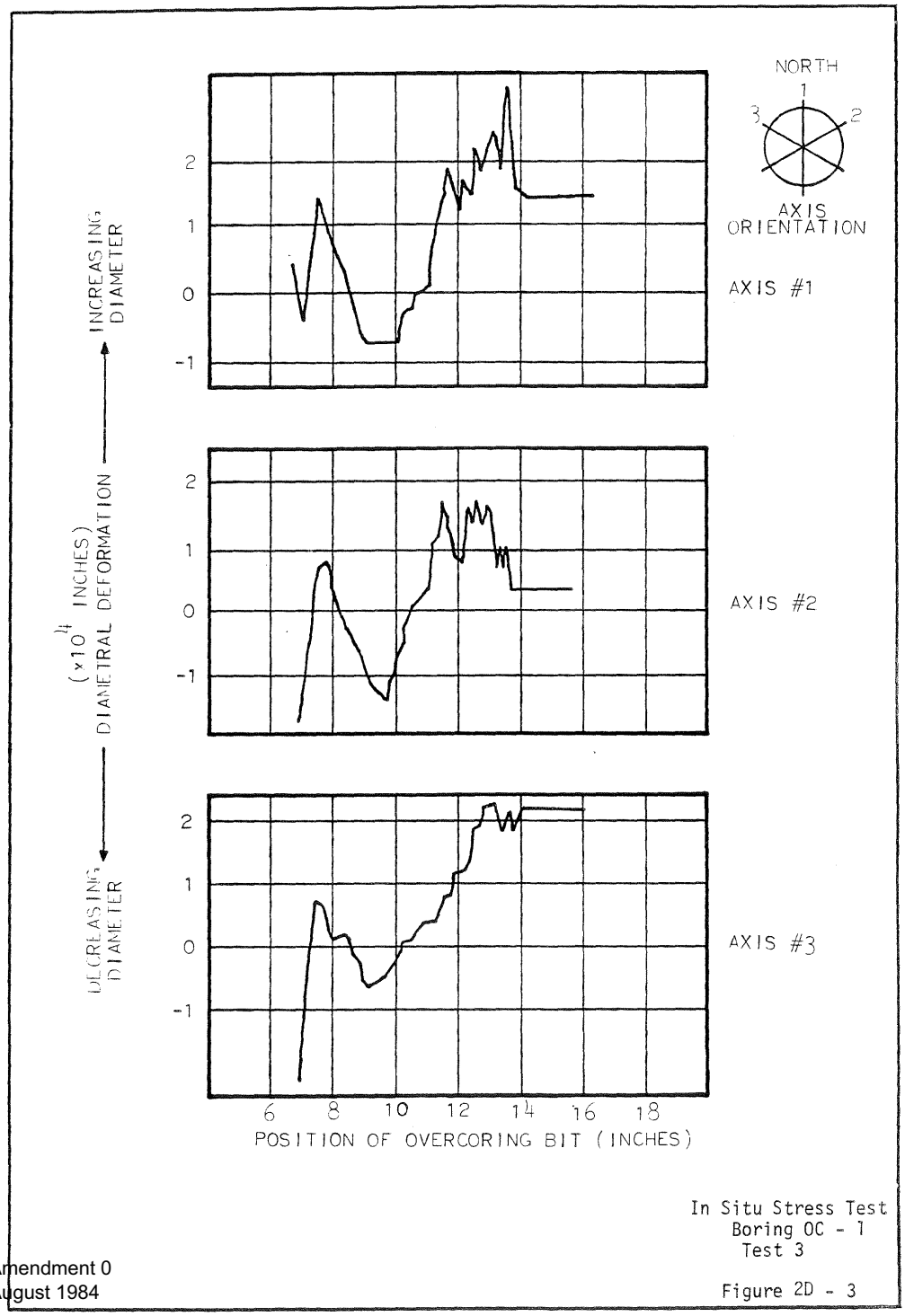
Figure 2.D-3
IN SITU STRESS TEST
BORING OC - 1 TEST 3



In Situ Stress Test
Boring OC - 1
Test 3

Figure 2D - 3

Amendment 0
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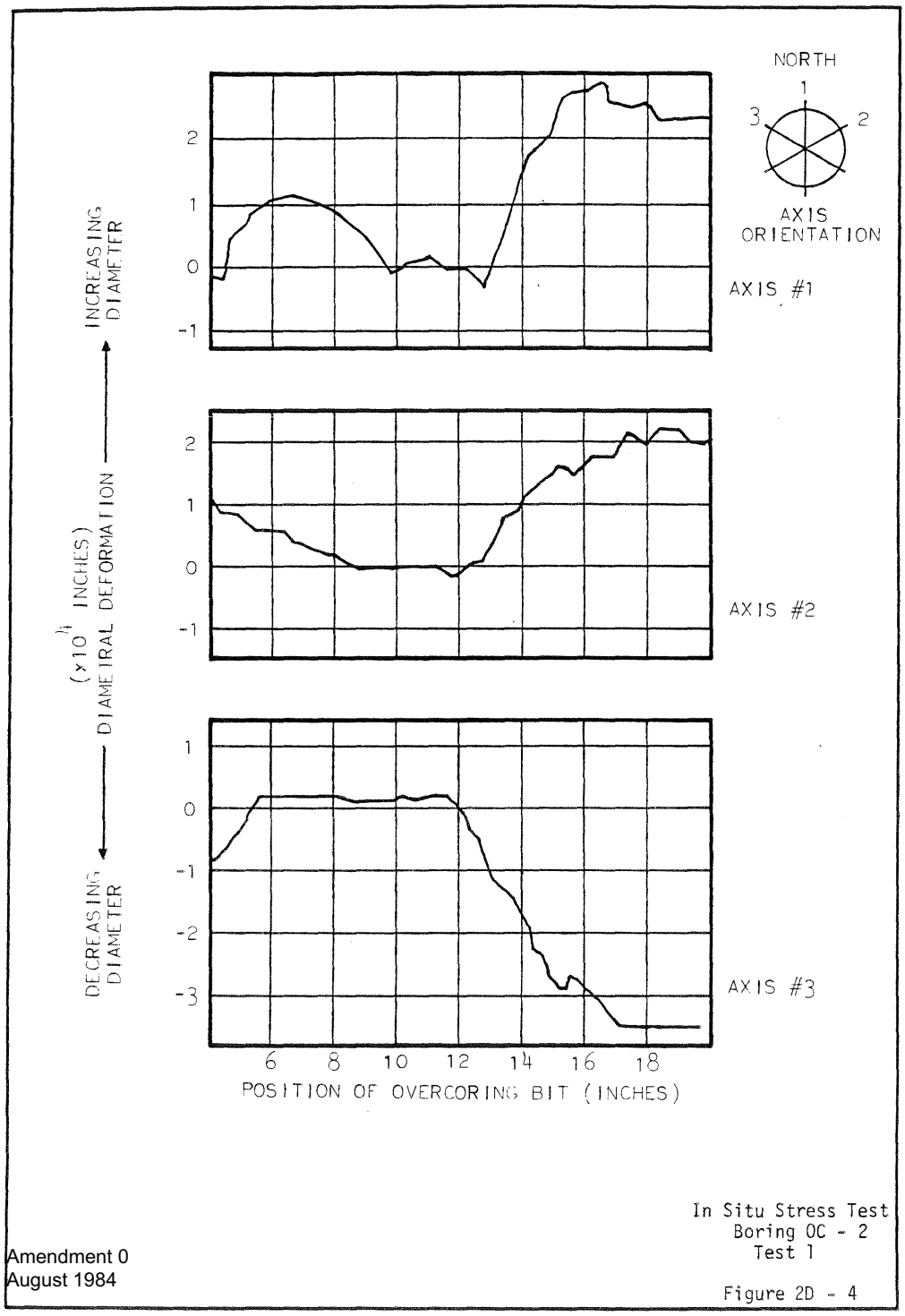
Figure 2.D-4
IN SITU STRESS TEST
BORING OC - 2 TEST 1



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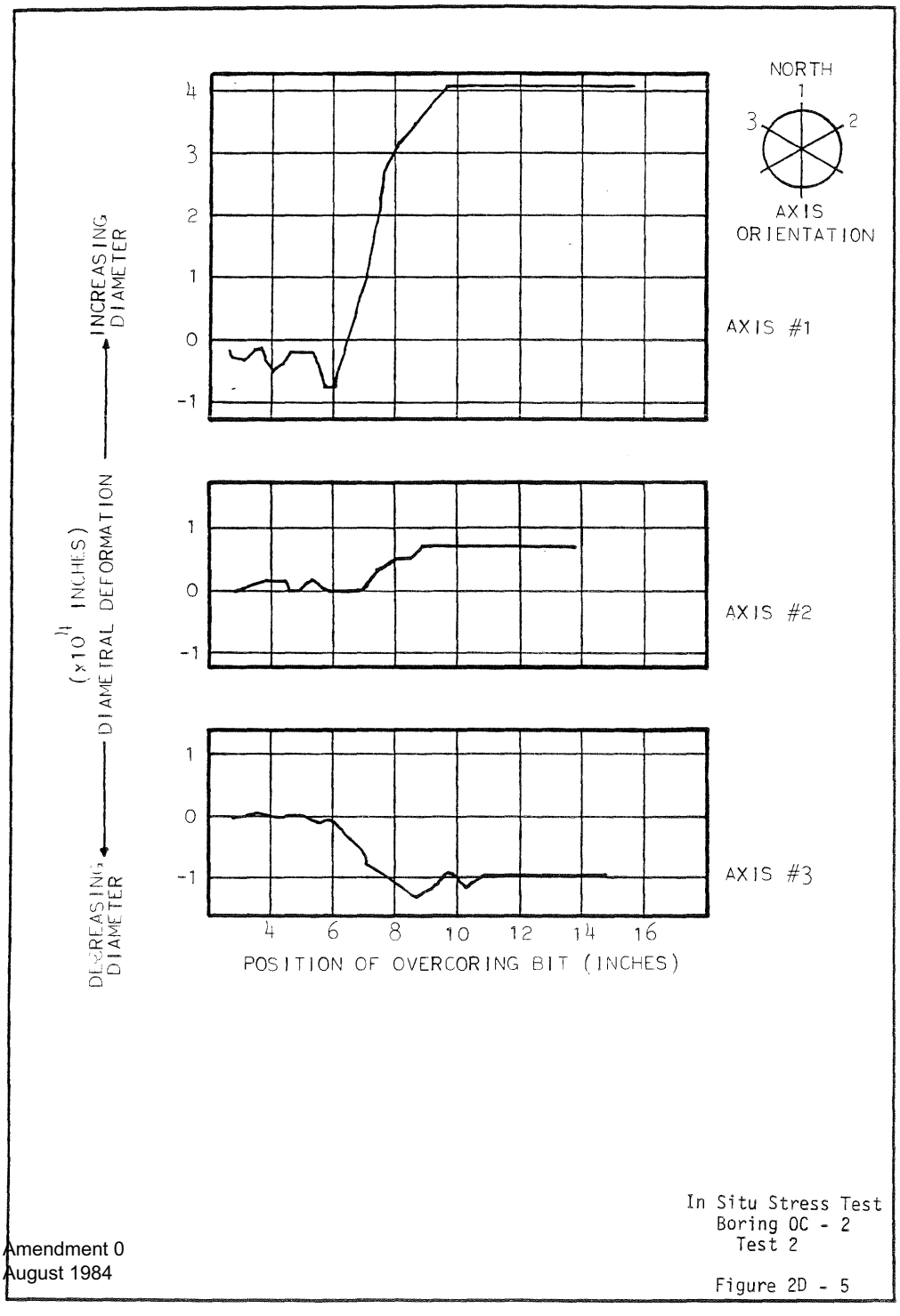
August 1984

Figure 2.D-5
IN SITU STRESS TEST
BORING OC - 2 TEST 2



In Situ Stress Test
Boring OC - 2
Test 2

Figure 2D - 5

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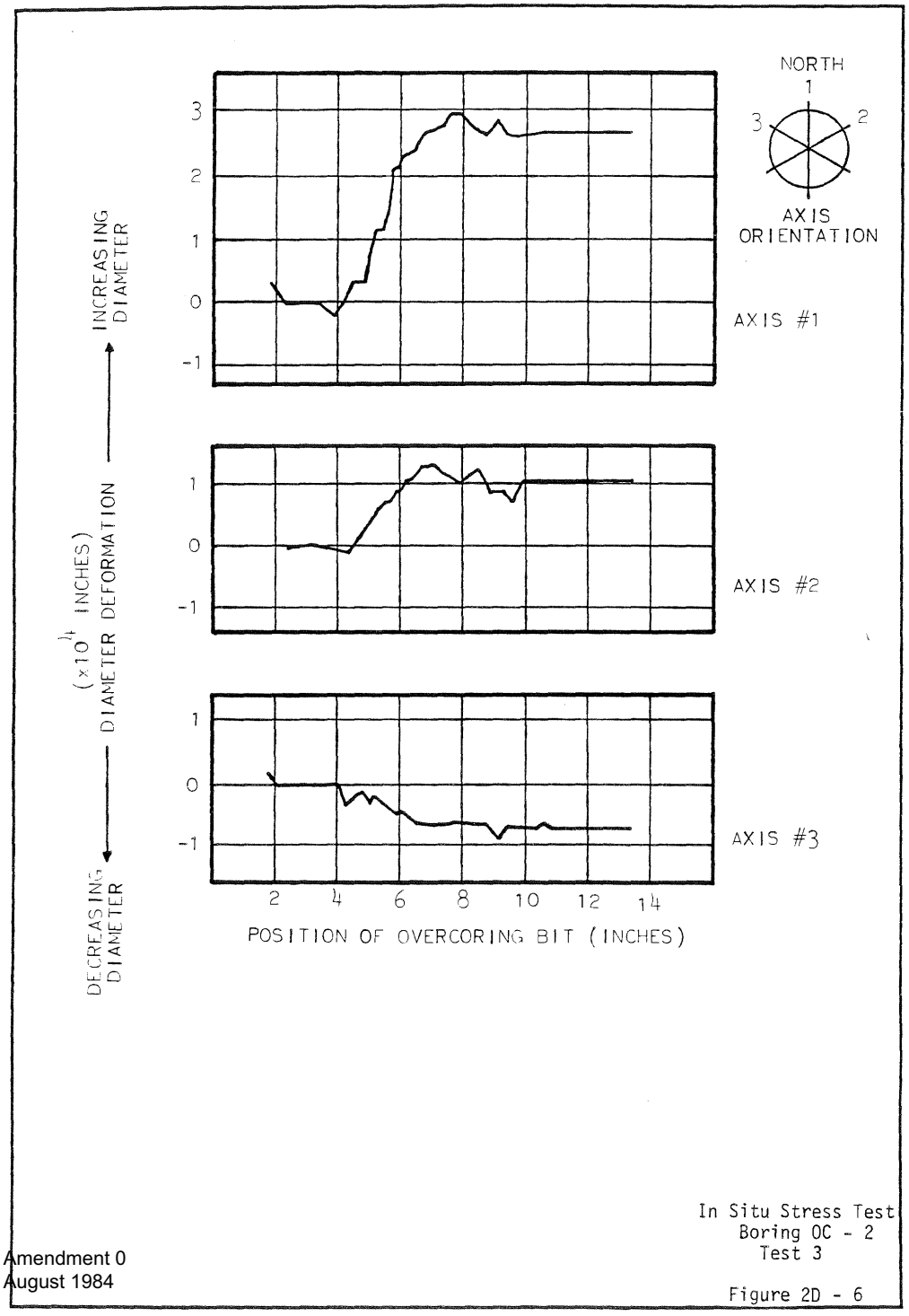
Figure 2.D-6
N SITU STRESS TEST
BORING OC - 2 TEST 3



Amendment 0
August 1984

Appendix 2E
LOGS OF BORINGS
NUCLEAR PLANT SITE AND GENERAL AREA

INSERT PAGES 2E-1 TO 2E-90

Figure 2.E-1 to Figure 2E-90

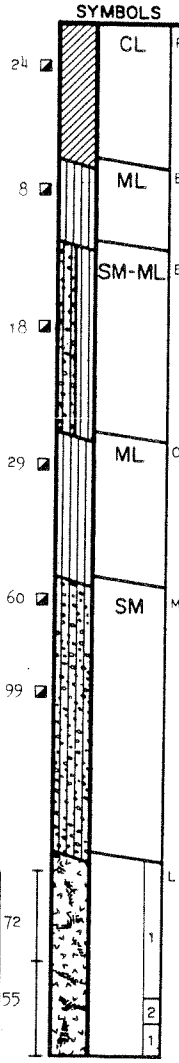
LOG OF BORING

BORING C-21

SURFACE ELEVATION 432.9
CO-ORDINATES N 472,726.77
E 1,904,793.5

OTHER TESTS	DIRECT SHEAR TEST DATA		TRIAXIAL COMPRESSION TEST DATA		FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
	NORMAL PRESSURE (PSF)	SHEAR STRENGTH (PSF)	CONFINING PRESSURE (PSF)	DEVIATOR STRESS (PSF)		

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 110, 120



SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY. (VERY STIFF)
	GRADES SANDY WITH MICA.
ML	BROWN MICACEOUS CLAYEY SANDY SILT. (MEDIUM DENSE)
SM-ML	BROWN MICACEOUS SILTY SAND TO SANDY SILT. (MEDIUM DENSE)
ML	OLIVE MICACEOUS SANDY SILT. (DENSE)
SM	MULTI-COLORED MICACEOUS SILTY SAND. (VERY DENSE)
	LIGHT TO DARK GREY MODERATELY JOINTED TO MASSIVE FINE TO MEDIUM GRAINED CONTACT BRECCIA MIGMATITE. 95' TO 107' MASSIVE FRESH ROCK. 6" SLIGHTLY WEATHERED JOINT ZONE AT 96'. 6" SLIGHTLY WEATHERED JOINT ZONE AT 99'. 6" SLIGHTLY WEATHERED JOINT ZONE AT 100'. 6" MODERATELY WEATHERED JOINT ZONE AT 107½'. 3" JOINT ZONE AT 108¼'. 107' TO 110' MODERATELY JOINTED. 110' TO 113½' MASSIVE.

BORING TERMINATED 5-[illegible]-73.

NOTE:
BORING DRILLED WITH HOLLOW-STEM AUGER RIG.
WATER LEVEL NOT MEASURED.
■ INDICATES STANDARD PENETRATION TEST.

LOG OF BORING C-21

Amendment 0
August 1984

Figure 2E-1

BORING C-22

SURFACE ELEVATION 426.3
CO-ORDINATES N 4,727.77
E 1,904,855.5

OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 110

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY. (VERY STIFF)
ML	REDDISH BROWN MICACEOUS CLAYEY SILT. (STIFF)
ML	OLIVE AND BROWN SANDY SILT. (MEDIUM DENSE)
SM	MOTTLED BROWN AND GREY SILTY SAND WITH SMALL GRAVEL (VERY DENSE)
	VERY HARD AUGER DRILLING FROM 70'.
	LIGHT TO DARK GREY HIGHLY JOINTED AND MASSIVE FINE TO MEDIUM GRAINED CONTACT BRECCIA MIGMATITE.
	83' TO 87' MODERATELY WEATHERED: HIGHLY JOINTED.
	87' TO 105' MASSIVE FRESH ROCK.
	SLIGHTLY WEATHERED JOINT AT 100½'.
	105' TO 105½' MODERATELY WEATHERED: HIGHLY JOINTED.
	105½' TO 106'8" FRESH ROCK; SLIGHTLY JOINTED.
	BORING TERMINATED 5-4-72.

18, 9, 11, 18, 29, 40, 111, 100/7"

92 | 45
100 | 100
97 | 64

3, 1, 3

NOTE:
BORING DRILLED WITH HOLLOW-STEM AUGER RIG.
WATER LEVEL NOT MEASURED.
◪ INDICATES STANDARD PENETRATION TEST.

LOG OF BORING C-22

Amendment 0
August 1984

Figure 2E-2

BORING C-23

SURFACE ELEVATION 478.8
CO-ORDINATES N 472,521.50
E 1,904,565.00

OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 110

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY
SC-SM	REDDISH BROWN MICACEOUS SILTY CLAYEY SAND
ML	OLIVE MICACEOUS SANDY SILT
	DARK GREY HIGHLY JOINTED TO MASSIVE MEDIUM GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE - QUARTZ GNEISS COMPOSITION. 90' TO 92' SLIGHTLY WEATHERED: HIGHLY JOINTED. 92' TO 94½' SLIGHTLY WEATHERED: MASSIVE.
	LIGHT TO DARK GREY SLIGHTLY JOINTED TO MASSIVE FINE TO MEDIUM GRAINED CONTACT BRECCIA MIGMATITE. FRESH TO SLIGHTLY WEATHERED IN ZONES. 2" JOINT ZONE AT 96½' 2" JOINT ZONE AT 102'
	LIGHT GREY SLIGHTLY JOINTED TO MASSIVE FINE TO MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION.

81 | 33 | 2
100 | 68 | 1-2
1-2

BORING TERMINATED 5-15-73.

NOTE:
BORING DRILLED WITH HOLLOW-STEM AUGER RIG.
WATER LEVEL NOT MEASURED.

LOG OF BORING C-23

Amendment 0
August 1984

Figure 2E-3

BORING C-24

SURFACE ELEVATION 484.5
CO-ORDINATES N 472,454.25
E 1,994,545.00

OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 110, 120

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY.
SC-ML	REDDISH BROWN MICACEOUS SILTY CLAYEY SAND AND SANDY CLAYEY SILT.
	GRADES TO BROWN IN COLOR.
77◪	
56 18	LIGHT TAN, MODERATELY JOINTED, MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION, MODERATELY WEATHERED.
55 13	DARK GREY TO LIGHT BROWN, HIGHLY JOINTED TO MASSIVE, FINE GRAINED MIGMATITE OF BIOTITE - PLAGIOCLASE, QUARTZ GNEISS COMPOSITION. 89½' TO 96' MODERATELY WEATHERED. 96' TO 109' HIGHLY JOINTED. 96' TO 106' HIGHLY WEATHERED. 106' TO 107½' MODERATELY WEATHERED. 107½' TO 109' SLIGHTLY WEATHERED. 109' TO 113' MODERATELY WEATHERED.
70 46	
	BORING TERMINATED AT 113'.

NOTE:
BORING DRILLED WITH HOLLOW-STEM AUGER RIG.
WATER LEVEL NOT MEASURED.
◪ INDICATES STANDARD PENETRATION TEST.

LOG OF BORING C-24

Amendment 0
August 1984

Figure 2E-4

BORING C-25

SURFACE ELEVATION 471.1
CO-ORDINATES N 472,509.50
E 1,994,691.63

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							
100							
110							
120							
130							

93	44		
100	16		
100	69		
100	47		

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY.
SC-SM	BROWN FINE MICACEOUS CLAYEY SAND.
SM	BROWN SILTY MICACEOUS SAND.
	GRADING WITH ZONES OF HIGHLY WEATHERED AND DECOMPOSED ROCK.
3 2 3 3 1 2 3 3 3 1 3 3 1	LIGHT GREY TO BROWN JOINTED MEDIUM TO COARSE GRAINED GRANODIORITE. 90' TO 90½' HIGHLY WEATHERED. 90' TO 91½' HIGHLY JOINTED. 90½' TO 91½' MODERATELY WEATHERED. 91½' TO 93' SLIGHTLY TO MODERATELY WEATHERED; MODERATELY JOINTED. 93' TO 95' HIGHLY WEATHERED; HIGHLY JOINTED. 95½' TO 97½' FRESH ROCK; NOT JOINTED. 97½' TO 100' SLIGHTLY WEATHERED; MODERATELY JOINTED. 100' TO 105½' MODERATELY WEATHERED. 105½' TO 100' VERY HIGHLY WEATHERED. 100' TO 100' HIGHLY JOINTED. 10" HIGHLY WEATHERED ZONE AT 101'. 9" SLIGHTLY WEATHERED ZONE AT 102'. 14" SLIGHTLY WEATHERED AND SLIGHTLY JOINTED ZONE AT 104'.
3 1 3 3 1	LIGHT BROWN TO GREY HIGHLY JOINTED AND MASSIVE FINE TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. 109' TO 115' FRESH ROCK; SLIGHTLY JOINTED TO MASSIVE. CONTAINS GNEISSIC INCLUSIONS. 115' TO 117½' MODERATELY WEATHERED; HIGHLY JOINTED. 116½' TO 120½' MASSIVE FRESH ROCK. 6" HIGHLY WEATHERED AND HIGHLY JOINTED ZONE AT 119'. 10" FINE GRAINED ZONE AT 120'. 6" HIGHLY WEATHERED AND HIGHLY JOINTED ZONE AT 121'. 121' TO 127' MODERATELY WEATHERED; HIGHLY JOINTED. 6" HIGHLY WEATHERED ZONE AT 124'. 125' TO 125' MASSIVE FRESH ROCK. 125' TO 129' MODERATELY WEATHERED; HIGHLY JOINTED.
	BORING TERMINATED AT 129.5'.

NOTE:
BORING DRILLED WITH ROTARY WASH RIG.
WATER LEVEL NOT MEASURED.

LOG OF BORING C-25

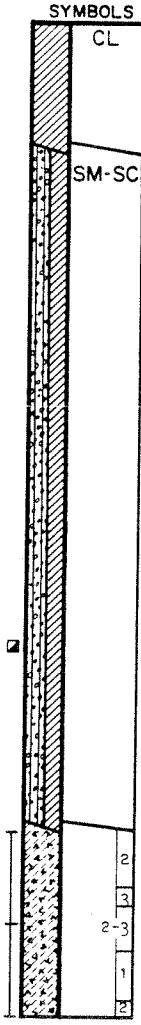
Amendment 0
August 1984

Figure 2E-5

BORING C-26

SURFACE ELEVATION 461.9
CO-ORDINATES N 472,509.25
E 1,904,799.25

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							
100							
110							



CL — REDDISH BROWN SILTY CLAY.

SM-SC — BROWN MICACEOUS SILTY TO CLAYEY SAND.

GRADING MULTI-COLORED.

HARD DRILLING.

LIGHT TAN AND LIGHT GREY HIGHLY JOINTED TO MASSIVE FINE TO VERY COARSE GRAINED (SOME PHENOCRYSTS) MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS SOME INCLUSIONS AND OCCASIONAL FOLIATION.
90' TO 95' MODERATELY WEATHERED; SLIGHTLY JOINTED.
95' TO 97' HIGHLY WEATHERED; HIGHLY JOINTED.
97' TO 102' MODERATELY TO SLIGHTLY WEATHERED; MODERATELY TO HIGHLY JOINTED.
102' TO 104' MASSIVE FRESH ROCK.
104' TO 107½' SLIGHTLY WEATHERED; MASSIVE.
2" MODERATELY WEATHERED JOINTED ZONE AT 104½'.
107½' TO 109'3" SLIGHTLY WEATHERED; HIGHLY JOINTED.

BORING TERMINATED 5-10-73.

NOTE:
BORING DRILLED WITH HOLLOW-STEM AUGER RIG.
WATER LEVEL NOT MEASURED.
◪ INDICATES STANDARD PENETRATION TEST.

LOG OF BORING C-26

Amendment 0
August 1984

Figure 2E-6

BORING C-27

SURFACE ELEVATION 461.3
CO-ORDINATES N 472,482.50
E 1,904,873.75

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							
100							
110							

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY.
ML	BROWN MICACEOUS SANDY SILT.
SM	BROWN MICACEOUS SILTY SAND.
ML	BROWN MICACEOUS SANDY SILT.
	GRADING GREENISH GREY.
	LIGHT TO DARK GREY SLIGHTLY TO MODERATELY JOINTED FINE TO MEDIUM GRAINED CONTACT BRECCIA MIGMATITE. SLIGHTLY WEATHERED.
	10" MODERATELY WEATHERED AND JOINTED ZONE AT 87'.
	LIGHT GREY MASSIVE MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS SOME INCLUSIONS. FRESH ROCK.
	2" SLIGHTLY WEATHERED AND JOINTED ZONE AT 89½'.
	2" SLIGHTLY WEATHERED AND JOINTED ZONE AT 90'.
	2" SLIGHTLY WEATHERED AND JOINTED ZONE AT 91'.
	2" SLIGHTLY WEATHERED AND JOINTED ZONE AT 97'.
	2" SLIGHTLY WEATHERED AND JOINTED ZONE AT 97⅓'.
	2" SLIGHTLY WEATHERED AND JOINTED ZONE AT 100'.
	BORING TERMINATED 5-9-72.

28 ◪
58/5" ◪
63 29 2
100 76 1

NOTE:
BORING DRILLED WITH HOLLOW-STEM AUGER RIG.
WATER LEVEL NOT MEASURED.
◪ INDICATES STANDARD PENETRATION TEST.

LOG OF BORING C-27

Amendment 0
August 1984

Figure 2E-7

BORING C-28

SURFACE ELEVATION 447.2

CO-ORDINATES N 472,579.0
E 1,904,886.75

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							
100							
110							
120							

SYMBOLS	DESCRIPTIONS
CL (33)	REDDISH BROWN SILTY CLAY. (VERY STIFF)
ML (12)	BROWN MICACEOUS SANDY SILT. (MEDIUM DENSE)
SM (14)	MULTI-COLORED MICACEOUS SILTY SAND. (MEDIUM DENSE)
SM-SW (26)	OLIVE MICACEOUS SILTY SAND WITH SMALL GRAVEL. (VERY DENSE)
131/4"	
100/2"	
80 / 45	LIGHT TAN TO LIGHT GREY HIGHLY JOINTED TO MASSIVE COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONARY FOLIATION.
88 / 28	78' TO 80' HIGHLY WEATHERED; HIGHLY JOINTED.
68 / 27	80' TO 86' FRESH ROCK; SLIGHTLY JOINTED TO MASSIVE.
100 / 100	LARGE INCLUSION AT 85'.

3
1
3
2
1
3
1
3
1

86' TO 90½' MODERATELY WEATHERED; HIGHLY TO MODERATELY JOINTED.
8" HIGHLY WEATHERED JOINT ZONE AT 90'.
90½' TO 91½' SLIGHTLY JOINTED.
90½' TO 97½' SLIGHTLY WEATHERED.
91½' TO 93' HIGHLY JOINTED WITH HIGH ANGLE AND VERTICAL JOINTS.
93' TO 97½' MASSIVE.
5" HIGH ANGLE JOINT ZONE AT 94'.
97½' TO 102' MODERATELY WEATHERED; HIGHLY JOINTED.
102' TO 10[illegible]' MASSIVE FRESH ROCK.
106' TO 10[illegible]' HIGHLY WEATHERED; HIGHLY JOINTED.
108' TO 11[illegible]' MASSIVE FRESH ROCK.
LARGE INCLUSION AT 10[illegible]'.

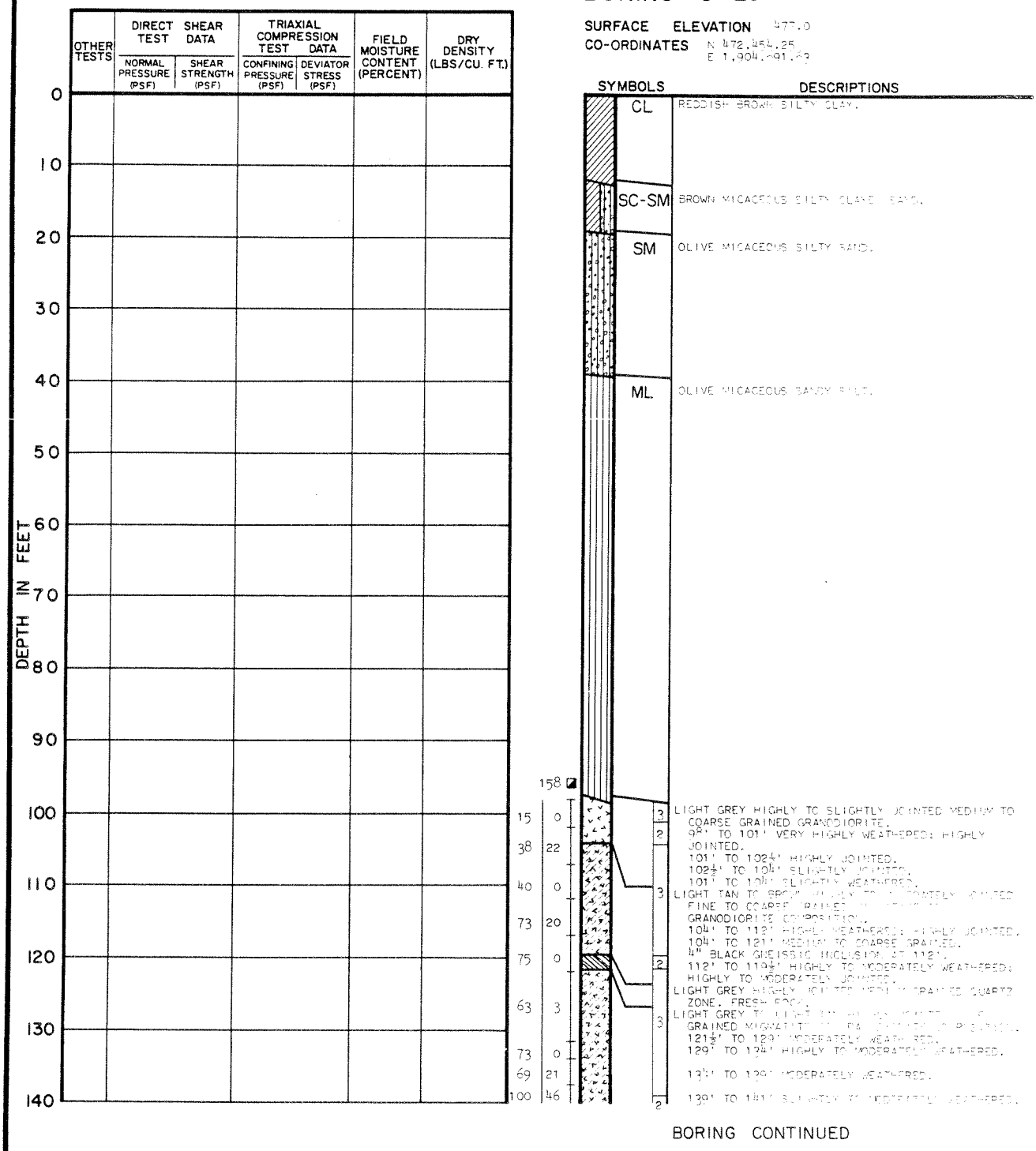
BORING TERMINATED E[illegible]-72.

NOTE:
BORING DRILLED WITH HOLLOW-STEM AUGER RIG.
WATER LEVEL NOT MEASURED.
◪ INDICATES STANDARD PENETRATION TEST.

LOG OF BORING C-28

Amendment 0
August 1984

Figure 2E-8



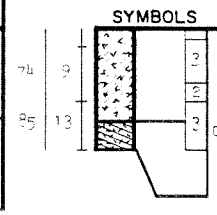
LOG OF BORING C-29

Amendment 0
August 1984

Figure 2E-9

BORING C-29 CONT'D

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
140							
150							
160							



SYMBOLS

DESCRIPTIONS

141' TO 144' MODERATELY WEATHERED.

144' TO 148' SLIGHTLY WEATHERED.
148' TO 150± MODERATELY WEATHERED.
4" QUARTZ ZONE.
DARK GREY HIGHLY JOINTED FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. MODERATELY WEATHERED.
4" HIGHLY WEATHERED ZONE AT 152'.

BORING TERMINATED 5-14-73.

NOTE:
BORING DRILLED WITH ROTARY WASH RIG.
WATER LEVEL NOT MEASURED.
◪ INDICATES STANDARD PENETRATION TEST.

LOG OF BORING C-29

Amendment 0
August 1984

Figure 2E-9a

BORING C-30

SURFACE ELEVATION [illegible]

CO-ORDINATES N 472,454.25
E 1,904,795.00

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							
100							

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY.
SC-SM	BROWN MICACEOUS SILTY CLAYEY [illegible].
SM	MULTI-COLORED MICACEOUS [illegible]
	LIGHT GREY MASSIVE MEDIUM TO COARSE GRAINED GRANODIORITE. 71' TO 80' MASSIVE FRESH ROCK. SLIGHTLY WEATHERED JOINT AT 79'.
	80' TO 94½' SLIGHTLY WEATHERED; MASSIVE. 3" MODERATELY WEATHERED JOINT ZONE AT 82½'. 94½' TO 96' HIGHLY WEATHERED; HIGHLY JOINTED. 96' TO 98½' MASSIVE FRESH ROCK. SLIGHTLY WEATHERED JOINT AT 97'.
	LIGHT GREY MASSIVE FINE TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS. SLIGHT FOLIATION. 98½' TO 98' MASSIVE FRESH ROCK.
	BORING TERMINATED [illegible].

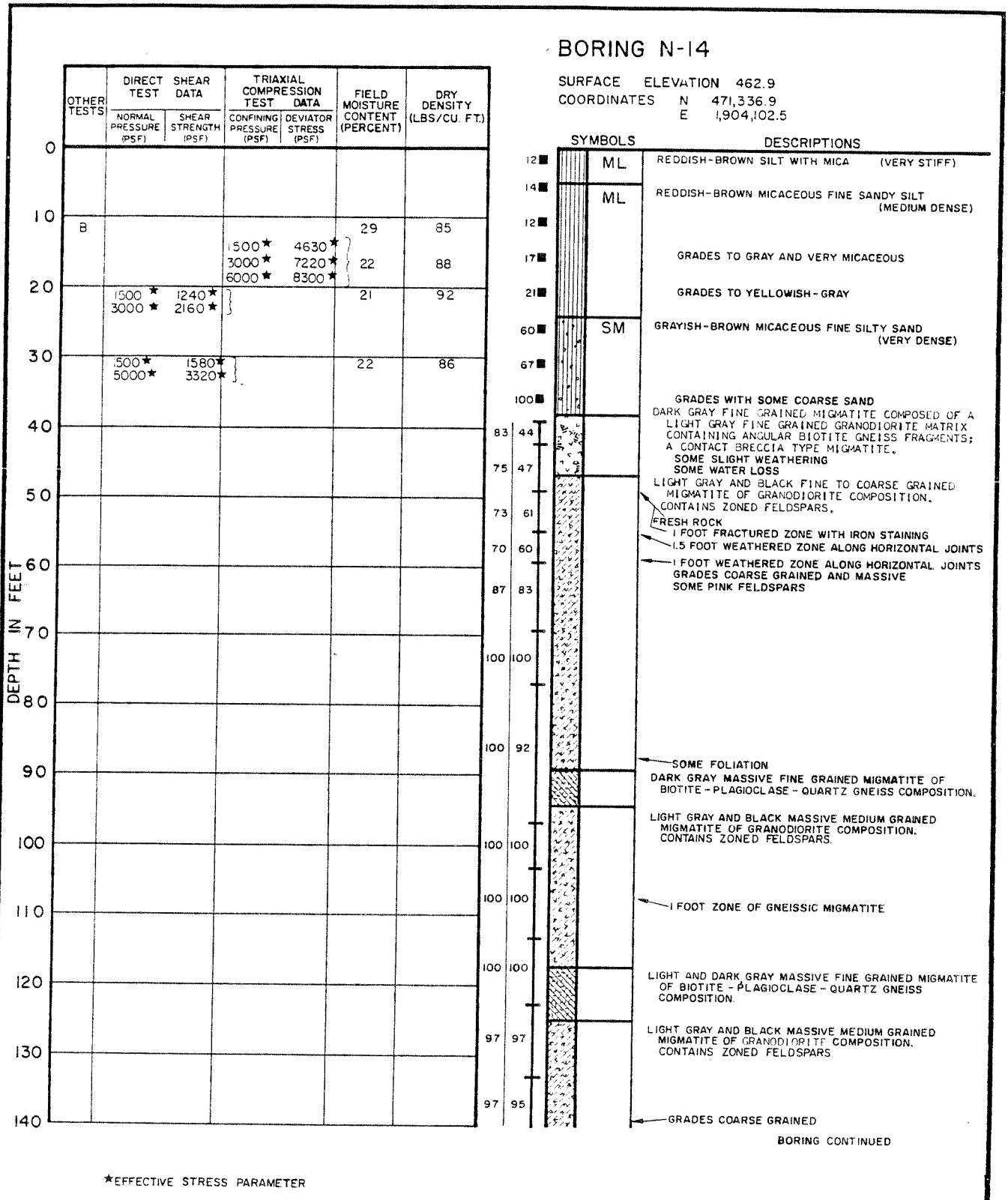
42	37	1	
100	69	3½	
91	88	1	

NOTE:
BORING DRILLED WITH ROTARY [illegible]
WATER LEVEL [illegible]

LOG OF BORING C-30

Amendment 0
August 1984

Figure 2E-10



LOG OF BORING N-14

Amendment 0
August 1984

Figure 2E-11

BORING N-14 (CONTD.)

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
140							
150							
160							
170							

100	100
100	100
100	96

SYMBOLS

DESCRIPTIONS

15 FOOT ZONE OF GNEISSIC MIGMATITE

BORING TERMINATED 2/16/71

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 26 INCHES.

GROUND WATER LEVEL AT DEPTH 43.7 FEET, ON 3-29-71.

NOTES:

1. ELEVATIONS REFER TO MEAN SEA LEVEL DATUM.
2. CO-ORDINATES REFER TO SOUTH CAROLINA CO-ORDINATE SYSTEM.
3. LABORATORY TESTS ARE DISCUSSED IN THE TEXT.
4. FOR THE KEY OF SYMBOLS REFER TO FIGURE 2.5.1-89.
5. "A" INDICATES GRAIN SIZE TEST; RESULTS PRESENTED ON FIGURES 2.5.1-104 THROUGH 2.5.1-107.
6. "B" INDICATES CONSOLIDATION TEST; RESULTS PRESENTED IN FIGURES 2.5.1-95 THROUGH 2.5.1-103.
7. "C" INDICATES ATTERBERG LIMIT EVALUATIONS; RESULTS PRESENTED ON TABLE 2.5.1-5.
8. "D"** INDICATES PERMEABILITY EVALUATIONS; RESULTS PRESENTED ON TABLE 2.5.1-4.
9. STRENGTH PARAMETERS IDENTIFIED WITH *STARS, ARE EFFECTIVE STRESS; OTHERS REFLECT TOTAL STRESS.

** NOT USED TO IDENTIFY TESTS ON "N"-SERIES BORINGS.

LOG OF BORING N-14

BORING N-15

SURFACE ELEVATION 493.9
COORDINATES N 472,012.2
E 1,904,156.9

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10							
20							
30		500★	600★			15	95
		3000★	2320★			15	96
40		1000	1420			15	98
		5000	4550				
50	B					23	91
60							
70							
80							
90							
100							
110							
120							
130							
140							

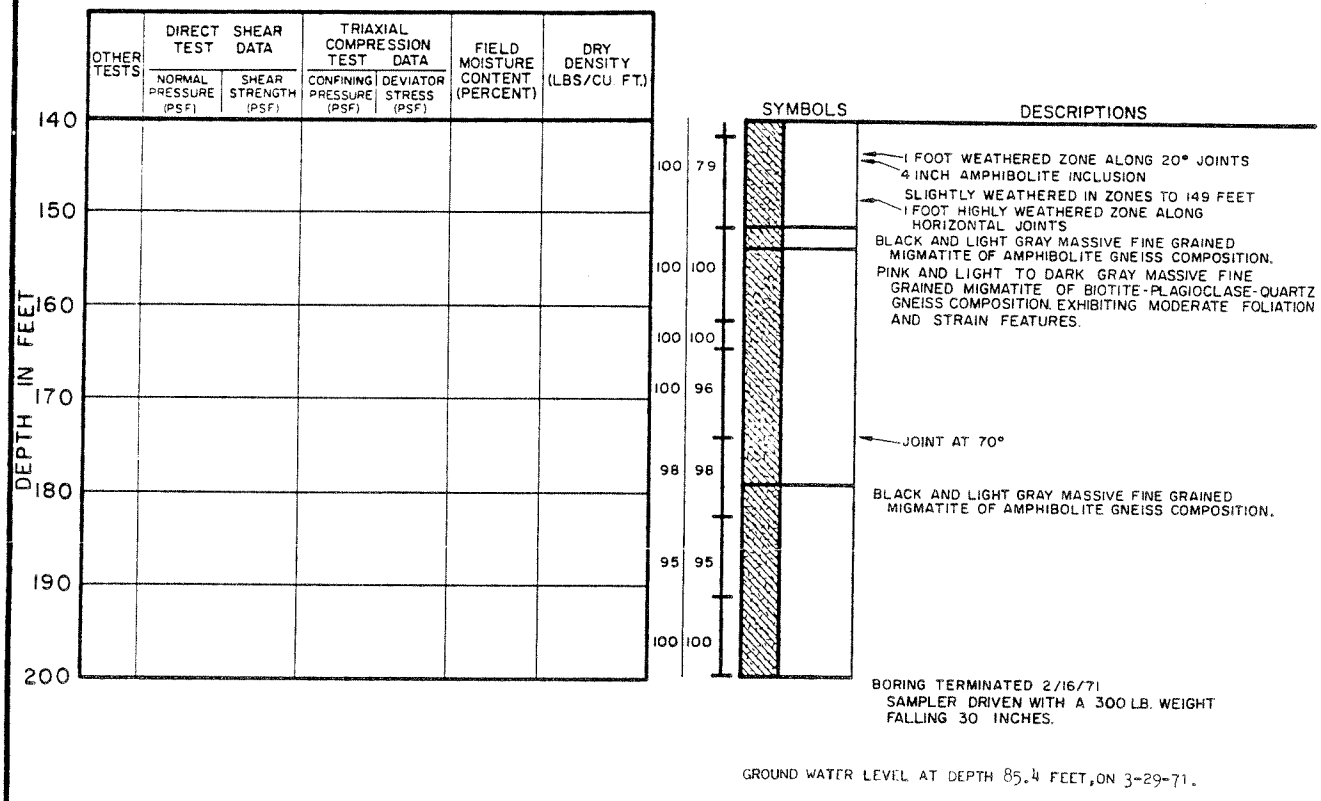
★EFFECTIVE STRESS PARAMETER

SYMBOLS		DESCRIPTIONS
30	CL	REDDISH-BROWN SANDY CLAY (VERY STIFF)
52		GRADES WITH YELLOWISH STREAKS OF CLAY
14	ML	LIGHT REDDISH-BROWN FINE SANDY SILT WITH MICA (MEDIUM DENSE)
12	SM	YELLOWISH AND LIGHT BROWN SILTY FINE TO MEDIUM SAND WITH MICA (MEDIUM DENSE)
15		GRADES SILTIER AND WITH LENSES OF MICACEOUS SILT
16		MICACEOUS LENSES GRADING OUT
13		GRADES WITH INCREASED MICA CONTENT
15		
18		
20	ML	LIGHT ORANGISH-BROWN FINE SANDY SILT WITH SOME MICA (MEDIUM DENSE)
22		
200/4"	SM	MOTTLED GRAY-LIGHT BROWN-WHITE-AND BLACK SILTY FINE TO MEDIUM SAND (VERY DENSE)
31 3		TAN PARTIALLY TO THOROUGHLY DECOMPOSED FINE TO MEDIUM GRAINED MIGMATITE OF GNEISS COMPOSITION. 60' TO 61' LESS DECOMPOSED ROCK. 61' TO 88' ALTERNATING GRADATIONAL ZONES OF MIGMATITE - VARYING FROM A MODERATELY WEATHERED ROCK TO A SOIL CONSISTENCY
50 0		
44 5		ABRUPT CHANGE TO MASSIVE FRESH ROCK
100 97		PINK AND LIGHT TO DARK GRAY MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. EXHIBITS MODERATE FOLIATION AND STRAIN FEATURES CONCORDANT WITH FOLIATION.
100 93		BLACK MASSIVE FINE GRAINED AMPHIBOLITE GNEISS.
100 92		
100 97		4 INCH WEATHERED ZONE, NEAR HORIZONTAL AND VERTICAL JOINTS
100 78		1 FOOT ZONE OF SLIGHT WEATHERING ALONG JOINTS
		PINK AND LIGHT TO DARK GRAY FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. EXHIBITS MODERATE FOLIATION AND STRAIN FEATURES. JOINTED AT 20° AND 70°. 6 INCH AMPHIBOLITE ZONE
98 91		
95 88		1 FOOT WEATHERED ZONE ALONG HORIZONTAL JOINTS
		BORING CONTINUED

LOG OF BORING N-15

Figure 2E-12

BORING N-15 (CONTD)



GROUND WATER LEVEL AT DEPTH 85.4 FEET, ON 3-29-71.

LOG OF BORING N-15

Figure 2E-12a

BORING N-16

SURFACE ELEVATION 439.4
COORDINATES N 471,438.8
E 1,905,353.3

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0	B					23	94
10							
20						18	98
30		2000	1950			22	88
		5000	3670			21	94
		2000	2000			25	89
40		5000	3700			23	94
						11	106
50							
60							
70							
80							
90							
100							
110							
120							
130							
140							

SYMBOLS	DESCRIPTIONS
ML	REDDISH-BROWN CLAYEY SILT (VERY STIFF) GRADES WITH MICA
ML-SM	REDDISH-BROWN MICACEOUS SANDY SILT (LOOSE)
SM	MOTTLED GRAY-WHITE-LIGHT BROWN AND BLACK MICACEOUS SILTY FINE TO MEDIUM SAND (LOOSE)
ML-SM	MOTTLED GRAY-LIGHT GRAY AND BROWN MICACEOUS FINE SANDY SILT (MEDIUM DENSE)
SM-ML	GRAY MICACEOUS SILTY FINE SAND (MEDIUM DENSE)
SM	MOTTLED GRAY-LIGHT GRAY-WHITE AND LIGHT BROWN MICACEOUS SILTY FINE TO COARSE SAND (VERY DENSE) CEMENTED FROM 55 FEET TO 58 FEET GRADES WITH FREQUENT CEMENTED LAYERS
	LIGHT TAN MASSIVE FINE GRAINED APLITE DIKE WITH ZONES OF SLIGHT FOLIATION. SOME SLIGHT WEATHERING 4 INCH WEATHERED ZONE AT 81 FEET LOST CIRCULATION 1 FOOT GNEISSIC MIGMATITE ZONE
	LIGHT TO DARK GRAY HIGHLY JOINTED FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. 92.3' TO 100.2': ZONES OF PARTIAL DECOMPOSITION ALONG JOINTING 97' TO 99': MIGMATITE OF GRANODIORITE COMPOSITION REGAIN CIRCULATION GRADES MASSIVE. FRESH ROCK 4 INCH EPIDOTE ZONE
	4 INCH EPIDOTE ZONE GRAY MASSIVE FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION.
	BLACK AND GRAY MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. 2 INCH QUARTZ-MUSCOVITE VEINS AT 121' AND 121.5' 126' TO 184.5': ORIGINAL FOLIATION HIGHLY CONTORTED BY PLASTIC DEFORMATION 1 INCH WEATHERED ZONE ALONG 30° JOINTS 2 INCH WEATHERED ZONE ALONG 30° JOINTS 1 INCH WEATHERED ZONE ALONG 30° JOINTS 1 INCH WEATHERED ZONE ALONG 30° JOINTS BORING CONTINUED

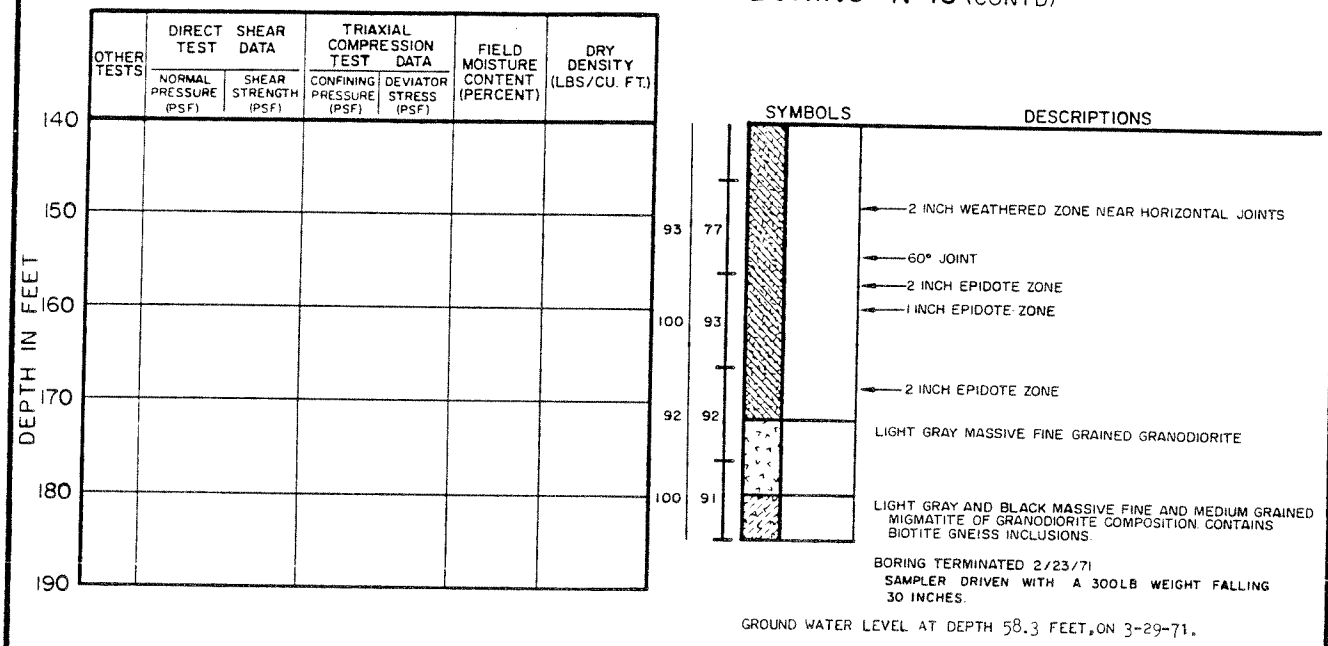
16	10	
10		
8		
9		
19		
17		
18		
20		
34		
22		
100/6"		
50/3"		
100/11"		
50/4"		
60/5"		
60/3"		
70	48	
64	19	
90	20	
98	60	
58	44	
100	63	
100	41	
100	86	

LOG OF BORING N-16

Amendment 0
August 1984

Figure 2E-13

BORING N-16 (CONTD)



GROUND WATER LEVEL AT DEPTH 58.3 FEET, ON 3-29-71.

LOG OF BORING N-16

Figure 2E-13a

BORING N-17

SURFACE ELEVATION 440.6
COORDINATES N 472,981.8
E 1,903,775.1

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0				0	4260	32	90
				0	4960	25	94
10	B					20	88
20						13	101
30							
40							
50							
60							
70							
80							
90							
100							
110							
120							
130							
140							

SYMBOLS	DESCRIPTIONS
25 / 33 — CL	REDDISH-BROWN SILTY CLAY WITH MICA (HARD)
39 / 23 — ML	REDDISH-BROWN MICACEOUS FINE SANDY SILT (DENSE)
	GRADES SANDIER
15 / 14 — SM	MOTTLED GRAY, LIGHT GRAY, WHITE AND LIGHT TAN MICACEOUS SILTY FINE TO MEDIUM SAND (MEDIUM DENSE)
	GRADES WITH COARSE SAND AND SMALL GRAVEL
17 / 39	GRADES TO DENSE
67	GRADES TO VERY DENSE
102	GRADES WITH LESS SILT
134/3"	LIGHT GRAY AND BLACK MASSIVE TO MEDIUM GRAINED GRANODIORITE, CONTAINS ZONED FELDSPARS AND INFREQUENT INCLUSIONS. 55' TO 67': WEATHERED ALONG HORIZONTAL JOINTS
60 / 26	
90 / 54	GRADES MASSIVE
97 / 90	
100 / 100	LARGE BIOTITE GNEISS INCLUSIONS AT 85' AND 87' GRADES COARSE GRAINED
100 / 96	LARGE BIOTITE GNEISS INCLUSION
100 / 93	SLIGHT WEATHERING ALONG JOINTS
	SMALL BIOTITE GNEISS INCLUSION
100 / 70	7 INCH ZONE OF HIGHLY STRAINED HEALED FRACTURES; 5 INCH ZONE OF HIGHLY STRAINED HEALED FRACTURES; 3 INCH WEATHERED ZONE OF HIGHLY STRAINED HEALED FRACTURES
100 / 91	
100 / 86	LIGHT GRAY TO GRAY MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION.
	BORING CONTINUED

LOG OF BORING N-17

Amendment 0
August 1984

Figure 2E-14

BORING N-17 (CONTD)

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
140							
150							
160							
170							
180							

		SYMBOLS	DESCRIPTIONS
95	88		LIGHT GRAY AND BLACK MASSIVE MEDIUM GRAINED GRANODIORITE.
			1 INCH WEATHERED ZONE ALONG HORIZONTAL JOINTS
100	91		SMALL BIOTITE GNEISS INCLUSION AND 1 INCH QUARTZ VEIN
93	90		LIGHT GRAY AND GRAY MASSIVE FINE GRAINED MIGMATITE OF BIOTITE - PLAGIOCLASE - QUARTZ GNEISS COMPOSITION. HIGHLY CONTORTED FOLIATION.
100	92		

BORING TERMINATED 2/23/71
SAMPLER DRIVEN WITH A 300LB. WEIGHT FALLING 26 INCHES.

GROUND WATER LEVEL AT DEPTH 61.8 FEET, ON 3-29-71.

LOG OF BORING N-17

Amendment 0
August 1984

Figure 2E-14a

BORING N-18

SURFACE ELEVATION 456.5 FEET
COORDINATES N 470,667.4
E 1,903,596.4

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0						25	95
				0	6230	25	100
10		1000	2,30			24	96
	A	6000	5830			24	94
20	B					20	89
30	A						
40							
50	A						
60						27	91
	B					28	95
70	A					29	96
80							
90							
100							
110							
120							
130							
140							

	SYMBOLS	DESCRIPTIONS
13	CL	REDDISH-BROWN SILTY CLAY (VERY STIFF)
23		
35	SM	LIGHT REDDISH BROWN SILTY SAND WITH MICA (DENSE)
15		
17	ML-SM	MOTTLED GREENISH-GRAY TO LIGHT BROWN MICACEOUS SANDY SILT AND SILTY SAND (MEDIUM DENSE)
16		GRADES GRAYISH-BROWN AND VERY MICACEOUS
16		
13		GRADES TO LIGHT BROWN
19		
15	SM	WHITE SILTY VERY FINE SAND (MEDIUM DENSE)
52		GRADES DENSE
100/5"		GRADES VERY DENSE
26	ML	GREENISH-GRAY MICACEOUS SANDY SILT (DENSE)
36		
126		
23		GRADES VERY DENSE
100/5"		WHITE TO LIGHT PINK AND BLACK BANDED HIGHLY JOINTED FINE GRAINED QUARTZ-FELDSPAR AND AMPHIBOLITE GNEISS. JOINTED PRIMARILY AT VERTICAL AND 45°
48 0		
59 16		
79 0		LESS JOINTING
73 32		
		CLOSE SPACED VERTICAL JOINTS, PROBABLY TENSIONAL
93 17		VERTICAL JOINTS, POORLY DEVELOPED
		1 FOOT HIGHLY JOINTED ZONE WITH SOME WEATHERING
		GRADES MASSIVE
		GRADES MIGMATITIC
100 81		BLACK AND GRAY MASSIVE FINE GRAINED MIGMATITE OF AMPHIBOLITE GNEISS COMPOSITION. FOLIATION HIGHLY DISTORTED.
100 99		CROSS JOINTED

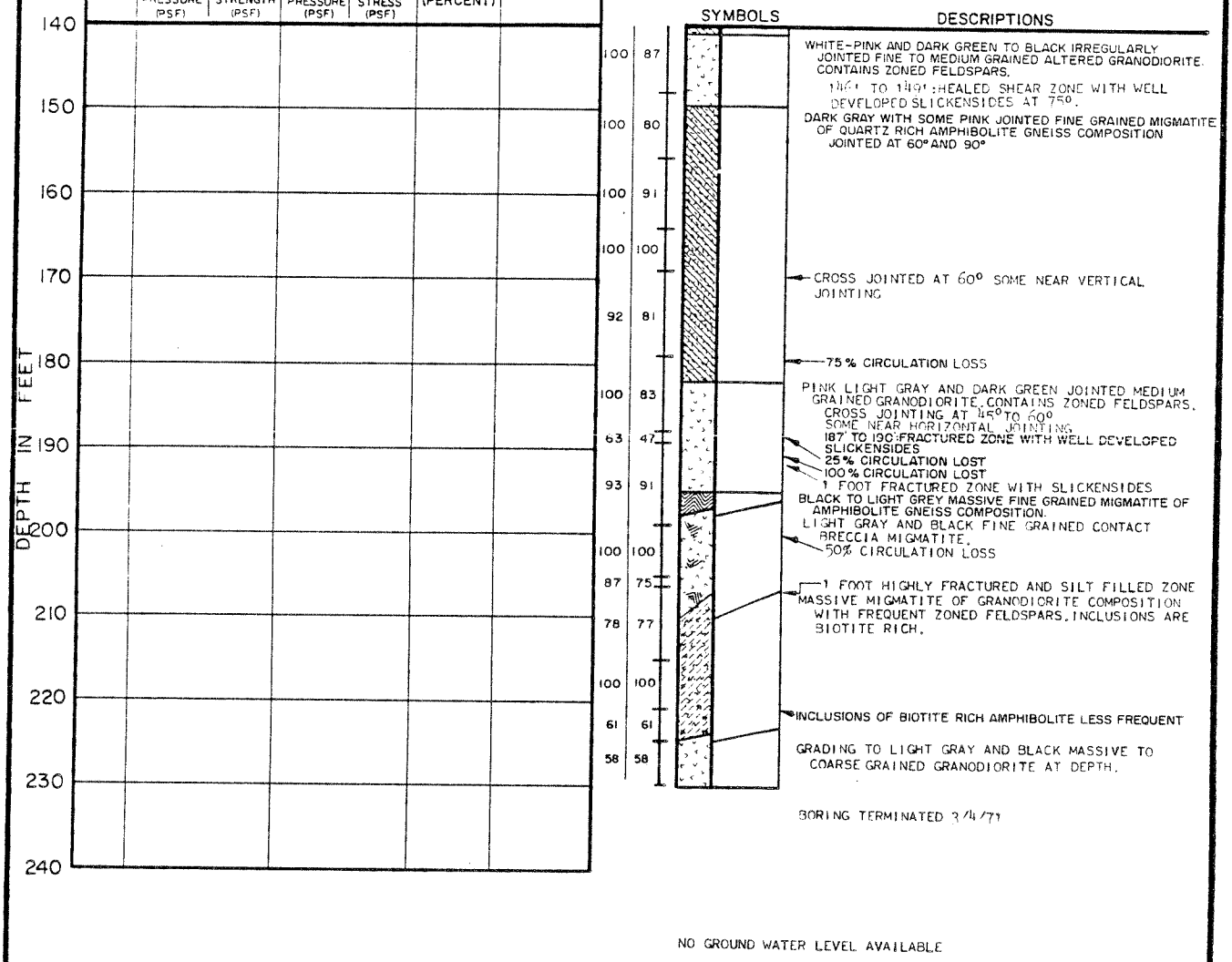
BORING CONTINUED

LOG OF BORING N-18

Amendment 0
August 1984

Figure 2E-15

BORING N-18 (CONTD.)



NO GROUND WATER LEVEL AVAILABLE

LOG OF BORING N-18

Amendment 0
August 1984

Figure 2E-15a

BORING N-19

SURFACE ELEVATION 4864
COORDINATES N 472,378.8
E 1,904,260.3

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0						28	93
10						20	93
20							
30		2000	2300			15	93
40	A					13	99
50		5000	4500			12	108
60	A B	4000	3400			31	93
70							
80							
90							
100							
110							
120							
130							
140							
150							

SYMBOLS	DESCRIPTIONS
CL	REDDISH-BROWN SANDY CLAY WITH SOME MICA (MEDIUM STIFF)
ML	REDDISH-BROWN AND GRAYISH-BROWN FINE SANDY SILT WITH MICA (MEDIUM DENSE)
SM-ML	MOTTLED LIGHT BROWN AND GRAY SILTY FINE SAND WITH MICA (MEDIUM DENSE)
	GRADES DENSE
SW-SM	MOTTLED LIGHT BROWN-GRAY-WHITE AND BLACK SILTY FINE TO MEDIUM SAND WITH SOME MICA (DENSE)
	GRADES TO VERY DENSE AND PARTLY CEMENTED
	GRADES LESS SILTY
ML	GRAYISH-BROWN MICACEOUS FINE SANDY SILT (VERY DENSE)
SM	MOTTLED LIGHT BROWN-GRAY-WHITE AND BLACK SILTY FINE TO MEDIUM SAND (VERY DENSE)
ML	GRAYISH BROWN MICACEOUS SANDY SILT (DENSE)
SM-GM	GRAY TO YELLOW SILTY SAND AND GRAVEL, PARTLY CEMENTED (DENSE)
	LIGHT TO DARK GRAY JOINTED FINE GRAINED BIOTITE-PLAGIOCLASE-QUARTZ GNEISS. SOME SLIGHT WEATHERING. JOINTED AT 10° TO 45°
	IRON STAINING ALONG JOINTS
	6 INCH HIGHLY WEATHERED ZONE
	MOTTLED WHITE TO LIGHT TAN JOINTED FINE GRAINED APLITE DIKE.
	LIGHT TO DARK GRAY MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ ALTERED GNEISS COMPOSITION CONTAINS SOME SMALL BIOTITE INCLUSIONS. FRESH ROCK.
	1 FOOT JOINTED AND HIGHLY WEATHERED
	6 INCH HIGHLY JOINTED ZONE WITH WEATHERING
	1 FOOT JOINTED ZONE WITH IRON STAINING
	SOME CIRCULATION LOSS
	1 FOOT HIGHLY JOINTED AT HORIZONTAL TO 30° WITH IRON STAINING
	JOINT AT 70° WITH IRON STAINING

25		
23		
26		
23		
27		
33		
43		
43		
57		
85		
200/9"		
172		
250/6"		
128		
45		
73		
84	42	
70	50	
100	100	
100	100	
100	70	
100	85	
60	56	
100	85	
90	74	

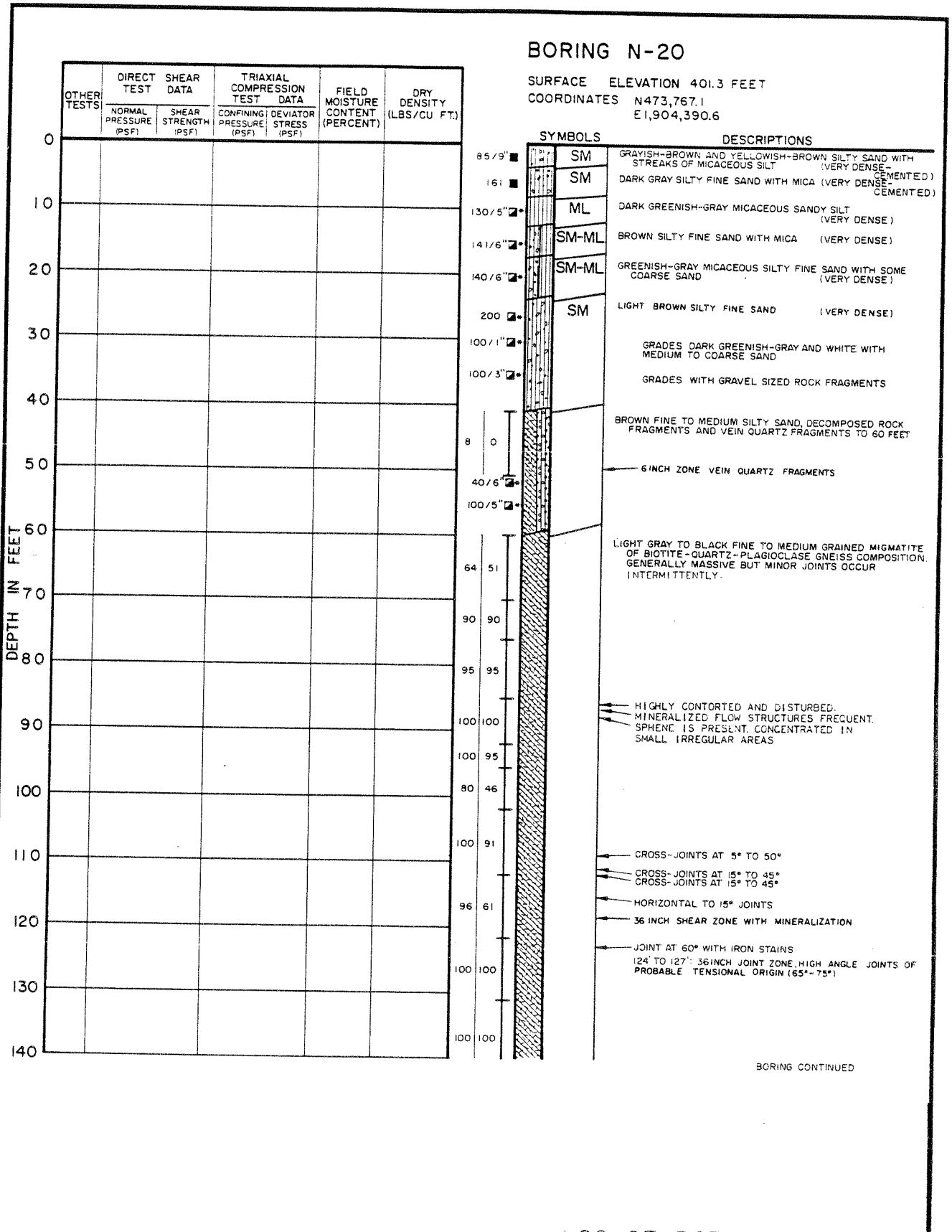
BORING TERMINATED 2/26/71
SAMPLER DRIVEN BY A 140 LB. WEIGHT FALLING 30 INCHES.

GROUND WATER LEVEL AT DEPTH 86.3 FEET, ON 3-29-71.

LOG OF BORING N-19

Amendment 0
August 1984

Figure 2E-16

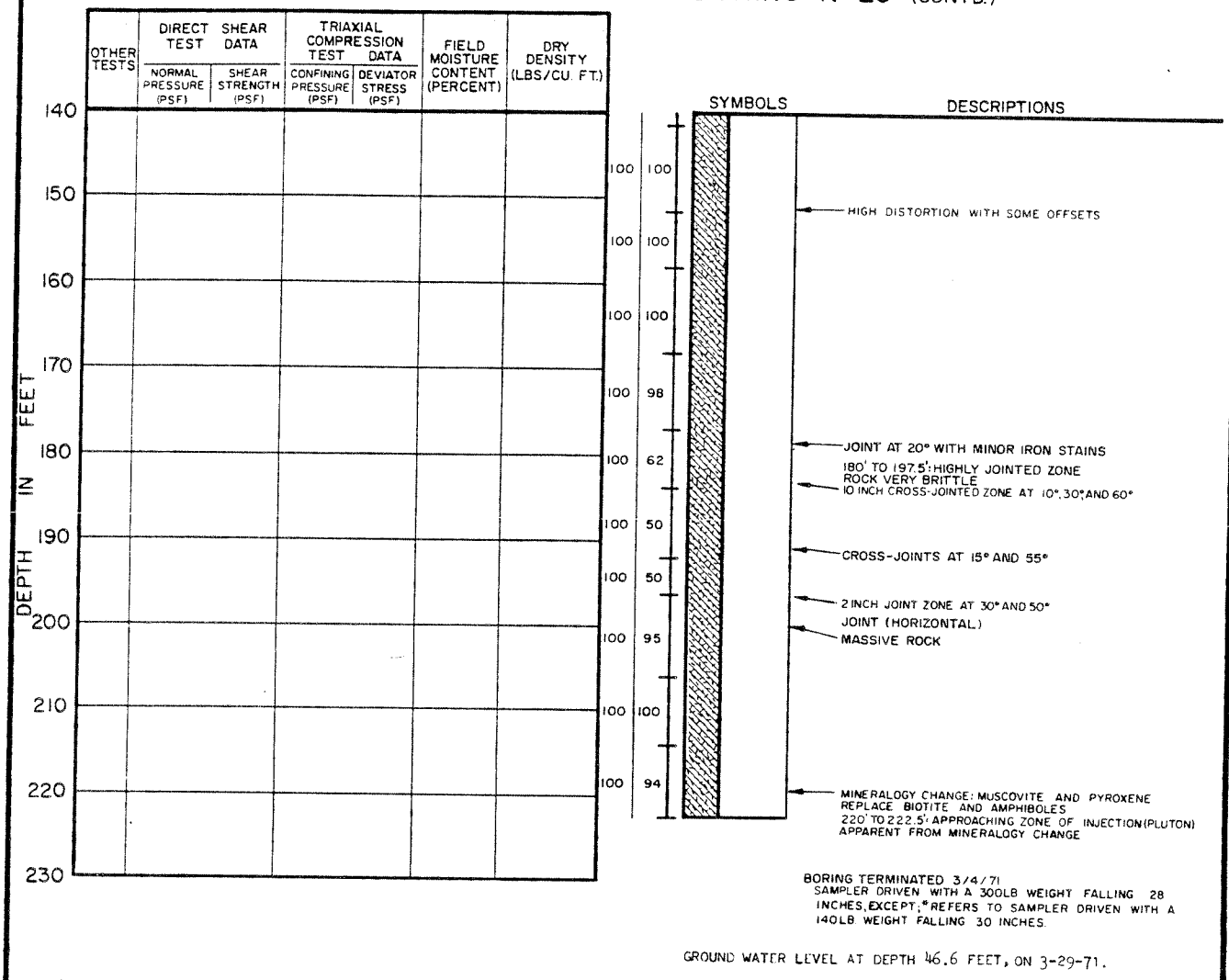


LOG OF BORING N-20

Amendment 0
August 1984

Figure 2E-17

BORING N-20 (CONTD.)

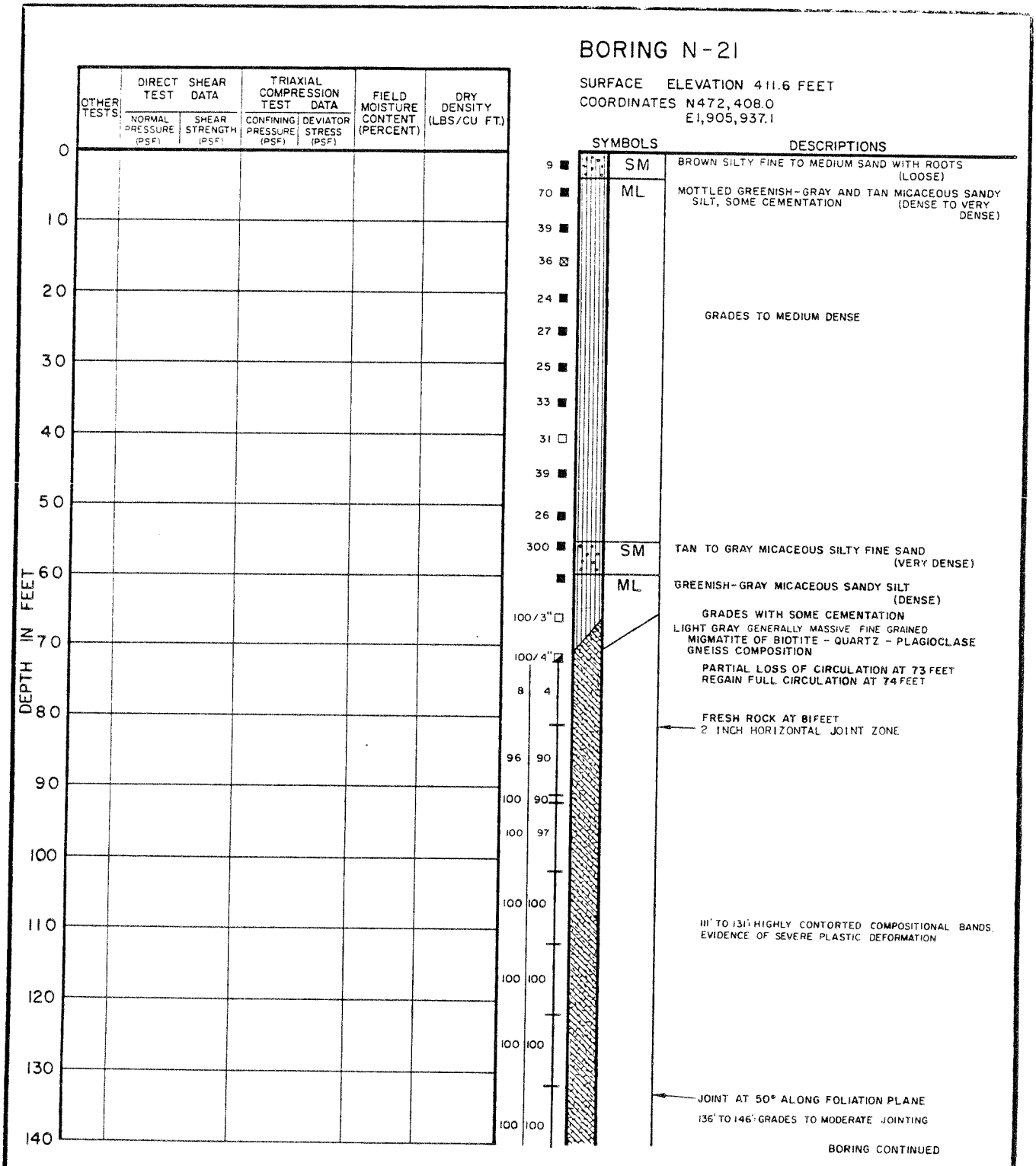


BORING TERMINATED 3/4/71
SAMPLER DRIVEN WITH A 300LB WEIGHT FALLING 28 INCHES, EXCEPT; * REFERS TO SAMPLER DRIVEN WITH A 140LB WEIGHT FALLING 30 INCHES.

GROUND WATER LEVEL AT DEPTH 46.6 FEET, ON 3-29-71.

LOG OF BORING N-20

Figure 2E-17a



LOG OF BORING N-21

Amendment 0
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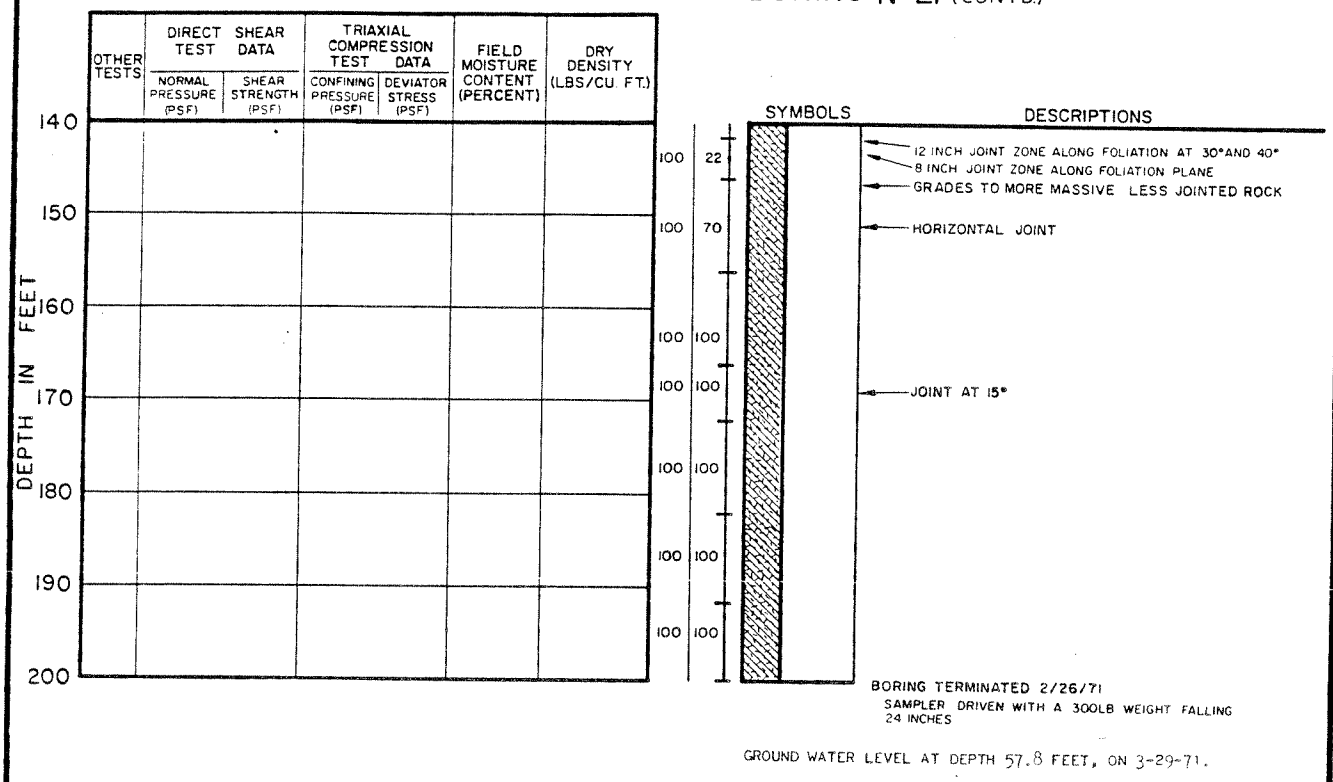
Figure 2E-18

BORING N-21 (CONTD.)



GROUND WATER LEVEL AT DEPTH 57.8 FEET, ON 3-29-71.

LOG OF BORING N-21

Amendment 0
August 1984

Figure 2E-18a

BORING N-22

SURFACE ELEVATION 475.1 FEET
COORDINATES N 472,373.8
E 1,904,768.0

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10		1000	1780			27	94
20							
30						18	99
40	A B	3000	3400			18	97
50						15	113
60							
70							
80							
90							
100							
110							
120							
130							
140							

		SYMBOLS	DESCRIPTIONS
9		CL	REDDISH-BROWN SILTY SANDY CLAY (STIFF)
12			GRADES WITH MORE SAND
8		SM	REDDISH-BROWN TO TAN MICACEOUS SILTY FINE SAND (LOOSE)
8			SOME CLAY IN UPPER FOUR TO FIVE FEET.
7			
9			
9			
10			
13			GRADES TO FINE TO MEDIUM GRAINED
13			
17			GRADES TO MEDIUM DENSE
32			
35			GRADES WITH ROCK FRAGMENTS
100/3"			
75/5"			
76	36		LIGHT TAN TO BUFF FINE GRAINED GRANODIORITE - PARTIALLY WEATHERED AND JOINTED TO 77 FEET.
22	7		4 INCH JOINT ZONE AT 0° AND 45°
			CROSS JOINTS AT 15° AND 45°
			JOINT AT 60°
99	28	SM-SP	TAN SILTY FINE TO MEDIUM SAND (MEDIUM DENSE)
			FRESH ROCK: LIGHT GRAY AND BLACK FINE TO MEDIUM GRAINED GRANODIORITE.
100	50		18 INCH HORIZONTAL JOINT ZONE. SOME IRON STAINING
			HORIZONTAL JOINT WITH IRON STAINS
			6 INCH HORIZONTAL JOINT ZONE WITH IRON STAINS
47	11		CROSS JOINTS AT 15° AND 50°
			HORIZONTAL JOINTS WITH MINOR IRON STAINS
54	17		1 FOOT HIGHLY JOINTED (MOSTLY HORIZONTAL) PARTIALLY DECOMPOSED ZONE
100	100		GRADES TO COARSE GRAINED GRANODIORITE WITH ZONED FELDSPARS
100	100		
100	99		CROSS JOINTS AT 15° AND 45°
			2 INCH HORIZONTAL JOINT ZONE WITH IRON STAINS
62	49		
99	69		2 FOOT HORIZONTAL JOINT ZONE WITH IRON STAINS
			BORING CONTINUED

LOG OF BORING N-22

Amendment 0
August 1984

Figure 2E-19

BORING N-22 (CONTD.)

OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)

DEPTH IN FEET

140
150
160
170
180
190
200
210

96	45
97	97
100	84
98	95
100	100
100	82
89	99
100	99
95	95
100	100

SYMBOLS

DESCRIPTIONS

12" ZONE OF HORIZONTAL JOINTS WITH IRON STAINS
142' TO 144.5':
INCLUSIONS OF PARTIALLY WEATHERED BIOTITE - RICH AMPHIBOLITES
148' TO 154':
HIGHLY JOINTED AT 30° TO 40°

MASSIVE ROCK INFREQUENTLY JOINTED

CROSS JOINTS AT 65° AND 15°

3" JOINT ZONE AT 10° WITH IRON STAINS

GRADES TO MIGMATITE OF GRANODIORITE COMPOSITION - SOME ZONED FELDSPARS STILL EVIDENT

CROSS JOINTS AT 45° AND 30°

BORING TERMINATED 3/6/71

SAMPLE DRIVEN WITH A 300LB. WEIGHT FALLING 28 INCHES.

GROUND WATER LEVEL AT DEPTH 81.0 FEET, ON 3-29-71.

LOG OF BORING N-22

Figure 2E-19a

BORING N-23

SURFACE ELEVATION 464.0
COORDINATES N 472,766.2
E 1,904,433.6

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)	SYMBOLS	DESCRIPTIONS
0								ML	REDDISH-BROWN MICACEOUS CLAYEY SANDY SILT (STIFF)
10								SM	TAN TO GRAY MICACEOUS SILTY FINE TO MEDIUM SAND (LOOSE TO MEDIUM DENSE)
20									
30									GRADES LESS SILTY
40									LIGHT GRAY FINE TO MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION - PARTIALLY WEATHERED TO MODERATELY TO HIGHLY DECOMPOSED TO 65 FEET. DECOMPOSED ZONE OF SOIL CONSISTENCY GRADES TO SLIGHTLY WEATHERED AND FOLIATED
50									50 TO 65 FEET THOROUGHLY DECOMPOSED ZONE (NO RECOVERY)
60									FRESH ROCK AT 65.5 FEET.
70									2 FOOT WEATHERED AND DECOMPOSED ZONE, IRON STAINS ON JOINT SURFACES
80									8 INCH CROSS JOINT ZONE AT 30°, 45° AND 90°
90									AMPHIBOLITE INCLUSION - PARTIALLY WEATHERED JOINT AT 45°
100									6 INCH PARTIALLY WEATHERED ZONE WITH IRON STAINS ON 15° JOINT SURFACES
110									18 INCH DECOMPOSED IRON STAINED ZONE
120									2 INCH JOINT ZONE AT 50° WITH IRON STAINS
130									10 INCH JOINT ZONE AT 0° AND 15° WITH IRON STAINS
140									JOINT AT 60° WITH IRON STAINS
									3 INCH JOINT ZONE AT 60° WITH IRON STAINS
									30 INCH WEATHERED ZONE WITH IRON STAINED JOINTS AT 0° AND 25°
									6 INCH JOINT ZONE AT 30° WITH IRON STAINS
									JOINT AT 30° WITH IRON STAINS
									LOST CIRCULATION. DECOMPOSED HIGHLY CROSS JOINTED ZONES AT 45° AND 20°
									REGAIN 80% CIRCULATION
									8 INCH COARSE GRAINED LIGHT GRAY GRANODIORITE ZONE
									BORING CONTINUED

0						20			
10						27			
20						17			
30						11			
40						14			
50						16			
60						13			
70						24			
80						17	17		
90						60/4"			
100						33	20		
110						0	0		
120						0	0		
130						84	66		
140						86	72		
						93	73		
						98	94		
						93	63		
						100	93		
						90	83		
						100	100		
						100	100		
						100	100		

LOG OF BORING N-23

Amendment 0
August 1984

Figure 2E-20

BORING N-23 (CONTD)

SURFACE ELEVATION
COORDINATES

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
140							
150							
160							
170							
180							
190							
200							
210							

		SYMBOLS	DESCRIPTIONS
100	92		3 INCH JOINT ZONE AT 30° WITH SOME IRON STAINS
99	91		2 INCH JOINT ZONE AT 15° WITH IRON STAINS
			3 INCH JOINT ZONE AT 30° AND 60° WITH IRON STAINS
100	99		AMPHIBOLITE INCLUSION
			FOLIATION MORE PRONOUNCED
93	79		4 INCH JOINT ZONE AT 15° AND 60° WITH IRON STAINS
83	76		6 INCH WEATHERED ZONE WITH SOME IRON STAINS CROSS JOINTS AT 45°
100	100		
100	98		36 INCH ZONE OF LIGHT GRAY COARSE GRAINED GRANODIORITE WITH ZONED FELDSPARS
			2 INCH JOINT ZONE AT 45° WITH IRON STAINS
100	95		1 INCH JOINT ZONE AT 15° WITH IRON STAINS

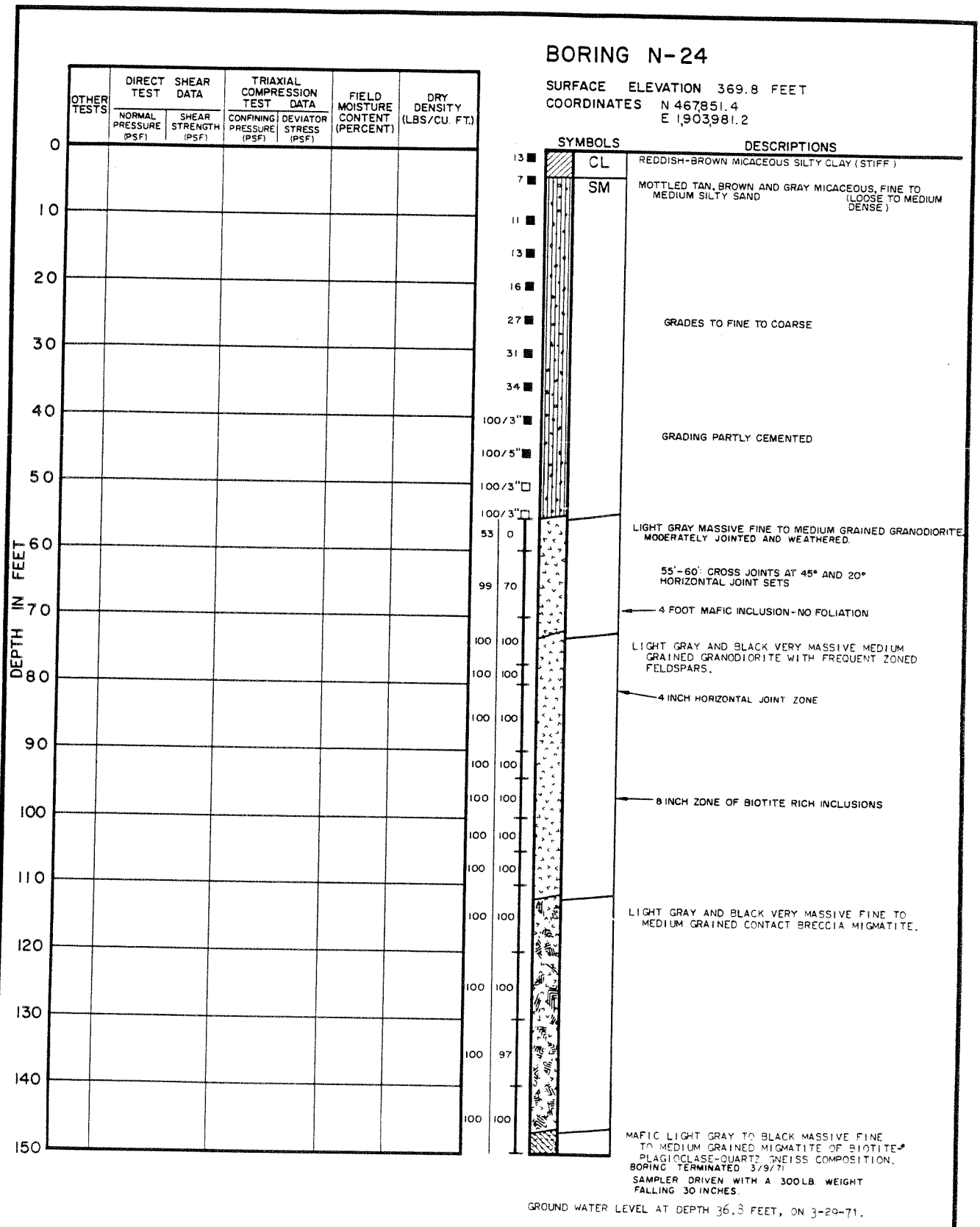
BORING TERMINATED 3/17/71

SAMPLER DRIVEN WITH A 300LB WEIGHT FALLING 30 INCHES.

GROUND WATER LEVEL AT DEPTH 67.0 FEET, ON 3-29-71.

LOG OF BORING N-23

Figure 2E-20a



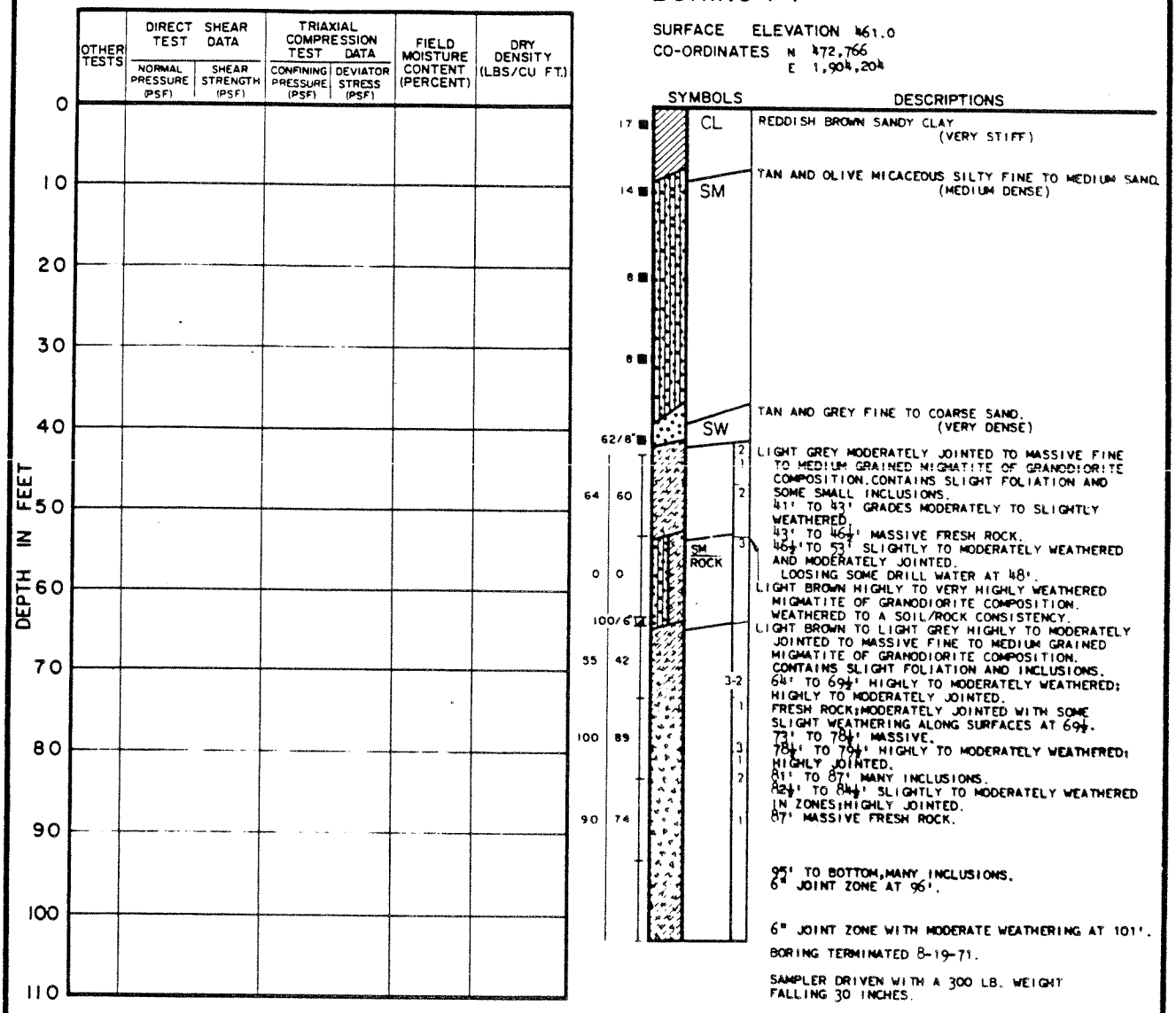
LOG OF BORING N-24

Amendment 0
August 1984

Figure 2E-21

BORING I-1

SURFACE ELEVATION 461.0
CO-ORDINATES N 472,766
E 1,904,204



LOG OF BORING I-1

Figure 2E-22

BORING 1-2

SURFACE ELEVATION 463.9
CO-ORDINATES N 472,660.5
E 1,904,081.5

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							

SYMBOLS	DESCRIPTIONS
9 ML CL	REDDISH BROWN SANDY CLAYEY SILT. (MEDIUM STIFF)
	REDDISH BROWN SANDY SILTY CLAY. (STIFF)
11 SM	REDDISH BROWN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE)
14	GRADING MOTTLED GREY BROWN.
15	
30 SM	GREY AND BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
34	
50/2"	GRADES VERY DENSE.
92 | 85	DARK GREY MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION; CONTAINS MANY INCLUSIONS. FRESH ROCK.
	SLIGHT WEATHERING ALONG JOINT AT 65'.
	2" WEATHERED ZONE ALONG JOINT AT 67½'.
	6" JOINT ZONE WITH MODERATE WEATHERING AT 70½'.
	6" JOINT ZONE WITH SOME WEATHERING AT 77½'.
100 | 93	LIGHT GREY MASSIVE FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. FRESH ROCK.

BORING TERMINATED 8-10-71.

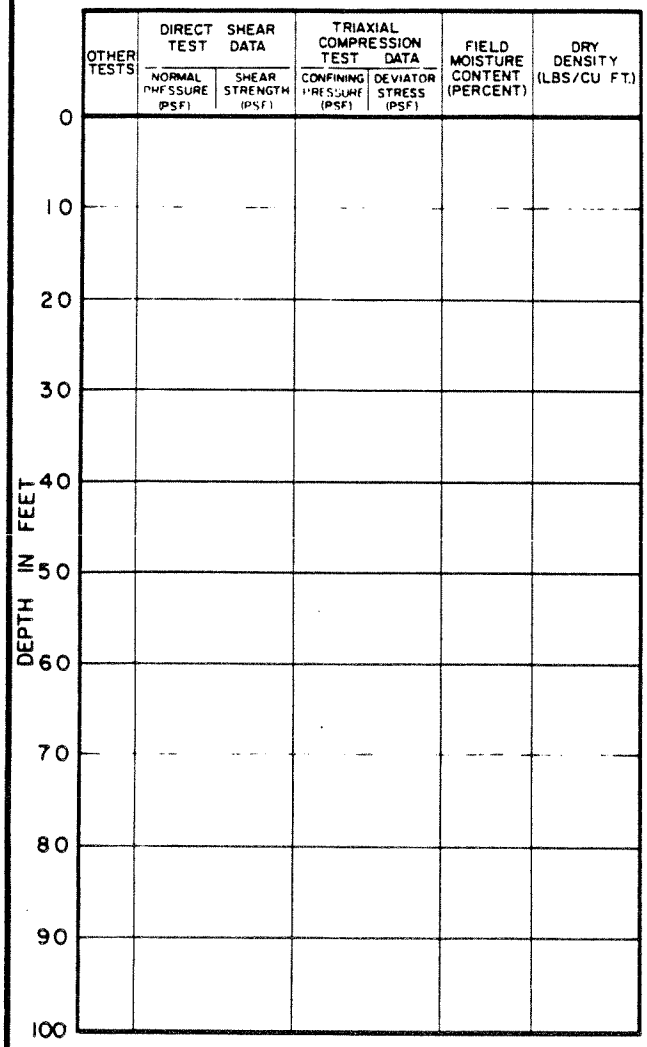
SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 18 INCHES.

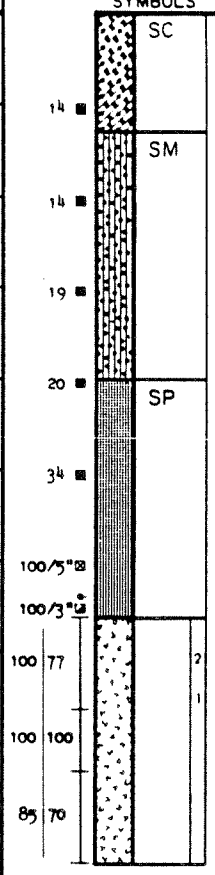
LOG OF BORING 1-2

Figure 2E-23

BORING I-3

SURFACE ELEVATION 467.4
CO-ORDINATES N 472,741.5
E 1,904,322





ORANGE RED SILTY CLAYEY SAND WITH SOME MICA. (STIFF)

YELLOW TAN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE)

GRADES COARSER.

TAN TO BROWN MICACEOUS FINE TO MEDIUM SAND. (DENSE)

GRADES VERY DENSE.

LIGHT GREY MASSIVE MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS SOME INCLUSIONS AND REMNANTS OF FOLIATION.

66' TO 71½' SLIGHTLY WEATHERED.
68½' TO 69½' FRACTURED ZONE.
71½' TO 73' MODERATELY WEATHERED.
FRESH ROCK AT 73'.
3" FRACTURED ZONE AT 77'.
6" FRACTURED ZONE AT 83½'.

6" JOINT ZONE WITH WEATHERED SURFACES.
BORING TERMINATED 8-5-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE DESIGNATED BY AN ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES. *INDICATES STANDARD PENETRATION TESTS.

LOG OF BORING I-3

BORING I-4

SURFACE ELEVATION 453.9
CO-ORDINATES N 472,600
E 1,904,000

OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100

SYMBOLS	DESCRIPTIONS
	RED CLAY, FILL FOR ACCESS.
CL	REDDISH BROWN SILTY CLAY. (STIFF)
SM-ML	MOTTLED REDDISH BROWN MICACEOUS VERY SILTY FINE SAND. (MEDIUM DENSE) GRADES TO OLIVE COLOR.
SM	MOTTLED BROWN MICACEOUS SILTY FINE SAND WITH LITTLE SILT. (VERY DENSE) GRADING OLIVE IN COLOR.
	DARK GREY MODERATE TO HIGHLY JOINTED FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION; HIGHLY CONTORTED FOLIATION. CONTAINS SOME INCLUSIONS. 58' TO 60' HIGHLY WEATHERED; HIGHLY JOINTED. 60' TO 70½' HIGHLY JOINTED. 60' TO 61' MODERATELY WEATHERED ZONE. 61' TO 65' SLIGHTLY WEATHERED. 65' TO 67½' FRESH ROCK. 67½' TO 70½' SLIGHTLY WEATHERED. 70½' TO 74½' MASSIVE. 70½' TO 76½' FRESH ROCK. 74½' TO 80½' HIGHLY JOINTED. 76½' TO 78' SLIGHTLY WEATHERED. 78' TO 80½' MODERATELY WEATHERED. 6" HIGHLY WEATHERED ZONE AT 78½'. MASSIVE FRESH ROCK, LESS CONTORTED FOLIATION AT 81'.
	LIGHT GREY MASSIVE COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION; CONTAINS SOME INCLUSIONS. LIGHT GREY MASSIVE COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS.

BORING TERMINATED 8-9-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE DESIGNATED BY AN ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES. *INDICATES STANDARD PENETRATION TESTS.

GROUND WATER LEVEL AT DEPTH 55 FEET, ON 10-14-71.

LOG OF BORING I-4

Amendment 0
August 1984

Figure 2E-25

BORING I-5

SURFACE ELEVATION 474.2
CO-ORDINATES N 472,603
E 1,904,210

OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 110, 120, 130, 140

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY WITH SOME SAND. (HARD)
SM-ML	REDDISH BROWN CLAYEY SILT WITH SOME MICA (VERY STIFF) AND MOTTLED WHITE AND ORANGE BROWN SILTY FINE SAND. (MEDIUM DENSE)
SM-ML	MOTTLED GREY, PINK, AND WHITE SILTY FINE SAND WITH SOME MICA (DENSE) AND SOME YELLOWISH BROWN SILT. DENSE) (MEDIUM DENSE)
SM	MOTTLED WHITE, LIGHT BROWN AND GREY MICACEOUS SILTY FINE TO MEDIUM SAND WITH SOME COARSE SAND. (MEDIUM DENSE)
SM	WHITE, BROWN, AND GREY MICACEOUS SILTY FINE TO MEDIUM SAND. (VERY DENSE)

11 ■
11 ■
12 ■
13 ■
16 ■
80/11½"*
51/4"*
50/1"*

80 | 29
70 | 0
28 | 0
100 | 65
100 | 92
100 | 95

3
2
3
2
1

DARK GREY TO TAN HIGHLY JOINTED FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-GNEISS COMPOSITION.
GRADES FROM HIGHLY TO MODERATELY WEATHERED WITH DEPTH.

LIGHT TAN MODERATELY JOINTED FINE GRAINED SLIGHTLY WEATHERED GRANODIORITE.

LIGHT GREY SLIGHTLY JOINTED FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS SLIGHT FOLIATION.

FRESH ROCK AT 85½'.

LOST WATER CIRCULATION AT 86'.

BLACK TO LIGHT GREY AND TAN HIGHLY TO MODERATELY JOINTED FINE TO COARSE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION.
86' TO 97½' HIGHLY JOINTED.
88' TO 98' MODERATELY WEATHERED.
7" GRANOFELS INCLUSION AT 89½'.
1 FOOT HIGHLY WEATHERED, CONTAINS SOME INCLUSIONS AND HEALED SHEARS AT 90½'.
FRESH ROCK; MODERATELY JOINTED AT 98'.
HIGHLY CONTORTED FOLIATION AT 100½'.

LIGHT GREY MASSIVE MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS SOME INCLUSIONS AND INTERMITTANT FOLIATION.

½" JOINT ZONE AT 103'.
½" ZONE OF WEATHERING ALONG FOLIATION AND JOINTS AT 105'.

LIGHT GREY MASSIVE FINE TO COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS.

LIGHT TO DARK GREY MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. CONTAINS MANY HEALED SHEARS.
SLIGHT WEATHERING ALONG TWO JOINTS AT 111'.

BORING TERMINATED 8-9-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE DESIGNATED BY AN ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES.
*INDICATES STANDARD PENETRATION TESTS.

GROUND WATER LEVEL AT DEPTH 73 FEET, ON 10-14-71.

LOG OF BORING I-5

Amendment 0
August 1984

Figure 2E-26

BORING I-6

SURFACE ELEVATION 459.4
CO-ORDINATES N 472,500
E 1,904,105

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY WITH SOME SAND AND SOME MICA. (VERY STIFF)
SM	MOTTLED YELLOWISH BROWN TO BROWN WITH SOME BLACK SILTY FINE SAND WITH SOME MICA. (DENSE)
	GRADES MOTTLED GREY BROWN, HIGHLY MICACEOUS.
SM	MOTTLED ORANGE, BROWN, AND GREY MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
	GRADES VERY DENSE; SOME WEATHERED ROCK FRAGMENTS.
	DARK GREY JOINTED TO MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. CONTAINS SOME INCLUSIONS AND MANY HEALED FRACTURES.
	52½' TO 58' HIGHLY JOINTED; SOME SLIGHT WEATHERING.
	6" MODERATELY WEATHERED ZONE AT 58'.
	6" SLIGHTLY WEATHERED ZONE AT 58½'.
	6" QUARTZOFELDSPATHIC DIKE AT 58½'.
	58½' TO 77' MASSIVE FRESH ROCK.
	2" HIGHLY WEATHERED ZONE ALONG JOINT AT 62'.
	6" JOINT ZONE WITH SOME WEATHERING AT 63½'.
	71½' TO 73' LIGHT GREY MASSIVE FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION.
	LIGHT GREY MASSIVE FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS REMNANTS OF FOLIATION. FRESH ROCK.
	BORING TERMINATED 8-10-71.
	SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE DESIGNATED BY AN ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES. *INDICATES STANDARD PENETRATION TESTS.

13							
23							
22							
25							
106/7"							
130							
67	0						
65	47						
99	73						
100	100						

2
1

LOG OF BORING I-6

Amendment 0
August 1984

Figure 2E-27

BORING I-7

SURFACE ELEVATION 456.0
CO-ORDINATES N 472,561
E 1,904,277

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							
100							

	SYMBOLS	DESCRIPTIONS
7*		LIGHT BROWN FINE TO MEDIUM SAND, FILL FOR ACCESS. (LOOSE)
	CL	REDDISH BROWN SILTY CLAY. (MEDIUM STIFF)
15	SM	LIGHT BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
19		GRADES TO DARK BROWN.
70/10½"		GRADES OLIVE IN COLOR AND VERY DENSE.
50/3"	SP	TAN MICACEOUS FINE TO MEDIUM SAND. (VERY DENSE)
60/4½"		GRADING SILTY.
		GRADING VERY DENSE, SOME ROCK FRAGMENTS.
90 40		LIGHT TAN TO BROWN HIGHLY JOINTED TO MASSIVE FINE TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION, CONTAINS SLIGHT FOLIATION.
41 0	3-2	65' TO 78' MODERATELY WEATHERED AND MODERATELY TO HIGHLY JOINTED.
		65' TO 74' COARSE GRAINED.
		74' TO 83' FINE GRAINED.
60 38	2	78' TO 80½' SLIGHTLY WEATHERED AND SLIGHTLY JOINTED; CONTAINS DISTINCT FOLIATION.
100 88	1	MASSIVE FRESH ROCK AT 80½'.
		LIGHT PINK-GREY WITH BLACK MASSIVE COARSE GRAINED GRANODIORITE WITH ZONED FELDSPARS.
91 76		LIGHT GREY SLIGHTLY JOINTED FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS FOLIATION AND INCLUSIONS.
90 80		LIGHT PINK-GREY WITH BLACK MASSIVE MEDIUM TO COARSE GRAINED GRANODIORITE WITH ZONED FELDSPARS.
		3" JOINT ZONE AT 90½'.
		GRADES VERY COARSE GRAINED AT 94'.
		2" JOINT ZONE AT 95'.
		BORING TERMINATED 8-4-71.
		SAMPLER DRIVEN WITH A 140 LB. WEIGHT FALLING 30 INCHES. *INDICATES STANDARD PENETRATION TESTS.

GROUND WATER LEVEL AT DEPTH 55 FEET, ON 10-14-71.

LOG OF BORING I-7

Figure 2E-28

BORING 1-8

SURFACE ELEVATION 466.3
CO-ORDINATES N 472,384
E 1,904,000

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							

SYMBOLS	DESCRIPTIONS
ML	REDDISH BROWN MICACEOUS CLAYEY SILT. (STIFF)
SM-SP	TAN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
	GRADES SILTY FINE SAND.
SP	MOTTLED YELLOW AND BROWN MICACEOUS FINE TO MEDIUM SAND WITH SOME SILT. (DENSE)
	GRADES GREY AND TAN.
SW ROCK	INTERLAYERED ZONES OF HIGHLY WEATHERED ROCK AND FINE TO COARSE SAND.
	LIGHT AND DARK GREY HIGHLY JOINTED TO MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. CONTAINS INCLUSIONS AND HEALED SHEARS. 56' TO 60½' GRADES FROM HIGHLY TO SLIGHTLY WEATHERED; HIGHLY JOINTED. 60½' TO 64' FRESH ROCK; MODERATELY JOINTED WITH SLIGHT WEATHERING ALONG JOINT SURFACES. 6" HIGHLY TO MODERATELY WEATHERED JOINT ZONE AT 64½'. 64½' TO 66½' FRESH ROCK; HIGHLY JOINTED. 66½' TO 69' FRESH ROCK; SLIGHLY JOINTED. MASSIVE FRESH ROCK AT 69'.
	6" HIGH ANGLE JOINT AND FRACTURED ZONE HEALED WITH PINK FELDSPARS AT 82'.
	BORING TERMINATED 8-19-71.
	SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

15		
19		
30		
23		
31		
41		
50/3"		
0	0	3
33	18	3-2
88	62	2
97	88	1
100	91	

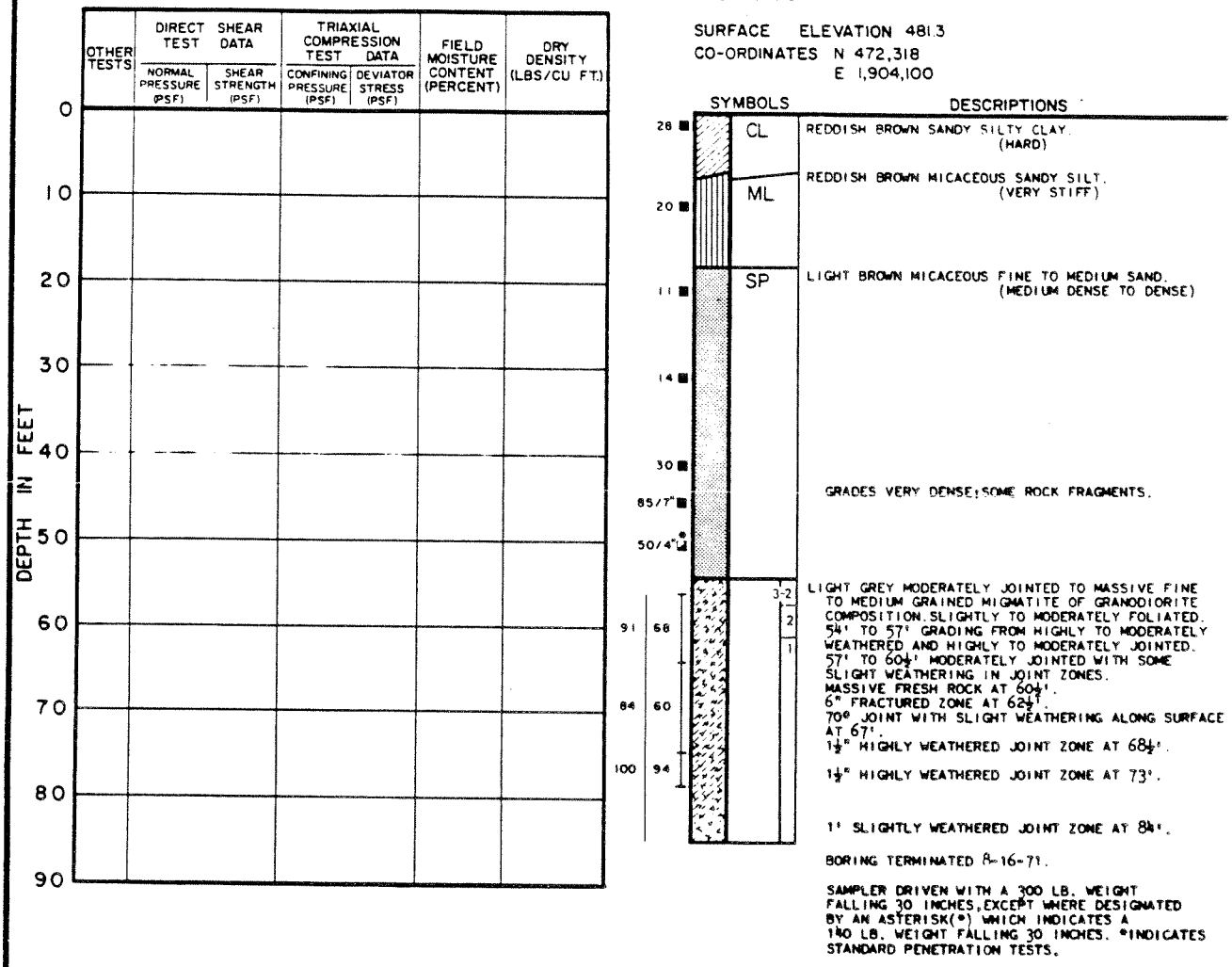
LOG OF BORING 1-8

Amendment 0
August 1984

Figure 2E-29

BORING 1-9

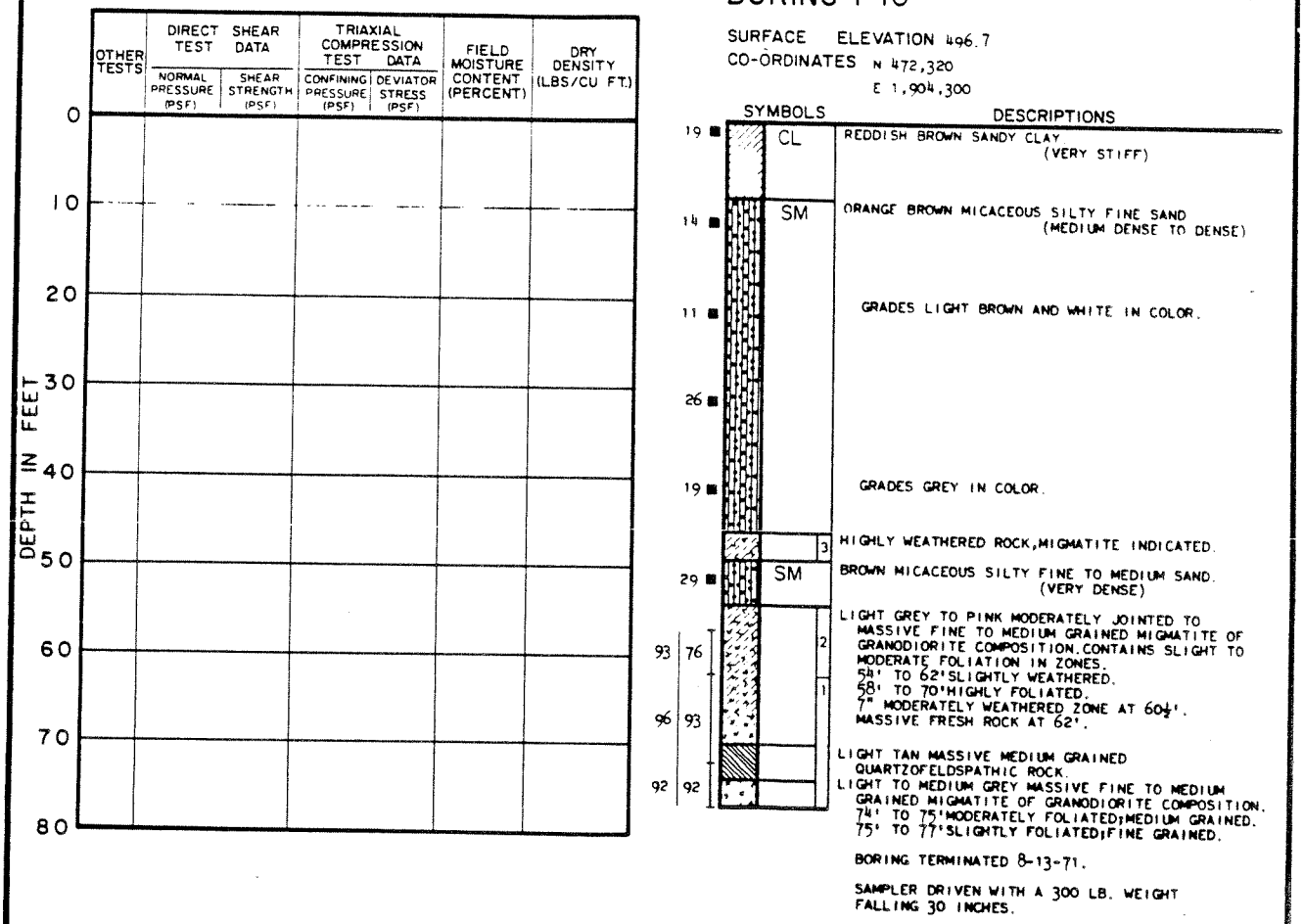
SURFACE ELEVATION 481.3
CO-ORDINATES N 472,318
E 1,904,100



LOG OF BORING 1-9

Amendment 0
August 1984

Figure 2E-30



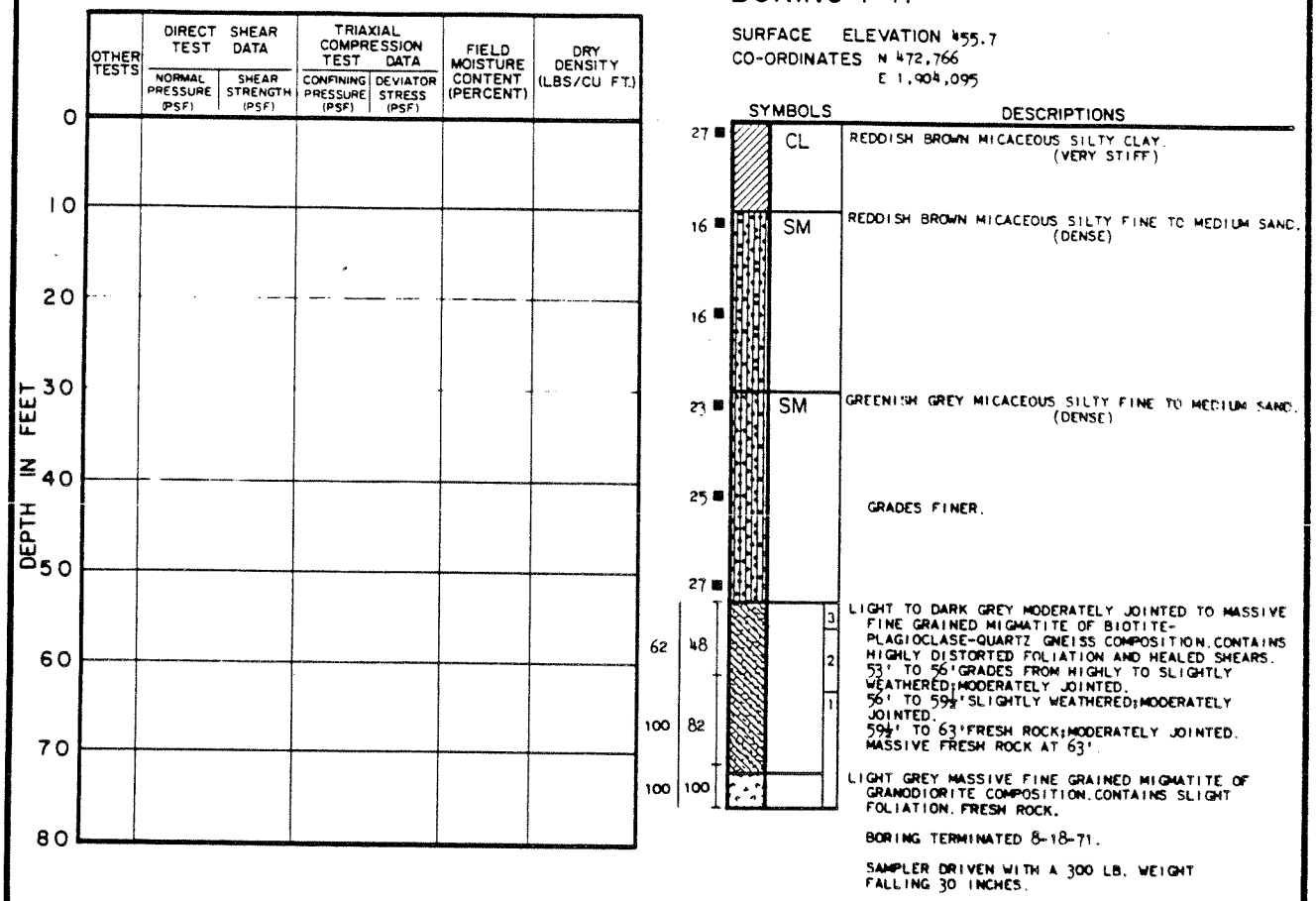
LOG OF BORING 1-10

Amendment 0
August 1984

Figure 2E-31

BORING I-11

SURFACE ELEVATION 455.7
CO-ORDINATES N 472,766
E 1,904,095



LOG OF BORING I-11

Amendment 0
August 1984

Figure 2E-32

BORING 1-12

SURFACE ELEVATION 400.6
CO-ORDINATES N 473,150
E 1,904,000

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							

SYMBOLS	DESCRIPTIONS
CL	RED BROWN SANDY CLAY (STIFF)
	GRADES MORE SANDY.
SM	TAN AND OLIVE MICACEOUS SILTY FINE SAND. (DENSE)
SP	TAN, OLIVE, BLACK AND WHITE MICACEOUS FINE TO MEDIUM SAND. (DENSE)
	LIGHT AND DARK GREY MASSIVE FINE GRAINED CONTACT BRECCIA MIGMATITE 61' TO 63' GRADES FROM WEATHERED TO FRESH ROCK. 63' TO 80' MASSIVE FRESH ROCK. LIGHT AND DARK GREY MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. LIGHT AND DARK GREY MASSIVE FINE GRAINED CONTACT BRECCIA MIGMATITE.

BORING TERMINATED 8-20-71.

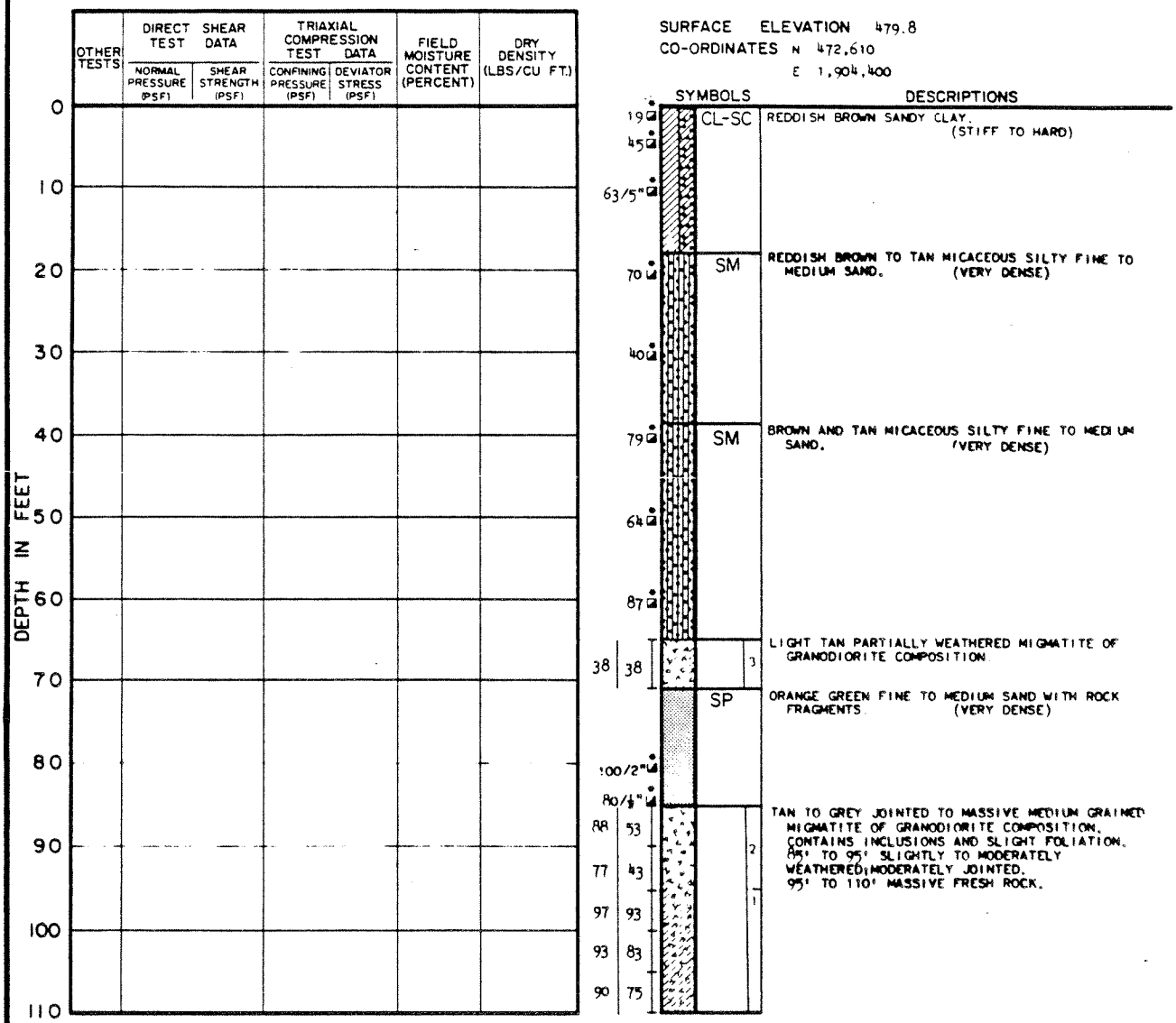
SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE DESIGNATED BY AN ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES. *INDICATES STANDARD PENETRATION TESTS.

GROUND WATER LEVEL AT DEPTH 31 FEET, ON 10-14-71.

LOG OF BORING 1-12

BORING 2-1

SURFACE ELEVATION 479.8
CO-ORDINATES N 472,610
E 1,904,400



BORING TERMINATED 7-30-71.

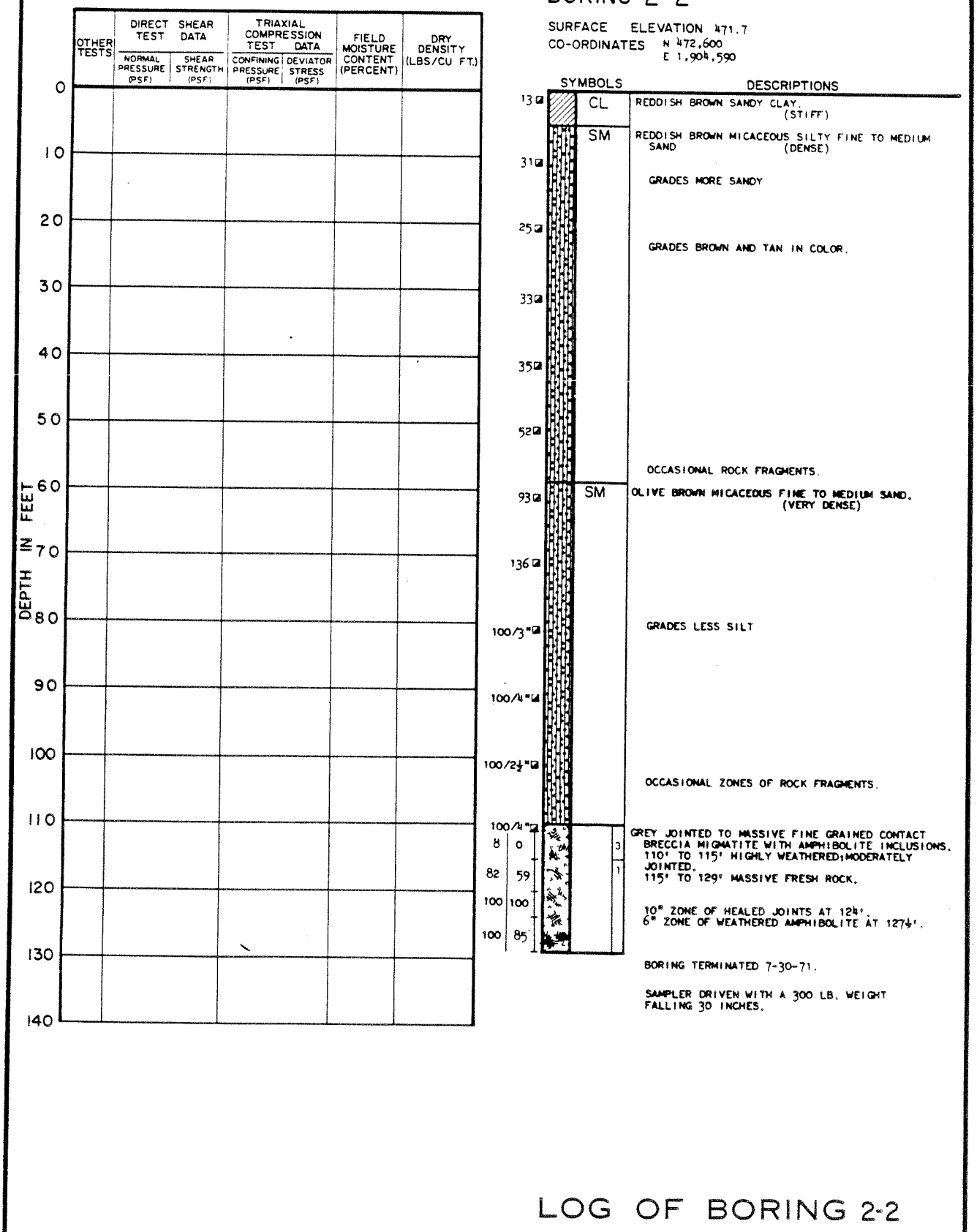
SAMPLER DRIVEN WITH A 140 LB. WEIGHT FALLING 30 INCHES. *INDICATES STANDARD PENETRATION TESTS.

NOTE:
BORING LOG IS A COMPOSITE OF TWO ADJACENT BORINGS, ONE OF WHICH WAS TERMINATED AT A SHALLOW DEPTH DUE TO EQUIPMENT PROBLEMS.

LOG OF BORING 2-1

Amendment 0
August 1984

Figure 2E-34

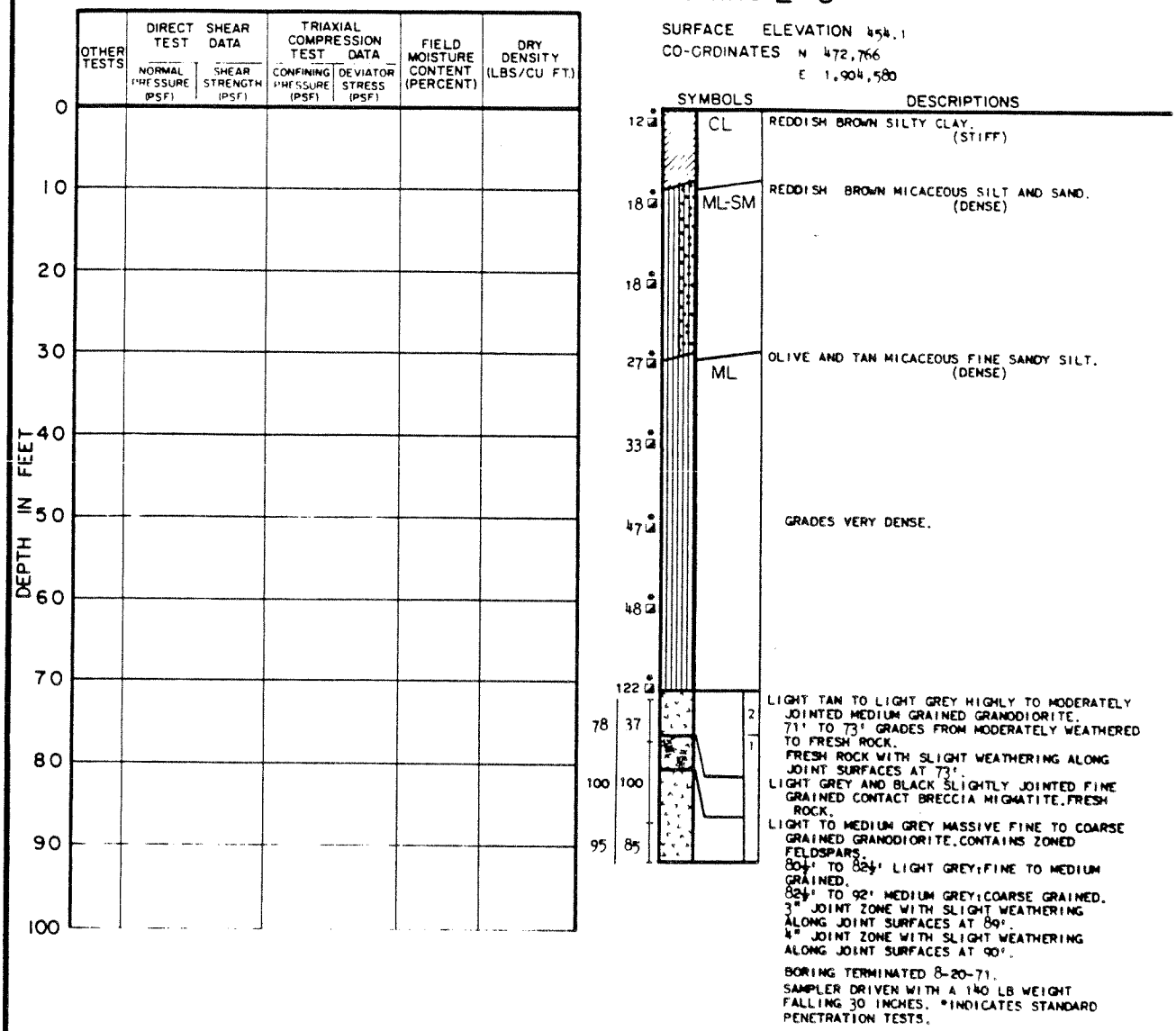


LOG OF BORING 2-2

Figure 2E-35

BORING 2-3

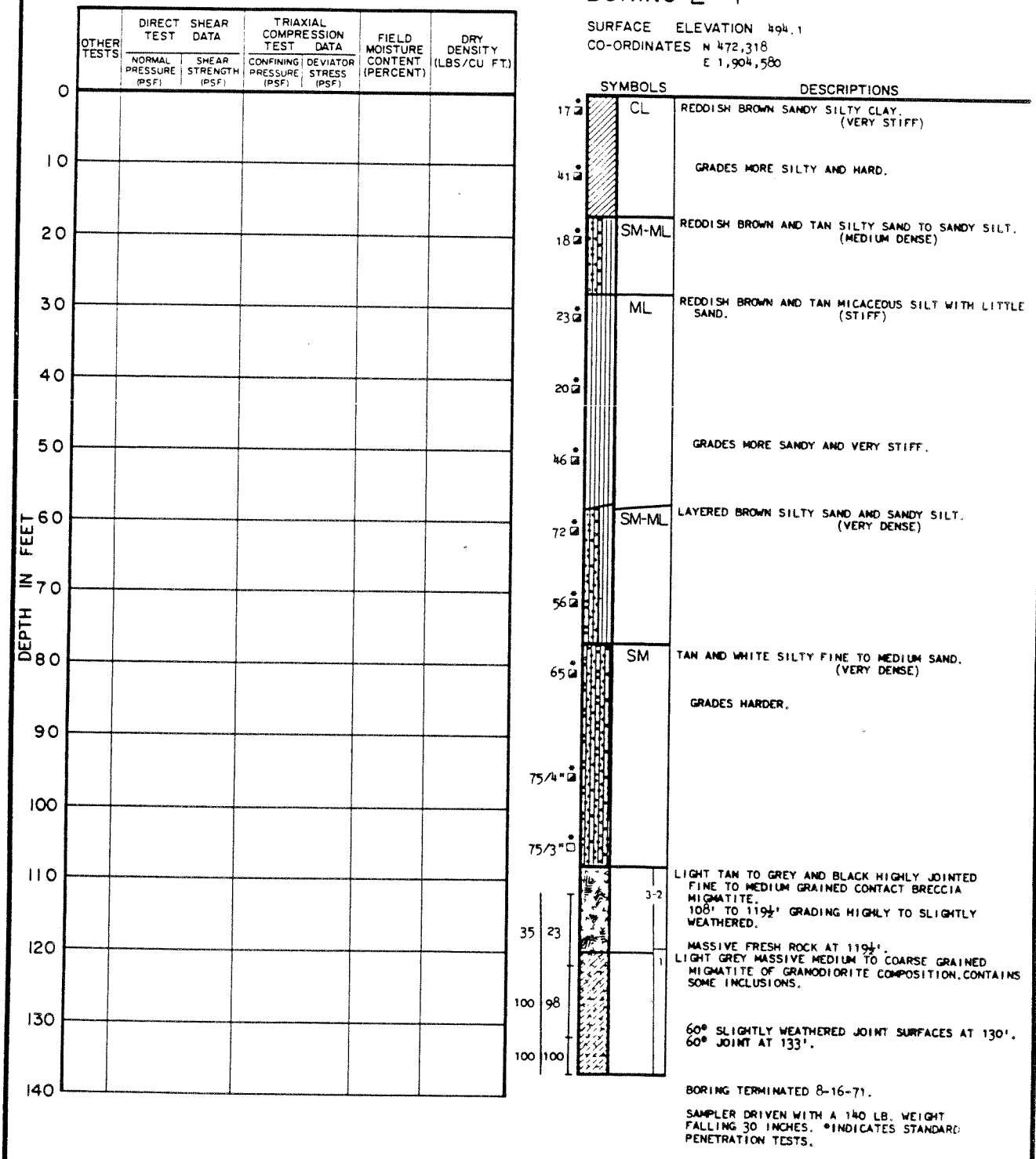
SURFACE ELEVATION 454.1
CO-ORDINATES N 472,766
E 1,904,580



LOG OF BORING 2-3

Amendment 0
August 1984

Figure 2E-36



LOG OF BORING 2-4

Amendment 0
August 1984

Figure 2E-37

BORING 3-1

SURFACE ELEVATION 457.6
CO-ORDINATES N 472,600
E 1,904,740

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							
100							
110							
120							

SYMBOLS	DESCRIPTIONS
	CLAY; FILL FOR ACCESS.
CL	REDDISH BROWN MICACEOUS SILTY CLAY. (VERY STIFF)
SM-ML	REDDISH BROWN MICACEOUS SANDY SILT TO SILTY SAND. (DENSE)
	GRADES PARTIALLY YELLOW IN COLOR.
	GRADES BROWN AND TAN IN COLOR.
SM	TAN AND BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (VERY DENSE)
	LIGHT GREY SLIGHTLY TO HIGHLY JOINTED FINE TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS. 80' TO 81' SLIGHTLY TO MODERATELY WEATHERED; HIGHLY JOINTED. 81' TO 82½' FRESH ROCK; SLIGHTLY JOINTED. 82½' TO 83' MODERATELY WEATHERED 6" JOINT ZONE WITH INCLUSIONS. 83' TO 84' SLIGHTLY TO MODERATELY WEATHERED; MODERATELY JOINTED. 84' TO 88½' MODERATELY WEATHERED; HIGHLY JOINTED. 1' ZONE OF SLIGHTLY WEATHERED ROCK AT 86'. 88½' TO 92½' MASSIVE FRESH ROCK. 92½' TO 98' MODERATELY WEATHERED; HIGHLY JOINTED. LIGHT GREY MASSIVE COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS. FRESH ROCK. 99' TO 100' SLIGHTLY WEATHERED JOINT ZONE. LIGHT GREY MASSIVE FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS AND REMNANTS OF FOLIATION. LIGHT GREY MASSIVE MEDIUM TO COARSE GRAINED GRANODIORITE. 1½' MODERATELY JOINTED WITH SOME ZONES OF SLIGHT WEATHERING AT 111' BORING TERMINATED 8-11-71.

SAMPLER DRIVEN WITH A 140 LB. WEIGHT FALLING 30 INCHES. *DENOTES STANDARD PENETRATION TEST.

29*			
24*			
14*			
26*			
26*			
37*			
67*			
80/4"*			
89	40		
100	100	2	
		1	
		3	
80	31		
		1	
98	91		

LOG OF BORING 3-1

Figure 2E-38

BORING 3-2

SURFACE ELEVATION 443.7
CO-ORDINATES N 472,600
E 1,904,900

OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
A D					18	104
B					12	115
	3000	4380			14	116

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 110, 120, 130, 140

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY. (VERY STIFF) GRADES YELLOW AND RED IN COLOR GRADES SANDY.
SM	TAN TO BROWN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE) GRADES REDDISH BROWN AND WITH FINE TO MEDIUM SAND. GRADES TAN TO BROWN IN COLOR. GRADES VERY DENSE.
SP	TAN TO BROWN MICACEOUS FINE TO MEDIUM SAND WITH A TRACE OF SILT AND SMALL ROCK FRAGMENTS. (VERY DENSE)
	LIGHT GREY-PINK HIGHLY JOINTED MEDIUM GRAINED GRANODIORITE. HIGHLY TO MODERATELY WEATHERED.
	LIGHT AND DARK GREY HIGHLY JOINTED FINE GRAINED CONTACT BRECCIA MIGMATITE. HIGHLY FRAGMENTED; SLIGHTLY TO MODERATELY WEATHERED.
SM/ ROCK	DARK BROWN HIGHLY JOINTED FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. HIGHLY WEATHERED WITH ZONES OF SOIL CONSISTENCY AND THIN LAYERS OF MORE COMPETENT CONTACT BRECCIA MIGMATITE.
SM/ ROCK	LIGHT AND DARK GREY HIGHLY JOINTED TO MASSIVE FINE GRAINED CONTACT BRECCIA MIGMATITE. 102' TO 110' HIGHLY JOINTED. 102' TO 105' MODERATELY WEATHERED. 105' TO 110' HIGHLY WEATHERED WITH ZONES OF SOIL CONSISTENCY.. MASSIVE FRESH ROCK AT 110'. STAINED JOINT AT 115'.
	LIGHT GREY MASSIVE FINE TO MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS AND FOLIATION. STAINED JOINT AT 120½'. 3" JOINT ZONE AT 126½'. BORING TERMINATED 8-9-71. SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

10		CL	
14			
		SM	
16			
13			
16			
21			
59			
		SP	
113			
90/4"	80		3
17	0		
			2
32	3		1
		SM/ ROCK	
78	17	SM/ ROCK	3
			1
99	88		
100	92		

GROUND WATER LEVEL AT A DEPTH OF 65 FEET ON 10-14-71.

LOG OF BORING 3-2

Amendment 0
August 1984

Figure 2E-39

BORING 3-3

SURFACE ELEVATION 425.4
CO-ORDINATES N 472,742
E 1,904,900

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0	C					23	
10							
20		2500	2050			19	86
30							
40	B	1500	1560			20	94
50	B					20	102
60	*,D					19	112
70							
80							
90							
100							
110							

SYMBOLS	DESCRIPTIONS
ML	BROWN SANDY CLAYEY SILT. (MEDIUM STIFF) GRADES REDDISH BROWN AND STIFF TO VERY STIFF
SM	REDDISH BROWN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE)
SM	TAN AND OLIVE FINE TO MEDIUM SAND WITH SILT. (DENSE)
	GRADES VERY DENSE.
SW/ROCK	ZONES OF VERY HIGHLY WEATHERED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION, AND FINE TO COARSE SAND DERIVED FROM DECOMPOSED ROCK.
	LIGHT TO MEDIUM GREY MODERATELY JOINTED TO MASSIVE FINE GRAINED MIGMATITE OF BIOTITE-QUARTZ-PLAGIOCLASE GNEISS COMPOSITION. CONTAINS HIGHLY DISTORTED FOLIATION. 80' TO 81½' GRADES FROM HIGHLY TO MODERATELY WEATHERED; HIGHLY TO MODERATELY JOINTED. 81½' TO 93' MASSIVE FRESH ROCK. 6" PINK FELDSPAR HEALED ZONE AT 93' 93' TO 95' FRESH ROCK; MODERATELY JOINTED WITH SOME WEATHERING ALONG JOINTS. 95' TO 106' MASSIVE FRESH ROCK.
	3" JOINT ZONE AT 102½'.

11	0	0
31	18	7
11	100	95
25	100	75
22	100	98
24		
62		

BORING TERMINATED 8-23-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE DESIGNATED BY AN ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES. *DENOTES STANDARD PENETRATION TEST.

LOG OF BORING 3-3

Figure 2E-40

BORING 3-4

SURFACE ELEVATION 472.1
CO-ORDINATES N 472,318
E 1,904,900

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50		500	1050			21	97
60							
70							
80							
90							
100							
110							

SYMBOLS		DESCRIPTIONS
15	CL	REDDISH BROWN SILTY CLAY. (STIFF)
15	SM	REDDISH BROWN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE)
17		GRADES PARTIALLY TAN IN COLOR.
61/8"	SM	TAN AND OLIVE MICACEOUS SILTY SAND. (MEDIUM DENSE) LENSES OF ROCK AT 31'.
15		
25		GRADES DENSE TO VERY DENSE.
40		
44		
50/2"		TAN TO MEDIUM GREY HIGHLY JOINTED TO MASSIVE FINE TO MEDIUM GRAINED GRANODIORITE. CONTAINS SOME AREAS OF FLOW STRUCTURE AND ZONED FELDSPARS. 55' TO 65' HIGHLY WEATHERED. 55' TO 70' MODERATELY JOINTED. 65' TO 66' MODERATELY WEATHERED. 66' TO 67½' SLIGHTLY WEATHERED. 67½' TO 68' HIGHLY WEATHERED. 68' TO 69' SLIGHTLY WEATHERED. 69' TO 70' MODERATELY WEATHERED. 70' TO 74' MASSIVE; VERY SLIGHTLY WEATHERED. 74' TO 78½' MODERATELY WEATHERED; MODERATELY JOINTED; TAN. 78½' TO 85' MASSIVE FRESH ROCK. 85' TO 88' FRESH TO SLIGHTLY WEATHERED; SLIGHTLY JOINTED. 88' TO 94½' FRESH TO SLIGHTLY WEATHERED; HIGHLY JOINTED.
50/1"		
62	32	
86	63	
97	90	
100	55	94½' TO 101' FRESH ROCK; SLIGHTLY JOINTED.
100	81	101' TO 109' MASSIVE FRESH ROCK.

BORING TERMINATED 8-23-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE DESIGNATED BY AN ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES.

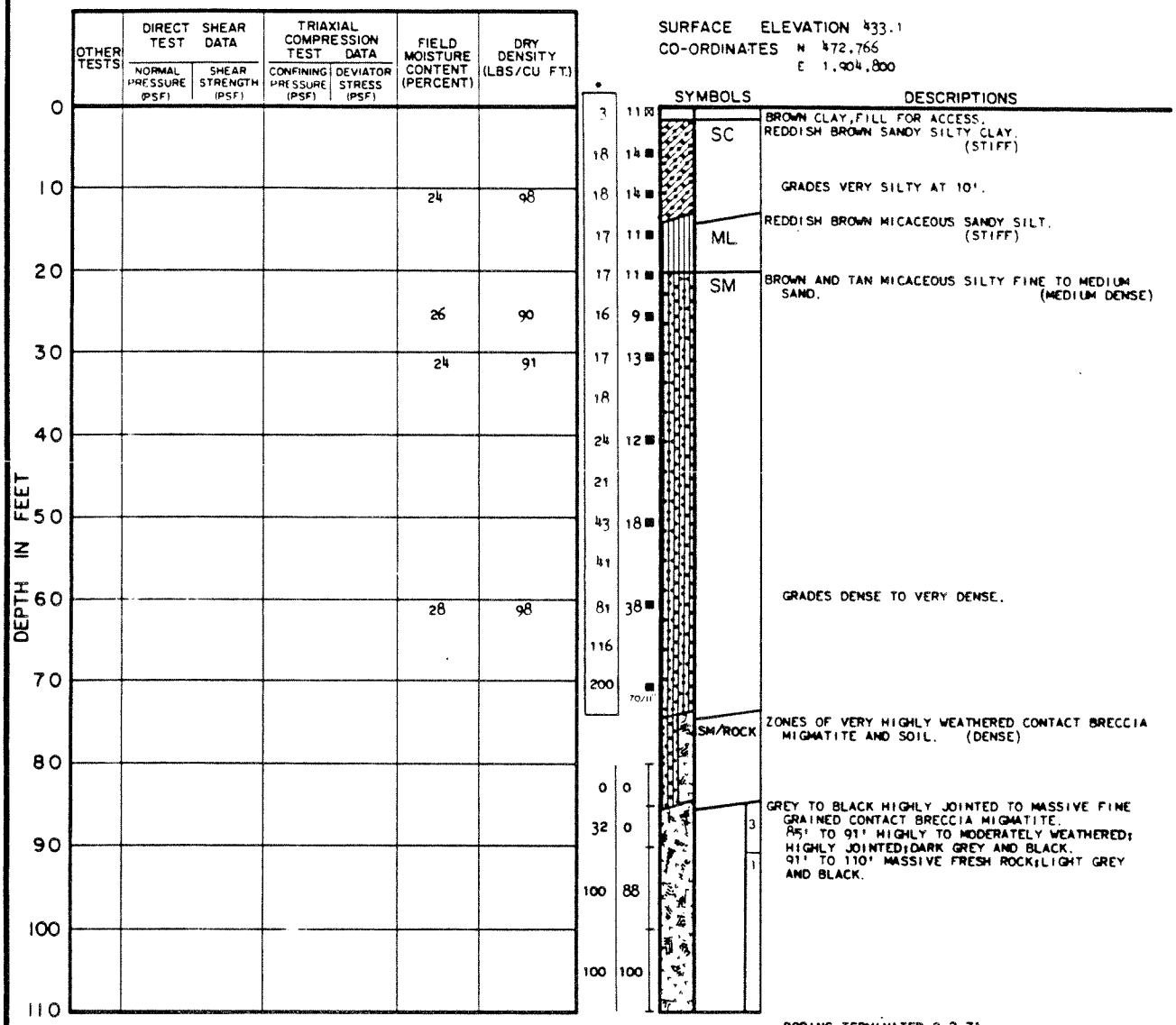
LOG OF BORING 3-4

Amendment 0
August 1984

Figure 2E-41

BORING 3-5

SURFACE ELEVATION 433.1
CO-ORDINATES N 472,766
E 1,904,800



BORING TERMINATED 9-2-71.

NUMBERS ENCLOSED WITHIN THE COLUMN DESIGNATED BY ASTERISK (*) INDICATE BLOWCOUNTS OBTAINED FROM AN ADJACENT BORING UTILIZING STANDARD PENETRATION EQUIPMENT.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE ENCLOSED WITHIN THE COLUMN DESIGNATED BY ASTERISK (*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES.
*INDICATES STANDARD PENETRATION TEST.

LOG OF BORING 3-5

Amendment 0
August 1984

Figure 2E-42

BORING 3-6

SURFACE ELEVATION 442.6
CO-ORDINATES N 472,640
E 1,904,875

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20		1500	1300			20	89
30							
40							
50		2500	2070			13	103
60							
70							
80							
90							
100							
110							
120							
130							
140							

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SANDY SILTY CLAY. (VERY STIFF)
ML	REDDISH BROWN AND TAN CLAYEY SANDY SILT. (VERY STIFF)
SM	REDDISH BROWN AND TAN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE)
SM	TAN AND OLIVE MICACEOUS FINE SAND WITH SILT. (MEDIUM DENSE)
SM	GREY, BROWN AND OLIVE MICACEOUS SILTY FINE TO MEDIUM SAND WITH ROCK FRAGMENTS. (DENSE)
	GRADES VERY DENSE
SP/ROCK	ZONES OF VERY HIGHLY JOINTED, HIGHLY WEATHERED CONTACT BRECCIA MIGMATITE AND SOIL.
	GREY AND BLACK HIGHLY JOINTED FINE TO MEDIUM GRAINED CONTACT BRECCIA MIGMATITE. CONTAINS VERY HIGHLY CONTORTED FOLIATION AND NUMEROUS ANGULAR INCLUSIONS. 91' TO 95' MODERATELY WEATHERED. 95' TO 99' FRESH ROCK WITH SLIGHT WEATHERING ALONG SOME JOINTS. 99' TO 103' MODERATELY WEATHERED. 103' TO 107' SLIGHTLY TO MODERATELY WEATHERED. 107' TO 108' FRESH ROCK.
	LIGHT GREY MASSIVE FINE GRAINED GRANODIORITE. FRESH ROCK. 2" SLIGHTLY WEATHERED JOINT ZONE AT 110'.
	LIGHT GREY AND BLACK HIGHLY JOINTED TO MASSIVE FINE GRAINED CONTACT BRECCIA MIGMATITE. 112' TO 113½' FRESH TO MODERATELY WEATHERED. 113½' TO 116½' MODERATELY WEATHERED; HIGHLY JOINTED. 116½' TO 122½' MASSIVE FRESH ROCK.
	LIGHT GREY MASSIVE MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS. FRESH ROCK.
	MEDIUM GREY AND BLACK MASSIVE FINE TO MEDIUM GRAINED CONTACT BRECCIA MIGMATITE. FRESH ROCK.

BORING CONTINUED

LOG OF BORING 3-6

Amendment 0
August 1984

Figure 2E-43

BORING 3-6 CONT'D.

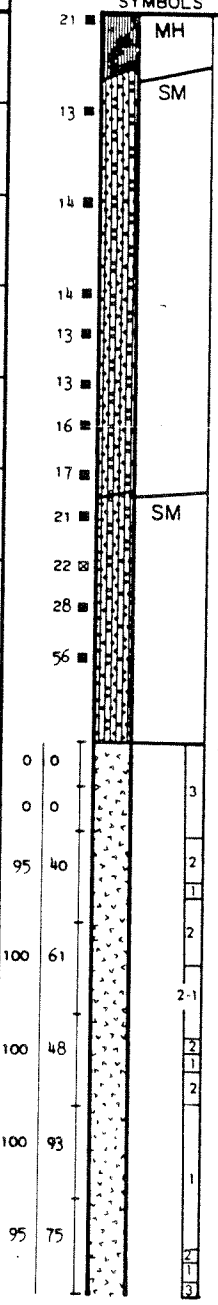
DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)	SYMBOLS	DESCRIPTIONS
140								100 100	MEDIUM GREY MASSIVE FINE TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION CONTAINS SOME INCLUSIONS GRADING TO GRANODIORITE AT 155'
150									
160									BORING TERMINATED 8-31-71. SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.
170									

LOG OF BORING 3-6

BORING 3-7

SURFACE ELEVATION 466.9
CO-ORDINATES N 472,500
E 1,904,740

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50		3500	3230			20	98
60							
70		4000	3690			18	102
80							
90							
100							
110							
120							
130							
140							



TAN TO GREY HIGHLY JOINTED TO MASSIVE MEDIUM TO COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS.
80' TO 90' HIGHLY WEATHERED; HIGHLY JOINTED; TAN.

90' TO 92' MODERATELY WEATHERED, MODERATELY JOINTED; TAN.
92' TO 93½' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED; TAN.
93½' TO 95' FINE GRAINED FRAGMENTED QUARTZ ZONE.
95' TO 95½' FRESH ROCK.
95½' TO 104½' MODERATELY WEATHERED; MODERATELY TO HIGHLY JOINTED; SOME THIN HIGHLY WEATHERED ZONES.
104½' TO 112' FRESH ROCK; SLIGHTLY TO MODERATELY JOINTED.
4" MODERATELY WEATHERED JOINT ZONE AT 107'.
4" MODERATELY WEATHERED JOINT ZONE AT 108'.
3" MODERATELY WEATHERED JOINT ZONE AT 111'.
112' TO 113½' SLIGHTLY WEATHERED; MODERATELY JOINTED.
113½' TO 115½' FRESH ROCK; SLIGHTLY JOINTED.
115½' TO 119' MODERATELY WEATHERED; HIGHLY JOINTED; SOME THIN HIGHLY WEATHERED ZONES.
119' TO 135' MASSIVE FRESH ROCK.

135' TO 136' SLIGHTLY WEATHERED, HIGHLY JOINTED.
136' TO 138½' MASSIVE FRESH ROCK.
138½' TO 140' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED.
140' TO 141' MODERATELY WEATHERED; MODERATELY JOINTED.
141' TO 149½' MASSIVE FRESH ROCK.

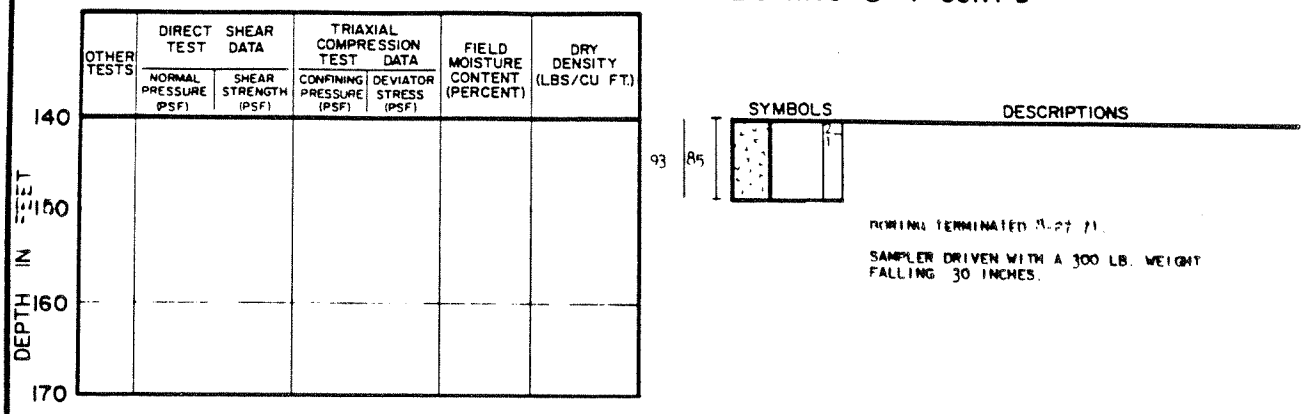
BORING CONTINUED

LOG OF BORING 3-7

Amendment 0
August 1984

Figure 2E-44

BORING 3-7 CONT'D



LOG OF BORING 3-7

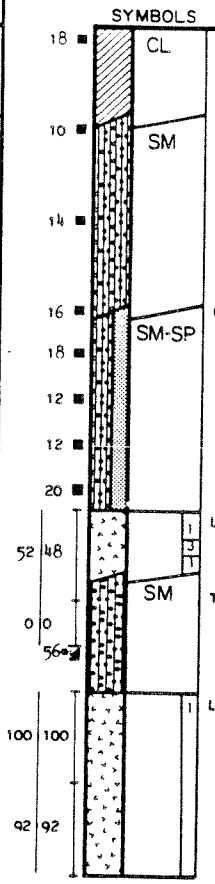
Amendment 0
August 1984

Figure 2E-44a

BORING 3-8

SURFACE ELEVATION 453.0
CO-ORDINATES N 472,500
E 1,904,900

DEPTH IN FEET	OTHER TESTS	DIRECT TEST SHEAR DATA: NORMAL PRESSURE (PSF)	DIRECT TEST SHEAR DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30		2000	1800			15	98
	8					15	95
40		3000	2420			21	96
50							
60							
70							
80							
90							
100							



DESCRIPTIONS

REDDISH BROWN MICACEOUS SILTY SANDY CLAY. (STIFF)

TAN AND OLIVE MICACEOUS SILTY FINE SAND (MEDIUM DENSE)

OLIVE AND TAN SILTY MICACEOUS FINE TO COARSE SAND AND ZONES OF SAND WITHOUT SILT. (MEDIUM DENSE)

LIGHT GREY MASSIVE COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS.
53' TO 56' FRESH ROCK.
56' TO 57½' VERY HIGHLY WEATHERED.
57½' TO 60' FRESH ROCK.
TAN SILTY FINE SAND. (VERY DENSE)

LIGHT GREY MASSIVE COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS. FRESH ROCK.

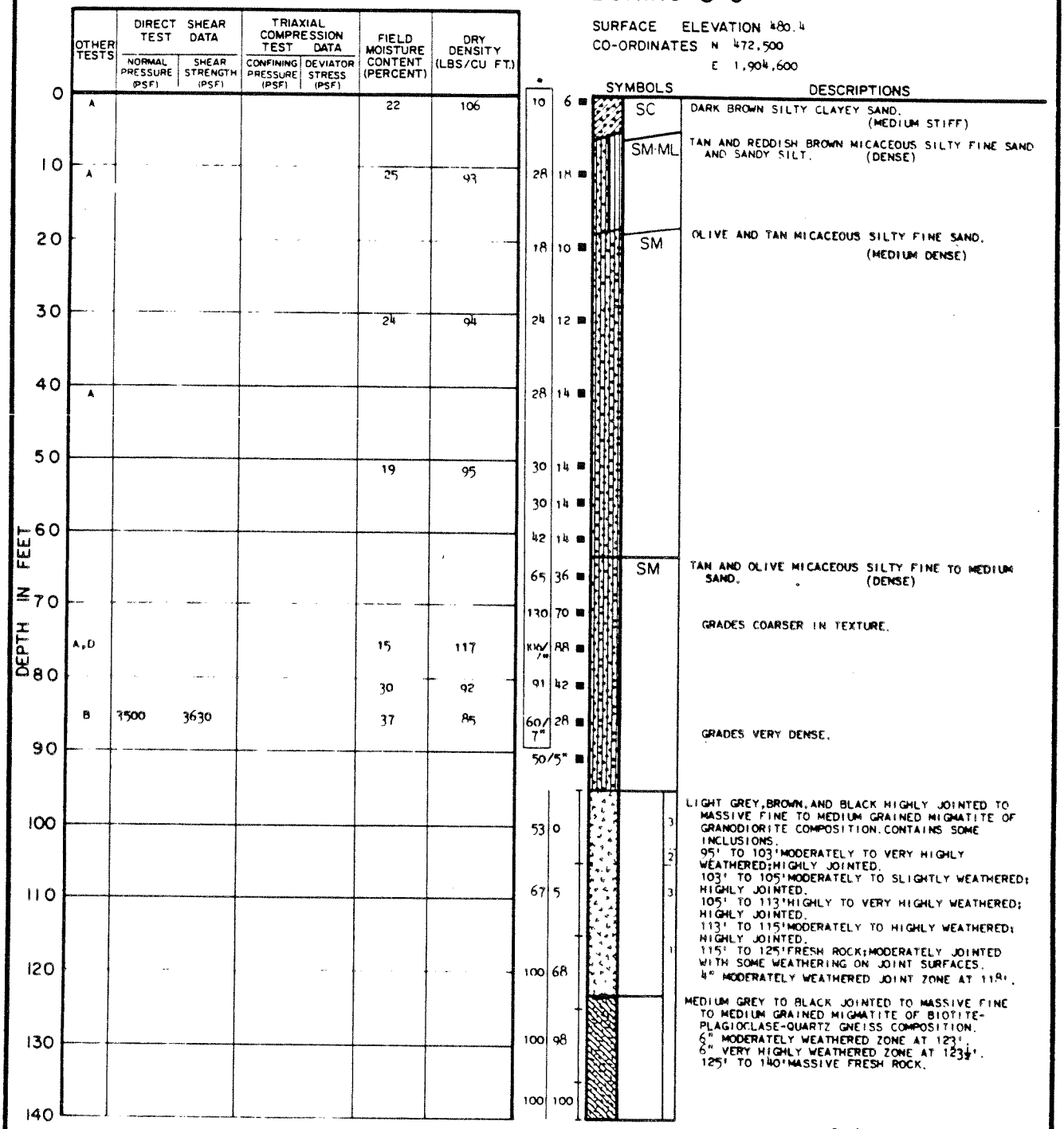
BORING TERMINATED 8-25-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE DESIGNATED BY AN ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES
*INDICATES STANDARD PENETRATION TEST.

LOG OF BORING 3-8

BORING 3-9

SURFACE ELEVATION 480.4
CO-ORDINATES N 472,500
E 1,904,600



BORING TERMINATED 8-26-71.

NUMBERS ENCLOSED WITHIN THE COLUMN DESIGNATED BY ASTERISK (*) INDICATE BLOWCOUNTS OBTAINED FROM AN ADJACENT BORING UTILIZING STANDARD PENETRATION EQUIPMENT.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE ENCLOSED WITHIN THE COLUMN DESIGNATED BY ASTERISK (*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES.

*INDICATES STANDARD PENETRATION TESTS.

LOG OF BORING 3-9

BORING 3-10

SURFACE ELEVATION 445.9
CO-ORDINATES N 472,400
E 1,905,000

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0	A					32	
10		1500	1830			18	94
20							
30							
40							
50							
60							
70							
80							
90							
100							
110							
120							
130							
140							

SYMBOLS

10 ■ SC — REDDISH BROWN SILTY CLAYEY SAND. (STIFF)

12 ■ 12 ■ 12 ■ 14 ■ 20. ■ SM — OLIVE AND BROWN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE)

88 88 — 3 — LIGHT GREY HIGHLY JOINTED TO MASSIVE COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS.
35' TO 38' HIGHLY WEATHERED.
38' TO 45' MASSIVE FRESH ROCK.

43 33 — SM — BROWN AND OLIVE SILTY FINE TO MEDIUM SAND. (VERY DENSE)

85/10" 70 82

98/3" 96 82 59 36 100 51 73 12 92 52 63 39 86 47

LIGHT GREY JOINTED TO MASSIVE COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS.
64' TO 71½' MASSIVE FRESH ROCK.
71½' TO 76' MODERATELY WEATHERED; HIGHLY JOINTED.
76' TO 79' MASSIVE FRESH ROCK.
79' TO 80' MODERATELY WEATHERED; HIGHLY JOINTED.
80' TO 86' HIGHLY TO VERY HIGHLY WEATHERED; HIGHLY JOINTED.
86' TO 87' SLIGHTLY WEATHERED; HIGHLY JOINTED.
87' TO 92' MASSIVE FRESH ROCK.
6" SLIGHTLY WEATHERED JOINT ZONE AT 89'.
LIGHT GREY JOINTED TO MASSIVE MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS SOME INCLUSIONS AND SLIGHT FOLIATION.
92' TO 93' SLIGHTLY WEATHERED; HIGHLY JOINTED.
93' TO 94' FRESH ROCK.
94' TO 95' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED AT HIGH ANGLE.
95' TO 103' HIGHLY TO VERY HIGHLY WEATHERED; HIGHLY JOINTED.
LIGHT GREY JOINTED TO MASSIVE COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS. FRESH ROCK.
103' TO 112' MASSIVE TO SLIGHTLY JOINTED.
3" MODERATELY WEATHERED JOINT ZONE AT 105½'.
12" SLIGHTLY WEATHERED JOINT ZONE AT 107½'.
LIGHT GREY JOINTED TO MASSIVE MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS AND FOLIATION.
112' TO 116½' MASSIVE FRESH ROCK.
116½' TO 120½' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED.
120½' TO 122½' SLIGHTLY WEATHERED; MODERATELY JOINTED.
LIGHT GREY TO BLACK HIGHLY JOINTED FINE TO MEDIUM GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. FRESH ROCK WITH SOME SLIGHT WEATHERING ALONG JOINTS.
129½' TO 134' MASSIVE FRESH ROCK.
LIGHT TO MEDIUM GREY MASSIVE FINE TO MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION CONTAINS INCLUSIONS AND FOLIATION.

BORING TERMINATED 8-30-71.

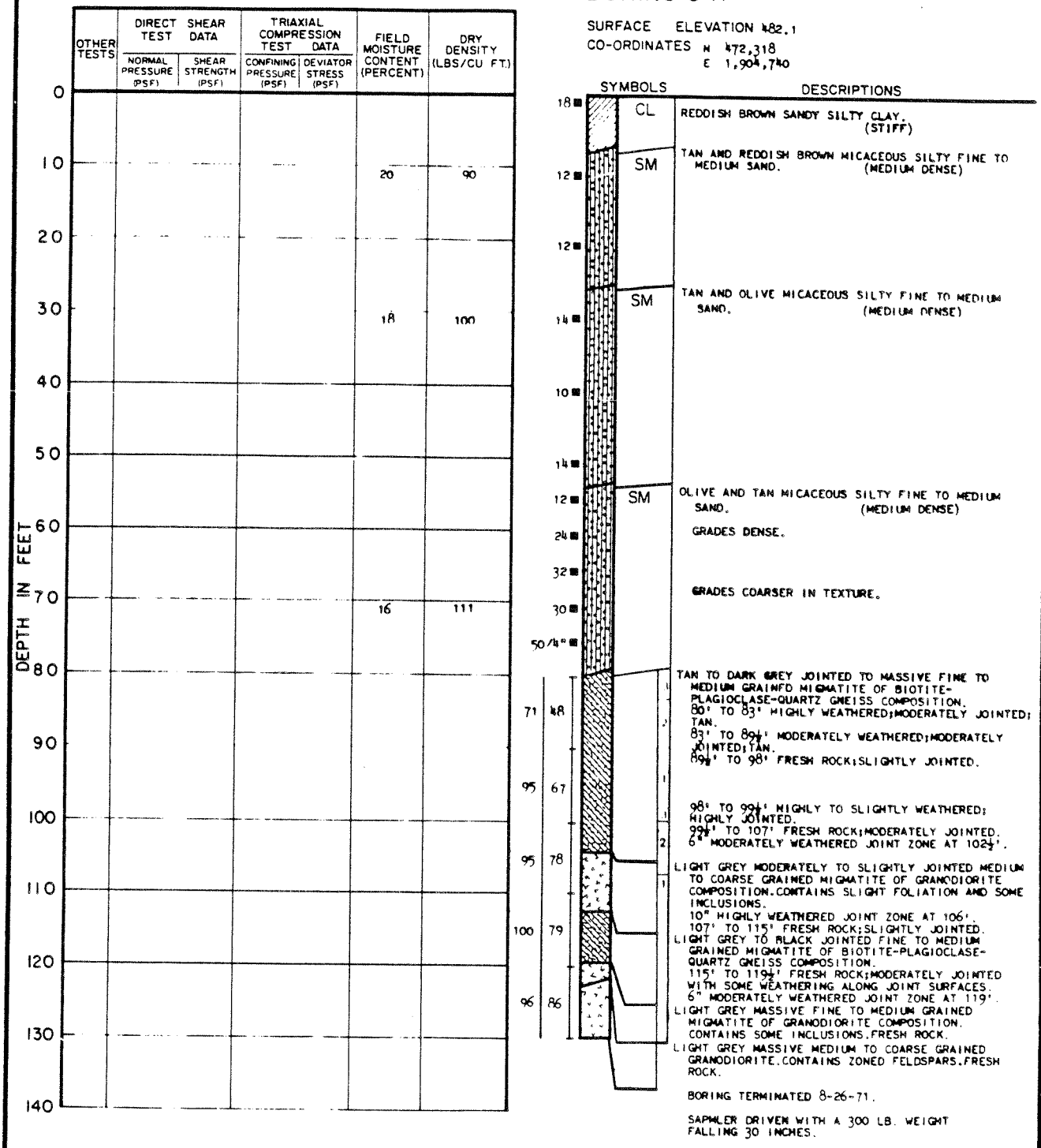
SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE DESIGNATED BY AN ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES.

*INDICATES STANDARD PENETRATION TEST.

LOG OF BORING 3-10

BORING 3-11

SURFACE ELEVATION 482.1
CO-ORDINATES N 472,318
E 1,904,740



LOG OF BORING 3-11

Amendment 0
August 1984

Figure 2E-48

BORING 3-12

SURFACE ELEVATION 417.7
CO-ORDINATES N 473,075
E 1,905,000

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							
100							
110							
120							
130							
140							

SYMBOLS	DESCRIPTIONS
CL-SC	BROWN CLAY TO CLAYEY SAND. (SOFT TO MEDIUM STIFF)
GM/ROCK	LIGHT GREEN TO DARK GREY-GREEN MODERATELY TO HIGHLY WEATHERED FRAGMENTED ROCK, AND FINE SILTY SANDY GRAVEL. (DENSE) PROBABLE CONTACT BRECCIA MIGMATITE. (HARD)
ML/ROCK	ZONES OF LIGHT GREY-GREEN AND TAN BANDED SILT (STIFF) AND BLACK ROCK. PROBABLE AMPHIBOLITE MIGMATITE.
GM/ROCK	GRADING MOTTLED LIGHT GREEN TO DARK GREY-GREEN AND GREEN SILT, FINE SAND, AND GRAVEL (MEDIUM DENSE) WITH INTERMITTENT HARD LAYERS OF ROCK. ROCK IS GNEISSIC MIGMATITE.
	BLACK HIGHLY JOINTED FINE GRAINED MIGMATITE OF AMPHIBOLITE GNEISS COMPOSITION. CONTAINS MANY HIGH ANGLE JOINTS. 49' TO 56½' HIGHLY WEATHERED. 56½' TO 57' FRESH ROCK. 57' TO 58' HIGHLY WEATHERED. 58' TO 78' MODERATELY WEATHERED WITH ZONES OF HIGHLY WEATHERED AND FRESH ROCK.
SM-GM ROCK	ALTERNATING ZONES OF FRESH TO VERY HIGHLY WEATHERED MIGMATITE OF GNEISSIC COMPOSITION, AND SOIL (DENSE) DERIVED FROM COMPLETELY DECOMPOSED ROCK FORMING DARK GREY AND GREEN SILTY AND GRAVELLY SAND.
	MEDIUM TO VERY DARK GREY HIGHLY JOINTED MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS FOLIATION AND INCLUSIONS. 118' TO 125' MODERATELY TO HIGHLY WEATHERED.
	BANDED GREY AND BLACK MODERATELY TO HIGHLY JOINTED FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. 125' TO 138' MODERATELY WEATHERED. 1' HIGHLY WEATHERED ZONE AT 136'. 138' TO 142' HIGHLY WEATHERED; HIGHLY JOINTED.

10 ■ 60 ■ 20 ■ REFUSAL ⊠ 17 ▣ 16 ▣ 21 ▣ 16 ▣ 48 ▣

55	0	3
30	0	2-3
40	0	
40	0	
30	0	
10	0	
10	0	
64	12	3
88	37	2
		3

BORING CONTINUED

LOG OF BORING 3-12

BORING 3-12 CONT'D

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
140							
150							
160							

SYMBOLS			DESCRIPTIONS
RR	37	3	142' TO 145' MODERATELY WEATHERED; MODERATELY JOINTED.
			LIGHT GREY JOINTED MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS FOLIATION AND INCLUSIONS.
			145' TO 147½' FRESH ROCK; MODERATELY JOINTED.
			147½' TO 152½' SLIGHTLY WEATHERED; MODERATELY JOINTED.
100	96	2	152½' TO 157' MODERATELY WEATHERED; MODERATELY JOINTED.
			DARK GREY TO BLACK HIGHLY JOINTED FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION.
		1	157' TO 160' HIGHLY TO MODERATELY WEATHERED.

BORING TERMINATED 9-7-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

GROUND WATER LEVEL AT DEPTH 62 FEET, ON 10-14-71.

LOG OF BORING 3-12

Figure 2E-49a

BORING 3-13

SURFACE ELEVATION 457.0
CO-ORDINATES N 472,275
E 1,905,000

DEPTH IN FEET	OTHER TESTS	DIRECT TEST SHEAR DATA: NORMAL PRESSURE (PSF)	DIRECT TEST SHEAR DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10						20	92
20							
30							
40	A					15	109
50	A						
60							
70							
80							
90							

SYMBOLS	DESCRIPTIONS
8 ■ CL	REDDISH BROWN SANDY SILTY CLAY. (MEDIUM STIFF)
8 ■ SM	TAN, OLIVE AND BROWN MICACEOUS FINE TO MEDIUM SILTY SAND. (MEDIUM DENSE)
8 ■ 14 ■ 14 ■	
34 ■ SP-SW	OLIVE AND TAN MICACEOUS SILTY FINE TO COARSE SAND. (DENSE)
22 ■ 28 ■	
34 ■ SP-SM	TAN AND OLIVE MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
34 ■ 32 ■	
70 ■	GRADING VERY DENSE.
95 81	LIGHT GREY MASSIVE FINE TO COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS. FRESH ROCK. 69' TO 72½' COARSE GRAINED. 72½' TO 74½' MODERATELY WEATHERED JOINT ZONE. 74½' TO 89' FINE GRAINED. 3" SLIGHTLY WEATHERED JOINT ZONE AT 78'.
100 99	1" JOINT ZONE WITH SOME WEATHERING ALONG JOINT SURFACES AT 86'. BORING TERMINATED 9-1-71. SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORING 3-13

Figure 2E-50

BORING 3-14

SURFACE ELEVATION 447.9
CO-ORDINATES N 472,670
E 1,904,770

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0	C					24	
10						30	94
20						28	90
30							
40							
50						27	86
60						27	96
70							
80							
90							
100							
110							
120							
130							
140							

SYMBOLS	DESCRIPTIONS
SC	REDDISH BROWN CLAYEY SAND, (STIFF)
SM-ML	REDDISH BROWN MICACEOUS FINE SILTY SAND WITH SOME SANDY SILT. (MEDIUM DENSE)
SM	TAN AND BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
SM-ML	TAN AND BROWN MICACEOUS FINE TO MEDIUM SILTY SAND AND SANDY SILT. (MEDIUM DENSE)
	MEDIUM GREY JOINTED TO MASSIVE MEDIUM TO COARSE GRAINED GRANODIORITE, CONTAINS ZONED FELDSPARS. 68' TO 85' HIGHLY TO MODERATELY WEATHERED; HIGHLY JOINTED.
	85' TO 92' FRESH ROCK; SLIGHTLY JOINTED. 1' SLIGHTLY WEATHERED JOINT ZONE AT 88'. 3" HIGHLY WEATHERED JOINT ZONE AT 89'. 92' TO 97' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED. 97' TO 98' MASSIVE FRESH ROCK.
	MEDIUM GREY JOINTED TO MASSIVE MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS SLIGHT FOLIATION AND INCLUSIONS. 98' TO 99' FRESH ROCK; MODERATELY JOINTED WITH SOME SLIGHT WEATHERING ALONG JOINT SURFACES. 99' TO 120' MASSIVE FRESH ROCK. SLIGHTLY WEATHERED JOINT AT 104'. SLIGHTLY WEATHERED JOINT AT 108'. 5" MODERATELY TO HIGHLY WEATHERED JOINT ZONE AT 116'. SLIGHTLY WEATHERED JOINT AT 118'. SLIGHTLY WEATHERED HEALED JOINTS AT 119'. 120' TO 125' SLIGHTLY WEATHERED; MODERATELY JOINTED WITH HIGH ANGLE OR VERTICAL JOINTS. 125' TO 128½' MODERATELY WEATHERED; MODERATELY TO HIGHLY JOINTED. 128½' TO 141½' MASSIVE FRESH ROCK.

10		SC	
12		SM-ML	
6		SM	
8			
6			
10		SM-ML	
8			
10			
14			
14			
14			
36			
50/0"			
50/2"			
50	46		3
			1
85	48		3
			1
			2
98	98		1
100	95		2
99	51		
100	100		1

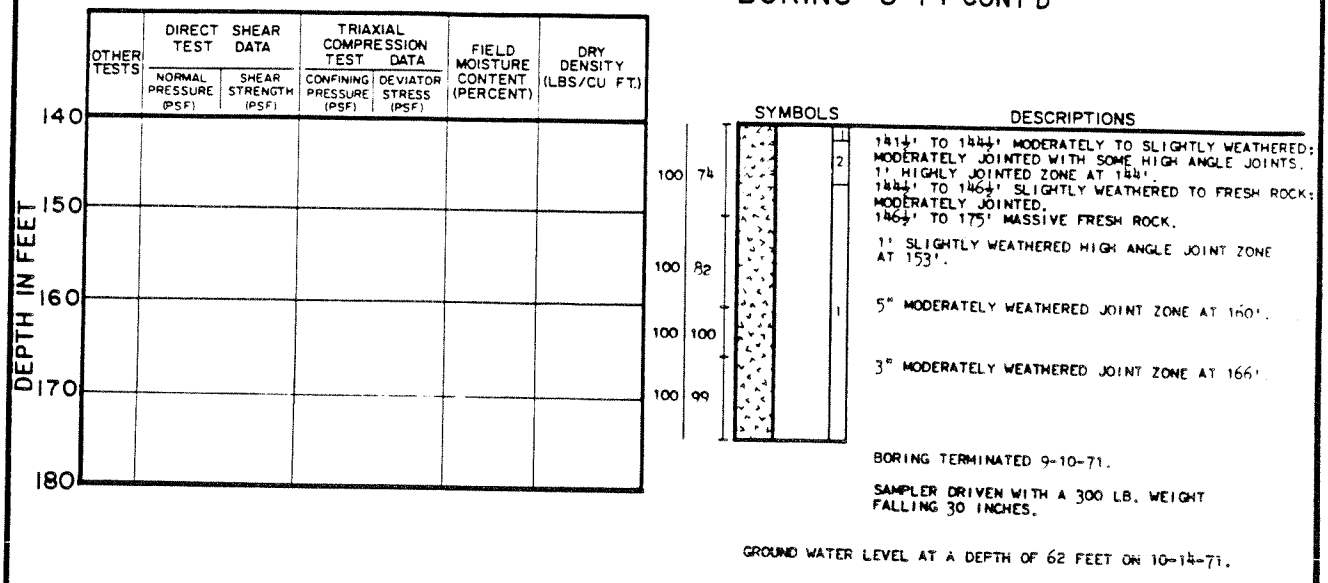
BORING CONTINUED

LOG OF BORING 3-14

Amendment 0
August 1984

Figure 2E-51

BORING 3-14 CONT'D



LOG OF BORING 3-14

Figure 2E-51a

BORING 3-15

SURFACE ELEVATION 451.9
CO-ORDINATES N 472,570
E 1,904,840

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0	C					22	
10						22	89
20							
30							
40						21	85
50							
60							
70							
80							
90							
100							
110							
120							
130							
140							
150							

SYMBOLS	DESCRIPTIONS
ML-SC	REDDISH BROWN SANDY CLAYEY SILT. (MEDIUM STIFF)
SM	OLIVE AND TAN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
SM	TAN AND OLIVE MICACEOUS SILTY FINE TO COARSE SAND. (MEDIUM DENSE TO DENSE)
	GRADES VERY DENSE TO HARD.
REFUSAL	LIGHT GREY JOINTED TO MASSIVE MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS FOLIATION AND INCLUSIONS.

6 11 14 14 16 16 19 19 20 23 32 58 95 80

17	0	3
87	58	1 3 1
98	33	2 3
94	86	21
91	55	1
93	79	3 1 3
68	37	

75' TO 89½' HIGHLY WEATHERED; HIGHLY JOINTED.

89½' TO 90' MODERATELY WEATHERED; HIGHLY JOINTED.
90' TO 93' MASSIVE FRESH ROCK.
93' TO 95' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED.
95' TO 99½' MASSIVE FRESH ROCK.
99½' TO 102' MODERATELY WEATHERED; HIGHLY JOINTED.
102' TO 105' SLIGHTLY WEATHERED; HIGHLY JOINTED.
105' TO 106½' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED.
106½' TO 120' FRESH ROCK; SLIGHTLY TO MODERATELY JOINTED.
1' WEATHERED ZONE AT 109'.
SOME HIGH ANGLE JOINTS AT 110'.
1' WEATHERED ZONE AT 113'.

1' SLIGHTLY TO MODERATELY WEATHERED ZONE AT 119'.
1" HIGHLY WEATHERED ZONE AT 120'.
120' TO 131½' MASSIVE FRESH ROCK.

131½' TO 133' MODERATLEY TO HIGHLY WEATHERED; HIGHLY JOINTED.
133' TO 138' MASSIVE FRESH ROCK.
4" MODERATELY WEATHERED JOINT ZONE AT 137'.
138' TO 143' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED.

BORING TERMINATED 9-8-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

GROUND WATER LEVEL AT DEPTH 66 FEET ON 10-14-71.

LOG OF BORING 3-15

Amendment 0
August 1984

Figure 2E-52

BORING 3-16

SURFACE ELEVATION 468.1
CO-ORDINATES N 472,390
E 1,904,840

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10						20	105
20							
30						16	99
40							
50							
60	B	3500	3700			11	117
70							
80							
90							
100							

SYMBOLS	DESCRIPTIONS
13 ■ CL	REDDISH BROWN SILTY SANDY CLAY. (STIFF)
31 ■ SC-SM	REDDISH BROWN SILTY CLAYEY FINE TO COARSE SAND. (DENSE)
12 ■ SM	TAN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
18 ■	
42 ■	PROBABLE DIKE.
20 ■ SM-SP	OLIVE AND TAN MICACEOUS FINE TO MEDIUM SAND. (DENSE)
25 ■	
30 ■	
39 ■	
63/9" ■	GRADES VERY DENSE
50/5" ⊠	
REFUSAL □ SP/ROCK	ALTERNATING ZONES OF HIGHLY WEATHERED GRANODIORITE AND FINE SAND DERIVED FROM DECOMPOSED ROCK.
95 92	LIGHT GREY MODERATELY JOINTED FINE GRAINED GRANODIORITE. FRESH ROCK. 80½' TO 83½' MODERATELY TO HIGHLY WEATHERED ZONE. (2, 3, 2)

BORING TERMINATED 9-10-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORING 3-16

BORING 3-17

SURFACE ELEVATION 449.8
CO-ORDINATES N 472,729
E 1,904,665

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10	A	1500	2420			28	94
20	A	3000	2200			28	71
30	D,A					23	98
40							
50						23	107
60							
70							
80							
90							
100							
110							
120							
130							
140							

SYMBOLS		DESCRIPTIONS
16	CL	REDDISH BROWN SANDY SILTY CLAY. (VERY STIFF)
25	ML	REDDISH BROWN SANDY CLAYEY SILT. (VERY STIFF)
16	SM	TAN TO REDDISH BROWN SILTY FINE TO COARSE SAND. (VERY DENSE)
60		
6	SM	TAN TO REDDISH BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
11		
11		
17		GRADING DENSER AND MORE SANDY.
14		
27	SM	GREY TO TAN FINE TO COARSE SILTY SAND WITH SOME MICA. (DENSE)
27		GRADING VERY DENSE AND MICACEOUS.
46		
46		GREY TO BLACK JOINTED TO MASSIVE FINE GRAINED CONTACT BRECCIA MIGMATITE, CONTAINS INCLUSIONS AND EXHIBITS SLIGHT TO MODERATE FOLIATION. 67' TO 80½' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED.
37 6		
96 96		80½' TO 108½' FRESH ROCK; SLIGHTLY JOINTED TO MASSIVE.
100 88		LOSING DRILL WATER AT 3 TO 4 GALLONS/MINUTE AT 90½'.
89 89		
100 100		LIGHT TO DARK GREY SLIGHTLY JOINTED TO MASSIVE COARSE GRAINED GRANODIORITE. CONTAINS ZONED FELDSPARS, FRESH ROCK.
90 90		
100 100		
* 70 70		

BORING TERMINATED 9-16-71

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

*PORTION OF ROCK CORE LEFT IN BORING, THEREFORE ACTUAL RECOVERY AND R.Q.D. ARE GREATER THAN INDICATED.

LOG OF BORING 3-17

Figure 2E-54

BORING 3-18

SURFACE ELEVATION 467.1
CO-ORDINATES N 472,600
E 1,904,665

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10						25	99
20	B	2000	2050			20	95
30							
40						20	97
50							
60	C					14	
70						15	116
80							
90							
100							
110							
120							
130							
140							
150							

SYMBOLS		DESCRIPTIONS
7	CL	REDDISH BROWN SILTY SANDY CLAY. (MEDIUM STIFF)
27	ML	REDDISH BROWN SANDY CLAYEY SILT. (VERY STIFF)
13	SM	REDDISH BROWN TO OLIVE AND TAN MICACEOUS SILTY FINE TO COARSE SAND. (MEDIUM DENSE)
16		
15		
21	SM	OLIVE AND TAN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
23		
30		
48		GRADING VERY DENSE.
60		
59		
74		
84/9"		
101		TAN HIGHLY JOINTED COARSE GRAINED GRANODIORITE. MODERATELY TO HIGHLY WEATHERED.
42	9	3
80	68	LIGHT GREY JOINTED TO MASSIVE FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS AND EXHIBITS SLIGHT FOLIATION.
		3
		95' TO 96½' SLIGHTLY WEATHERED TO FRESH; MASSIVE. 1
		96½' TO 98½' HIGHLY WEATHERED; HIGHLY JOINTED. 2
		98½' TO 100½' MASSIVE FRESH ROCK. 3
65	55	LIGHT GREY JOINTED TO MASSIVE COARSE GRAINED GRANODIORITE, CONTAINS ZONED FELDSPARS.. 3
		100½' TO 102½' MASSIVE FRESH ROCK.
		102½' TO 106½' FRESH ROCK; MODERATELY JOINTED.
		106½' TO 109½' HIGHLY WEATHERED; HIGHLY JOINTED.
85	72	109½' TO 110½' MASSIVE FRESH ROCK. 2
		110½' TO 111½' MODERATELY WEATHERED; HIGHLY JOINTED.
		111½' TO 125½' FRESH ROCK; MODERATELY JOINTED. 3
		6" MODERATELY WEATHERED HIGHLY JOINTED ZONE AT 114'.
72	72	125½' TO 127' MODERATELY TO HIGHLY WEATHERED: HIGHLY JOINTED. 2
		127' TO 133½' FRESH ROCK; MODERATELY JOINTED. 3
		133½' TO 135½' MODERATELY TO HIGHLY WEATHERED: HIGHLY JOINTED.
100	100	135½' TO 143½' FRESH ROCK; MODERATELY JOINTED. 2

BORING TERMINATED 9-17-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORING 3-18

Figure 2E-55

BORING 3-19

SURFACE ELEVATION 442.6
CO-ORDINATES N 472,585
E 1,904,960

DEPTH IN FEET	OTHER TESTS	DIRECT TEST SHEAR DATA: NORMAL PRESSURE (PSF)	DIRECT TEST SHEAR DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT)
0							
10							
20		2000	1800			31	76
30						22	84
40						27	78
50							
60							
70							
80							
90							
100							
110							
120							

		SYMBOLS	DESCRIPTIONS
19	10	ML-CL	REDDISH BROWN CLAYEY SILT TO SILTY CLAY. (STIFF)
23	14	SM	DARK BROWN, TAN, AND ORANGE-BROWN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE)
17	8		
21	14	ML-SM	GREY AND BROWN MICACEOUS FINE SANDY SILT AND SILTY SAND. (STIFF TO MEDIUM DENSE)
28	12		
29	14		
29	12		
27	14		
39	24		GRADES DENSE.
40	28		
60	32	SM	TAN AND LIGHT GREY MICACEOUS SILTY FINE SAND. (DENSE TO VERY DENSE)
88	36		
80	41		
120	61		
30	23		LIGHT GREY, DARK GREY, AND BLACK HIGHLY JOINTED TO MASSIVE FINE GRAINED CONTACT BRECCIA MIGMATITE. 82' TO 89½' HIGHLY WEATHERED; HIGHLY JOINTED. 89½' TO 91' MASSIVE FRESH ROCK.
93	84		LIGHT GREY MASSIVE FINE TO MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS NUMEROUS INCLUSIONS. FRESH ROCK. 3" JOINT ZONE WITH MODERATELY WEATHERED SURFACES AT 93'. 6" JOINT ZONE WITH SLIGHTLY WEATHERED SURFACES AT 100'.
86	85		

BORING TERMINATED 9-13-71.

NUMBERS ENCLOSED WITHIN THE COLUMN DESIGNATED BY ASTERISK (*) INDICATE BLOWCOUNTS FROM AN ADJACENT BORING UTILIZING STANDARD PENETRATION EQUIPMENT.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE ENCLOSED WITHIN THE COLUMN DESIGNATED BY ASTERISK (*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES.

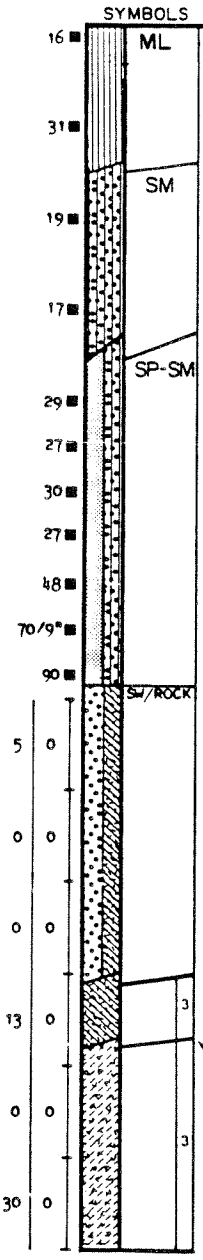
*INDICATES STANDARD PENETRATION TESTS.

LOG OF BORING 3-19

BORING 3-20

SURFACE ELEVATION 483.4
CO-ORDINATES N 472,390
E 1,904,680

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0	C					26	
10	A	3000 1500	3700 2305			23 23	93 93
20						7	116
30	A					24	88
40							
50							
60							
70							
80							
90							
100							
110							
120							
130							
140							



REDDISH BROWN CLAYEY SANDY SILT. (VERY STIFF)

OLIVE AND TAN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)

TAN TO YELLOW-BROWN FINE TO MEDIUM SAND WITH LITTLE SILT. (DENSE)

ALTERNATING ZONES OF HIGHLY JOINTED AND HIGHLY WEATHERED MIGMATITE OF GNEISSIC COMPOSITION, AND FINE TO COARSE SAND DERIVED FROM THE DECOMPOSED ROCK. ROCK CONTAINS SOME THIN QUARTZ VEINS.
73½' TO 91½' SOME QUARTZ PRESENT.

TAN TO BROWN HIGHLY JOINTED FINE GRAINED MIGMATITE OF GNEISSIC COMPOSITION. CONTAINS HIGHLY DISTORTED FOLIATION. MODERATELY TO VERY HIGHLY WEATHERED. MUCH HIGH ANGLE JOINTING.

GREY TO TAN HIGHLY JOINTED COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. MODERATELY TO HIGHLY WEATHERED. MUCH HIGH ANGLE JOINTING.

BORING TERMINATED 9-13-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORING 3-20

BORING AR-1

SURFACE ELEVATION TO BE SURVEYED
CO-ORDINATES N 471,824
E 1,904,576

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0						17	109
10						21	102
20							

SYMBOLS		DESCRIPTIONS
25 / 16	CL-SC	REDDISH BROWN SILTY SANDY CLAY. (HARD)
20	ML-MH	REDDISH BROWN SANDY CLAYEY SILT. (HARD)
35		
21	SM	REDDISH BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)

BORING TERMINATED 10-16-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING AR-2

SURFACE ELEVATION TO BE SURVEYED
CO-ORDINATES N 471,480
E 1,905,428

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0	A,C			0	8700	20	107
	A,C					22	106
10							
20							

SYMBOLS		DESCRIPTIONS
24	CL-ML	RED-BROWN SANDY SILTY CLAY. (HARD)
62	SC-MH	RED-BROWN CLAYEY SILT AND CLAYEY SAND. (HARD)
21	SM	REDDISH BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
20		

BORING TERMINATED 10-16-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING AR-3

SURFACE ELEVATION TO BE SURVEYED
CO-ORDINATES N 471,547
E 1,906,425

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0						21	101
	A,C					21	95
10							
20							

SYMBOLS		DESCRIPTIONS
26		RED-BROWN CLAYEY SILT. (FILL)
	ML-MH	RED-BROWN SANDY CLAYEY SILT. (HARD)
16	SM	REDDISH BROWN AND BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
18		
14		

BORING TERMINATED 10-16-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS AR-1 AR-2 & AR-3

Amendment 0
August 1984

Figure 2E-58

BORING AR-4

SURFACE ELEVATION TO BE SURVEYED
CO-ORDINATES N 471,526
E 1,907,306

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0						4	120
10							
20							

SYMBOLS		DESCRIPTIONS
25	ML	REDDISH BROWN CLAYEY SILT TO BROWN SAND. (FILL) (DENSE)
49	ML	REDDISH BROWN SANDY CLAYEY SILT TO SANDY CLAY. (HARD)
15	SM	RED-BROWN AND BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
15	SM	

BORING TERMINATED 10-16-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING AR-5

SURFACE ELEVATION TO BE SURVEYED
CO-ORDINATES N 471,699
E 1,908,130

DEPTH IN FEET							
0						24	98
10						22	105
20							

39	CL-ML	REDDISH BROWN SANDY SILTY CLAY TO CLAYEY SILT. (HARD)
50	SM	REDDISH BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE TO DENSE)
21	SM	GRADES COARSER AND PARTIALLY GREY AND WHITE IN COLOR.
19	SM	

BORING TERMINATED 10-16-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING AR-6

SURFACE ELEVATION TO BE SURVEYED
CO-ORDINATES N 471 534
E 1,909,101

DEPTH IN FEET							
0	A					12	119
10	A,C			0	4600*	20	99
20							

*FAILED ALONG DESICCATION CRACKS

28		REDDISH BROWN CLAYEY SILTY SAND. (FILL) (DENSE)
32	SM-CH	REDDISH BROWN SANDY CLAYEY SILT. (HARD)
34	SM	REDDISH BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE) GRADES TAN AND BROWN.
20	SM	

BORING TERMINATED 10-15-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS AR-4 AR-5 & AR-6

BORING AR-7

SURFACE ELEVATION TO BE SURVEYED
CO-ORDINATES N 470,950
E 1,909,772

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0	A					16	109
10							
20							

	SYMBOLS	DESCRIPTIONS
37		REDDISH BROWN CLAYEY SAND AND SAND. (FILL) (STIFF TO DENSE)
38	SC	REDDISH BROWN CLAYEY SAND. (DENSE)
	SM-ML	REDDISH BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
	3	ROCK(WEATHERED)

BORING TERMINATED 10-15-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING AR-8

SURFACE ELEVATION TO BE SURVEYED
CO-ORDINATES N 470,309
E 1,910,450

DEPTH IN FEET							
0						22	102
10							
20							

19	SC-SM	REDDISH BROWN AND WHITE SILTY CLAYEY SAND. (DENSE TO VERY DENSE)
80		
23	SM	REDDISH BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
	3	ROCK (WEATHERED)

BORING TERMINATED 10-15-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING AR-9

SURFACE ELEVATION TO BE SURVEYED
CO-ORDINATES N 470,565
E 1,911,051

DEPTH IN FEET							
0	A,C		0	1100*	17	109
10					14	107
20						

*SAMPLE FAILED ALONG VERTICAL SAND LENSES

21	SM-ML	REDDISH BROWN CLAYEY SILTY SAND. (DENSE)
24		GRADING LESS CLAYEY AND VERY MICACEOUS.
24	SP-SM	TAN AND BROWN FINE TO MEDIUM SAND WITH LITTLE SILT. (DENSE)
29		GRADES WHITE IN COLOR.

BORING TERMINATED 10-15-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS AR-7 AR-8 & AR-9

Figure 2E-60

BORING CT-4

SURFACE ELEVATION 456.0
CO-ORDINATES N 472,318
E 1,903,700

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50		4000	5260			6	133
60							
70							
80							

	SYMBOLS	DESCRIPTIONS
16 ■	CL	REDDISH BROWN CLAY. (STIFF)
15 ■	ML	REDDISH ORANGE SANDY SILT. (MEDIUM STIFF)
13 ■	SM	OLIVE AND TAN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
18 ■		
52 ■		GRADES LESS SILTY AND VERY DENSE TO HARD.
57 ■		GRADING SMALL ROCK FRAGMENTS.
50/5" □		
75/6" ■		
49/9" ■		
50/3" □		
96 | 60	3 / 1	LIGHT GREY JOINTED COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS; 61' TO 63' MODERATELY WEATHERED; HIGHLY JOINTED. 63' TO 71' FRESH ROCK; SLIGHTLY TO MODERATELY JOINTED. 4" JOINT ZONE WITH SLIGHT WEATHERING ALONG JOINT SURFACES AT 65'. 2" JOINT ZONE WITH SLIGHT WEATHERING ALONG JOINT SURFACES AT 66'. 5" JOINT ZONE WITH SLIGHT WEATHERING ALONG JOINT SURFACES AT 67'.

BORING TERMINATED 8-31-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORING CT-4

BORING CT-5

SURFACE ELEVATION 416.1
CO-ORDINATES N 472,318
E 1,903,200

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0		2000	2200			10	122
		2000	2680			15	114
10		4000	5060			10	124
20							
30							
40							

SYMBOLS	DESCRIPTIONS
7 ■ SM	BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
16 ■	GRADES DENSE.
33 ■	
52 ■ SM/ROCK	ZONES OF VERY HIGHLY WEATHERED MIGMATITE OF GRANODIORITE COMPOSITION AND SOIL.
65 | 42	LIGHT GREY MODERATELY TO SLIGHTLY JOINTED FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION, CONTAINS SLIGHT FOLIATION AND INCLUSIONS. FRESH ROCK. 1/4" SLIGHTLY WEATHERED JOINT ZONE AT 25'. LIGHT TO DARK GREY JOINTED FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. 26' TO 27' FRESH ROCK; MODERATELY JOINTED. 27' TO 31½' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED. 31½' TO 32' FRESH ROCK; MODERATELY JOINTED.
	BORING TERMINATED 8-31-71.
	SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING CT-6

SURFACE ELEVATION 422.5
CO-ORDINATES N 472,000
E 1,903,500

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10		2000	2090			10	115
20							
30							
40							

SYMBOLS	DESCRIPTIONS
4 ■	BROWN SILTY SAND. (FILL) (LOOSE)
11 ■ SM	REDDISH BROWN MICACEOUS FINE TO MEDIUM SAND. (MEDIUM DENSE)
22 ■	GRADES OLIVE AND TAN IN COLOR.
64/9" ■ SW	OLIVE AND TAN MICACEOUS SILTY FINE TO COARSE SAND. (VERY DENSE)
50 | 14	GREY JOINTED MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION, CONTAINING INCLUSIONS. 20' TO 25' VERY HIGHLY WEATHERED; HIGHLY JOINTED. 25' TO 28' MODERATELY WEATHERED; MODERATELY JOINTED. 28' TO 30' MODERATELY WEATHERED; HIGHLY JOINTED.
	BORING TERMINATED 9-1-71.
	SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS CT-5 & CT-6

Amendment 0
August 1984

Figure 2E-62

BORING DP-1

SURFACE ELEVATION 495.0
CO-ORDINATES N 472,130
E 1,904,200

OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100

	SYMBOLS	DESCRIPTIONS
12	CL	REDDISH BROWN SANDY CLAY. (MEDIUM STIFF TO STIFF)
10	ML	RED, BROWN AND YELLOW MICACEOUS SILT. (STIFF)
12	SM-SP	TAN AND GREY MICACEOUS SILTY FINE SAND. (MEDIUM DENSE)
16		
68		GRADES COARSER IN TEXTURE AND DENSE.
105/10"		
100 11	2	LIGHT GREY HIGHLY TO MODERATELY JOINTED MEDIUM GRAINED GRANODIORITE DIKE. MODERATELY WEATHERED.
	ROCK/SW	ZONES OF VERY HIGHLY WEATHERED MIGMATITE OF GRANODIORITE COMPOSITION AND FINE TO COARSE SAND DERIVED FROM ROCK WEATHERED TO A SOIL CONSISTENCY. CONTAINS SOME WEATHERED INCLUSIONS.
80 73	1 / 3-2 / 3-2	LIGHT TO MEDIUM GREY HIGHLY JOINTED TO MASSIVE FINE TO MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. 69½' TO 70½' HIGHLY WEATHERED. 70½' TO 75' MASSIVE FRESH ROCK. 75' TO 78' MODERATELY WEATHERED AND JOINTED. 6" HIGHLY WEATHERED AND HIGHLY JOINTED ZONE AT 77½'.
100 42	1-2	ZONED LIGHT BROWN, GREY, AND BLACK HIGHLY JOINTED FINE TO MEDIUM GRAINED CONTACT BRECCIA MIGMATITE. 78' TO 85' VERY HIGHLY TO MODERATELY WEATHERED.
100 34	2	LIGHT GREY SLIGHTLY TO MODERATELY JOINTED FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS SOME LARGE INCLUSIONS; SOME SLIGHT WEATHERING NEAR JOINTS. 18" VERY HIGHLY WEATHERED ZONE AT 93'.

BORING TERMINATED 8-23-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORING DP-1

Figure 2E-63

BORING DP-2

SURFACE ELEVATION 488.2
CO-ORDINATES N 472,150
E 1,904,700

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10						20	87
20							
30						17	94
40							
50						12	108
60		3500	3860			12	113
70							
80							
90							

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY. (HARD)
SM	BROWN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE)
SM	TAN, BROWN, AND OLIVE MICACEOUS SILTY FINE SAND (MEDIUM DENSE)
	GRADES DENSE.
SM	TAN, WHITE, AND OLIVE MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
	LIGHT GREY TO BLACK JOINTED TO MASSIVE FINE TO MEDIUM GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE GNEISS COMPOSITION. CONTAINS SOME HIGHLY DISTORTED FOLIATION.
	71' TO 76' VERY HIGHLY WEATHERED.
	76' TO 79' MASSIVE FRESH ROCK.
	79' TO 82½' MODERATELY TO SLIGHTLY WEATHERED; MODERATELY JOINTED.
	82½' TO 85' MODERATELY WEATHERED; MODERATELY TO HIGHLY JOINTED.
	LIGHT TO DARK GREY MASSIVE MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS SOME INCLUSIONS.
	BORING TERMINATED 8-24-71.
	SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

100/2½"	0	3
67	53	1
92	68	1-2
		2
		1

LOG OF BORING DP-2

Amendment 0
August 1984

Figure 2E-64

BORING DP-3

SURFACE ELEVATION 425.5
CO-ORDINATES N 472,130
E 1,905,200

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10		1500	1520			24	93
20							
30							

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN MICACEOUS SILTY CLAY. (SOFT TO MEDIUM STIFF)
SM	TAN AND OLIVE MICACEOUS SILTY FINE TO COARSE SAND. (MEDIUM DENSE)
	GRADES PARTIALLY BLACK IN COLOR.
3	VERY LIGHT GREY TO LIGHT TAN AND BLACK HIGHLY TO MODERATELY JOINTED COARSE GRAINED GRANODIORITE.
2	$21\frac{1}{4}$' TO $24\frac{1}{2}$' HIGHLY WEATHERED.
	$24\frac{1}{2}$' TO $26\frac{1}{2}$' SLIGHTLY WEATHERED WITH MODERATE WEATHERING ALONG JOINTS. MODERATELY JOINTED. TAN MICACEOUS FINE TO MEDIUM SAND.
SP	

4 ■ 9 ■ 7 ■ 25 ■

BORING TERMINATED 8-23-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING DP-4

SURFACE ELEVATION 443.7
CO-ORDINATES N 471,980
E 1,905,700

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10		1500	1550			21	96
20							
30		3000	2690			17	91
40							
50							
60							

SYMBOLS	DESCRIPTIONS
SC	REDDISH BROWN SANDY CLAY. (SOFT TO MEDIUM STIFF)
SM	TAN AND GREY MICACEOUS FINE TO MEDIUM SILTY SAND. (MEDIUM DENSE)
	GRADES VERY DENSE.

9 ■ 10 ■ 8 ■ 12 ■ 6 ■ 8 ■

BORING TERMINATED 8-24-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS DP-3 & DP-4

Amendment 0
August 1984

Figure 2E-65

BORING DP-5

SURFACE ELEVATION 426.9
CO-ORDINATES N 471,750
E 1,906,300

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10		3000	2,340			20	86
20						20	98
30							
40							

SYMBOLS		DESCRIPTIONS
5 ■		REDDISH BROWN CLAYEY SAND. (FILL) (SOFT)
19 ■	ML	REDDISH BROWN AND TAN MICACEOUS FINE SANDY SILT (DENSE)
13 ■		
42 ■	SM	ORANGE AND GREY MICACEOUS SILTY FINE SAND. (DENSE)
17 ■		
28 ■		

GRADES MORE SILTY.
REFUSAL AT 39', ROCK INDICATED.

BORING TERMINATED 8-24-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORING DP-5

Figure 2E-66

BORING ECP-1

SURFACE ELEVATION 367.1
CO-ORDINATES N 472,600
E 1,905,350

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10		2000	2540			16	114
20							
30		4000	3730			30	95
40							
50							
60							
70							
80							
90							

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN CLAY. (FILL) (SOFT TO STIFF)
	REDDISH BROWN SANDY SILTY CLAY. (STIFF)
SM	GREENISH GREY MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)
	GRADES MORE SILTY.
	GRADES GREY AND YELLOW IN COLOR; VERY DENSE.
	GRADING SOME LENSES AND LAYERS OF HIGHLY WEATHERED ROCK.
SM/ROCK	ALTERNATING ZONES OF VERY HIGHLY WEATHERED MIGMATITE AND MICACEOUS SILTY SAND.
SM	GREY MICACEOUS SILTY SAND. (VERY DENSE)
	LIGHT AND DARK GREY VERY HIGHLY TO MODERATELY JOINTED FINE GRAINED MIGMATITE OF BIOTITE-PLAGIOCLASE-QUARTZ GNEISS COMPOSITION. 66½' TO 69' MODERATELY WEATHERED; MODERATELY JOINTED. 69' TO 70½' HIGHLY WEATHERED; VERY HIGHLY JOINTED. 70½' TO 75½' MODERATELY TO SLIGHTLY WEATHERED; MODERATELY JOINTED.
SM	GREY SILTY FINE SAND. (VERY DENSE)

BORING TERMINATED 8-25-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

GROUND WATER LEVEL AT DEPTH 3 FEET, ON 10-14-71.

LOG OF BORING ECP-1

Amendment 0
August 1984

Figure 2E-67

BORING ECP-2

SURFACE ELEVATION 364.±
CO-ORDINATES N 472,700
E 1,905,370

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATION STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT)
0							
10		3000	2910			23	101
20							
30						22	102
40						25	96
50							
60						32	92
70							
80							

*		SYMBOLS	DESCRIPTIONS
67	37	SM	REDDISH BROWN SILTY SANDY CLAY. (FILL)
30	33		TAN AND YELLOW BROWN MICACEOUS FINE SILTY SAND. (DENSE TO VERY DENSE)
47	28		
56	43		
50	33	SP-SM	TAN AND YELLOW BROWN MICACEOUS FINE SAND WITH SOME SILT. (DENSE TO VERY DENSE)
67	27		
82	50		
72	32	SM	TAN AND YELLOW BROWN MICACEOUS FINE SILTY SAND. (DENSE TO VERY DENSE)
54	45		
33	23		
68/8"@			
***			GREY JOINTED COARSE GRAINED GRANODIORITE. WEATHERING IN UPPER FOOT GRADING TO FRESH ROCK AT 74'.

BORING TERMINATED 9-20-71.

NUMBERS ENCLOSED WITHIN THE COLUMN DESIGNATED BY ONE ASTERISK(*) INDICATE BLOWCOUNTS OBTAINED FROM AN ADJACENT BORING UTILIZING STANDARD PENETRATION EQUIPMENT.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES, EXCEPT WHERE ENCLOSED WITH THE COLUMN DESIGNATED BY ONE ASTERISK(*) WHICH INDICATES A 140 LB. WEIGHT FALLING 30 INCHES.

*INDICATES STANDARD PENETRATION TESTS.

*** CORE BARREL NOT RECOVERED.

LOG OF BORING ECP-2

Figure 2E-68

BORING ECP-3

SURFACE ELEVATION 354.8
CO-ORDINATES N 472,800
E 1,905,500

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10		2000	2340			16	108
		3000	4290			15	116
20							
30							

SYMBOLS		DESCRIPTIONS
5 ■		REDDISH BROWN TO YELLOW SILTY SANDY CLAY (FILL) (STIFF)
17 ■	CL-SC	BROWN SILTY SAND AND CLAY (MEDIUM DENSE)
49 ■	SP-SM	GREY TO TAN FINE SAND WITH SOME MICA AND SILT. (VERY DENSE)
88/7" ■		
60/2" ▨	3	WEATHERED ROCK.

BORING TERMINATED 9-21-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING ECP-4

SURFACE ELEVATION 434.0
CO-ORDINATES N 472,502
E 1,905,035

DEPTH IN FEET	SYMBOLS		DESCRIPTIONS
0	14 ■	CL	REDDISH BROWN SILTY SANDY CLAY. (STIFF)
10	15 ■	ML	TAN TO REDDISH BROWN SANDY SILT WITH SOME MICA. (DENSE)
	26 ■	SM	TAN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE)

BORING TERMINATED 10-5-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING ECP-5

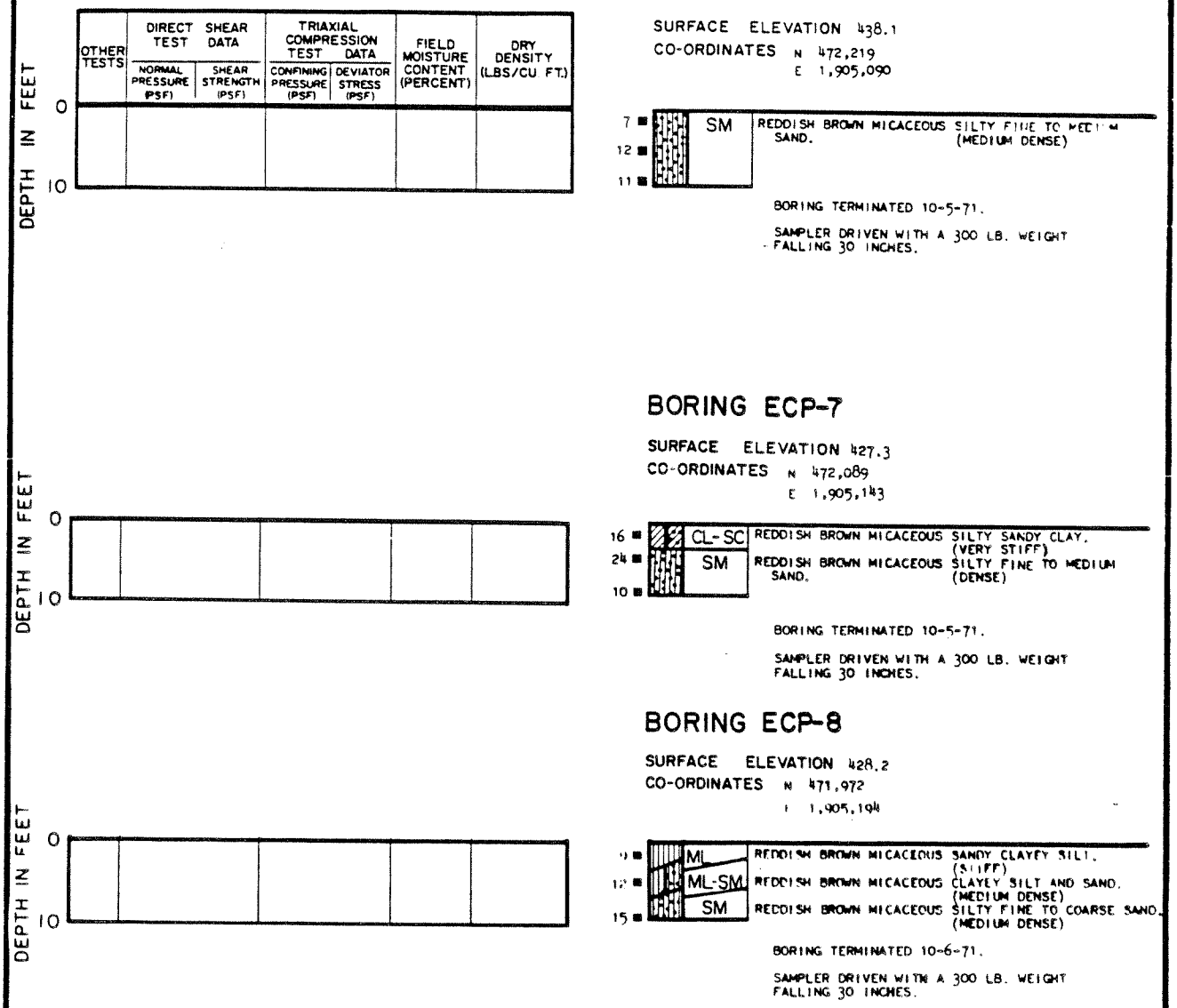
SURFACE ELEVATION 427.6
CO-ORDINATES N 472,360
E 1,905,062

DEPTH IN FEET	SYMBOLS		DESCRIPTIONS
0	18 ■	CL-SC	REDDISH BROWN SILTY SANDY CLAY. (STIFF TO VERY STIFF)
	18 □		
10	20 ■		
	25 ■	ML-SM	REDDISH BROWN SANDY SILT WITH SOME CLAY AND MICA. (DENSE)
20	14 ■		

BORING TERMINATED 10-5-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS ECP-3 ECP-4 & ECP-5



LOG OF BORINGS ECP-6 ECP-7 & ECP-8

Amendment 0
August 1984

Figure 2E-70

BORING IP-3

SURFACE ELEVATION 420.7
CO-ORDINATES N 473,000
E 1,905,000

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							

SYMBOLS	DESCRIPTIONS
CL-ML	BROWN AND OLIVE SILTY CLAY TO SILTY SAND (DENSE)
	BLACK JOINTED FINE GRAINED ULTRA MAFIC INTRUSIVE ROCK.
SM	BROWN AND OLIVE SILTY SAND. (DENSE)
	BLACK JOINTED FINE GRAINED ULTRA MAFIC INTRUSIVE ROCK. HARD FRESH HIGHLY FRAGMENTED ROCK WITH WEATHERED ZONES. 12' TO 13' VERY HIGHLY WEATHERED. 16' TO 18' VERY HIGHLY WEATHERED.

BORING TERMINATED 8-30-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING IP-4

SURFACE ELEVATION 424.0
CO-ORDINATES N 472,800
E 1,905,000

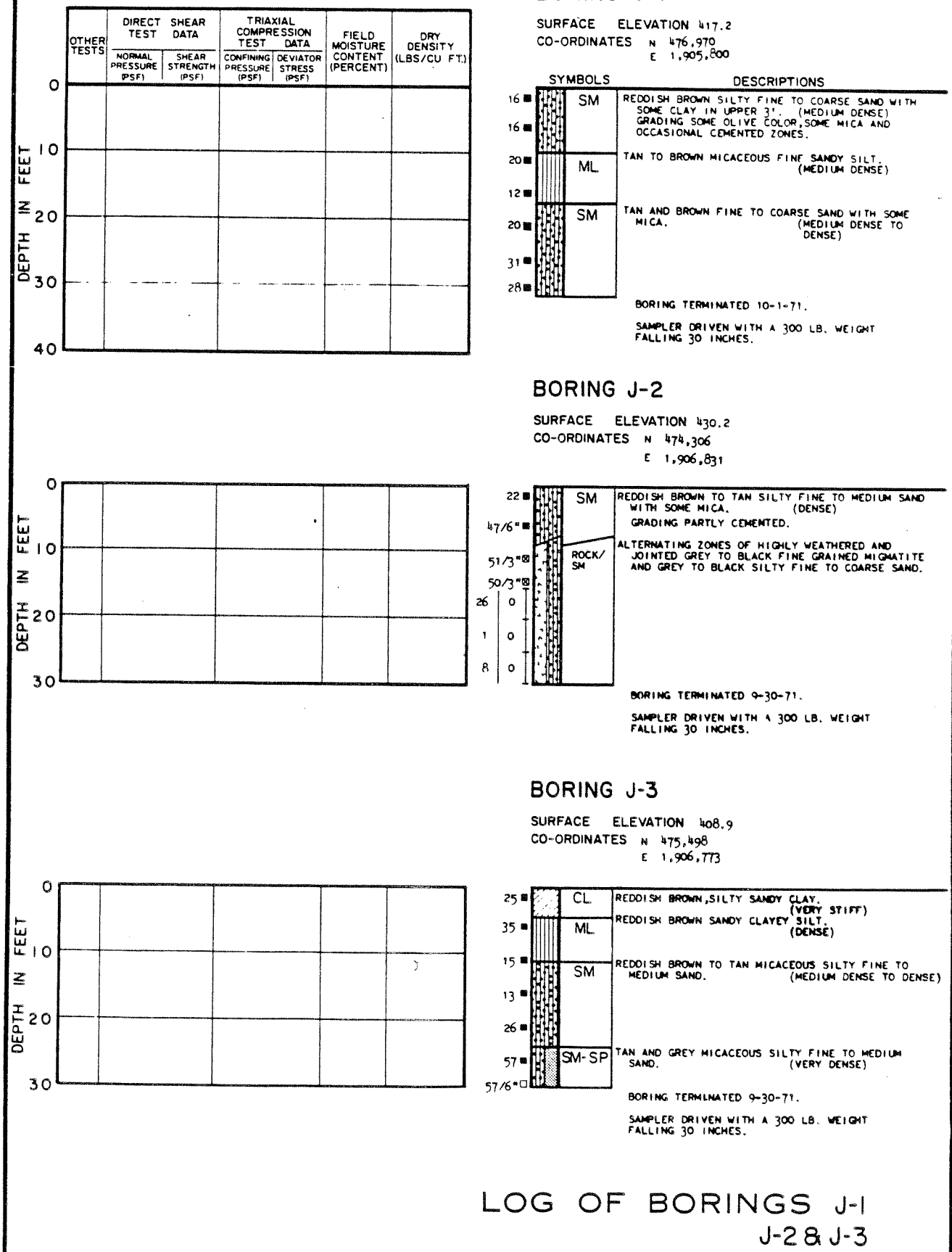
DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10		2500	1930			9	89
20							
30							

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY CLAY. (STIFF)
SM	REDDISH BROWN MICACEOUS SILTY FINE SAND. (MEDIUM DENSE) GRADES TAN AND OLIVE IN COLOR.

BORING TERMINATED 8-30-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS IP-3 & IP-4



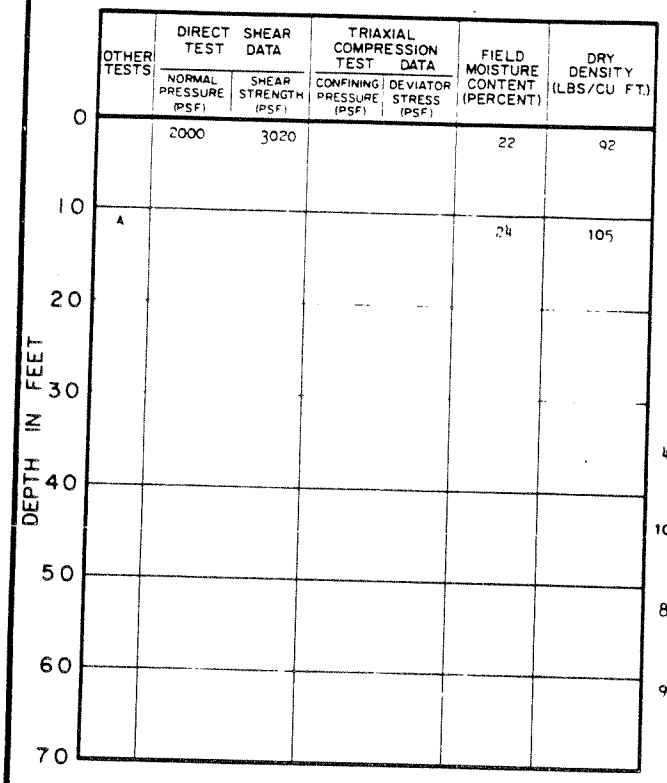
LOG OF BORINGS J-1 J-2 & J-3

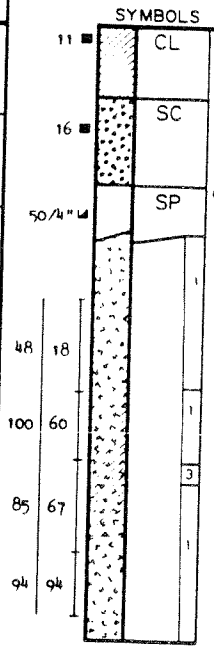
Amendment 0
August 1984

Figure 2E-72

BORING SSA-6

SURFACE ELEVATION 482.7
CO-ORDINATES N 471,830
E 1,904,293





DESCRIPTIONS

REDDISH BROWN CLAY. (STIFF)

REDDISH BROWN CLAYEY SAND. (MEDIUM DENSE TO FINES)

OLIVE AND TAN MICACEOUS SILTY SAND. (VERY FINES)

TAN TO LIGHT GREY JOINTED TO MASSIVE FINE TO MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION.
23' TO 35' HIGHLY TO VERY HIGHLY WEATHERED; HIGHLY JOINTED; TAN.

35' TO 37½' HIGHLY WEATHERED; MODERATELY JOINTED.
37½' TO 39' MODERATELY WEATHERED; MODERATELY JOINTED; LIGHT GREY.
39' TO 44' MASSIVE FRESH ROCK; LIGHT GREY.
44' TO 47' FRESH ROCK; MODERATELY JOINTED WITH SOME SLIGHT WEATHERING ALONG JOINT SURFACES.
47' TO 49' MODERATELY TO HIGHLY WEATHERED; HIGHLY JOINTED.
49' TO 64½' MASSIVE FRESH ROCK.
1' JOINT ZONE WITH SLIGHT WEATHERING AT 53'.

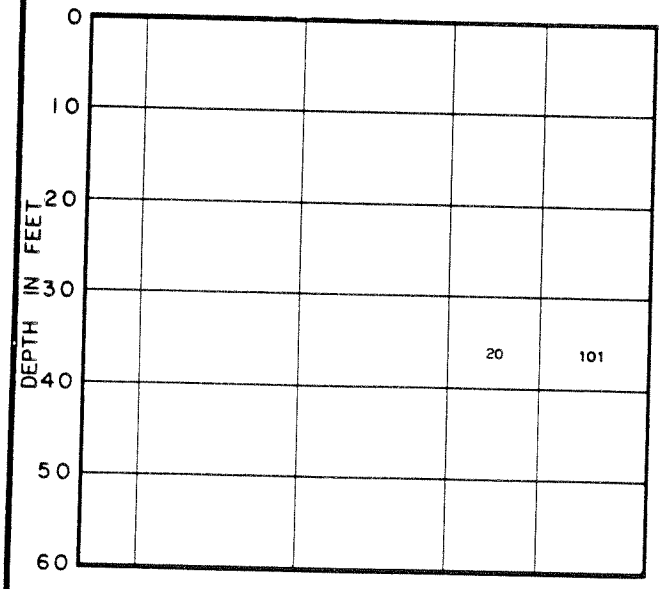
2" JOINT ZONE AT 57'.

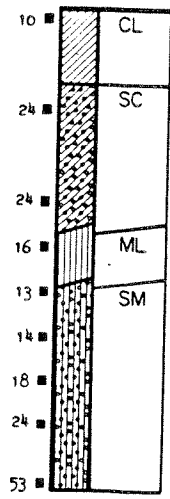
BORING TERMINATED 9-2-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING SSA-7

SURFACE ELEVATION 460.5
CO-ORDINATES N 471,635
E 1,904,508





REDDISH BROWN SANDY SILTY CLAY. (STIFF)

REDDISH BROWN CLAYEY SAND. (DENSE)

REDDISH BROWN SANDY SILT. (STIFF)

TAN AND OLIVE MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)

GRADES DENSE TO VERY DENSE.

BORING TERMINATED 9-1-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS SSA-6 & SSA-7

Amendment 0
August 1984

Figure 2E-73

BORING SSA-8

SURFACE ELEVATION 478.6
CO-ORDINATES N 471,895
E 1,904,550

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0						22	97
10	A						
20							
30							
40		3000	2830			14	109
50						19	103
60							
70							

SYMBOLS		DESCRIPTIONS
6	CL	REDDISH BROWN SILTY CLAY. (MEDIUM STIFF)
18	ML	REDDISH BROWN SANDY CLAYEY SILT. (HARD)
12	SM	OLIVE AND TAN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
12		
16		
24		GRADES DENSE AND COARSER IN TEXTURE.
40		
22		
34		
20		

BORING TERMINATED 9-1-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING SSA-9

SURFACE ELEVATION 443.9
CO-ORDINATES N 471,545
E 1,904,703

DEPTH IN FEET					
0					
10				15	101
20					
30					
40					

4	SM	BROWN MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
16		
16		GRADES OLIVE AND TAN AND FINER.
16		
18		
34		GRADES DENSE TO VERY DENSE.
40		
54		

BORING TERMINATED 9-1-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS SSA-8 & SSA-9

Figure 2E-74

BORING SSA-10

SURFACE ELEVATION 467.0
CO-ORDINATES N 471,795
E 1,904,850

OTHER TESTS	DIRECT SHEAR TEST: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT)
A					18	84
A	4000	5480			10	113
					13	116

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SANDY SILTY CLAY. (STIFF)
SM	TAN AND OLIVE MICACEOUS SILTY FINE TO MEDIUM SAND. (MEDIUM DENSE)
SM	OLIVE AND TAN MICACEOUS SILTY FINE TO MEDIUM SAND. (DENSE TO VERY DENSE)

14, 8, 12, 30, 66, 90/10", 50/4", 50/5", 87/9"

BORING TERMINATED 9-1-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING SSA-11

SURFACE ELEVATION 444.0
CO-ORDINATES N 471,635
E 1,905,090

OTHER TESTS	DIRECT SHEAR TEST: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT)
					23	87

DEPTH IN FEET: 0, 10, 20, 30, 40

SYMBOLS	DESCRIPTIONS
SC	REDDISH BROWN SILTY SANDY CLAY. (MEDIUM STIFF)
SM-ML	OLIVE, BROWN AND TAN MICACEOUS SILTY SAND AND SANDY SILT. (MEDIUM DENSE)

14, 11, 12, 15, 14, 17, 13

BORING TERMINATED 9-2-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

LOG OF BORINGS SSA-10 & SSA-11

BORING SWP-I

SURFACE ELEVATION 382.8

CO-ORDINATES N 473,100
E 1,905,480

OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)

DEPTH IN FEET: 0, 10, 20, 30, 40, 50, 60, 70, 80

		SYMBOLS	DESCRIPTIONS
7 ■		ML	BROWN TO TAN CLAYEY SANDY SILT WITH SOME MICA. (MEDIUM DENSE)
88 ■		SM	BROWN AND TAN MICACEOUS SILTY SAND WITH SOME SANDY SILT. (VERY DENSE)
60 ■			
100 ■			
57/2"⊠			GREY TO TAN MODERATELY TO HIGHLY JOINTED FINE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. HIGHLY WEATHERED. CONTAINS INCLUSIONS AND IS MODERATELY FOLIATED
38	15		
17	0		
52	18		TAN TO GREY JOINTED TO MASSIVE COARSE GRAINED GRANODIORITE. 43' TO 61' HIGHLY WEATHERED; MODERATELY TO HIGHLY JOINTED.
86	46		
100	73		61' TO 75' SLIGHTLY WEATHERED TO FRESH; SLIGHTLY JOINTED TO MASSIVE.
100	100		MODERATELY WEATHERED, HIGHLY JOINTED ZONES AT 63' TO 64' AND 65' TO 66½'
			LOST DRILLING CIRCULATION AT 71'
			BORING TERMINATED 9-24-71.
			SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

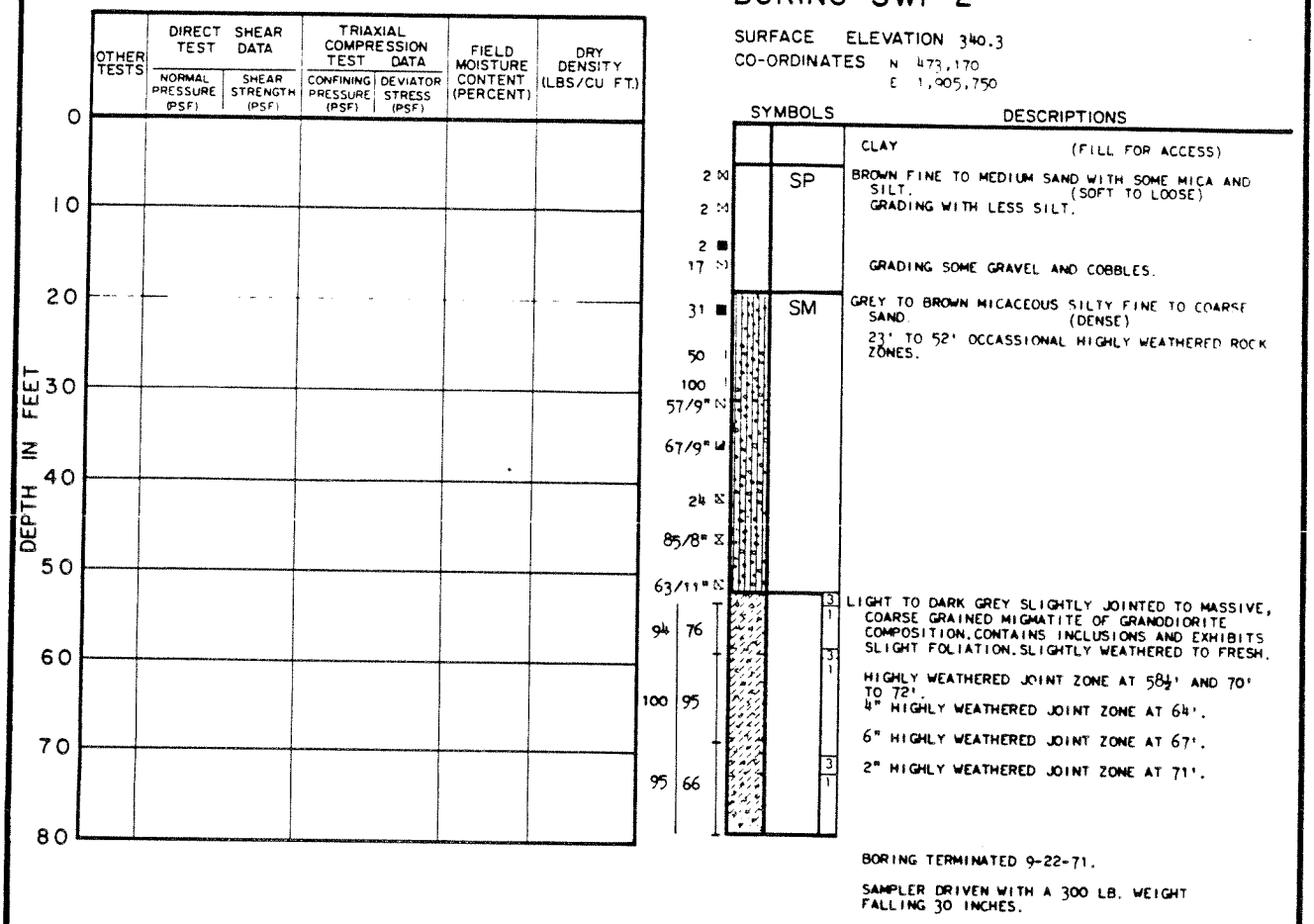
LOG OF BORING SWP-I

Amendment 0
August 1984

Figure 2E-76

BORING SWP-2

SURFACE ELEVATION 340.3
CO-ORDINATES N 473,170
E 1,905,750



LOG OF BORING SWP-2

Amendment 0
August 1984

Figure 2E-77

BORING SWP-3

SURFACE ELEVATION 393.2

CO-ORDINATES N 473,250
E 1,906,050

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							

SYMBOLS	DESCRIPTIONS
4 ■	BROWN SILTY FINE TO MEDIUM SAND. (LOOSE)
90/8"■	GRADING VERY DENSE AND MICACEOUS, PARTIALLY CEMENTED AT 3½'.
30 ⊠	GREY TO BLACK JOINTED FINE TO MEDIUM GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS AND EXHIBITS MODERATE FOLIATION.
95 15	10' TO 52' HIGHLY WEATHERED; HIGHLY JOINTED.
70 0	
93 5	
90 7	
52 0	52' TO 61' SLIGHTLY TO MODERATELY WEATHERED; MODERATELY TO HIGHLY JOINTED.
90 50	CIRCULATION LOST AT 52½'.
	BORING TERMINATED 9-28-71.
	SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

SM

3

32

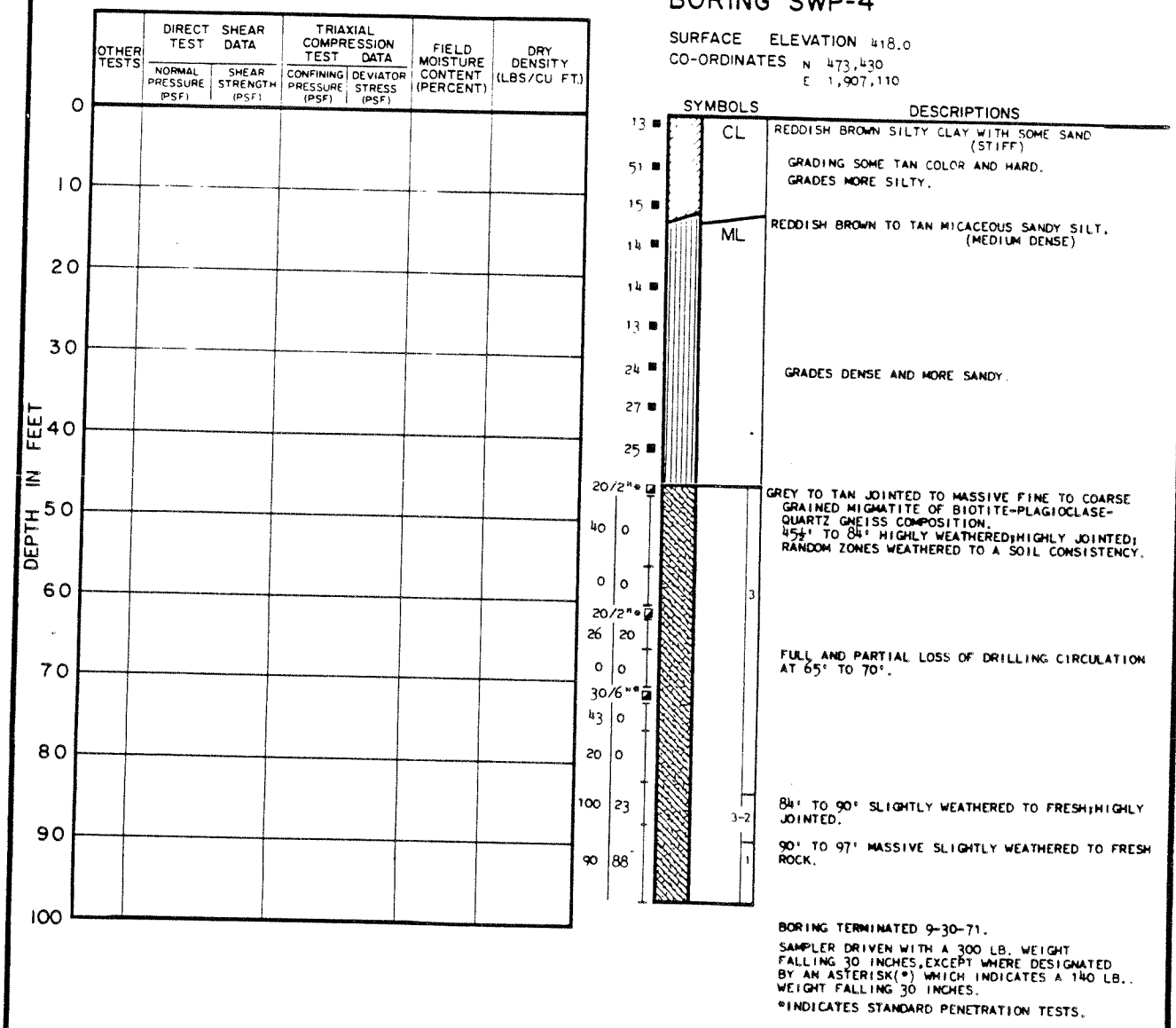
LOG OF BORING SWP-3

Amendment 0
August 1984

Figure 2E-78

BORING SWP-4

SURFACE ELEVATION 418.0
CO-ORDINATES N 473,430
E 1,907,110



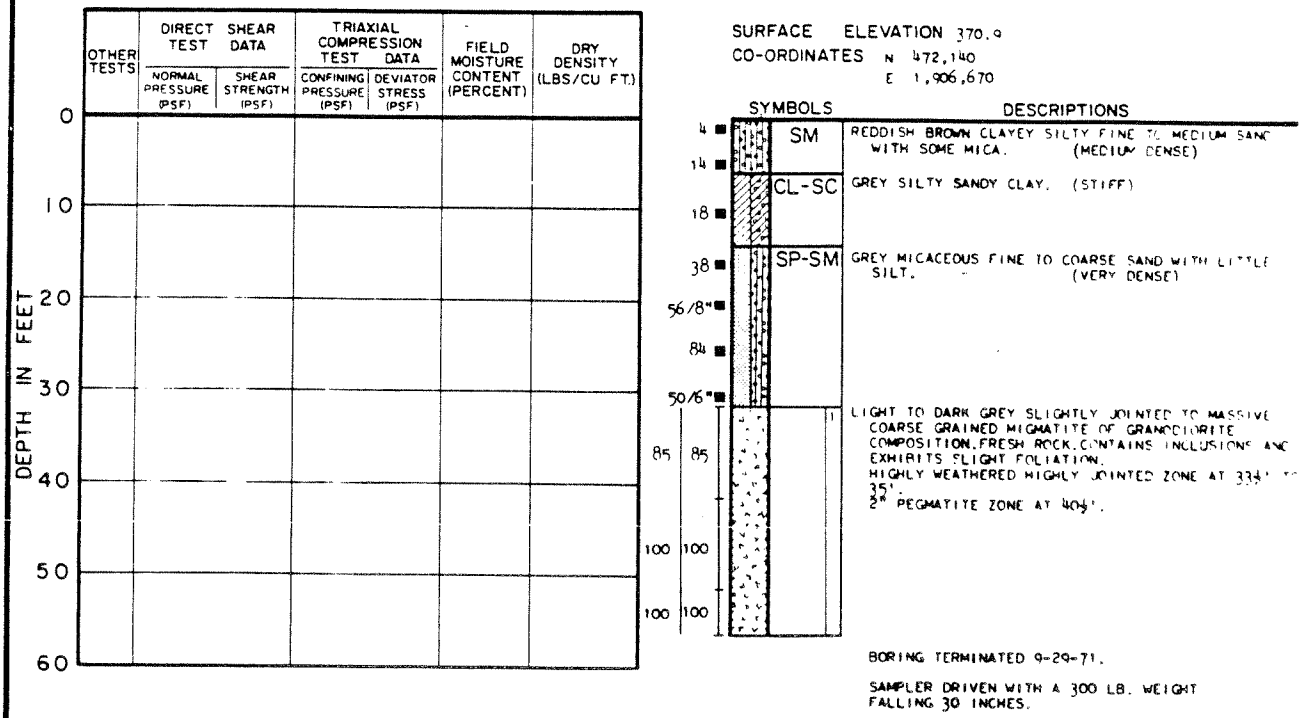
LOG OF BORING SWP-4

Amendment 0
August 1984

Figure 2E-79

BORING SWP-5

SURFACE ELEVATION 370.9
CO-ORDINATES N 472,140
E 1,906,670

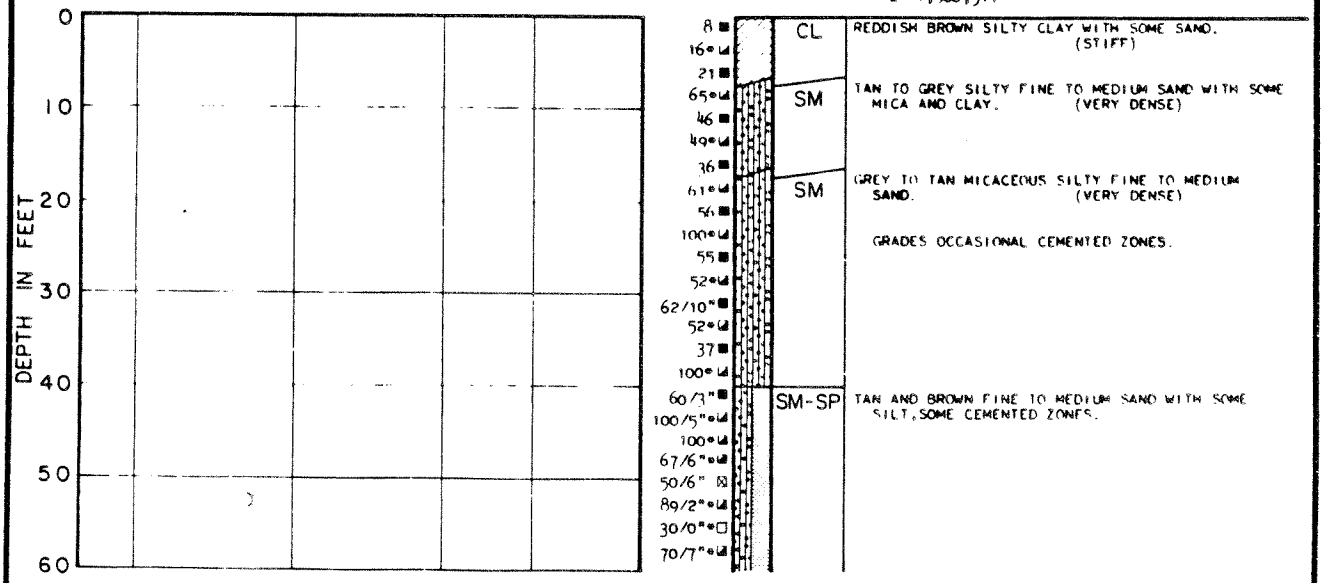


BORING TERMINATED 9-29-71.

SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.

BORING SWP-6

SURFACE ELEVATION 410.9
CO-ORDINATES N 471,964
E 1,906,511



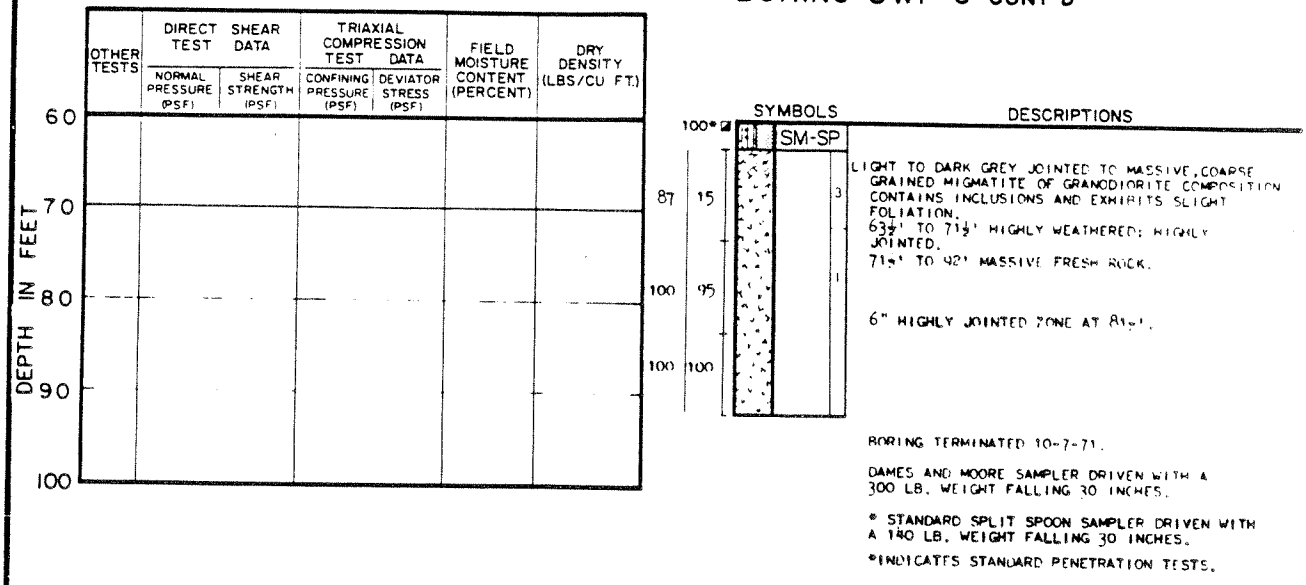
BORING CONTINUED

LOG OF BORINGS SWP-5 & SWP-6

Amendment 0
August 1984

Figure 2E-80

BORING SWP-6 CONT'D



LOG OF BORING SWP-6

Amendment 0
August 1984

Figure 2E-80a

BORING SWP-7

SURFACE ELEVATION 410.4
CO-ORDINATES N 472,096
E 1,906,810

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							

	SYMBOLS	DESCRIPTIONS
40 ■ 81 ● 50 ■ 102 ● 83/9" ■ 125 ● 112 ■ 100/6" ● 120 ■ 105/7" ● 70/6" ■ 164/10" ● 174/7" ■ 100/6" ● 120/4" ● 100/2" ●	SM	YELLOW TAN MICACEOUS SILTY FINE TO MEDIUM SAND (DENSE)
	SP-SM	GREY TO TAN MICACEOUS FINE TO MEDIUM SAND WITH LITTLE SILT. (VERY DENSE)
		GRADING SOME CEMENTATION AT 7½'.
50 0		GREY TO TAN JOINTED TO MASSIVE COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION. CONTAINS INCLUSIONS AND EXHIBITS SLIGHT FOLIATION. 40' TO 52' HIGHLY WEATHERED; HIGHLY JOINTED.
100 0		52' TO 70': SLIGHTLY WEATHERED TO FRESH; SLIGHTLY JOINTED TO MASSIVE.
95 67		HIGHLY WEATHERED JOINTS AT 56½' TO 59'.
79 68		HIGHLY WEATHERED, HIGHLY JOINTED ZONE AT 64' TO 66'.
		BORING TERMINATED 10-13-71
		DAMES AND MOORE SAMPLER DRIVEN WITH A 300 LB. WEIGHT FALLING 30 INCHES.
		*SPLIT SPOON DRIVEN WITH A 140 LB. WEIGHT FALLING 30 INCHES.
		•INDICATES STANDARD PENETRATION TESTS.

LOG OF BORING SWP-7

BORING SWP-8

SURFACE ELEVATION 430.5
CO-ORDINATES N 471,450
E 1,906,960

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							

SYMBOLS	DESCRIPTIONS
CL	REDDISH BROWN SILTY SANDY CLAY. (VERY STIFF)
SM	REDDISH BROWN TO TAN MICACEOUS SILTY SAND. (MEDIUM DENSE)
ML	YELLOW TAN SILT WITH SOME MICA AND SAND. (DENSE)
SM	TAN TO BROWN MICACEOUS SILTY FINE TO COARSE SAND. (DENSE)
ML-SM	GREY MICACEOUS SILT AND FINE SAND. (VERY DENSE)
ROCK / SM	ZONES OF HIGHLY WEATHERED MIGMATITE OF GRANODIORITE COMPOSITION AND SOIL.
	TAN TO BROWN MODERATELY TO HIGHLY JOINTED COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION, CONTAINS INCLUSIONS AND EXHIBITS SLIGHT FOLIATION. HIGHLY WEATHERED.
	MODERATELY WEATHERED ZONE AT 60' TO 62'.
	MODERATELY WEATHERED ZONE AT 77' TO 80'.

18 38* 19 17* 12 14* 14 17* 17 21* 27 21* 26 37* 28 32* 35 60* 60/8" 77/6"*

11 0
40 0
100 10
100 27
100 30

2 3 2 3

BORING TERMINATED 10-11-71

SAMPLER DRIVEN WITH 300 LB. WEIGHT FALLING 30 INCHES.

*SPLIT SPOON DRIVEN WITH A 140 LB. WEIGHT FALLING 30 INCHES.
*INDICATES STANDARD PENETRATION TESTS.

LOG OF BORING SWP-8

Amendment 0
August 1984

Figure 2E-82

BORING 4-1

SURFACE ELEVATION 436
CO-ORDINATES N 472,420
E 1,905,020

DEPTH IN FEET	OTHER TESTS	DIRECT TEST / SHEAR DATA: NORMAL PRESSURE (PSF)	DIRECT TEST / SHEAR DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT)
0							
10						15 15	
20				1500 3000 6000	2015 4601 7051	14 12	86
30						9	
40						9 12	87
50						11 10 7	101
60							
70							
80							

SYMBOLS	DESCRIPTIONS
SC	REDDISH BROWN SILTY CLAYEY SAND GRADES WITH MICA
SM-SC	OLIVE AND BROWN MICACEOUS SILTY SAND TO CLAYEY SAND (MEDIUM DENSE TO STIFF)
SM	BROWN MICACEOUS SILTY FINE TO MEDIUM COARSE SAND (SAPROLITE) (LOOSE)
	GRADES MEDIUM DENSE
	GRADES MOTTLED BROWN, GRAY AND BLACK - BLACK BANDS
	GRADES WITH TRACE OF COARSE SAND
	GRADES DENSE
	GRADES VERY DENSE
	LIGHT GRAY, JOINTED AND MASSIVE, MEDIUM TO COARSE GRAINED MIGMATITE OF GRANODIORITE COMPOSITION.
	55.5' TO 63' SLIGHTLY TO MODERATELY WEATHERED WITH BROWN STAINING. ABUNDANT MEDIUM TO HIGH ANGLE WEATHERED JOINTS.
	63' TO 66.8' - HIGHLY WEATHERED
	66.8' TO 68.5' - SLIGHLTY WEATHERED WITH OCCASIONAL LOW TO HIGH ANGLE OPEN JOINTS
	68.5' TO 71' - UNWEATHERED AND MASSIVE
	71' TO 73.5' - SLIGHTLY WEATHERED ZONES WITH OCCASIONAL OPEN JOINTS AND OCCASIONAL INCLUSIONS OF ALTERED GNEISSIC MATERIAL
	BORING TERMINATED AT 73.5' ON 4-21-76
	GROUNDWATER LEVEL NOT ENCOUNTERED

P ■ 9 ■ P ■ 8 ■ P ■ 12 ■ P ■ 19 ■ P ■ 23 ■ P ■ 43 ■ P ■ 34 ■ P ■ 38 ■ P ■ 49 ■ P ⊠ 70 ■

74 | 23 | 2

89 | 60 | 1 | 2

NOTES:

- 9 ◪ INDICATES DISTURBED SAMPLE WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- 9 ⊠ INDICATES NO RECOVERY WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- TW ■ INDICATES UNDISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHEMENT HYDRAULICALLY PUSHED
- TW ⊠ INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW ☐ INDICATES NO RECOVERY WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- P ■ INDICATES UNDISTRUBED SAMPLE WITH 3 INCH O.D. SHELBY TUBE HYDRAUICALLY PUSHED

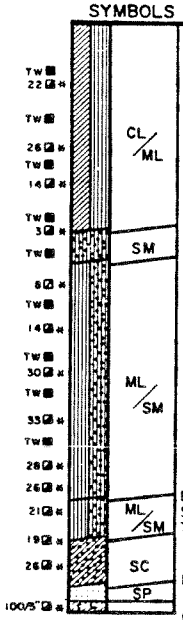
LOG OF BORING 4-1

Figure 2E-83

BORING 4-2

SURFACE ELEVATION 433.05
COORDINATES N 472,474.22
E 1,905,182.55

	OTHER TESTS	DIRECT SHEAR TEST DATA		TRIAXIAL COMPRESSION TEST DATA		FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
		NORMAL PRESSURE (PSF)	SHEAR STRENGTH (PSF)	CONFINING PRESSURE (PSF)	DEVIATOR STRESS (PSF)		
0							
						27.0	98.4
10						22.9	99.7
						24.4	96.6
20						24.3	95.9
						28.5	84.0
30						23.2	104.6
						23.9	99.8
40						22.7	104.0
						24.2	100.8
50							
60							
70							



FILL: REDDISH BROWN SILTY CLAY TO CLAYEY SILT (STIFF)

LAYER OF REDDISH BROWN CLAYEY SILT OF HIGH PLASTICITY (MH)
GRADES WITH MICA
GRADES SOFTER WITH LAYER OF SILTY FINE SAND
CIRCULATION LOST AT 18 FEET

GRADES TO SOFT

FILL: GRAYISH BROWN MICACEOUS SILTY FINE SAND (MEDIUM DENSE) GRADES WITH GRAVEL

FILL: ALTERNATING LAYERS OF REDDISH BROWN SILTY CLAY TO CLAYEY SILT AND GRAYISH BROWN MICACEOUS SILTY FINE SAND (MEDIUM STIFF TO LOOSE)
GRADES STIFF TO MEDIUM DENSE

SET CASING TO 51'

BROWN AND GRAY MICACEOUS FINE SANDY SILT TO SILTY FINE SAND (MEDIUM DENSE TO STIFF)

REDDISH BROWN CLAYEY FINE TO MEDIUM COARSE SAND (MEDIUM DENSE)

BROWN SILTY FINE TO MEDIUM COARSE SAND WITH MICA (SAPROLITE) (VERY DENSE)

WEATHERED ROCK
BORING TERMINATED AT 64' ON 9/30/76
BORING CAVED AT 23'-6"; WATER LEVEL NOT RECORDED

NOTES:

- 9 ⊡ INDICATES DISTURBED SMAPLE WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- 9 ☒ INDICATES NO RECOVERY WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- TW ■ INDICATES UNDISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW ⊠ INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW □ INDICATES NO RECOVERY WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- P ■ INDICATES UNDISTURBED SAMPLE WITH 3 INCH O.D. SHELBY TYBE HYDRAULICALLY PUSHED

LOG OF BORING 4-2

BORING 4-3

SURFACE ELEVATION 414.28
COORDINATES N 472,561.62
E 1,905,088.60

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10							
20							
30							
40							
50							
60							
70							

SYMBOLS	DESCRIPTIONS
12 P* 7 P* 45 P*	ML/CL — FILL: REDDISH BROWN MICACEOUS CLAYEY SILT TO SILTY CLAY (MEDIUM STIFF)
	TRACE OF ORGANIC MATERIAL
21 P*	ML/CL — REDDISH BROWN MICACEOUS CLAYEY SILT TO SILTY CLAY WITH TRACE OF ORGANICS AND MICA (VERY STIFF)
27 P*	ML — MOTTLED REDDISH BROWN, BROWN, TAN AND BLACK FINE SANDY SILT WITH TRACE OF CLAY (SAPROLITE) (STIFF)
24 P* 45 P* 28 P* 36 P* 33 P* 32 P* 52 P*	ML/SM — ALTERNATING ZONES OF VERY HIGHLY WEATHERED MIGMATITE OF GNEISSIC COMPOSITION, AND SAPROLITE DERIVED FROM COMPLETELY DECOMPOSED MIGMATITE OF GNEISSIC COMPOSITION FORMING MULTICOLORED SILT AND SILTY FINE SAND (MEDIUM DENSE TO VERY DENSE)
	HARDER ZONE FROM 24' TO 26'
	GRAY AND TAN COLOR
	GRADES WITH TRACE OF MICA
	GRADES WITH MORE MICA
	GRAY, WHITE AND BROWN COLOR
	GRAY AND TAN COLOR
	GREENISH GRAY TO TAN COLOR
100/7" P*	GRAY HIGHLY WEATHERED MIGMATITE OF GNEISSIC COMPOSITION

BORING TERMINATED AT 63'-2" ON 10/1/76

WATER LEVEL AT 40' ON 10/4/76

NOTES:

- P* ◪ INDICATES DISTURBED SAMPLE WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- P* ⊘ INDICATES NO RECOVERY WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- TW ■ INDICATES UNDISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW ⊠ INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW □ INDICATES NO RECOVERY WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- P ■ INDICATES UNDISTURBED SAMPLE WITH 3 INCH O.D. SHELBY TUBE HYDRAULICALLY PUSHED

LOG OF BORING 4-3

BORING 4-4

SURFACE ELEVATION 434.24
COORDINATES N 472,476.12
E 1,905,203.30

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10	B					27.7	94.2
20						18.9	108.3
30						22.0	103.5
						20.8	106.3
40							
50						22.6	103.5
60						21.5	104.0
70							

SYMBOLS	DESCRIPTIONS
ML/CL	FILL: REDDISH BROWN MICACEOUS CLAYEY SILT TO SILTY CLAY (STIFF)
	LAYER OF SILTY FINE SAND
ML/SM	FILL: ALTERNATING LAYERS OF BROWN AND GRAYISH BROWN MICACEOUS SILTY SAND AND REDDISH BROWN MICACEOUS SANDY AND CLAYEY SILT (MEDIUM DENSE TO STIFF)
	DENSER FROM 37' TO 42'
	LAYER OF REDDISH BROWN MICACEOUS CLAYEY SILT OF HIGH PLASTICITY (MH)
SM/ML	FILL: REDDISH BROWN MICACEOUS SILTY FINE SAND TO FINE SANDY SILT (MEDIUM DENSE TO STIFF)
SM	REDDISH BROWN SILTY CLAY WITH A TRACE OF MICA (VERY STIFF)
SM	GRAY, GREENISH BROWN MICACEOUS SILTY FINE SAND (SAPROLITE) (DENSE)
	WEATHERED ROCK
	BORING TERMINATED AT 67' ON 10/5/76
	HOLE CAVED; WATER LEVEL NOT RECORDED

NOTES:

- S: INDICATES DISTURBED SAMPLE WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- S: INDICATES NO RECOVERY WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- TW: INDICATES UNDISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW: INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW: INDICATES NO RECOVERY WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- P: INDICATES UNDISTURBED SAMPLE WITH 3 INCH O.D. SHELBY TUBE HYDRAULICALLY PUSHED

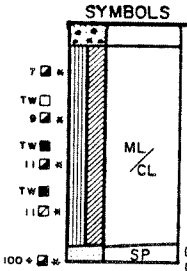
LOG OF BORING 4-4

Figure 2E-86

BORING 4-5

SURFACE ELEVATION 432.83
COORDINATES N 472,463.70
E 1,905,156.30

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10						26.3	88.5
20						27.6	98.6
30							



SYMBOLS / DESCRIPTIONS

CRUSHED ROCK DRILLING MAT
FILL: REDDISH BROWN CLAYEY SILT TO SILTY CLAY (MEDIUM STIFF TO STIFF)

LAYER OF SILTY FINE SAND

SOFT ZONE FROM 21'-6" TO 23'

GRAY MICACEOUS SILTY FINE SAND
OBSTRUCTION (MASSIVE AND HARD) AT 25'-10"
BORING TERMINATED AT 25'-10" ON 10/6/76
HOLE CAVED; WATER LEVEL NOT RECORDED

NOTES:

- 9 ■ INDICATES DISTURBED SAMPLE WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- 9 ☒ INDICATES NO RECOVERY WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- TW ■ INDICATES UNDISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW ☒ INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW □ INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- P ■ INDICATES UNDISTURBED SAMPLE WITH 3 INCH O.D. SHELBY TUBE HYDRAULICALLY PUSHED

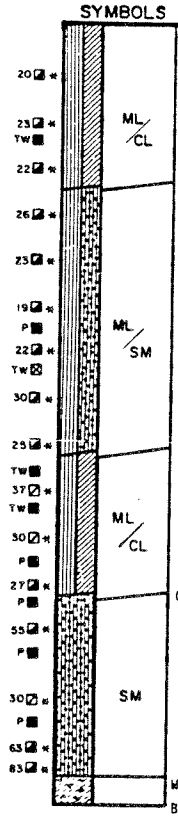
LOG OF BORING 4-5

Figure 2E-87

BORING 4-6

SURFACE ELEVATION 435.68
COORDINATES N 472,392.82
E 1,905,270.70

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10							
20							
30							
40							
50							
60							
70							
80							
90							



NOTES:

- 9 ◪ INDICATES DISTURBED SAMPLE WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- 9 ⊠ INDICATES NO RECOVERY WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- INDICATES UNDISTURBED SAMPLE WITH
- TW ■ DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW ⊠ INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW □ INDICATES NO RECOVERY WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- P ■ INDICATES UNDISTURBED SAMPLE WITH 3 INCH O.D. SHELBY TUBE HYDRAULICALLY PUSHED

LOG OF BORING 4-6

BORING 4-7

SURFACE ELEVATION 435.67
COORDINATES N 471,843.48
E 1,905,726.82

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU FT.)
0							
10							
20							
30							
40							
50							
60							

SYMBOLS	DESCRIPTIONS
ML-CL	FILL: REDDISH BROWN CLAYEY SILT TO SILTY CLAY (MEDIUM STIFF)
11 ⊠ *	SAPROLITE DERIVED FROM COMPLETELY DECOMPOSED MIGMATITE OF GRANODIORITE COMPOSITION FORMING MOTTLED BROWN, TAN, WHITE AND GRAY MICACEOUS SILTY FINE TO COARSE SAND WITH FINE GRAVEL SIZE ROCK FRAGMENTS (MEDIUM DENSE)
11 ⊠ *	
TW ■	
12 ⊠ *	
P ■	
14 ⊠ *	
P ■	
19 ⊠ *	
SM	
15 ⊠ *	
TW ■	
22 ⊠ *	GRADES TO DENSE
	GRADES COARSER
33 ⊠ *	
TW ⊠	
47 ⊠ *	
100/3" ⊠ *	MOTTLED BROWN, GRAY AND TAN HIGHLY WEATHERED MIGMATITE OF GRANODIORITE COMPOSITION
	BORING TERMINATED AT 50'-3" ON 10/11/73
	HOLE CAVED AT 39'; WATER LEVEL NOT RECORDED

NOTES:

- 9 ⊠ * INDICATES DISTURBED SAMPLE WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- 9 ☒ INDICATES NO RECOVERY WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- TW ■ INDICATES UNDISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW ⊠ INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW ☐ INDICATES NO RECOVERY WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- P ■ INDICATES UNDISTURBED SAMPLE WITH 3 INCH O.D. SHELBY TUBE HYDRAULICALLY PUSHED

LOG OF BORING 4-7

Figure 2E-89

BORING 4-8

SURFACE ELEVATION 432.9
COORDINATES N472,519.12
E 1,905,162.43

DEPTH IN FEET	OTHER TESTS	DIRECT SHEAR TEST DATA: NORMAL PRESSURE (PSF)	DIRECT SHEAR TEST DATA: SHEAR STRENGTH (PSF)	TRIAXIAL COMPRESSION TEST DATA: CONFINING PRESSURE (PSF)	TRIAXIAL COMPRESSION TEST DATA: DEVIATOR STRESS (PSF)	FIELD MOISTURE CONTENT (PERCENT)	DRY DENSITY (LBS/CU. FT.)
0							
10						25.7	99.1
						27.3	91.8
20							
30							
						21.4	105.1
40							
50						18.8	106.2
60							
70							

SYMBOLS		DESCRIPTIONS
12 S4, TW, 14 S, TW, 10 S, TW	CL/ML	FILL: REDDISH BROWN CLAYEY SILT TO SILTY CLAY (STIFF)
20 S, TW	SP	FILL: GRAY MICACEOUS SILTY FINE SAND
32 S	GP	FILL: SAND AND GRAVEL
36 S, TW, 32 S, TW	SM/ML	FILL: ALTERNATING LAYERS OF GRAYISH BROWN AND REDDISH BROWN SILTY SAND TO SANDY SILT (DENSE TO VERY STIFF)
27 S, P, 16 S	ML/CL	FILL: ALTERNATING LAYERS OF REDDISH BROWN MICACEOUS CLAYEY SILT TO SILTY CLAY AND GRAYISH BROWN MICACEOUS SANDY SILT (STIFF)
TW, 14 S, P	CL/ML	REDDISH BROWN SILTY CLAY TO CLAYEY SILT WITH A TRACE OF SAND (STIFF)
20 S	SM	REDDISH BROWN SILTY FINE SAND WITH CLAY
		WEATHERED ROCK
26 S, P	SM/ML	BROWN, REDDISH BROWN AND TAN SILTY FINE SAND TO SANDY SILT (SAPROLITE) (MEDIUM DENSE)
133 S	SP	BROWN MICACEOUS SILTY FINE TO COARSE SAND (SPAROLITE) (VERY DENSE)
100/1" S		WEATHERED ROCK
		BORING TERMINATED AT 69' ON 10/13/76
		WATER LEVEL NOT RECORDED

NOTES:

- S* INDICATES DISTURBED SAMPLE WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- S INDICATES NO RECOVERY WITH 2 INCH O.D. SAMPLER (STANDARD PENETRATION TEST)
- TW INDICATES UNDISTRUBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW INDICATES DISTURBED SAMPLE WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- TW INDICATES NO RECOVERY WITH DAMES & MOORE TYPE U SAMPLER AND THIN-WALLED SAMPLING TUBE ATTACHMENT HYDRAULICALLY PUSHED
- P INDICATES UNDISTURBED SAMPLE WITH 3 INCH O.D. SHELBY TUBE HYDRAULICALLY PUSHED

LOG OF BORING 4-8

Appendix 2F
LOGS OF BORING AND TEST PITS FOR SERVICE WATER POND EMBANKMENTS

Logs of Boring and Test Pits for Service Water Pond Embankments Index Sheet

Page	Boring	Page	Boring
2F-1	Index Sheet	2F-44	C-4, C-5
2F-2	Key to Soil Symbols and Terms	2F-45	C-6, C-7
2F-3	ND-1, ND-2	2F-46	C-8, C-9
2F-4	ND-3, ND-4	2F-47	C-10, C-11
2F-5	ND-5, ND-6	2F-48	WE-1
2F-6	ND-7, RND-8	2F-49	WE-2
2F-7	RND-9, ND-13	2F-50	WE-3
2F-8	ND-13A, ND-13	2F-51	WE-4, WE-5
2F-9	ND-14, ND-15	2F-52	WE-6 (1 of2)
2F-10	ND-16, ND-17	2F-53	WE-6 (2 of 2)
2F-11	ND-18, ND-19	2F-54	WE-7 (1 of 2)
2F-12	ND-20, ND-21	2F-55	WE-7 (2 of 2)
2F-13	ND-22, ND-23	2F-56	TPW-1
2F-14	ND-24, ND-25	2F-57	TPW-2
2F-15	ND-26, ND-27	2F-58	TPW-3
2F-16	ND-28, ND-29	2F-59	F-1, F-2
2F-17	ND-30, ND 1/4	2F-60	F-3, F-4
2F-18	ND-4/11, ND-11/17	2F-61	F-5
2F-19	ND-17/20, SD-1	2F-62	F-6
2F-20	SD-1A, SD-1B	2F-63	F-7, F-7A
2F-21	SD-2, SD-3	2F-64	F-8, F-9 (1 of 2)
2F-22	SD-4, SD-5 (1 of 2)	2F-65	F-9, (2 of 2), F-10
2F-23	SD-5 (2 of 2), SD-5B	2F-66	F-11, F-12 (1 of 2)
2F-24	SD-6, SD-7	2F-67	F-12, (2 of 2), F-13 (1 of 2)

Page	Boring	Page	Boring
2F-25	SD-8	2F-68	F-13, (2 of 2), F-14
2F-26	SD-8B, SD-9	2F-69	F-15
2F-27	SD-1/5, SD-5/8	2F-70	F-16
2F-28	TP-S1, TP-S2	2F-71	TBG-2
2F-29	TP-S3, TP-S4	2F-72	TBG-3
2F-30	TP-S5, ED-1	2F-73	TBG-5
2F-31	ED-2, ED-3	2F-74	TBG-7
2F-32	ED-4, ED-5	2F-75	TBG-8
2F-33	ED-6, WD-1	2F-76	TBG-10
2F-34	WD-2, WD-5	2F-77	TBG-12
2F-35	RWD-5, WD-6	2F-78	TBG-14
2F-36	WD-7, RWD-7	2F-79	TBG-15
2F-37	WD-8, WD-9	2F-80	TBG-16
2F-38	WD-10, WD-12A	2F-81	TBG-17, TBG-19 (1 of 2)
2F-39	RWD-13, WD-14	2F-82	TBG-19 (2 of 2), TBG-20 (1 of 2)
2F-40	RWD-14, SS-1	2F-83	TBG-20 (2 of 2), TBG-23 (1 of 2)
2F-41	SS-3, SS-4	2F-84	TBG-23 (2 of 2), TPG-4, TPG-9
2F-42	SS-5, C-1	2F-85	TPG-11, TPG-18, TPG-21, TPS-22
2F-43	C-2, C-3	2F-86	TPG-24, TPG-25

INSERT BORINGS 2F-2 - 2F-86

Figure 2.F-2 to Figure 2F-86

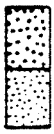
LOG OF BORING

KEY TO SOIL SYMBOLS AND TERMS

Terms used in this report for describing soils according to their texture or grain size distribution are in accordance with the Unified Soil Classification System, as described in Technical Memorandum No. 3-357, Waterways Experiment Station, March 1953.

Gravel

Gravelly



Sand

Sandy

Silt

Silty

Clay

Clayey

Organic matter

Organic

Rock

Shale

Topsoil

Misc. Fill

Sample Recovered

Sample Not Recovered

TERMS DESCRIBING CONSISTENCY OR CONDITION

COARSE GRAINED SOILS (major portion retained on No. 200 sieve). Includes (1) clean gravels and (2) silty or clayey gravels and sands. Condition is rated according to relative density, as determined by laboratory tests.

Descriptive Term	Relative Density
Very loose	0 to 15%
Loose	15 to 40%
Medium dense	40 to 70%
Dense	70 to 85%
Very dense	85 to 100%

FINE GRAINED SOILS (major portion passing No. 200 sieve). Includes (1) inorganic and organic silts and clays, (2) gravelly, sandy, or silty clays, and (3) clayey silts. Consistency is rated according to shearing strength as indicated by penetrometer readings or by unconfined compression tests.

Descriptive Term	Unconfined Compression Strength, tons sq.ft.
Very soft	less than 0.25
Soft	0.25 to 0.50
Firm	0.50 to 1.00
Stiff	1.00 to 2.00
Very stiff	2.00 to 4.00
Hard	4.00 and higher

SAMPLING RESISTANCE

15 – The number of blows (15) of a 140-pound hammer falling 30 inches used to drive a 2" O.D. split-barrel sampler for the last 12 inches of penetration.

50/2 – Number of blows (50) used to drive the split-barrel a certain number of inches (2).

P – Thin-wall tube sample.

P250 – Thin-wall tube pushed hydraulically, using a certain pressure (250 psi) to push the last 6 inches.

P_S/ C – Denison or Pitcher-Type core-barrel sample.

BS/P_S – Piston sample.

A – Auger sample.

BX – Rock cored with BX core barrel, which obtains a 1-5/8" diameter core.

NX – Rock cored with NX core barrel, which obtains a 2-1/8" diameter core.

65% – Percentage (65) of rock core recovered.

LABORATORY TEST IDENTIFICATION

C – Consolidation and specific gravity tests performed.

D – Maximum & minimum density.

DS – Direct Shear test performed.

G – Specific gravity test performed.

K – Permeability test performed.

M – Mechanical (sieve or hydrometer) analysis performed.

T – Triaxial compression test performed.

U – Unconfined compression test performed.

W – Unit weight & natural moisture content determined

X – Special tests performed - see Laboratory test results.

LOG of BORING No. ND-1

DATE 12-22-71 SURFACE ELEV. 337.1 LOCATION N 473, 684 E 1,905,540

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	RQD	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		P		Very stiff dark brown micaceous fine sandy silty clay with rock fragments; CL					
5		20		(Residual Soil becoming Decomposed Rock)	327.1				
10		P		Very dense brown micaceous medium to fine silty sand; SM		11.3			
15		153/10"		(Decomposed Rock)	317.1				
20		100% NX	70%	White to black granite gneiss highly contorted banding badly broken zone from 28.2 to 33.0 ft.					
25		98% NX	60%						
30		46% NX	13%						
35					298.6				
40									

COMPLETION DEPTH 38.5' Water Depth 1.75 ft. / 5.75 ft. Date 1-20-72

SAMPLER 2 O.D. SPLIT BARREL SAMPLER 3-3-72

LOG of BORING No. ND-2

DATE 12-10-71 SURFACE ELEV. 410.3 LOCATION N 473, 075 E 1,904,935

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		160	Very dense bluish gray to tan fine sandy silt with rock fragments, slight plasticity; ML		20.6			
5		144	(Decomposed Rock)	403.8	18.9			
10								

COMPLETION DEPTH 6.5' Water Depth None Date 12-10-71

SAMPLER 2 O.D. SPLIT BARREL SAMPLER

LOG of BORING No. ND-3

DATE 12-10-71 SURFACE ELEV. 391.7 LOCATION N 473,287 E 1,905,297

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		17	Dense bluish gray fine sandy silt becoming very dense decomposed rock; ML		22.9			
5		48			5.6			
		91			16.3			
10		7"	(Residual Soil)					
				378.2				
			Note: Drilled from 8'7" to 13'6" with rock bit to check soundness of rock					

COMPLETION DEPTH 13.5' Water Depth None Date 12-11-71
SAMPLER 2" O.D. SPLIT BARREL SAMPLER Dry 3-1-72

LOG of BORING No. ND-4

DATE 1-12-72 SURFACE ELEV. 335.1 LOCATION N 473,480 E 1,905,630

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	ROD	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0									
		P		Very stiff micaceous silty clay; CL					
5		20							
				(Residual Soil)					
10		P			325.1				
		80		Very dense dark brown and tan silty fine to medium sand; SM		18.6			C
15						15.0			W
		PS		(Saprolite becoming Decomposed Rock)					T
20		80				10.1			C
		8"							W
25		PS			309.1				
		100							
		1"							
30		100%	92%	Sound blue-gray migmatite (varying from granite gneiss to diorite) slightly fractured except for highly fractured and broken zones from 31 to 32 ft. and from 39.4 to 39.6 ft.					
		NX							
35		100%	100						
		NX							
40		100%	92%						
		NX			293.1				
45									

COMPLETION DEPTH 42.0' Water Depth 1.0' Date 1-20-72
SAMPLER 2" O.D. SPLIT BARREL SAMPLER 2.9' 3-3-72

LOG of BORING No. ND-5

DATE 12-8-71 SURFACE ELEV. 386.8 LOCATION N 473,600 E 1,906,090

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill for drilling pad	384.8				
		22	Very stiff light brown fine sandy clayey silt, medium plasticity; ML (Saprolite)	381.8	17.8			
5		120/8"			10.0			
		100/3"	Very dense light brown silty clayey fine sand; SC/SM (Decomposed Rock)	371.8				
10								
			Note: Drilled from 8'3" to 15'0" with rock bit to check soundness of rock					
			* Water observed seeping from hillside and saturating drilling pad					

COMPLETION DEPTH 15.0' Water Depth 0 * Date 12-15-71

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-6

DATE 12-7-71 SURFACE ELEV. 418.3 LOCATION N 473, 650 E 1,906,500

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		200/7"	Very dense light brown micaceous silty clayey fine sand; SC/SM (Decomposed Rock)	413.3	13.6			
5		100/0"	Very dense brown silty fine to coarse sand; SM					
		144/7"	(Decomposed Rock)	408.9	13.9			
10		268/7"	Very dense tan silty fine sand; SM (Decomposed Rock)	405.9	4.5			
15			Note: Fishtail bit refusal at 5'; used roller bit to advance hole below 5 ft.					
			* Water observed seeping from hillside and saturating drilling pad					

COMPLETION DEPTH 12.4' Water Depth 0 * 3 ft. Date 12-15-71 1-20-72

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. RND-7

DATE 12-16-71 SURFACE ELEV. 423.9 LOCATION N 472,900 E 1,905,035

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	RQD	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		70/3"	0%	Very dense red-brown and light gray silty fine sandy clay; CL (Decomposed Rock)	408.9	21.5			
20		71/6"	0%	Decomposed friable grandodiorite with biotite mica					
40			0%						
60			0%						
80			0%						
100			0%						
			5%	Quartz Inclusions encountered					
120			0%	Quartz inclusions encountered with some clay content					
140			0%						
			8%						
160			72%	Yellow-green to gray green weathered seamy altered chlorite biotite schist	268.9				
			30%		259.7				
				Light gray to gray granite gneiss	254.6	0.41			W
180			100%	Light gray to black chlorite biotite schist and granite gneiss/schist	247.9	0.53			*

COMPLETION DEPTH 176.0' Water Depth ____ Date ____

SAMPLER 2" O.D SPLIT BARREL SAMPLER

* Sonic Velocity Tests on Rock Cores

LOG of BORING No. RND-8

DATE 2-29-72 SURFACE ELEV. 420.7 LOCATION N 473,038 E 1,905,164

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		34	Hard brown silty clay; CL (Residual Soil)	415.7				
5		44/6"	Very dense brown micaceous silty sand, slight plasticity; SM (Decomposed Rock)	408.7				
10		60/6"						
		18%/NX	Highly fractured and weathered rock	-				
15								
20		3%/NX						
25		4%/NX		393.7				
30								

COMPLETION DEPTH 27.0' Water Depth ____ Date ____

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. RND-9

DATE 3-1-72 SURFACE ELEV. 407.0 LOCATION N 473,100 E 1,905,360

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
10		80/2"	Very dense decomposed rock with occasional thin layers of hard rock at various elevations below 20 ft. depth; boring advanced with roller rock bit from 20 to 65 ft.					
20		30/0"						
30								
40								
50								
60				342.00				
70			*Field permeability tests run in this boring					

COMPLETION DEPTH 65.0' Water Depth * Date 3-1-72
SAMPLER: 2" O.D. SPLIT BARREL SAMPLER None 3-3-72

LOG of BORING No. ND-11

DATE 1-12-72 SURFACE ELEV. 337.8 LOCATION N 473,310 E 1,905,740

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	RQD	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0				Fill for drilling pad	335.3				
				Very loose brown micaceous silty medium to fine sand; SM (Alluvium)	324.3				
20				Dense to very dense gray brown micaceous silty coarse to fine sand; SM (Saprolite)	303.8				
40		100% NX	100%						
		100% NX	100%						
		100% NX	100%	Bluish gray unweathered sound granodiorite with veins of lighter minerals					
60		100% NX	100%						
		100% NX	100%						
80		100% NX	100%						
		100% NX	100%						
100		100% NX	100%						
		100% NX	100%						
120		100% NX	100%						
		100% NX	100%						
140		100% NX	100%		191.3				
160									

COMPLETION DEPTH 146.6' Water Depth 0 ft. Date 1-24-72
SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. ND-13A

DATE 2/23/72 SURFACE ELEV. 410.5 LOCATION N 473,328 E 1,906,119

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	RQD	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
10				Very dense decomposed rock					
20									
30					376.5				
40	NX 83%		22%	Highly fractured and weathered dark gray gneiss					
	NX 33%		0%						
	NX 40%		0%						
	NX 8.6%		0%	Granitic composition from 38.0' to 40.0'					
50	NX 4.6%		0%						
	NX 0%		0%						
60	NX 10%		0%	(contact uncertain)	346.5				
	NX 0%		0%	Highly fractured dark greenish-gray diorite with veins of lighter minerals					
70	NX 0%		0%	(contact uncertain)	337.5				
	NX 37%		0%	Highly fractured light gray gneiss	333.2				
80				NOTE: Loss of drill water from 34.0' to 61.0'					

COMPLETION DEPTH 77.3' Water Depth ____ Date ____

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. ND-13

DATE 2-16-72 SURFACE ELEV. 410.5 LOCATION N 473,400 E 1,906,100

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5								
10		60/6"	Very dense decomposed rock					
15								
20		50/2"						
25								
30		50/1"		379.5				
			Fractured and partially friable rock	376.5				
35			*Field Permeability tests run in this boring					

COMPLETION DEPTH 34.0' Water Depth * Dry Date 3-6-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. ND-14

M 473, 420
E 1,906,310

DATE 1-6-72 SURFACE ELEV. 426.4 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		P 60/4"	Very dense light tan silty medium to fine sand with rock fragments; SM		9.0			
5		PS 50/5"	increasing clay content with depth		7.9			C W T
10		PS 60/3"	(Decomposed Rock)		6.1			C W T
15		PS						
20				403.9				
25			Note: Drilled from 17'6" to 22'6" with rock bit to check soundness of rock					
30								
35								
40								

COMPLETION DEPTH 22.5' Water Depth 7.5 ft. Dry Date 1-20-72 3-6-72
SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-15

N 473,444
E 1,906,501

DATE 12-6-71 SURFACE ELEV. 435.6 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		23	Very stiff red-brown clay, high plasticity; CH		29.2	61	29	
5		38	(Residual Soil)	428.6	17.9			
		102	Very hard light brown fine sandy silty clay, medium plasticity; CL (Saprolite)	425.1	17.7			
10		35	Dense to very dense light brown fine sandy clayey silt, medium plasticity; ML		12.9	31	28	
15		37	(Saprolite)		19.9			
		70			7.6			
20		112		415.6	8.3			
		183/7"	Very dense Decomposed Rock; ML	411.1	14.1	23	NP	
25								

COMPLETION DEPTH 24.5' Water Depth Dry to 24 ft. Date 12-15-71
SAMPLER 2" O.D SPLIT BARREL SAMPLER Dry & Closed @ 10.5 ft. 1-20-72

None 3-7-72

LOG of BORING No. ND-16

DATE 12-10-71 SURFACE ELEV. 376.2 LOCATION N 472,940 E 1,905,475

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		50	Hard tan red-brown medium to fine sandy silty clay, medium plasticity; CL/CH		24.6 30.7			
			(Residual Soil)	371.2				
5		130/11"	Very dense tan micaceous silty fine sand, low plasticity; SM		13.6			
		140/11"	(Decomposed Rock)	365.3	12.4			
10								
15								

COMPLETION DEPTH 10.4' Water Depth Dry Date 12-10-71 3-8-72

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-17

DATE 1-19-72 SURFACE ELEV 343.2 LOCATION N 473,155 E 1,905,820

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill for drilling pad	337.2				
10		P 29	Very dense light blue gray and dark brown-gray medium to fine silty sand; SM					
20		P 90/10"	(Saprolite)					
		58						
30		80		313.2				
		125/10"	Very dense Decomposed Rock					
40		100/6"						
		100/6"						
50		100/3"		287.2				
		50%/NX	Fresh to badly weathered broken and seamed, gray migmatite (granodiorite)					
60		38%/NX						
		87%/NX						
70		68%/NX		267.2				
80			NOTE: Drilled from 47'3" to 56'0" with rock bit					
90								

COMPLETION DEPTH 76.0' Water Depth 4.0 ft. Date 1-19-71 3-8-72

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-18

DATE 12-8-71 SURFACE ELEV. 401.2 LOCATION N 473,200 E 1,906,120

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		100/3"	Very hard light brown fine sandy clayey silt; ML		22.9			
5		149	becoming		11.1			
		100/5"	less sandy with depth; (Decomposed Rock)		15.5			
10				388.2				
15			Note: Drilled from 8'3" to 13'0" with rock bit to check soundness of rock * Water observed seeping from hillside above drilling pad					

COMPLETION DEPTH 13.0' Water Depth 1.0 ft. * Date 12-15-71
SAMPLER 3" O.D SPLIT BARREL SAMPLER 5.5 ft. 3-7-72

LOG of BORING No. ND-19

DATE 12-8-71 SURFACE ELEV. 421.4 LOCATION N 473,230 E 1,906,510

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		170/7"	Light brown very hard fine sandy clayey silt, low plasticity; ML		11.5			
5		100/5"	(Decomposed Rock)		9.8			
		100/3"		413.4	10.8			
10			Very dense brown coarse to fine silty sand; SM (Decomposed Rock)					
15				406.4				
			Note: Drilled from 8'3" to 15'0" with rock bit to check soundness of rock					

COMPLETION DEPTH 15.0' Water Depth 6.25 ft. Date 12-15-71
SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-20

DATE 1-17-72 SURFACE ELEV. 342.4 LOCATION N 472,966 E 1,905,912

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill for drilling pad	339.4				
		2	Organic Clay	337.4				
		16	Very loose gray silty sand; SM (Alluvium)	335.4				
10		21	Very stiff brown to bluish gray micaceous sandy silty clay; CL (Residual Soil)	329.9				
		50 4"						
		132 10"						
20		85	Very dense brown micaceous silty sand; SM (Saprolite)	313.4				
30			Gray fresh to weathered granite gneiss with iron stains, highly fractured	305.4				
40			Migmatite (varying from granite gneiss amphibolite), highly fractured	279.4				
50			Sound granite gneiss	285.9				
60			Fractured migmatite (varying from amphibolite to granite gneiss), highly weathered in zones	274.6				

COMPLETION DEPTH 67.8' Water Depth 1.25 ft Date 1-20-72
SAMPLER: 2" O.D SPLIT BARREL SAMPLER 0.5 ft. 3-9-72

LOG of BORING No. ND-21

DATE 2/18/72 SURFACE ELEV. 359.3 LOCATION N 472,850 E 1,906,560

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		40	Very stiff red-brown silty clay; CL (Residual Soil)					
5		34		351.3				
10		37	Very dense brown micaceous Saprolite	345.3				
15		145						
20			Very dense decomposed rock					
25								
30								
35				323.3				
40			Intact rock - sound gray granite gneiss					
145				212.8				

COMPLETION DEPTH 146.5' Water Depth Date
SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-22

DATE 3/1/72 SURFACE ELEV. 416.4 LOCATION N 473,205 E 1,906,255

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
5								
10			Stiff red-brown clay; CL (Residual Soil)					
			becoming					
15			very dense sandy Saprolite					
				397.9				
20			Very dense decomposed rock					
25								
				387.6				
30			NOTE: Permeability tests run in this boring					

COMPLETION DEPTH 28.75' Water Depth 6.6' Date 3/14/72

SAMPLER 2" O D SPLIT BARREL SAMPLER

LOG of BORING No. ND-23

DATE 3/3/72 SURFACE ELEV. 398.4 LOCATION N 473,065 E 1,906,300

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
			NOTE: Boring advanced to 54.0' with fishtail bit.					
			Permeability tests run in this boring;					

COMPLETION DEPTH 54.0' Water Depth Date

SAMPLER 2" O D SPLIT BARREL SAMPLER

LOG of BORING No. ND-24

DATE 3/6/72 SURFACE ELEV. 370.2 LOCATION N 472,920 E 1,906,350

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
			NOTE: Boring advanced to 29.0' with fishtail bit, and from 29.0' to 31.5' with roller rock bit. Intact rock encountered at 29.5'. Permeability tests run in this boring					

COMPLETION DEPTH 30.5' Water Depth 12.7' Date 3/14/72

SAMPLER 2 O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-25

DATE 3/3/72 SURFACE ELEV. 353.1 LOCATION N 472,775 E 1,906,385

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
			NOTE: Boring advanced to 19.0' with fishtail bit, and with roller rock bit from 19.0' to 30.0'. Intact rock encountered at 30.0'. Permeability tests run in this boring					

COMPLETION DEPTH 30.0' Water Depth 6.0' Date 3/14/72

SAMPLER 2 O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-26

N 473,079
DATE 2/23/72 SURFACE ELEV. 342.0 LOCATION E 1,905,699

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill for drilling pad	340.0				
5		4	Soft tan and gray micaceous clay, with roots; CL					
		2	(Alluvium)	335.0				
10		2	Loose tan and gray silty fine sand; SM (Alluvium)	332.0				
		29	Very stiff tan and bluish gray clay; CL (Saprolite)	329.0				
15		19	Dense tan and gray silty medium to fine sand; SM					
		20	(Saprolite)	322.0				
20		134	Very dense decomposed rock					
25								
50				288.0				
55			NOTE: Drilled from 20.5' to 54.0' with rock bit. *Piezometer installed at 54.0'					

COMPLETION DEPTH 54.0' Water Depth 14.1' * Date 3/3/72
SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-27

Centerline
DATE April 17, 1974 SURFACE ELEV. 392.8 LOCATION Station 6 + 19

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE OR PERCENT RECOVERY	DESCRIPTION	ELEVATION
0				
		89% NX	(All surficial soils stripped for grout curtain construction), Casing set to 5 feet.	
10		90% NX		
20		3% NX		
		4% NX	Highly weathered and fractured granodiorite with micaceous seams and layers. All intact joints and fractures filled with light brown to tan highly plastic silty clays.	
30		28% NX		
40		28% NX		
		67% NX		
		50% NX		
50		8% NX		
		24% NX		
60		90% NX	Intact fresh rock at 59± feet.	328.9
70				
80				
90				

COMPLETION DEPTH 63.9' Water Depth --- Date April 17, 1974
SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-28

DATE April 16, 1974 SURFACE ELEV. 338.5 LOCATION Centerline Station 9 + 84

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE OR PERCENT RECOVERY	DESCRIPTION	ELEVATION
0				
10	23		Fill - red brown silty clay; CL	
				321.5
20	87		Very dense gray brown micaceous silty coarse to fine sand; SM (Saprolite)	
	58/11"			
30		10% NX		309.5
		20% NX		
40		18% NX	Fresh to highly weathered bluish gray broken and seamed granodiorite with veins of lighter minerals.	
		60% NX		
50		100% NX		
		100% NX		
60		100% NX		
		82% NX		
70		100% NX	Soft zone at 71.0 to 71.5 feet	
		100% NX		
80				259.4
			Note: Casing set at 29.3 feet	
90				

COMPLETION DEPTH 79.1' Water Depth --- Date April 17, 1974

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. ND-29

DATE Oct. 8, 1974 SURFACE ELEV. 415.6 ± LOCATION Centerline Station 14 + 41

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE OR PERCENT RECOVERY	DESCRIPTION	ELEVATION
0				
		0% NX	(All surficial residual soils stripped for grout curtain construction), Casing set to 5 feet.	
10		7% NX		
		0% NX		
20		0% NX		
	100/4"		Very dense highly decomposed rock with occasional thin layers of hard rock at various elevations but too thin to recover in NX-double tube core barrel.	
		0% NX		
30		3% NX		
		0% NX	Wash water indicates material becomes less micaceous with depth.	
40		0% NX		
		67% NX		
50		58% NX		
		0% NX		
60		0% NX		
		2% NX		
70				346.6
80				
90				

COMPLETION DEPTH 69' Water Depth Dry Date Oct. 8, 1974

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-30

DATE Oct. 9, 1974 SURFACE ELEV. 424.0± LOCATION Centerline Station 16 + 21

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE OR PERCENT RECOVERY	DESCRIPTION	ELEVATION
0				
		120	(All surficial residual soils stripped for grout curtain construction), Casing set to 5 feet.	
		0% NX		
10		100/3"		
		59% NX		
		5% NX		
20		100/5"		
		33% NX		
		15% NX		
30		13% NX	Very dense highly decomposed rock with occasional thin layers of hard rock at various elevations but too thin to recover in NX-double tube core barrel.	
		0% NX		
40		18% NX		
		33% NX		
50		0% NX		
		0% NX		
60		0% NX		
		0% NX		355.0
70				

COMPLETION DEPTH 69.0' Water Depth Dry Date Oct. 9, 1974

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. ND-1/4

N 473,570

DATE 1-25-72 SURFACE ELEV. 335.0 LOCATION E 1,905,578

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		11	Dense to very dense organic gray to red-brown silty sand; SM	332.6				
		80/10"						
5		100/4"	Very dense decomposed rock	325.0				
10			Note: Drilled from 4' to 10' with rock bit					

COMPLETION DEPTH 10.0' Water Depth 0.1 ft. Date 3-8-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. ND-4/11

DATE 1-25-72 SURFACE ELEV. 335 LOCATION N 473,397 E 1,905,692

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill for drilling pad	333.0				
		3	Organic silt and muck; OL					
5		2						
		1	(Alluvium)	329.0				
		3	Very loose red-brown wet sandy silt/ silty sand; ML/SM					
10		5						
		2						
		4	(Alluvium)	321.5				
15		127/9"	Very dense dark gray to black micaceous silty fine to medium sand; SM					
		100/3"						
20		129	(Decomposed Rock)	312.0				
25			Note: Drilled from 17' to 23' with rock bit					

COMPLETION DEPTH 23.0 Water Depth 2 ft. Date 3-7-72

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-11/17

DATE 1-24-72 SURFACE ELEV. 338 LOCATION N 473,230 E 1,905,754

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill for drilling pad	335.0				
		1/6"						
5		3	Soft red-brown to brown-gray organic sandy micaceous silt and clay; OL					
		1/6"						
		6						
10		1	becoming					
		1	loose gray coarse silty sand; organic; SM					
		4						
15		28	(Alluvium)	323.0				
			Highly weathered and friable rock					
20				317.0				
			Note: Drilled from 15'6" to 21'0" with fishtail bit					

COMPLETION DEPTH 21.0' Water Depth 3.1 ft. Date 3-7-72

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ND-17/20

DATE 1/24/72 SURFACE ELEV. 340 LOCATION N 473,057 E 1,905,860

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		2	Fill for drilling pad	338.0				
		1/9"						
		1/9"	Very soft gray to brown sandy clayey organic silt with gravel inclusions with depth; OL					
5		3						
		25						
		100/4"						
		25	(Alluvium)	331.0				
		100/4"	Very dense decomposed rock					
10		50/5"	(Saprolite)	328.5				
15			Note: Refused with fishtail bit at 11.5 ft.					

COMPLETION DEPTH 11.5' Water Depth 0.9 ft. Date 3-8-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. SD-1

DATE 12-17-71 SURFACE ELEV. 365.8 LOCATION N 472,228 E 1,906,615

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Firm reddish brown medium to fine sandy silty clay, trace coarse sand, medium plasticity; CL					
		P/300						
5		7	(Colluvium)	357.8	14.5			
10		P/800	Hard brown coarse to fine sandy silty clay with trace of gravel, medium plasticity; CL					
		45			26.8			
15			(Colluvium)	347.8				
		P/550	Very stiff brown micaceous medium to fine sandy clayey silt, trace coarse gravel, slight plasticity; ML					
20		21	(Saprolite)	343.8				
		NX/87%	Coarse to medium grained salt and pepper colored granodiorite with quartzofeldspathic inclusions					80/2 73
25								
30		NX/100%						56%
35		NX/100%		328.8				100
			* Sonic Velocity Tests run on rock cores in laboratory					

COMPLETION DEPTH 37.0' Water Depth +0.5 ft. Artesian Date 1-19-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER Artesian 3-2-72

LOG of BORING No. SD-1A

DATE 12-13-72 SURFACE ELEV. 367.0 LOCATION N 472,170 E 1,906,585

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		16	Medium dense micaceous brown and gray medium to fine silty sand, trace gravel; SM (Colluvium)	363.5	13.2			
5		18	Very stiff blue-gray-red fine to medium sandy clayey silt; ML (Colluvium)	361.5	29.9			
10		54	Very dense red-brown coarse to fine sand and silt with trace rock fragments; SM/ML (Saprolite becoming Decomposed Rock)		11.7			
15		140/11"		353.0	11.5			

COMPLETION DEPTH 14.0' Water Depth ____ Date ____

SAMPLER 2 O.D SPLIT BARREL SAMPLER

LOG of BORING No. SD-1B

DATE 12-22-71 SURFACE ELEV. 365.9 LOCATION N 472,218 E 1,906,629

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Firm red-brown micaceous fine sandy clay, medium plasticity; CL (Colluvium)	360.9				
5			Firm bluish gray medium to fine sandy clay with trace coarse gravel, medium plasticity; CL (Colluvium)	353.9				
10			Very dense saprolite	350.9				
15								

COMPLETION DEPTH 15.0' Water Depth 2 ft. / 2 ft. Date 1-19-72 / 3-3-72

SAMPLER 2 O.D SPLIT BARREL SAMPLER

LOG of BORING No. SD-2

DATE 11-30-71 SURFACE ELEV. 421.9 LOCATION N 472,548 E 1,906,784

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill	419.9				
		19	Stiff-very stiff red-brown slightly micaceous clayey silt with root inclusions, medium to low plasticity; ML					
5		15	(Residual Soil)	413.9				
		14						
10		20	Medium dense to dense red-brown to tan micaceous fine sandy silt, slightly plastic; ML					
		22	(Residual Soil becoming Saprolite)					
15		24	becoming					
		38	less plastic with depth					
20		30	to					
		50	dense to very dense tan-bluish gray fine sandy silt with trace rock fragments; ML					
25		72	(Saprolite becoming Decomposed Rock)					
		110						
30		115/7"		385.8				
35								
40								
45								

COMPLETION DEPTH 36.1' Water Depth None Date 11-30-71

SAMPLER 2 O D SPLIT BARREL SAMPLER

LOG of BORING No. SD-3

DATE 11/30/71 SURFACE ELEV. 436.9 LOCATION N 471,808 E 1,906,461

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill	435.4				
		32	Hard red-brown fine sandy silty clay, medium plasticity; CL		36.2			
5		36	(Residual Soil)	430.4	25.6			
		23			20.5			
10		15	Very stiff to hard red-brown to dark brown micaceous clayey silt, trace fine sand, slight plasticity; ML		17.6			
		24	(Saprolite)		23.0			
15		25	becoming		17.3			
		36	dark gray and very hard with depth		16.3			
20		34			22.9			
		79		410.9	13.9			
25		100	Hard to very hard blue-gray to tan micaceous fine to coarse sandy clayey silt, trace fine gravel, slight plasticity; ML		14.5			
		45	(Saprolite)		20.3			
30		65			20.4			
		97/8"		398.9				
35			Very dense dark gray micaceous clayey silty sand, rock fragments; SM (Decomposed Rock)	397.7	8.8			
40								

COMPLETION DEPTH 39.2' Water Depth None Date 12-1-71

SAMPLER 2 O D SPLIT BARREL SAMPLER

LOG of BORING No. SD-4

DATE 12-13-71 SURFACE ELEV. 406.8 LOCATION N 471,923 E 1,906,461

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		P 100/6"	Very hard dark gray fine sandy clayey silt; ML (Decomposed Rock)	402.7	5.8			
5								

COMPLETION DEPTH 4.1' Water Depth None Date 12-15-71

SAMPLER 2 O.D SPLIT BARREL SAMPLER

LOG of BORING No. SD-5

Sheet 1 of 2

DATE 12-22-71 SURFACE ELEV. 370.5 LOCATION N 472,115 E 1,906,725

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		P250	Stiff red-brown fine sandy silty clay, medium plasticity; CL		17.5			
					18.7			
5		15	(Colluvium)	364.5	22.3	23	15	W C
					19.9			
		P800	Hard bluish gray fine sandy silt, medium plasticity; ML		18.2	39	27	W C T
		81			18.7			
10		P1000	(Colluvium)		21.6			
				358.0	25.4			
		85	Very dense brown coarse to fine silty sand trace fine gravel (Decomposed Rock)	356.0	10.7			
15		70/3"						
		80/2"	Very dense bluish gray micaceous coarse to fine silty clayey sand, trace fine gravel; SM/SC (Decomposed Rock)	351.3				
		85/2"						
20		0"	Very dense dark brown micaceous coarse to fine silty sand, trace fine gravel; SM					
			(Decomposed Rock)					
25		40/1"						
				337.1				
30			See sheet 2 for log from 0' to 146'					
35								
40								
45								

COMPLETION DEPTH 146.0' Water Depth +1.25' (Artesian) Date 2-14-72

SAMPLER 2 O.D SPLIT BARREL SAMPLER (Artesian) 3-3-72

LOG of BORING No. SD-5

Sheet 2 of 2

DATE 12-22-71 SURFACE ELEV. 370.5 LOCATION N 472, 115 E 1,906, 725

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	RQD	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0				See sheet 1 for Overburden Log					
20					337.1				
40		95%	61%	Migmatite and Diorite					
		100%	100%						
60		100%	100%	(Intact Rock)					
		100%	98%						
		100%	97%						
80		100%	100%						
		100%	100%						
100		100%	100%						
		100%	100%						
120		100%	100%						
					241.1				
		100%	91%	Granite	237.5				
140		100%	90%	Diorite					
					224.5				
160				Diameter of core = 1-7/8"					
				Offset Boring: SD-5C; Undisturbed Sample: 9'-11.5'					

COMPLETION DEPTH 146.0' Water Depth +1.25 ft. (Artesian) Date 2-24-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER Artesian 3-3-72

LOG of BORING No. SD-5B

DATE 2-9-72 SURFACE ELEV. 370.8 LOCATION N 472,122 E 1,906,725

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Firm red-brown micaceous sandy silty clay, medium plasticity; CL (Colluvium)	365.8				
5		55	Very stiff gray silty clay, trace fine sand, medium plasticity; CL (Colluvium)	361.8				
10		*	Very dense gray silty coarse to fine sand and gravel; SM/GM (Colluvium)	356.3				
15		100 / 1½"	Very dense dark gray micaceous fine sandy silt, trace rock fragments; ML (Decomposed Rock)	350.0				
20			Bit refusal at 20.75'					
25			*Blow count not recorded					

COMPLETION DEPTH 20.8' Water Depth 1 ft. Date 2-24-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER 2.5 ft. 3-3-72

LOG of BORING No. SD-6

DATE 2-2-72 SURFACE ELEV. 409.7 LOCATION N 472,268 E 1,906,818

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		94	Very dense multi-colored decomposed crystalline bedrock					
10		77	(Decomposed Rock)					
20		60/6"						
30		60/3"						
40		60/3"		367.7				
		NX 40%	Migmatite of fine to medium grained diorite. Highly fractured and decomposed from 44' to 50' (Intact Rock)					RQD 28%
50		NX 36%		357.7				0%
60								

COMPLETION DEPTH 52.0' Water Depth Dry to 52 ft. Date 2-14-72

SAMPLER 2 O.D SPLIT BARREL SAMPLER

LOG of BORING No. SD-7

DATE 1-3-72 SURFACE ELEV. 439.5 LOCATION N 472,425 E 1,906,941

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0	P	37	Hard red-brown silty clay, medium plasticity; CL (Residual Soil)	435.2	37.3			
10	P	22	Very stiff brown micaceous clayey silt, trace fine to medium sand and fine gravel, slight plasticity to non-plastic; ML		18.0	43	40	
20	P	20	becoming		22.7	36	NP	
30	P	63	Very hard with depth (Saprolite)	405.5	18.7			
	P	76	Very hard brown micaceous fine sandy clayey silt, slight plasticity; ML		14.9			
40	C	100/6"	(Saprolite)	396.0				
50	C		Very dense brown-gray silty fine sand, trace clay; SM					
60		100/4"	(Decomposed Rock)		11.6			
				372.5				
70			Intact Rock	370.5				

COMPLETION DEPTH 69.9' Water Depth None Date 1-4-72

SAMPLER 2 O.D SPLIT BARREL SAMPLER Dry & Closed at 45 ft. 1-20-72

LOG of BORING No. SD-8

DATE 12-9-71 SURFACE ELEV. 378.6 LOCATION N 471,963 E 1,906,878

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		20	Stiff to very stiff red-brown to tan micaceous fine sandy silty clay, medium plasticity; CL		20.1			
5		11	(Colluvium)		23.2			
		18			28.8			
10		20			26.5			
				364.6				
		14	Stiff red-brown to gray micaceous silty fine sandy clay, medium plasticity; CL (Colluvium)	362.1	23.0			
15		7	Loose gray fine to coarse silty clayey sand; SC (Colluvium)	359.6	17.4			
20		37			15.4			
		100/3"	Dense to very dense brown micaceous coarse to fine silty sand, trace clay; SM		14.6			
25		100/4"	(Saprolite becoming Decomposed Rock)		16.5			
30								
35								
				338.6				
40		NX 52%	Fractured Rock					RQD 30%
45								

COMPLETION DEPTH 55.0' Water Depth * Date

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. SD-8 Continued N 471,963 E 1,906,878

DATE 12-9-71 SURFACE ELEV. LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45								
			Intact Rock					
50								
				323.6				
55								

* Water Depth — Date

5.5 ft. — 12-15-71
3.0 ft. — 1-19-72
1.7 ft. — 2-24-72

COMPLETION DEPTH 55.0' Water Depth * Date

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. SD-8B

DATE 2-1-72 SURFACE ELEV. 378.6 LOCATION N 471,983 E 1,906,874

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Firm red-brown micaceous fine sandy clay, medium plasticity; CL (Colluvium)					
5			Contact Uncertain					
10		29	Very dense mottled red-brown and gray clayey coarse to fine sand becoming all gray with depth; SC (Colluvium)	363.6				
15								
20			Very dense brown silty coarse to fine sand; SM (Saprolite becoming Decomposed Rock)					
25		100/5"		352.6				
30								

* Water Depth — Date

1.5 ft. — 2- 1-72
1.0 ft. — 2- 2-72
1.25 ft. — 2-14-72

COMPLETION DEPTH 26.4 Water Depth * Date

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. SD-9

DATE 2/14/72 SURFACE ELEV. 377.1 LOCATION N 471,937 E 1,906,767

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		7	Organic debris & red-brown micaceous sandy silty clay, medium plasticity; CL (Colluvium)	374.6				
			Medium dense red-brown clayey medium to fine sand; SC (Colluvium)	372.6				
5		13	Stiff dark red-brown silty clay, trace fine sand, medium plasticity (Colluvium)	369.6				
		17	Dense mottled gray and brown silty clay, trace medium to fine sand, medium plasticity; CL (Colluvium)	366.6				
10		55	Very dense gray medium to fine sandy clay, clayey sand; CL/SC (Saprolite)	364.1				
		24	Very dense gray clayey micaceous coarse to fine sand; SC	-				
15		47	(Saprolite becoming Decomposed Rock)	358.5				
		50/1"						
20								

Offset Borings — Undisturbed Samples

SD-9B	4' - 6.5'	19.7			
		26.4	38	26	T
	7' - 9.5'	22.2			C
		20.6	26	19	T, W
	10' -12.3'	11.5			C,T,W
		16.7			
		13.8			
SD-9D	4' - 6.5'	19.7	31	20	C T
		26.4			
		22.4			
		24.5			
	12.5' - 15.0'	24.3			
			21	17	

COMPLETION DEPTH 18.6' Water Depth 2.5 ft. (piezometer at 16 ft.) Date 3-3-72

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. SD-1/5

DATE 1-26-72 SURFACE ELEV. 367.5 LOCATION N 472, 174 E 1,906,678

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		4	Loose brown red-brown fine sandy clayey silt; slight plasticity; ML (Colluvium)	364.5				
		7						
		34						
5		66	Very stiff gray medium to fine sandy clay/clayey sand, CL/SC (Colluvium)	359.5				
		34						
		29	Very dense decomposed and highly weathered crystalline rock					
10		21						
		49	(Saprolite becoming Decomposed Rock)					
15		100/5"						
20								
				342.5				
25			Bit refusal at 25'					

COMPLETION DEPTH 25.0' Water Depth +9" (Artesian) Date 2-14-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER Artesian 3-9-72

LOG of BORING No. SD-5/8

DATE 1-27-72 SURFACE ELEV. 375.2 LOCATION N 472,031 E 1,906,805

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		6	Very stiff red-brown micaceous clay trace fine sand, medium plasticity; CL (Colluvium)	370.2				
		20						
		20						
5		15	Medium dense to dense gray coarse to fine sandy clay and clayey sand, trace fine gravel; CL/SC (Colluvium)	361.2				
		13						
		12						
10		9						
		23						
		17						
15		12	Dense highly weathered crystalline rock (Saprolite)					
		48						
		32						
20		31						
25								
30								
35								
				335.2				
40			Boring terminated - no refusal					

COMPLETION DEPTH 40.0' Water Depth 3.0 ft. Date 2-14-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER 3.75 ft. 3-7-72

LOG OF TEST PIT NO. TP-S1

DATE 2-15-72 SURFACE ELEV. 372.8 LOCATION N 472,144 E 1,906,732

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Red brown clay - Fill	372.3				
			Firm dark red-brown sandy clay, with roots, medium plasticity; CL (Colluvium)	365.8				
5			Very stiff micaceous gray sandy clay, medium plasticity; CL (Colluvium)	365.3				
10								

COMPLETION DEPTH 7.5' Water Depth 6 ft. Date 2-15-72

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG OF TEST PIT NO. TP-S2

DATE 2-15-72 SURFACE ELEV. 369.7 LOCATION N 472,142 E 1,906,694

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Red-brown micaceous sandy clay fill	368.2				
5			Brown medium to fine sandy clay, with roots & organic material, medium plasticity; CL (Colluvium)	364.7				
10			Mottled gray and brown medium to fine sandy clay, small roots, medium plasticity; CL (Colluvium)	359.2				
15								

COMPLETION DEPTH 10.5' Water Depth 2.5' Date 2-15-72

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG OF TEST PIT NO. TP-S3

DATE 2-15-72 SURFACE ELEV. 377.2 LOCATION N 471,974 E 1,906,842

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Red-brown clay, trace mica and fine sand, medium plasticity; CL (Alluvium)	373.2				
5			Mottled brown and tan clay, trace mica and fine sand, medium plasticity; CL (Colluvium)	368.2				
10			Mottled gray and red-brown clay, trace mica & fine sand, becoming all gray with depth, medium plasticity; CL (Colluvium)	367.2				

COMPLETION DEPTH 10.0' Water Depth 3.7' Date 2-18-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

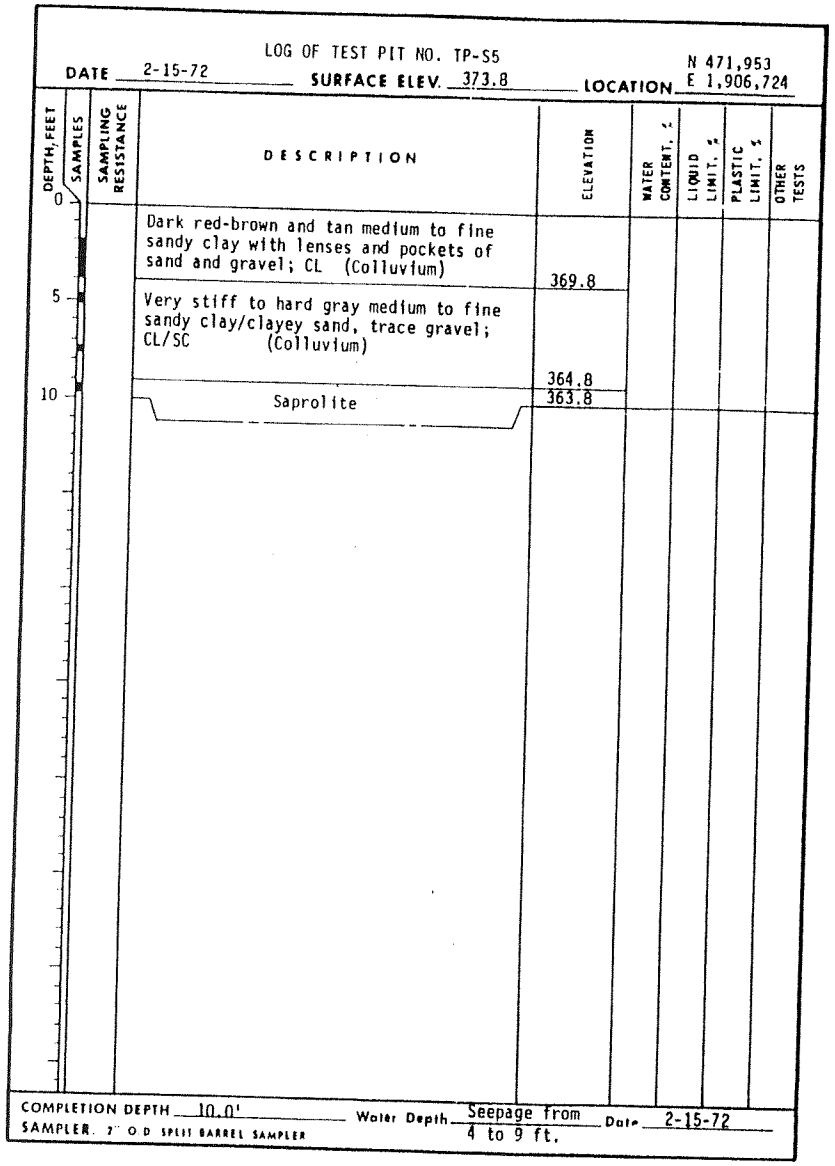
LOG OF TEST PIT NO. TP-S4

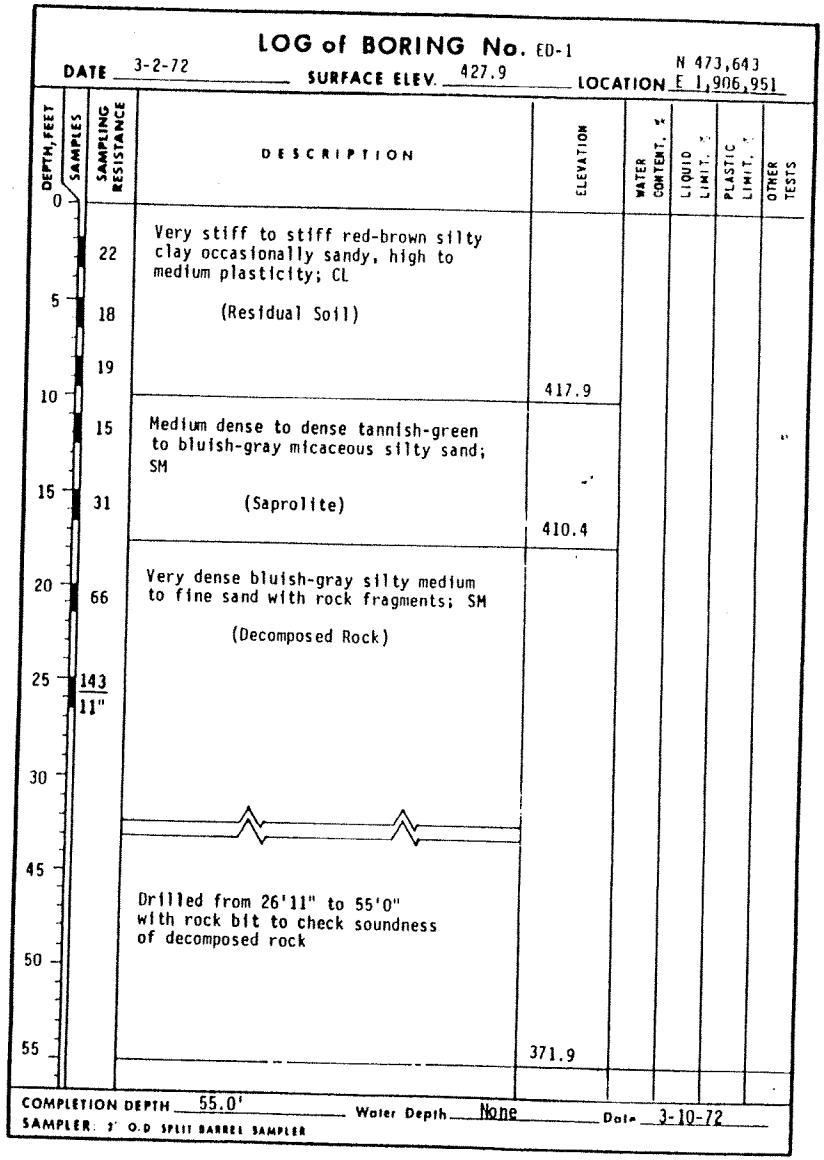
DATE 2-15-72 SURFACE ELEV. 376.0 LOCATION N 472,011 E 1,906,734

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
			Red-brown clay & roots, medium plasticity CL (Colluvium)	374.5				
			Red-brown & tan silty medium to fine sand, trace roots; SM (Colluvium)	372.0				
5			Red-brown micaceous fine sandy clay, medium plasticity; CL (Colluvium)	370.0				
			Mottled gray & brown fine sandy clay, becoming all gray with depth, medium plasticity; CL (Colluvium)	366.5				
10								

COMPLETION DEPTH 9.5' Water Depth 4.5' Date 2-15-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER


LOG OF TEST PIT NO. TP-S5
DATE 2-15-72
SURFACE ELEV. 373.8
LOCATION N 471,953 E 1,906,724
DEPTH, FEET
SAMPLES
SAMPLING RESISTANCE
DESCRIPTION
ELEVATION
WATER CONTENT, %
LIQUID LIMIT, %
PLASTIC LIMIT, %
OTHER TESTS
0
5
10
Dark red-brown and tan medium to fine sandy clay with lenses and pockets of sand and gravel; CL (Colluvium)
369.8
Very stiff to hard gray medium to fine sandy clay/clayey sand, trace gravel; CL/SC (Colluvium)
364.8
Saprolite
363.8
COMPLETION DEPTH 10.0'
Water Depth Seepage from 4 to 9 ft.
Date 2-15-72
SAMPLER: 2" O.D SPLIT BARREL SAMPLER


LOG of BORING No. ED-1
DATE 3-2-72
SURFACE ELEV. 427.9
LOCATION N 473,643 E 1,906,951
DEPTH, FEET
SAMPLES
SAMPLING RESISTANCE
DESCRIPTION
ELEVATION
WATER CONTENT, %
LIQUID LIMIT, %
PLASTIC LIMIT, %
OTHER TESTS
0
5
10
15
20
25
30
45
50
55
22
18
19
15
31
66
143
11"
Very stiff to stiff red-brown silty clay occasionally sandy, high to medium plasticity; CL
(Residual Soil)
417.9
Medium dense to dense tannish-green to bluish-gray micaceous silty sand; SM
(Saprolite)
410.4
Very dense bluish-gray silty medium to fine sand with rock fragments; SM
(Decomposed Rock)
Drilled from 26'11" to 55'0" with rock bit to check soundness of decomposed rock
371.9
COMPLETION DEPTH 55.0'
Water Depth None
Date 3-10-72
SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ED-2

DATE 1-5-72 SURFACE ELEV. 418.2 LOCATION N 473,525 E 1,907,114

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0	P		Hard to very stiff red-brown clayey silt, medium plasticity; MH/ML		27.3	47	36	U
					29.4			W
5		55	(Residual Soil)		41.4			
	P				50.8	60	51	U
					46.3			W
10		24		406.2	43.9			
	P		Stiff red-brown fine sandy clayey silt, medium to high plasticity; MH		59.7	65	58	U
					60.4			
15		16			45.8			C
			(Residual Soil)			54	48	W
	P							
20		16		397.2	43.4			
	P		Medium dense to tan micaceous fine sandy silt, low plasticity to non-plastic; ML					
		25			32.1			
25			(Saprolite)					
	P				36.7	45	NP	W
					37.3	40	NP	C
30		18			35.0			T
				386.2				
	P		Very dense tan silty fine sand, trace rock fragments; SM		19.8			
	60/4"		(Decomposed Rock)	384.2				
35								
40								

COMPLETION DEPTH 34.0' Water Depth Dry & Closed Date 1-20-72

SAMPLER 2" O.D SPLIT BARREL SAMPLER @ 23.5 ft. None 3-10-72

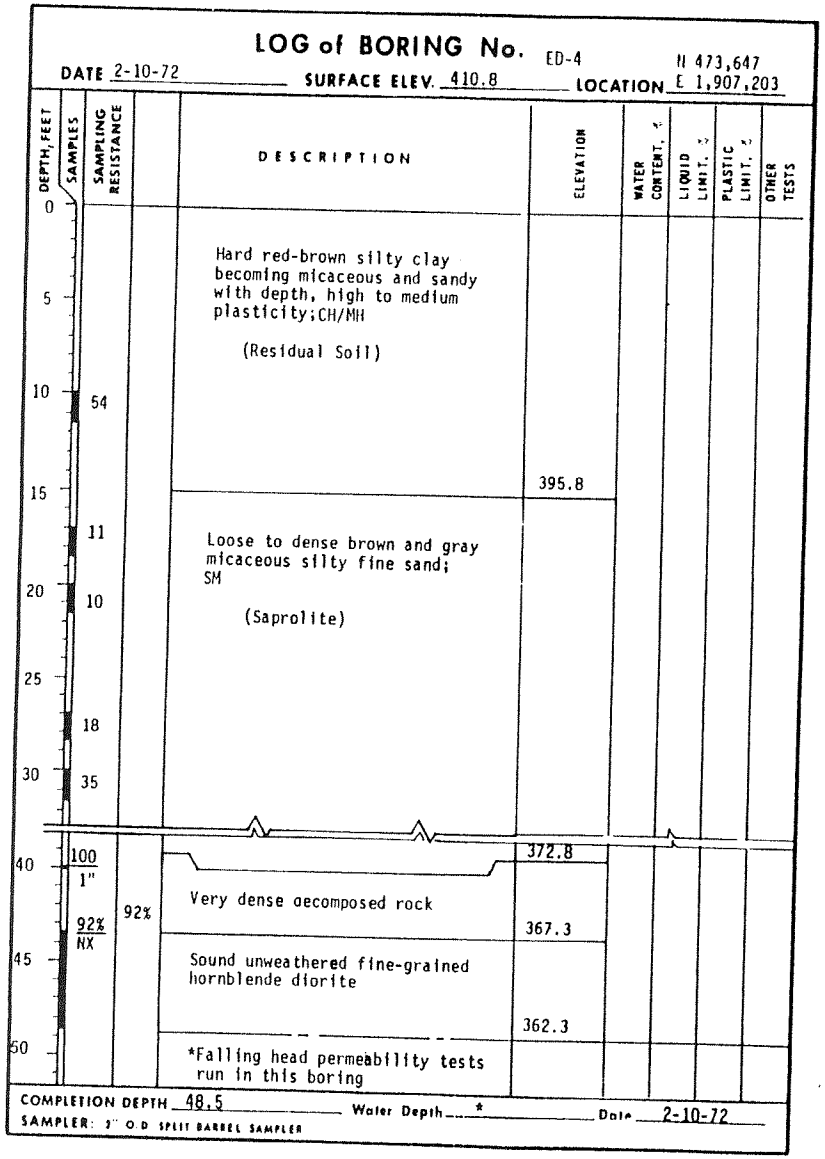
LOG of BORING No. ED-3

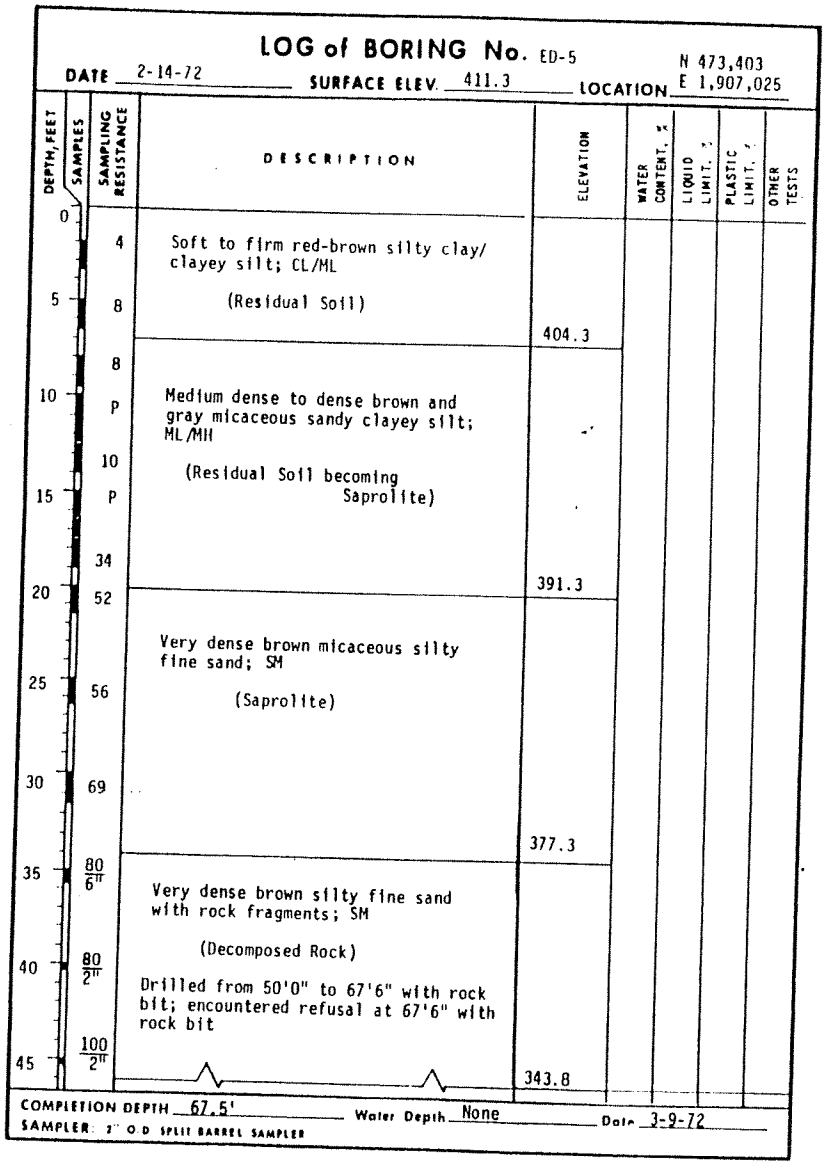
DATE 12-23-71 SURFACE ELEV. 423.2 LOCATION N 473,407 E 1,907,277

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0	P		Hard to stiff red-brown micaceous fine sandy silty clay, high to medium plasticity; CL/CH					
		51						
10	P							
		19	(Residual Soil)	407.2				
	P		Medium dense to dense micaceous red-brown to tan fine sandy clayey silt, low plasticity; ML					
20		13						
	P							
30		35	(Saprolite)					
	P				31.2			
		26		381.2				
40	P		Tan to gray micaceous fine sandy silt, increasing coarser sand content with depth; ML		26.6			
		26	(Saprolite)	372.0				
50	P		Dark gray to black silty medium fine sand, trace clay; SM		16.0			
		118	(Decomposed Rock)	365.0				
		100/2½"						
60								

COMPLETION DEPTH 58.2' Water Depth Dry & Closed Date 1-20-72

SAMPLER: 2" O.D SPLIT BARREL SAMPLER @ 33.5 ft. None 3-10-72


LOG of BORING No. ED-4
DATE 2-10-72
SURFACE ELEV. 410.8
LOCATION N 473,647 E 1,907,203
DEPTH, FEET
SAMPLES
SAMPLING RESISTANCE
DESCRIPTION
ELEVATION
WATER CONTENT, %
LIQUID LIMIT, %
PLASTIC LIMIT, %
OTHER TESTS
Hard red-brown silty clay becoming micaceous and sandy with depth, high to medium plasticity; CH/MH
(Residual Soil)
395.8
Loose to dense brown and gray micaceous silty fine sand; SM
(Saprolite)
372.8
Very dense decomposed rock
367.3
Sound unweathered fine-grained hornblende diorite
362.3
*Falling head permeability tests run in this boring
COMPLETION DEPTH 48.5
Water Depth *
Date 2-10-72
SAMPLER: 3" O.D SPLIT BARREL SAMPLER


LOG of BORING No. ED-5
DATE 2-14-72
SURFACE ELEV. 411.3
LOCATION N 473,403 E 1,907,025
DEPTH, FEET
SAMPLES
SAMPLING RESISTANCE
DESCRIPTION
ELEVATION
WATER CONTENT, %
LIQUID LIMIT, %
PLASTIC LIMIT, %
OTHER TESTS
Soft to firm red-brown silty clay/ clayey silt; CL/ML
(Residual Soil)
404.3
Medium dense to dense brown and gray micaceous sandy clayey silt; ML/MH
(Residual Soil becoming Saprolite)
391.3
Very dense brown micaceous silty fine sand; SM
(Saprolite)
377.3
Very dense brown silty fine sand with rock fragments; SM
(Decomposed Rock)
Drilled from 50'0" to 67'6" with rock bit; encountered refusal at 67'6" with rock bit
343.8
COMPLETION DEPTH 67.5'
Water Depth None
Date 3-9-72
SAMPLER: 3" O.D SPLIT BARREL SAMPLER

LOG of BORING No. ED-6

DATE 2-15-72 SURFACE ELEV. 411.3 LOCATION N 473, 408 E 1,907,020

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Soft to firm red-brown silty clay/ clayey silt; CL/ML (Residual Soil)	404.3				
5	P							
10	P		Medium dense to dense brown and gray micaceous sandy clayey silt; ML/MH (Residual Soil becoming Saprolite)	391.3				
15	P							
20	P		Very dense brown micaceous silty fine sand; SM (Saprolite)	382.0				
25	P							
30	P							
35								

COMPLETION DEPTH 29' 3" Water Depth None Date 3-9-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WD-1

DATE 12-21-71 SURFACE ELEV. 411.7 LOCATION N 473 025 E 1,904,635

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		27	Very stiff micaceous fine sandy silty clay, high plasticity; CL/CH (Residual Soil)	401.7	40.3 37.4 39.3 29.7			
5		34						
10			Medium dense red-brown to tan micaceous medium to fine silty sand with rock fragments; slight plasticity; SM (Saprolite)	391.7	12.4 17.0 27.1 29.8			
15		40						
20		32	Dense to very dense light gray silty fine sand; SM (Saprolite becoming Decomposed Rock)	385.2	11.9 17.1 7.5 9.4			
25		138						
30								

COMPLETION DEPTH 26.5' Water Depth Date 12-21-71

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WD-2

DATE 12-21-71 SURFACE ELEV. 411.7 LOCATION N 473, 025 E 1,904,635

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		79	Hard red-brown micaceous fine sandy silty clay, high to medium plasticity; CL		29.7			
5		41	(Residual Soil)		29.9			
				434.0	29.4			
10		34	Hard to very stiff red brown micaceous fine sandy clayey silt, low plasticity; ML		26.2			
		29			28.1			
					24.1			
15		21	(Residual Soil)		23.8			
					22.6			
				426.0	21.6			
		21	Medium dense to dense brown micaceous fine sandy silt, slight plasticity; ML		28.4			
20					18.0			
		23	becoming		19.6			
		24	greenish gray and with rock fragments		18.7			
25					23.2			
		43	(Saprolite)		27.2			
					29.4			
30		40			27.9			
		46		410.0				
			Very dense gray micaceous medium to fine sand and silt with rock fragments; SM/ML		20.8			
35		56	(Saprolite)		9.4			
					17.6			
40		110		402.5	8.9			

COMPLETION DEPTH 39.5' Water Depth ____ Date 12-21-71

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. WD-5

DATE 12-14-71 SURFACE ELEV. 449.1 LOCATION N 472,805 E 1,903,995

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		52	Hard red-brown micaceous fine sandy silty clay, high to medium plasticity; CL		20.7			
5		38	becoming fine sandy clayey silt, low plasticity; ML		24.5			
			(Residual Soil)	441.1				
10		61	Very dense to medium dense brown and blue gray silty medium to fine sand with rock fragments; SM		14.9			
		23	(Saprolite)	435.6	18.7			
15		15	Medium dense brown dark brown micaceous medium to fine sandy silt; ML		20.1			
		22	becoming		32.2			
20		24	more sandy with depth		23.8			
		17	(Saprolite)		15.4			
25		22			24.1			
		77		420.1	16.5			
30		81	Very dense bluish gray silty medium to fine sand, slight plasticity; SM		11.6			
		83	(Saprolite becoming Decomposed Rock)		10.8			
35		37			9.0			
		141 10"		407.2	9.4			
40								
45								

COMPLETION DEPTH 41.9' Water Depth ____ Date 12-14-71

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. RWD-5

DATE 2-28-72 SURFACE ELEV. 401.7 LOCATION W 473,124 E 1,903,935

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		25	Very stiff red-brown micaceous silty clay, high plasticity; CH (Residual Soil)	397.7				
5		20	Medium dense tan, brown and gray micaceous silty fine sand, slight plasticity; SM (Saprolite)					
10		27						
		21						
15		22						
		25						
20		21		379.7				
		44	Dense multi-colored micaceous silty medium to fine sand with rock fragments; SM (Saprolite)					
25		45						
30		42		370.7				
		139	Very dense blue-green silty sand with rock fragments; SM (Decomposed Rock)					
35		143/5"		365.3				
40								
45								

COMPLETION DEPTH 36.4' Water Depth _____ Date _____

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. WD-6

DATE 1-10-72 SURFACE ELEV. 443.0 LOCATION N 472,915 E 1,904,360

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		P	Hard red micaceous clayey silt, medium plasticity; MH (Residual Soil)		42.6 35.7	54	37	W U
5		43		433.0				
10		P	Medium dense to dense tan and gray micaceous silty sand, slight plasticity to non-plastic; SM (Saprolite)		35.4 17.7	37	NP	W S T
15		15						
20		P 34			32.2	36	NP	W T
25				417.0				
30		P 42	Dense to very dense multi-colored micaceous silty sand; SM (Saprolite)					
35		P 62						
40				403.0				
45		P 187/8"	Very dense multi-colored micaceous silty sand; SM (Decomposed Rock)	399.4				

COMPLETION DEPTH 43.6' Water Depth _____ Date 1-12-72

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. WD-7

DATE 12-14-71 SURFACE ELEV. 406.2 LOCATION N 472,945 E 1,904,700

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		16	Very stiff red-brown micaceous fine sandy silty clay, medium plasticity; CL		30.7			
5		21	(Residual Soil)	398.7	29.9			
		14	Stiff red-brown micaceous fine sandy clayey silt, low plasticity; ML/MH		24.5			
10		11	(Residual Soil)	392.2	19.3			
15		20	Medium dense gray brown fine sandy silt, non-plastic; ML		27.4			
		23			15.7			
20		32	(Saprolite) becoming		15.8			
		27	slightly plastic with depth		30.5			
25		31			24.0			
		100/2"	Decomposed Rock	378.2				
30				377.1				

COMPLETION DEPTH 29.1 Water Depth — Date 12-14-71

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. RWD-7

DATE 2-24-72 SURFACE ELEV. 400.3 LOCATION N 473,098 E 1,904,657

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		4	Fill for drilling pad	396.3				
5		24	Medium dense to very dense brown and gray micaceous silty medium to fine sand with rock fragments; SM					
		160						
10		39	(Saprolite)					
		38		383.3				
15		100/3"	Very dense multi-colored decomposed rock					
		100/4"		380.0				
20								
25								

COMPLETION DEPTH 20.25' Water Depth — Date 2-24-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WD-8

DATE 12-14-71 SURFACE ELEV. 392.7 LOCATION N 472,715 E 1,905,220

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0	P		Very stiff red-brown fine sandy silty clay, high plasticity; CH (Residual Soil)		41.2	58	24	W
					36.1			C
5		17			29.8			U
					27.2			
				382.7				
10	P		Hard tan fine sandy clayey silt; ML (Saprolite)		30.9	45	NP	W
		42			17.7			T
					26.0			
				377.7				
15	P		Light tan and bluish gray fragmented fine grained decomposed rock		5.7			
	NX			375.7	6.3			
					6.1			
20								

COMPLETION DEPTH 17.0' Water Depth ____ Date 12-14-71

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. WD-9

DATE 12-9-71 SURFACE ELEV. 386.9 LOCATION N 472,830 E 1,905,305

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		30	Very stiff red-brown fine sandy silty clay, high plasticity; CH (Residual Soil)	381.9	27.1			
5		43	Very dense light brown silty clayey medium to fine sand with rock fragments; SM/SC (Saprolite becoming Decomposed Rock)		17.8			
		137			10.6			
10		150/11"		374.9	9.3			
15								

COMPLETION DEPTH 12.0' Water Depth ____ Date 12-9-71

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. WD-10

DATE 12-13-71 SURFACE ELEV. 368.7 LOCATION N 472,490 E 1,905,490

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Stiff red-brown micaceous fine sandy silty clay, medium to high plasticity; CL/CH (Residual Soil)	363.7	21.7			
5		18						
		24	Very stiff red-brown micaceous clayey medium to fine sand; SC (Residual Soil)	357.7	18.3			
10		26			19.2			
		23	Medium dense light brown micaceous fine to medium sandy clayey silt, medium plasticity; ML (Saprolite)	351.7	19.5			
15		28			17.4			
		100	Very dense brownish gray micaceous fine sandy silt, slight plasticity; ML (Decomposed Rock)	344.9	15.4			
20		150/10"			18.1			
		172/9"			15.1			
25								

COMPLETION DEPTH 23.8' Water Depth ____ Date 12-13-71

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WD-12A

DATE 2-22-72 SURFACE ELEV. 354.5 LOCATION N 472,744 E 1,905,414

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill for drilling pad	346.5				
5								
10		P	Very dense blue-gray, tan and green micaceous silty medium to fine sand with rock fragments; SM (Decomposed Rock)					
		90						
15								
		100/4"						
20								
25		100/4"		328.2				
30								

COMPLETION DEPTH 26.3' Water Depth ____ Date ____

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. RWD-13

DATE 2-22-72 SURFACE ELEV. 403.6 LOCATION N 472,252 E 1,905,725

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		P	Dense re[illegible]brown micaceous silty fine sand; SM					
5		22	(Residual Soil to Saprolite)					
		P		393.1				
10		100/3"	Dense to very dense brown and gray micaceous silty medium to fine sand ; SM					
		40						
15		P	(Saprolite)					
		30						
20		P						
		47						
25		P		369.6				
		107	Very dense tan gray micaceous silty fine sand; SM					
30		P	(Decomposed Rock)					
		109						
35		149		357.1				
40								
45								

COMPLETION DEPTH 46.5' Water Depth _____ Date _____

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WD-14

DATE 12-13-71 SURFACE ELEV. 400.9 LOCATION N 472,110 E 1,906,270

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		47	Very dense blue-gray and tan micaceous silty fine sand; SM		16.7			
5			(Saprolite)					
		100/2"	Very dense blue-gray Decomposed Rock		10.3			
10		178/9"			5.3			
15								

COMPLETION DEPTH 11.3' Water Depth None Date 12-13-71

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. RWD-14

DATE 2-17-72 SURFACE ELEV. 428.2 LOCATION N 472,252 E 1,905,981

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		42	Hard to stiff red-brown silty clay, high to medium plasticity; CL/CH					
5		36	(Residual Soil)					
10		24		417.7				
		21	Medium dense multi-colored micaceous silty medium to fine sand; SM					
15		20	(Saprolite)					
20		24		405.7				
25		72	Very dense blue-gray-green micaceous silty sand with rock fragments, slight plasticity to non-plastic; SM					
30		77	(Dense Decomposed Rock)					
35		50						
40		57		386.7				
45								

COMPLETION DEPTH 41.5' Water Depth ____ Date ____

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. SS-1

DATE 1-6-72 SURFACE ELEV. 440.6 LOCATION N 471,674 E 1,907,009

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
	P	32	Hard red-brown micaceous fine sandy clayey silt, medium plasticity; MH		38.5			
5			(Residual Soil)	435.3	35.9	55	43	U
					31.9			W
10	P	16	Medium dense to dense tan micaceous fine sandy silt, slight plasticity; ML		24.6			
15			(Residual Soil becoming Saprolite)					
20	P	26			22.0			
25	P	31		414.6				
30			Tan brown micaceous fine to medium sandy silt, slight plasticity to non-plastic; ML		23.5			
35	P	36	(Saprolite)					
40								
		44		396.9				

COMPLETION DEPTH 43.75' Water Depth ____ Date 1-6-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. SS-3

DATE 2-29-72 SURFACE ELEV. 427.3 LOCATION N 471,450 E 1,907,009

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5			Dense to very dense tan-brown micaceous silty medium to fine sand; slight plasticity to non-plastic; SM					
10		25	(Saprolite)					
15								
20		44						
25								
30		35						
35				391.3				
			Very dense tan-green silty medium to fine sand with rock fragments; SM					
40		160/5"	(Decomposed Rock)	386.1				
			*Field Permeability Tests run in this boring					

COMPLETION DEPTH 41.2 Water Depth * Date

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. SS-4

DATE 1-6-72 SURFACE ELEV. 420.8 LOCATION N 471,742 E 1,907,166

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		P				40	NP	
		31			25.6			
5			Medium dense to very dense red-brown to tan micaceous fine sandy silt, slight plasticity to non-plastic; ML					
10		P			31.1			
					24.0	40	NP	T
		19	(Saprolite)		19.9			W
15								
		P			26.9	31	NP	W
20					19.8			T
		32						
25								
		P		392.2				
		52			12.8			
30			Very dense tan micaceous coarse to fine silty sand with rock fragments; SM					
		119/9"	(Decomposed Rock)	385.6				
35								
40								

COMPLETION DEPTH 35.25' Water Depth Date 1-7-72

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. SS-5

DATE 2-16-72 SURFACE ELEV. 436.0 LOCATION N 471,619 E 1,907,323

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0	P	51	Hard red-brown silty clay; CL					
			becoming					
10	P	9	firm red-brown micaceous clayey silt; MH (Residual Soil)	419.0	44.0	59	40	W U
20	P	21	Medium dense to very dense tan-green-gray-white micaceous silty medium to fine sand, low to slight plasticity, and light red-brown highly micaceous clayey sandy silt; SM/ML (Saprolite)		24.5	42	NP	W U
30	P	33						
35	P	66		392.5				
40		132 9"	Very dense decomposed rock	395.3				

COMPLETION DEPTH 38.7 Water Depth Date 2-16-72
SAMPLER 2 O.D SPLIT BARREL SAMPLER

LOG of BORING No. C-1

DATE 12-15-71 SURFACE ELEV. 429.1 LOCATION N 472, 236 E 1,907,092

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		14	Stiff red-brown micaceous fine sandy clayey silt, low plasticity; MH (Residual Soil)	424.6	31.0	56	50	
5		15	Medium dense to dense light brown to tan micaceous fine silty sand, slight plasticity to non-plastic; ML (Saprolite)		13.8	30	NP	
		15			17.9			
10		20			17.3	35	NP	
		26			18.3			
15		21			17.3	30	NP	
		15			22.6			
20		29			14.6	29	NP	
		37			15.5			
25		67		399.1	19.9	32	NP	
30		130	Very dense brown micaceous medium to fine silty sand with rock fragments; SM (Decomposed Rock)		18.0			
35		160 10"		392.8	14.7	26	NP	
40								

COMPLETION DEPTH 36.3 Water Depth Date 12-15-71
SAMPLER 2 O.D SPLIT BARREL SAMPLER

LOG of BORING No. C-2

DATE 12-15-71 SURFACE ELEV. 456.5 LOCATION N 472, 609 E 1,907,239

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, % (1)	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		7	Firm to rd red-brown micaceous fine sandy silty clay, medium plasticity; MH		42.3			
		38			33.1	59	43	
		53			26.7			
10		37	(Residual Soil)		28.6	72	43	
		31		439.5	30.0			
		28	Medium dense to dense tan to light brown micaceous fine sandy silt, slight to low plasticity; ML/MH		29.1	57	56	
20		24			33.9			
		23			30.5	46	38	
		36			24.9			
30		31	(Saprolite)		22.7	37	NP	
		32			25.3	35	NP	
		46			30.2			
40		43			25.0	45	42	
		43		413.0	25.6			
		53	Very dense dark brown micaceous silty clayey fine to medium sand; ML		28.6			
		64			24.5			
50		55	(Saprolite)	403.5	21.0			
		69	Very dense tan micaceous fine sandy clayey silt; ML	399.0				
		158/10"	(Decomposed Rock)		20.2			
60								

(1) Average of two water content tests for each sample depth

COMPLETION DEPTH 57.5 Water Depth Dry and closed at 31 ft. Date 1-20-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. C-3

DATE 1-4-72 SURFACE ELEV. 437.0 LOCATION N 472, 982 E 1,907,386

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		P	Hard red brown fine sandy silty clay/ clayey silt, medium to high plasticity; CL/MH		25.0			
		35			22.9	49	20	W,U
					24.0	87	39	
			(Residual Soil)	427.0	33.6			
10		P						
		30	Very stiff to stiff red-brown micaceous fine sandy clayey silt, low plasticity MH		48.1	59	54	W
					34.7			U
		P						
20		14			44.7	53	49	W
			(Residual Soil becoming Saprolite)	411.0				T
		P						
30		17	Medium dense dark brown micaceous fine sandy clayey silt, slight to low plasticity; ML					
		P						
		25						
40			(Saprolite)					
		P						
		30						
50		P						
		27						
		100/1"		379.0				
60			Very dense dark brown fine silty clayey sand; SC					
			(Decomposed Rock)	369.0				
70								

COMPLETION DEPTH 68.0 Water Depth Date 1-5-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. C-4

DATE 2-28-72 SURFACE ELEV. 459.6 LOCATION N 472, 572 E 1,907,333

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		28	Stiff to hard red-brown silty clay, medium to high plasticity; CL					
		54						
10		48	(Residual Soil)	449.6				
		22						
		27	Medium dense to dense tan-red micaceous silty fine sand, slight to low plasticity; SM					
20		27						
		P						
		18	(Residual Soil becoming Saprolite)	432.6				
		P						
30		33						
		P						
		40	Dense to very dense tan-brown and gray micaceous silty medium to fine sand, slight plasticity to non-plastic; SM					
		P						
40		36	(Saprolite)					
		38						
		42						
50		64						
		80		401.6				
60		80/6"	Very dense brown and gray silty medium to fine sand; SM					
		100/3"	(Decomposed Rock)	394.4				
70								

COMPLETION DEPTH 65.25 Water Depth ____ Date ____

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. C-5

DATE 1-5-72 SURFACE ELEV. 427.2 LOCATION N 472, 162 E 1,907,280

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		P	Medium dense tan-brown micaceous medium to fine silty clayey sand, low plasticity to non-plastic; SM					
		18			21.6	31	27	
5		P	(Saprolite)					
		P			35.7	35	25	T,W
10		19			23.9	35	32	
		P						
15		23			25.0	35	30	
		P						
		23			36.5			T
20					23.0	35	30	W
		P		405.2	19.4	30	NP	
		71	Very dense light tan micaceous medium to fine silty sand					
25		P			18.0			
		145	(Decomposed Rock)					
30					16.1			
				387.2				
35								

COMPLETION DEPTH 40.0' Water Depth ____ Date 1-5-72

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. C-6

DATE 12-16-71 SURFACE ELEV. 461.0 LOCATION N 472,535 E 1,907,427

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		53	Hard to very hard red brown micaceous fine sandy clayey silt, low to medium plasticity; MH		30.7 (1) 39.8			
5		108	(Residual Soil)	453.0	28.2 31.7	66	53	
10		64			27.3 27.4			
		55	Very hard to stiff red brown micaceous fine sandy clayey silt, medium to low plasticity; MH		28.4 28.7	60	46	
15		20			31.4 32.1	50	43	
		33	(Residual Soil becoming Saprolite)					
20		36		438.0	29.6 25.4			
		32	Dense light brown micaceous fine sandy silt slight plasticity to non-plastic; ML		32.5	45	NP	
25		39			24.4			
			(Saprolite)					
30		34		430.5	25.9	44	NP	
35			(1) Range of water contents on each sample as determined by 2 to 4 tests per sample					

COMPLETION DEPTH 30.5' Water Depth Dry and closed at 20 ft Date 1-20-72

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. C-7

DATE 12-30-71 SURFACE ELEV. 432.2 LOCATION N 472,908 E 1,907,574

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		49	Hard red brown fine sandy clayey silt, medium plasticity; MH		32.1			
5		43	(Residual Soil)		32.9	67	47	
		43			31.6			
10		30			30.6			
				418.2				
20		14	Medium dense tan micaceous fine sandy silt, slight plasticity to non-plastic; ML		25.2			
		15	(Saprolite)	412.2	25.2	40	39	
30		21			30.3			
		23	Dense blue gray micaceous fine sandy silt, non-plastic; ML		25.8 30.5	37	NP	
40		38	(Saprolite)	405.7	23.1			
50								

COMPLETION DEPTH 26.5' Water Depth Date 12-20-71

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. C-8

DATE 12-22-71 SURFACE ELEV. 437.0 LOCATION N 472,945 E 1,907,475

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		BS*	Red brown fine sandy silty clay, high plasticity; CH with increasing silt content with depth; ML		28.2	70	32	M
5		BS			25.3	66	26	M
10		BS	(Residual Soil)		26.7	50	30	M
15		BS		420.0	18.2	31	21	M
20		BS	Light tan micaceous fine sandy clayey silt/silty clay, medium to high plasticity; CL/ML/MH becoming red brown then greenish gray with decreasing sand and clay with depth		24.3	47	32	M
25		BS			19.7	50	32	M
30		BS	(Saprolite)		21.9	57	33	M
35				402.0				
40			* Bag Sample					

COMPLETION DEPTH 35.0' Water Depth None Date 12-22-71
SAMPLER: 2" O.D. SPLIT BARREL SAMPLER Dry & Closed at 29.5 ft. 1-20-72

LOG of BORING No. C-9

DATE 12-21-71 SURFACE ELEV. 445.8 LOCATION N 472,755 E 1,907,405

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		BS*	Dark red-brown fine sandy silty clay, low plasticity; CL					
5		BS	becoming a lighter red-brown and increasing in silt content with depth; ML					
10		BS						
15		BS	(Residual Soil becoming Saprolite)					M
20		BS						
25		BS	Red-brown micaceous fine sandy clayey silt, high plasticity; MH	420.8				
30		BS	becoming greenish brown in color					M
35		BS	(Saprolite)			74	46	
40		BS				65	43	
45			* Bag Sample	400.8				

COMPLETION DEPTH 45.0' Water Depth None Date 12-21-71
SAMPLER: 2" O.D. SPLIT BARREL SAMPLER Dry & Closed at 31 ft. 1-20-72

AMENDMENT 97-01
AUGUST 1997

LOG of BORING No. C-10

DATE 12-21-71 SURFACE ELEV. 454.3 LOCATION N 472,385 E 1,907,260

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		BS*	Dark red-brown fine sandy clayey silt, high plasticity; MH					
			becoming a					
5		BS	lighter red-brown with depth		21.2	69	46	M
			(Residual Soil)					
10		BS			23.6	71	50	M
				439.3				
15		BS	Red-brown micaceous clayey silt, medium to high plasticity; MH		21.7	72	46	M
20		BS	(Saprolite)		25.1	70	55	M
25		BS			21.1	53	36	M
				424.3				
30		BS	Brown micaceous fine sandy silt, medium plasticity; ML		15.8	40	31	M
35		BS	with decreasing sand content with depth		17.9	46	29	M
40		BS	(Saprolite)		17.0	40	26	M
				409.3				
45			* Bag Sample					

COMPLETION DEPTH 45.0' Water Depth None Date 12-21-71
SAMPLER 2" O.D SPLIT BARREL SAMPLER Dry & closed at 34 ft. 1-10-72

LOG of BORING No. C-11

DATE 12-22-71 SURFACE ELEV. 428.8 LOCATION N 472,200 E 1,907,185

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		BS*	Dark red-brown fine sandy silty clay, low plasticity; CL					
			(Residual Soil)	423.8				
5		BS	Tan micaceous fine sandy silt, low plasticity to non-plastic; ML					M
10		BS	Becoming					
			greenish gray in color and increasing sand content with depth			41	NP	
15		BS	(Saprolite)					
20		BS				43	NP	M
				403.8				
25			* Bag Sample					
30								

COMPLETION DEPTH 25.0' Water Depth None Date 12-22-71
SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. WE-1

DATE 5/23/73 SURFACE ELEV. 367.4' LOCATION N 472,535 E 1,905,427

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill for drilling pad	361.4				
5		4						
10		9	Loose to medium dense silty medium to fine sand, trace fine gravel; SM (Alluvium)					
15		21		350.4				
20		26						
25		53	Dense to very dense dark brown, gray-brown and multicolored silty medium to fine sand; SM (Saprolite)					
30		59		334.4				
35		144						
40		5.0% NX	Very dense decomposed migmatite (Decomposed Rock)					
45								

COMPLETION DEPTH 48.5' Water Depth dry before coring Date 5/23/73

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WE-1

DATE 5/23/73 SURFACE ELEV. 367.4' LOCATION N 472,535 E 1,905,427

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		92	Same as above	318.9				
50								

COMPLETION DEPTH 48.5' Water Depth Dry before coring Date 5/23/73

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WE-2

DATE 5/23-26/73 SURFACE ELEV. 364.9' LOCATION N 472,621 E 1,905,420

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		2	Fill for drilling pad	358.9				
			Soft dark brown topsoil	356.9				
10		28	Dense light gray coarse to medium clayey sand, trace rock fragments; SC (Alluvium)	353.9				
15		5	Loose dark brown micaceous sandy silt; ML (Saprolite)	347.9				
20		32						
25		24	Dense to very dense gray-brown very micaceous silty medium to fine sand and sandy silt; SM/ML (Saprolite)					
30		38						
35		33		327.9				
40		57	Very dense black, gray-brown and multicolored silty medium to fine sand; SM (Decomposed Rock)					
45		54						

COMPLETION DEPTH 65.0' Water Depth 17.0 enc. Date 5/23/73

SAMPLER 3" O D SPLIT BARREL SAMPLER

LOG of BORING No. WE-2

DATE 5/23-26/73 SURFACE ELEV. 364.9' LOCATION N 472,621 E 1,905,420

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45								
50		47						
55		58	Same as above					
60		88						
65		101		299.9				

COMPLETION DEPTH 65.0' Water Depth enc. 17' Date 5/23/73

SAMPLER 3" O D SPLIT BARREL SAMPLER

LOG of BORING No. WE-3

DATE 5/30/73 SURFACE ELEV. 365.2' LOCATION N 472,647 E 1,905,334

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		10	Fill for drilling pad	358.2				
10		36						
15		27	Dense gray-brown silty medium to fine sand; SM (Saprolite)					
20		26						
25		33		338.2				
30		69	Very dense gray-brown micaceous silty fine sand; SM (Decomposed Rock)					
35		67						
40		61						
45		76						

COMPLETION DEPTH 55.0' Water Depth 11.5' enc. Date 5/30/73

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. WE-3

DATE 5/30/73 SURFACE ELEV. 365.2' LOCATION N 472,647 E 1,905,334

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45								
50		41	Same as above					
55		52		310.2				

COMPLETION DEPTH 55.0' Water Depth 11.5' enc. Date 5/30/73

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. WE-4

DATE 5/31/73 SURFACE ELEV. 364.5' LOCATION N 472,759 E 1,905,468

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			Fill for drilling pad	356.5				
10		18	Stiff red clayey sand; SC (Residual Soil)	350.5				
15		26	Very dense orange-brown clayey medium to fine sand, trace gravel; SC (Saprolite)	342.5				
20		62						
25		92/11"	Very dense dark gray-brown silty medium to fine sand; SM (Decomposed Rock)					
30		95/11"						
35		50/5"						
40		50/4"						
45		52/4"		320.7				

COMPLETION DEPTH 43.8' Water Depth dry Date 5/31/73

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

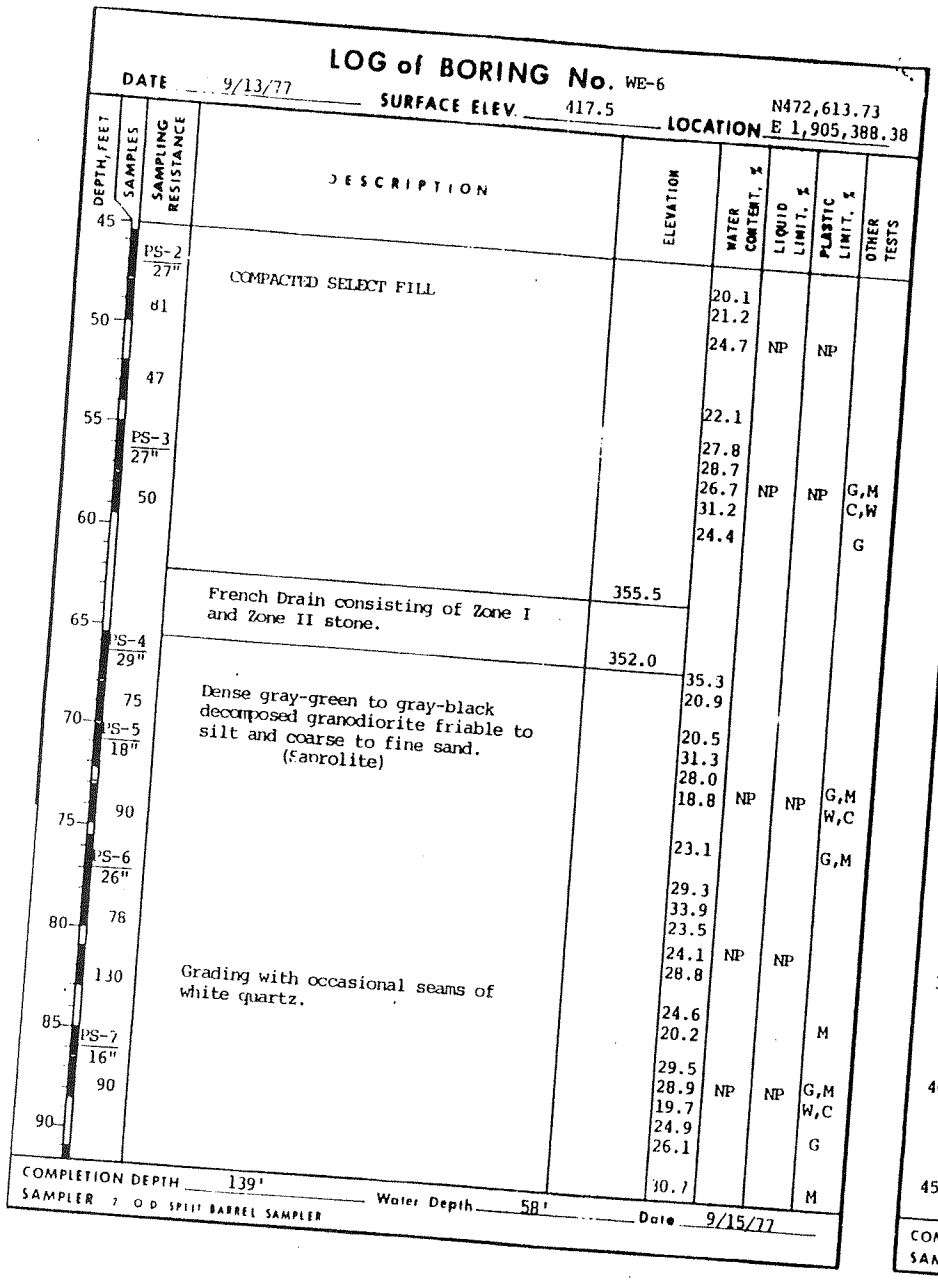
LOG of BORING No. WE-5

DATE 6/1/73 SURFACE ELEV. 374.4" LOCATION N 472,667 E 1,905,545

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		68/9"	Very dense orange brown sandy clay and clayey sand; CL/SC (Saprolite)	367.4				
10		50/6"						
15		83/9"	Very dense gray-brown coarse to fine sand, trace rock fragments, occasionally silty (Decomposed Rock)					
20		50/3"						
25		83/10"						
30		36		344.4				
			NOTE: Topsoil and Residual Soil stripped					

COMPLETION DEPTH 30.0' Water Depth dry Date 6/1/73

SAMPLER 2" O.D. SPLIT BARREL SAMPLER



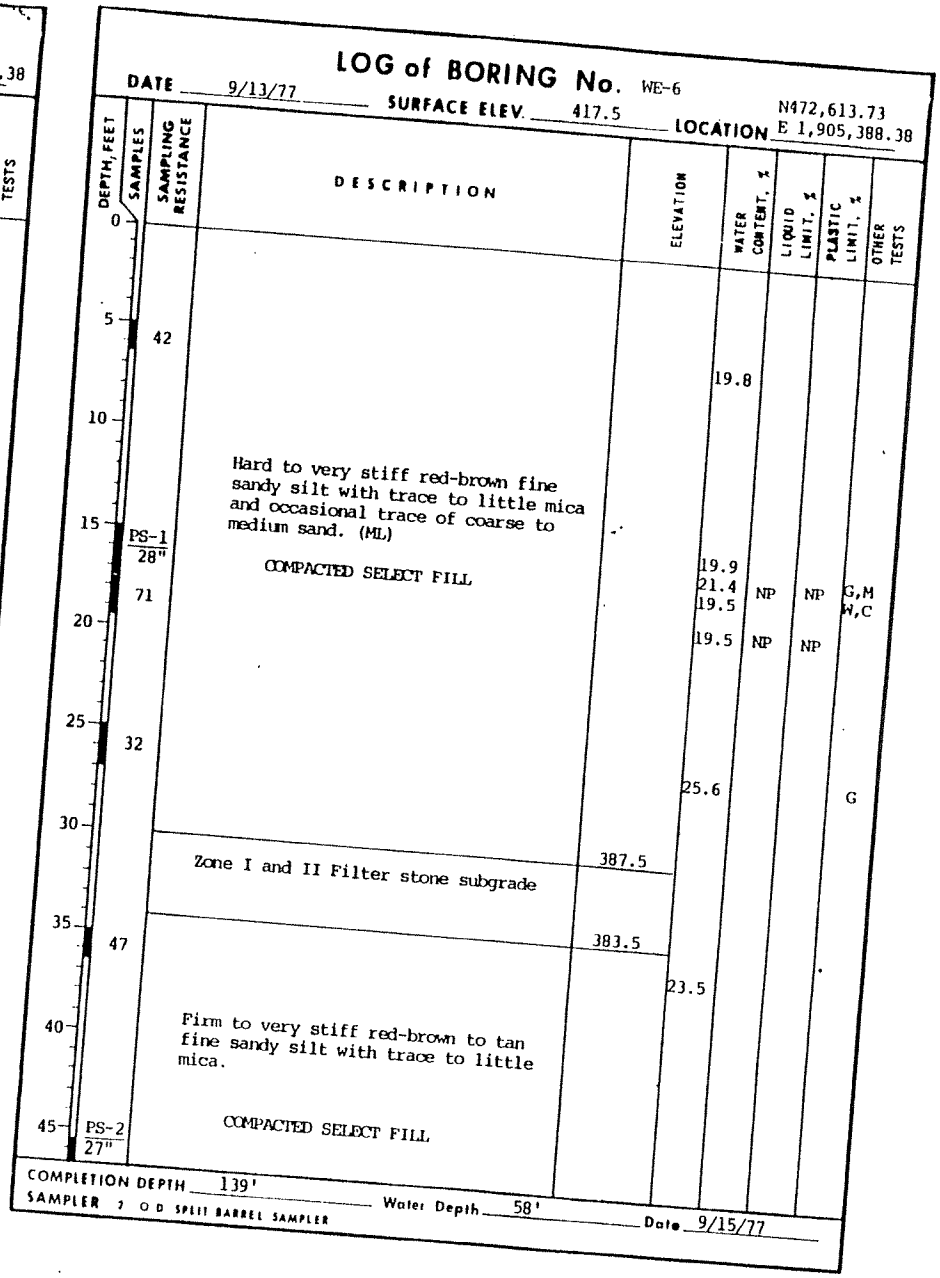
LOG of BORING No. WE-6

DATE 9/13/77 SURFACE ELEV. 417.5 LOCATION N472,613.73 E 1,905,388.38

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45	PS-2 27"	81	COMPACTED SELECT FILL		20.1			
					21.2			
50					24.7	NP	NP	
		47						
55	PS-3 27"	50			22.1			
					27.8			
					28.7			
					26.7	NP	NP	G,M
60					31.2			C,W
					24.4			G
			French Drain consisting of Zone I and Zone II stone.	355.5				
65	PS-4 29"	75		352.0				
			Dense gray-green to gray-black decomposed granodiorite friable to silt and coarse to fine sand. (Saprolite)		35.3			
					20.9			
70	PS-5 18"	90			20.5			
					31.3			
					28.0			
75					18.8	NP	NP	G,M
								W,C
	PS-6 26"	78			23.1			G,M
					29.3			
80					33.9			
		130	Grading with occasional seams of white quartz.		23.5			
					24.1	NP	NP	
					28.8			
85	PS-7 16"	90			24.6			
					20.2			M
					29.5			
					28.9	NP	NP	G,M
					19.7			W,C
90					24.9			
					26.1			G
					30.7			M

COMPLETION DEPTH 139' Water Depth 58' Date 9/15/77

SAMPLER 2" O.D. SPLIT BARREL SAMPLER



LOG of BORING No. WE-6

DATE 9/13/77 SURFACE ELEV. 417.5 LOCATION N472,613.73 E 1,905,388.38

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		42			19.8			
10								
15	PS-1 28"	71	Hard to very stiff red-brown fine sandy silt with trace to little mica and occasional trace of coarse to medium sand. (ML)		19.9			
					21.4	NP	NP	G,M
					19.5			W,C
20			COMPACTED SELECT FILL		19.5	NP	NP	
25		32						
					25.6			G
30			Zone I and II Filter stone subgrade	387.5				
35		47		383.5				
					23.5			
40			Firm to very stiff red-brown to tan fine sandy silt with trace to little mica.					
45	PS-2 27"		COMPACTED SELECT FILL					

COMPLETION DEPTH 139' Water Depth 58' Date 9/15/77

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WE-6

DATE 9/13/77 SURFACE ELEV. 417.5 LOCATION N472,613.73 E 1,905,388.38

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
90		95			30.7			M
				323.5	21.8			
		PS-8 4"			20.0			G
95		100 5"	Dense to very dense gray-green and green-gray to white decomposed rock friable to coarse to fine sand and silt becoming more dense and less weathered with depth. (Decomposed Rock)		17.3			
		PIT-1 9"						
100		100 5"			25.3			
		PIT-2 22"						
105		100 3"			21.7			
		100 6"			24.6			
110		PIT-3 10"						
		107			21.6			
115								
		67			25.0			
120					13.6			
		PIT-4 15"						
125		100 2"			14.3			
				288.5				
130		NX 100%	Dark to light gray fresh granodiorite with two slightly weathered seams at 133' and 135'.					
135								

COMPLETION DEPTH 139' Water Depth 58' Date 9/15/77

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WE-6

DATE 9/13/77 SURFACE ELEV. 417.5 LOCATION N472,613.73 E 1,905,388.38

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
135		NX 100%		278.5				
140			Hole terminated at 139'.					
145			Note: One Casagrande Type piezometer was installed in this boring WE6-P1 Elev 306.2					

Legend:

PS-1 / 28" : 3" Piston Sample / 28" of recovery

PIT-1 / 9" : Pitcher Sample / 9" of recovery

COMPLETION DEPTH 139' Water Depth 58' Date 9/15/77

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. WE-7

DATE 9/23/77 SURFACE ELEV. 419.9 LOCATION N 472,565.39 E 1,905,500.45

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		35			19.7			
					21.5			
10								
15		35	Stiff to very stiff red-brown fine clayey sandy silt with trace to little coarse to fine sand and mica		22.6			
20					23.2			
			COMPACTED SELECT FILL					
25		38						
30		43			21.6			
					27.3			
35	PS-1	16"			24.0			
		100			23.5			
		5"	Zone I and II Filter stone subgrade	383.9	24.3			G,W
40					2.2			
					24.0			
	PS-2	27"		379.9				
		80	Stiff to very stiff red-brown fine sandy clayey silt with trace mica and medium sand		21.9			
45					22.1			W
	PS-3	27"	COMPACTED SELECT FILL		24.4			
					24.0			
					23.2			

COMPLETION DEPTH 101.25' Water Depth 55' Date 9/26/77
SAMPLER 2" OD SPLIT BARREL SAMPLER

LOG of BORING No. WE-7

DATE 9/23/77 SURFACE ELEV. 419.9 LOCATION N 472,565.39 E 1,905,500.45

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45	PS-3	27"			23.2			
		76						
50	PS-4	27"	Stiff to very stiff red-brown fine sandy clayey silt with trace mica.		24.9			
					24.4			
		66			22.7			
55	PS-5	28"			26.8			
					24.9			
		66			24.0			
60	PS-6	28"	Grading more brown		22.1			W,C
					24.5			
		42			26.8			
65	PS-7	24"			24.1			
					30.0			
		32			24.5			
70	PS-8				25.3			
					21.4			
					30.0			
			French Drain consisting of Zone I and Zone II stone.	348.6				
75								
		54	Dense gray, tan and brown decomposed granodiorite rock friable to silt and coarse to fine sand.	343.9				
80	PS-8A	25"			28.7			
			(Saprolite)					
	100	5"		337.4	26.1			W,G
85			(Decomposed Rock)					
	100	5"	Same as above but more dense.		26.6			
					21.2			
90	PS-9	3"						

COMPLETION DEPTH 101.25' Water Depth 55' Date 9/26/77
SAMPLER 2" OD SPLIT BARREL SAMPLER

LOG of BORING No. WE-7

DATE 9/23/77 SURFACE ELEV. 419.9 LOCATION N 472,565.39 E 1,905,500.45

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
90	PS-9	3"						
		100/3"			20.1			
95		100/4"	Becoming gray-brown and more dense with depth		17.1			
100		100/3"		318.6				
105			Note: Two Casagrande type piezometers were installed in this boring. WE7-P1 Elev. 325.6 WE7-P2 Elev. 347.1 Legend: PS-1 / 16" : 3" piston sample / 16" recovery					

COMPLETION DEPTH 101.25' Water Depth 55' Date 9/26/77

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG OF TEST PIT NO. TPW-1

DATE 10/16/75 SURFACE ELEV. 414.5 LOCATION N471, 965 E 1, 906, 031

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0			Uncontrolled fill and spoil materials*	
10				403.5
			Tan, brown and black sandy silt to silty sand ** (Decomposed Rock)	
19				397

* This material to be removed prior to embankment construction

** Top of stratum ranges from 11 to 12.5 feet deep in test pit

COMPLETION DEPTH 19 Water Depth None Date 10/16/75

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG OF TEST PIT NO. TPW-2

DATE 10/16/75 SURFACE ELEV. 414.9 LOCATION N 471, 949 E 1, 906, 029

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0			Red-Brown, yellow and tan sandy clayey silt with few rock fragments. (Sapprolite)	408.9
5			Tan, black and brown micaceous silty fine sand and sandy silt (Decomposed Rock)	400.9
10				
15			Green-gray and tan micaceous silt (Decomposed Rock)	400.0

COMPLETION DEPTH 14.9 Water Depth None Date 10/16/75

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG OF TEST PIT NO. TPW-3

DATE 10/16/75 SURFACE ELEV. 412.5 LOCATION N 971, 948 E 1, 906, 045

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0			Uncontrolled Fill *	410.00
5			Tan and black silty sand (Decomposed Rock)	405.5
10			Brown, Gray and Black micaceous sandy silt to silty sand (Decomposed Rock)	399.5
15			* To be removed prior to constructing embankment	

COMPLETION DEPTH 13.0 Water Depth None Date 10/16/75

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. Auger Boring F-1

DATE 9/18/75 SURFACE ELEV. ____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	% PASSING #200 SIEVE
0			RESIDUAL - Very stiff to hard dark red-brown silty clay		26.5			63
5					23.9			37
10			TRANSITION - Dark red-brown micaceous clayey sandy silt grading from RESIDUAL TO SAPROLITE		22.1			41
15					23.4			50
20			SAPROLITE - Medium dense light red-brown micaceous sandy silt becoming variegated tan and gray-green below 30 feet ±		22.7			44
25					21.0			38
30					20.1			31
35								
40								
45								

COMPLETION DEPTH 43.5 Water Depth --- Date 9/18/75
SAMPLER Auger Cuttings

LOG of BORING No. Auger Boring F-2

DATE 9/18/75 SURFACE ELEV. ____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	% PASSING #200 SIEVE
0			RESIDUAL - Hard to very stiff red-brown clayey silt with sand becoming micaceous below 10'± grading to SAPROLITE		27.4			61
5					26.1			51
10					27.6			43
15			SAPROLITE - Medium dense tan and pink micaceous sandy silt becoming variegated green-gray and tan sandy micaceous silt		25.4			48
20					25.9			56
25					22.7			38
30								
35								
40								
45								

COMPLETION DEPTH 43.5 Water Depth — Date 9/18/75
SAMPLER

LOG of BORING No. Auger Boring F-3

DATE 9/18/75 SURFACE ELEV. LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	% PASSING #200 SIEVE
0			RESIDUAL - Very stiff red-brown clayey silt becoming micaceous with depth and grading with fine sand					
5								
10								
15			TRANSITION Medium dense red-brown very fine sandy micaceous silt with trace of clay, grading from RESIDUAL to SAPROLITE		29.3			62
20					28.1			59
25			SAPROLITE - Medium dense tan to red-brown micaceous silty fine sand with trace medium sand becoming variegated gray to gray-green and tan with relic rock structure apparent		31.1			67
30								
35					30.7			64
40					30.5			63
45								

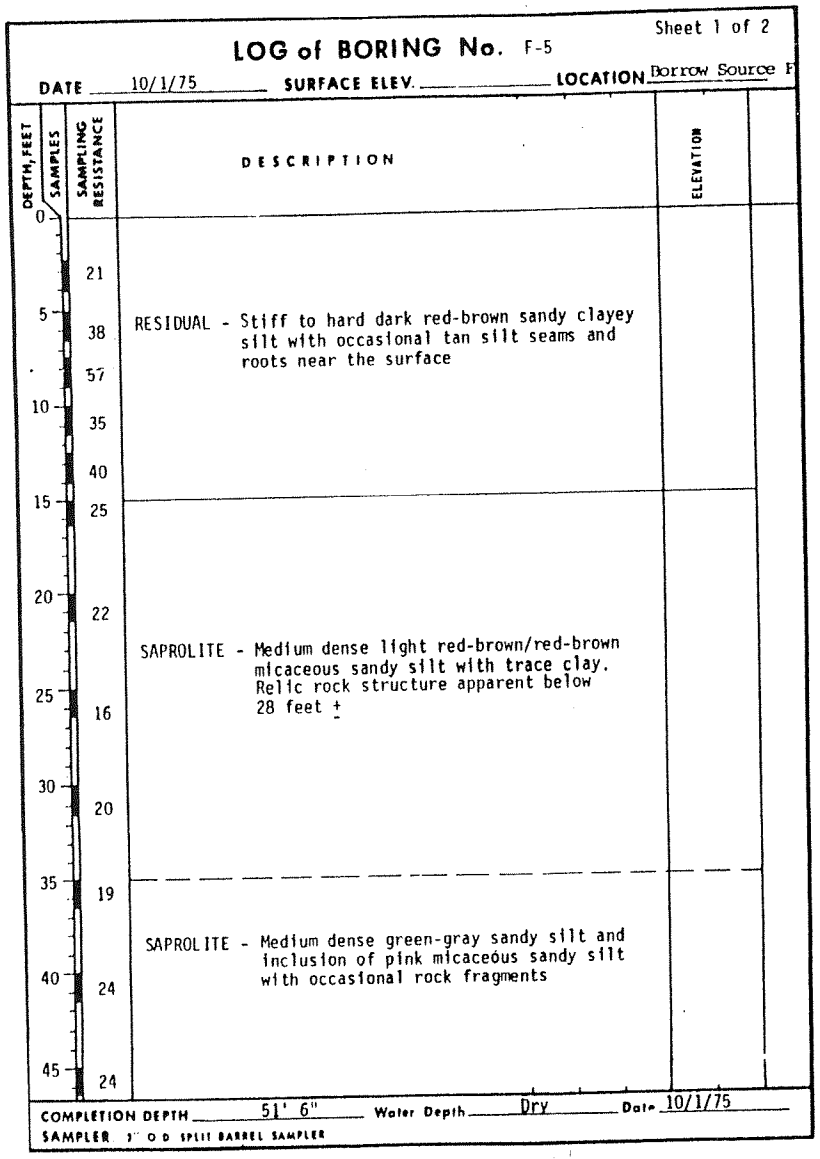
COMPLETION DEPTH 43.5 Water Depth -- Date 9/18/75
SAMPLER Auger Cuttings

LOG of BORING No. Auger Boring F-4

DATE 9/18/75 SURFACE ELEV. LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	% PASSING #200 SIEVE
0			RESIDUAL - Hard to stiff red-brown clayey silt grading micaceous with depth					
5								
10								
15					29.2			78
20			SAPROLITE - Medium dense to dense red-brown slightly micaceous medium to fine sandy silt		23.4			
25					18.1			46
30			Grading to tan and more micaceous with depth		20.3			
35								41
40					16.8			33
45					16.6			39

COMPLETION DEPTH 43.5 Water Depth -- Date 9/18/76
SAMPLER Auger Cuttings



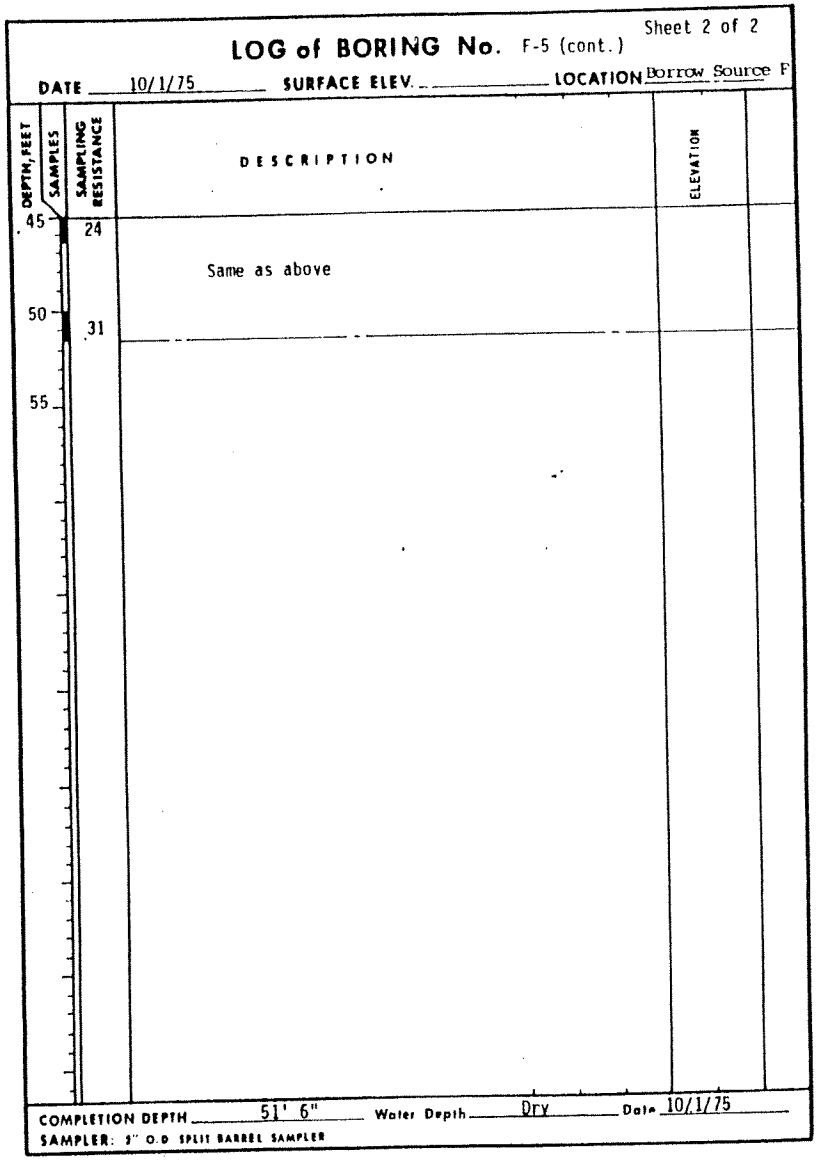
LOG of BORING No. F-5 Sheet 1 of 2

DATE 10/1/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0				
		21	RESIDUAL - Stiff to hard dark red-brown sandy clayey silt with occasional tan silt seams and roots near the surface	
5		38		
		57		
10		35		
		40		
15		25	SAPROLITE - Medium dense light red-brown/red-brown micaceous sandy silt with trace clay. Relic rock structure apparent below 28 feet ±	
20		22		
25		16		
30		20		
35		19	SAPROLITE - Medium dense green-gray sandy silt and inclusion of pink micaceous sandy silt with occasional rock fragments	
40		24		
45		24		

COMPLETION DEPTH 51' 6" Water Depth Dry Date 10/1/75

SAMPLER 3" O.D SPLIT BARREL SAMPLER



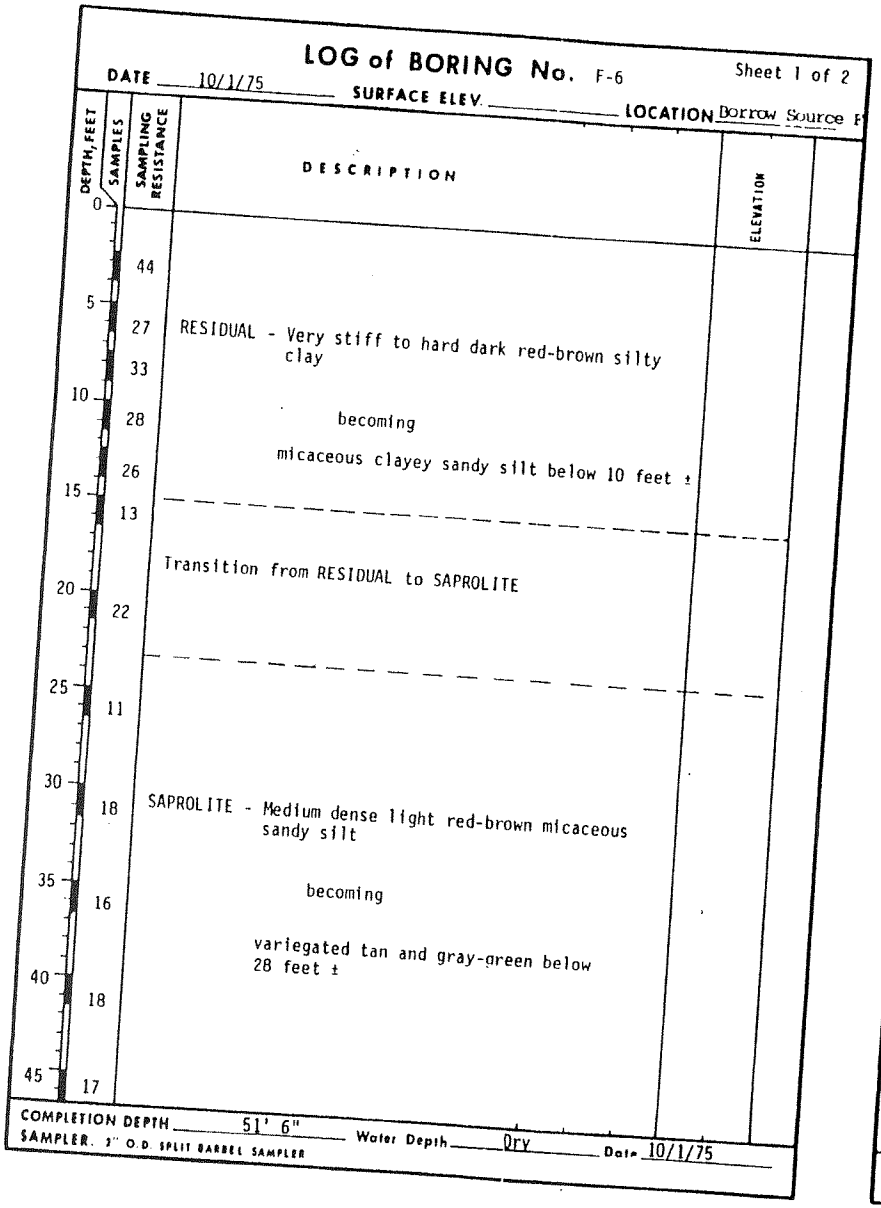
LOG of BORING No. F-5 (cont.) Sheet 2 of 2

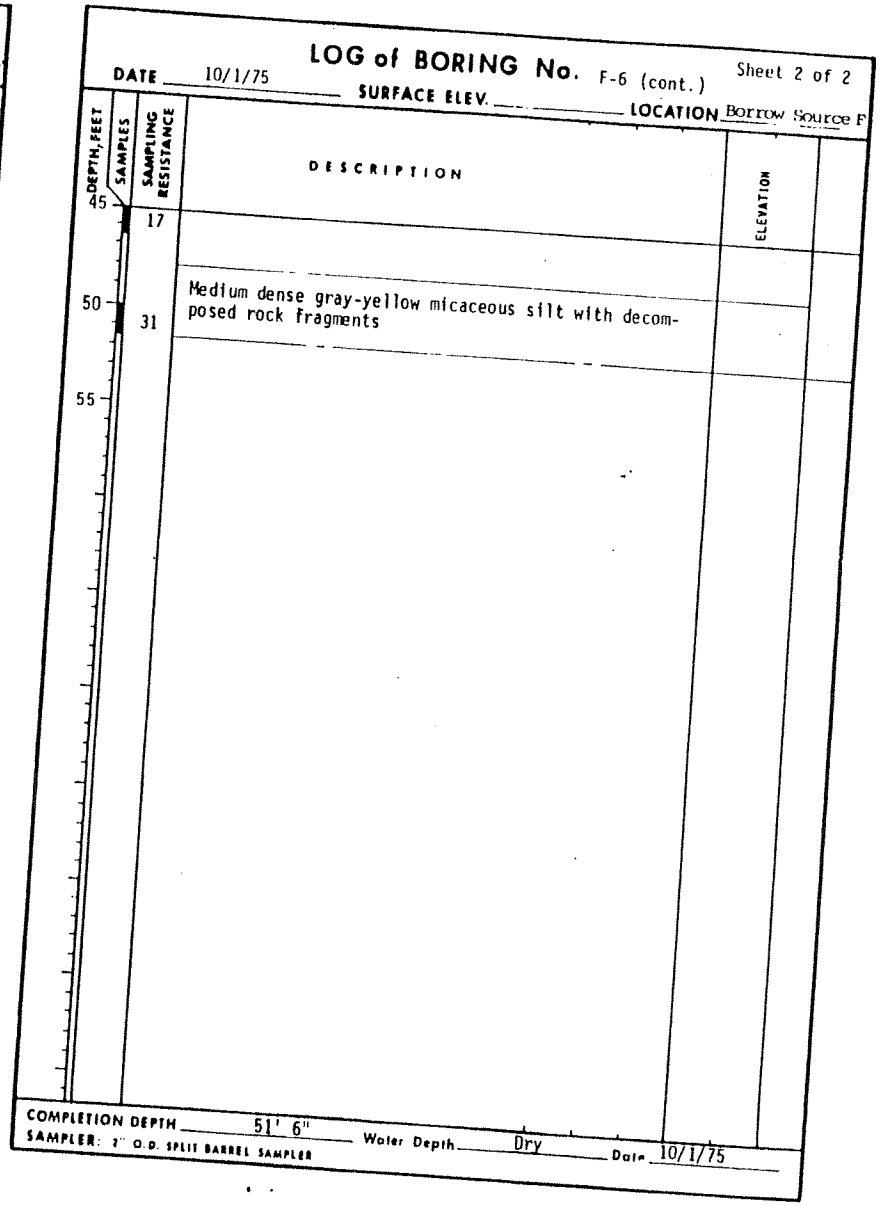
DATE 10/1/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
45		24	Same as above	
50		31		
55				

COMPLETION DEPTH 51' 6" Water Depth Dry Date 10/1/75

SAMPLER: 3" O.D SPLIT BARREL SAMPLER


LOG of BORING No. F-6
Sheet 1 of 2
DATE 10/1/75
SURFACE ELEV.
LOCATION Borrow Source F
DEPTH, FEET
SAMPLES
SAMPLING RESISTANCE
DESCRIPTION
ELEVATION
0
5
10
15
20
25
30
35
40
45
44
27
33
28
26
13
22
11
18
16
18
17
RESIDUAL - Very stiff to hard dark red-brown silty clay
becoming
micaceous clayey sandy silt below 10 feet ±
Transition from RESIDUAL to SAPROLITE
SAPROLITE - Medium dense light red-brown micaceous sandy silt
becoming
variegated tan and gray-green below 28 feet ±
COMPLETION DEPTH 51' 6"
Water Depth Dry
Date 10/1/75
SAMPLER: 2" O.D. SPLIT BARREL SAMPLER


LOG of BORING No. F-6 (cont.)
Sheet 2 of 2
DATE 10/1/75
SURFACE ELEV.
LOCATION Borrow Source F
DEPTH, FEET
SAMPLES
SAMPLING RESISTANCE
DESCRIPTION
ELEVATION
45
50
55
17
31
Medium dense gray-yellow micaceous silt with decomposed rock fragments
COMPLETION DEPTH 51' 6"
Water Depth Dry
Date 10/1/75
SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-7

DATE 9/30/75 SURFACE ELEV. ____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			RESIDUAL - [illegible] red-brown micaceous silty clay with trace sand					
		20	SAPROLITE - Medium dense red-brown micaceous silt with trace to little clay and fine sand					
5		16						
		20			30.1	53	45	G,M C,T X
10		21	SAPROLITE - Medium dense red-brown micaceous fine sandy silt becoming decomposed rock					
		19						
15		23						
20			Auger refusal at 18' Offset boring 10' NW to drill Boring F-7A					

COMPLETION DEPTH 18' Water Depth dry Date 9/30/75

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-7A

DATE 9/30/75 SURFACE ELEV. ____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5								
10			Augered to 20' See log of F-7 for soil description					
15								
20		19						
		25	SAPROLITE - Medium dense tan micaceous silt with some sand becoming variegated tan, pink and brown micaceous sandy silt		20.8			G,M C,T X
25								
30		20						
35		25						
40		77	Very dense buff-white silty sand (decomposed rock)					
			Auger refusal at 41' 6"					
45								

COMPLETION DEPTH 41' 6" Water Depth dry Date 9/30/75

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. F-8

DATE 10/1-2/75 SURFACE ELEV. LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0				
		45	RESIDUAL - Very stiff red-brown micaceous silty clay with trace sand	
5		49		
		29		
10		30	SAPROLITE - Medium dense red-brown micaceous sandy silt with trace clay	
		24		
15		20		
20		17		
			SAPROLITE - Medium dense red-brown and gray micaceous sandy silt	
25		24	becoming	
			green-gray with more sand	
30		31		
35		24		
40		16		
			SAPROLITE - Medium dense tan and brown micaceous sandy silt	
45		22		

COMPLETION DEPTH 46'6" Water Depth dry Date 10/2/75

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. F-9

Sheet 1 of 2

DATE 10/1/75 SURFACE ELEV. LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0				
		66		
5		31		
		53	RESIDUAL - Hard to very stiff red-brown clayey silt with sand	
10		36	becoming	
		37	micaceous below approximately 8 feet	
15		16	becoming	
			less stiff with depth and more sandy	
20		15	Grading to SAPROLITE	
25		13	SAPROLITE - Medium dense tan and pink micaceous sandy silt	
30		20		
35		16		
			SAPROLITE - Medium dense variegated green-gray and tan sandy micaceous silt	
40		19		
45		18		

COMPLETION DEPTH 51'6" Water Depth dry Date 10/1/75

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. F-9 (cont.)

Sheet 2 of 2

DATE 10/1/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
45		18	Same as above	
50		25		
55				

COMPLETION DEPTH 51'6" Water Depth dry Date 10/1/75

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-10

DATE 9/30/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0		48	RESIDUAL - Very stiff red-brown micaceous clayey sandy silt	
5		31		
		29	Medium dense red-brown to tan micaceous silt with trace fine sand. (Transition from RESIDUAL to SAPROLITE)	
10		28		
		24	SAPROLITE - Medium dense red-brown and tan micaceous silt	
15		17		
20		20		
25		19	SAPROLITE - Medium dense tan micaceous sandy silt with relic rock structure apparent	
30		24		
35		31		
40		28		
45		31		

COMPLETION DEPTH 46'6" Water Depth dry Date 9/30/75

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-11

DATE 10/2/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		51	RESIDUAL - Very stiff red-brown sandy clayey silt					
		51	becoming					
10		34	micaceous with depth		23.6			M
		38						
15		18	Medium dense red-brown and yellow-tan micaceous silt with trace fine sand. (Transition from RESIDUAL to SAPROLITE)					
		28						
20		19	SAPROLITE - Medium dense variegated tan, red-brown and white micaceous sandy silt					
25		19	becoming					
30		20	yellow-green/gray micaceous silt		26.4			M
35		23						
40		22	SAPROLITE - Medium dense tan and gray micaceous sandy silt					
45		24						

COMPLETION DEPTH 46' 6" Water Depth dry Date 10/2/75

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. F-12

Sheet 1 of 2

DATE 10/1/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0				
5		56	RESIDUAL - Very stiff red-brown clayey silt	
		60	becoming	
10		60	micaceous and sandy with depth	
		24	RESIDUAL - Medium dense red-brown very fine sandy micaceous silt with trace clay	
15		30	Grading more micaceous with depth	
		21	Grading to SAPROLITE	
20		13		
25		14	SAPROLITE - Medium dense tan to red-brown micaceous silty fine sand with trace medium sand	
30		20	becoming	
35		13	gray to gray-green and tan with relic rock structure apparent.	
40		21		
45		21		

COMPLETION DEPTH 51'6" Water Depth dry Date 10/1/75

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. F-12 (cont.)

Sheet 2 of 2

DATE 10/1/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
45		21	Same as above	
50		15		
55				

COMPLETION DEPTH 51'6" Water Depth dry Date 10/1/75

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-13

Sheet 1 of 2

DATE 9/30/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0		26	RESIDUAL - Stiff red-brown clayey silt with little mica					
5		24						
		24						
10		17	Medium stiff/dense red-brown to tan clayey silt/fine sandy silt with mica. Grading from RESIDUAL to SAPROLITE		22.0	43	41	G,M X
		18						
15		13						
20		28	SAPROLITE - Medium dense to dense tan to red-brown micaceous very sandy silt					
25		16						
30		24						
35		19	SAPROLITE - Medium dense to dense tan, red-brown to gray micaceous fine sandy silt with relic rock structure apparent					
40		25	Grading more gray/white and coarser sand with depth					
45		18						

COMPLETION DEPTH 51' 6" Water Depth dry Date 9/30/75

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-13 (cont.)

Sheet 2 of 2

DATE 9/30/75 SURFACE ELEV. LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		18	Same as above					
50		33						
55								

COMPLETION DEPTH 51' 6" Water Depth dry Date 9/30/75

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-14

DATE 10/2/75 SURFACE ELEV. LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0		13	RESIDUAL - Moderately stiff red-brown clayey silt with trace of fine sand and mica	
5		11		
		16	RESIDUAL - Medium dense to dense micaceous very fine sandy silt	
10		10		
		19		
15		11	Grading to SAPROLITE	
20		15		
			SAPROLITE - Medium dense yellow-green, gray, white and tan micaceous medium to fine sandy silt	
25		13		
30		21	Grading more sandy with depth	
			Relic rock structure more apparent with depth	
35		15		
40		24		
45		14		

COMPLETION DEPTH 46'6" Water Depth dry Date 10/2/75

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-15

Sheet 1 of 2

DATE 9/30/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
		49	RESIDUAL - Hard to stiff red-brown clayey silt grading micaceous with depth					
5		26						
		24						
10		25			23.4	47	36	M,X
		16						
15		19						
			SAPROLITE - Medium dense to dense red-brown slightly micaceous medium to fine sandy silt					
20		14						
			Grading to tan and more micaceous with depth					
25		24						
30		25						
35		23						
40		24			25.7			G,M T,X
			SAPROLITE - Dense variegated tan/gray medium to fine sandy silt with rock fragments. Relic rock structure apparent.					
45		27						

COMPLETION DEPTH 51' 6" Water Depth dry Date 9/30/75

SAMPLER 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-15 (cont.)

Sheet 2 of 2

DATE 9/30/75 SURFACE ELEV. _____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		27						
			Same as above					
50		28						
55								

COMPLETION DEPTH 51' 6" Water Depth dry Date 9/30/75

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-16

Sheet 1 of 2

DATE 9/30/75 SURFACE ELEV. ____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
0				
		53	RESIDUAL - Very stiff red-brown clayey silt with little mica	
5		32		
		36		
10		18	RESIDUAL - Stiff/dense red-brown clayey medium to fine sandy silt with little mica	
		18		
15		16	SAPROLITE - Medium dense to dense tan micaceous fine sandy silt	
20		21		
25		14		
30		28	Grading more sandy with depth	
35		28	Relic rock structure more apparent with depth	
40		25		
45		31		

COMPLETION DEPTH 51'6" Water Depth dry Date 9/30/75

SAMPLER: 3" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. F-16 (cont.)

Sheet 2 of 2

DATE 9/30/75 SURFACE ELEV. ____ LOCATION Borrow Source F

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION
45		31		
50		32	Same as above	
55				

COMPLETION DEPTH 51'6" Water Depth dry Date 9/30/75

SAMPLER: 3" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. TBG-2

Sheet 1 of 2

DATE 2/11/76 SURFACE ELEV. 418.8 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			RESIDUAL - Very stiff to hard dark red brown with tan mottling, sandy clayey silt					
5		47						
10		28		406.8				
15		20	SAPROLITE - Medium dense red-brown micaceous silty fine sand becoming more silty with depth becoming variegated with tan below 20 feet ±					M
20		26						M
25		26						
30		18						M
35		17						
40		14						M
45		14						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-2 (cont.)

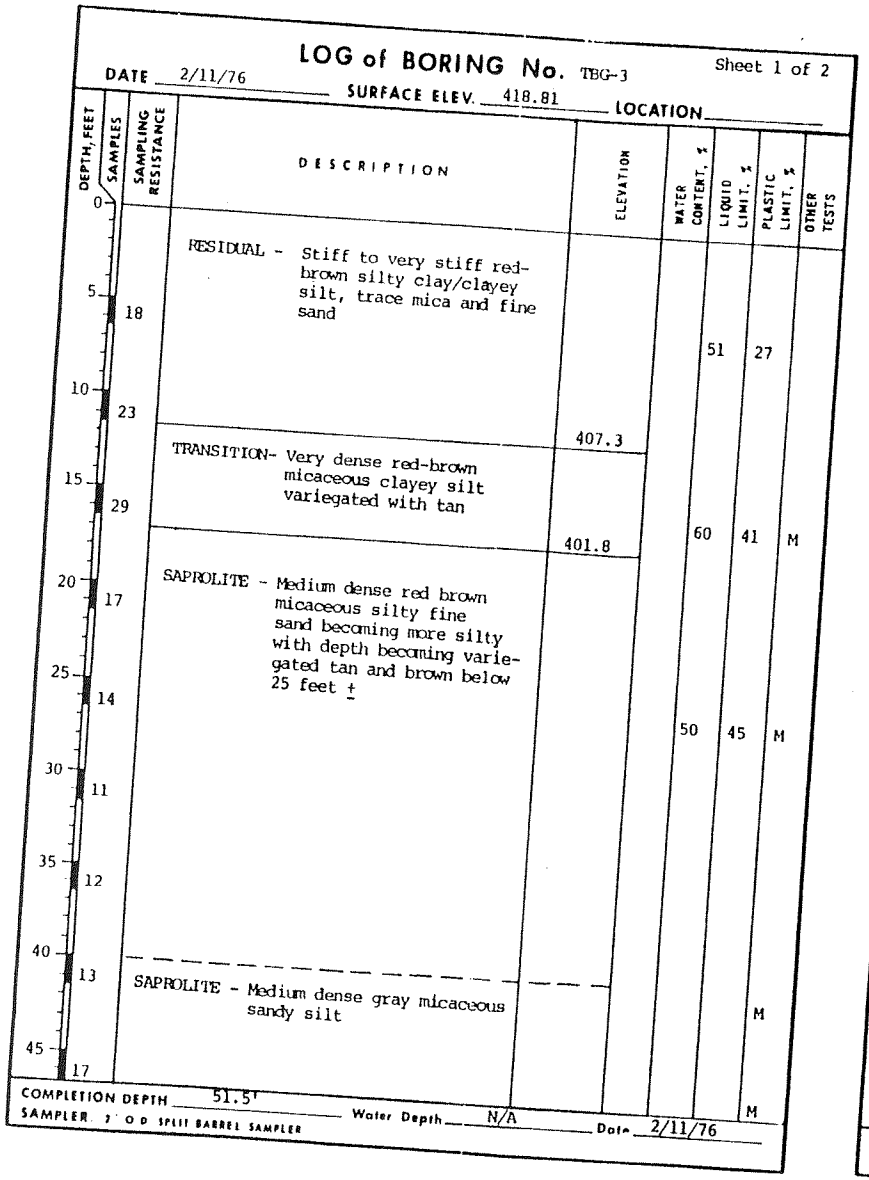
Sheet 2 of 2

DATE 2/11/76 SURFACE ELEV. 418.8 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		14	SAPROLITE - Medium dense gray-green micaceous sandy silt					
50		22		367.6				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER 2" O.D SPLIT BARREL SAMPLER



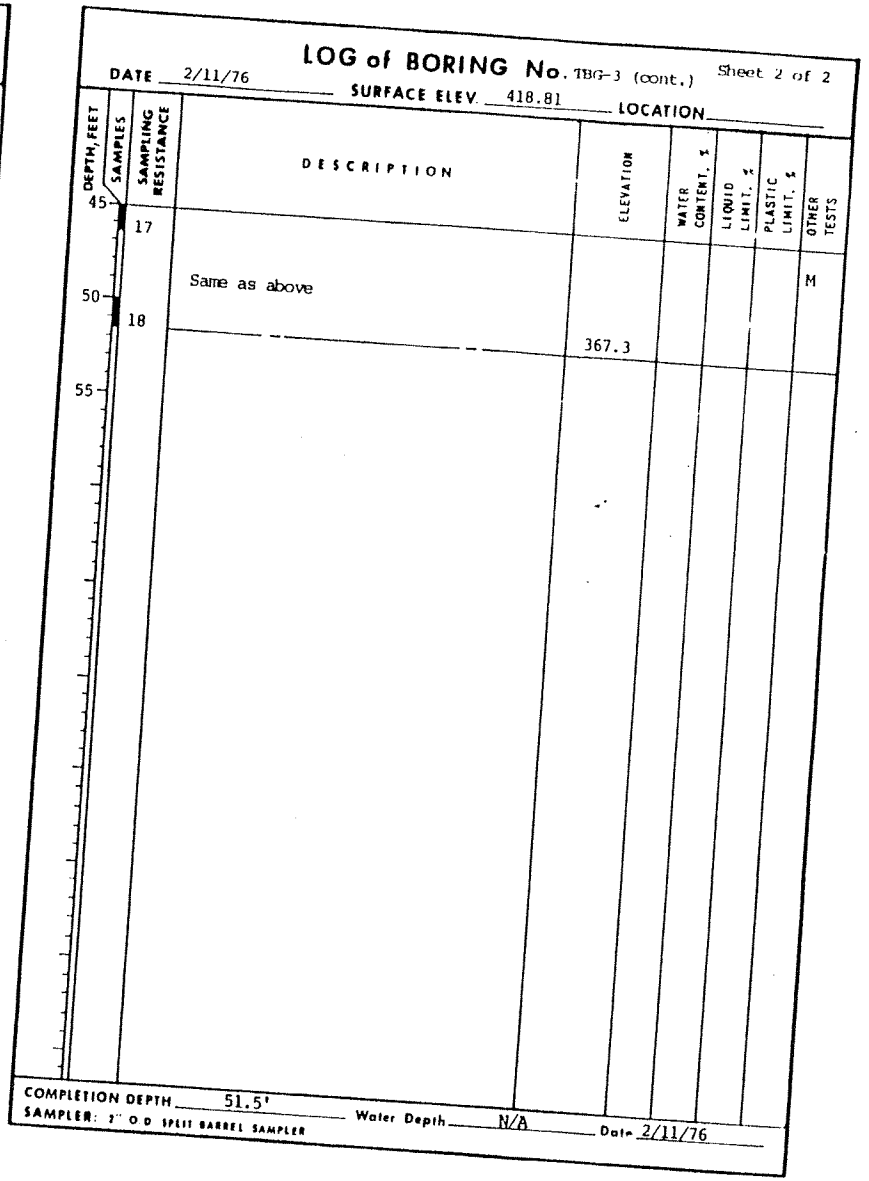
LOG of BORING No. TBG-3 Sheet 1 of 2

DATE 2/11/76 SURFACE ELEV. 418.81 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		18	RESIDUAL - Stiff to very stiff red-brown silty clay/clayey silt, trace mica and fine sand			51	27	
10		23		407.3				
15		29	TRANSITION- Very dense red-brown micaceous clayey silt variegated with tan	401.8		60	41	M
20		17	SAPROLITE - Medium dense red brown micaceous silty fine sand becoming more silty with depth becoming variegated tan and brown below 25 feet ±					
25		14				50	45	M
30		11						
35		12						
40		13						
45		17	SAPROLITE - Medium dense gray micaceous sandy silt					M

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER 2" O.D SPLIT BARREL SAMPLER



LOG of BORING No. TBG-3 (cont.) Sheet 2 of 2

DATE 2/11/76 SURFACE ELEV. 418.81 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		17						
50		18	Same as above	367.3				M
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-5

Sheet 1 of 2

DATE 2/9/76 SURFACE ELEV. 434.21 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		17	RESIDUAL - Stiff dark red-brown fine sandy clayey silt, trace mica		24.9	50	36	
10		19		421.2		54	32	
15		32	TRANSITION - Very dense red-brown, with tan mottling, fine sandy silt, trace mica	417.2				
20		28						
		BAG						
25		19	SAPROLITE - Medium dense red-brown micaceous sandy silt becoming variegated tan and gray below 30 feet ±					M
30		16						M
35		18						
		BAG						M
40		18	SAPROLITE - Medium dense light tan/ gray-white fine to medium silty sand					
45		16						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/9/76

SAMPLER 3" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. TBG-5 (cont.)

Sheet 2 of 2

DATE 2/9/76 SURFACE ELEV. 424.21 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		16						
		BAG	Same as above					M
50		21		382.7				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/9/76

SAMPLER 3" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. TBG-7

Sheet 1 of 2

DATE 2/9/76 SURFACE ELEV. 397.69 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		40	RESIDUAL - Very stiff to hard dark red-brown silty clay/ clayey silt, trace coarse to fine sand					
10		26		385.7				
15		16	TRANSITION- Medium dense red-brown micaceous fine sandy silt variegated with tan	380.7		44	42	M
20		13	SAPROLITE - Medium dense red-brown micaceous sandy silt becoming variegated with tan below 30 feet ±					
25		14						
30		18						
35		16						
40		21						
	BAG		SAPROLITE - Medium dense red-brown micaceous sandy silt becoming variegated tan and white below 40 feet ±					M
45		21						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/9/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-7 (cont.)

Sheet 2 of 2

DATE 2/9/76 SURFACE ELEV. 397.69 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		21	Same as above					
50		16		346.2				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/9/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-8

Sheet 1 of 2

DATE 2/10/76 SURFACE ELEV. 438.75 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			RESIDUAL - Very stiff dark red-brown silty clay becoming micaceous clayey sandy silt below 5 feet ±					
5		46			28.2	65	33	M
				429.8				
10		30	SAPROLITE - Medium dense red-brown micaceous sandy silt becoming variegated with tan below 10 feet ±					
15		23			27.3			M
20		13						
25		16						
30		17						
35		18			22.3	35	27	M
					37.1	66	54	M
40		25	SAPROLITE - Medium dense red-brown fine to medium micaceous sandy silt					
45		27						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER: 3" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. TBG-8 (cont.)

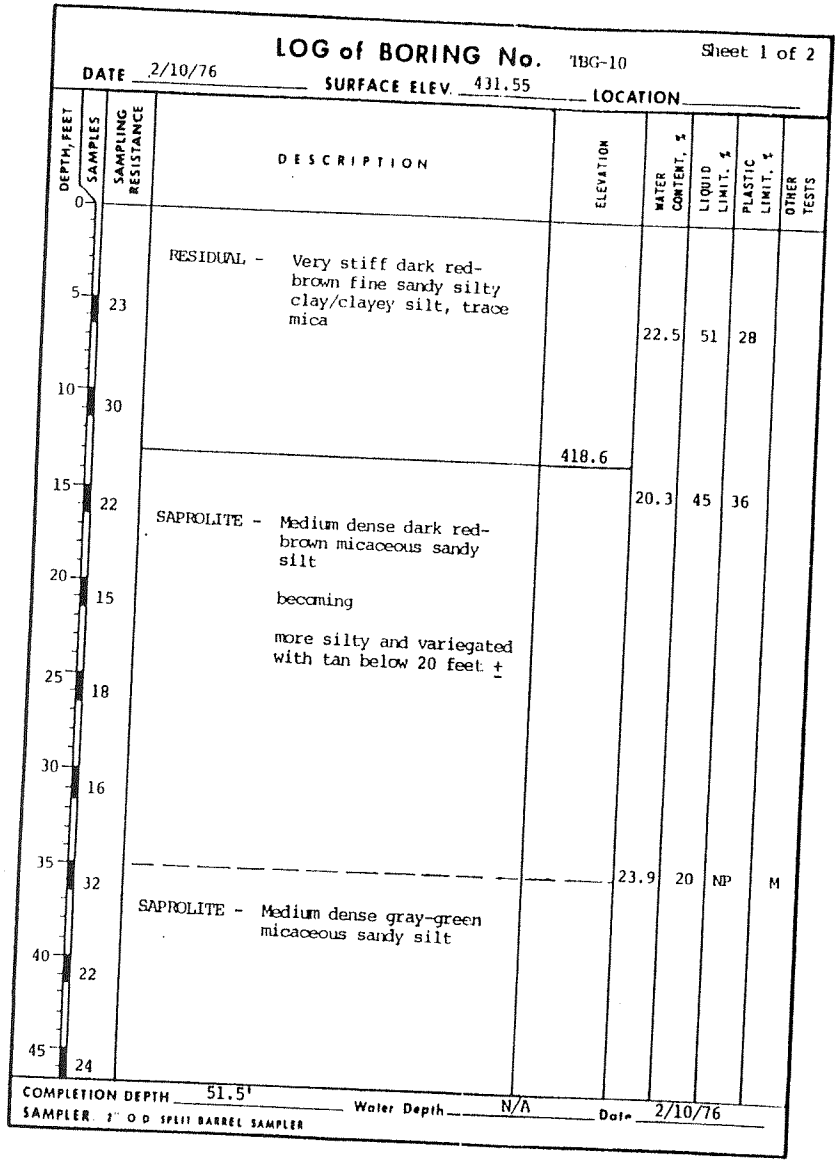
Sheet 2 of 2

DATE 2/10/76 SURFACE ELEV. 438.75 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		27	SAPROLITE - Medium dense red-brown micaceous sandy silt variagated with tan					
50		21		387.3				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER: 3" O.D. SPLIT BARREL SAMPLER



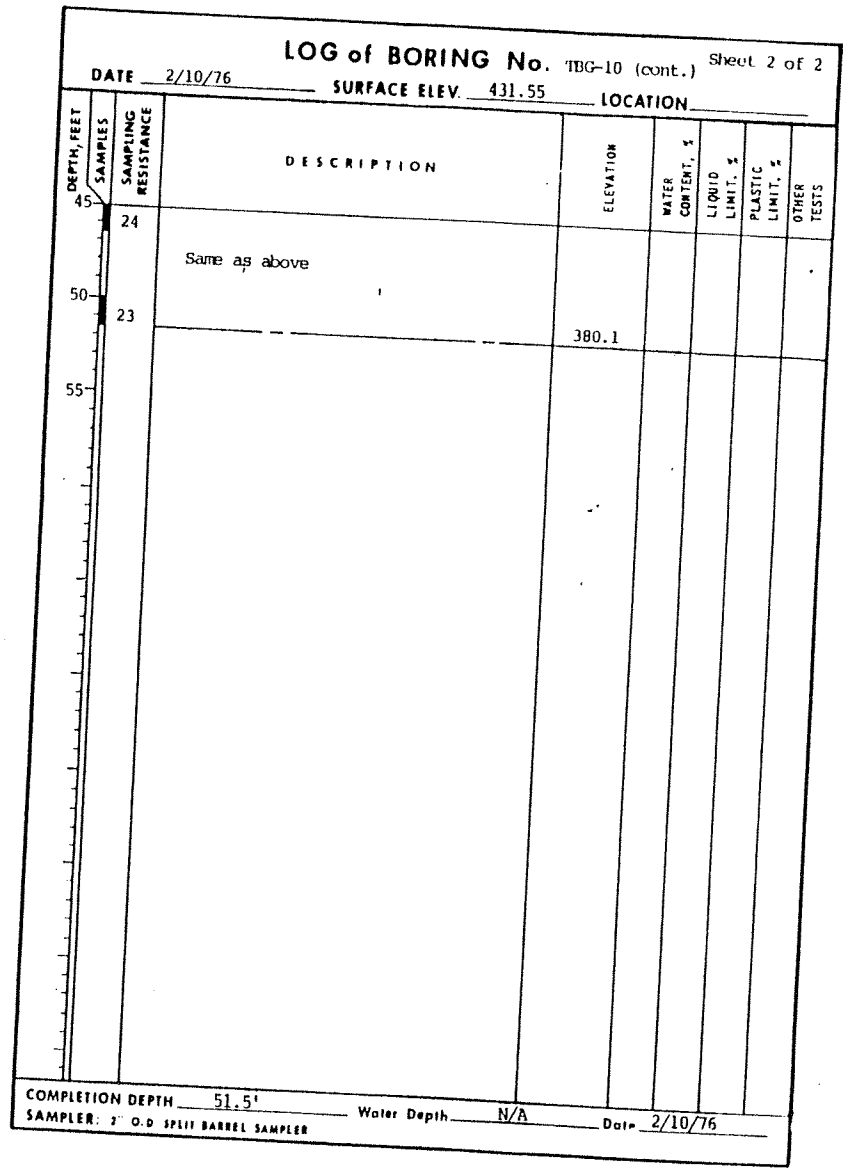
LOG of BORING No. TBG-10 Sheet 1 of 2

DATE 2/10/76 SURFACE ELEV. 431.55 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		23	RESIDUAL - Very stiff dark red-brown fine sandy silty clay/clayey silt, trace mica		22.5	51	28	
10		30						
				418.6				
15		22	SAPROLITE - Medium dense dark red-brown micaceous sandy silt		20.3	45	36	
20		15	becoming more silty and variegated with tan below 20 feet ±					
25		18						
30		16						
35		32			23.9	20	NP	M
40		22	SAPROLITE - Medium dense gray-green micaceous sandy silt					
45		24						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER



LOG of BORING No. TBG-10 (cont.) Sheet 2 of 2

DATE 2/10/76 SURFACE ELEV. 431.55 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		24	Same as above					
50		23		380.1				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-12

Sheet 1 of 2

DATE 2/9/76 SURFACE ELEV. 434.75 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			RESIDUAL - Very stiff to hard dark red-brown silty clay/ clayey silt, trace fine sand and mica					
5		52						
10		23		423.8				
15		20	SAPROLITE - Medium dense red-brown micaceous fine sandy silt			66	60	M
20		21	becoming more micaceous and variegated with tan below 18 feet ±					
25		16			22.9			M
30		18			26.3	44	NP	M
35		BAG						
40		18						
45		16						M
		BAG						
		21						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/9/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-12 (cont.)

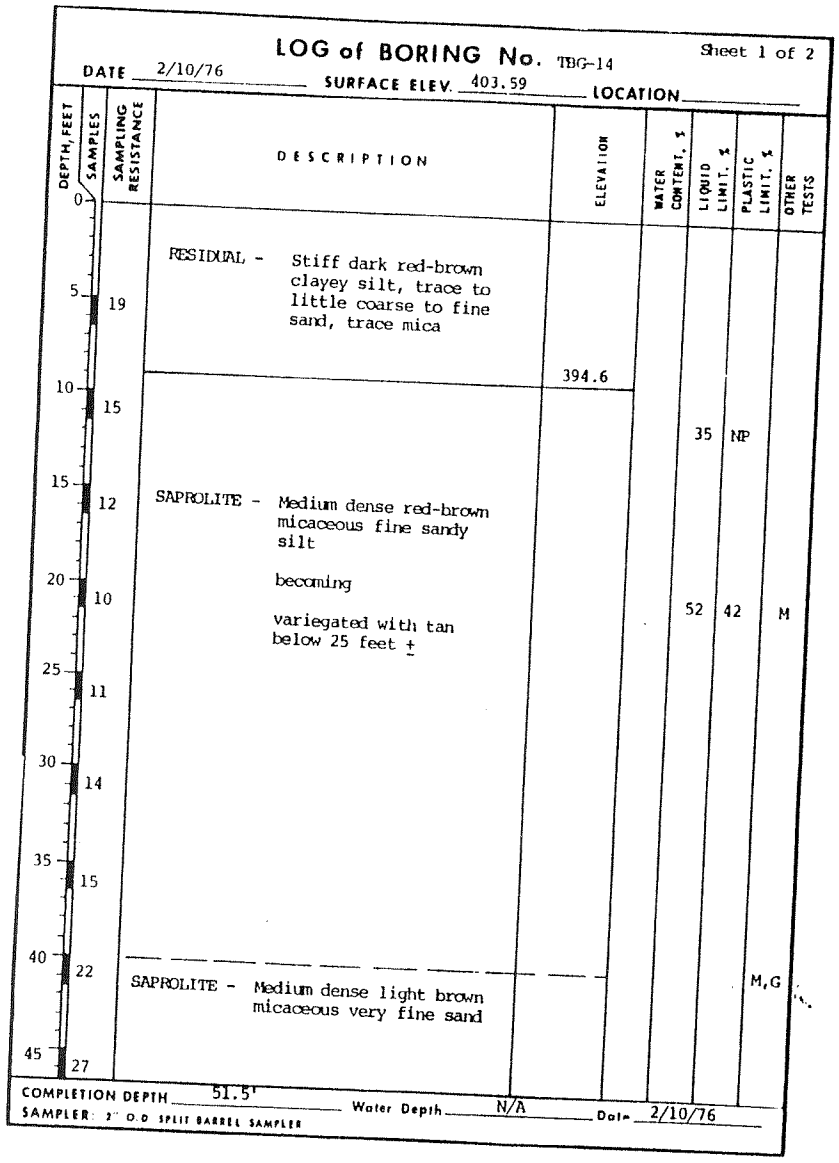
Sheet 2 of 2

DATE 2/9/76 SURFACE ELEV. 434.75 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		21	Same as above					
50		19		383.3				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/9/76

SAMPLER 2 O.D SPLIT BARREL SAMPLER



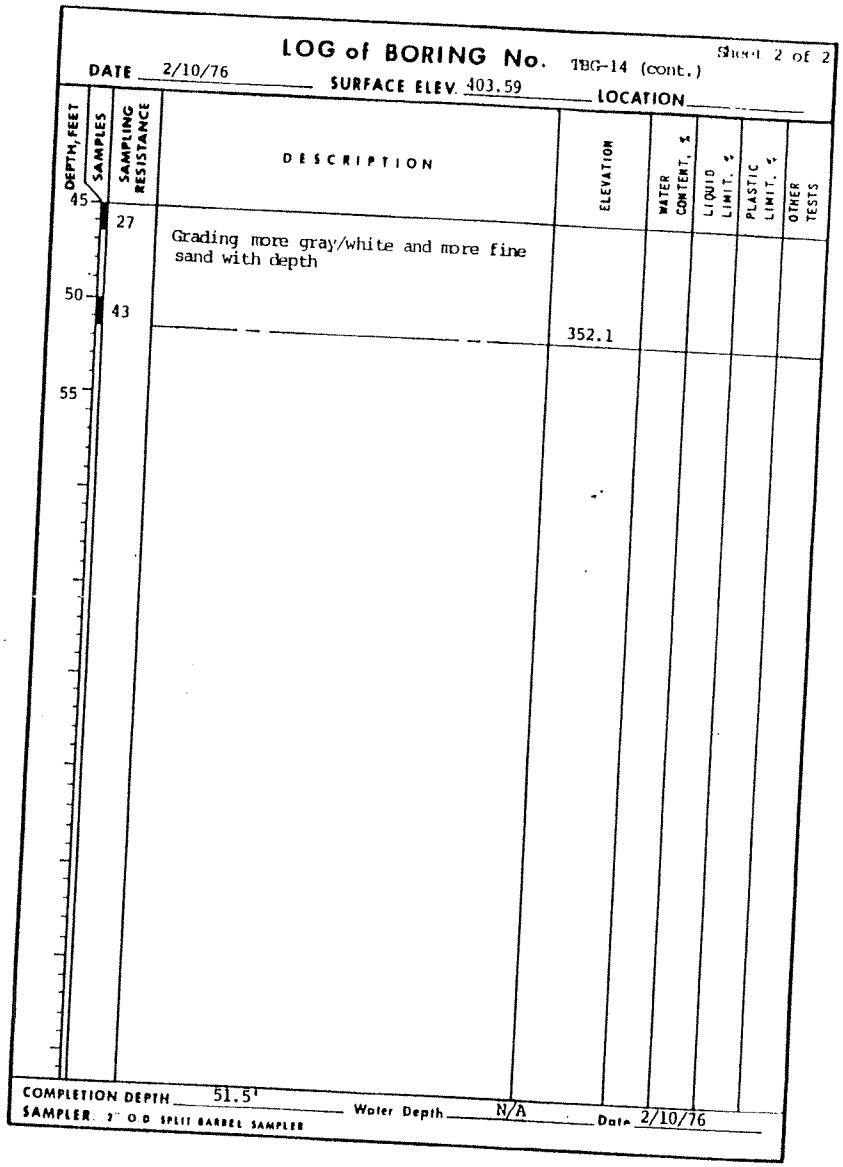
LOG of BORING No. TBG-14 Sheet 1 of 2

DATE 2/10/76 SURFACE ELEV. 403.59 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			RESIDUAL - Stiff dark red-brown clayey silt, trace to little coarse to fine sand, trace mica					
5		19						
				394.6				
10		15				35	NP	
15		12	SAPROLITE - Medium dense red-brown micaceous fine sandy silt					
			becoming					
20		10	variegated with tan below 25 feet ±			52	42	M
25		11						
30		14						
35		15						
40		22	SAPROLITE - Medium dense light brown micaceous very fine sand					M,G
45		27						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER



LOG of BORING No. TBG-14 (cont.) Sheet 2 of 2

DATE 2/10/76 SURFACE ELEV. 403.59 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		27	Grading more gray/white and more fine sand with depth					
50		43		352.1				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-15

Sheet 1 of 2

DATE 2/10/76 SURFACE ELEV. 419.61 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		26	RESIDUAL - Very stiff dark red-brown clayey silt, trace fine sand					
			becoming			53	41	
10		26	micaceous fine sandy clayey silt					
				406.6				
15		18	SAPROLITE - Medium dense red-brown micaceous fine sandy silt					M
20		18	becoming					M
		BAG	variegated tan and brown below 17 feet ±					M
25		16						
30		16						
								M,G
35		23						
		BAG						
40		20						M
45		33						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER 3" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. TBG-15 (cont.)

Sheet 2 of 2

DATE 2/10/76 SURFACE ELEV. 419.61 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		33	Same as above					
50		23		368.1				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER 3" O.D. SPLIT BARREL SAMPLER

LOG of BORING No. TBG-16

Sheet 1 of 2

DATE 2/10/76 SURFACE ELEV. 394.61 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			RESIDUAL - Medium dense red-brown fine sandy clayey silt, trace of mica					
5		14						
		BAG						M
				385.6				
10		14	SAPROLITE - Medium dense to dense red-brown micaceous fine sandy silt					
			becoming					
15		13	variegated with tan below 15 feet ±					
20		11						
			SAPROLITE - Medium dense to dense light gray micaceous fine sandy silt					
25		18						
			becoming					
		BAG	variegated tan and white below 25 feet ±					
30		14						M
			SAPROLITE - Medium dense to dense green-yellow micaceous sandy silt					
35		21						
40		24						
			Grading to decomposed rock					
45		30						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-16 (cont.)

Sheet 2 of 2

DATE 2/10/76 SURFACE ELEV. 394.61 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		30						
50		66	Decomposed rock at 50 feet ±	343.1				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/10/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-17

DATE 2/10/76 SURFACE ELEV. 367.97 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			RESIDUAL - Stiff dark red-brown clayey silt with trace of mica					
5		21		350.0	25.9	48	33	
10		10	TRANSITION - Medium dense red-brown to tan clayey silt/fine sandy silt with mica, grading from RESIDUAL to SAPROLITE	346.0				
15		20						M
20		15	SAPROLITE - Medium dense to dense gray-green micaceous fine sandy silt					
25		15	Grading with more gray/ white and with coarser sand below 30 feet ±					
30		14						
35		24						
40		BAG 22	Grading to decomposed rock	324.0				M
45		70	Decomposed rock	321.5				

COMPLETION DEPTH 46.5' Water Depth N/A Date 2/10/76

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-19

Sheet 1 of 2

DATE 2/11/76 SURFACE ELEV. 410.71 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0			RESIDUAL - Stiff red-brown silty clay with little fine sand and trace of mica					
5		23		402.7				
10		15	SAPROLITE - Medium dense red-brown micaceous fine sandy silt					
15		12	becoming					
20		13	variegated tan and brown below 22 feet ±					
25		12						
30		15						
35		18	SAPROLITE - Medium dense light gray micaceous fine sandy silt					
40		13	becoming					
45		15	variegated black and white below 42 feet ±					

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-19 (cont.)

Sheet 2 of 2

DATE 2/11/76 SURFACE ELEV. 410.71 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45								
		15	Same as above					
50		19		369.2				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-20

Sheet 1 of 2

DATE 2/11/76 SURFACE ELEV. 392.11 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
			RESIDUAL - Stiff to very stiff dark red-brown fine sandy clayey silt with trace of mica					
5		24			23.4	53	31	
10		33	TRANSITION -Very stiff red-brown micaceous fine sandy silt, grading from RESIDUAL to SAPROLITE	382.1	29.8	69	44	
15		27		378.1				
			SAPROLITE - Medium dense to dense red-brown micaceous very fine sandy silt					
20		16						
25		20						
30		25	Grading more gray-green and finer sand with depth					M
35		14						
40		15						M
45		20						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER: 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-20 (cont.)

Sheet 2 of 2

DATE 2/11/76 SURFACE ELEV. 392.11 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		20	Same as above					
50		16		340.6				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-23

Sheet 1 of 2

DATE 2/11/76 SURFACE ELEV. 441.85 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
0								
5		13	RESIDUAL - Moderately stiff to stiff dark red-brown fine sandy silty clay		25.2	53	23	
10		23		429.9	28.2	59	37	
15		38	TRANSITION - Very stiff red-brown micaceous fine sandy silt, grading from RESIDUAL to SAPROLITE	423.9				
20		22	SAPROLITE - Medium dense to dense red-brown micaceous fine sandy silt					
25		15	becoming variegated tan and brown below 25 feet ±		34.0	50	51	M
30		20						
35		16						M
40		18	Grading more yellow-brown and more mica with depth					
45		14						

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER 2" O.D SPLIT BARREL SAMPLER

LOG of BORING No. TBG-23 (cont.)

Sheet 2 of 2

DATE 2/11/76 SURFACE ELEV. 441.85 LOCATION

DEPTH, FEET	SAMPLES	SAMPLING RESISTANCE	DESCRIPTION	ELEVATION	WATER CONTENT, %	LIQUID LIMIT, %	PLASTIC LIMIT, %	OTHER TESTS
45		14	Same as above					
50		12		390.4				
55								

COMPLETION DEPTH 51.5' Water Depth N/A Date 2/11/76

SAMPLER: 2" O.D. SPLIT BARREL SAMPLER

LOG of Test Pit No. TPG-4

DATE 2/11/76 SURFACE ELEV. 434.65 LOCATION

DEPTH, FEET	SAMPLES	BLOWS PER INCHES	DESCRIPTION	Elevation		Liquid Limit, %	Plastic Limit, %	Other Tests
0								
5	BAG		RESIDUAL - Stiff dark red-brown fine sandy clayey silt, trace mica			56	38	M, X G
10				421.7				
15								

COMPLETION DEPTH 13.0' WATER DEPTH N/A DATE 2/11/76

LOG of Test Pit No. TPG-9

DATE 2/11/76 SURFACE ELEV. 428.15 LOCATION

DEPTH, FEET	SAMPLES	BLOWS PER INCHES	DESCRIPTION	Elevation		Liquid Limit, %	Plastic Limit, %	Other Tests
0								
5			RESIDUAL - Stiff to very stiff red-brown silty clay/clayey silt, trace mica and fine sand	419.2				
10	BAG		TRANSITION - Very dense red-brown micaceous clayey silt variegated with tan	415.2		53	31	M, X G
15								

COMPLETION DEPTH 13.0' WATER DEPTH N/A DATE 2/11/76

LOG of Test Pit No. TPG-11

DATE 2/11/76 SURFACE ELEV. 414.35 LOCATION

DEPTH, FEET	SAMPLES	BLOWS PER INCHES	DESCRIPTION	Elevation	Liquid Limit, %	Plastic Limit, %	Other Tests
0							
5	BAG		RESIDUAL - Very stiff to hard dark red-brown sandy clayey silt		52	38	M,X G
10				402.4			
15							

COMPLETION DEPTH 12.0' WATER DEPTH N/A DATE 2/11/76

LOG of Test Pit No. TPG-18

DATE 2/11/76 SURFACE ELEV. 409.61 LOCATION

DEPTH, FEET	SAMPLES	BLOWS PER INCHES	DESCRIPTION	Elevation	Liquid Limit, %	Plastic Limit, %	Other Tests
0							
5	BAG		RESIDUAL - Stiff red-brown silty clay with little fine sand and trace of mica		57	41	M,X G
10				397.6			
15							

COMPLETION DEPTH 12.0' WATER DEPTH N/A DATE 2/11/76

LOG of Test Pit No. TPG-21

DATE 2/11/76 SURFACE ELEV. 390.81 LOCATION

DEPTH, FEET	SAMPLES	BLOWS PER INCHES	DESCRIPTION	Elevation	Liquid Limit, %	Plastic Limit, %	Other Tests
0							
5			RESIDUAL - Stiff to very stiff dark red-brown fine sandy clayey silt with trace of mica	380.8			
10	BAG		SAPROLITE - Medium dense to dense red-brown micaceous very fine sandy silt	377.8	NP	NP	M,X G
15							

COMPLETION DEPTH 13.0' WATER DEPTH N/A DATE 2/11/76

LOG of Test Pit No. TPG-22

DATE 2/11/76 SURFACE ELEV. 401.21 LOCATION

DEPTH, FEET	SAMPLES	BLOWS PER INCHES	DESCRIPTION	Elevation	Liquid Limit, %	Plastic Limit, %	Other Tests
0							
5			RESIDUAL - Stiff dark red-brown clayey silt, trace to little coarse to fine sand, trace mica				
10	BAG			389.2	NP	NP	M,X G
15							

COMPLETION DEPTH 12.0' WATER DEPTH N/A DATE 2/11/76

LOG of Test Pit No. TPG-24

DATE 2/11/76 SURFACE ELEV. 444.11 LOCATION

DEPTH, FEET	SAMPLES	BLOWS PER INCHES	DESCRIPTION	Elevation		Liquid Limit, %	Plastic Limit, %	Other Tests
0								
5			RESIDUAL - Moderately stiff to stiff dark red-brown fine sandy silty clay					
10				432.1				
15	BAG		TRANSITION - Very stiff red-brown micaceous fine sandy silt	429.1		52	34	M,X G

COMPLETION DEPTH 15.0' WATER DEPTH N/A DATE 2/11/76

LOG of Test Pit No. TPG-25

DATE 2/11/76 SURFACE ELEV. 432.65 LOCATION

DEPTH, FEET	SAMPLES	BLOWS PER INCHES	DESCRIPTION	Elevation		Liquid Limit, %	Plastic Limit, %	Other Tests
0								
5			RESIDUAL - Very stiff dark red-brown fine sandy silty clay/ clayey silt, trace mica					
10								
15	BAG			417.7		46	33	M,X G

COMPLETION DEPTH 15.0' WATER DEPTH N/A DATE 2/11/76

V.C. Summer Nuclear Station
Safety Analysis Report

Design of Structures, Components, Equipment, and Systems

Chapter 3

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 3 - DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.0 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

The chapter includes identification, description and discussion of the principal architectural and engineering design of those structures, components, equipment and systems important to safety.

3.1 CONFORMANCE WITH NRC GENERAL DESIGN CRITERIA

This section discusses briefly the extent to which the design criteria for the plant structures, systems and components important to safety meet the NRC "General Design Criteria for Nuclear Power Plants" specified in Appendix A to 10 CFR 50. A summary is provided to show how the principal design features meet each criterion and identify any exceptions.

3.1.1 Summary Description

The Virgil C. Summer Nuclear Station is designed, constructed and operated to comply with South Carolina Electric and Gas Company's understanding of the intent of the NRC's "General Design Criteria for Nuclear Power Plants," Appendix A to 10 CFR 50. This section outlines the philosophy that will be adopted in meeting the criteria. Detailed evaluations of compliance with the various General Design Criteria are incorporated in applicable sections of the Final Safety Analysis Report as referenced herein.

3.1.2 Conformance With NRC General Design Criteria

3.1.2.1 Overall Requirements

Criterion 1 - Quality Standards and Records

Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Discussion

South Carolina Electric and Gas Company and Westinghouse, with its subcontractors, maintains, either in their possession or under their control, a complete set of records of the design,

fabrication, construction and testing of safety components. Recognized codes and standards, when used, are identified and evaluated to assure their applicability, adequacy, and sufficiency in keeping with the required safety function.

The quality assurance program conforms with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Plants.” This program is discussed in Chapter 17. Chapter 14 describes the initial test program to assure performance of installed equipment commensurate with the importance of the safety function.

Criterion 2 - Design Bases for Protection Against Natural Phenomena

Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect: (1) appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena, and (3) the importance of the safety functions to be performed.

Discussion

The natural phenomena and their magnitude are selected in accordance with their probability of occurrence at this specific site. The criteria adopted in the design of affected structures, systems and components, also depend on the likelihood of the natural phenomenon under consideration. The designs are based upon the most severe of the natural phenomena recorded for the site, with an appropriate margin to account for uncertainties in the historical data. The natural phenomena postulated in the design are presented in Chapter 2. The design criteria for the structures, systems and components affected by each natural phenomenon are presented in the sections listed below. These sections also identify which combinations of natural and plant originated accidents are considered in the design.

The design criteria developed meet the requirements of Criterion 2.

For further discussion, see the following sections:

		Section
1.	Meteorology	2.3
2.	Hydrologic Engineering	2.4
3.	Geology, Seismology, and Geotechnical Engineering	2.5
4.	Classification of Structures, Components and Systems	3.2
5.	Wind and Tornado Loadings	3.3
6.	Water Level (Flood) Design	3.4
7.	Missile Protection	3.5
8.	Seismic Design	3.7
9.	Design of Category I Structures	3.8
10.	Mechanical Systems and Components	3.9
11.	Seismic Qualification of Seismic Category I Instrumentation and Electrical Equipment	3.10
12.	Environmental Design of Mechanical and Electrical Equipment	3.11

Criterion 3 - Fire Protection

Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and Control Room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Fire-fighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

Discussion

Fires in the plant are prevented or mitigated by the use of noncombustible and fire retardant materials. Redundant safety class equipment is separated by 1 or 2 hour fire barriers or adequate clear space separation based upon the fire hazard. Safety-related ventilation systems are designed and arranged to ensure that no single fire occurrence will jeopardize plant safety. In addition,

special attention is given to the safety-related electrical systems by providing items such as metal cabinets, metal wireways and fire retardant insulation.

Cabling within trays is suitably derated and cable tray loading is designed to minimize internal heat buildup. Cable trays are suitably separated to avoid the loss of redundant channels of protection cabling should fires occur. The arrangement of equipment in protection channels assigned to separate cabinets provides physical separation and minimizes the effects of a possible fire.

Combustible supplies such as logs, records, manuals, etc., are limited in such areas as the Control Room to amounts required for current operation, thus minimizing the effect of a fire. No explosive gases or flammable liquids exist in these areas and therefore no explosion hazard exists.

The Plant Fire Protection System includes the following provisions:

1. Automatic fire detection equipment in those areas where fire danger is greatest.
2. Physical barriers and fire rated walls.
3. Automatic extinguishing systems for areas of highest fire loading as well as manually operated fire extinguishers for all areas.
4. Fire alarms and detection devices are connected to the Station Communication System in the Control Room.

The Westinghouse supplied equipment is designed to minimize the probability and effect of fires and explosions. Noncombustible and fire resistant materials are used in this equipment wherever practical.

The requirements of the National Fire Protection Association, the American Insurance Association, the Nuclear Energy-Liability Property Insurance Association (NE-LPIA), and the applicable local codes and regulations are observed in the design and installation of Westinghouse supplied equipment.

The design of the Fire Protection System thus meets the requirements of Criterion 3.

For further discussion, see the following sections:

		Section
1.	Instrumentation and Controls	7.0
2.	Electric Power	8.0
3.	Separation Criteria	8.3.1
4.	Fire Protection System	9.5.1
5.	Conduct of Operations	13.0

Criterion 4 - Environmental and Missile Design Bases

Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing and postulated accidents, including loss-of-coolant accidents. These structures, systems and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit.

Discussion

Structures, systems and components important to safety are designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss of coolant accidents (LOCA).

These structures, systems and components are appropriately protected against dynamic effects including the effects of missiles, pipe whipping and discharging fluids that may result from equipment failures and from events and conditions outside the nuclear power unit.

The electrical equipment, instrumentation and cables for protection of engineered safety feature systems which are located inside the Reactor Building are discussed in the sections listed below indicating the design requirements in terms of the time which each must survive the extreme environmental conditions following a loss of coolant accidents or a main steam line break.

The design of these structures, systems, and components meets the requirements of Criterion 4.

For further discussion, see the following sections:

		Section
1.	Meteorology	2.3
2.	Hydrologic Engineering	2.4
3.	Geology, Seismology, and Geotechnical Engineering	2.5
4.	Classification of Structures, Components and Systems	3.2
5.	Wind and Tornado Loadings	3.3
6.	Water Level (Flood) Design	3.4
7.	Missile Protection	3.5
8.	Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping	3.6
9.	Seismic Design	3.7
10.	Design of Category I Structures	3.8
11.	Mechanical Systems and Components	3.9
12.	Seismic Qualification of Seismic Category I Instrumentation and Electrical Equipment	3.10
13.	Environmental Design of Mechanical and Electrical Equipment	3.11
14.	Integrity of Reactor Coolant Pressure Boundary	5.2
15.	Engineered Safety Features	6.0
16.	Instrumentation and Controls	7.0
17.	Electric Power	8.0
18.	Main Steam System	10.3

Criterion 5 - Sharing of Structures, Systems, and Components

Structures, systems, and components important to safety shall not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

Discussion

No evaluation is required since this is a 1 unit installation and there are no shared facilities. This criterion does not apply.

3.1.2.2 Protection by Multiple Fission Product Barriers

Criterion 10 - Reactor Design

The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Discussion

The reactor core and associated coolant, control, and protection systems are designed with adequate margins to:

Preclude significant fuel damage during normal core operation and operational transients (Condition I) (Reference 1) or any transient conditions arising from occurrences of moderate frequency (Condition II) (Reference 1).

Ensure return of the reactor to a safe state following a Condition III (Reference 1) event with only a small fraction of fuel rods damaged although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.

Assure that the core is intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV) (Reference 1).

Chapter 4 discusses the design bases and design evaluation of reactor components including the fuel, reactor vessel internals, and reactivity control systems. Details of the control and protection systems instrumentation design and logic are discussed in Chapter 7. This information supports the accident analyses of Chapter 15 which show that the acceptable fuel design limits are not exceeded for Condition I and II occurrences.

Criterion 11 - Reactor Inherent Protection

The reactor core and associated coolant systems shall be designed so that in the power operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

Discussion

Prompt compensatory reactivity feedback effects are assured when the reactor is critical by the negative fuel temperature effect (Doppler effect) and by the nonpositive operational limit on the moderator temperature coefficient of reactivity. The negative Doppler coefficient of reactivity is

assured by the inherent design using low enrichment fuel; the nonpositive moderator temperature coefficient of reactivity is assured by administratively controlling the dissolved absorber concentration or by burnable poison.

These reactivity coefficients are discussed in Section 4.3.

Criterion 12 - Suppression of Reactor Power Oscillations

The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible, or can be reliably and readily detected and suppressed.

Discussion

Power oscillations of the fundamental mode are inherently eliminated by the negative Doppler and nonpositive moderator temperature coefficients of reactivity.

Oscillations, due to xenon spatial effects, in the radial, diametral, and azimuthal overtone modes are heavily damped due to the inherent design and due to the negative Doppler and nonpositive moderator temperature coefficients of reactivity.

Oscillations, due to xenon spatial effects, in the axial first overtone mode may occur. Assurance that fuel design limits are not exceeded by xenon axial oscillations is provided by reactor trip functions using the measured axial power imbalance as an input.

Oscillations, due to xenon spatial effects, in axial modes higher than the first overtone, are heavily damped due to the inherent design and due to the negative Doppler coefficient of reactivity.

Xenon stability control is discussed in Section 4.3.

Criterion 13 - Instrumentation and Control

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Discussion

Plant instrumentation and control systems are provided to monitor significant variables in the reactor core, Reactor Coolant System, and containment over their anticipated range for all conditions to the extent required. The installed instrumentation provides continuous monitoring, warning, and initiation of safety functions, by the use of instrumentation and control provided.

The following processes are controlled to maintain key variables within their normal ranges:

1. Reactor power level (manual or auto by controlling thermal load).
2. Reactor coolant temperature (manual or auto by rod control cluster assembly (RCCA) motion, in sequential groups).
3. Reactor coolant pressure (manual or auto by heaters and spray in the pressurizer).
4. Reactor coolant water inventory, as indicated by the water level in the pressurizer (manual or auto charging flow).
5. Reactor axial power balance.
6. Reactor Coolant System boron concentration (manual or auto makeup of charging flow).
7. Steam generator water inventory on secondary side (manual or auto feedpump flow through feedwater control valves).

The Reactor Control System is designed to automatically maintain a programmed average temperature in the reactor coolant during steady state operation and to ensure that plant conditions do not reach reactor trip settings, as the result of a transient caused by a load change.

The Reactor Protection System trip setpoints are selected so that anticipated transients do not cause a departure from nucleate boiling ratio (DNBR) of less than the safety limit.

Proper positioning of the control rods is monitored in the control room by bank arrangements of individual meters for each rod cluster control assembly (RCCA). A rod deviation alarm alerts the operator of a deviation of 1 rod cluster control assembly from its bank position. There are also insertion limit monitors with visual and audible annunciation to avoid loss of shutdown margin. Each full length rod cluster control assembly is provided with an indication of positioning at the bottom of its travel. This condition is also alarmed in the control room. Four(4) excore long ion chambers also detect asymmetrical flux distribution indicative of rod misalignment.

Movable incore flux detectors and fixed incore thermocouples are provided as operational aids to the operator. Chapter 7 contains further details on instrumentation and controls. Section 7.5 details the information available to the operator for the performance of required safety functions. Information regarding the Radiation Monitoring System provided to measure environmental activity and alarm high levels is contained in Section 11.4.

Overall reactivity control is achieved by the combination of soluble boron and rod cluster control assemblies. Long term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short term reactivity control for power changes is accomplished by the Reactor Control System which automatically moves rod cluster control assemblies. This system uses input signals including neutron flux, coolant temperature, and turbine load.

These systems are described in Chapters 6, 7, 8, 9, 11 and 12.

Criterion 14 - Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed, fabricated, erected and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

Discussion

The Reactor Coolant System boundary is designed, fabricated and erected to accommodate the system pressures and temperatures attained under all expected modes of plant operation, including all anticipated transients, and to maintain the stresses within applicable stress limits. See Sections 3.9 and 5.2 for details. Reactor Coolant System boundary materials selection and fabrication techniques ensure a low probability of gross rupture or significant leakage.

In addition to the loads imposed on the system under normal operating conditions, consideration is also given to abnormal loading conditions, such as pipe rupture and seismic, as discussed in Sections 3.6 and 3.7, respectively. The system is protected from overpressure by means of pressure relieving devices as required by applicable codes.

Means are provided to detect significant uncontrolled leakage from the reactor coolant pressure boundary with indication in the Control Room. See Section 5.2 for details.

The Reactor Coolant System boundary has provision for inspection, testing and surveillance of critical areas to assess the structural and leaktight integrity. See Section 5.2 for details. For the reactor vessel, a material surveillance program conforming to applicable codes is provided. See Section 5.4 for details.

Criterion 15 - Reactor Coolant System Design

The Reactor Coolant System and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

Discussion

The design pressure and temperature for each component in the reactor coolant and associated auxiliary, control and protection systems are selected to be above the maximum coolant pressure and temperature under all normal and anticipated transient load conditions.

Additionally, Reactor Coolant System boundary components achieve a large margin of safety by the use of proven ASME materials and design codes, use of proven fabrication techniques, nondestructive shop testing and integrated hydrostatic testing of assembled components.

The effect of radiation embrittlement is considered in reactor vessel design and surveillance samples monitor adherence to expected conditions throughout plant life.

Multiple safety and relief valves are provided for the Reactor Coolant System. These valves and their setpoints satisfy ASME criteria for overpressure protection. The ASME criteria are satisfactory based upon a long history of industry use. Chapter 5 discusses the reactor coolant system design.

Transient analyses are included in Reactor Coolant System design which conclude that design conditions are not exceeded during normal operation. Protection and control setpoints are based upon these transient analyses. The design margin includes the effects of thermal lag, coolant transport times, pressure drops, system relief valve characteristics and instrumentation and control response characteristics.

Criterion 16 - Containment Design

Reactor containment and associated systems shall be provided to establish an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

Discussion

A steel lined prestressed concrete reactor building is provided. This structure encloses the entire Reactor Coolant System and is designed to sustain, without loss of required integrity, all effects of gross equipment failures up to and including the simultaneous occurrence of a double ended rupture of the largest pipe in the Reactor Coolant System and the safe shutdown earthquake (SSE). Should such an event occur, the engineered safety features (ESF) serve to cool the reactor core and return the containment to near atmospheric pressure. The containment systems and their associated engineered safety features are designed to ensure the functional capability of preventing the uncontrolled release of radioactive material and that the design conditions important to safety remain inviolate for as long as postulated accident conditions require.

For further discussion, see the following sections:

		Section
1.	Design of Category I Structures	3.8
2.	Engineered Safety Features	6.0

Criterion 17 - Electrical Power Systems

An Onsite Electric Power System and an Offsite Electric Power System shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of

anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electric power from the transmission network to the Onsite Electric Distribution System shall be supplied by 2 physically independent circuits (not necessarily on separate rights-of-way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One (1) of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

Discussion

Onsite and offsite power systems each independently provide the total power requirements to perform the functions required of the safety-related systems. The onsite power required to operate Engineered Safety Features System equipment is supplied by two 100% capacity diesel generators. The offsite power required to operate safety-related systems is supplied by 2 independent sources, one from the 230 kV system and 1 from the 115 kV system. Each source will supply total power requirements for either 1 or both of the redundant and independent power distribution systems for the Engineered Safety Features Systems.

Each Engineered Safety Features power supply bus is normally connected to physically and electrically independent power supplies. Electric power from the transmission network to the substation is provided by a sufficient number of independent lines to minimize the likelihood of simultaneous failure.

Two (2) onsite independent battery systems provide control power for the redundant and independent power distribution systems for Engineered Safety Features Systems as well as control power for the onsite power sources. The reactor protective instrumentation is powered from 4 independent 120 volt nominal ac vital buses which provide uninterrupted power from single phase inverters. Each bus is supplied by its own associated inverter. Each Class 1E battery system supplies power to 2 static inverters.

These systems are designed in accordance with IEEE-308 (Reference 2).

For further discussion, see the following sections:

		Section
1.	General Plant Description	1.2
2.	Seismic Qualification of Seismic Category I Instrumentation and Electrical Equipment	3.10
3.	Environmental Design of Mechanical and Electrical Equipment	3.11
4.	Offsite Power Systems	8.2
5.	Onsite Power Systems	8.3

Criterion 18 - Inspection and Testing of Electric Power Systems

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches and buses, and (2) the operability of the systems as whole and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

Discussion

The ESF power supply buses and associated diesel generators are arranged for periodic, independent testing of each system. These tests, performed periodically in accordance with the Technical Specifications, prove the operability of the Emergency Power Supply System under conditions as close to design as practical, thus permitting assessment of the continuity of the system and condition of the components.

The design of the standby power systems provides testability in accordance with the requirements of Criterion 18.

For further discussion, see the following sections:

		Section
1.	Onsite Power System	8.3
2.	Initial Test Program	14.0
3.	Technical Specifications	

Criterion 19 - Control Room

The Control Room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Equipment at appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

Discussion

Safe occupancy of the Control Room under normal, abnormal, and accident conditions is assured by the design. The Control Room is located in a Seismic Category I structure. Adequate shielding is provided to maintain tolerable radiation levels in the Control Room in the event of a design basis accident. Redundant equipment is provided in the Control Room Ventilation System which permits recirculation of Control Room air through HEPA and charcoal filters. This equipment also permits control room air to be drawn from outside through roughing and HEPA filters and to be discharged outside or for the use of various combinations of outside and recirculated air. Radiation and smoke detectors are provided for the Control Room Ventilation System. Excessive concentrations of any one of these contaminants causes an alarm in the Control Room. High radiation places the Control Room Ventilation System in the emergency filtration mode and causes an alarm in the Control Room.

The Control Room includes the following: substation control panel, electrical relay panels and control panels which contain those instruments and controls necessary for operation of the station functions, such as the reactor and its auxiliary systems, engineered safety features, turbine generator, steam and power conversion systems, station electrical distribution boards, and heating, ventilating and air conditioning systems.

The Control Room is continuously occupied by qualified operating personnel under all operating and accident conditions.

In the unlikely event that occupancy of the Control Room is restricted, a local control room evacuation panel and manual operation of critical components are used to effect cold shutdown from outside the Control Room.

By use of appropriate procedures and equipment, the unit can also be brought to cold shutdown conditions. For this operation, it is assumed that offsite power will be available.

In accordance with the implementation of the alternative source term for the Virgil C. Summer Nuclear Station, the above dose criteria is replaced by the 5 rem total effective dose equivalent

(TEDE) acceptance criterion provided in 10 CFR 50.67(b)(2) for a loss-of-coolant accident (LOCA), main steam line break (MSLB) accident, fuel handling accident (FHA), steam generator tube rupture (SGTR), reactor coolant pump locked rotor accident (RCPLRA) and the control rod ejection accident (CREA).

For further discussion, see the following sections:

		Section
1.	General Plant Description	1.2
2.	Control Room Diffusion Estimates	2.3.4.3
3.	Control Building Design	3.8
4.	Habitability Systems	6.4
5.	Instrument and Controls	7.0
6.	Shutdown from Outside Control Room	7.4
7.	Air Conditioning, Heating, Cooling and Ventilation Systems	9.4
8.	Fire Protection System	9.5.1
9.	Radiation Shielding	12.1
10.	Ventilation	12.2
11.	Control Room Dose	15.4

3.1.2.3 Protection and Reactivity Control Systems

Criterion 20 - Protection System Functions

The protection system shall be designed: (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences; and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

Discussion

A fully automatic protection system with appropriate redundant channels is provided to cope with transients where insufficient time is available for manual corrective action. The design basis for all protection systems is in accordance with the intent of IEEE-279 (Reference 3) and trial use guide IEEE-379 (Reference 4). The Reactor Protection System automatically initiates reactor trip when any variable monitored by the system or combination of monitored variables exceeds the normal operating range. Setpoints are designed to provide an envelope of safe operating

conditions with adequate margin for uncertainties to ensure that fuel design limits are not exceeded.

Reactor trip is initiated by removing power to the rod drive mechanisms of all the full length rod cluster control assemblies. This causes the rods to insert by gravity into the core, rapidly reducing the reactor power. The response and adequacy of the protection system has been verified by analysis of all anticipated transients.

The Engineered Safety Features Actuation System automatically initiates emergency core cooling and other safeguards functions by sensing accident conditions, using redundant analog channels measuring diverse variables. Manual actuation of safeguards may be performed where time is available for operator action but is not relied upon to satisfy this criterion. The Engineered Safety Features Actuation System automatically trips the reactor upon manual or automatic safety injection (S) signal generation. See Section 7.5 and Section 7.1.2.1.5 for additional details.

The response and adequacy of the protection systems are analyzed for all environmental conditions specified by ANS N18.2 (Reference 1), through Condition IV.

Criterion 21 - Protection System Reliability and Testability

The Protection System shall be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the Protection System shall be sufficient to assure that (1) no single failure results in loss of the protection function and (2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The Protection System shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

Discussion

The Protection System is in accordance with IEEE-279 (Reference 3). It provides high functional reliability and adequate independence, redundancy, and testability commensurate with the safety functions of the system. All actuation circuitry is provided with a capability of online testing. This extends to the final actuating device except where operational safety requirements prohibit actual operation of the device; e.g., turbine trip, steam line isolation, etc.

The Reactor Protection System is designed for high functional reliability by providing electrically isolated and physically separated, redundant analog channels and two separate trip logic trains. This assures that no single failure will result in the loss of any protection function. Except for certain defined backup trip functions detailed in Section 7.2, the redundancy and independence provided in the Reactor Protection System allows individual channel test of channels required at power operation to be made during power operation without negating reactor protection or the single failure criterion. This testing will determine failures and losses of redundancy that may have occurred. This arrangement also permits removal of a channel from service while still

maintaining the high reliability of the protection function. Details of the Protection system design and testing provisions are contained in Chapter 7.

There are 2 series connected circuit breakers, 1 breaker for each trip logic train, which supply all power to the full length rod drive mechanisms. A reactor trip train supplies a signal to the undervoltage coil of its respective trip breaker and opening of either train breaker will trip the reactor.

The Engineered Safety Features Actuation System is in accordance with IEEE-279 (Reference 3). It also utilizes redundant analog channels measuring the same parameter and redundant logic trains, either of which will actuate safety injection and/or reactor building spray.

The Engineered Safety Features Actuation System is testable at power with certain exceptions as detailed in Section 7.3. As with the components of the Reactor Protection System, both physical and electrical separation is practiced for the Engineered Safety Features Actuation System to provide a high degree of availability for its safety function.

Criterion 22 - Protection System Independence

The Protection System shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

Discussion

Protection System components are designed and arranged so that the environment accompanying any emergency situation in which the components are required to function does not result in loss of the safety function. Various means are used to accomplish this. Functional diversity has been designed into the system. The extent of this functional diversity has been evaluated for a wide variety of postulated accidents. The general conclusion is that diverse protection functions would automatically terminate an accident before intolerable consequences could occur.

Automatic reactor trips occur as listed in Table 7.2-1.

Regarding the ESF actuation system, a safety injection signal can be obtained manually or by automatic initiation from any one of the following diverse sets of signals:

1. Low pressurizer pressure.
2. High Reactor Building pressure (Hi-1).

For a steam break accident, diversity of safety injection is provided by:

1. Low steam line pressure.
2. High steam line differential pressure.
3. For a steam break inside the Reactor Building, high Reactor Building pressure (Hi-1) provides an additional parameter for generation of the safety injection signal.

All of the above sets of signals are redundant and physically separated and meet the intent of the criterion.

High quality components, suitable derating and applicable quality control, inspection, calibration and tests are utilized to guard against common mode failure. Qualification testing is performed on the components of the various safety systems to demonstrate functional operation at normal and post accident conditions of temperature, humidity, pressure, and radiation for specified periods, if required. Typical protection system equipment is subjected to tests under simulated seismic conditions using conservatively large accelerations and applicable frequencies. The test results indicate no loss of the protection function.

The design criteria for instrumentation are given in Section 7.2 and qualification of the instrumentation is outlined in Sections 3.10 and 3.11.

Criterion 23 - Protection System Failure Modes

The Protection System shall be designed to fall into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

Discussion

The Protection System is designed with due consideration of the most probable failure modes of the components under various perturbations of energy sources and the environment. Each reactor trip channel is designed on the de-energize-to-trip principle so that a loss of power or disconnection of the channel causes that channel to go into its tripped mode. In addition, a loss of power to the full length Rod Cluster Control Assembly drive mechanisms causes the Rod Cluster Control Assembly to insert by gravity into the core. See Section 7.2 for details.

With regard to engineered safety features, should a loss of the preferred offsite power source occur, onsite diesel generators are available to power emergency loads, with the station batteries being used to supply instrumentation power only for that period of time required for the diesel to start. See Section 8.3 for details. A loss of power to one train of safety injection equipment does not affect the ability of the other train to perform its function.

Criterion 24 - Separation of Protection and Control Systems

The Protection System shall be separated from control systems to the extent that failure of a single control system component or channel, or failure or removal from service of any single Protection

System component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired.

Discussion

Protection and control channels in the facility protection systems will be designed in accordance with the IEEE-279 (Reference 3).

The reactor protection system itself is designed to maintain separation between redundant protection channels and protection logic trains. Separation of redundant analog channels originates at the process sensors and continues along the wiring route and through reactor building penetrations to analog protection racks and terminating at the Reactor Protection System logic racks. Isolation of wiring is achieved using separate wireways, cable trays, conduit runs and reactor building penetrations for each redundant channel. Analog equipment is separated by locating components associated with redundant functions in different protection racks. Each redundant protection channel set is energized from a separate ac power feed.

The redundant (2) reactor trip logic trains are physically separated from one another. The Reactor Protection System is comprised of identifiable channels which are physically separated and electrically isolated.

Each trip circuit is designed so that the trip occurs upon de-energization of the circuit; an open circuit or loss of power to a channel will, therefore, result in that channel going into its trip mode. Redundant protection channels are provided to prevent a single failure from defeating a protection function. Redundancy provides reliability and independence of operation. Channel independence is carried throughout the system from the sensor to the logic interface. In some cases, however, it is advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel. As such, a failure in the control circuitry does not adversely affect the protection channel.

The electrical supply and control conductors for redundant or backup circuits have such physical separation as is required to assure that no single credible event will prevent operation of the associated function by reason of electrical conductor damage. Critical circuits and functions include power, control and analog instrumentation associated with the operation of Reactor Protection, Engineered Safety Features, Reactor Shutdown and Residual Heat Removal Systems.

See Sections 7.1 and 8.3 for more details.

Criterion 25 - Protection System Requirements for Reactivity Control Malfunctions

The Protection System shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Discussion

The Protection System is designed to limit reactivity transients so that fuel design limits are not exceeded. Reactor shutdown by full length rod insertion is completely independent of the normal control function since the trip breakers interrupt power to the rod mechanisms regardless of existing control signals. Thus, in the postulated accidental withdrawal, (assumed to be initiated by a control malfunction) flux, temperature, pressure, level and flow signals would be independently generated. Any of these signals (trip demands) would operate the breakers to trip the reactor.

Analyses of the effects of possible malfunctions are discussed in Chapter 15. These analyses show that for postulated dilution during refueling, startup, or manual or automatic operation at power, the operator has ample time to determine the cause of dilution, terminate the source of dilution and initiate reboration before the shutdown margin is lost. The analyses show that acceptable fuel damage limits are not exceeded even in the event of a single malfunction of either system.

Criterion 26 - Reactivity Control System Redundancy and Capability

Two (2) independent reactivity control systems of different design principles shall be provided. One (1) of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One (1) of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Discussion

Two (2) reactivity control systems are provided. These are rod cluster control assemblies (RCCA’s) and chemical shim (boric acid). The rod cluster control assemblies are inserted into the core by the force of gravity.

During operation the shutdown rod banks are fully withdrawn. The full length control rod system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. The shutdown rod banks, along with the full length control banks, are designed to shut down the reactor with adequate margin under conditions of normal operation and anticipated operational occurrences, thereby ensuring that specified fuel design limits are not exceeded. The most restrictive period in core life is assumed in all analyses and the most reactive rod cluster is assumed to be in the fully withdrawn position.

The Boron System will maintain the reactor in the cold shutdown state independent of the position of the control rods and can compensate for all xenon burnout transients.

Details of the construction of the rod cluster control assembly are presented in Chapter 4. Operation is discussed in Chapter 7. The means of controlling the boric acid concentration is

described in Chapter 9. Performance analyses under accident conditions are included in Chapter 15.

Criterion 27 - Combined Reactivity Control Systems Capability

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the Emergency Core Cooling System, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

Discussion

The plant is provided with means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. These means are discussed in detail in Sections 4.3 and 9.3. Combined use of the Rod Cluster Control System and the Chemical Shim Control System permits the necessary shutdown margin to be maintained during long term xenon decay and plant cooldown. The single highest worth control cluster is assumed to be stuck full-out upon trip for this determination.

In the event of a loss of coolant accident, the Safety Injection System is actuated and concentrated boric acid is injected into the cold legs of the Reactor Coolant System. This is in addition to the boric acid content of the accumulators which is passively injected due to a decrease in system pressure. See Section 6.3 for further details.

Criterion 28 - Reactivity Limits

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither: (1) result in damage to the reactor coolant pressure boundary greater than limited local yielding; nor (2) sufficiently disturb the core, its support structures or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

Discussion

The maximum reactivity worth of control rods and the maximum rates of reactivity insertion employing control rods are limited to values that prevent rupture of the Reactor Coolant System boundary or disruptions of the core or vessel internals to a degree that could impair the effectiveness of emergency core cooling.

The maximum positive reactivity insertion rates for the withdrawal of rod cluster control assemblies and the dilution of the boric acid in the reactor coolant system are limited by the physical design characteristics of the rod cluster control assemblies and of the Chemical and Volume Control System. Technical Specifications on shutdown margin and on rod cluster control

assembly insertion limits and bank overlaps as functions of power provide additional assurance that the consequences of the postulated accidents are no more severe than those presented in the analyses of Chapter 15. Reactivity insertion rates, dilution, and withdrawal limits are also discussed in Section 4.3. The capability of the Chemical and Volume Control System to avoid an inadvertent excessive rate of boron dilution is discussed in Section 9.3.

Assurance of core cooling capability following Condition IV accidents, such as rod ejection, steam line break, etc., is obtained by keeping the reactor coolant pressure boundary stresses within faulted condition limits as specified by applicable ASME Codes. Structural deformations are checked also and limited to values that do not jeopardize the operation of necessary safety features.

Criteria 29 - Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

Discussion

The protection and reactivity control systems are designed to assure extremely high reliability in performing their required safety functions in any anticipated operational occurrence. Likely failure modes of system components are designed to be safe modes. Equipment used in these systems is designed, constructed, operated, and maintained with a high level of reliability. Loss of power to the Protection System results in a reactor trip. Details of system design are covered in Chapter 7. Also refer to responses to General Design Criteria 20 through 25.

3.1.2.4 Fluid Systems

Criterion 30 - Quality of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

Discussion

Reactor coolant pressure boundary components are designed, fabricated, inspected and tested in conformance with the ASME Code, Section III. All components are classified in accordance with ANS N18.2 (Reference 1) and are accorded the quality measures appropriate to the classification. The design bases and evaluations of reactor coolant pressure boundary components are discussed in Chapter 5.

Leakage is detected by an increase in the amount of makeup water required to maintain a normal level in the pressurizer. The reactor vessel closure joint is provided with a temperature monitored

leak off between double gaskets. Leakage inside the Reactor Building is drained to the Reactor Building sump where it is monitored.

Leakage is also detected by measuring the airborne activity within the Reactor Building and activity of manual samples of the condensate drained from the Reactor Building and recirculation units. Monitoring the inventory of reactor coolant in the system at the pressurizer, volume control tank and coolant drain collection tanks make available an accurate indication of integrated leakage. The Reactor Coolant Pressure Boundary Leakage Detection System is discussed in Section 5.2.7.

Criterion 31 - Fracture Prevention of Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions: (1) the boundary behaves in a nonbrittle manner; and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining: (1) material properties; (2) the effects of irradiation on material properties; (3) residual, steady-state and transient stresses; and (4) size of flaws.

Discussion

Close control is maintained over material selection and fabrication for the Reactor Coolant System to assure that the boundary behaves in a nonbrittle manner. The Reactor Coolant System materials which are exposed to the coolant are corrosion resistant stainless steel or inconel. The reference temperature (RTNDT) of the reactor vessel structural steel is established by Charpy V-notch and drop weight tests. Materials testing is consistent with the intent of 10 CFR 50, Appendices G and H. These tests ensure the selection of materials with adequate toughness properties and margins.

As part of the reactor vessel specification, certain requirements which are not specified by the applicable ASME Codes are performed as follows:

1. Ultrasonic Testing

In addition to code requirements, the performance of a 100% volumetric ultrasonic test of reactor vessel plate for shear wave and a post hydrostatic test ultrasonic map of welds in the pressure vessel are required. Also, Westinghouse requires cladding bond ultrasonic inspection to more restrictive requirements than Code to preclude interpretation problems during inservice inspection.

2. Radiation Surveillance Program

In the surveillance programs, the evaluation of the radiation damage is based on pre-irradiation and post-irradiation testing of Charpy V-notch and tensile specimens. These programs are directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based

on the reference transition temperature approach and the fracture mechanics approach, and are in accordance with ASTM E-185 (Reference 5), and the requirements of 10 CFR 50, Appendix H.

The fabrication and quality control techniques used in the fabrication of the Reactor Coolant System are equivalent to those used for the reactor vessel. The inspections of reactor vessel, pressurizer, piping, pumps, and steam generators are governed by ASME Code requirements. See Chapter 5 for details.

Heatup and cooldown rates during plant life are predicted using conservative values for the change in ductility transition temperature due to irradiation.

Criterion 32 - Inspection of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed to permit (1) periodic inspection and testing of important areas and features to assess their structural and leaktight integrity, and (2) an appropriate material surveillance program for the reactor pressure vessel.

Discussion

Provision has been made in the Reactor Coolant System design for adequate inspection, testing and surveillance during the service lifetime. Necessary accessibility has been factored into the design. The vessel inspection program will conform to ASTM E-185 (Reference 5). These provisions are discussed in detail in Section 5.2.

Criterion 33 - Reactor Coolant Makeup

A system to supply reactor coolant makeup for protection against small breaks in the reactor coolant pressure boundary shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the reactor coolant pressure boundary and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for Onsite Electric Power System operation (assuming offsite power is not available) and for Offsite Electric Power System operation (assuming onsite power is not available) the system safety function can be accomplished using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation.

Discussion

The Chemical and Volume Control System provides a means of reactor coolant makeup and adjustment of the boric acid concentration. Makeup is added automatically if the level in the volume control tank falls below a preset level. High pressure centrifugal charging pumps are provided which are capable of supplying the required makeup and reactor coolant pump seal injection flow when power is available from either onsite or offsite electric power systems. These pumps also serve as high head safety injection pumps. Details of system design are included in Chapters 6 and 9. Details of the electric power systems are presented in Chapter 8.

Criterion 34 - Residual Heat Removal

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for Onsite Electric Power System operation (assuming offsite power is not available) and for Offsite Electric Power System operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The Residual Heat Removal (RHR) System, in conjunction with the Steam and Power Conversion System, is designed to transfer the fission product decay heat and other residual heat from the reactor core within acceptable limits.

Suitable redundancy is accomplished with the two residual heat removal pumps, located in separate compartments with means available for draining and monitoring of leakage, the 2 heat exchangers and the associated piping, cabling, and electric power source. The residual heat removal system is able to operate on either onsite or offsite electrical power systems.

The Residual Heat Removal System is able to accommodate a single failure (see Section 3.1.3). During the injection phase, no single active failure prevents the accomplishment of Residual Heat Removal System objectives. During the recirculation phase, but not in the injection phase, the Residual Heat Removal System can accommodate one active or passive failure. One active or passive failure in the systems required for long term Residual Heat Removal System operation does not prevent the accomplishment of Residual Heat Removal System objectives.

Details of the system design can be found in Section 5.5.7.

Criterion 35 - Emergency Core Cooling System

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that: (1) fuel and clad damage that could interfere with continued effective core cooling is prevented; and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for Onsite Electric Power System operation (assuming Offsite Power is not available) and for Offsite Electric Power System operation (assuming onsite power is not available), the system safety function can be accomplished, assuming a single failure.

Discussion

An Emergency Core Cooling System (ECCS) is provided to cope with any loss of coolant accident due to a pipe rupture. Abundant cooling water is available to the core at a rate sufficient to maintain the core geometry and to assure that clad metal-water reaction is limited to less than 1%. The design is adequate to ensure performance of the required safety functions assuming a single failure and that electrical power is available from either the Offsite or Onsite Electrical Power System. Details of the capability of the system are discussed in Section 6.3. An evaluation of the adequacy of the system functions is presented in Chapter 15.

Criterion 36 - Inspection of Emergency Core Cooling System

The Emergency Core Cooling System shall be designed to permit appropriate periodic inspection of important components, such as spray rings in the reactor pressure vessel, water injection nozzles, and piping, to assure integrity and capability of the system.

Discussion

Equipment design facilitates access to the critical parts of the reactor vessel internals, injection nozzles, pipes, and valves for visual inspection and for nondestructive inspection where such techniques are desirable and appropriate. The design enables compliance with ASME Code, Section XI requirements.

Components located outside the Reactor Building are accessible for leaktightness inspection during normal operation of the plant.

Details of the inspection program for the reactor vessel internals are included in Section 5.4. Inspection of the Emergency Core Cooling System is discussed in Section 6.3.

Criterion 37 - Testing of Emergency Core Cooling System

The Emergency Core Cooling System shall be designed to permit appropriate periodic pressure and functional testing to assure: (1) the structural and leaktight integrity of its components; (2) the operability and performance of the active components of the system; and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Discussion

Components of the system are accessible for leaktightness inspection during periodic tests.

Active components of the Emergency Core Cooling System may be individually actuated on the normal power source at any time during plant operation to demonstrate operability.

Tests may be performed during shutdown to demonstrate proper automatic operation of the Emergency Core Cooling System.

Active components are identified in Section 3.9.2. Inservice testing is discussed in Section 3.9.4. The details of these tests are included in Section 6.3. Emergency power details are included in Chapter 8.

Criterion 38 - Containment Heat Removal

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss-of-coolant accident and maintain them at acceptably low levels.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for Onsite Electric Power System operation (assuming offsite power is not available) and for Offsite Electric Power System operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

Two systems based on different principles are provided to remove heat from the Reactor Building following an accident to maintain the pressure below the Reactor Building design pressure. The Reactor Building spray and the Reactor Building cooling units are each independently capable of removing sufficient energy to maintain the pressure below the Reactor Building design pressure. Each of these systems consists of redundant components supplied from separate power buses. No single failure can cause a loss of more than half of the installed 200% cooling capacity. These systems are described in Section 6.2.

Criterion 39 - Inspection of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic inspection of important components, such as the torus, sumps, spray nozzles, and piping to assure the integrity and capability of the system.

Discussion

The Reactor Building Heat Removal Systems consist of the Reactor Building Spray System and the Reactor Building Cooling Units. The Reactor Building Cooling Units, the Reactor Building sump and Reactor Building spray pumps, are located so that the visual inspection of these items is possible during normal plant operation. The spray rings and nozzles of the Reactor Building Spray System are located under the dome of the Reactor Building. An air connection is provided on the supply piping to the spray rings for testing the spray nozzles. Functional operability of each nozzle is tested by blowing air or smoke into the spray rings and observing tell-tale devices such as streamers or balloons.

For further discussion, see Section 6.2.2.

Criterion 40 - Testing of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole, and, under conditions as close to the design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

Discussion

The Reactor Building Heat Removal Systems have the capability of being periodically tested as follows:

1. Reactor Building Cooling Units
    a. The Reactor Building cooling units are used during normal operation and can be individually tested for emergency operation.
    b. The cooling coil service water valves can be operated through their full travel.
    c. The service water pumps can be tested for automatic operation.
    d. The service water booster pumps can be tested for automatic operation.
2. Reactor Building Spray System
    a. The operation of the spray pumps can be tested by recirculation to the refueling water storage tank through a test line.
    b. The Reactor Building Spray System valves can be operated through their full travel.

Active components are identified in Section 3.9.2. Inservice testing is discussed in Section 3.9.4. The Reactor Building cooling units and Reactor Building Spray System are discussed in Sections 6.2 and 9.2.

Criterion 41 - Containment Atmosphere Cleanup

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for Onsite

Electric Power System operation (assuming offsite power is not available) and for Offsite Electric Power System operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.

Discussion

The following systems are designed to clean up the reactor building atmosphere after a postulated loss of coolant accident (LOCA):

1. The Reactor Building Spray System sprays a sodium hydroxide (NaOH) solution into the Reactor Building to remove elemental iodine. The power supply consists of 2 independent subsystems each supplied from separate buses. Either subsystem alone can provide the iodine removal capacity for which credit is taken in Chapter 15. No single active failure will cause both subsystems to fail to operate. System design is discussed in Section 6.2.
2. The post accident hydrogen removal system is also designed with redundancy of vital components so that a single active failure will not prevent timely operation of the system. This system is described in Section 6.2.5.
3. The recirculation system HEPA filters are capable of filtering the full post loss of coolant accident recirculation air flow for which credit is taken in Chapter 15. This system is discussed in Sections 6.2.2 and 6.5.1.

Criterion 42 - Inspection of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic inspection of important components, such as filter frames, ducts, and piping to assure the integrity and capability of the systems.

Discussion

The Reactor Building atmosphere cleanup systems, with the exception of the spray headers and nozzles, are designed and located such that they can be inspected periodically as required. The spray headers and nozzles can be air tested as described in the discussion of Criterion 39.

Criterion 43 - Testing of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the systems such as fans, filters, dampers, pumps, and valves, and (3) the operability of the systems as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.

Discussion

The Reactor Building Atmosphere Cleanup System can be tested as follows:

1. Reactor Building Spray System
   a. The operation of the spray pumps can be tested by recirculation of borated refueling water to the refueling water storage tank through a test line.
   b. The system valves can be operated through their full travel.
   c. The system is checked for leaktightness during testing.
2. Post Accident Hydrogen Removal System
   a. The post accident hydrogen recombiners are periodically tested to verify operation of the control system and functional performance of the heaters at the required temperature level. These tests are performed during normal plant operation from the recombiner control panels.
   b. The alternate purge line can be operated to test the full operational sequence.
3. Reactor Building Cooling Unit HEPA Filters
   a. The operation of the HEPA filter bypass dampers can be functionally tested.
   b. The HEPA filters are tested for through leakage during system testing.

Identification of active components is presented in Section 3.9.2. A further discussion of inservice testing is provided in Section 3.9.4.

Criterion 44 - Cooling Water

A system to transfer heat from structures, systems, and components important to safety, to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for Onsite Electric Power System operation (assuming offsite power is not available) and for Offsite Electric Power System operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Discussion

The systems provided to transfer heat from items important to safety to the service water pond consist of systems identified as: Service Water, Component Cooling Water and Chilled Water.

Redundancy is provided by the creation of the Seismic Category I service water pond which functions as the ultimate heat sink in the unlikely event of main dam failure, by the installation of

three 100% capacity pumps and by the provision of features of redundancy and isolation capability.

The cooling water systems provided to transfer heat produced under operating and accident conditions from the plant to the environment are as follows: service water pond, Service Water System, Chilled Water System, and Component Cooling Water System. The service water pond is the ultimate heat sink. The Service Water System transfers heat from the component cooling heat exchangers to the service water pond. The Component Cooling Water System and the Chilled Water System are intermediate, closed cycle cooling systems. The Component Cooling Water System is used to isolate service water (water from the service water pond) from normally radioactive streams that initially carry heat to be rejected to the environment.

The service water pond is an impounded portion of Monticello Reservoir and is enclosed by dams designed to withstand the effects of the SSE and by natural features. For additional details, see Sections 2.4 and 9.2.

The Service Water System, Component Cooling Water System and Chilled Water System have 2 independent subsystems supplied with electric power from separate buses. These subsystems are operable from either Offsite or Onsite (emergency diesel generators) Electric Power Systems. Therefore, for each system, the subsystems are totally redundant and the availability of the minimum engineered safety features requirements is ensured assuming a single failure.

Criterion 45 - Inspection of Cooling Water System

The Cooling Water System shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

Discussion

Important Cooling Water System components are accessible for required periodic inspection. These components have suitable manholes, handholes or inspection ports to allow for periodic inspection.

Criterion 46 - Testing of Cooling Water System

The Cooling Water System shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and the performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for loss-of-coolant accidents, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.

Discussion

Redundancy and isolation are provided to allow periodic pressure and functional testing of the systems as a whole, including the functional sequence that initiates system operation, and also including transfer between the normal and diesel power sources. At least one of the redundant systems is in service during normal operation.

Identification of active components is presented in Section 3.9.3. A further discussion of inservice testing is provided in Section 3.9.4.

3.1.2.5 Reactor Containment

Criterion 50 - Containment Design Basis

The reactor containment structure, including access openings, penetrations and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any loss-of-coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

Discussion

The design of the Reactor Building is based upon the containment design basis accident which assumes the double ended rupture of a main steam line inside the Reactor Building and the worst single active failure. The maximum pressure and temperature determined for the design basis accident are 53 psig and 372.7°F. The super heated temperatures within the Reactor Building are limited in magnitude and duration via closure of the main steam isolation valves and spray actuation. Following spray actuation, the Reactor Building remains saturated in the long term and below the Reactor Building design temperature of 283°F. The pressure differential between 53 psig and the reactor building design pressure of 57 psig, and the long term temperature of less than 283°F, provide ample margin to allow for increase energy sources as the result of degraded performance of emergency core cooling systems.

For further discussion, see the following sections:

		Section
1.	Classification of Structures, Components and Systems	3.2
2.	Wind Design Criteria	3.3
3.	Missile Protection Criteria	3.5
4.	Criteria for Protection Against Dynamic Effects Associated with a Loss of Coolant Accident	3.6
5.	Seismic Design	3.7
6.	Design of Reactor Building	3.8
7.	Containment Functional Design	6.2.1
8.	Reactor Building Heat Removal System	6.2.2
9.	Accident Analyses	15.0

Criterion 51 - Fracture Prevention of Containment Pressure Boundary

The reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions (1) its ferritic materials behave in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions, and the uncertainties in determining (1) material properties, (2) residual, steady state, and transient stresses, and (3) size of flaws.

Discussion

The Reactor Building liner material has a maximum nil ductility transition temperature of at least 300°F below the minimum service temperature.

Ferritic materials exposed to the external environment have been selected so that their temperatures under normal operating and testing conditions are 30°F or more above nil ductility transition temperature (see Section 3.8).

Criterion 52 - Capability for Containment Leakage Rate Testing

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

Discussion

The Containment System is designed and constructed and the necessary equipment is provided to permit periodic integrated leak rate tests during the plant lifetime. The testing program satisfies the requirements of Appendix J to 10 CFR 50.

The provisions for testing and the test program satisfy the requirements of Criterion 52.

For further discussion, see the following sections:

		Section
1.	Concrete Reactor Building (Equipment Hatch and Personnel Airlocks)	3.8.1
2.	Containment Functional Design	6.2.1
3.	Containment Leakage Testing	6.2.6
4.	Technical Specifications	16.0

Criterion 53 - Provisions for Containment Testing and Inspection

The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important areas, such as penetrations, (2) an appropriate surveillance program, and (3) periodic testing at containment design pressure of the leaktightness of penetrations which have resilient seals and expansion bellows.

Discussion

The program defining, and the means for performing, individual leakage rate tests on applicable penetrations in accordance with Appendix J to 10 CFR 50 are presented in Section 6.2.6. The program defining the lifetime inservice tendon surveillance is presented in Chapter 18. This program provides physical evidence that the structural integrity of the Reactor Building has been maintained.

The provisions made for penetration testing satisfy the requirements of Criterion 53.

For further information, see the following sections:

		Section
1.	Containment Functional Design	6.2.1
2.	Containment Leakage Testing	6.2.6
3.	Technical Specifications	

Criterion 54 - Piping Systems Penetrating Containment

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Discussion

The required isolation and testing capabilities are provided in all piping systems penetrating containment. Test connections are provided as required to enable periodic leak rate determination for individual valves and other isolation barriers. Means are provided for demonstrating the operability of remotely operated isolation valves or other isolation barriers. The Engineered Safety Features Actuation System test circuitry provides the means for testing isolation valve operability. This is discussed in Section 6.2.

For further discussion, see the following sections:

		Section
1.	Containment Functional Design	6.2.1
2.	Containment Isolation Systems	6.2.4
3.	Containment Leakage Testing	6.2.6

Criterion 55 - Reactor Coolant Pressure Boundary Penetrating Containment

Each line that is part of the reactor coolant pressure boundary and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

1. One locked closed isolation valve inside and one locked closed isolation valve outside containment, or
2. One automatic isolation valve inside and one locked closed isolation valve outside containment, or
3. One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment, or
4. One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as high quality in design, fabrication, and testing, additional provisions for inservice inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

Discussion

The boundary for the Reactor Coolant System is defined in accordance with Section 4 of ANS N18.2 (Reference 1). The entire Reactor Coolant System as defined above, is located within the Reactor Building. Thus, this criterion does not apply to Westinghouse pressurized water reactors. However, the specific valving arrangements specified in Criterion 55 have been adhered to in the design of this plant with the specific exceptions listed and justified in Chapter 6.

Criterion 56 - Primary Containment Isolation

Each line that connects directly to the containment atmosphere and penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

1. One locked closed isolation valve inside and one locked closed isolation valve outside containment, or
2. One automatic isolation valve inside and one locked closed isolation valve outside containment, or
3. One locked closed isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment, or
4. One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to the containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Discussion

Each line that connects directly to the Reactor Building atmosphere and penetrates containment is provided with containment isolation valves, except where it can be demonstrated that the

containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable. Details are provided in Sections 5.5 and 6.2 and on the flow diagrams included in Chapters 6 and 9.

Criterion 57 - Closed System Isolation Valves

Each line that penetrates primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. This valve shall be outside the containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

Discussion

Each line that penetrates containment and is not connected directly to the Reactor Building atmosphere and is not part of the reactor coolant pressure boundary has at least one isolation valve located outside containment near the penetration or is a closed system outside containment. Details are provided in Sections 5.5 and 6.2 and in the flow diagrams included in Chapters 6 and 9.

3.1.2.6 Fuel and Radioactivity Control

Criterion 60 - Control of Release of Radioactive Materials to the Environment

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

Discussion

Waste handling systems have been incorporated in the plant design for retention and/or processing of radioactive wastes resulting from normal operation. Controls and monitoring are provided to ensure that Appendix I to 10 CFR 50 is satisfied. The plant is also designed such that radioactive releases during accidents will not exceed the limits of 10 CFR 100.11 or 10 CFR 50.67.

Chapter 11 describes the Radioactive Waste Processing System, design criteria, and amounts of estimated releases of radioactive effluents to the environment. Chapter 5 and Sections 6.2, 12.1 and 12.2 describe the containment system which forms a barrier to the escape of fission products should a loss of coolant occur. Chapter 6 describes the engineered safety features for control of reactivity and Reactor Building pressure.

Criterion 61 - Fuel Storage and Handling and Radioactivity Control

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit appropriate periodic inspection and testing of components important to safety, (2) with suitable shielding for radiation protection, (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

Discussion

The Spent Fuel Cooling System, Fuel Handling System, Radioactive Waste Processing Systems and other systems that contain radioactivity are designed to assure adequate safety under normal and postulated accident conditions.

1. Components are designed and located such that appropriate periodic inspection and testing may be performed.
2. All areas of the plant are designed with suitable shielding for radiation protection based on anticipated radiation dose rates and occupancy as discussed in Section 12.1.
3. Individual components which contain significant radioactivity are located in confined areas which are adequately ventilated through appropriate filtering systems or are vented to the Gaseous Waste Processing System. Details of the ventilation systems are presented in Section 9.4.
4. The Spent Fuel Cooling System provides cooling to remove residual heat from the fuel stored in the spent fuel pool. The system is designed with redundancy and testability to assure continued heat removal. The Spent Fuel Cooling System is described in Section 9.1.3.
5. The spent fuel pool is designed such that no postulated accident could cause excessive loss of coolant inventory.

Criterion 62 - Prevention of Criticality in Fuel Storage and Handling

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

Discussion

Criticality in new and spent fuel storage areas is prevented by physical separation of fuel assemblies and the presence of borated water in the spent fuel pool. The fuel storage racks are constructed so that fuel assemblies may be inserted in prescribed locations only. These have a minimum center to center spacing in both directions to ensure subcriticality even if assemblies are immersed in unborated water. Criticality prevention and criticality considerations are discussed in Sections 9.1 and 4.3, respectively.

Criterion 63 - Monitoring Fuel and Waste Storage

Appropriate systems shall be provided in fuel storage and radioactive waste systems and associated handling areas: (1) to detect conditions that may result in loss of residual heat removal capability and excessive radiation levels; and (2) to initiate appropriate safety actions.

Discussion

Monitoring systems are provided to cause alarms when excessive temperature or low water level occurs in the spent fuel pool. Appropriate safety actions are initiated by operator action as outlined in Section 9.1.3.

Radiation monitors and alarms are provided as required to warn personnel of impending excessive levels of radiation or airborne activity. The radiation monitoring system is described in Sections 11.4, 12.1.4, and 12.2.4.

Criterion 64 - Monitoring Radioactivity Releases

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss-of-coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Discussion

The Reactor Building atmosphere is continually monitored during normal and transient plant operations, using the Reactor Building particulate, gaseous, and iodine radiation monitors. Under accident conditions, when temperature and pressure permit, samples of the Reactor Building atmosphere can be obtained to provide data on existing airborne radioactivity concentrations within the Reactor Building. In addition, a Reactor Building high range area gamma monitor is used to monitor the potential gamma radiation dose which may result from the postulated accident. Radioactivity levels contained in the plant effluent discharge paths and in the environs are monitored during normal and accident conditions by the plant radiation monitoring system, described in Sections 11.4 and 12.2.4, and the health physics program described in Section 12.3.

3.1.3 Single Failure Criterion

The Engineered Safety Features systems are designed to tolerate a single failure (see General Design Criteria 34 and 35) during the period of recovery following an incident without loss of their protective function.

During the short term immediately following the incident, this single failure is limited to a failure of an active component to complete its function as required. Should the failure occur during the long term rather than the short term period following the incident, the failure definition is expanded such that the systems designs will tolerate either an active failure or a passive failure without loss of their protective function.

3.1.3.1 Definitions

1. Engineered Safety Features

   Engineered safety features are provided for sensing the incident occurrence, initiating protective action and completing the necessary protective function to remain within NRC specified criteria for radioactivity release from the plant site.

   The engineered safety features are as follows:

   a. The containment
   b. The Reactor Building Heat Removal Systems (Reactor Building Spray System and Reactor Building Cooling Units)
   c. The Reactor Building Air Purification and Cleanup Systems
   d. The Containment Isolation System
   e. The Combustible Gas Control System
   f. The Emergency Core Cooling System
   g. Habitability systems
   h. Fission Product Removal and Control Systems

Engineered Safety Features Support Systems include Component Cooling, Service Water, Chilled Water, related heating, ventilating and cooling equipment, and electric power supply associated with the required fluid or steam system. Compressed air is not required. For systems failure analysis, the effect of a single failure is considered on the total of the engineered safety features and the related service system required for reactor protection following the incident. As an example, if the Emergency Core Cooling System is required and a diesel generator failure is postulated, that would be the active failure for which the consequences are analyzed. The consequences would include other failures specifically caused by the diesel failure. No further active or passive failures of the systems are considered either for the short or long term.

2. Period of Recovery

   The period of recovery is the time necessary to bring the plant to cold shutdown and regain access to faulted equipment. The recovery period is the sum of the short and long term periods defined below.

3. Incident

   An incident is any natural or accidental event of infrequent occurrence and the related consequences which affect plant operation and require the use of Engineered Safety Features systems. Such events, which are analyzed independently, are not assumed to occur simultaneously and include loss of coolant accident, steam line ruptures, steam generator tube ruptures, etc. Loss of offsite power may be an isolated occurrence or may be concurrent with any event requiring Engineered Safety Features systems use.

4. Short Term

   The short term is the time immediately following the incident during which automatic actions are performed, system responses are checked, type of incident is identified and preparations for long term recovery operation are made. In the event of a loss of coolant accident, the period of the injection mode of operation during Emergency Core Cooling System operation is the basis for the short term period.

5. Long Term

   The long term is the remainder of the recovery period following the short term. In comparison with the short term, where the main concern is to remain within NRC specified site criteria, the long term period of operation involves bringing the plant to cold shutdown conditions where access to the Reactor Building can be gained and repair effected.

6. Active Failure

   The failure of a powered component, such as a piece of mechanical equipment, component of the Electrical Supply System or instrumentation and control equipment, to act on command to perform its design function constitutes an active failure. Examples include failure of a valve to move to its correct position, failure of an electrical circuit breaker or relay to respond, failure of a pump, fan or diesel generator to start, etc.

   Consideration of equipment moving spuriously from the proper safeguards position, such as a motor operated valve inadvertently shutting, is specifically excluded.

7. Passive Failure

   The structural failure of a static component which limits the effectiveness of that component in carrying out its design function constitutes a passive failure. When applied to a fluid system, this means a break in the pressure boundary resulting in abnormal leakage not exceeding 50 gpm. Such leak rates are consistent with limited cracks in pipes, sprung flanges, valve packing leaks or pump seal failures.

3.1.4 References

1. American Nuclear Society, *Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants*, ANS N18.2, as discussed in Appendix 3A, Regulatory Guide 1.26.
2. Institute of Electrical and Electronics Engineers, *Criteria for Class 1E Electric Systems for Nuclear Power Generating Systems*, IEEE-308-1971.
3. Institute of Electrical and Electronics Engineers, *IEEE Criteria for Nuclear Power Plant Generating Station Protection Systems*, IEEE-279-1971.
4. Institute of Electrical and Electronics Engineers, *Trial Use Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection System*s, IEEE-379-1972.
5. American Society for Testing and Materials, *Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels*, ASTM E-185, 1970.

3.2 CLASSIFICATION OF STRUCTURES, COMPONENTS, AND SYSTEMS

Certain structures, components and systems of a nuclear plant are considered important to safety because they perform safety functions required to avoid or mitigate the consequences of abnormal operational transients or accidents. This section discusses the classification of structures, components and systems according to the importance of the safety function they perform. In addition, design requirements are placed upon such equipment to ensure the proper performance of safety actions, when required.

3.2.1 Seismic Classification

Structures, components and systems are designated as Safety Class 1, 2a, 2b, 3 or Non-Nuclear Safety (NNS); Class 1E and/or Seismic Category I. These items are listed in Tables 3.2-1, 3.2-2, and 3.10-1. The Seismic Category I structures are designed to withstand the effects of the safe shutdown earthquake (SSE). The design of safety class structures, components and systems to resist the earthquake and other loads is based upon levels of material stress or load factors, as applicable. Such design yields margins of safety appropriate for the earthquake. The margin of safety provided for safety class structures, components and systems with respect to the SSE ensures that safety functions are not jeopardized.

Additionally, some components, the function of which does not require designation as safety class, but the failure of which under seismic conditions might be unacceptable, have been considered with regard to Seismic Category I requirements.

The designation of structures, components and systems as Seismic Category I is in conformance with the recommendations of Regulatory Guide 1.29 (see Appendix 3A) for balance of plant. Nuclear Steam Supply System fluid system components important to safety are classified in accordance with the August 1970 Draft of ANSI N18.2, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants”, except that components of the accumulator subsystem are classified in accordance with the 1973 version of N18.2, as finally accepted by ANSI, and components of the Liquid and Gaseous Waste Processing Systems and the Boron Recycle System are classified in accordance with Regulatory Guide 1.143.

3.2.2 System Quality Group Classifications

3.2.2.1 Mechanical Components

Mechanical components are classified as Safety Class 1, 2a, 2b, or 3, in accordance with their importance to nuclear safety. This importance, as established by class assignment, is considered in design, materials, manufacture or fabrication, assembly, erection, construction and operation.

These safety classes are in conformance with ANS N18.2. This classification system differs from the system of Quality Group Classification defined in Regulatory Guide 1.26 (see Appendix 3A), but meets the intent of Regulatory Guides 1.26 and 1.143.

Safety classes are defined as follows:

1. Safety Class 1

   Safety Class 1 (SC-1) applies to Reactor Coolant System components, the failure of which could cause a Condition III or Condition IV loss of reactor coolant as defined by ANS N18.2.

2. Safety Class 2

   Safety Class 2 (SC-2) applies to those components of safety systems required to fulfill a system function. Safety Class 2 is subdivided into Safety Class 2a and Safety Class 2b. A safety system (in this context) is any system that functions to shutdown the reactor, cool the core, cool another safety system or the containment and contains, controls or reduces radioactivity released in an accident.

   a. Safety Class 2a

      Safety Class 2a (SC-2a) applies to containment and to components of those safety systems, or portions thereof, through which reactor coolant water flows directly from the Reactor Coolant System or the Reactor Building recirculation sumps.

   b. Safety Class 2b

      Safety Class 2b (SC-2b) applies to all other components of Safety Class 2.

3. Safety Class 3

   Safety Class 3 (SC-3) applies to components not classified as Safety Class 1 or Safety Class 2 and:

   a. The failure of which would result in the release to the environment of radioactive gases normally required to be held for decay *,

   b. That provide or support any safety system function,

      * The Liquid and Gaseous Waste Processing Systems and the Boron Recycle System are designated non-nuclear safety consistent with Regulatory Guide 1.143.

   c. That control airborne radioactivity released outside the reactor containment, or

   d. That remove decay heat from spent fuel.

4. Non-Nuclear Safety

   Those structures, components and systems which do not fall into the above safety class categories are designated as Non-Nuclear Safety (NNS).

3.2.2.2 Electrical Components

Electrical components are classified as either Class 1E, as defined in IEEE-380 (Reference 1), or as NNS.

3.2.2.3 Structures

Structures are classified as Seismic Category I or non seismic category.

3.2.3 Quality Assurance Classification

All structures, components and systems classified as Seismic Category I, including all safety class items, are Quality Assurance Class 1.

3.2.4 Correlation of Safety Classes With Industry Codes

Table 3.2-3 provides a correlation between safety class and industry codes and standards applicable to mechanical components.

3.2.5 Equipment and Structure Lists

Table 3.2-1 provides a listing of major mechanical components and indicates the safety class, code class, seismic category and quality assurance class of each. Table 3.2-2 provides a listing of structures and indicates the classification of each. Table 3.10-1 provides a listing of Seismic Category I electrical components.

3.2.6 References

1. Institute of Electrical and Electronics Engineers, *Definitions of Terms Used in IEEE Standards on Nuclear Power Generating Stations*, IEEE-380-1975.

Table 3.2-1
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
MECHANICAL COMPONENTS (by system)							
REACTOR COOLANT SYSTEM							
Reactor Vessel	NSSS	1	ASME III	1	Y	1	1
Full Length CRDM Housing (48)	NSSS	1	ASME III	1	Y	1	2
Reactor Coolant Pump Assemblies (3)	NSSS	1	ASME III	1	Y	1	-
Reactor Coolant Pump Casings (3)	NSSS	1	ASME III	1	Y	1	2
Reactor Coolant Pump Internals (3)	NSSS	1	ASME III	1	Y	1	2
Reactor Coolant Pump Motors (3)	NSSS	2b	NEMA 20	-	Y	1	2
Steam Generator, tube side (3)	NSSS	1	ASME III	1	Y	1	2
Steam Generator, shell side (3)	NSSS	2a	ASME III	1	Y	1	2,3
Pressurizer	NSSS	1	ASME III	1	Y	1	2
Reactor Coolant Thermowell	NSSS	1	ASME III	1	Y	1	4
Reactor Coolant Piping and Fittings	NSSS	1	ASME III	1	Y	1	1,5
Surge Pipe and Fittings	NSSS	1	ASME III	1	Y	1	1
Relief Valves (3), Safety Valves (3), Block Valves (3)	NSSS	1	ASME III	1	Y	1	1
Valves to Reactor Coolant System Boundary	NSSS/BOP	1	ASME III	1	Y	1	6

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Piping to Reactor Coolant System Boundary	NSSS/BOP	1	ASME III ANSI B31.1	1	Y	1	5, 6, 29
Pressurizer Relief Tank (PRT)	NSSS	NNS	ASME VIII	-	N	-	-
Fuel Assemblies	NSSS	NA	-	-	Y	1	-
CETNA Assembly	NSSS	1	ASME III	1	Y	1	42
CHEMICAL AND VOLUME CONTROL SYSTEM							
Regenerative Heat Exchanger	NSSS	2a	ASME III	2	Y	1	1
Letdown Heat Exchanger, tube side	NSSS	2a	ASME III	2	Y	1	1
Letdown Heat Exchanger, shell side	NSSS	2b	ASME III	3	Y	1	1, 7
Mixed Bed Demineralizers (2)	NSSS	3	ASME III	3	Y	1	4
Cation Bed Demineralizer	NSSS	3	ASME III	3	Y	1	4
Reactor Coolant Filter	NSSS	2a	ASME III	2	Y	1	1
Volume Control Tank	NSSS	2a	ASME III	2	Y	1	1
Charging Pumps, centrifugal (3)	NSSS	2a	ASME III	2	Y	1	1, 7, 8a, 8c, 8d
Seal Water Injection Filters (2)	NSSS	2a	ASME III	2	Y	1	1
Letdown Orifices (3)	NSSS	2a	ASME III	2	Y	1	4
Excess Letdown Heat Exchanger, tube side	NSSS	2a	ASME III	2	Y	1	1
Excess Letdown Heat Exchanger, shell side	NSSS	2b	ASME III	3	Y	1	1

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Seal Water Return Filter	NSSS	2a	ASME III	2	Y	1	1
Seal Water Heat Exchanger tube side	NSSS	2a	ASME III	2	Y	1	1
Seal Water Heat Exchanger, shell side	NSSS	2b	ASME III	3	Y	1	1, 7
Boric Acid Tanks (2)	BOP	2b	ASME III	3	Y	1	9
Boric Acid Filter	NSSS	2b	ASME III	3	Y	1	4
Boric Acid Transfer Pumps (2)	NSSS	2b	ASME III	3	Y	1	1, 8b
Boric Acid Transfer Pump Bypass Orifices (2)	BOP	2b	ASME III	3	Y	1	-
Boric Acid Blender	NSSS	2b	ASME III	3	Y	1	1
Resin Fill Tank	BOP	NNS	ASME VIII	-	N	-	9
Boric Acid Batching Tank	NSSS	NNS	ASME VIII	-	N	-	9
Boric Acid Batching Tank Agitator	NSSS	NNS	-	-	N	-	-
Alternate Seal Injection Pump (1)	NSSS	2a	ASME III	2	Y	-	39
Chemical Mixing Tank	NSSS	NNS	ASME VIII	-	N	-	6, 9
Chemical Mixing Tank Orifice	BOP	NNS	No Code	-	N	-	-
Reactor Coolant Pump Seal Bypass Orifices (3)	NSSS	2a	ASME III	2	Y	1	4
Chemical and Volume Control System Piping	BOP	2a	ASME III	1,2	Y	1	5

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Chemical and Volume Control System Valves	NSSS/BOP	2a/2b/3	ASME III	2,3	Y	1	1, 2, 4, 5, 10
BORON THERMAL REGENERATION SYSTEM							
Moderating Heat Exchanger, tube side	NSSS	3	3	ASME III	3	Y	4
Moderating Heat Exchanger, shell side	NSSS	3	ASME III	3	Y	1	4
Letdown Chiller Heat Exchanger, tube side	NSSS	3	3	ASME III	3	Y	4
Letdown Chiller Heat Exchanger, shell side	NSSS	NNS	NNS	ASME VIII	-	N	-
Letdown Reheat Heat Exchanger, tube side	NSSS	2a	2a	ASME III	2	Y	1
Letdown Reheat Heat Exchanger, shell side	NSSS	3	3	ASME III	3	Y	1
Thermal Regeneration Demineralizers (4)	NSSS	3	3	ASME III	3	Y	4
Boron Thermal Regeneration Chiller	NSSS	NNS	NNS	ASME VIII	-	N	7
Boron Thermal Regeneration Chiller Surge Tank	NSSS	NNS	NNS	ASME VIII	-	N	6
Boron Thermal Regeneration Chiller Pumps (2)	NSSS	NNS	No Code	-	N	-	-
Boron Thermal Regeneration System Piping	BOP	3	ASME III	3	Y	1	5
Boron Thermal Regeneration System Valves	NSSS/BOP	3	ASME III	3	Y	1	4. 5

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
BORON RECYCLE SYSTEM							
Recycle Holdup Tanks (2)	BOP	NNS	ASME III	3	Y	1	31, 35
Recycle Evaporator Feed Pumps (2)	NSSS	NNS	ASME III	3	Y	1	1, 31
Recycle Evaporator Feed Demineralizers (2)	NSSS	NNS	ASME III	3	Y	1	4, 31
Reactor Grade Water System Demineralizers (3)	BOP	NNS	ASME VIII	-	N	-	-
Recycle Evaporator Feed Filter	NSSS	NNS	ASME III	3	Y	1	4,31
Recycle Holdup Tank Vent Ejector	BOP	NNS	ASME III	3	Y	1	31,35
Recycle Evaporator **–No Longer In Service–**	NSSS	NNS	ASME III	3	Y	1	4,7,31
Recycle Evaporator Concentrates Sample Cooler**–No Longer In Service–**	BOP	2b	ASME III	3	N	-	7
Recycle Evaporator Pumps and Valves	NSSS	NNS	ANSI B31.1 / ASME III	-/3	N/Y	1	4,7,31
Recycle Evaporator Piping**–No Longer In Service–**	NSSS	NNS	ANSI B31.1 / ASME III	-/3	N/Y	1	4,7,31
Recycle Evaporator Condensate Demineralizer	NSSS	NNS	ASME VIII	-	N	-	-
Recycle Evaporator Condensate Filter	NSSS	NNS	ASME VIII	-	N	-	-
Recycle Evaporator Concentrate Filter	NSSS	NNS	ASME VIII	-	N	-	-
Recycle Evaporator Reagent Tank	NSSS	NNS	ASME VIII	-	N	-	6

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Sample Vessel (2)	BOP	NNS	ASME VIII	-	N	-	
Boron Recycle System Piping	BOP	NNS	ANSI B31.1 / ASME III	-/3	N/Y	1	5,31,35
Boron Recycle System Valves	NSSS/BOP	NNS	ANSI B31.1 / ASME III	-/3	N/Y	1	4,5,31
SAFETY INJECTION SYSTEM							
Accumulators (3)	NSSS	2a	ASME III	2	Y	1	1
Protective Chambers on Recirculation Sump Isolation Valves	BOP	2a	ASME III	MC	Y	1	-
Hydrostatic Test Pump	NSSS	NNS	-	-	N	-	-
Safety Injection System Piping	BOP	2a	ASME III	2	Y	1	5
Safety Injection System Valves	NSSS/BOP	2a	ASME III	2	Y	1	4,5
RESIDUAL HEAT REMOVAL SYSTEM							
Residual Heat Removal Low Head Safety Injection Pumps (2)	NSSS	2a	ASME III	2	Y	1	1,7,8a,8c
Residual Heat Exchangers, tube side (2)	NSSS	2a	ASME III	2	Y	1	1,c
Residual Heat Exchangers, shell side (2)	NSSS	2b	ASME III	3	Y	1	1
Residual Heat Removal System Piping	BOP	2a	ASME III	2	Y	1	5
Residual Heat Removal System Valves	NSSS/BOP	2a	ASME III	2	Y	1	1,5

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
LIQUID WASTE PROCESSING SYSTEM							
Reactor Coolant Drain Tank	NSSS	NNS	ASME VIII	-	N	-	31
Reactor Coolant Drain Tank Pumps (2)	NSSS	NNS	ASME III	3	N	-	31
Reactor Coolant Drain Tank Heat Exchanger, tube side	NSSS	NNS	ASME VIII	-	N	-	31
Reactor Coolant Drain Tank Heat Exchanger, shell side	NSSS	2b	ASME III	3	Y	1	1,31
Waste Holdup Tank	NSSS	NNS	ASME III	3	Y	1	4,31
Waste Evaporator Feed Pump	NSSS	NNS	ASME III	3	Y	1	4,31
Waste Evaporator Feed Filter – **No Longer In Service**							
Waste Evaporator – **No Longer In Service**							
Waste Evaporator Concentrates Sample Cooler	BOP	2b	ASME III	3	N	-	7
Waste Evaporator Pumps and Valves	NSSS	NNS	ANSI B31.1 / ASME III	-/3	N/Y	1	4,31
Waste Evaporator Piping	NSSS	NNS	ANSI B31.1 / ASME III	-/3	N/Y	1	4,31,35
Waste Evaporator Condensate Demineralizer	NSSS	NNS	ASME VIII	-	N	-	31
Waste Evaporator Condensate Filter	NSSS	NNS	ASME VIII	-	N	-	31
Duratek Demineralizers	BOP	NNS	ASME VIII	-	N	-	-

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Waste Evaporator Condensate Tank	NSSS	NNS	ASME VIII	-	N	-	31
Waste Evaporator Condensate Tank Pump	NSSS	NNS	ASME III	3	N	-	31
Chemical Drain Tank	NSSS	NNS	ASME VIII	-	N	-	6,31
Chemical Drain Tank Pump	NSSS	NNS	ASME III	3	N	-	31
Spent Resin Storage Tank	NSSS	NNS	ASME III	3	Y	1	4,31
Spent Resin Sluice Pump	NSSS	NNS	ASME III	3	Y	1	4,31
Spent Resin Sluice Filter	NSSS	NNS	ASME III	3	Y	1	4,31
Laundry and Hot Shower Tank	NSSS	NNS	ASME VIII	-	N	-	9,31
Laundry and Hot Shower Tank Pump	NSSS	NNS	ASME III	3	N	-	11,31
Laundry and Hot Shower Tank Strainer	NSSS	NNS	ASME VIII	-	N	-	31
Laundry and Hot Shower Tank Filter	NSSS	NNS	ASME VIII	-	N	-	6,31
Floor Drain Tank	NSSS	NNS	ASME VIII	-	N	-	9,31
Floor Drain Tank Filter	NSSS	NNS	ASME VIII	-	N	-	31
Floor Drain Tank Strainer	NSSS	NNS	No Code	-	N	-	6,31
Floor Drain Tank Pump	NSSS	NNS	No Code	-	N	-	31
Waste Monitor Tanks (2)	NSSS	NNS	ASME VIII	-	N	-	9,11,31
Waste Monitor Tank Pumps (2)	NSSS	NNS	ASME III	3	N	-	11,31
Waste Monitor Tank Demineralizer	NSSS	NNS	ASME VIII	-	N	-	31
Waste Monitor Tank Filter	NSSS	NNS	ASME VIII	-	N	-	31

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Drumming Header Strainer	NSSS	NNS	ASME VIII	-	N	-	6,31
Waste Evaporator Concentrates Holdup Tank	BOP	NNS	ASME VIII	-	N	-	31
Waste Evaporator Concentrates Transfer Pumps	BOP	NNS	ASME III	3	N	-	31
Waste Evaporator Reagent Tank – **No Longer In Service**							
Excess Waste Holdup Tank	BOP	NNS	ASME VIII	-	N	-	31
Decontamination Pit Collection Tank	BOP	NNS	ASME VIII	-	N	-	31
Excess Liquid Waste Pumps (2)	BOP	NNS	No Code	-	N	-	31
Excess Liquid Waste Filters (2)	BOP	NNS	ASME VIII	-	N	-	31
Excess Liquid Waste Demineralizers (2)	BOP	NNS	ASME VIII	-	N	-	31
Excess Liquid Waste System Piping and Valves	BOP	NNS	ANSI B31.1 / ASME III	-/3	N/Y	-/1	31
GASEOUS WASTE PROCESSING SYSTEM							
Waste Gas Decay Tanks (8)	NSSS	NNS	ASME III	3	Y	1	1,31,32,35
Gas Decay Tank Drain Pump	NSSS	NNS	ASME III	3	N	-	1,11,31
Catalytic Hydrogen Recombiners (2)	NSSS	NNS	ASME III	3	Y	1	1,4,7,12,31,35
Waste Gas Compressor (2)	NSSS	NNS	ASME III	3	Y	1	1,7,31,35

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Waste Gas Compressor Pumps and Valves (2)	NSSS/BOP	NNS	ANSI B31.1 / ASME III	-/3	N/Y	1	1,5,31,35
Waste Gas Compressor Piping (2)	BOP	NNS	ANSI B31.1 / ASME III	-/3	N/Y	1	1,5,31,35
REACTOR BUILDING SPRAY SYSTEM							
Reactor Building Spray Pumps (2)	BOP	2a	ASME III	2	Y	1	7
Sodium Hydroxide Storage Tank	BOP	2b	ASME III	3	Y	1	-
Protective Chambers for Recirculation Sump Isolation Valves	BOP	2a	ASME III	MC	Y	1	-
Reactor Building Spray System Piping	BOP	2a	ASME III	2	Y	1	5
Reactor Building Spray System Valves	BOP	2a	ASME III	2	Y	1	5
SPENT FUEL COOLING SYSTEM							
Refueling Water Storage Tank	BOP	2a	ASME III	2	Y	1	-
Spent Fuel Cooling Pumps (2)	BOP	2b	ASME III	3	Y	1	-
Spent Fuel Cooling Heat Exchangers (2)	BOP	2b	ASME III	3	Y	1	-
Spent Fuel Purification Pump	BOP	NNS	No Code	-	N	-	-
Spent Fuel Purification Demineralizer	BOP	NNS	ASME VIII	-	N	-	-
Spent Fuel Purification Filter (2)	BOP	NNS	ASME VIII	-	N	-	-
Spent Fuel Cooling System Piping	BOP	2b	ASME III	3	Y	1	5
Spent Fuel Cooling System Valves	BOP	2b	ASME III	3	Y	1	5

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
NUCLEAR SAMPLING SYSTEM							
Residual Heat Removal Sample Cooler	BOP	2b	ASME III	3	Y	1	-
Pressurizer Sample Cooler	BOP	2b	ASME III	3	Y	1	-
Reactor Coolant Sample Coolers (2)	BOP	2b	ASME III	3	Y	1	-
Steam Generator Blowdown Sample Coolers (3)	BOP	2b	ASME III	3	Y	1	-
Volume Control Tank Gas Space Sample	BOP	NNS	ASME III	-	N	-	-
Sample Sink	BOP	NNS	--	-	N	-	-
Steam Generator Blowdown Sample Piping	BOP	2a	ASME III	2	Y	1	5
Steam Generator Blowdown Sample Valves	BOP	2a	ASME III	2	Y	1	5
Nuclear Sampling System Piping	BOP	3	ASME III	3	Y	1	5
Nuclear Sampling System Valves	BOP	3	ASME III	3	Y	1	5
Reactor Coolant Sampling Delay Coils (2)	BOP	2a	ASME III	2	Y	1	-
CVCS Sampling Delay Coils (2)	BOP	3	ASME III	3	Y	1	-
Flush Water Storage	BOP	NNS	--	-	N	-	-
Flush Water Pumps (2)	BOP	NNS	--	-	N	-	13
Auxiliary Sample Coolers (2)	BOP	NNS	--	-	N	-	13
Auxiliary Sample Cooler Chiller	BOP	NNS	--	-	N	-	13
Vacuum Pump	BOP	NNS	--	-	N	-	13

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Flush/Dilution Water Storage Tank	BOP	NNS	--	-	N	-	-
Waste Pump	BOP	NNS	--	-	N	-	13
Flush & Dilution Water Pump	BOP	NNS	--	-	N	-	13
NUCLEAR SAMPLE PANEL							
Sample Panel Enclosure	BOP	NNS	--	-	N	-	-
Pressurized Sample Flask	BOP	NNS	ASME VIII	-	N	-	-
Gas Expansion Flask	BOP	NNS	ASME VIII	-	N	-	-
Vacuum Expansion Flask	BOP	NNS	ASME VIII	-	N	-	-
Auxiliary Gas Expansion Flask	BOP	NNS	ASME VIII	-	N	-	-
Auxiliary Vacuum Expansion Flask	BOP	NNS	ASME VIII	-	N	-	-
Liquid Sample Circulation Pump	BOP	NNS	--	-	N	-	13
Liquid Sample Dilution Flask	BOP	NNS	ASME VIII	-	N	-	-
Nuclear Sample Panel Valves	BOP	NNS	--	-	N	-	5,13
Nuclear Sample Panel Tubing	BOP	NNS	--	-	N	-	5,13
POST ACCIDENT HYDROGEN REMOVAL SYSTEM							
Electric Hydrogen Recombiner	NSSS	2b	--	-	Y	1	13
Piping and Valves	BOP	2a/NNS	ASME III/-	2/-	Y/N	1/-	5
1000CC Collection Flasks (2)	BOP	NNS	ASME VIII	-	N	-	-

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Particulate Paper & Silver Zeolite Cartridge (2)	BOP	NNS	--	-	N	-	13
Air Ejector (2)	BOP	NNS	--	-	N	-	13
Purge Pressure Blower (2)	BOP	NNS	--	-	N	-	13
Hydrogen Analyzer (2)	BOP	3	--	-	Y	1	-
REACTOR MAKEUP WATER SYSTEM							
Reactor Makeup Water Storage Tank	BOP	2b	ASME III	3	Y	1	-
Reactor Makeup Water Pumps (2)	BOP	2b	ASME III	3	Y	1	-
Reactor Makeup Water System Piping	BOP	2b/NNS	ASME III/ ANSI B31.1	3/-	Y/N	1/-	-
Reactor Makeup Water System Valves	BOP	2b/NNS	ASME III/ ANSI B16.5	3/-	Y/N	1/-	-
COMPONENT COOLING SYSTEM							
Component Cooling Pumps (3)	BOP	2b	ASME III	3	Y	1	-
Component Cooling Heat Exchangers (2)	BOP	2b	ASME III	3	Y	1	-
Booster Pumps (3)	BOP	2b	ASME III	3	Y	1	-
Surge Tank	BOP	2b	ASME III	3	Y	1	11
Component Cooling Drain Tank	BOP	NNS	AWWA D-100	-	N	-	-
Component Cooling Drain Tank Pump	BOP	NNS	HIS	-	N	-	-

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Chemical Injection Tank	BOP	NNS	-	-	N	-	13
Chemical Injection Tank Agitator	BOP	NNS	-	-	N	-	13
Chemical Injection Pump	BOP	NNS	-	-	N	-	13
Component Cooling System Piping	BOP	2b	ASME III	3	Y	1	5
Component Cooling System Valves	BOP	2b	ASME III	3	Y	1	5
SERVICE WATER SYSTEM							
Service Water Pump A	BOP	2b	ASME III	3	Y	1	-
Service Water Pump B	BOP	2b	ASME III	3	Y	1	-
Service Water Pump C	BOP	2b	ASME III	3	Y	1	36
Booster Pumps (2)	BOP	2b	ASME III	3	Y	1	-
Traveling Screens (3)	BOP	2b	ASME III	3	Y	1	14
Trash Racks (3)	BOP	2b	No Code	-	Y	1	-
Service Water System Piping	BOP	2b	ASME III	3	Y	1	5
Service Water System Valves	BOP	2b	ASME III	3	Y	1	5
MAIN STEAM SYSTEM							
From Steam Generators to Main Steam Isolation Valves							
Flow Elements	BOP/NSSS	2a	ASME III	2	Y	1	-
Piping	BOP	2a	ASME III	2	Y	1	5

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Valves	BOP	2a	ASME III	2	Y	1	5
Components Downstream of Main Steam Isolation Valves	BOP	2a/NNS	ASME III/ ANSI B31.1	2/-	Y/N	1/-	15
FEEDWATER SYSTEM							
From Containment Isolation Valves to Steam Generators							
Piping	BOP	2a	ASME III	2	Y	1	5
Valves	BOP	2a	ASME III	2	Y	1	5
Components Upstream of Containment Isolation Valves	BOP/NSSS	2a/NNS	ASME III/ ANSI B31.1	2/-	Y/N	1/-	15
EMERGENCY FEEDWATER SYSTEM							
Pumps, motor driven (2)	BOP	2b	ASME III	3	Y	1	-
Pump, turbine driven	BOP	2b	ASME III	3	Y	1	-
Emergency Feedwater System Piping	BOP	2b	ASME III	3	Y	1	5
Emergency Feedwater System Valves	BOP	2b	ASME III	3	Y	1	5
Emergency Feedwater Control Valves Air Volume Tanks	BOP	-	ASME VIII	-	Y	1	24
CONDENSATE SYSTEM							
Condensate Storage Tank	BOP	2b	ASME III	3	Y	1	-
Remainder of Condensate System	BOP	NNS	ANSI B31.1	-	N	-	5

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
STEAM GENERATOR BLOWDOWN SYSTEM							
Piping and Valves from Steam Generators to Containment Isolation Valves	BOP	2a	ASME III	2	Y	1	-
Remainder of Steam Generator Blowdown System	BOP	NNS/QR	ASME VIII/ ANSI B31.1	-	N	-	-
NUCLEAR BLOWDOWN PROCESSING SYSTEM							
Holdup Tank	BOP	NNS	ASME VIII	-	N	-	-
Monitor Tank	BOP	NNS	ASME VIII	-	N	-	-
Blowdown Spent Resin Storage Tank	BOP	NNS	ASME VIII	-	N	-	-
Primary Demineralizers (2)	BOP	NNS	ASME VIII	-	N	-	-
Polishing Demineralizers (2)	BOP	NNS	ASME VIII	-	N	-	-
Demineralizer Inlet Filter	BOP	NNS	ASME VIII	-	N	-	-
Spent Resin Sluice Filter	BOP	NNS	ASME VIII	-	N	-	-
Demineralizer Outlet Filter	BOP	NNS	ASME VIII	-	N	-	-
Holdup Tank Transfer Pumps (2)	BOP	NNS	HIS	-	N	-	-
Monitor Tank Transfer Pump	BOP	NNS	-	-	N	-	13
Spent Resin Sluicing Pump	BOP	NNS	-	-	N	-	13
Piping	BOP	NNS	ANSI B31.1	-	N	-	-

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Valves	BOP	NNS	ANSI B16.5	-	N	-	-
CRDM COOLING WATER							
CRDM Cooling Coils	BOP	NNS	ANSI B31.1	-	Y	-	41
Remaining of CRDM Cooling Water System	BOP	NNS	ASME VIII/ ANSI B31.1	-	N	-	41
VENTILATION EQUIPMENT							
Reactor Building Cooling Units (4)	BOP	2b	ASME III	3	Y	1	16,17,25,27
Reactor Building Charcoal Cleanup System Fans (2)	BOP	NNS	-	-	Y	1	18
Reactor Building Purge Valves	BOP	2a	ASME III	2	Y	1	-
Auxiliary Building Charcoal Exhaust System Fans (4)	BOP	NNS	-	-	N	-	13
Fuel Handling Building Exhaust Fans	BOP	3	-	-	Y	1	18
Spent Fuel Pool Supply Fan	BOP	NNS	-	-	N	-	13
Residual Heat Removal/Spray Pump Room Cooling Unit	BOP	2b	ASME III	3	Y	1	17,18
Charging Pump Room Cooling Unit	BOP	2b	ASME III	3	Y	1	17,18
Auxiliary Building Charcoal Filter System Plenum (2)	BOP	NNS	-	-	N	-	13
Fuel Handling Building Charcoal Filter Plenum (3)	BOP	3	-	-	Y	1	13,27

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Intermediate Building Pump Area Cooling Units (2)	BOP	2b	ASME III	3	Y	1	17,18
Control Room Emergency Filtering System Fans	BOP	2b	-	-	Y	1	18
Control Room Normal Supply Units	BOP	2b	ASME III	3	Y	1	17,18
Relay Room Cooling System Units	BOP	2b	ASME III	3	Y	1	17,18
Battery Room Air Supply Fans	BOP	2b	-	-	Y	1	18
Battery Room Exhaust Fans	BOP	2b	-	-	Y	1	18
Safety Class Water Chillers	BOP	2b	ASME III	3	Y	1	-
Safety Class Chilled Water Pumps	BOP	2b	ASME III	3	Y	1	-
Reactor Building Charcoal Cleanup Plenums	BOP	NNS	-	-	N	-	26
Control Room Emergency Filter Plenums	BOP	2b	-	-	Y	1	13,27
Service Water Pumphouse Supply Fans (2)	BOP	2b	-	-	Y	1	18
ESF Switchgear Room Cooling Units (2)	BOP	2b	ASME III	3	Y	1	17,18
Speed Switch Room Cooling Units (2)	BOP	2b	ASME III	3	Y	1	17,18
Motor Control Center 12-28 Cooling Units (2)	BOP	2b	ASME III	3	Y	1	17,18
Switchgear 63-01 Cooling Unit (1)	BOP	2b	ASME III	3	Y	1	17,18

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Duct Work, Dampers (including Control Room Outside Air Intake Isolation Valves), Supports for Safety Related Ventilation Systems	BOP	2b	-	-	Y	1	38
FIRE PROTECTION SYSTEM							
Fire Pumps (2)	BOP	NNS	-	-	N	-	30
Jockey Pump	BOP	NNS	-	-	N	-	30
Fire Protection Piping and Fittings	BOP	NNS	-	-	N	-	30
Fire Protection Valves	BOP	NNS	-	-	N	-	30
Fire Protection Containment Isolation Valves	BOP	2a	ASME III	2	Y	1	37
Diesel Generator Building Ventilation Fans	BOP	2b	-	-	Y	1	18
Emergency Feedwater Pump Room Ventilation Fans	BOP	2b	-	-	Y	1	18
Piping and Ductwork for above Systems	BOP	2b/NNS	ASME III/ None	3/None	Y/N	1/-	19
DIESEL GENERATOR FUEL OIL SYSTEM							
Fuel Oil Transfer Pumps (4)	BOP	2b	ASME III	3	Y	1	-
Fuel Oil Day Tanks (2)	BOP	2b	ASME III	3	Y	1	-
Fuel Oil Storage Tanks (2)	BOP	2b	ASME III	3	Y	1	-

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Fuel Oil Piping and Valves for Diesel Generators	BOP	2b	ASME III	3	Y	1	-
DIESEL GENERATOR COOLING WATER SYSTEM							
Intercooler Pump	BOP	2b	-	-	Y	1	-
Intercooler Heat Exchanger	BOP	2b	ASME VIII	-	Y	1	36
Intercooler Thermostatic Valve	BOP	2b	ASME III	3	Y	1	-
Jacket Water Heat Exchanger	BOP	2b	ASME VIII	-	Y	1	36
Jacket Water Pump	BOP	2b	-	-	Y	1	-
Jacket Water Motor Driven Auxiliary Pump	BOP	2b	ASME III	3	Y	1	-
Jacket Water Expansion Tank	BOP	NNS	ASME VIII	-	Y	1	-
Jacket Water Heater	BOP	2b	-	-	Y	1	-
Jacket Water Thermostatic Valve	BOP	2b	ASME III	3	Y	1	-
Cooling Water System Piping and Manual Valves	BOP	2b	ASME III	3	Y	1	-
DIESEL GENERATOR STARTING SYSTEM							
Air Start Distributors	BOP	2b	-	-	Y	1	-
Main Air Start Control Valves	BOP	2b	-	-	Y	1	-
Air Filters	BOP	2b	-	-	Y	1	-

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Air Tanks	BOP	2b	ASME III	3	Y	1	-
Shutdown Solenoids Valve	BOP	2b	ASME III	3	Y	1	-
Fuel Rack Shutdown Cylinder	BOP	2b	-	-	Y	1	-
Air Tank (accumulator)	BOP	2b	ASME III	3	Y	1	-
Shuttle Valve	BOP	2b	ASME III	3	Y	1	-
Air Start Solenoid Valves	BOP	2b	ASME III	3	Y	1	-
Barring Gear Interlock	BOP	2b	-	-	Y	1	-
Air Compressors	BOP	NNS	-	-	N	-	-
Air Dryers	BOP	NNS	-	-	N	-	-
DIESEL GENERATOR LUBRICATION SYSTEM							
Main Oil Pump, Engine Driven	BOP	2b	-	-	Y	1	-
Thermostatic Valve	BOP	2b	ASME III	3	Y	1	-
Main Lube Oil Strainer	BOP	2b	ASME III	3	Y	1	-
Auxiliary Motor Driven Oil Pump	BOP	2b	-	-	Y	1	-
Auxiliary Strainer	BOP	2b	ASME III	3	Y	1	-
Electric Heater	BOP	2b	-	-	Y	1	-
Oil Filter	BOP	2b	-	-	Y	1	-
Motor Driven Rocker Prelube Pump	BOP	2b	-	-	Y	1	-

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Lube Oil Cooler	BOP	2b	ASME VIII	-	Y	1	36
Lube Oil Piping and Valves	BOP	2b	ASME III	3	Y	1	-
DIESEL GENERATOR COMBUSTION AIR INTAKE AND EXHAUST SYSTEM							
Intake Filter/Silencers	BOP	2b	-	-	Y	1	-
Exhaust Muffler	BOP	2b	-	-	Y	1	-
Ducting	BOP	2b	-	-	Y	1	-
REACTOR VESSEL OR CORE-RELATED							
Reactor Vessel Head and Shell Insulation	NSSS	QR	-	-	N	-	33
Irradiation Sample Holder	NSSS	2a	-	-	Y	1	4,20
Irradiation Samples	NSSS	NNS	-	-	N	-	1
Reactor Vessel Stud Tensioners	NSSS	NNS	-	-	N	-	6
Reactor Vessel Support Shoes & Shims	NSSS	1	-	-	Y	1	4
CRDM Dummy Can Assemblies	NSSS	NNS	-	-	N	-	6
Reactor Vessel Core Support Structures & Internal Structures	NSSS	2a	-	-	Y	1	1,20
Reactor Vessel Internals Package	NSSS	2a	ASME III	2	Y	1	2
Control Rod Guide Tubes	NSSS	2a	-	-	Y	1	1,2
RCC Full Length Assembly	NSSS	2a	-	-	Y	1	1,2

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Burnable Poison Rod Assembly	NSSS	NNS	-	-	N	-	1
Primary & Secondary Sources	NSSS	NNS	-	-	N	-	1
FUEL HANDLING AND STORAGE EQUIPMENT							
Reactor Cavity Seals	NSSS	NNS	-	-	N	-	6
Cable Reels	NSSS	NNS	-	-	N	-	6,21
Load Cell	NSSS	NNS	-	-	N	-	-
Stud Hole Plug Handling Fixture	NSSS	NNS	-	-	N	-	21
Stud Hole Plugs	NSSS	NNS	-	-	N	-	21
Fuel Handling Machine	NSSS	3	-	-	Y	1	4
Refueling Machine	NSSS	NNS	-	-	N	-	-
New Fuel Storage Racks	NSSS	2b	-	-	Y	1	4
Burnable Poison Assembly Rack Inserts	NSSS	NNS	-	-	N	-	6,21
Spent Fuel Storage Racks	NSSS	2b	-	-	Y	1	4
Upper Internal Storage Stand	NSSS	NNS	-	-	N	-	21
RCC Changing Fixture	NSSS	NNS	-	-	N	-	-
CRD Shaft Handling Fixture	NSSS	NNS	-	-	N	-	21
CRD Shaft Unlatching Tool, Full Length	NSSS	NNS	-	-	N	-	6,21
New Fuel Elevator Winch	NSSS	NNS	-	-	N	-	21

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
New Fuel Elevator	NSSS	NNS	-	-	N	-	21
New Fuel Assembly Handling Fixture	NSSS	NNS	-	-	N	-	6,21
Spent Fuel Assembly Handling Tool	NSSS	3	-	-	Y	1	4
Polar Crane	BOP	-	-	-	Y	1	23,24
IHA Lift Rig Components	NSSS	1/NNS	ASME III	NF	Y/N	1/-	43
CRDM Seismic Support Assembly (SSA)	NSSS	2a	ASME III	NF	Y	1	22
Reactor Vessel Internals Lifting Device	NSSS	NNS	-	-	N	-	-
Irradiation Sample Handling Tool	NSSS	NNS	-	-	N	-	6,21
Burnable Poison Handling Tool	NSSS	NNS	-	-	N	-	6,21
New RCC Handling Fixture	NSSS	NNS	-	-	N	-	6,21
Crane Scales	NSSS	NNS	-	-	N	-	6,21
Primary Source Installation Guide	NSSS	NNS	-	-	N	-	6,21
Stud Tensioner Handling Device	NSSS	NNS	-	-	N	-	6,21
RCC Thimble Plug Tool	NSSS	NNS	-	-	N	-	6,21
Fuel Transfer System							
Fuel Transfer Tube and Flange	NSSS	2a	ASME III	MC	Y	1	4
Track Upenders and Conveyor - Winches and Car	NSSS	QR	-	-	Y	-	4
Control Panels and Hydraulic Units	NSSS	NNS	-	-	N	-	-

Table 3.2-1 (continued)
Mechanical Equipment Classification

Component	Scope	ANS Safety Class	Code	Code Class	Seismic Category I	QA Class	Notes
Refueling Cavity Seal Ring	NSSS	NNS	-	-	N	-	6
Neutron Detector Positioning Device	NSSS	2a	-	-	Y	1	4
CRD Shaft Storage Racks	NSSS	NNS	-	-	N	-	-
Lower Internals Storage Stand	NSSS	NNS	-	-	N	-	-
Stud Nut Washer and Carrier	NSSS	NNS	-	-	N	-	-
Irradiation Tube End Plug Seat Jack	NSSS	NNS	-	-	N	-	6
Long Handle Tool Storage Rack	NSSS	NNS	-	-	N	-	6
Fuel Handling Building Crane	BOP	-	-	-	Y	1	24
Lift Yoke for HI-TRAC VW	BOP	-	ASME III	NF	Y	1	24
Lift Yoke Extension for HI-TRAC VW	BOP	-	ASME III	NF	Y	1	24
Cask Pedestal for HI-TRAC VW	BOP	-	ASME III	NF	Y	1	24
VECASP for HI-TRAC VW	BOP	-	ASME III	NF	Y	1	40
INCORE INSTRUMENTATION							
Instrument Conduit and Couplings	NSSS	1	ASME III	1	Y	1	1
Seal Table Assembly	NSSS	1	ASME III	NF	Y	1	1
Flux Thimble Assemblies	NSSS	2	-	-	Y	1	1

TABLE 3.2-1 NOTES
MECHANICAL EQUIPMENT CLASSIFICATION

Certain pressure retaining parts exist within a system which do not fall within the normal definition of pipes, pumps, or valves. In some cases these are not commercially available fabricated from materials conforming to ASTM specifications allowed in ANSI B31.1, ASME III or ASME VIII; in addition, instrumentation is specifically excluded from ASME III. Examples of these items are strainers, sight glasses, level switches, pressure transmitters, thermowells, etc. These items are specified and procured in a manner which ensures that these components are comparable with the remainder of the systems to preclude their structural failure under operating, accident, or test conditions. Also, certain consumable products used in conjunction with safety related equipment are considered safety related. Examples of these items are weld rod, diesel fuel oil, boric acid, lithium hydroxide, etc.

The NRC has granted relief per 10CFR50.55(a)(3) to licensees that choose to use the guidance provided in Generic Letter 89-09 (issued May 8, 1989) for procuring replacements that are not currently available in full compliance with the stamping and documentation requirements of Section III of the ASME Boiler and Pressure Vessel Code. The replacements meet all other applicable requirements of Section III (including third party inspection by an Authorized Nuclear Inspector) endorsed by NRC regulations and are procured in accordance with the SCE&G Quality Assurance Program Description. Replacements procured per this relief are designated by Note (36).

1. Meets “Quality Control System Requirements,” Westinghouse QCS-1, which satisfies the requirements of 10CFR50, Appendix B.
2. Meets the quality assurance program of one of the Westinghouse NES Manufacturing Divisions, and is in accordance with 10CFR50, Appendix B.
3. As permitted by Paragraph NA-2134 of the ASME Code, Section III, this component is upgraded from the minimum required Code Class 2 to Code Class 1.
4. Meets “Quality Requirements for Manufacturer of Nuclear Plant Equipment,” Westinghouse QCS-2, which satisfies the requirements of 10CFR50, Appendix B.
5. The classifications shown are for the predominant portion of the system. There may be portions that are classified higher or lower. Safety class boundaries are shown on applicable system diagrams. Seismic category, code, and QA classes for other safety classes are consistent with those other safety classes.
6. Access for inspection and test is required by Westinghouse; however, no formal quality program approval is required.
7. Portions of equipment containing Component Cooling Water are Safety Class 2b, Code Class 3.

TABLE 3.2-1 NOTES (Continued)

8. Services required to support a safety or other necessary function:
   a. Emergency power - automatic loading.
   b. Emergency power - automatic loading.
   c. Component Cooling Water.
   d. Service Water.
9. Not stamped.
10. Designed in accordance with the Draft of the ASME Code for Pumps and Valves for Nuclear Power Plants, November, 1968. Ordered before the 1971 edition of the ASME Code, Section III became mandatory.
11. Outside the jurisdiction of ASME but designed, fabricated, and tested according to the ASME Code.
12. In the catalytic hydrogen combiner package, the control panel and gas analyzer shall be Non-Nuclear Safety, with no code requirements.
13. No applicable code. Built to supplier's standards.
14. ASME Code, Section III, applies to screen wash header only.
15. Main Steam and Feedwater piping, excluding branch lines, between the associated isolation valves and the wall between the Intermediate Building and Turbine Building satisfies all requirements, except for stamping, of the ASME Code, Section III, Code Class 2.
16. No code. The fans and motors are specifically designed for operation in the containment atmosphere under both normal operating and post LOCA conditions.
17. Code and Code Class apply to unit coils.
18. No code. The fans are designed and manufactured in accordance with the intent of ANS Safety Class 2b.
19. No code. Ductwork is designed to withstand expected pressures and shocks for the section of the plant in which it is located.
20. Any reactor vessel internal, the single failure of which could cause release of a mechanical piece having potential for direct damage (as to the vessel cladding) or flow blockages, shall be classified to a minimum of Safety Class 1.
21. Failure can cause no nuclear safety problem, although an economic loss may result.
22. Portions which transmit loading from CRDM seismic supports are Safety Class 2a.
23. Applicable code is Crane Manufacturers Association of America, Specification No. 70 for Electric Overhead Traveling Cranes.

TABLE 3.2-1 NOTES (Continued)

24. Equipment is not ANS Safety Class but is safety related.
25. Supports for Reactor Building Cooling Units are safety related.
26. The supports which attach the plenums to the Reactor Building wall are seismically qualified and safety related.
27. HEPA filters are an integral part of the Reactor Building Cooling Units, the Fuel Handing Building charcoal filter plenum, and the control room emergency filter plenums.
28. Portions of this system are used for post accident sampling. The Post Accident Sampling System is not safety related. Procedures associated with post accident sampling are under the pertinent requirements of the Quality Assurance Program.
29. Refer to Table 5.2-1 for information regarding the design code addenda.
30. See the response to NRC Questions 421.77 and 421.78a.
31. Equipment in this system was originally supplied to ASME III code. This system has subsequently been downgraded to NNS. Future equipment procurement and modifications will meet or exceed the code and quality requirements of Regulatory Guide 1.143, Revision 1, with exceptions noted in FSAR Appendix 3A.
32. The seismic design criteria given in FSAR Section 3.7 are applicable.
33. Quality Related (QR) is a V. C. Summer classification used to impose controls for procurement, installation, or repair of that equipment.
34. DELETED
35. Equipment in this system was originally supplied to ASME III code. This system was then downgraded to NNS in accordance with Regulatory Guide 1.143, Revision 1, with exceptions noted in FSAR Appendix 3A. Subsequently, the portions of this system which may have the potential of carrying combustible concentration gas mixtures were upgraded to a Quality Related Classification (including seismic design and falldown protection) as defined by QRP-1.
36. Meets the requirements for ASME Section III component replacements pursuant to the 10CFR50.55(a)(3) relief granted in Generic Letter 89-09.
37. Includes valves XVG06772, XVG06773, XVG06797, & XVC06799 only.
38. Control Room Outside Air Intake Isolation Valves XVB00003A,B-AH and XVB00004A,B-AH are ANS safety class 2b butterfly valves. These valves serve the function of air flow isolation in the Control Room HVAC system which is a ducted ventilation system. This function does not necessitate the imposition of ASME code requirements.
39. The Alternate Seal Injection (ASI) pump would have technically been NSSS scope, but was added to the station per internal SCE&G modification ECR50780C. The ASI pump and interconnecting piping are ASME Code Class 2 for pressure boundary only. The actual function of supplying flow to the reactor coolant pump seals is NNS. While not required, the ASI pump was conservatively procured as an active pump and its motor as 1E.

TABLE 3.2-1 NOTES (Continued)

40. Equipment is not ANS Safety Class but is quality related per TRP-43.
41. The CRDM Cooling Water System has been placed in a lay-up condition per ECR 50897.
42. CETNA Assembly consists of various pressure retaining subcomponents
43. ANSI N14.6 and NUREG 0612 codes also apply. Refer to IHA Certified Design Spec., AREVA 08-9241459

Table 3.2-2
Classification of Structures

	Seismic Category I	Non-Seismic Category	Method of Tornado Missile Protection [1]	Tornado Missile [2] Grade to 30 Feet	Tornado Missile [2] Above 30 Feet
Reactor Building, Liner, Penetrations and Hatches [5] [6]	X		A,C	1,2,3,4,5,6,7	3,5,6,7
Reactor Building Interior Structures [5] [6] [7]	X		Reactor Building	Reactor Building	Reactor Building
Control Building [5] [6]	X		A,B,C,D,E	1,2,3,4,5,6,7	3,5,6,7
Auxiliary Building [5] [6]	X		A,B,D,E	1,2,3,4,5,6,7	3,5,6,7
Fuel Handling Building [5] [6]	X				
a. General structures for fuel pools and protective barriers for equipment (see Figures 3.8-58, 3.8-59, 3.8-60)			A,B,C,D,E	1,2,3,4,5,6,7	3,5,6,7
b. Steel superstructure [3] (see Figures 3.8-58, 3.8-59, 3.8-60)			[4]	[4]	[4]
Intermediate Building [5] [6]	X		A,B,C,D,E	1,2,3,4,5,6,7	3,5,6,7
Diesel Generator Building [5] [6]	X		A,B,C,D,E	1,2,3,4,5,6,7	3,5,6,7
Service Water Intake, Pumphouse and Discharge Structures [5] [6]	X		A,B,C	1,2,3,4,5,6,7	Not applicable

Table 3.2-2 (continued)
Classification of Structures

	Seismic Category I	Non-Seismic Category	Method of Tornado Missile Protection [1]	Tornado Missile [2] Grade to 30 Feet	Tornado Missile [2] Above 30 Feet
Service Water Pond Dams	X		Not applicable	Not applicable	Not applicable
Supports for Safety Class Components	X		A,B,C,D,E	1,2,3,4,5,6,7	3,5,6,7
Turbine Building		X			
Substation Structure and Control Houses		X			
Water Treatment Building		X			
Circulating Water Intake and Discharge Structure		X			
Service Building		X			
Auxiliary Boiler House		X			
Warehouse(s)		X			
Guard House(s)		X			
Monticello Reservoir Dams		X			
Jetty		X			
Sanitary Waste Facility		X			
Industrial Waste Facility		X			
Containment Access Runway		X			

Table 3.2-2 (Continued)
Classification of Structures

(1) Method of tornado missile protection is as follows:

A. Reinforced concrete walls.

B. Reinforced concrete slabs.

C. Reinforced concrete barriers.

D. Orientation.

E. Probability studies, probability criteria < 10^{-7}.

(2) Numbers correspond to tornado missiles identified in Table 3.5-5.

(3) Refer to discussion of probability study, response to Question 010.7.

(4) Steel frame is designed to maintain its integrity under tornado missile impact.

(5) Biological shielding and missile barrier structural components related to Category I structures identified in Table 3.2-2 are classified as either safety-related and meet Seismic Category I requirements or as Quality Related designed for the Safe Shutdown Earthquake.

(6) Fire stops for electrical penetrations are safety related.

(7) The supports for the Reactor Building charcoal cleanup filter plenums which attach the plenums to the Reactor Building wall are seismically qualified and safety related.

Table 3.2-3
Summary of Codes and Standards for Components

Component	Safety Class 1	Safety Class 2a	Safety Classes 2b and 3	Non-Nuclear Safety Class
Pressure Vessels	ASME Code, Section III, Class 1 (1)(1a)	ASME Code, Section III, Class 2 (2)	ASME Code, Section III, Class 3 (3)	ASME Code, Section VIII, (4) Division 1
Piping	ASME Code, Section III, Class 1 (1)	ASME Code, Section III, Class 2 (2)	ASME Code, Section III, Class 3 (3)	ANSI B31.1.0 (5)
Pumps and Valves	ASME Code, Section III, Class 1 (1)	ASME Code, Section III, Class 2 (2)	ASME Code, Section III, Class 3 (3)	Pumps: Hydraulic Institute Standards or Manufacturer's Standards Valves: ANSI B16.5
Storage Tanks (0-15 psig)	-	ASME Code, Section III, Class 2 (2)	ASME Code, Section III, Class 3 (3)	API 620
Storage Tanks (atmospheric)	-	ASME Code, Section III, Class 2 (2)	ASME Code, Section III, Class 3 (3)	AWWA D-100 or API 650

Table 3.2-3 (Continued)
Summary of Codes and Standards for Components

NOTES TO TABLE 3.2-3

Specific editions and addenda of codes are dependent upon contract award dates for individual components.

1. American Society of Mechanical Engineers (ASME), Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," including revisions to the following paragraphs published in the 1971 edition: NB-2510, NB-2541, NB-2553, NB-2561; except as noted in Table 3.2-1 for specific items in the Reactor Coolant System.
   a. Replacement Reactor Vessel Closure Head designed to ASME Section III, 2007 Edition through 2008 Addenda Rules for Construction of Nuclear Power Plant Components and Application Codes Cases. Reconciled to the Code of Record.
2. ASME, Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," including a or b, below:
   a. Revisions to the following paragraphs published in the 1971 edition: NC-2510, NC-2571, NC-2573.
   b. The 1974 edition with all applicable addenda.
3. ASME, Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," including a or b, below:
   a. Revisions to the following paragraphs published in the 1971 edition: ND-2510, ND-2571.
   b. The 1974 edition with all applicable addenda.
4. ASME, Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessels."
5. American National Standards Institute, ANSI B31.1.0, "Power Piping Code," 1967 issue with addenda through 1972.

3.3 WIND AND TORNADO LOADINGS

3.3.1 Wind Loadings

3.3.1.1 Design Wind Velocity

A design wind velocity of 100 mph was used in the analysis of Seismic Category I structures. This value represents the maximum wind velocity at the site for an altitude of 30 feet above grade and for a 100 year recurrence interval. Sections 2.3.1 and 2.3.2 provide the basis for this selection of design wind velocity.

The wind velocity profile for the Reactor Building was computed on the basis of Table 1a of ASCE Paper No. 3269 (Reference 1). The 140 mph velocity at the top of the Reactor Building, which is 167 feet above grade, was conservatively applied for the full height of the structure as shown by Figure 3.3-2.

(Reference 1) recommends a gust factor of 1.1 for structures similar in size to the Reactor Building. However, due to the conservative application of the design wind velocity over the Reactor Building height, the design gust factor was taken as 1.0.

The wind velocity profile for other Seismic Category I structures was computed based upon (Reference 1), using equation (2) with x equal to 0.20. These velocities were multiplied by a gust factor of 1.1, based upon the recommendations of (Reference 1). The resulting wind velocity profiles are shown by Figure 3.3-1. These velocities are somewhat conservative since equation (2) of (Reference 1) applies to “coastal areas” and the plant is located in an “inland area,” as defined by (Reference 1).

The conservative wind velocity profiles result in “actual gust factors used” as given below:

Reactor Building

Height Above Grade (Feet)	Percent of Total Exposed Height	Wind Velocities (mph)		Actual Gust Factor Used	Stated Design Gust Factor
		Required By Ref. (1) Table 1a	Used in Design		
0-50	30	100	140	1.40	1.0
50-150	60	120	140	1.17	1.0
150-167	10	140	140	1.0	1.0

Other Seismic Category 1 Structures

Height Above Grade (Feet)	Percent of Total Exposed Height	Wind Velocities (mph) Required By Ref. (1) Table 1a	Wind Velocities (mph) Used in Design*	Actual Gust Factor Used	Stated Design Gust Factor
0-30	30	100	110	1.10	1.1
30-50	20	100	122	1.22	1.1
50-99	50	120	140	1.17	1.1

* $VZ = 1.1\ [V_{30}(Z/30)^{0.20}]$

3.3.1.2 Determination of Applied Forces

The effective pressures resulting from the design winds were computed using Equation (6) and the shape coefficients from Reference 1. Resulting pressures for the Reactor Building and other Seismic Category I structures are shown by Figures 3.3-1 and 3.3-2.

3.3.2 Tornado Loadings

3.3.2.1 Applicable Design Parameters

The design parameters applicable to the design basis tornado are as follows:

1. Rotational wind speed of 290 mph.
2. Translational wind speed of 70 mph.
3. Atmospheric pressure drop of 3 psi at the rate of 2 psi/sec.

3.3.2.2 Determination of Forces on Structures

Forces upon structures resulting from tornado winds were determined as follows:

1. The effective pressures on the Reactor Building due to a 360 mph wind were computed using the same shape coefficients as were used for design wind analysis (Reference 1). These pressures were combined with the 3 psi atmospheric pressure and are shown in Figure 3.3-3. For all other Seismic Category I structures, the design pressures are as follows:
   a. Maximum positive pressure on each building wall was obtained by applying a shape coefficient of 0.9 to the 332 lb/ft^2 dynamic pressure, neglecting the atmospheric pressure drop. This resulted in a positive pressure of approximately 300 lb/ft^2.

b. Maximum negative pressure (suction) on each building wall and roof was obtained by applying a shape coefficient of -0.7 to the 332 lb/ft^2 dynamic pressure and superimposing on this value the 3 psi suction due to atmospheric pressure drop. This resulted in a negative pressure (suction) of approximately 664 lb/ft^2.

The design tornado wind velocity of 360 mph was assumed to be constant with height.

2. No reduction in tornado wind pressure due to venting was assumed.
3. Structures were designed to resist the effects of tornado generated missiles described in Section 3.5.1.4. In the design it is assumed that these missiles can occur simultaneously with the tornado loads described in item 1, above.
4. General stability of the entire structure was checked using net pressures of wind, tornado, and other loads as described in Section 3.8. However, individual elements are designed for the maximum effect in either direction.

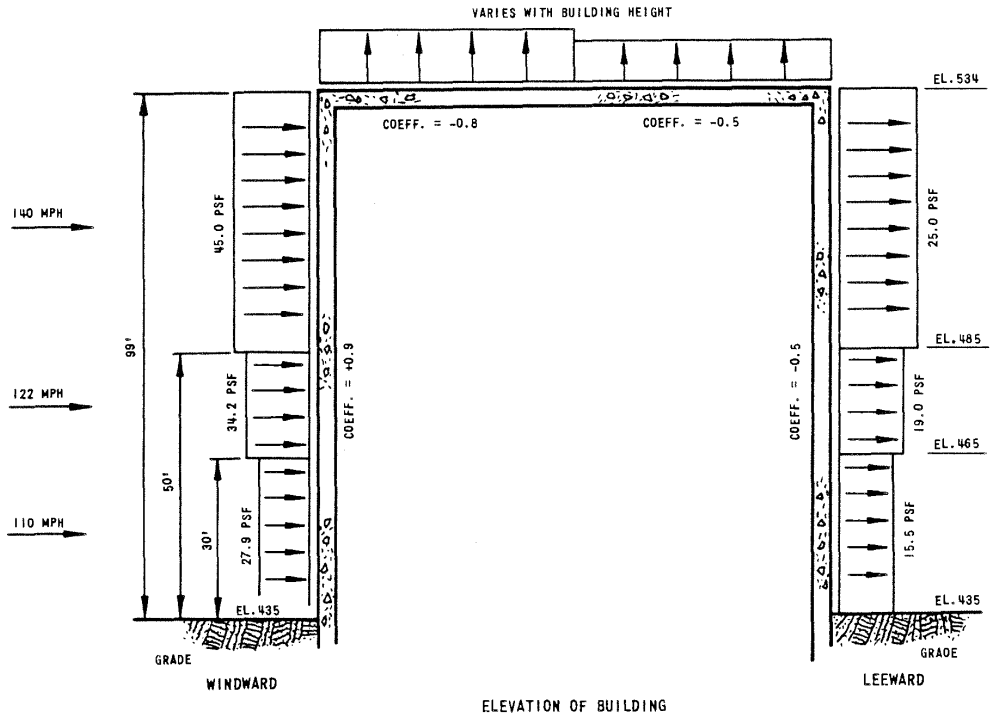
3.3.2.3 Effect of Failure of Structures or Components not Designed for Tornado Loads

Structures not designed to resist tornado loadings are either located so that their failure does not affect structures designed for tornado loads or are designed not to collapse. The metal siding and roofing of the Fuel Handling Building will blow off under tornado loading. The structural steel frames supporting the overhead traveling crane will resist the tornado and wind loads. Non-Seismic Category I structures may lose parts or portions but such parts or portions are less serious missiles than those described in Section 3.5.1.4.

3.3.3 Reference

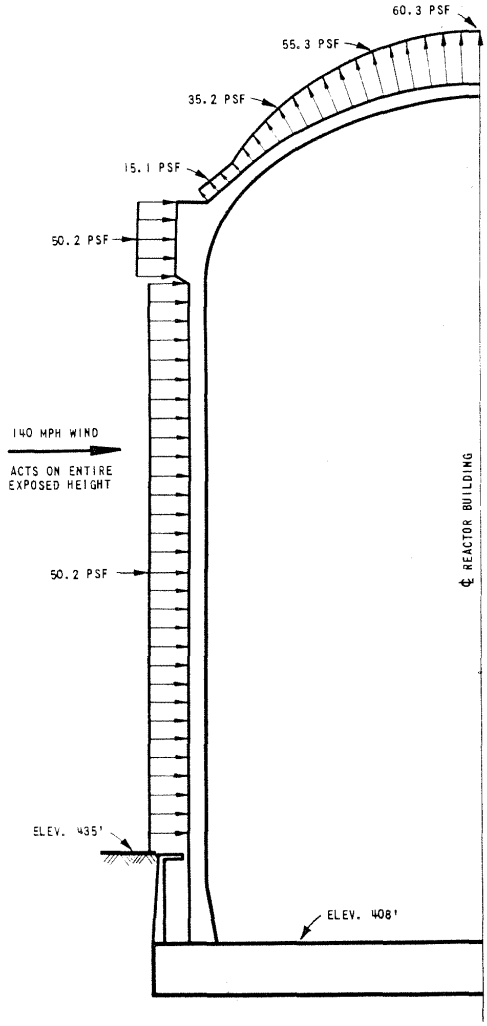
1. *Wind Forces on Structures*, Transactions of the American Society of Civil Engineers (ASCE), Paper No. 3269, Volume 126, Part 2.

Figure 3.3-1
WIND PRESSURE FOR OTHER SEISMIC CATEGORY I BUILDINGS

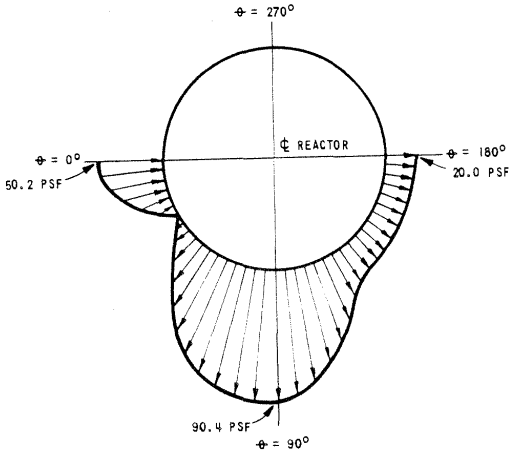


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Wind Pressures for Other Seismic Category I Buildings Figure 3.3-1

Figure 3.3-2
REACTOR BUILDING WIND PRESSURES



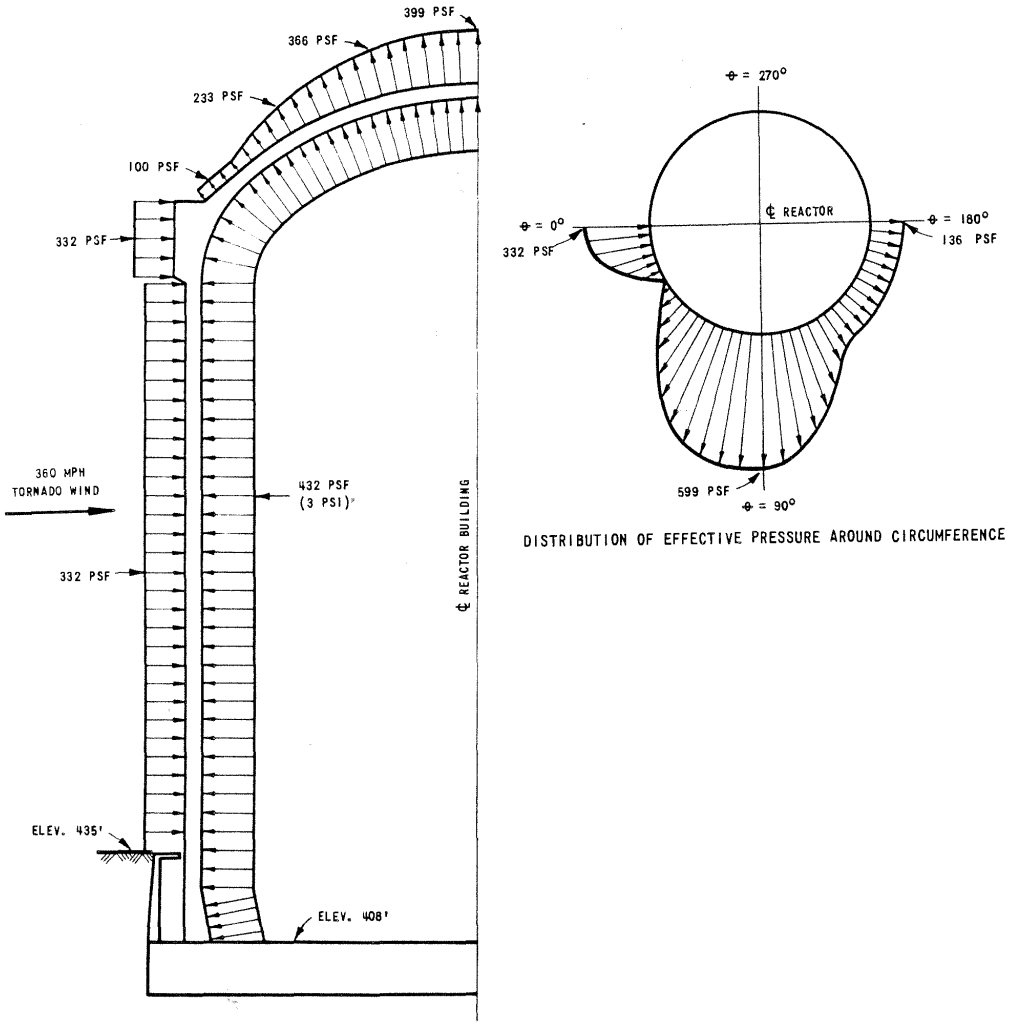
EFFECTIVE PRESSURES FOR 100 MPH DESIGN WIND



DISTRIBUTION OF EFFECTIVE PRESSURE AROUND CIRCUMFERENCE

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Building Wind Pressures Figure 3.3-2

Figure 3.3-3
REACTOR BUILDING TORNADO PRESSURES



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Building Tornado Pressures Figure 3.3-3

3.4 WATER LEVEL (FLOOD) DESIGN

All Seismic Category I structures are designed for a maximum flood water level elevation of 437’-6" at the berm and a high water table ground water level elevation of 420’ ± 3’.

3.4.1 Flood Protection

3.4.1.1 Safety-Related Systems and Components Protected Against Floods

All safety-related systems and components are protected against surface flooding by grading the site to carry surface water away from structures housing these systems and components, and by either permanently installed flood protection features or temporary flood protection features as described in Section 3.4.1.2. See Section 2.4 for details. Systems located below the maximum water surface elevation are protected as described in Sections 3.4.1.2 and 3.4.1.3.

3.4.1.2 Structures that House Safety-Related Equipment

The portions of Seismic Category I structures located below finished grade are protected on their outside surfaces by a continuous waterproofing membrane. In addition, the auxiliary building mat is protected by a waterproof membrane on the bottom surface.

Below grade penetrations for conduit and piping are provided with waterproofing membrane covers. No personnel or equipment hatches are located in outer walls below grade.

Exterior door thresholds across the site below the maximum water surface elevation which lead to safety related equipment are protected from flooding by attaching temporary flood barriers. These flood barriers are able to be quickly installed and removed due to rapidly changing flooding conditions.

3.4.1.3 Means of Providing Flood Protection for Vulnerable Equipment

In the event that leakage occurs, additional flood protection is provided for safety class components, equipment, and systems located below grade by sloping of floors to sumps and pumping of any water from these sumps.

3.4.1.4 Procedures Required and Implementation Times for Cold Shutdown for Flood Conditions

Special procedures for use in the event of flooding are not required. See Section 2.4.14.

3.4.1.5 Safety-Related Systems or Components Capable of Normal Function While Flooded

Safety-related electrical cabling in underground duct runs is capable of fulfilling its normal function when completely or partially flooded.

3.4.2 Analysis Procedures

Seismic Category I structures are designed for buoyancy. No Seismic Category I structures become unstable with respect to uplift or overturning due to load combinations including the design water level. Load combinations are presented in Section 3.8. The plant site is protected against potential floods up to elevation 438.0’ (for details see Section 2.4.10). Therefore, dynamic effects of flooding are not applicable and were not considered.

3.5 MISSILE PROTECTION

3.5.1 Missile Selection and Description

3.5.1.1 Internally Generated Missiles (Outside Containment)

3.5.1.1.1 Missile Selection

Rotating and high pressure system components located inside the following buildings and areas are examined to identify and classify potential missiles:

1. Auxiliary Building
2. Intermediate Building
3. Penetration access areas
4. Fuel Handling Building
5. Diesel Generator Building
6. Service Water Pump House

Pumps located outside the Reactor Building are evaluated for missiles associated with potential failure due to overspeed. The maximum no-load speed of these pumps is equivalent to associated motor operating speed. No pipe break or other single failure in a pump suction line results in pump speeds exceeding the no-load speed. Pump casings are designed to contain impeller fragments should an impeller fail. Therefore, missiles generated by pumps outside the Reactor Building are not postulated.

Components within the NSSS supplier’s scope outside the Reactor Building have been evaluated for potential missile sources. Valves in high pressure systems have been reviewed. As a result of this review, it is concluded that there are no credible sources of missiles associated with valves since there is no single failure associated with any potential valve parts that can result in the generation of a missile. Therefore, there are no postulated missiles associated with valves within the NSSS supplier’s scope outside the Reactor Building.

Valves with threaded stems and backseats are not postulated as potential missile sources because of the unlikelihood of coincident failure of both the threaded stem and the backseat. Valve bonnets are not postulated as potential missile sources when the allowable stress for bonnet retaining ring material is less than 20 percent of the material yield strength.

Bolted valve bonnets are not postulated as missiles since the safety factor for the bolting is greater than 4. Valves outside the Reactor Building were reviewed and none were postulated as missiles.

(The main feedwater check valve bonnets were previously postulated as missiles. These valves were replaced, because of feedwater water hammer concerns, with those of another design which meet the criteria described above).

Non-seismically supported piping and components were considered as a source of gravity missiles.

High pressure compressed gas containers are postulated as missile sources due to rupture and rocketing. Discussion of this analysis is provided in Section 3.5.1.1.3.

3.5.1.1.2 Missile Protection Methods

The design basis for protection of safety-related systems and components against postulated missiles outside the Reactor Building is to provide for continued safe operation or shutdown under operating conditions, including transients and accidents.

Protection of safety-related systems and components from postulated missiles is accomplished by one, or more, of the following methods:

1. Compartmentalization

   Equipment is enclosed in missile protected compartments.

2. Barriers

   Barriers are erected to stop missiles either at the source or at equipment locations.

3. Separation

   Redundant components of vital systems are separated by one or a combination of the following methods:

   a. Components are located within separate cubicles.
   b. Adequate spatial separation is provided between redundant components and electric circuits.
   c. Physical barriers are installed, such as concrete block, concrete or steel walls.

4. Equipment Design

   Structures or components can, by virtue of design, withstand impact of postulated missiles without loss of function.

5. Strategic Orientation

   Equipment or components are so oriented that postulated missile paths are directed away from equipment and components requiring protection.

6. Distance

   Equipment is located out of range of postulated missiles.

Safety-related instrument and control components and instrument impulse lines outside the Reactor Building, which are required for safe plant shutdown, are not in the paths of postulated missiles.

A seismic induced physical interactions program ensured that safety-related systems and components required for safe plant shutdown would not be prevented from performing their intended safety functions as a result of physical interactions with non-safety related structures, systems, and components. This program consisted of seismically supporting such items as non-safety cable trays, HVAC ducts, and electric cabinets in areas containing safety-related components required for safe plant shutdown. Plant walkdowns were then carried out to identify for future evaluation other possible missile sources such as non-safety piping, tanks, pumps, motors, and light fixtures; which, if their supports failed, could impact on safety-related systems and components required for safe plant shutdown. Additional supports were provided where required.

Safety related systems and components outside the Reactor Building that are required for safe plant shutdown under all plant conditions are listed in Table 3.5-2.

3.5.1.1.3 Missiles Generated by Components Containing Compressed Gas

Missiles are postulated to result from rupture of a gas cylinder, rocketing of a gas cylinder due to failure of the valve, and explosion of a hydrogen storage tank. The events just listed bound the spectrum of missile-generating accidents associated with compressed gas containers. None of these events is considered to be a credible occurrence; however, without supporting probabilistic data, the potential impacts of these events on safety-related equipment has been examined. Components containing compressed gas are installed at various locations outside of buildings housing safety-related equipment, with any exceptions identified and analyzed on a case-by-case basis. Section 3.5.1.4 demonstrates that components located outside of Seismic Category I structures need not be protected from design basis missiles. Therefore, missiles generated by compressed gas components are normally only analyzed for their ability to penetrate Seismic Category I structures. Postulated missiles generated by compressed gas components inside of Seismic Category I structures are specifically analyzed to demonstrate postulated failures associated with compressed gas components have no adverse affects on safety-related equipment inside of Seismic Category I structures.

Reference 4 provides formulas for determining the penetration of concrete by high velocity missiles and the mass and velocity of fragments produced by explosions. The penetration of structural concrete by a solid, cylindrical missile of high strength steel is estimated by:

$$X_f = (0.162 \times 10^{-5}) W_f^{0.4} v_s^{1.8} K$$

Where:

X_f = penetration depth (in)

W_f = fragment weight (oz)

v_s = striking velocity (ft/sec)

K = hardness factor (1 for armor piercing steel)

Note: the equation listed above is based on a concrete compression strength of 5000 psi. According to Reference 4, this equation can be corrected for other strengths by multiplying Xf by the square root of the ratio of 5000 psi to the strength of interest. A compression strength of 3000 psi was used in this analysis, which is listed in Section 3.8.4.1 as the minimum compressive strength of Seismic Category I structures.

The maximum fragment weight resulting from an explosion of a cylindrical metal casing is given by Reference 4 as:

$$W_f = \left(M_a \ln\left(8 \frac{wc}{M_a^2} \right) \right)^2$$

Where:

$$M_a = 0.3 t^{\frac{5}{6}} d^{\frac{1}{3}} \left(1 + \frac{t}{d} \right)$$

and

W_f = fragment weight (oz)

W_c = casing weight (lb)

t = casing thickness (in)

d = casing diameter (in)

The explosion or rupture is conservatively assumed to occur at point blank range from the target structure, and drag effects are ignored. The striking velocity, then, is equal to the maximum fragment velocity resulting from the explosion. The maximum fragment velocity is given by Reference 4 as:

$$v_o = G\sqrt{\frac{\frac{W}{W_c}}{1+0.5\frac{W}{W_c}}}$$

Where:

v_o = initial fragment velocity (ft/sec)

W = explosive yield (lb-TNT)

W_c = casing weight (lb)

G = Gurney velocity for TNT (6490 ft/sec)

For explosions occurring more than 20 feet from the target structure, it is reasonable to calculate a reduced striking velocity. Reference [4] gives this velocity as:

$$v_s = v_o e^{-0.004 R_f W_f^{-\frac{1}{3}}}$$

Where:

v_s = striking velocity (ft/sec)

v_o = initial fragment velocity (ft/sec)

R_f = distance traveled by the fragment (ft)

Three bounding cases were analyzed: nitrogen cylinder rupture, hydrogen storage tank explosion and nitrogen cylinder rocket. Detailed analyses of these cases is found in Reference 18. The results of these analyses are summarized below.

Rupture of a standard high-pressure nitrogen cylinder may result in a release of energy equivalent to 1 lb-TNT. An equivalent TNT explosion could potentially generate a fragment missile of up to 5 ounces, traveling at an initial velocity of 585 ft/sec. Such a missile would penetrate less than 0.4 inches into a concrete structure.

Explosion of one of the bulk hydrogen storage tanks may result in a release of energy equivalent to 274 lb-TNT. A 70 ounce, 1526 ft/sec fragment missile could be generated by such an explosion. Since hydrogen tanks are not located within 275 feet of any Seismic Category I structure, the striking velocity is reduced to 1168 ft/sec. Such a missile could penetrate up to 3.8 inches into a concrete structure. All Seismic Category I structures at this site are 2 feet thick,

double re-enforced; therefore, this missile may result in spalling and cracking of the concrete, but will not penetrate and damage components housed within.

Assuming that an accident were to occur (such as breaking the valve after falling over) that resulted in a high-pressure nitrogen cylinder rocketing, the cylinder could reach an impulse of 95,500 lbm-ft/sec. The striking velocity for a 100 lb cylinder would be 955 ft/sec. Conservatively assuming the cylinder missile weight to be 2240 ounces (140 lb), the resulting penetration depth would be 10.6 inches. Since a gas cylinder is a thin-walled vessel and not a solid projectile, much of the impact energy would be dissipated by vessel deformation, resulting in less actual penetration. Cylinder impact may result in cracking and spalling of the structure, but will not penetrate and damage components housed within.

3.5.1.2 Internally Generated Missiles (Inside Containment)

3.5.1.2.1 Missile Selection

Systems and components located inside the Reactor Building are examined to identify and classify potential missiles.

Non-Safety related systems inside containment are low energy systems. Therefore, generation of missiles from these systems need not be postulated.

Catastrophic failure of the reactor vessel, steam generator, pressurizer, reactor coolant pump casings, and piping resulting in the generation of missiles is not postulated because massive and rapid failure of these components is unlikely due to: the material characteristics; inspections; quality control during fabrication, erection, and operation; conservative design; and prudent operation as applied to the particular component.

Valves within the reactor coolant pressure boundary have been examined to identify potential missiles. As a result of this review, there are no credible failures that could result in missile formation. Therefore, valves are not considered a credible source of missiles.

Motor operated and air operated valves contain design features which effectively preclude the ejection of valve stems. Valves are designed against bonnet to body connection failure and subsequent bonnet ejection by means of the following:

1. Compliance with the ASME Code, Section III.
2. Control of load during tightening of bonnet to body studs.

Reactor coolant pressure containing parts are designed in accordance with the requirements of the ASME Code, Section III, Class 1. The complete valves are hydrostatically tested in accordance with the ASME Code, Section III. Valve bodies and bonnets are also volumetrically and surface tested to verify soundness.

In the special case of those valves located on the top of the pressurizer which extends above the operating deck, certain missiles, although also considered incredible, are postulated and protection is provided, due to the greater potential for damage to the Reactor Building liner, engineered safety features pipes, and components located outside the secondary shield wall. For this case, the pressurizer and associated piping and valves are enclosed in a separate concrete cubicle designed to contain the postulated pressurizer valve missiles listed in Table 3.5-3.

Postulated missiles generated inside the Reactor Building are listed in Table 3.5-3. Missile numbers in the following paragraphs are assigned for ease of reference to Table 3.5-3.

Missile 1 consists of three resistance temperature detectors located on the hot legs of reactor coolant piping. Rupture locations are postulated around the weld between the boss and the piping. A 10 degree expansion angle jet is postulated for these jet propelled missiles. Application of the modified Petry formula (Reference 1) results in estimated penetration of 0.01 inches into the 3 foot, 6 inch thick concrete shield wall.

Missile 2 consists of three resistance temperature detectors located on the cold legs of reactor coolant piping. Rupture locations are postulated around the weld between the boss and the piping. A 10 degree expansion angle jet is postulated for these jet propelled missiles. Application of the modified Petry formula (Reference 1) results in estimated penetration of 0.01 inches into the 3 foot, 6 inch thick concrete shield wall.

Missile 3 consists of three 6 inch safety valves located in the pressurizer compartment and on the top of the pressurizer. A tearing between bonnet and valve body is postulated for these jet propelled missiles. A velocity of 180 ft/sec is estimated as a result of application of analytical methods. Application of the modified Petry formula (Reference 1) results in estimated penetration of 2.1 inches into the 2 foot thick concrete slab.

Missile 4 consists of two 4 inch diaphragm operated control valves located in the pressurizer compartment and on the side of pressurizer. Rupture locations are postulated between the drive shaft and vee ball. It is postulated that the valve drive shaft and diaphragm actuator are forced out by the 2300 psig reactor coolant pressure and form a jet propelled missile. A velocity of 130 ft/sec is estimated as a result of application of analytical methods. Application of the modified Petry formula (Reference 1) results in estimated penetration of 0.5 inches into the pressurizer compartment wall for Valve 1-PCV-444D and 2.66 inches into the wall corbal concrete missile shield provided for Valve 1-PCV-444C.

Missile 5 was a control rod drive mechanism (CRDM) housing plug located in the reactor compartment on the top of reactor. The top plug on the CRDM Housing has been eliminated by the new design of the CRDM Travel Housings. The end of the travel housing is an integral forging of the overall Travel Housing, thus eliminating the end Cap Housing Plug. This change was made with the Replacement Reactor Vessel Closure Head per ECR 50868.

Missile 6 is a control rod drive shaft located in the reactor compartment on the top of reactor. After a postulated failure of the top of the Travel Housing, the drive shaft is postulated to be pushed out of the core by the 2300 psi differential pressure across the drive shaft. The drive shaft

and control rod cluster, latched together, are assumed to be fully inserted when the accident starts. After approximately 12 feet of travel, the control rod cluster spider hits the underside of the upper support plate. Upon impact, the flexure arms in the coupling joining the drive shaft and control cluster fracture, completely freeing the drive shaft from the control rod cluster. It is assumed that the control rod cluster is completely stopped by the upper support plate. The drive shaft continues to be accelerated until its top hits the missile shield. A velocity of 180 ft/sec is estimated as a result of the application of analytical methods with a velocity of 185 ft/sec use for conservation. Missile 6 travels approximately 50 inches from the top of the CRDM Travel Housing to the bottom of the Integrated Head Assembly (IHA) mounted missile shield. The application of the BRL Formula (Reference 2) and the modified Petry Formula (Reference 1) determine the penetration of the missile into the steel plate that makes up the IHA mounted missile shield. Conservative application of this criteria identifies a penetration of approximately 1.357 inches into the 2 inch thick missile shield. The missile can originate from any of the 48 CRDM locations on the Replacement Head. Various locations were evaluated to ensure structural integrity of the missile shield and the IHA are maintained.

Missile 7 consists of two instrument wells located on the wall of the pressurizer. Failure of the weld between the instrument well and the pressurizer wall is postulated. A velocity of 100 ft/sec is estimated. Application of the modified Petry formula (Reference 1) results in estimated penetration of 3 inches into the 3 foot thick pressurizer compartment wall.

Missile 8 consists of 78 pressurizer heaters located on the bottom shell of the pressurizer. It is postulated that the pressurizer heaters could loosen and become jet propelled missiles. A velocity of 55 ft/sec is estimated. Application of the modified Petry formula (Reference 1) results in penetration of 0.144 inches into the 3 foot, 6 inch thick concrete floor.

Within the Reactor Building there are no gravity missiles which could constitute a threat to safety class equipment or systems. Gratings, handrails and stair treads inside the Reactor Building are fastened in place by welds, pins or clamps. Overhead light fixtures, located above safety related equipment, are installed by means of hangers capable of withstanding seismic forces.

Non-Seismically supported piping and components were considered as a source of gravity missiles.

3.5.1.2.2 Missile Protection Methods

The design basis is that postulated missiles generated within the Reactor Building in coincidence with a loss of coolant accident, do not cause loss of function of any redundant engineered safety feature. Protection of safety related equipment and redundant components of vital systems from postulated missiles is accomplished by one, or more, of the methods described in Section 3.5.1.1.2.

Thicknesses of barriers, including walls, slabs and specially designed barriers, which protect safety class equipment or systems satisfy the criteria discussed in Section 3.5.3. Thus, scabbing or the generation of secondary missiles from the nonimpacted face of such a barrier is precluded. Concrete fragments ejected from the impacted face (spalling effect), if any, will have energies too

low for consideration as missiles due to the small weight and velocity of such fragments. Fragments and the initial missile constitute no threat as gravity missiles to safety class equipment or systems as secondary missiles during the drop following impact.

Safety related instrument and control components and instrument impulse lines inside the Reactor Building, which are required for safe plant shutdown, are not in the paths of postulated missiles.

A seismic induced physical interactions program ensured that safety-related systems and components required for safe plant shutdown would not be prevented from performing their intended safety functions as a result of physical interactions with non-safety related structures, systems, and components. This program consisted of seismically supporting such items as non-safety cable trays, HVAC ducts, and electric cabinets in areas containing safety related components required for safe plant shutdown. Plant walkdowns were then carried out to identify for future evaluation if other possible missile sources such as non-safety piping, tanks, pumps, motors, and light fixtures; which, if their supports failed, could impact on safety related systems and components required for safety plant shutdown. Additional supports were provided where required.

Safety related structures, systems, and components inside the Reactor Building which are required for safe shutdown of the plant under all operating conditions are listed in Table 3.5-4.

3.5.1.3 Turbine Missiles

Turbine missiles are discussed in Reference 19.

3.5.1.4 Missiles Generated by Natural Phenomena

Potential tornado missiles which are assumed to be generated by the design basis tornado, described in Section 3.3., are listed in Table 3.5-5. The properties of the missiles, needed to determine penetrations, are also indicated by Table 3.5-5.

The utility pole and the automobile missiles are limited to elevations of 30 feet above grade within one-half mile of the plant structures. Hence, these missiles are not postulated as missiles on roofs which are at least 30 feet above grade.

Virgil C. Summer Nuclear Station components important to safety are, with certain exceptions listed in Table 3.5-6, housed within Seismic Category I structures that are designed to withstand the effects of the design basis tornado, including tornado missiles. The exceptions include safety class components located wholly, or partially, outside of Seismic Category I structures. These components, however, are not necessary to ensure the following:

1. Integrity of the reactor coolant pressure boundary.
2. Long term capability to shut down the reactor and maintain safe shutdown conditions.
3. Capability to prevent accidents that could result in potential offsite exposures that are a significant fraction of the guideline exposures of 10 CFR 100.11 or 10 CFR 50.67.

The safety related components listed in Table 3.5-6 are discussed in the following paragraphs.

The locations of the refueling water storage tank (RWST), sodium hydroxide (NaOH) storage tank, makeup water storage tank (MWST), and the condensate storage tank (CST) are shown by Figures 1.2-1, 1.2-4, 1.2-5, and 1.2-10. Emergency feedwater (EFW) pump suction line and EFW pump recirculation line piping is also connected to the condensate storage tank and partially located outdoors.

The diesel generator combustion air intakes are protected by missile resistant structural labyrinths and therefore are considered to be indoors. A short segment of the diesel generator exhaust pipes are exposed on the roof of the Diesel Generator Building. The general arrangement of the diesel generator intakes and exhausts are shown by Figures 1.2-13 and 1.2-14.

The diesel generator day tank vents and the diesel generator fuel oil storage tank vents extend outside the tornado protected structures. The location of the diesel generator fuel oil storage tanks is shown in Figure 1.2-1.

A portion of the EFW turbine exhaust steam stack is not physically protected from tornados since the stack extends through the roof of the structure in which it is located. The general arrangement of this stack is shown in Figures 1.2-11,1.2-13, and 1.2-26.

Portions of the main steam (MS) system power operated relief valve discharge stacks are not physically protected from tornados since the stacks extend through the roofs of the structures in which they are located. The MS power operated relief valve discharge stacks are not classified as safety related but provide the capability to allow for a controlled cooldown of the primary system. The general arrangement of these stacks is shown in Figures 1.2-5,1.2-12,1.2-13, and 1.2-26.

The control room air intake ductwork penetrates the wall and roof of the Control Building and the general arrangement is shown in Figure 1.2-26. The Control Building exhaust air relief heads are located on the Control Building roof and are not provided with tornado missile shields. The general arrangement for these components is provided in Figures 1.2-16 and 1.2-26. The chilled water expansion tanks are located on the Control Building roof underneath the tornado missile shield provided for the Control Building outside air openings. Based on the structure and component arrangement the expansion tanks are partially exposed to a potential tornado missile strike. The general arrangement of the chilled water expansion tanks is shown in Figures 1.2-16 and 1.2-26.

The safety class, seismic category, quality assurance class, and code designation of systems and components; and the seismic category of structures; are provided in Tables 3.2-1 and 3.2-2, respectively. The location of equipment listed in Table 3.2-1 is shown by layout drawings, Figures 1.2-1 through 1.2-29. Those safety related items required for integrity of the reactor coolant pressure boundary, safe shutdown, or to prevent accidents which could result in potential offsite radiation exposure are either located within buildings designed for tornado missile protection, are provided with missile shields, or are located external to tornado missile proof structures. Those components located external to tornado missile proof structures are listed in Table 3.5-6. The refueling water storage tank, sodium hydroxide storage tank, reactor makeup water storage tank, and condensate storage tank including the outdoor portion of the EFW suction line are designed to mitigate the consequences of a design basis accident. However, these tanks and components would either be emptied during the injection phase of the post accident sequence or alternate

sources of makeup water have been provided as discussed in Section 3.5.3. Therefore, these tanks are not required as part of the long term Emergency Core Cooling System (see Appendix 3A discussion on Regulatory Guide 1.117) and do not require protection from tornado missiles.

The probability of tornado missiles striking the remaining components listed in Table 3.5-6 is evaluated and included in the strike probability computation. Protection of these outdoor components against tornado missiles is demonstrated by strike probability computations which indicate that the tornado missile strike probability for all missiles and targets is less than 1.0×10^{-7}. Therefore, no additional physical missile protection is provided.

Systems and components listed in Table 3.2-1 required to ensure the integrity of the reactor coolant pressure boundary and to maintain safe shutdown conditions or to provide the capability to prevent accidents which could result in exceeding offsite radiation exposure limits, are provided tornado missile protection through location within Seismic Category I structures, missile barriers (see Table 3.5-7), or probability analysis. The total probability per year of potential tornado missiles, generated by the design basis tornado, striking external safety related targets or penetrating a critical opening and striking critical components beyond the exposed walls and roofs of Seismic Category I structures is determined. Tornado missile protection is provided for the missiles listed in Table 3.5-5 when the total probability, PT, per year per missile satisfies the following equation:

$$P_T = \sum_{i=1}^{i=n} P_1 x P_2 x P_3 x P_4 x P_5 x P_6 x P_7 x P_8 \leq 1.0 x 10^{-7}$$

where:

n = Total number of external targets and openings on the exposed surfaces of Seismic Category I structures.

P_1 = Probability of the design basis tornado striking the reactor site = 1.0×10^{-3} (see Reference [14])

P_2 = Probability of a missile being acted upon by a maximum wind over a sufficiently long distance, conservatively assumed to be 1.0.

P_3 = Probability of an object maintaining an orientation inside the tornado which exposes its maximum cross-sectional area to the full force of the wind. Since missiles tend to tumble, this probability will be quite low; a conservative estimate is 1.0×10^{-1} (see Reference [15]).

P4 = Probability of a missile being hurled to the exact location of the specific target. Missiles of the type being considered could land anywhere within the area confined by the width of tornado damage path. This area is about

$$\frac{\pi(500)^2}{4} = 196{,}350 \text{ ft}^2$$

compared to the area of the external target or the opening, A_T. Therefore, the probability of the geometric center of the object being hurled to the external target or opening is:[15]

$P_4 = A_T/196{,}350$

P_5 = Probability of the missile being in an orientation that will allow it to penetrate the target opening. Since the missile would have no preferred angle of impact on the target opening, the probability of impacting within the critical angle required to cause penetration is dependent upon the length of the missile and the general dimensions of the opening. Therefore the probability can be expressed as:

$$P_5 = \frac{(2\theta_1)}{(180)}\frac{(2\theta_2)}{(180)}$$

Where:

θ_1 = Arcsin x/lm,

θ_2 = Arcsin y/lm,

x = One dimension of the opening,

y = Other dimension of the opening,

lm = Length of the missile, or
P_5 = 1.0 for external targets.

P_6 = Probability of a missile impacting a target opening of specific dimension and the ability of the missile to pass through the target opening by nature of the frontal area of the missile.

$$P_6 = \frac{A_T - A_M}{A_T}$$

Where:

A_T = Area of target

A_M = Frontal area of missile

If A_T is greater than A_M, $P_6 = 1.0$.
If A_T is less than A_M, $P_6 = 0.0$, or
$P_6 = 1.0$ for external targets.

P_7 = Probability that a missile will pass around structures or barriers to external targets or openings on the exposed surfaces or walls of Seismic Category I structures. The directional probability density per unit solid angle can be expressed as:

$$P_7 = \frac{1}{2}\left(\frac{\theta_H}{180} \times \frac{\theta_V}{180}\right) \leq 0.5$$

Where θ_H and θ_V are the angles in the horizontal and vertical planes, respectively, through which the missile must pass to strike the opening.

P_8 = Probability of a missile striking the exact location of components required to ensure the integrity of the reactor coolant pressure boundary and to maintain safe shutdown conditions or to provide the capability to prevent accidents which could result in exceeding offsite radiation exposure limits after the missile has passed through the opening on the exposed surface or wall of a Seismic Category I structure. The directional probability density per unit solid angle per component can be determined using the following expression:

$$P_8 = \frac{\theta_H}{B_H} \times \frac{\theta_V}{B_V}$$

Where θ_H and θ_V are the angles in the horizontal and vertical planes, respectively, through which the missile must pass to strike the critical component and B_H and B_V are the preferred angles of impact through which the missile must pass to penetrate through the opening in the horizontal and vertical planes, respectively. The angles B_H and B_V are defined by the wall or roof thickness and the physical dimensions of the opening.

P_8 is evaluated for all critical components located behind the subject opening.

$P_8 = 1.0$ for external targets.

3.5.1.5 Missiles Generated by Events near the Site

3.5.1.5.1 Introduction

In Section 2.2.3, it was determined that there were no design basis accidents external to the site (events with an annual probability of occurrence greater than 10^{-7}) which would generate high energy missiles and fragments impacting the Reactor Building walls. The events analyzed include transportation, (highway, railway and air) industrial (including pipelines) and military proximity to the site.

3.5.1.5.2 Penetration by Onsite Missiles

Compressed gas containers stored or installed onsite are considered potential sources of high velocity fragment missiles. Evaluation of these missiles are included in Section 3.5.1.1.3.

3.5.1.5.3 Pipeline Explosions

The nearest pipeline to the site containing natural gas is located about 13,000 feet from the Reactor Building. A surface ignition of the natural gas (methane) carried in this line would not produce a detonation resulting in high energy fragments. However, if leaking gas were to permeate the soil, it could produce a cratering explosion, throwing soil up and away from the leak point. The detonation speeds of the exploding volume would be reduced below those of ordinary gas mixtures. The maximum range of soil and small rocks in the pipeline cover are estimated at 500 feet, which is the minimum safe distance recommended for separating personnel from ditching explosions using TNT (Reference 5). Thus, no detrimental effects on plant structures or personnel are considered credible.

3.5.1.5.4 Offsite Hazards Less Likely Than 10^{-7} Per Year

3.5.1.5.4.1 Industrial Facilities

Although a storage site for explosives was identified (see Section 2.2.2) about 2.5 miles from the reactor, the maximum range of high energy fragments from detonation of these explosives would be approximately 1 mile. This range is determined by extrapolating the velocity decay to 0.1 ft/sec, a value which is below the damage threshold for structures. Thus, no detrimental effects on plant structures or personnel are considered credible.

3.5.1.5.4.2 Transportation Facilities

The probability of a rail car accident involving ordinance and explosive materials on the rail line near the site was determined in Section 2.2.3 to be less than 10-7 per year. In 1975, no traffic of this type was carried by rail within 100 miles of the site by the Southern Railway (which operates the lines near the site).

3.5.1.5.4.3 Military Activities

Military activities generating missiles, fragments and shells within 30 miles of the site are discussed in Section 2.2.2.

3.5.1.6 Aircraft Hazards

The analysis of potential aircraft hazards is discussed in Section 2.2.2.5. Results of this analysis indicate an extremely low probability that an aircraft failure in the vicinity of the site would result in a plant failure. Based upon this extremely low probability, discussed in Section 2.2.2.5, the Virgil C. Summer Nuclear Station design does not consider aircraft impact.

3.5.2 Systems To Be Protected

Safety class systems and components and Seismic Category I structures whose failure could result in radiological consequences offsite or that are required to shut down the plant and maintain it in a safe condition are listed in Tables 3.5-2 and 3.5-4. Separation and independence of these systems, components, and structures are demonstrated by the system drawings presented in the applicable sections which discuss those systems.

3.5.3 Barrier Design Procedures

The exposed walls and roofs of Seismic Category I structures have minimum concrete thicknesses of 24 inches and are reinforced each way, each face with a minimum of number 9 bars at 12 inches, center to center. Based upon the results of tests at Sandia Laboratories (References 6,7,8) and by Calspan Corporation (Reference 9), these structural elements are more than adequate to resist impact of the postulated tornado missiles.

The Fuel Handling Building exterior walls are not designed to prevent the penetration of tornado missiles. However, the walls of the spent fuel pool and safety dam components are protected and designed to prevent penetration, spalling or overall failure due to impact of tornado generated missiles.

Entry of tornado generated missiles into the top of the spent fuel pool (28 feet above grade) is very unlikely.

The Fuel Handling Building framework is designed with sufficient redundancy that failure of any structural element due to missile impact does not cause a general failure. The framework is also designed to resist tornado generated pressure forces. The metal wall and roof panels are designed to collapse under tornado pressure loads. However, due to their light weight and large area, these panels will not cause damage to the spent fuel elements should they fall into the spent fuel pool.

The loss of function of the refueling water storage tank, sodium hydroxide (NaOH) storage tank, makeup water storage tank and condensate storage tank will not affect the capability to shut down the reactor and maintain it in a safe shutdown condition (hot standby) since either the tanks will be emptied during the injection phase or alternate sources of makeup water are provided. These

alternate makeup water sources are protected against tornado missiles or are housed within Seismic Category I structures, designed to withstand the effects of the design basis tornado, including tornado missiles.

The alternate source of borated makeup water for the primary system is the boric acid tanks; the alternate source for the secondary system is the Service Water System (see Section 10.4.9.2).

Loss of function of the diesel generator combustion air intakes and exhausts is not anticipated. The intakes are protected by missile resistant structural labyrinths (see Figure 9.5-10). Only a short section of each diesel generator exhaust pipe is exposed above the Diesel Generator Building roof. The probability of a tornado missile impacting the short exposed length of pipe has been determined and included in the tornado missile strike probability computation which concluded that protection is provided based on a low strike probability. Table 3.5-6 has been revised to indicate that only the short sections of exhaust piping are outdoors. The intakes are no longer located outdoors.

Loss of function of the Control Building outside air and relief openings is not anticipated. The outside air openings are protected by missile shields (see Figure 1.2-26). The probability of impact of a tornado missile on the exhaust air relief heads has been included in the tornado missile strike computation which concluded that protection is provided based on a low strike probability. In addition, the Control Building Ventilation System can be operated satisfactorily in the recirculation mode even assuming loss of function of the outside air and relief openings.

Barrier requirements for internally generated missiles are checked on a case by case basis using either the modified National Research Defense Committee (NRDC) formula (Reference 10), for concrete barriers, or the BRL formula (Reference 11), for steel barriers.

Effective loads due to impact of these missiles are derived by idealizing the target as an equivalent single-degree-of-freedom structure.

Ductility ratios for reinforced concrete structures are in accordance with Reference 12. Barriers of steel are designed with the ductility ratio for flexure not to exceed 20 for plates, walls, or slabs and 1.3 for columns.

For missiles considered to be nondeformable, such as steel missiles, the investigation encompasses the cases of no penetration and penetration. This procedure is in accordance with that outlined by Williamson and Alvy (Reference 13).

In the case of no penetration, momentum transfer principles are used to calculate an equivalent static load. This load is shown to be less than the load that the structure can withstand.

For the case of penetration, energy balance techniques are used to define a triangular load-time history. The required ductility factor for the target structure is estimated using standard analytical procedures and is shown to be within the permissible value.

The above approaches are found to be conservative when considering the impact of deformable missiles. A significant portion of the kinetic energy of such a missile is dissipated in the deformation of the missile and this fact is taken into account. The impact of the missile upon a rigid barrier is studied and a reaction-time history for the barrier is developed. An idealized version of this time history is then treated as the loading in the target structure response analysis. The corresponding ductility factor is shown to be within the permissible value.

Wall and roof concrete thicknesses and concrete strengths at the specified age for each exterior tornado missile barrier are summarized by Table 3.5-7. In addition, Table 3.5-7 provides a list of components protected by exterior tornado missile barriers. These components are required to ensure the integrity of the reactor coolant pressure boundary and to maintain safe shutdown conditions or to provide the capability to prevent accidents which could result in exceeding offsite radiation exposure limits.

The minimum compressive strength of structural concrete for the exposed walls and roofs of Seismic Category I structures is 3000 psi in 28 days. The thicknesses of exposed walls and roofs of Seismic Category I structures are defined earlier in this section. The safety class, seismic category, quality assurance class, and code designation of systems and components are provided in Table 3.2-1. The seismic category of structures is presented in Table 3.2-2. The location of equipment listed in Table 3.2-1 is shown by Figures 1.2-1 through 1.2-29.

3.5.4 References

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Table 3.5-2
Safety Class Systems and Components and Seismic Category I Structures
Outside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against	Provisions for Protection
Chemical and Volume Control System		9.3.4		
Letdown Heat Exchanger	Auxiliary Building		None	Compartmentalization by concrete wall
Reactor Coolant Filter	Auxiliary Building		None	Compartmentalization by concrete wall
Volume Control Tank	Auxiliary Building		None	Concrete wall
Seal Water Return Filter	Auxiliary Building		None	Compartmentalization by concrete wall
Seal Water Heat Exchanger	Auxiliary Building		None	Compartmentalization by concrete wall
Charging Pumps	Auxiliary Building		None	Physical separation and compartmentalization by concrete wall
Seal Water Injection Filters	Auxiliary Building		None	Physical separation and compartmentalization by concrete wall
Boric Acid Tanks	Auxiliary Building		None	Concrete wall

Table 3.5-2 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Outside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against	Provisions for Protection
Boric Acid Transfer Pumps	Auxiliary Building		None	Physical separation and compartmentalization by concrete wall
Boric Acid Filter	Auxiliary Building		None	Concrete wall
Boric Acid Blender	Auxiliary Building		None	Concrete wall
Chemical and Volume Control System Piping(1)	Auxiliary Building Penetration Access Area		None	Physical separation
Safety Injection System		6.3		
Safety Injection System Piping	Auxiliary Building Penetration Access Area, Fuel Handling Building		None	Physical separation
Residual Heat Removal System		5.5.7		
RHR Pumps	Auxiliary Building		None	Physical separation and compartmentalization by concrete wall
Residual Heat Exchangers	Auxiliary Building		None	Physical separation and compartmentalization by concrete wall

Table 3.5-2 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Outside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against	Provisions for Protection
Residual Heat Removal System Piping	Auxiliary Building Penetration Access Area		None	Physical separation
Reactor Building Spray System		6.2.3		
Reactor Building Spray Pumps	Auxiliary Building		None	Compartmentalization and physical separation by concrete wall
Sodium Hydroxide Storage Tank	Auxiliary Building		None	Compartmentalization by concrete wall
Reactor Building Spray System Piping(1)	Auxiliary Building Penetration Access Area		None	Physical separation
Spent Fuel Cooling System		9.1.3		
Refueling Water Storage Tank	Auxiliary Building		None	Compartmentalization by concrete wall
Component Cooling System		9.2.2		
Component Cooling Pumps	Intermediate Bldg.		None	Separation by distance

Table 3.5-2 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Outside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against	Provisions for Protection
Component Cooling Heat Exchangers	Intermediate Bldg.		None	Physical separation
Booster Pumps	Intermediate Bldg.		None	Separation by distance
Surge Tank	Intermediate Bldg.		None	Compartmentalization by concrete wall
Component Cooling System Piping(1)	Auxiliary Building Penetration Access Area, Intermediate Bldg.		None	Physical separation
Main Steam System		10.3		
Main Steam System Piping(1)	Penetration Access Area, Intermediate Bldg.		None	Strategic orientation
Feedwater System		10.4.7		
Feedwater System Piping(1)	Penetration Access Area, Intermediate Bldg.		None	Strategic orientation
Emergency Feedwater System		10.4.9		
Emergency Feedwater Pumps	Intermediate Bldg.		None	Compartmentalization and physical separation by concrete wall

Table 3.5-2 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Outside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against	Provisions for Protection
Emergency Feedwater System Piping(1)	Penetration Access Area Intermediate Bldg.		None	Strategic orientation
Reactor Makeup Water System		9.2.7		
Reactor Makeup Water Storage Tank	Auxiliary Building		None	Compartmentalization by concrete wall
Reactor Makeup Water Pumps	Auxiliary Building		None	Physical separation and compartmentalization by concrete wall
Reactor Makeup Water System Piping(1)	Auxiliary Building		None	Physical separation
Service Water System		9.2.1		
Service Water Pumps	Service Water Pumphouse		None	Physical separation and compartmentalization by concrete wall
Service Water Booster Pumps	Intermediate Bldg.		None	Compartmentalization by concrete wall

Table 3.5-2 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Outside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against	Provisions for Protection
Service Water System Piping(1)	Intermediate Bldg. Penetration Access Area, Service Water Pumphouse		None	Physical separation
Chilled Water System		9.4.7		
Chilled Water Pumps	Intermediate Bldg.		None	Compartmentalization by concrete wall
HVAC Mechanical Chillers	Intermediate Bldg.		None	Compartmentalization by concrete wall
Chilled Water System Piping(1)	Intermediate Bldg. Auxiliary Building Control Building		None	Physical separation
Emergency Diesel Generator Services System		9.5.4, 9.5.5, 9.5.6, 9.5.7, 9.5.8		
Fuel Oil Transfer Pumps	Diesel Generator Building		None	Physical separation by concrete wall
Diesel Generator Coolers	Diesel Generator Building		None	Physical separation by concrete wall
Air Receiver Tanks	Diesel Generator Building		None	Physical separation by concrete wall

Table 3.5-2 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Outside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against	Provisions for Protection
Fuel Oil Day Tanks	Diesel Generator Building		None	Physical separation by concrete wall
Emergency Diesel Generator Services System Piping(1)	Diesel Generator Building		None	Physical separation by concrete wall
Emergency Diesel Generators	Diesel Generator Building	8.3	None	Physical separation by concrete wall
Electrical Components		8.0		
120V Inverters, Nuclear Steam Supply System	Control Building		None	-
120V, a-c, Vital Distribution Panels	Control Building		None	-
Battery Bus Panels	Intermediate Bldg.		None	Physical separation by concrete wall
DC Distribution Panels	Intermediate Bldg.		None	Physical separation by concrete wall
125V Batteries	Intermediate Bldg.		None	Physical separation by concrete wall
Battery Chargers	Intermediate Bldg.		None	Physical separation by concrete wall

Table 3.5-2 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Outside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against	Provisions for Protection
Diesel Generator Control Cubicles	Diesel Generator Building		None	Physical separation by concrete wall
Component Cooling Pump Speed Switches	Intermediate Building		None	Physical separation by concrete wall
Service Water Pump Speed Switches	Service Water Pumphouse		None	Physical separation by concrete wall
Component Cooling Pump Transfer Switch	Intermediate Bldg.		None	Concrete wall
Charging Pump Transfer Switch	Auxiliary Building		None	Concrete wall
Engineered Safety Features Motor Control Centers 1DA2X 1DB2X	Intermediate Bldg.		None None	Concrete wall Concrete wall
Engineered Safety Features Motor Control Centers 1DA2Y 1DB2Y	Auxiliary Building		None None	Concrete wall Concrete wall

Table 3.5-2 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Outside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against	Provisions for Protection
Engineered Safety Features Motor Control Centers	Diesel Generator Building		None	Physical separation by concrete wall
Engineered Safety Features Motor Control Centers	Service Water Pumphouse		None	Physical separation by concrete wall
7.2 KV Switchgears	Intermediate Bldg.		None	Concrete wall
7.2 KV Switchgears	Service Water Pumphouse		None	Physical separation by concrete wall
480V Engineered Safety Features Unit Substations 1DA1 1DA2	Intermediate Bldg.		None None	Concrete wall Concrete wall
480V Engineered Safety Features Unit Substation 1DB1	Auxiliary Building		None	Concrete wall
480V Engineered Safety Features Unit Substation	Service Water Pumphouse		None	Physical separation by concrete wall

(1) Piping includes pipes, fittings and valves.

Table 3.5-3
Postulated Missiles Inside the Reactor Building

Missile Number	Description	Tag Number	Elevation and Location	Weight (lbs)	Impact Area (in^2)	Effect
1	9 RTD's of Reactor Coolant Hot Legs	N/A	436'-9" Inside Secondary Shield Wall	11	3.14	Will hit operating floor at elevation 459'-6", and penetrate 0.01 inches into 3'-6" thick concrete
2.	9 RTD's of Reactor Coolant Cold Legs	N/A	436'-9" Inside Secondary Shield Wall	11	3.14	Will hit operating floor at elevation 459'-6", and penetrate 0.01 inches into 3'-6" thick concrete
3	3 Six Inch Safety Valves	1-8010A 1-8010B 1-8010C	480'-2-1/2" Pressurizer Compartment	350	38.5	Will penetrate 2.1 inches into 2 foot thick concrete slab at elevation 486'-6"
4	2 Four Inch Diaphragm Operated Control Valves	1-PVC-444C	464'-6" Pressurizer Compartment	200	50.0	Will penetrate 2.66 inches into concrete missile shield provided on wall.
		1-PVC-444D	464'-6" Pressurizer Compartment	200	50.0	Will penetrate 0.5 inches into 1.5 foot thick concrete wall.
5						
6	Control Rod Drive Shaft	N/A	451'-2" Reactor Compartment	120	2.41	Will penetrate approximately 1.357 inches of the 2 inch steel plate missile shield
7	2 Instrument Wells of Pressurizer	N/A	1 at 477'-3¼" 1 at 444'-8⅜" Pressurizer Compartment	5.5	1.35	Will penetrate 3 inches into 3 foot thick pressurizer compartment concrete wall
8	78 Pressurizer Heaters	N/A	438'-3" Pressurizer Compartment	15	2.4	Will penetrate 0.144 inches into concrete floor at elevation 437'-6"

Table 3.5-4
Safety Class Systems and Components and Seismic Category I Structures
Inside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against (1)	Provisions for Protection
Reactor Building Liner	Reactor Building Wall	3.8.1	1,2,3,4,5,6	Primary and secondary shield walls and missile shield
Reactor Vessel Supports	Reactor Building	5.5.14	None	High strength of support material and strategic orientation
Steam Generator Supports	Reactor Building	5.5.14	None	High strength of support material and strategic orientation
Reactor Coolant Pump Supports	Reactor Building	5.5.14	None	High strength of support material and strategic orientation
Pressurizer Support	Reactor Building	5.5.14	None	High strength of support material and strategic orientation
Reactor Coolant System		5.0		
Reactor Vessel	Reactor Compartment		1,2,5,6	Primary shield wall and missile shield

Table 3.5-4 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Inside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against (1)	Provisions for Protection
Reactor Coolant Pumps	Inside Secondary Shield Wall		1,2	Physical separation and secondary shield wall
Steam Generators	Inside Secondary Shield Wall		1,2	Physical separation and secondary shield wall
Pressurizer	Inside Secondary Shield Wall		3,4	Secondary shield wall
Reactor Coolant Piping (2)	Reactor Building		1,2,3,4	Physical separation and secondary shield wall
Chemical and Volume Control System		9.3.4		
Regenerative Heat Exchanger	Reactor Building		None	Distance and strategic orientation
Excess Letdown Heat Exchanger	Reactor Building		None	Distance and strategic orientation
CVCS Piping(2)	Reactor Building		1,2	Physical separation and secondary shield wall

Table 3.5-4 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Inside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against (1)	Provisions for Protection
Safety Injection System		6.3		
Accumulators	Reactor Building		1,2	Secondary shield wall
Safety Injection System Piping (2)	Reactor Building		1,2	Separation and secondary shield wall
Residual Heat Removal System Piping (2)	Reactor Building	5.5.7	1,2	Physical separation and secondary shield wall
Reactor Building Spray System Piping (2)	Reactor Building	6.2.3	1,2,3,4	Physical separation and secondary shield wall
Main Steam System Piping (2)	Reactor Building	10.3	1,3	Physical separation and secondary shield wall
Feedwater System Piping (2)	Reactor Building	10.4.7	1,2	Physical separation and secondary shield wall
Service Water System Piping (2)	Reactor Building	9.2.1	None	Physical separation
Reactor Building Cooling Units	Reactor Building	6.2.2	None	Secondary shield wall and strategic orientation

Table 3.5-4 (continued)
Safety Class Systems and Components and Seismic Category I Structures
Inside the Reactor Building to be Protected

System, Component or Structure	Location	FSAR Section	Postulated Missiles to be Protected Against (1)	Provisions for Protection
Electrical Components		8.0		
Electrical Containment Penetrations	Reactor Building	6.2.4	1,2,3,4	Physical separation and secondary shield wall
Power, Control and Instrument Cable	Reactor Building	8.0	1,2,3,4	Physical separation and secondary shield wall
Cable Trays	Reactor Building	8.0	1,2,3,4	Physical separation and secondary shield wall
Post Accident Hydrogen Recombiners	Reactor Building	6.2.5	None	Physical separation and secondary shield wall

(1) Missile numbers refer to missiles described in Table 3.5-3.
(2) Piping includes pipe, fittings and valves.

Table 3.5-5
Potential Tornado Missiles

	Tornado Missile	Geometric Properties (1)	Weight (lb)	Velocity (mph)
1.	Utility Pole (2)	L=35 ft, D=14 in	1880	150
2.	Compact Auto (2)	A=6.25 ft^2	2000	150
3.	Wood Plank	A=4 in x 12 in L=12 ft	108	300
4.	Passenger Auto (2)	A=20 ft^2	4000	50
5.	3 inch Schedule 40 Pipe, piece	A=9.62 in^2 L=10 ft	75.8	100
6.	Wood Pole, piece	D=8 in L=12 ft	209	225
7.	Steel Rod	D=1.0 in L=3.0 ft	8	216

(1) L = length, D = diameter, A = minimum cross sectional area
(2) Impact point will not be more than 30 feet above grade

Table 3.5-6
Safety Related Components Located Outdoors

Component	Location Shown by Figure
Refueling Water Storage Tank	1.2-4, 1.2-5, 1.2-10
Reactor Makeup Water Storage Tank	1.2-4, 1.2-5
Sodium Hydroxide (NaOH) Storage Tank	1.2-4
Condensate Storage Tank (CST) (including Emergency Feedwater suction line at CST)	1.2-1
Emergency Feedwater Pump Recirculation Line (at CST)	1.2-1
Emergency Feedwater Turbine Exhaust Steam Stack	1.2-11,1.2-13,1.2-26
Diesel Generator Exhaust Stacks	1.2-13,1.2-14,1.2-26
Diesel Generator Day Tank Vents	1.2-12
Diesel Generator Fuel Oil Storage Tank Vents	1.2-1
Control Room Outside Air Intake Ductwork	1.2-26
Control Building Exhaust Air Relief Heads	1.2-16, 1.2-26
Chilled Water Expansion Tanks	1.2-16, 1.2-26
Main Steam System Power Operated Relief Valve Discharge Stacks*	1.2-5, 1.2-12, 1.2-13, 1.2-26

* The main steam system power operated relief valve discharge stacks are not classified as safety related but provide the capability to allow for a controlled cooldown of the primary system.

Table 3.5-7
Physical Properties and Function of Tornado Missile Barriers

Structure	Fig. No. & Grid Location	Thickness (ft) Wall	Thickness (ft) Roof	Concrete Strength	Components Protected Tag No	Components Protected Equipment
Control Complex	1.2-26 F-13, F-14	2.0	2.0	3000 psi in 28 days	Following equipment, related solenoids, and limit switches:	
					XDP-19A, 19B	Control Room Outside Air Intake Shutoff Damper
					XDP-21A, 21B	Control Room Relief Vent Control Damper
					XDP-22A, 22B	Control Room Return Duct Control Damper
					XDP-23A, 23B	Control Room Emergency Filter Shutoff Damper
					XDP-24A, 24B	Control Room Emergency Fan Discharge Shutoff Damper
					XDP-45	Controlled Access Outside Auxiliary Damper
					XDP-39A, 39B	Computer Room Outside Air Intake Control Damper
					XDP-96	Instrument Repair Room Outside Air Intake Control Damper
					XDP-105A, 105B	Control Room AHU Face and Bypass Control Damper
					XDP-106	Controlled Access Outside Air Intake Manual Isolation Damper

Table 3.5-7 (continued)
Physical Properties and Function of Tornado Missile Barriers

Structure	Fig. No. & Grid Location	Thickness (ft) Wall	Thickness (ft) Roof	Concrete Strength	Components Protected Tag No	Components Protected Equipment
Control Complex (Cont'd)					XDP-112A, 112B	Computer Room Outside Air Intake Control Damper
					XDP-113A, 113B	Relay Room Cooling System Return Air Damper
					XDP-129	Instrument Room Outside Air Damper
					XDP-133A, 133B, 133C, 133D	Control Complex Equipment Room General Area Relief Air Damper
					XDP-234A, 234B	Control Complex Equipment Room General Area Redundant Relief Air Damper
					XFN 30A, 30B	Control Room Emergency Filtering System Fan
					XFN 32A, 32B	Control Room Normal Supply Fan
					XFN 36A, 36B	Relay Room Cooling System Fan
					XAH 12A, 12B	Control Room Normal Supply Air Handling Unit
					XAH 113A, 113B	Relay Room Air Handling Unit
					XAH 29A, 29B	Control Room Emergency Filter Plenum
					XFL 56A, 56B	Relay Room Air Handling Unit Filter Box

Table 3.5-7 (continued)
Physical Properties and Function of Tornado Missile Barriers

Structure	Fig. No. & Grid Location	Thickness (ft) Wall	Thickness (ft) Roof	Concrete Strength	Components Protected Tag No	Components Protected Equipment
Control Complex (Cont'd)						
					6490A, 6490B	Valve
					6412A, 6412B	Valve
					-	Circuits and raceways north of column line F.2 and east of column line 13.9
					XTK-174A, 174B	Chilled Water (VU) Expansion Tanks
					LT-9004	Chilled Water (VU) Expansion Tank A Level Transmitter
					LT-9006	Chilled Water (VU) Expansion Tank B Level Transmitter
					ILT-9004-HR-VU	Chilled Water (VU) Expansion Tank A LT-9004 High Root Valve
					ILT-9006-HR-VU	Chilled Water (VU) Expansion Tank A LT-9006 High Root Valve
Diesel Generator Building	1.2-12 F-3, G-3	2.0		3000 psi in 28 days	-	Diesel Generator A and Auxiliaries
					-	Diesel Generator B and Auxiliaries
					XTK 20A, 20B	Diesel Generator Fuel Oil Day Tank
					XTK 9A, 9B, 9C, 9D	Diesel Generator Air Receiver
					XTK 114A, 114B	Diesel Generator Jacket Water Head Tank

Table 3.5-7 (continued)
Physical Properties and Function of Tornado Missile Barriers

Structure	Fig. No. & Grid Location	Thickness (ft) Wall	Thickness (ft) Roof	Concrete Strength	Components Protected Tag No	Components Protected Equipment
Control Complex (Cont'd)						
					XPP 4A, 4B	Diesel Generator Fuel Oil Transfer Pump
					XCX 5201, 5202	Diesel Generator Control Cubicle
Fuel Handling Building	1.2-6 D-7	1.0	1.0	5000 psi in 90 days	-	Service Water Lines for Reactor Building Cooling Units
					-	Cable Trays for Hydrogen Recombiner Power Cables and for Reactor Building Cooling Unit Power Cables
					-	Pressure Transmitter PT-951
Intermediate Building	1.2-12 C-6	2.0	2.0	3000 psi in 28 days		-
						-
						-
						-
Intermediate Building	1.2-13 C-6	2.0		3000 psi in 28 days		-
Service Water Pumphouse	1.2-24 F-7	2.0		3000 psi in 28 days	XPP 39A, 39B, 39C	
					XRS 2A, 2B, 2C	
					MPP 39A, 39B, 39C	

Table 3.5-7 (continued)
Physical Properties and Function of Tornado Missile Barriers

Structure	Fig. No. & Grid Location	Thickness (ft) Wall	Thickness (ft) Roof	Concrete Strength	Components Protected Tag No	Components Protected Equipment
Service Water Pumphouse (Cont'd)						
					1063, 1064, 4616	-
Service Water Pumphouse	1.2-24 G-11	2.0	2.0	3000 psi in 28 days	Following equipment, related solenoids, limit switches, and associated cabinets:	
					XDP 71A, 71B	Service Water Pumphouse Building Exhaust Air Control Damper
					XDP 73A, 73B	Service Water Pumphouse Building Recirculation Control Damper
					XDP 74A, 74B	Service Water Pumphouse Building Fan Inlet Isolation Damper
					XES 2003B	Service Water Pump Special Switch
					XFN 80A, 80B	Service Water Pumphouse Building Supply Fan

Table 3.5-7 (continued)
Physical Properties and Function of Tornado Missile Barriers

Structure	Fig. No. & Grid Location	Thickness (ft)		Concrete Strength	Components Protected	
		Wall	Roof		Tag No	Equipment
Service Water Pumphouse (Cont'd)					XSW1EB	7.2kV Switchgear, Bus 1EB
					XSW1EB1	Engineered Safety Features 480 Volt Unit Substation, Bus 1EB1
					XMC1EB1X	Engineered Safety Features Motor Control Center 1EB1X
					DPN1HB3	D-C Distribution Panels 1HB3
					1060, 1063	Cable Tray
					4610, 4615	Cable Tray
					4616, 4627	Cable Tray
					5223	Cable Tray

3.6 PROTECTION AGAINST DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

Protection of structures, systems, and components important to safety from the dynamic effects of piping failure is provided in accordance with the requirements of 10 CFR 50, Appendix A, General Criterion 4. Subsequent to the General Design Criterion 4 final rule change (Reference 16), postulated breaks in the reactor coolant loop piping, except for branch line connections, have been eliminated for V. C. Summer. The dynamic effects of the postulated breaks at six terminal ends in the cold, hot, and crossover legs, the steam generator inlet elbow, and the loop closure weld in the crossover leg were eliminated from the structural design basis by application of leak-before-break methodology, as presented in Reference 17 and updated by Reference 19. Approval of the elimination of the V. C. Summer reactor coolant loop piping breaks is given in the Summer Safety Evaluation Report, dated January 11, 1993 (Reference 18). To provide the high margins of safety required by General Design Criterion 4, the nonmechanistic pipe rupture design basis is maintained for containment design and ECCS analysis, and the postulated pipe ruptures are retained for electrical and mechanical equipment environmental qualification.

This section describes the design bases and design measures employed to protect the containment, reactor coolant pressure boundary, and other essential systems and equipment from the effects of postulated pipe ruptures. This protection is provided inside and outside of containment and considers jet blowdown from postulated breaks, as well as pipe whip and reactive forces.

3.6.1 Postulated Piping Failures in Fluid Systems

3.6.1.1 Design Bases

3.6.1.1.1 Essential Systems Outside Containment

Essential piping systems required for postulated piping failures outside of containment are as follows:

1. Main Steam System up to and including containment isolation valves.
2. Feedwater System up to and including containment isolation valves.
3. Emergency Feedwater System.
4. Chemical and Volume Control System.
5. Residual Heat Removal System.
6. Safety Injection System.
7. Steam Generator Blowdown System up to and including containment isolation valves.
8. Service Water System.
9. Chilled Water System.
10. Reactor Makeup Water System.

11. Component Cooling Water System.

3.6.1.1.2 Essential Systems Inside Containment

Essential piping systems required for postulated piping failures inside containment are as follows:

1. Reactor Coolant System.
2. Main Steam System.
3. Feedwater System.
4. Chemical and Volume Control System.
5. Residual Heat Removal System.
6. Safety Injection System.
7. Steam Generator Blowdown System.
8. Service Water System.
9. Reactor Building Spray System.
10. Steam Generator Sampling System.

3.6.1.1.3 Criteria for Protection Against Postulated Pipe Breaks in Reactor Coolant System Piping

A loss of reactor coolant accident (LOCA) is assumed to occur for a Reactor Coolant System branch line break down to the restraint of the second normally open automatic isolation valve (Case II in Figure 3.6-1) on outgoing lines and down to and including the second check valve (Case III in Figure 3.6-1) on incoming lines normally with flow. A pipe break beyond the restraint or second check valve does not result in an uncontrolled loss of reactor coolant if either of the two valves in the line close.

Accordingly, both of the automatic isolation valves must be suitably protected and restrained as close to the valves as possible so that a pipe break beyond the restraint does not jeopardize the integrity and operability of the valves. This criterion takes credit for only one of the two valves performing its intended function. For normally closed isolation or incoming check valves (Cases I and IV in Figure 3.6-1), a LOCA is assumed to occur for pipe breaks on the reactor side of the valve.

Branch lines connected to the Reactor Coolant System are defined as “large” for purposes of these criteria when the inside diameter is greater than 4 inches up to the largest connecting line. Rupture of these lines results in a rapid blowdown from the Reactor Coolant System and basic protection is provided by the accumulators and the low head safety injection pumps (residual heat removal pumps).

Branch lines connected to the reactor coolant system are defined as “small” if they have an inside diameter equal to or less than 4 inches. This size is such that Emergency Core Cooling System

analyses using realistic assumptions show that no fuel cladding damage is expected for a break area of up to 12.5 in^2 which corresponds to a 4 inch inside diameter piping.

Engineered safety features provide for core cooling and boration, reactor building temperature and pressure reduction, and activity confinement in the event of a LOCA or steam or feedwater line break accident. This ensures that the public is protected in accordance with 10 CFR 50.67 guidelines. These safety systems are designed to provide protection for a Reactor Coolant System pipe rupture of a size up to and including double ended severance of a Reactor Coolant System main loop.

To assure the continued integrity of the essential components and the engineered safety features systems, consideration is given to the consequential effects of the pipe break itself to the extent that:

1. Minimum performance capabilities of engineered safety features systems are not reduced to less than those required to protect against the postulated break.
2. Containment leak tightness is not decreased to less than the design value if the break leads to a loss of reactor coolant. The containment is here defined as the Reactor Building liner and penetrations, the steam generator shell, the steam generator steam side instrumentation connections and the steam, feedwater, blowdown, and steam generator drain pipes within the Reactor Building.
3. Propagation of damage is limited in type and/or degree to the extent that:
   a. A pipe break which does not directly result in a loss of reactor coolant will not cause a loss of reactor coolant or steam or feedwater line break, through consequential damage.
   b. A Reactor Coolant System pipe break does not cause a Steam or Feedwater System pipe break and vice versa.

Criteria relative to large and small branch line breaks are as follows:

1. Large Branch Lines

   Large branch line piping is restrained to satisfy the following criteria:

   a. Propagation of the break to unaffected loops is prevented to assure the delivery capacity of the accumulators and low head safety injection pumps.
   b. Propagation of the break in the affected loop is permitted to occur but does not exceed 20% of the area of line which initially ruptured. This criterion is voluntarily applied so as not to substantially increase the severity of the loss of coolant. Two exceptions to this criterion are permitted:
      (1) The postulated rupture of the 12 inch accumulator injection lines is permitted to result in rupture of the 6 inch safety injection lines.

(2) A postulated rupture of reactor coolant loop 2, 6 inch cold leg injection line is permitted to result in a rupture of the 3 inch normal charging line. This results in an additional break area equal to 25% of the area of the line which initially ruptured.

c. Where restraints on the lines are necessary to prevent impact on and subsequent damage to neighboring equipment or piping, restraint type and spacing are chosen such that either a plastic hinge on the pipe at the two support points closest to the break is not formed or, if a plastic hinge is formed, piping does not impact essential equipment.

2. Small Branch Lines

In the unlikely event that one of the small pressurized lines should fail and result in a LOCA, the piping is restrained or arranged to satisfy the following criteria in addition to the criteria previously discussed for large branch lines:

a. Break propagation is limited to the affected leg (i.e., propagation to the other leg of the affected loop and to other loops shall be prevented).

b. Propagation of the break in the affected leg is permitted but is limited to a total break area of 12.5 in^2 (4 inch inside diameter). The exception to this criterion is when the initiating small break is in the high head safety injection line. Further propagation is not permitted for this case.

c. Damage to the high head safety injection lines connected to the other leg of the affected loop or to other loops is prevented.

d. Propagation of the break to the high head safety injection line connected to the affected leg is prevented if the line break results in a loss of core cooling capability due to a spilling injection line.

3.6.1.2 Description

3.6.1.2.1 High Energy Systems

High energy systems, systems with normal operating temperatures in excess of 200°F or normal operating pressures above 275 psig, are as follows:

1. Reactor Coolant System.
2. Main Steam System.
3. Feedwater System.
4. Emergency Feedwater System.
5. Chemical and Volume Control System.
6. Safety Injection System.
7. Steam Generator Blowdown System.
8. Auxiliary Steam System.

9. Main Steam Dump System to atmosphere, up to control valves.
10. Main Steam Drains System.
11. High energy systems with lines all 1 inch and smaller. No breaks are postulated in the following systems:
    a. Nuclear Sampling System.
    b. NSSS Carbon Dioxide and Nitrogen Supply Systems.
12. High energy systems remotely located in the Turbine Building and not considered for pipe rupture.
    a. Extraction Steam System.
    b. Condensate System.
    c. High Pressure Heater Drip, Vent and Relief System.
    d. Low Pressure Heater Drip, Vent and Relief System.
    e. Feedwater Pump Startup Drain System.
    f. Miscellaneous Steam Drain System.
    g. Auxiliary Boiler Chemical Feed System.
    h. Turbine Cycle Sampling System.
    i. Main Steam Dump System to condensers, up to control valves.
    j. Turbine Generator Electrohydraulic Fluid Control System.

3.6.1.2.2 Moderate Energy Systems

Moderate energy systems, systems with normal operating temperatures less than or equal to 200°F and normal operating pressures equal to or less than 275 psig, include all piping systems not listed in Section 3.6.1.2.1.

3.6.1.2.3 High Energy Systems Enclosed in Compartment to Protect Nearby Essential Systems and Components

Main steam and feedwater lines are enclosed in the penetration access areas at floor elevation 436’ and on the upper level of the Intermediate Building to protect nearby essential systems and components.

The high and moderate energy lines outside of containment are enclosed in structures and compartments. The pressure buildups due to postulated pipe break within the enclosures are calculated to verify the adequacy of the structural design. The postulated break of the 32 inch main steam line produces the most adverse effects in the east and west penetration access areas, and Intermediate Building, while the 30 inch main steam line produces the most adverse effects in the Turbine Building. The FLASH-2 (Reference 1) and FLASH-4 (Reference 2) computer codes, which perform mass and energy balance calculations for specified control volumes and flow paths

on a time step basis, were used to determine the blowdown flow rates and enthalpies for these ruptures. These results were then used as input for FLASH-4 (Reference 2) and CONTEMPT (Reference 4) calculations to determine the pressure responses of the compartment. In calculating these pressure responses, the following assumptions were made:

1. As mass and energy are introduced into a control volume, thermodynamic equilibrium is assumed throughout the node.
2. No heat transfer occurs between the accident environment and the surrounding structures and equipment.
3. Relief and vent areas are multiplied by a conservative 0.6 discharge coefficient.
4. The models used for subcompartment analysis in the Intermediate and Turbine Buildings are shown by Figures 3.6-1a through 3.6-1e and Tables 3.6-0 through 3.6-0. Intermediate Building models were analyzed using the FLASH-4 (Reference 2) computer code. The Turbine Building was analyzed using the CONTEMPT (Reference 4) computer code to determine loadings on the Intermediate Building wall. Appropriate Tables and Figures are as follows:

   a. Intermediate Building - West Penetration Access Area

      (1) Nodalization model - Figure 3.6-1a, Table 3.6-0.

      (2) Mass/energy release data - Table 3.6-0b.

   b. Intermediate Building - East Penetration Access Area

      (1) Nodalization model - Figure 3.6-1b, Table 3.6-0a.

      (2) Mass/energy release data - Table 3.6-0b.

   c. Intermediate Building - Subcompartment Containing Main Steam and Feedwater Headers

      (1) Nodalization model - Figure 3.6-1c, Table 3.6-0c.

      (2) Mass/energy release data - Table 3.6-0e.

   d. Intermediate Building - Outside Subcompartment Containing Main Steam and Feedwater Headers

      (1) Nodalization model - Figure 3.6-1d, Table 3.6-0d.

      (2) Mass/energy release data - Table 3.6-0e.

   e. Turbine Building - Loading on Intermediate Building Wall

      (1) Nodalization model - Figure 3.6-1e, Table 3.6-0f.

      (2) Mass/energy release data - Table 3.6-0g.

5. Initial conditions:

   A steam-water mixture with a density equal to dry air at 120°F was used as the initial condition in FLASH-4 pressure response calculations. Initial conditions for CONTEMPT pressure response calculations are presented in Table 3.6-0f.

Since both the 30 inch and 32 inch main steam lines are at an elevation between 436’ and 463’ elevation slabs, each structure is analyzed assuming that the mass and energy released are introduced into the compartments between these two elevations. The results of these studies are shown by Figures 3.6-2 through 3.6-16. Table 3.6-0h presents a cross reference between the results shown by Figures 3.6-2 through 3.6-16 and the models listed in Item 4, above. The peak differential pressures, design and calculated, are listed in Table 3.6-0i. The analytical methods used to determine subcompartment pressure and temperature responses are the same for subcompartments inside or outside containment.

Where piping systems have been enclosed in compartments to protect essential systems in other compartments, the pressure versus time curves, Figures 3.6-2 through 3.6-16, are used to determine the peak pressure to be applied as loads to the compartments walls or slabs.

This is done by considering the pressure versus time as a forcing function and calculating the resistance function of the structural elements. From this a dynamic load factor is determined and applied to the peak differential pressure to arrive at an equivalent static load. The equivalent static load is applied to the structure in the load combination described in Section 3.8.4.

For postulated ruptures of high and moderate energy lines outside containment, there is the possibility that adverse environmental conditions might result. To ensure proper design of safety-related equipment to withstand such an environment, it is necessary to calculate the extent to which the environment would be effected by such ruptures. These calculations are performed using the FLASH-2 (Reference 1) and FLASH-4 (Reference 2) computer code results for the mass and energy releases from these ruptures as input to the MNODE (Reference 3) and CONTEMPT (Reference 4) computer codes. Where it is desirable to calculate the environmental response to a postulated rupture in a few interconnected volumes, the MNODE computer code is used. However, when a one-node study of the resulting environmental conditions is sufficient, the CONTEMPT program is used. Both of these programs give the pressure and temperature of each control volume directly. Humidity must be calculated. This is easily performed using the following equation:

$$\text{Relative humidity} = \frac{P_v}{P_g}$$

Where:

P_g = Saturation pressure corresponding to control volume temperature.

P_v = Partial pressure of vapor which:

a. For CONTEMPT results - can be taken directly from the output.

b. For MNODE results - calculated using the control volume vapor mass and temperature in the ideal gas law equation.

The environmental conditions of the various compartments of the penetration access areas and the Intermediate Building are studied to determine how they are affected by postulated ruptures of the 32 inch diameter main steam line, the 4 inch main steam line to the emergency feedwater pump turbine and the 3 inch steam generator blowdown line.

Results of these calculations for a postulated main steam line rupture in the penetration rooms and Intermediate Building are presented in Table 3.6-1.

Reactor Building temperature and pressure versus time curves used to determine the effect on the structure of accident temperature during a pipe break are discussed in Section 6.2.1.

No postulated rupture of a high energy line will have any adverse effect on the control room.

Environmental qualification of equipment is discussed in Section 3.11.

3.6.1.3 Safety Evaluation

Failures which could affect the ability to bring the plant to a safe shutdown condition are analyzed in Chapter 15. These analyses include consideration of the occurrence of a single active component failure in required systems concurrent with postulated pipe rupture except as noted below in Section 3.6.2.1.1.1, for APCSB 3-1, paragraphs B.3.b and B.3.d, for an environmentally-induced failure which would not of itself result in protective action. The pipe rupture analysis required for safe plant shutdown under the applicable criteria is rendered inoperable as a consequence of postulated pipe rupture.

3.6.2 Determination of Break Locations and Dynamic Effects Associated With the Postulated Rupture of Piping

This section discusses the following:

1. The design bases for determining the location of postulated cracks in piping inside and outside of containment.
2. Procedures used to define the jet thrust reaction at the break or crack location.
3. The jet impingement loadings on adjacent safety-related structures, systems, and components.

3.6.2.1 Criteria Used to Define Break and Crack Location and Configuration

3.6.2.1.1 High Energy System Piping Outside Containment

Breaks are postulated to occur in ASME Code, Section III, Class 2 and 3 piping and branch runs at the following locations:

1. At terminal ends. The terminal end for piping which penetrates containment is the pipe to penetration weld (see Figure 3.8-15) outside the Reactor Building.
2. At intermediate locations selected by either one of the following criteria:
   a. At each pipe fitting.

b. At each location where the stresses exceed 0.8 ($1.2S_h + S_a$). Stresses are determined under the combination of loadings associated with the OBE and the nominal and upset plant condition loadings.

Specific non-nuclear safety class piping has been classified as Quality Related piping for the purpose of minimizing postulated pipe break locations. This Quality Related piping is designed in accordance with Code requirements. A rigorous analysis of this Quality Related piping is performed and breaks are then postulated based on the criteria noted above for Code Class piping.

Breaks in non-nuclear safety class piping are postulated to occur at the following locations in each piping or branch run:

1. At terminal ends.
2. At each intermediate pipe fitting, welded attachment, and valve.

Circumferential breaks are postulated to occur in fluid system piping and branch runs with nominal pipe size in excess of 1 inch.

Where a pipe elbow break location is selected without benefit of stress calculations, the pipe-to-elbow weld that joins the elbow to the shorter, straight, piping run is considered as the location of the break. Where break locations are selected in full size branch connection tees without benefit of stress calculations, the two pipe-to-tee welds that join the tee to the shorter, straight, piping runs are considered to be break locations. Where break locations are selected in reduced size branch connection tees without benefit of stress calculations, the pipe to tee weld that joins the tee to the shorter, straight, main piping run and the pipe to tee weld that joins the tee to the branch piping run are considered to be break locations.

Longitudinal breaks are postulated to occur in high energy system piping at the location of each postulated circumferential break except at the terminal ends under conditions discussed below:

1. Longitudinal breaks are not postulated to occur in high energy system piping and branch runs of nominal 3 inch pipe size and smaller.
2. Longitudinal breaks are postulated to occur in addition to, but not concurrently with, circumferential breaks.
3. Longitudinal breaks are not postulated to occur at terminal ends if the system piping at the terminal ends contains no longitudinal pipe welds.
4. Longitudinal breaks are assumed to result in an axial pipe split without pipe severance. Splits are oriented at two diametrically opposed points on the circumference of the pipe or fitting such that a jet reaction results that is normal to the plane formed by two of the applicable orthogonal axes, x, y, and z, of the piping configuration.

3.6.2.1.1.1 Conformance to Branch Technical Positions APCSB 3-1 [13] and MEB 3-1 (Reference 14)

An analysis has been performed which demonstrates that acceptable protection against the effects of piping failures outside containment has been provided. This analysis satisfies the intent of the guidelines of Branch Technical Positions (BTP) APCSB 3-1 and MEB 3-1. Since these positions were published a considerable period of time after the Virgil C. Summer Nuclear Station pipe rupture analysis had commenced, certain requirements could not be followed.

However, in certain respects, the design and analyses to cope with postulated pipe rupture for the Virgil C. Summer Nuclear Station are more stringent than required by the previously referenced BTPs. Specific differences are as follows:

1. APCSB 3-1: Paragraph B.3.b(1):	Offsite power was assumed to be unavailable for all postulated piping failures.

Criteria stated in the previously referenced BTPs with which the analysis does not fully comply and the alternative approaches are as follows:

1. APCSB 3-1:	
a. Paragraph B.2.c(1):	The fluid system piping between containment isolation valves is not designed to the stress limits specified in Paragraphs B.1.b or B.2.b of BTP MEB 3-1. Breaks or cracks, as appropriate, are postulated in these portions of the fluid system piping in accordance with the criteria stated in Section 3.6.2.1.1.
b. Paragraph B.2.d(2):	For these portions of fluid system piping identified in Paragraph B.2.c, the inservice examination will be that required by the ASME Code, Section XI.
c. Paragraph B.3.b and B.3.d:	The effects of an environmentally - induced failure caused by a leak or rupture which would not of itself result in protective action may include a loss of redundancy in the protective function, but not a loss of the protective function, as permitted by BTP-APCSB 3-1, Appendix B, paragraph 11.b. (Reference 15). In these cases, plant shutdown is required. The use of Appendix B in lieu of BTP-APCSB 3.1 is permitted by the implementation schedule of paragraph B.4.c, since the V. C. Summer construction permit is dated March 1973. Other criteria of BTP-APCSB 3.1 for single failure analyses are met, including the paragraph B.3 criteria for evaluating effects of cracks in moderate energy lines.

3.6.2.1.2 High Energy System Piping Inside Containment

As indicated in Section 3.6, dynamic effects resulting from postulated breaks in the reactor coolant loop piping (i.e., the six terminal ends in the cold, hot, and crossover legs, a split in the steam generator inlet elbow, and the loop closure weld in the crossover leg) were eliminated from

the structural design basis for V. C. Summer. Reactor coolant loop branch line connection (i.e., accumulator connection, pressurizer surge line, residual heat removal, etc.) breaks are postulated. These postulated break locations and methods that are used to determine them are described in Reference 5.

Breaks are postulated to occur in ASME Code, Section III, Class 1, piping, other than piping discussed in Reference 5, at the following locations in each piping or branch run:

1. At the terminal ends.
2. At any intermediate location between terminal ends where the primary plus secondary stress intensities (circumferential or longitudinal) derived on an elastically calculated basis under loadings associated with specific seismic events and normal and upset operational plant conditions exceed $2.4S_m$.
3. At any intermediate location between terminal ends where the cumulative usage factor, U, derived from the piping fatigue analysis under the loadings associated with specified seismic events and normal and upset plant operational conditions exceeds 0.1.

Breaks are postulated to occur in ASME Code, Section III, Class 2 and 3 piping at the following locations in each piping or branch run:

1. At the terminal ends. The terminal end for piping which penetrates containment is the pipe to penetration weld (see Figure 3.8-15) inside the Reactor Building.
2. At intermediate locations selected by either one of the following criteria:
   a. Each pipe fitting.
   b. Any location where either the circumferential or longitudinal stresses, derived on an elastically calculated basis under loadings associated with specified seismic events and normal and upset operational plant conditions exceeds $0.8\ (1.2\ S_h + S_a)$.

The following types of breaks are postulated to occur at locations previously identified for ASME Code, Section III, Class 1, 2, and 3 piping:

1. Circumferential breaks in piping runs and branch runs exceeding 1 inch nominal pipe size.
2. Longitudinal breaks in piping runs and branch runs of 4 inch nominal pipe size and large except as discussed in item 3, below.
3. Longitudinal breaks are not postulated to occur at terminal ends if system piping at the terminal ends dose not contain longitudinal pipe welds.

Where break locations are selected without benefit of stress calculations, breaks are postulated to occur at the piping welds to each fitting or valve.

Longitudinal breaks are assumed to result in an axial split without pipe severance. Splits are oriented at two diametrically opposed points on the circumference of the pipe or fitting such that a

jet reaction results that is normal to the plane formed by two of the applicable orthogonal axes, x, y, and z, of the piping configuration.

3.6.2.1.3 (Section Deleted)

3.6.2.1.4 Moderate Energy System Piping

Leakage cracks are postulated to occur in the following moderate energy piping system locations where the maximum stress range exceeds 0.4 ($1.2 S_h + S_a$):

1. In system piping located within structures and compartments containing required systems and components. Cracks are postulated to occur individually at locations appropriate to the formation of a basis for provision of maximum required protection against spray and flooding and resultant hazard or environmental conditions.
2. In system piping and branch runs with nominal pipe size larger than 1 inch.

Crack openings are assumed to be a circular orifice of cross sectional flow area equal to that of a rectangle with dimensions of one-half pipe diameter in length and one-half pipe wall thickness in width.

3.6.2.2 Analytical Methods to Define Forcing Functions and Response Models

3.6.2.2.1 Reactor Coolant Loop Piping Branch Line Connections

Following is a summary of the methods used to determine the dynamic response of the reactor coolant loop associated with postulated pipe breaks at the loop piping branch nozzle. Detailed descriptions of the methods are given in Reference 5.

1. Time Functions of Jet Thrust Force on Ruptured and Intact Loop Piping

   To determine the thrust and reactive force loads to be applied to the reactor coolant loop during the postulated LOCA resulting from a break at the branch line nozzle, it is necessary to have a detailed description of the hydraulic transient. Hydraulic forcing functions are calculated for the reactor coolant loops as a result of a postulated LOCA. These forces result from the transient flow and pressure histories in the Reactor Coolant System. The calculation is performed in two steps. The first step is calculation of the transient pressure, mass flow rates, and thermodynamic properties as a function of time. The second step uses the results obtained from the hydraulic analysis, along with input of areas and direction coordinates, and calculates the time history of forces at appropriate locations in the reactor coolant loops.

The hydraulic model represents the behavior of the coolant fluid within the entire Reactor Coolant System. Key parameters calculated by the hydraulic model are pressure, mass flow rate, and density. These are supplied to the thrust calculation, together with appropriate plant layout information, to determine the time dependent loads exerted by the fluid on the loops. In evaluating the hydraulic forcing functions during a postulated LOCA, the pressure and momentum flux terms are dominant. The inertia and gravitational terms are taken into account in evaluation of the local fluid conditions in the hydraulic model.

The blowdown hydraulic analysis was required to provide the basic information concerning the dynamic behavior of the reactor core environment for the loop forces, reactor kinetics and core cooling analysis. This requires the ability to predict the flow, quality, and pressure of the fluid throughout the Reactor Coolant System. The MULTIFLEX computer code (Reference 6) was developed with a capability to provide this information.

The MULTIFLEX computer code performs a comprehensive space-time dependent analysis of a LOCA and is designed to treat all phases of the blowdown. The stages are as follows:

a. A subcooled stage where the rapidly changing pressure gradients in the subcooled fluid exert the influence upon the Reactor Coolant System internals and support structures.
b. A two phase depressurization stage.
c. The saturated stage.

The MULTIFLEX code employs a one dimensional analysis in which the entire Reactor Coolant System is divided into control volumes. The fluid properties are considered uniform and thermodynamic equilibrium is assumed in each element. Pump characteristics, pump coastdown and cavitation, core and steam generator heat transfer, including the W-3 DNB correlation, in addition to the reactor kinetics are incorporated in the code.

The MULTIFLEX computer program (Reference 7) was developed to compute the transient (blowdown) hydraulic loads resulting from a LOCA.

The blowdown hydraulic loads on primary loop components are computed from the following equation which includes both static and dynamic effects:

$$F = 144A\left[(P-14.7)+\left(\frac{\dot{m}^2}{\rho g A_m^2 144}\right)\right]$$

Where:

F = Force, lb_f,

A = Aperture area, ft^2,

P = System pressure, lb_f/in^2,

$\dot{m}$ = Mass flow rate, lb_m/sec,

ρ = Density, lb_m/ft^3,

g = Gravitational constant = 32.174 ft-lb_m/lb_f - sec^2,

A_m = Mass flow area, ft^2

In the model to compute forcing functions, the reactor coolant loop system is represented by a model similar to that employed in the blowdown analysis. The entire loop layout is described in a global coordinate system. Each node is fully described by the following:

a. Blowdown hydraulic information.

b. The orientation of the streamlines of the force nodes in the system which includes flow areas and projection coefficients along the three axes of the global coordinate system.

Each node is modeled as a separate control volume with one or two flow apertures associated with it. Two apertures are used to simulate a change in flow direction and area. Each force is divided into its x, y, and z components using the projection coefficients. The force components are then summed over the total number of apertures in any one node to give a total x force, total y force, and total z force. These thrust forces serve as input to the piping/restraint dynamic analysis.

2. Dynamic Analysis of the Reactor Coolant Loop Piping Equipment Supports and Pipe Whip Restraints.

The dynamic analysis of the reactor coolant loop piping for the LOCA loadings is described in Section 5.2.1.10.

3.6.2.2.2 Balance of Plant Piping

By using the transient response of a piping system to a postulated rupture, the resulting blowdown thrust and jet forces are calculated as functions of time. For the secondary systems this information is calculated using the FLASH-2 (Reference 1) and FLASH-4 (Reference 2)

computer codes. In performing these calculations, the following assumptions are made for both circumferential and longitudinal ruptures:

1. For feedwater line ruptures, it is assumed that the break area takes 1 millisecond to be fully opened, while for the main steam lines, it is assumed that the rupture is instantaneous.
2. A discharge coefficient of 1.0 for the escaping fluid.
3. For Reactor Coolant System and Feedwater System piping ruptures, the plant is at 100% power.
4. For Main Steam System piping breaks, the plant is in the hot standby condition.

Using these results, the blowdown forces after the wave propagation period are calculated using the JIP computer code [8]. The techniques used by this program depend upon the fluid stagnation conditions present in the piping system. However, in general, the thrust is calculated from the following equation as presented by Moody (Reference 9),

$$\frac{T}{A_E} = P_E - P_\infty + \frac{G_E^2 V_{ME}}{g_c} \qquad (3.6\text{-}1)$$

Where:

T = Thrust,
A_E = Exit (break) area,
P_E = Exit pressure,
P_∞ = Environmental pressure,
G_E = Exit mass flow rate per unit area,
V_{ME} = Exit momentum specific volume, defined below,
g_c = Gravitational constant

The momentum specific volume, V_M is defined by the following equation:

$$V_M = \left[XV_g + (1-X)KV_f\right]\left(X + \frac{1-X}{K}\right) \quad (3.6\text{-}2)$$

$$K = (V_g/V_f)^R \quad (3.6\text{-}3)$$

Where:

X = Quality,
V_g = Vapor specific volume,
V_f = Liquid specific volume,
K = Vapor to liquid velocity ratio,
R = Velocity ratio exponent

Evaluation of P_E, G_E, and V_{ME} is discussed below for the various stagnation conditions:

1. Cold Water (i.e., T < 212°F)

The thrust is calculated assuming the exit pressure, P_E, is equal to the environmental pressure, P_∞. The mass flow rate, G_E, is then calculated from the Bernoulli equation.

$$G_E = \left[\frac{2g_c(P_o - P_E)}{V_f}\right]^{1/2} \quad (3.6\text{-}4)$$

Where:

V_f = Liquid specific volume at calculated exit pressure,
P_o = Stagnation pressure

The thrust is then calculated using Equation (3.6-1) above, assuming that V_{ME} is equal to V_f.

2. Subcooled Water

Thrust for subcooled water at stagnation conditions is calculated by the use of the Henry-Fauske model [10]. Solution of the transcendental expressions of the Henry-Fauske model gives predictions for the exit pressure, P_E, and mass flow rate, G_E. The quantity V_{ME} is calculated assuming that the exit quality is equal to the stagnation quality. The thrust is calculated using Equation (3.6-1) where a unity velocity ratio at the exit is assumed, in Equation (3.6-2).

3. Water-Steam Mixtures

Water-steam mixtures, or two phase flow, are handled by a combination of the Moody model [9,11] and the Henry-Fauske model. For stagnation qualities greater than 2%, the Moody model is used and the mass flow rate and exit conditions are calculated with the velocity ratio exponent, R, equal to 1/3. The thrust is then calculated using Equation (3.6-1). For stagnation quality less than or equal to 2% [12] the Henry-Fauske model is used and the thrust is calculated using a unity velocity ratio.

4. Steam

Saturated and superheated steam is analyzed as a perfect gas with k, the ratio of specific heats, nominally equal to 1.3 and the gas constant equal to 85.76 $ft\text{-}lb_f/°F\text{-}lb_m$. For frictionless flow, the thrust reduces to a theoretical maximum as shown in Equations (3.6-5) and (3.6-6) below:

$$\frac{T}{A_E} = \left[(1+k)\frac{(2)}{k+1}\frac{k}{k-1}\right]P_o - P_\infty \qquad (3.6\text{-}5)$$

$$\approx 1.26P_o - P_\infty \qquad (3.6\text{-}6)$$

Where:

k = C_P/C_v = 1.3 for steam

Typical results of thrusts versus time for postulated main steam and feedwater breaks are shown by Figures 3.6-17 and 3.6-18.

In certain cases, for small lines instead of the above, the blowdown force is represented by a steady-state function equal to KpA.

Where:

K = Thrust coefficient,
p = System pressure prior to pipe break,
A = Pipe break area

The K values used are 1.26 for steam-saturated water and 2.0 for subcooled, nonflashing water.

3.6.2.3 Dynamic Analysis Methods to Verify Integrity and Operability

In addition to pipe restraints, barriers and layout are used to provide protection from pipe whip, blowdown jet, and reactive forces.

One of the barriers utilized for protection against pipe whip is the steam generator compartment wall which serves as a barrier between the reactor coolant loops and the Reactor Building liner. In addition, the refueling cavity walls and the steam generator compartment wall enclose each reactor coolant loop in a separate compartment, thereby preventing an accident, which may occur in any loop, from affecting another loop or the Reactor Building liner. The portion of the steam and feedwater lines within the containment are routed behind barriers which separate these lines from all reactor coolant piping. These barriers are designed to withstand loadings caused by jet forces and pipe whip impact forces.

Engineered safety features, except Emergency Core Cooling System lines which must circulate cooling water to the reactor vessel and engineered safety features instrument lines, are located outside the steam generator compartment wall. Emergency Core Cooling System lines which penetrate the steam generator compartment wall are routed around and outside the wall so that they penetrate the wall in the vicinity of the loop to which they connect.

Each individual postulated break is reviewed to determine which essential components and piping, if any, are in the projected path of either the pipe whip or the jet.

In each case where essential components are in the path of either the pipe whip or the jet from a postulated break, such components are moved, where practical, to unaffected locations. Components that cannot be relocated are protected from pipe whip by restraining the pipe in which a break is postulated to occur and from jet impingement by installation of shields.

In reviewing the mechanical aspects of these lines, it has been demonstrated, through tests performed by the nuclear steam supply system manufacturer [5], that lines hitting equal or larger size lines of the same schedule do not cause failure of the line being hit; e.g., a 1 inch line, should it fail, does not cause subsequent failure of a 1 inch or larger size line. The converse, however, is assumed to be probable; i.e., a 4 inch line, should it fail and whip as a result of the fluid discharged through the line, could break smaller size lines, such as neighboring 3 inch or 2 inch lines.

Piping, that can be damaged and is determined to be in the projected path of a postulated whipping pipe and that cannot be relocated, is protected by restraint of the postulated whipping pipe. Piping in the projected path of a jet resulting from a postulated break is either rerouted or shielded. When rerouting or shielding is not practical, the piping system design specification identifies jet impingement loadings of safety-related piping, as well as the allowable stress limits and loading combination requirements.

The piping system is then analyzed using the equivalent static load method or, in some cases, a detailed time history method of analysis to determine the jet impingement effect upon the piping. The resulting loads are then combined and compared to the allowable stress limits as defined in

the design specification. In the event that compliance with the specified stress limits cannot be demonstrated, shielding of the piping is provided.

3.6.2.3.1 Restraint Criteria

Where pipe restraints are employed they are designed using the principles of the equations of motion (dynamic analysis) or those of energy balance. Since the forces due to dead, live, seismic, and thermal loads are considered negligible or self relieving, only the dynamic effect of the whipping pipe is considered in the design.

The equation of motion methods (dynamic analysis) employ the use of the computer programs DYREC (S061), DYNAL (S085), and nonlinear numerical integration techniques. See Section 3.8.4.4 for a description of computer codes.

The program uses the thrust versus time data described previously. The pipe and the restraint are modeled as lump mass systems. Nodal masses and element spring properties are determined and gaps are input. Using direct numerical integration of the equations of motion, the dynamic response of the pipe and restraint are calculated at specific time points.

The following criteria were used for material properties:

1. Minimum yield strength of pipe steel is reduced in accordance with operating temperature.
2. Minimum tensile strength of the pipe material, as listed in the material specification, is used as the ultimate strength of the pipe. Refinement of assumed ultimate strength for changes due to operating temperatures would not result in a substansive change in pipe restraint design or reactions.
3. Ultimate tensile strain of both piping and restraint material is one half of guaranteed minimum percent elongation. Ultimate shear strain is equal to guaranteed percent elongation.
4. Minimum values of yield strength, ultimate strength, and modulus of elasticity for pipe are taken from the ASME Code. Values for restraint material are taken from the applicable ASTM specification.
5. A 10% increase in material properties is applied to allow for strain rate effect.

Acceptability of the restraint design was based upon the results of the dynamic analysis. Neither the pipe nor the restraint stresses and strains exceed the following limits:

1. Tensile strains are limited to 50% of the assumed ultimate tensile strain. This is equal to 0.25 times percent elongation.
2. Bending and axial tensile stresses are limited to the values at the above strain limit as determined appropriate from the stress/strain, moment/curvature, or P/Ä curves.
3. Shearing strains are limited to 50% of the assumed ultimate shear strain. This is equal to 0.5 times percent elongation.

4. Shearing stresses are limited to the value at the above strain limit as determined from the shear/shear strain curve.

Restraints, connections, anchorages and the supporting structure are designed for the maximum reactions obtained from the dynamic analysis.

In the energy balance method, an amplification factor of 1.2 is applied to the peak thrust force to determine the force on the pipe.

Initial gap and the kinetic energy of the pipe are considered in balancing the internal work with the external.

Pipe and restraint properties as described for the dynamic analysis, are used with the exception that no strain rate effect is assumed.

Acceptable restraints design limits are the same as for the dynamic analysis.

Restraint connections, anchorages and the supporting structure are designed for 15% more than the maximum reactions from the energy balance analysis.

3.6.2.3.2 Jet Impingement

1. Balance of Plant Piping

   Blowdown forces obtained as described in Section 3.6.2.2 are used in the jet impingement analysis. It is assumed that the total jet impingement force is equal to the thrust calculated at the break (Reference 9) and is uniformly distributed across the cross sectional area of the jet at any particular location.

   For both circumferential and longitudinal ruptures, the configuration of the break areas is assumed to be circular in nature. These break areas, i.e., for the longitudinal rupture and for each end of the circumferential rupture, are assumed to be equal to the flow area of the pipe in the vicinity of the postulated rupture (Reference 12).

Calculation of the jet expansion profile is accomplished assuming a constant 10 degree half angle of expansion for the escaping fluid. Due to these assumptions, the area of the jet as a function of distance from the break point can be expressed by the following equation:

$$A_j(x) = A_E\left(1+\frac{2x}{D_E \tan 10^\circ}\right)^2 \qquad (3.6\text{-}7)$$

Where:

$A_j(x)$ = The jet area as a function of distance from the break,
x = The distance from the break,
A_E = Exit or break area,
D_E = Equivalent diameter of break area (equals the pipe diameter in these cases)

In some instances where the postulated break is very close to structures, a more detailed blowdown analysis may be performed to evaluate jet impact forces. This detailed analysis may prove beneficial if the fluid properties support the jet expansion profile as presented by Moody [9]. In such cases, calculation of the jet profile may be performed by the computer code JIP [8], which evaluates the fluid properties and determined jet profiles and pressures in accordance with the following expansion model.

The Moody expansion model estimates fully expanded, one-dimensional asymptotic jet properties for jet expansion calculations. Diffusion, friction, turbulent momentum, and energy exchange, and heat transfer effects with the environment are not considered. Current usage of this model conservatively assumes that the expansion takes place over the first five equivalent diameters from the break [12]. The area ratio existing at five diameters can be calculated using the following equation [9]:

$$\frac{A_\infty}{A_E} = \frac{G_E^{\,2}\; W_{M\infty}}{g_c\;(T/A_E)} \qquad (3.6\text{-}8)$$

Where:

A_∞ = Area at 5 diameters,
A_E = Exit or break areas,
G_E = Exit mass flow rate per unit area,
g_c = Gravitational constant,
$V_{M\infty}$ = Environmental momentum specific volume, discussed below,
T = Total thrust at the break

The environmental momentum specific volume, VM_{∞}^{2}, is defined by Equation (3.6-2) of Section 3.6.2.2. However, the velocity ratio used in evaluating $V_{M\infty}$ different for jet impingement than for thrust. As concluded in Reference 9, a unity velocity ratio predicts the two-phase jet force better than a velocity ratio, $(V_g/V_f)^{1/3}$, as used in the Moody thrust evaluation. Therefore, a unity velocity ratio is used for determination of the Moody area ratio at five diameters. For calculation of areas before the full expansion at five diameters is reached, an additional assumption is made, i.e., that the jet area increases uniformally from zero to five diameters (Reference 12). After the Moody area ratio is determined and the break geometry specified, the equivalent Moody angle can be determined.

The jet expansion profile calculations used by JIP (Reference 8) are discussed for cold water, subcooled water, and water-steam and steam conditions in the following paragraphs:

a. Cold and Subcooled water

   Subcooled water is treated with a 10 degree half angle and a Moody expansion angle, if applicable. If the subcooled thrust is calculated from the Bernoulli equation, as discussed in Section 3.6.2.2, a jet expansion half angle of 10 degrees is used. However, if the thrust is calculated using the Henry-Fauske theory (Reference 10), as explained in Section 3.6.2.2, this uniform expansion is not always used. Henry-Fauske gives predictions for exit pressure and mass flow rate. In addition, an equilibrium exit quality is calculated. If the equilibrium exit quality is greater than or equal to 0.1% (approximately equal to a volume breakdown of 10% steam and 90% saturated water at the exit), the Moody expansion model, as described earlier, is used. Subsequent to jet expansion out to five diameters, the area is held constant until the 10 degree half angle is applicable. The overall jet geometry combining the Moody expansion profile with the 10 degree half angle is shown in Figure 3.6-19. If the calculated exit quality is less than 0.1%, the uniform 10 degree half angle expansion is used. the application of this jet profile is limited, however, since the pressure will rapidly drop to the saturation value.

b. Water-Steam and Steam

   For water-steam and steam conditions, the Moody expansion model is directly applicable. Therefore, the jet geometry for water-steam, saturated steam, and superheated steam is depicted in Figure 3.6-19.

   NUREG/CR-2913 (Reference 20) contains a model that has been developed for predicting two phase, water jet loadings on targets. The model was developed using advanced two dimensional computational techniques to solve the governing equations of mass, momentum, and energy. The application of this model results in a series of charts of the target load and pressure distributions. These charts were developed for a wide range of pressure and temperatures that completely cover the range of interest in pressurizer water reactors. In lieu of the methodology described previously, the charts contained in NUREG/CR-2913 are used to determine the effective jet pressure at varying distances from the jet origination.

2. Reactor Coolant Loop Piping

The methods described below are used in the design and verification of the adequacy of reactor coolant loop components and supports.

The design basis postulated pipe rupture locations for the main reactor coolant loop piping are determined using the criteria given in Section 3.6.2.1.2 and Reference 5. These design basis ruptures are used as the rupture locations for consideration of jet impingement effects on primary equipment and supports.

The dynamic analysis as discussed in Section 5.2, is used to determine maximum piping displacements at each design basis rupture location. These maximum piping displacements are used to compute the effective rupture flow area at each location. These areas and rupture orientations are then used to determine the jet flow patterns and to identify any primary components and supports which are potential targets for jet impingement.

The jet thrust at the point of rupture is based on the fluid pressure and temperature conditions occurring during normal (100%) steady-state operating conditions of the plant. At the point of rupture, the jet force is equal and opposite to the jet thrust. The force of the jet is conservatively assumed to be constant throughout the jet flow distance. The subcooled jet is assumed to expand uniformly at a half angle of 10 degrees, from which the area of the jet at the target and the fraction of the jet intercepted by the target structure can be determined.

The shape of the target affects the amount of momentum change in the jet and thus affects the impingement force on the target. The target shape factor is used to account for target shapes which do not deflect the flow 90 degrees away from the jet axis.

The method used to compute the jet impingement load on a target is one of the following:

a. The dynamic effect of jet impingement on the target structure is evaluated by applying a step load whose magnitude is given by:

   $F_j = K_o P_o A_{mB} RS$

   Where:

   F_j = jet impingement load on target,

   K_o = dimensionless jet thrust coefficient based on initial fluid conditions in broken loop,

   P^o = initial system pressure,

   A_{mB} = calculated maximum break flow area,

   R = fraction of jet intercepted by target,

   S = target shape factor

Discharge flow areas for limited flow area circumferential breaks are obtained from reactor coolant loop analyses performed to determine the axial and lateral displacements of the broken ends as a function of time. A_{mB} is the maximum break flow area occurring during the transient, and is calculated as the total surface area through which the fluid must pass to emerge from the broken pipe. Using geometrical formulations, this surface area is determined to be a function of the pipe separation (axial and transverse) and the dimensions of the pipe (inside and outside diameter).

If a simplified static analysis is performed instead of a dynamic analysis, the above jet load (F_j) is multiplied by an appropriate dynamic load factor. For an equivalent static analysis at the target structure, the jet impingement force is multiplied by a dynamic load factor of 2.0. This factor assumes the target can be represented as essentially a one-degree of freedom system and the impingement force is conservatively applied as a step load.

b. The dynamic effect of jet impingement is evaluated by applying the following time-dependent load to the target structure:

$F_j = KPA_B\ RS$

where the system pressure P is a function of time; the jet thrust coefficient K is evaluated as a function of a system pressure and enthalpy, and the break flow area A_B is a function of time.

3.6.2.4 Guard Pipe Assembly Design Criteria

Guard pipes are used as shields as described in sections 3.6.2.1.4 and 3.6.2.5.1 and are designed consistent with the moderate energy piping postulated to crack.

3.6.2.5 Material to be Submitted for the Operating License Review

3.6.2.5.1 Location and Orientation of Design Basis Breaks

The locations and orientations of the postulated design basis breaks are determined by stress analysis. Break locations and orientations for postulated reactor coolant piping branch line connection breaks are discussed below. Break locations for all other high energy system piping are postulated at terminal ends according to Sections 3.6.2.1.1 and 3.6.2.1.2. Break orientations for lines outside containment are discussed in Sections 3.6.2.1.1 and 3.6.2.1.2.

Cracks are postulated in moderate energy system piping in the vicinity of essential components. Components located in the vicinity of moderate energy system piping were relocated, if practical, or were specified as spray proof. In instances where neither relocation nor specification as spray proof is possible, shields are provided.

Due to the elimination of postulated breaks in the reactor coolant loop piping, as described in Section 3.6, jets are no longer considered in the analysis of the reactor coolant loop piping supports.

Table 3.6-2 and Figure 3.6-51 identify the design basis break locations and orientations for the main reactor coolant loop.

3.6.2.5.2 Restraint and Shield Location and Design Information

The E-303-300 series drawings includes a summary of the protection of essential equipment, located outside containment, from pipe whip and jet impingement resulting from postulated rupture of high energy system piping.

Reference should be made to E-303-300 series drawings for protection of essential equipment for the plant. Pipe whip restraints associated with the reactor coolant loop are discussed in Section 5.5.14.

3.6.2.5.3 Analytical Results

The analytical results show that no essential system or component is rendered incapable of performing its necessary functions as a result of any postulated pipe rupture.

The methods and analysis procedures used to determine jet impingement loads associated with the rupture of the main reactor coolant loop are discussed in Section 3.6.2.3.2.

3.6.2.5.4 Interface Responsibilities

The interface responsibility between Westinghouse and the Balance of Plant Supplier for the design of the component supports and the reactor coolant pressure boundary, which is not part of the reactor coolant loop is as follows:

Westinghouse

1. Design and evaluation of all primary equipment supports,
2. Design of the pressurizer surge line piping and fittings,
3. Analysis of all Class 1 branch lines attached to the reactor coolant loop piping (except for the pressurizer spray line) for deadweight, pressure, thermal, seismic, and effects of pipe rupture in the reactor coolant loop piping,
4. Design and analysis of All Class 1 reactor coolant loop branch line nozzles, including the pressurizer spray nozzle,
5. Provide the Balance of Plant supplier with loop displacements due to all loading conditions at branch line nozzle locations.

Balance of Plant Supplier

1. Design of all Class 1 branch lines except for pressurizer surge line,
2. Analysis of all Class 1 branch lines not within Westinghouse’s scope for deadweight, pressure, thermal, seismic, and effects of pipe rupture in the reactor coolant loop piping,

3. Evaluation of all Class 1 branch lines for effects of pipe rupture in auxiliary Class 1 branch lines,
4. Supply Westinghouse with loads at the reactor coolant loop and line branch nozzles.

3.6.3 References

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Table 3.6-0
Intermediate Building - West Penetration Access Area
Nodalization Model

Control Volume Number	Control Volume Identification	Volume (ft^3)	Area (ft^2)	Height (ft)	Bottom (ft)
1	Intermediate Building	134,000	5570	24	436
2	Intermediate Building	50,000	2070	24	436
3	Intermediate Building	168,000	7650	22	412
4	Environment	1. + 8	1. + 7	10	458
5	East Penetration Access Area	72,200	2887	25	436
6	West Penetration Access Area	63,500	2900	22	412

Junction Number	From C.V.	To C.V.	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction (K)
1	1	2	448	550	.013	1.5
2	1	3	448	525	.0074	1.5
3	1	4	448	350	.00787	1.5
4	2	4	448	350	.0079	1.5
5	2	4	448	350	.0079	1.5
6	2	4	448	350	.0079	1.5
7	2	4	448	350	.0079	1.5
8	5	1	448	12.5	.25	1.5
9	5	1	448	335	.096	1.5
10	5	6	448	50	.048	1.5

Table 3.6-0a
Intermediate Building - East Penetration Access Area
Nodalization Model

Control Volume Number	Control Volume Identification	Volume (ft^3)	Area (ft^3)	Height (ft)	Bottom (ft)
1	Intermediate Building	134,000	5570	24	436
2	Intermediate Building	50,000	2070	24	436
3	Intermediate Building	168,000	7650	22	412
4	Environment	1. + 8	1. + 7	10	458
5	East Penetration Access Area	63,400	2643	24	436
6	East Penetration Access Area	58,100	2643	22	412

Junction Number	From C.V.	To C.V.	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction (K)
1	1	2	448	550	.013	1.5
2	1	3	448	525	.0074	1.5
3	1	4	448	350	.00787	1.5
4	2	4	448	350	.0079	1.5
5	2	4	448	350	.0079	1.5
6	2	4	448	350	.0079	1.5
7	2	4	448	350	.0079	1.5
8	5	1	448	12	.23	1.5
9	5	1	448	410	.067	1.5
10	5	6	448	45	.05	1.5
11	6	3	430	11	.24	1.5

Table 3.6-0b
Intermediate Building - Penetration Access Area
Mass/Energy Release Data

Time (sec)	Mass Release Rate (lbm/sec)	Enthalpy (Btu/lbm)
0.0	2.202 + 4	1186
.00375	1.586 + 4	1198
.0113	1.079 + 4	1203
.0238	9.592 + 3	1204
.0463	1.184 + 4	1202
.108	9.358 + 3	1204
.413	7.009 + 3	1203
.875	8.312 + 3	1203
1.95	7.838 + 3	1203

Table 3.6-0c
Intermediate Building - Subcompartment Containing
Main Steam and Feedwater Headers Nodalization Model

Control Volume Number	Control Volume Identification	Volume (ft^3)	Area (ft^2)	Height (ft)	Bottom (ft)
1	Intermediate Building	134,000	5570	24	436
2	Intermediate Building	50,000	2070	24	436
3	Intermediate Building	168,000	7650	22	412
4	Environment	1. + 8	1. + 7	10	458

Junction Number	From C.V.	To C.V.	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction (K)
1	1	2	448	550	.013	1.5
2	1	3	448	525	.0074	1.5
3	1	4	448	350	.00787	1.5
4	2	4	448	372	.0079	1.5

Table 3.6-0d
Intermediate Building - Outside Subcompartment
Containing Main Steam and Feedwater Heaters
Nodalization Model

Control Volume Number	Control Volume Identification	Volume (ft^3)	Area (ft^2)	Height (ft)	Bottom (ft)
1	Intermediate Building	134,000	5570	24	436
2	Intermediate Building	60,500	2520	24	436
3	Intermediate Building	168,000	7650	22	412
4	Environment	1. +8‘	1. +7	10	458

Junction Number	From C.V.	To C.V.	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction (K)
1	1	2	448	580	.0107	1.5
2	1	3	448	525	.0074	1.5
3	1	4	448	350	.00787	1.5
4	2	4	448	1372	.0060	1.5

Table 3.6-0e
Intermediate Building - Main Steam and Feedwater Headers
Inside and Outside Header Subcompartment
Mass/Energy Release Data

Time (sec)	Mass Release Rate (lbm/sec)	Enthalpy (Btu/lbm)
0.0	2.202 + 4	1186
.00625	1.900 + 4	1193
.0163	1.538 + 4	1198
.0313	1.354 + 4	1200
.0413	1.409 + 4	1199
.0563	1.555 + 4	1197
.188	1.404 + 4	1198
.363	1.248 + 4	1200
.488	1.151 + 4	1201
.725	1.034 + 4	1201
.975	9.880 + 3	1201
1.43	9.232 + 3	1202

Table 3.6-0f
Turbine Building Nodalization Model

Volume, ft^3	3×10^6
Initial Temperature, °F	80
Initial Relative Humidity,%	60
Relief Area, ft^2	570
Discharge Coefficient	0.6

Table 3.6-0g
Turbine Building Mass/Energy Release Data

Time (sec)	Mass Release Rate (lbm/sec)	Enthalpy (Btu/lbm)
0.0	1.65 + 4	1197
.005	1.65 + 4	1197
.04	1.06 + 4	1203
.1	9.71 + 3	1204
.2	9.09 + 3	1204
.4	8.32 + 3	1203
.6	7.52 + 3	1203
.8	7.15 + 3	1203
1.	6.87 + 3	1203
1.6	6.55 + 3	1203
2.1	6.36 + 3	1203
3.1	1.04 + 4	717
5.1	1.57 + 4	559
7.1	1.63 + 4	574
10.1	1.57 + 4	594
15.0	8.59 + 3	623
20.0	5.36 + 3	675

Table 3.6-0h
Intermediate and Turbine Building Subcompartment
Pressure Response Cross Reference

Analysis	Applicable Control Volumes	FSAR Figure
West Penetration Access Area	5; 6	3.6-2
	5-6	3.6-3
	5-1; 5-3	3.6-4
	1-6; 3-6	3.6-5
East Penetration Access Area	5; 6	3.6-6
	5-6	3.6-7
	5-1; 5-3	3.6-8
	1-6; 3-6	3.6-9
Intermediate Building (Inside compartment containing main steam and feedwater headers)	2; 1 2-1 2-3; 2-1	3.6-10 3.6-13 3.6-15
Intermediate Building (Outside compartment containing main steam and feedwater headers)	1 1-3 1-4; 1-2	3.6-11 3.6-12 3.6-14
Turbine Building (Loading on Intermediate Building wall)	1	3.6-16

Table 3.6-0i
Intermediate and Turbine Building Differential Pressures

Subcompartment	Calculated Pressure (psi)	Design Pressure (psi) (Including Dynamics Effect)
West Penetration Access Area	5.0	6.5
East Penetration Access Area	4.8	5.9
Intermediate Building (Inside compartment main steam and feedwater headers)	3.0	4.0
Intermediate Building (Outside compartment containing main steam and feedwater headers)	2.2	4.0
Turbine Building (Loading on intermediate building wall)	2.3	4.0

Table 3.6-1
Environmental Conditions Resulting From Postulated
Pipe Ruptures Outside of Containment

Large Line Break Conditions (1)

Area	Temperature (°F)	Relative Humidity (%)
East and West Penetration Access Areas, Floor Elevation 412’	220	100
East and West Penetration Access Areas, Floor Elevation 436’	220 (2)	100
West Penetration Access Area, Floor Elevation 463’	220	100
Intermediate Building, Floor Elevation 412’	212	100
Intermediate Building, Floor Elevation 436’	212 (3)	100

Small Line Break Conditions (4)

Area	Temperature (°F)	Relative Humidity (%)
East and West Penetration Access Areas and Intermediate Building, All Elevations	200	100

(1) Conditions last for 3 minutes, then return to 100 F in about 30 minutes.
(2) Temperature of 320 F for 30 seconds.
(3) Temperature of 283 F for 4 seconds.
(4) Conditions last for 3 hours, then return to 100 F in about 30 minutes.
NOTE: Details of the main steam line break HELB/SBOC (High Energy Line Break / Superheated Blowdown Outside Containment) environmental conditions are provided in Section 3.11.2.2.2.2

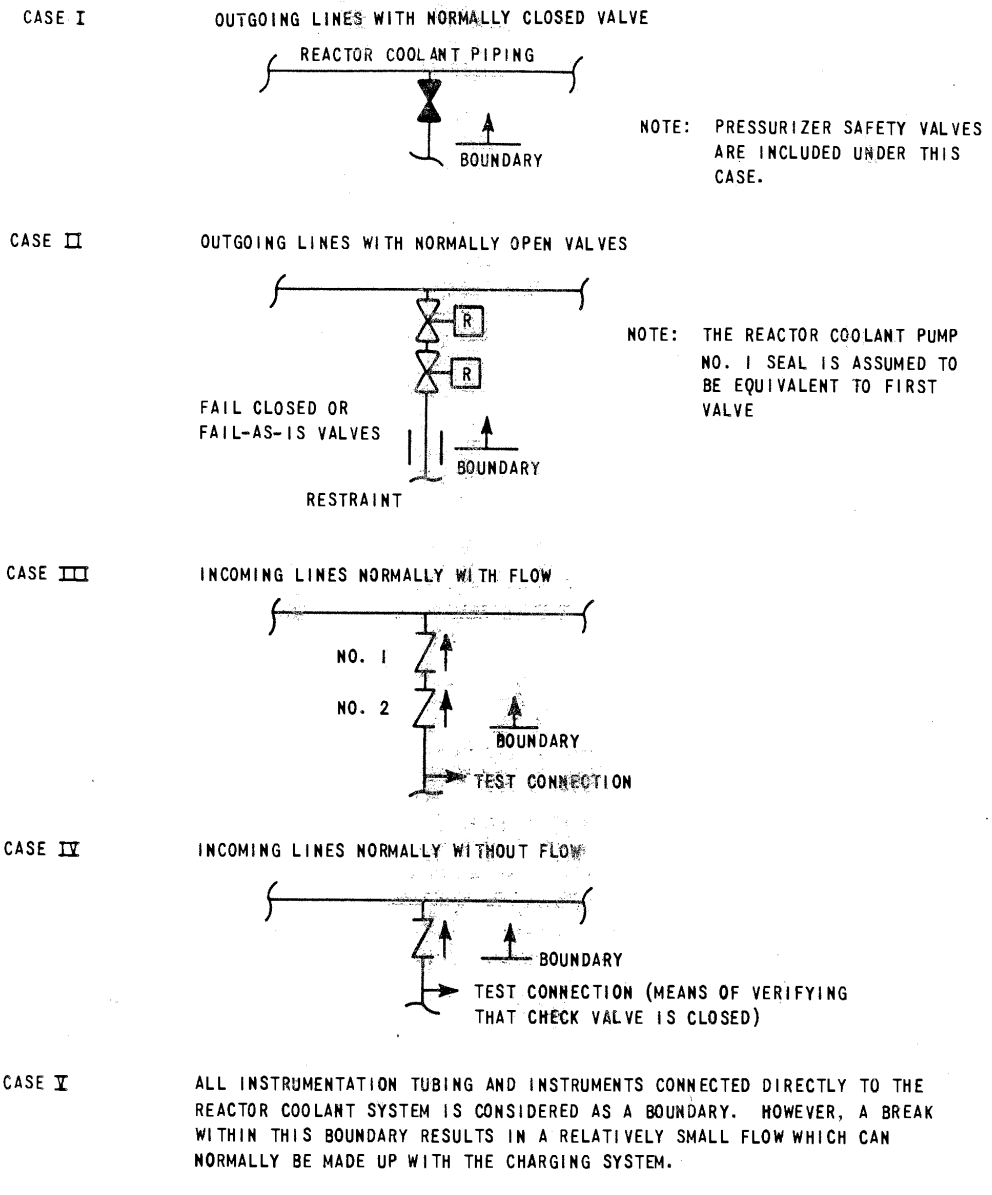
Table 3.6-2
Postulated Break Locations For the LOCA Analysis of the Primary Coolant Loop [1,3]

	Location of Postulated Rupture	Type	Break Opening Area [2]
1.	Residual Heat Removal (RHR) Line/Primary Coolant Loop Connection	Guillotine (viewed from the RHR line)	Cross-sectional flow area of the RHR line
2.	Accumulator Line/Primary Coolant Loop Connection	Guillotine (viewed from the accumulator line)	Cross-sectional flow area of the accumulator line
3.	Pressurizer Surge Line/Primary Coolant Loop Connection	Guillotine (viewed from the pressurizer surge line)	Cross-sectional flow area of the pressurizer surge line

(1) Refer to Figure 3.6-51 for location of postulated breaks in reactor coolant loop.
(2) Less break opening area will be used if justified by analysis, experiments or considerations of physical restraints such as concrete walls or structural steel.
(3) Elimination of the dynamic effects of postulated pipe ruptures in the reactor coolant loop piping at the terminal ends, steam generator inlet elbows, and crossover leg closure welds have been eliminated as allowed by the revised General Design Criterion 4 (Section 3.6).

Figure 3.6-1

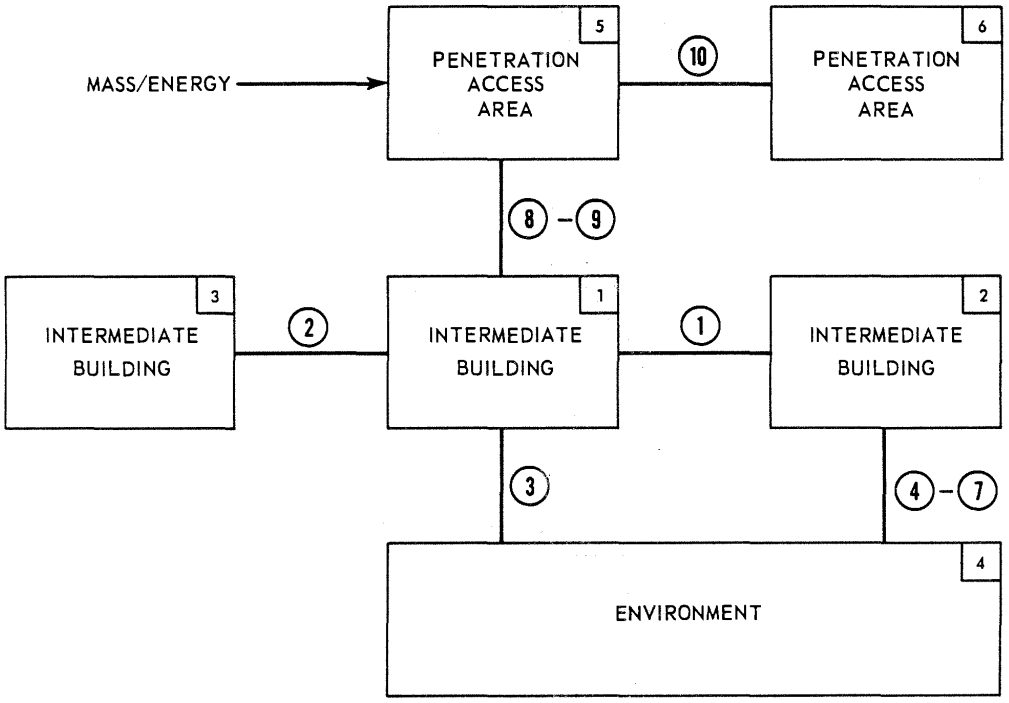
LOSS OF REACTOR COOLANT ACCIDENT BOUNDARY LIMITS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loss of Reactor Coolant Accident Boundary Limits Figure 3.6-1

Figure 3.6-1a

INTERMEDIATE BUILDING - WEST PENETRATION ACCESS AREA - NODALIZATION MODEL



LEGEND:

N – CONTROL VOLUME NUMBER

M – JUNCTION NUMBER

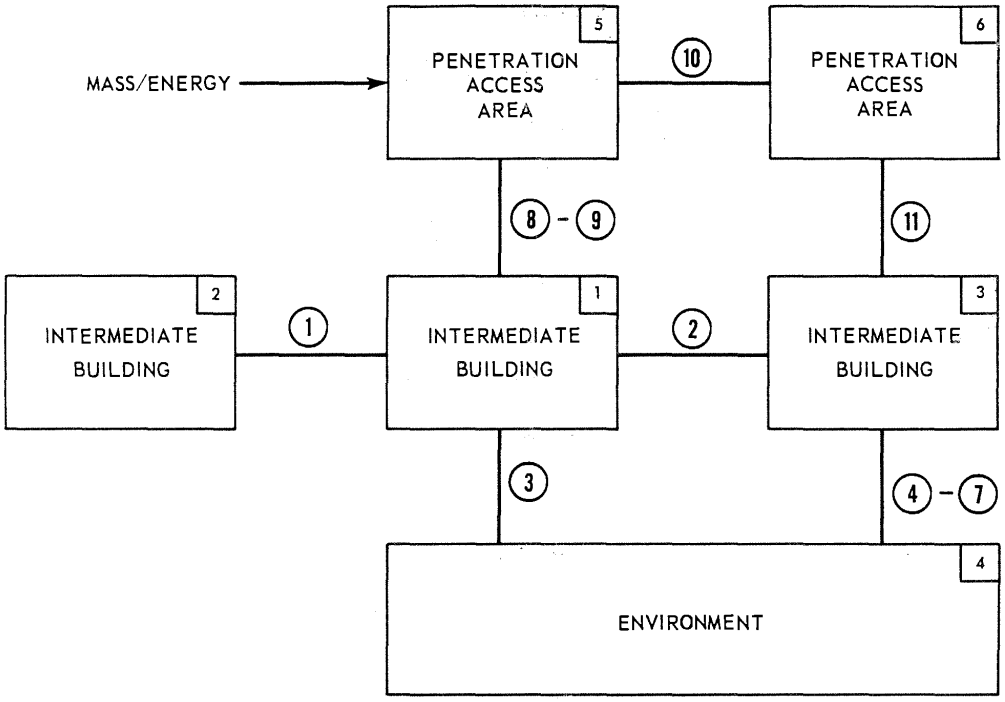
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Intermediate Building - West Penetration Access Area - Nodalization Model

Figure 3.6-1a

Figure 3.6-1b

INTERMEDIATE BUILDING - EAST PENETRATION ACCESS AREA - NODALIZATION MODEL



LEGEND:

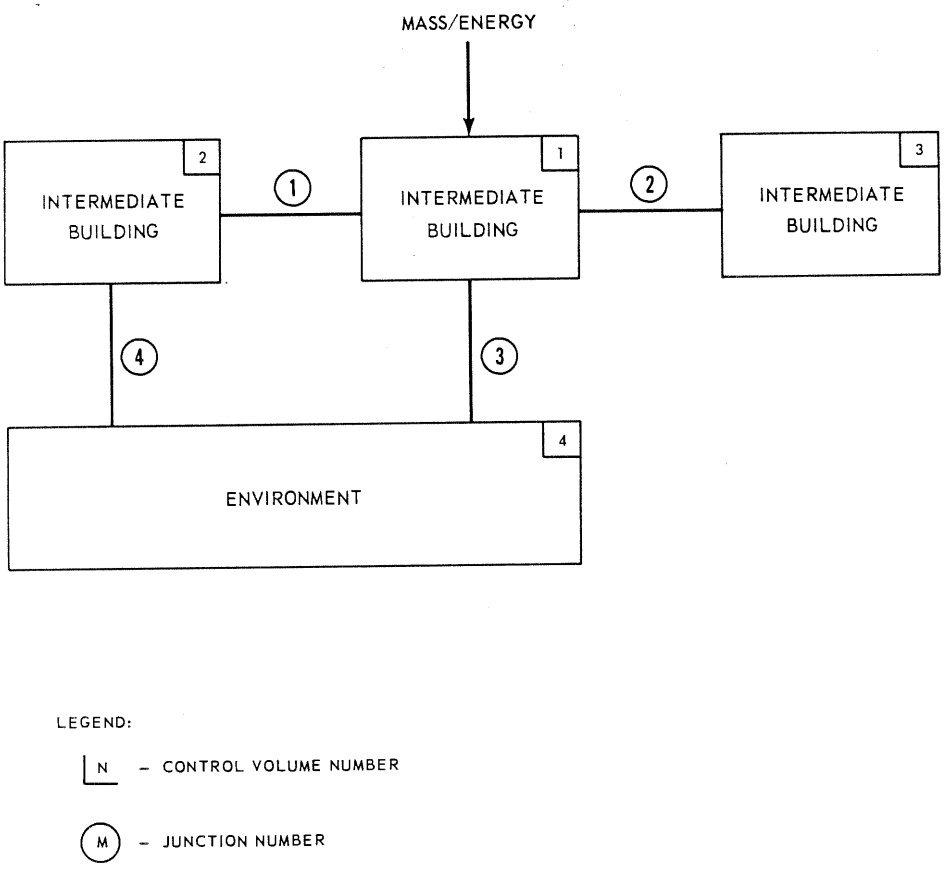
N – CONTROL VOLUME NUMBER

(M) – JUNCTION NUMBER

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Intermediate Building - East Penetration Access Area - Nodalization Model Figure 3.6-1b

Figure 3.6-1c

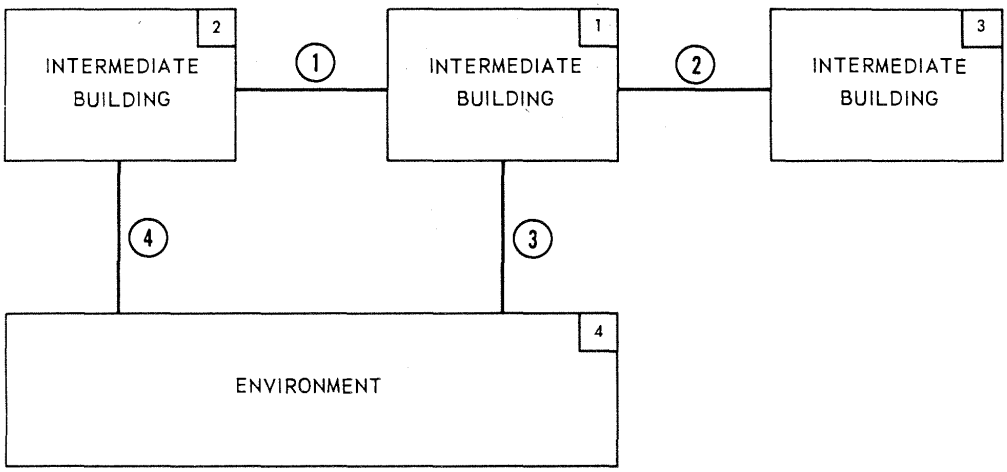
INTERMEDIATE BUILDING - SUBCOMPARTMENT CONTAINING MAIN STEAM AND FEEDWATER HEADERS - NODALIZATION MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Intermediate Building - Subcompartment Containing Main Steam and Feedwater Headers - Nodalization Model Figure 3.6-1c

Figure 3.6-1d

INTERMEDIATE BUILDING - OUTSIDE SUBCOMPARTMENT CONTAINING MAIN STEAM AND FEEDWATER HEADERS - NODALIZATION MODEL



LEGEND:

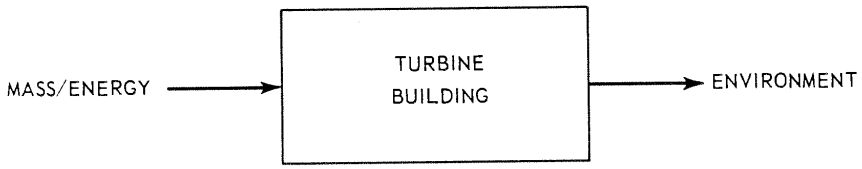
N – CONTROL VOLUME NUMBER

M – JUNCTION NUMBER

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Intermediate Building - Outside Subcompartment Containing Main Steam and Feedwater Headers - Nodalization Model Figure 3.6-1d

Figure 3.6-1e

TURBINE BUILDING - NODALIZATION MODEL

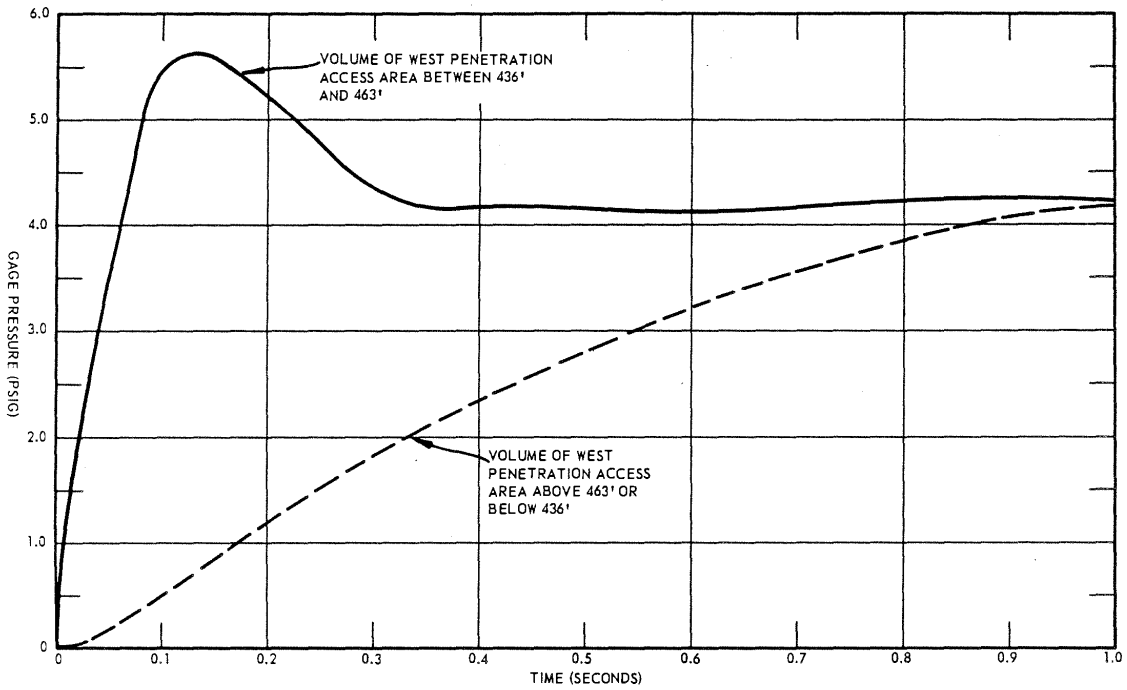


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Turbine Building - Nodalization Model

Figure 3.6-1e

Figure 3.6-2
GAGE PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE WEST PENETRATION ACCESS AREA

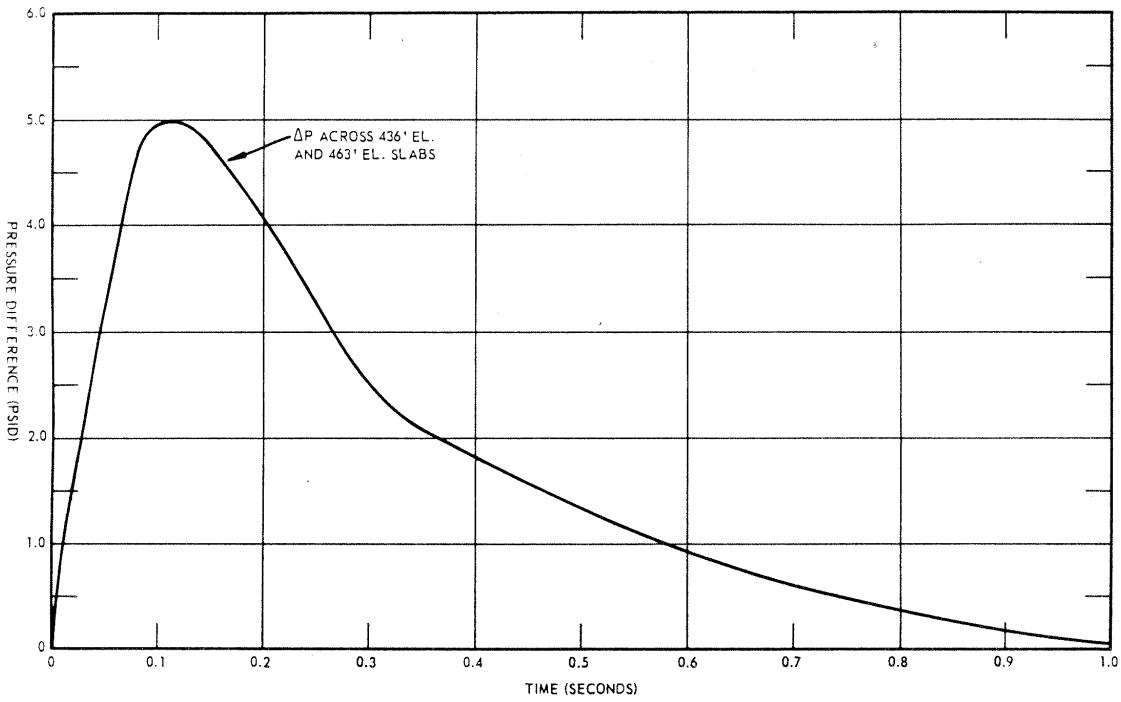


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Gage Pressure versus Time Following a Main Steam Line Rupture in the West Penetration Access Area

Figure 3.6-2

Figure 3.6-3
DIFFERENTIAL PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE WEST PENETRATION AREA



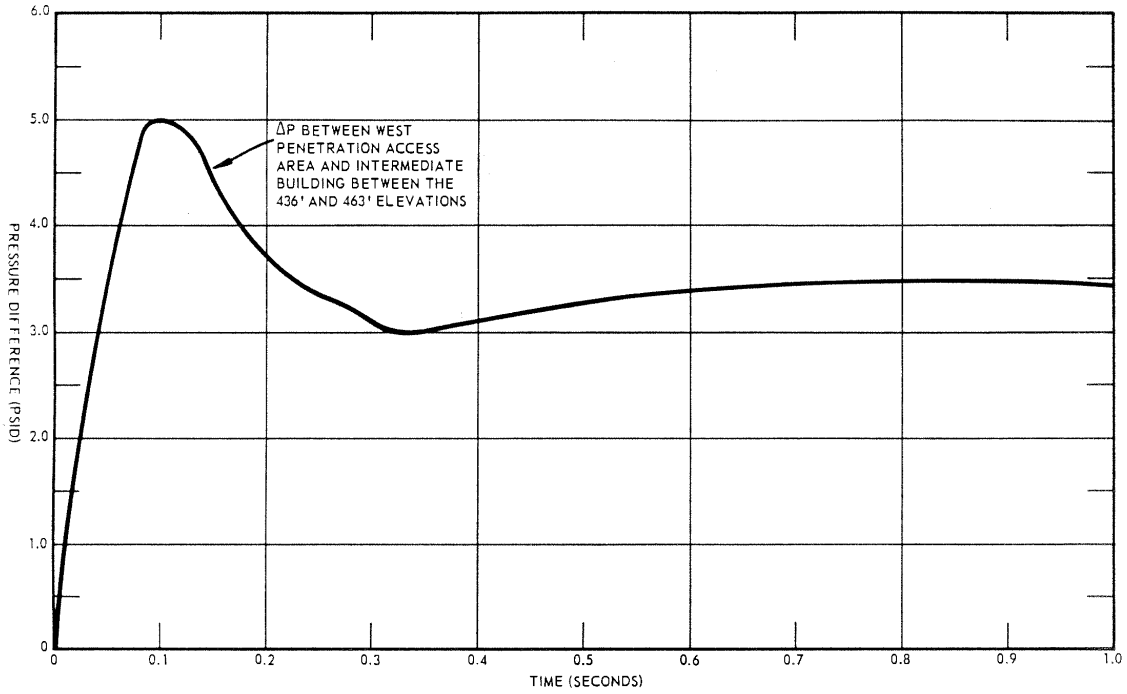
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Differential Pressure versus Time Following a Main Steam Line Rupture in the West Penetration Area

Figure 3.6-3

Figure 3.6-4

DIFFERENTIAL PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE WEST PENETRATION AREA



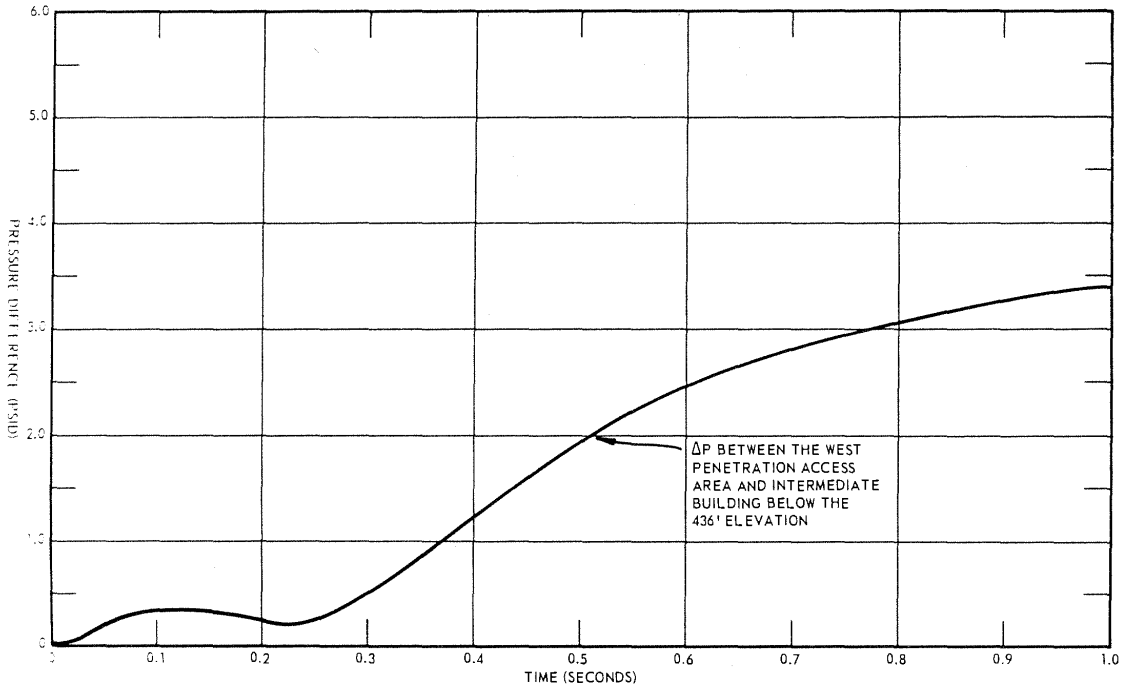
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Differential Pressure versus Time Following a Main Steam Line Rupture in the West Penetration Area

Figure 3.6-4

Figure 3.6-5

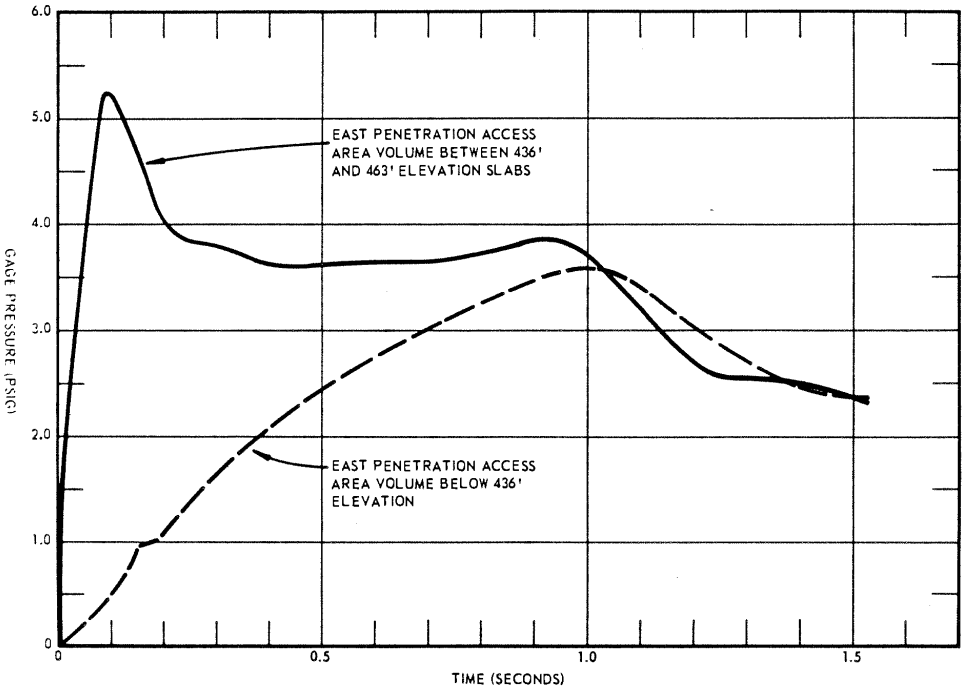
DIFFERENTIAL PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE WEST PENETRATION ACCESS AREA



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Differential Pressure versus Time Following a Main Steam Line Rupture in the West Penetration Access Area Figure 3.6-5

Figure 3.6-6

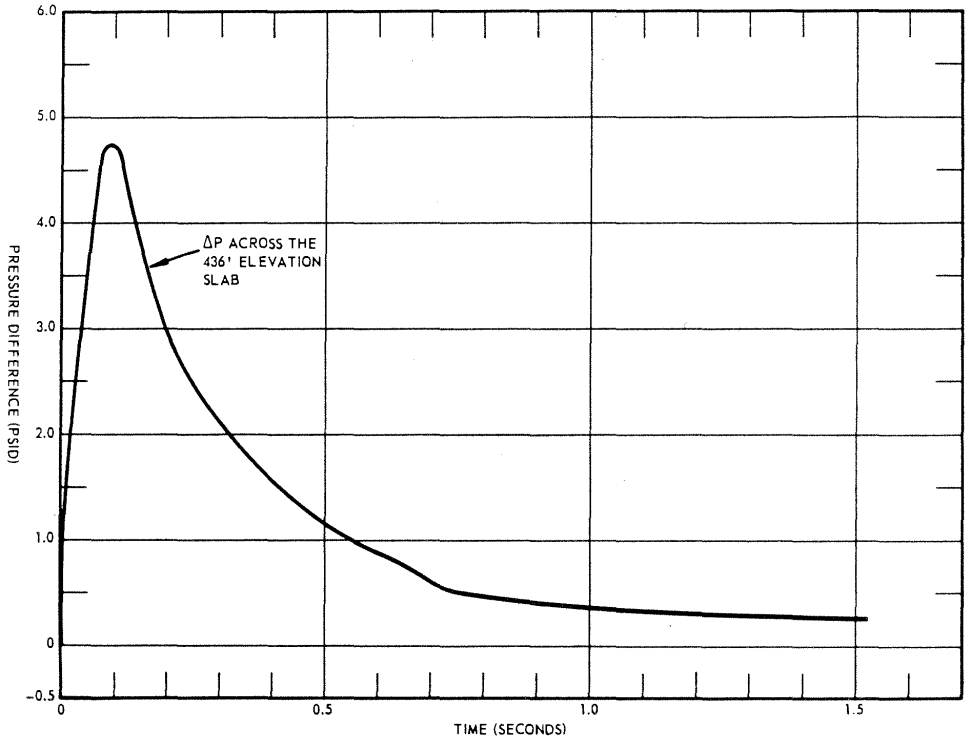
GAGE PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE EAST PENETRATION ACCESS AREA



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Gage Pressure versus Time Following a Main Steam Line Rupture in the East Penetration Access Area Figure 3.6-6

Figure 3.6-7

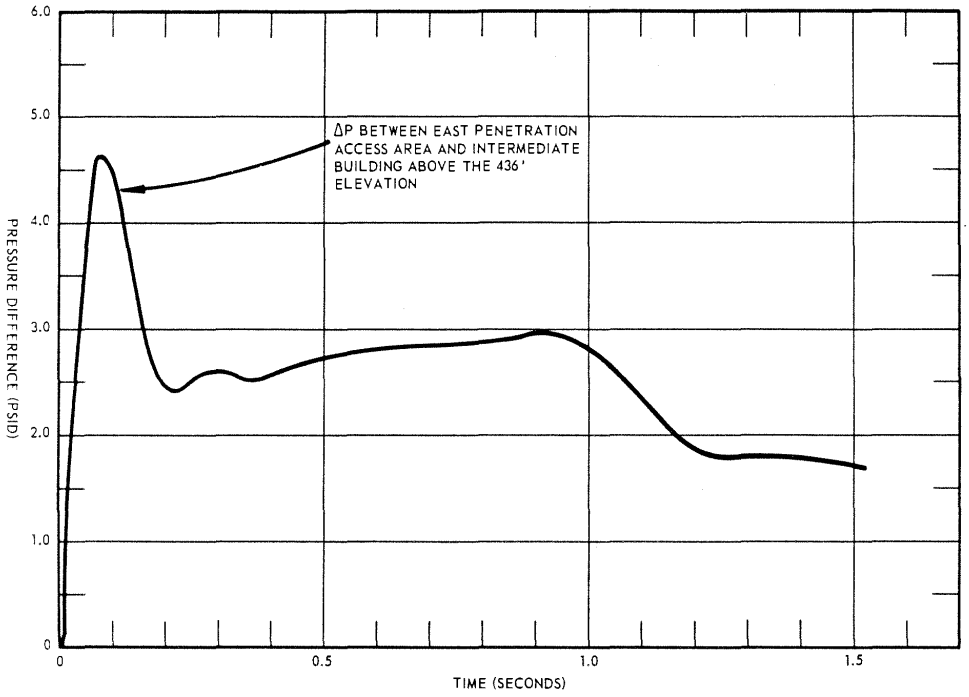
DIFFERENTIAL PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE EAST PENETRATION ACCESS AREA



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Differential Pressure versus Time Following a Main Steam Line Rupture in the East Penetration Access Area Figure 3.6-7

Figure 3.6-8

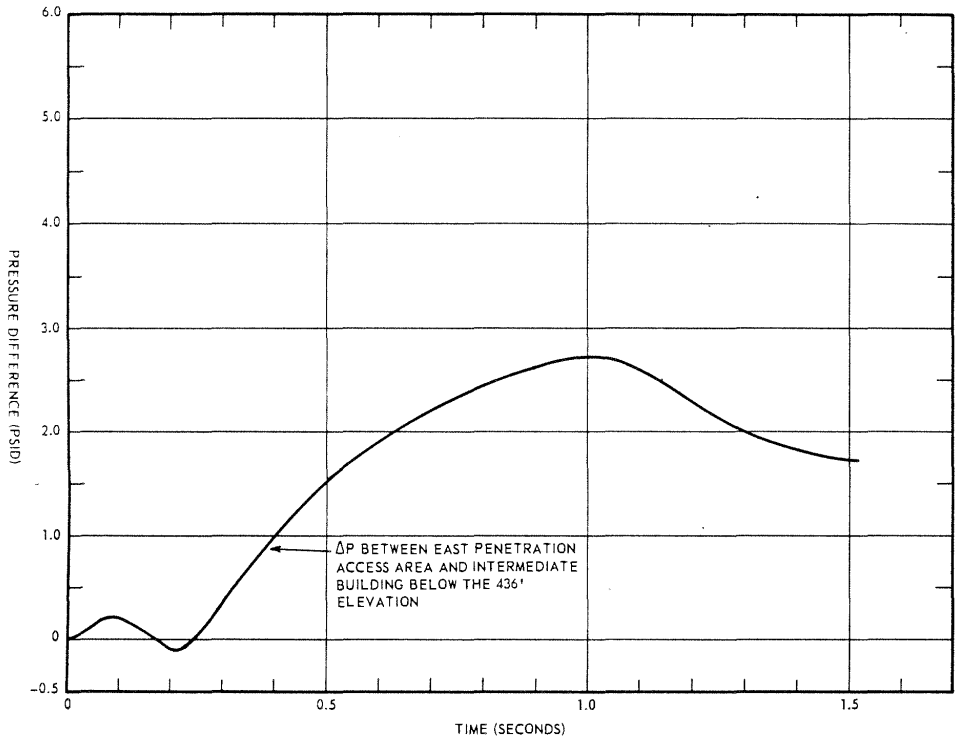
DIFFERENTIAL PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE EAST PENETRATION ACCESS AREA



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Differential Pressure versus Time Following a Main Steam Line Rupture in the East Penetration Access Area Figure 3.6-8

Figure 3.6-9

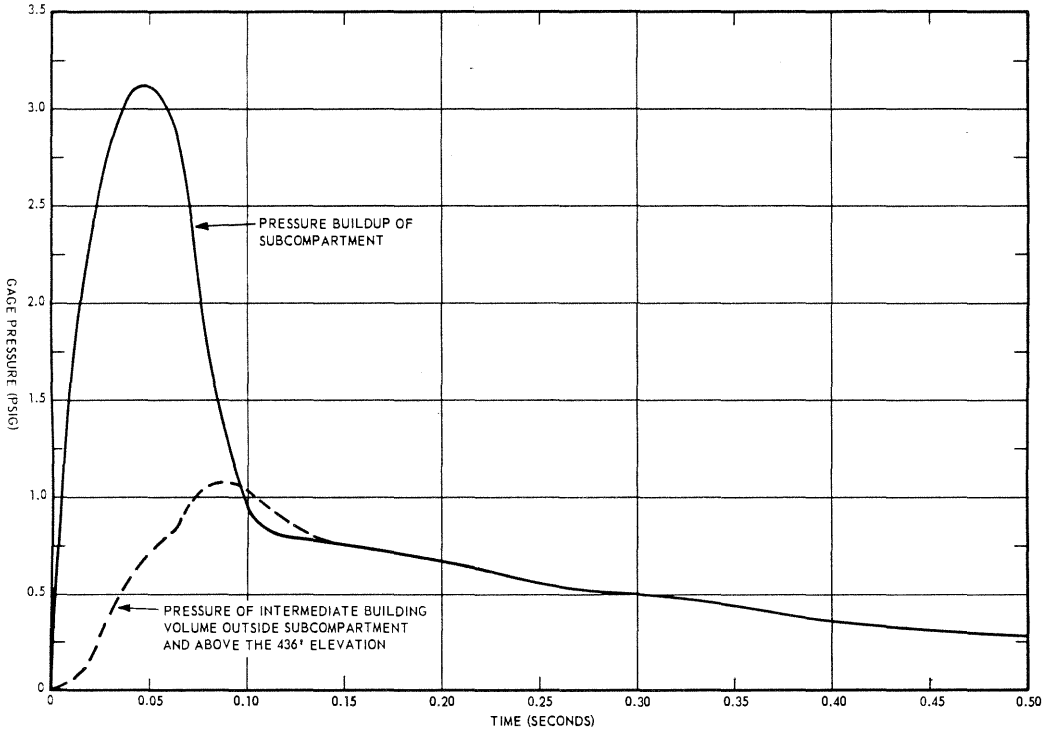
DIFFERENTIAL PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE EAST PENETRATION ACCESS AREA



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Differential Pressure versus Time Following a Main Steam Line Rupture in the East Penetration Access Area Figure 3.6-9

Figure 3.6-10

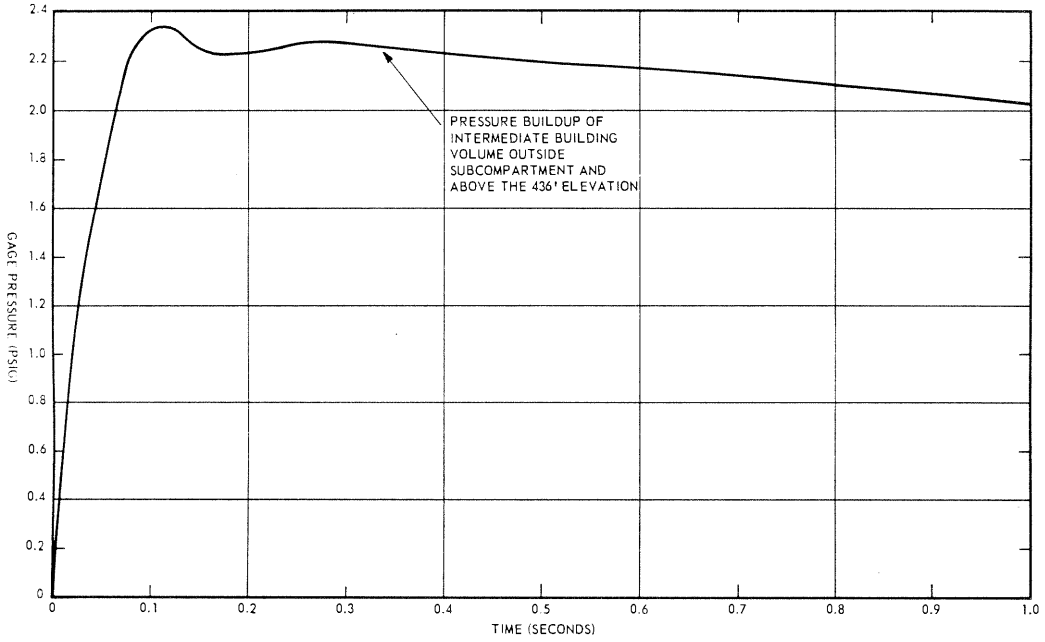
GAGE PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE INTERMEDIATE BUILDING SUB-COMPARTMENT CONTAINING THE MAIN STEAM AND FEEDWATER HEADERS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Gage Pressure versus Time Following a Main Steam Line Rupture in the Intermediate Building Sub-Compartment Containing the Main Steam and Feedwater Headers Figure 3.6-10

Figure 3.6-11

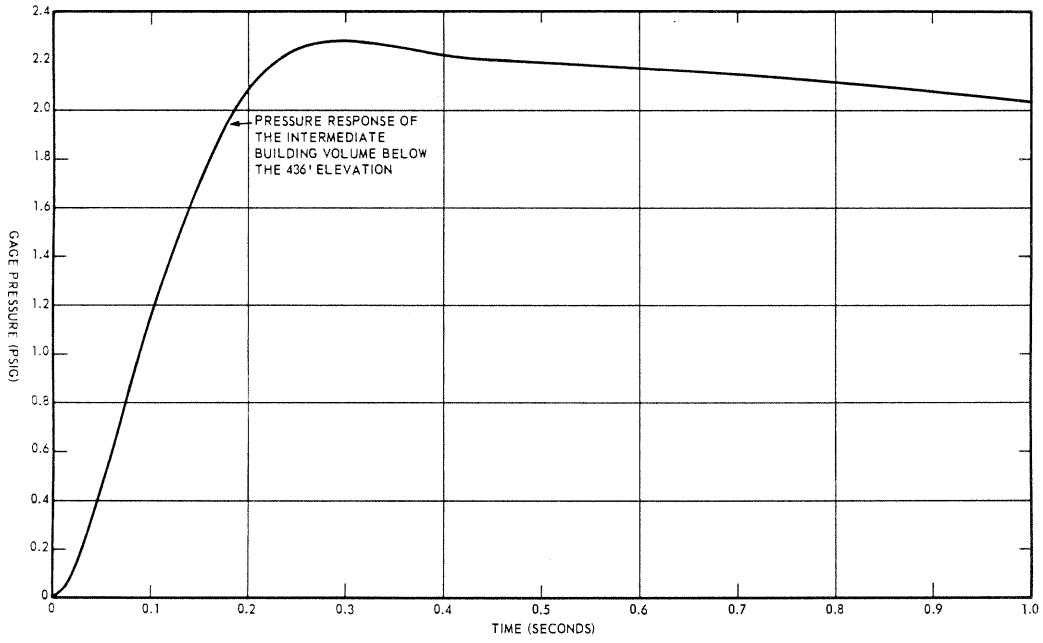
GAGE PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE INTERMEDIATE BUILDING OUTSIDE THE SUB-COMPARTMENT CONTAINING THE MAIN STEAM AND FEEDWATER HEADERS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Gage Pressure versus Time Following a Main Steam Line Rupture in the Intermediate Building Outside the Sub-Compartment Containing the Main Steam and Feedwater Headers Figure 3.6-11

Figure 3.6-12

GAGE PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE INTERMEDIATE BUILDING OUTSIDE THE SUB-COMPARTMENT CONTAINING THE MAIN STEAM AND FEEDWATER HEADERS

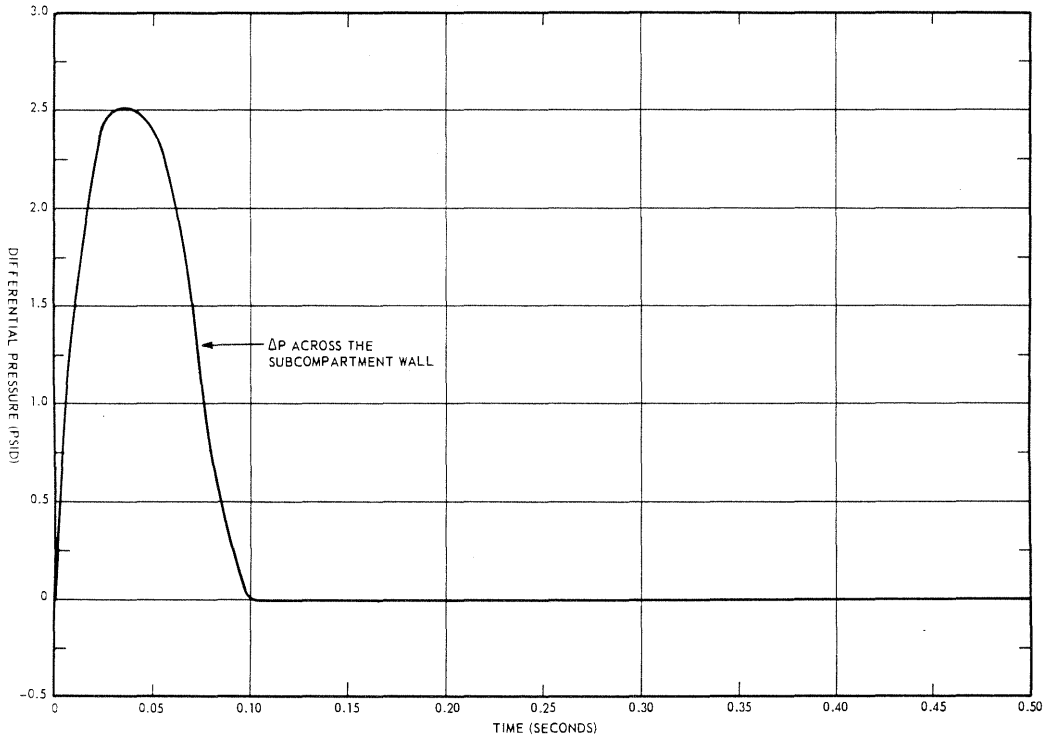


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Gage Pressure versus Time Following a Main Steam Line Rupture in the Intermediate Building Outside the Sub-Compartment Containing the Main Steam and Feedwater Headers
Figure 3.6-12

Figure 3.6-13

DIFFERENTIAL PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE INTERMEDIATE BUILDING SUB-COMPARTMENT CONTAINING THE MAIN STEAM AND FEEDWATER HEADERS

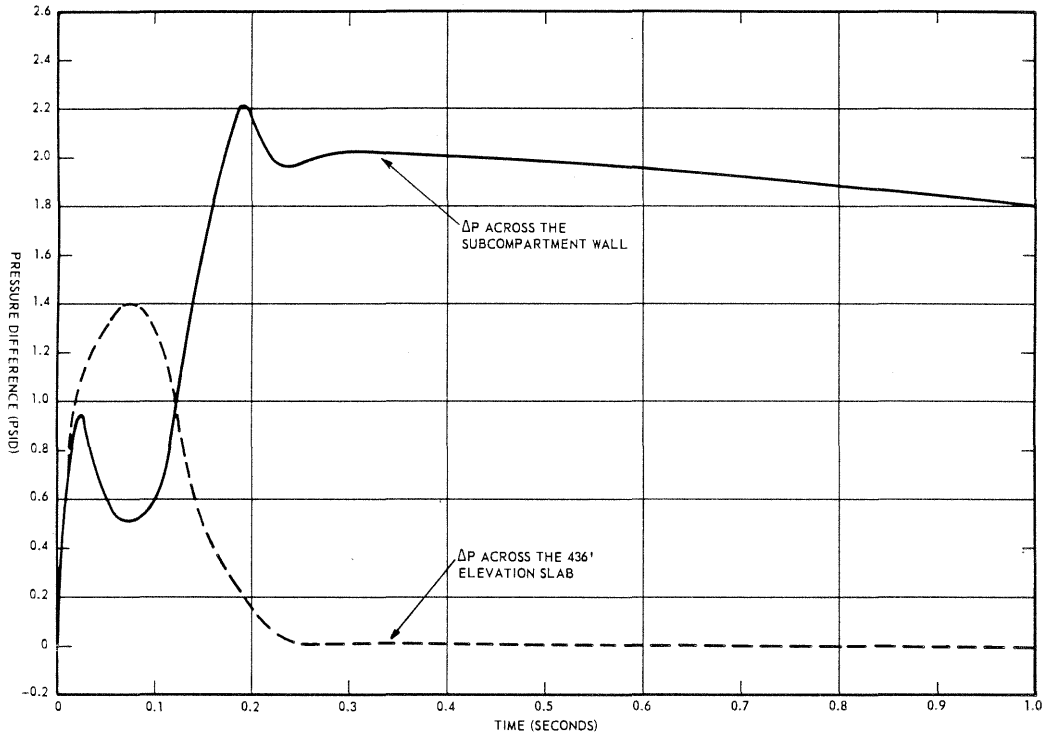


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Differential Pressure versus Time Following a Main Steam Line Rupture in the Intermediate Building Sub-Compartment Containing the Main Steam and Feedwater Headers
Figure 3.6-13

Figure 3.6-14

DIFFERENTIAL PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE INTERMEDIATE BUILDING OUTSIDE THE SUB-COMPARTMENT CONTAINING THE MAIN STEAM AND FEEDWATER HEADERS

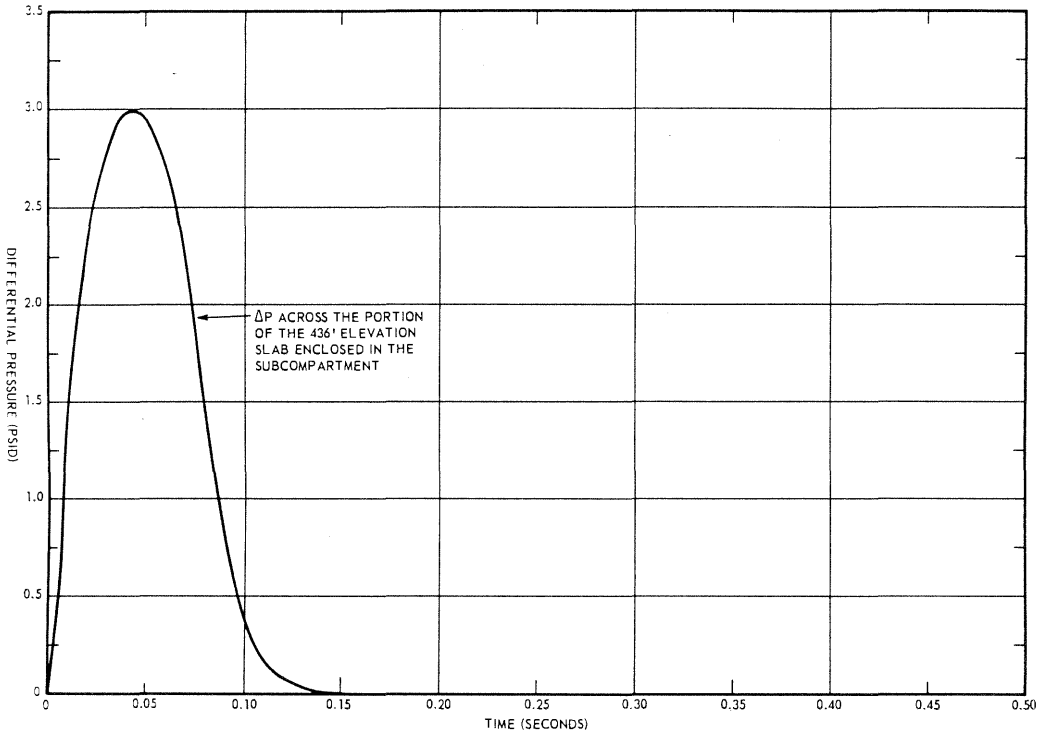


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Differential Pressure versus Time Following a Main Steam Line Rupture in the Intermediate Building Outside the Sub-Compartment Containing the Main Steam and Feedwater Headers
Figure 3.6-14

Figure 3.6-15

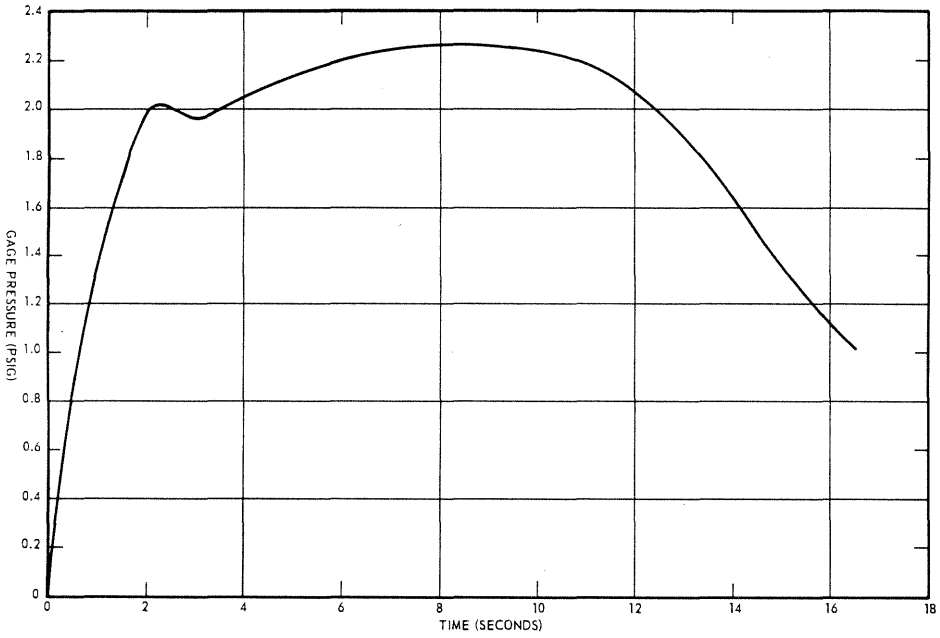
DIFFERENTIAL PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE INTERMEDIATE BUILDING SUB-COMPARTMENT CONTAINING THE MAIN STEAM AND FEEDWATER HEADERS



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Differential Pressure versus Time Following a Main Steam Line Rupture in the Intermediate Building Sub-Compartment Containing the Main Steam and Feedwater Headers
Figure 3.6-15

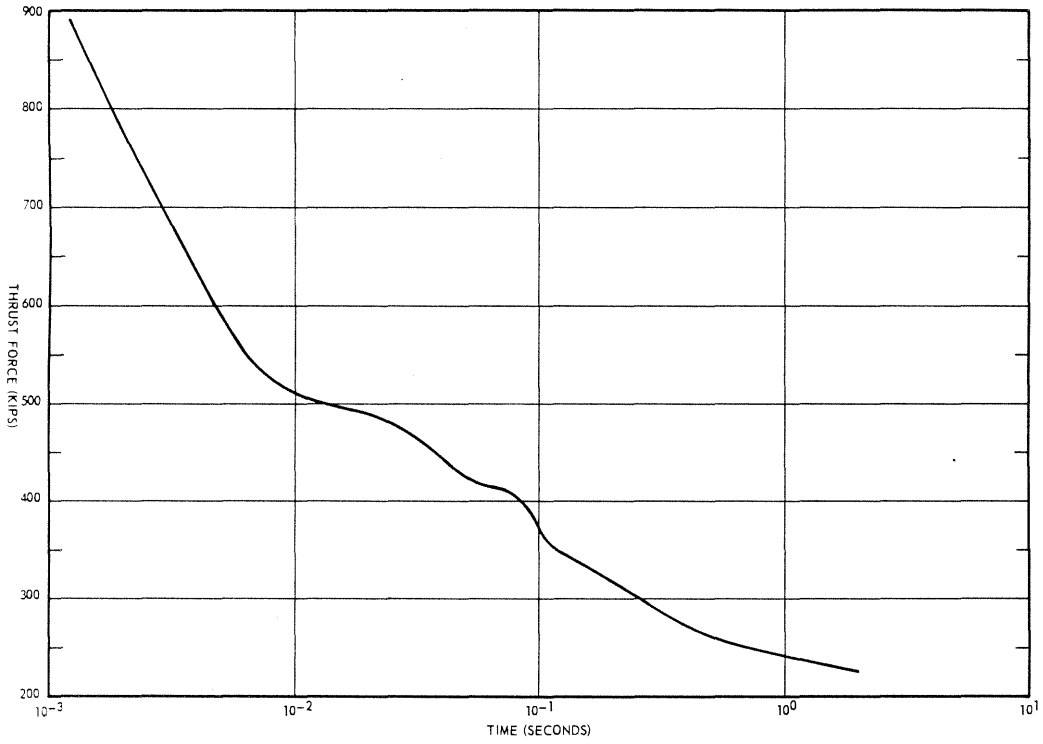
Figure 3.6-16
GAGE PRESSURE VERSUS TIME FOLLOWING A MAIN STEAM LINE RUPTURE IN THE TURBINE BUILDING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Gage Pressure versus Time Following a Main Steam Line Rupture in the Turbine Building Figure 3.6-16

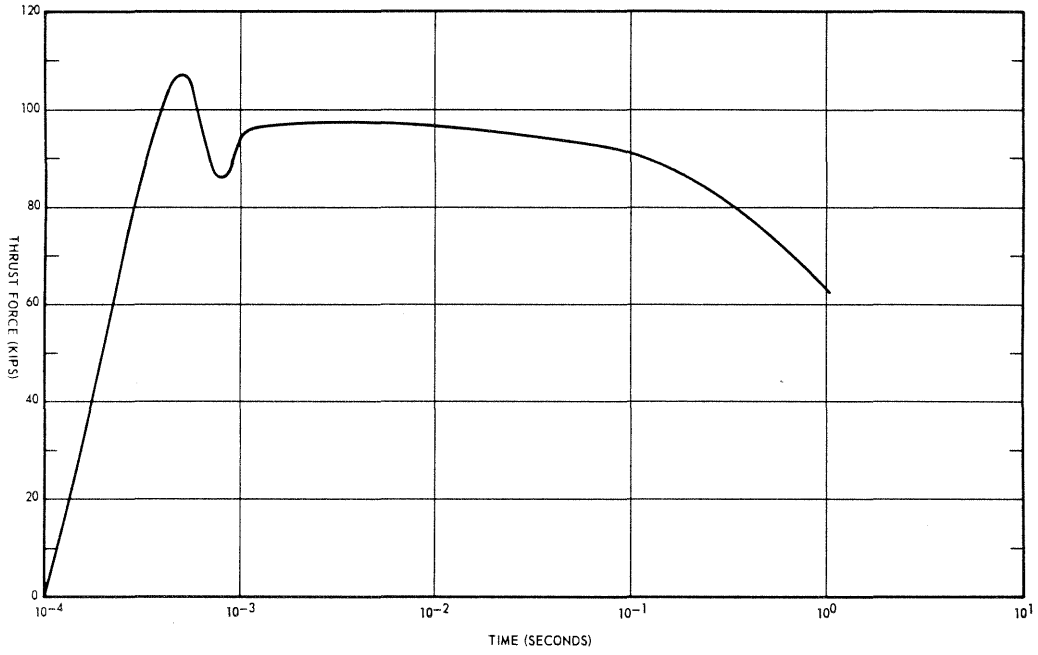
Figure 3.6-17

THRUST FORCE VERSUS TIME FOR STEAM GENERATOR SIDE OF A MAIN STEAM LINE BREAK AT THE CONTAINMENT WALL PENETRATION



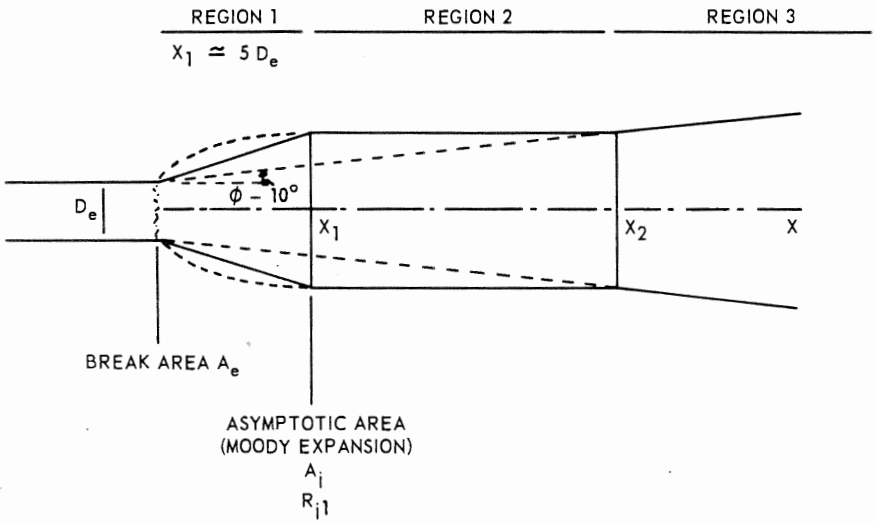
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Thrust Force versus Time for Steam Generator Side of a Main Steam Line Break at the Containment Wall Penetration Figure 3.6-17

Figure 3.6-18
THRUST FORCE VERSUS TIME FOR PUMP SIDE OF FEEDWATER LINE BREAK AT LOOP A OR B SECONDARY SHIELD PENETRATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Thrust Force versus Time for Pump Side of Feedwater Line Break at Loop A or B Secondary Shield Penetration Figure 3.6-18

Figure 3.6-19
FLUID JET GEOMETRY

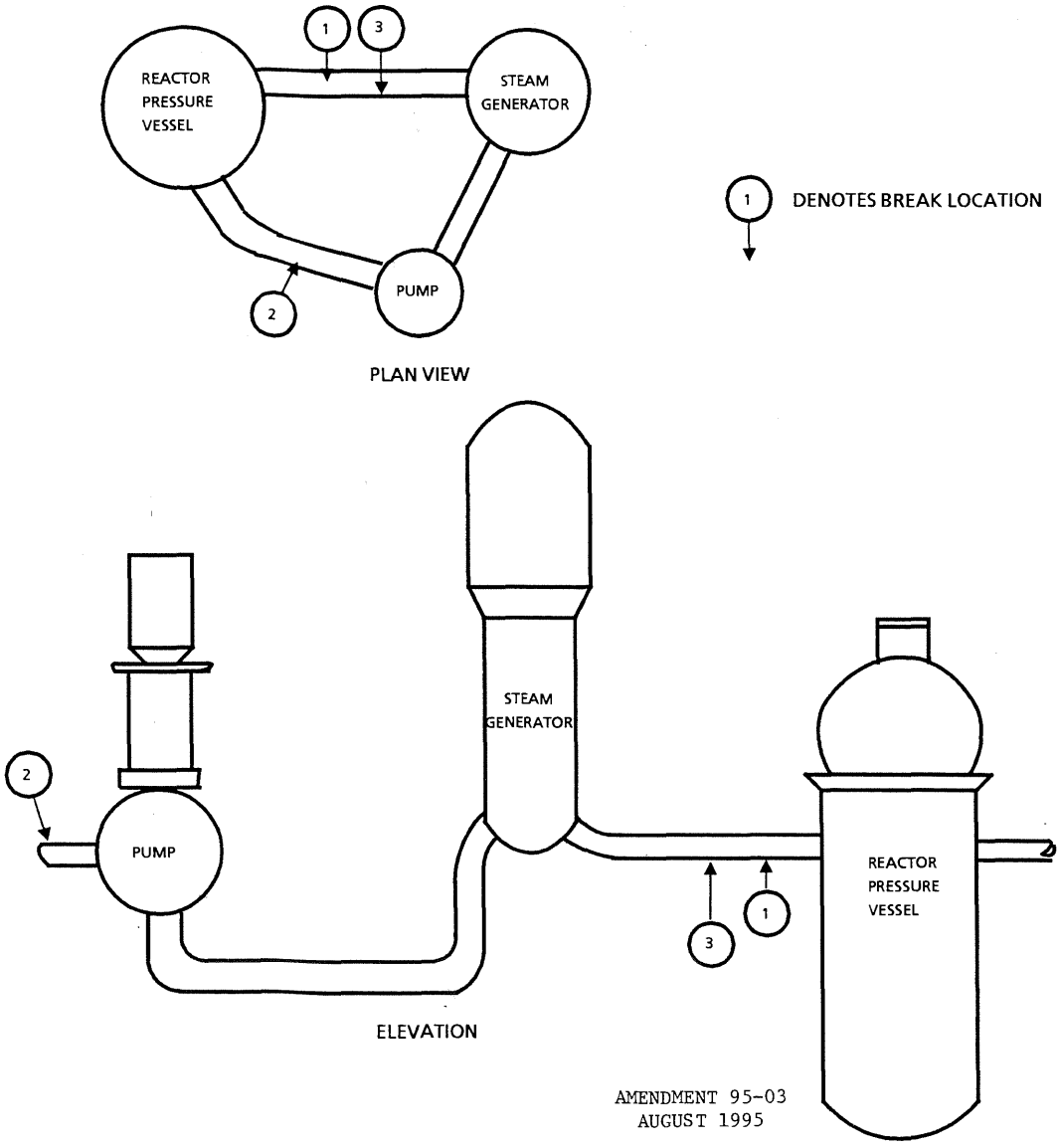


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Fluid Jet Geometry Figure 3.6-19

Figure 3.6-20 - Figure 3.6-50

FIGURES 3.6-20 THROUGH 3.6-50 WERE DELETED BY AMENDMENT 1 DATED AUGUST, 1985 (RN 01-071)

Figure 3.6-51
LOCATION OF POSTULATED BREAKS IN MAIN REACTOR COOLANT PUMP



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Location of Postulated Breaks in Main Reactor Coolant Loop Figure 3.6-51

3.7 SEISMIC DESIGN

In addition to the steady-state loads imposed on the system under normal operating conditions, the design of equipment, equipment supports, and Seismic Category I structures requires that consideration also be given to abnormal loading conditions such as earthquakes. Seismic loading, are considered for earthquakes of two magnitudes: safe shutdown earthquake (SSE) and operating basis earthquake (OBE). The SSE is defined as the maximum vibratory ground motion at the plant site that can reasonably be predicted from geologic and seismic evidence. The OBE is that earthquake which, considering the local geology and seismology, can be reasonably expected to occur during the plant life.

Aside from these two major earthquakes, the effects of reservoir induced seismicity were reviewed in a separate study which is summarized in Section 3.7.1.5. Specific details on input, analysis methods and procedures, etc. for reservoir induced seismicity are not included within Section 3.7 but are contained in Reference 26.

For the OBE loading condition, the Nuclear Steam Supply System and safety-related balance of plant equipment and structures are designed to be capable of continued safe operation. The design for the SSE is intended to assure:

1. That the integrity of the reactor coolant pressure boundary is not compromised;
2. That the capability to shutdown the reactor and maintain it in a safe condition is not compromised; and
3. That the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100.11 and 10 CFR 50.67 is not compromised.

It is necessary to ensure that required Seismic Category I structures, systems, and components do not lose their capability to perform their safety function. Not all components have the same functional safety requirements. For example, a charging pump must retain its capability to function normally during the SSE. Therefore, the deformation in the pump must be restricted to appropriate limits to assure its ability to function. On the other hand, many components can experience significant permanent deformation without loss of function. Piping and vessels are examples of the latter where the principal requirement is that they retain their contents and allow fluid flow.

This Section is presented in the following subsections:

3.7.5 Seismic Design Control

3.7.1 Seismic Input

3.7.2 Seismic System Analysis

3.7.3 Seismic Subsystem Analysis

3.7.4 Seismic Instrumentation Program

3.7.5 Seismic Design Control

The seismic requirements for safety-related instrumentation and electrical equipment are covered in Section 3.10. The safety class definitions and classifications are given in Section 3.2.

3.7.1 Seismic Input

3.7.1.1 Design Response Spectra

Design response spectra for the horizontal component of the SSE, formerly the design basis earthquake, and OBE are applied in the design of Seismic Category I structures, systems, and components according to preliminary results of studies conducted by N. M. Newmark and J. A. Blume, consultants to the AEC. These studies were performed prior to and the response spectra were developed before issuance of Regulatory Guide 1.60. Regulatory Guide 1.60 is discussed in Appendix 3A.

Separate design response spectra are specified at rock and soil foundation elevations. Horizontal spectra for structures founded upon rock like media are presented as Figures 3.7-1 and 3.7-2 for the SSE and OBE, respectively. Design response spectra for structures founded upon soil are presented as Figures 3.7-3 and 3.7-4 for the SSE and OBE, respectively.

The vertical component spectra used are two thirds of the horizontal components in all frequency ranges and occur simultaneously.

The maximum horizontal ground acceleration for the SSE is 0.15g at the competent rock foundation elevation and 0.25g for the soil foundation. For the OBE, the maximum horizontal ground accelerations used are 0.1g (rock) and 0.15g (soil). Seismological and geological background data pertaining to the plant site are presented in Section 2.5.

The design response spectra are similar to the previous NRC minimum criteria (see Figure 17 of Reference 20). The differences between the design response spectra and the current NRC recommended spectra of Regulatory Guide 1.60 have been investigated for all damping values considered. It was found that the design response spectra are, in general, enveloped by the recommended spectra throughout the entire frequency range and are apparently less conservative in the range of frequencies below about 0.55 Hz. In the latter region, the difference is of no concern, in general, for Seismic Category I structures, systems, and components. For the region from about 2 to 9 Hz, where the predominant frequencies of the Seismic Category I structures lie, the differences between the spectra are relatively small. Specifically, in the frequency range from about 4.6 to 6.8 Hz, the two sets of spectra are practically the same for the 2, 5, and 7% curves. In the frequency ranges from about 2 to 4.6 Hz and from about 6.8 to 9 Hz, the maximum differences with respect to the design spectra are about 22, 20, 18, 18, and 23%, respectively, for 0.5, 2, 5, 7, and 10% critical damping values. In the ranges of frequencies from about 0.55 to 2 Hz and from about 9 to 33 Hz, the differences between the spectra are again relatively small, except possibly for the spectrum curves of 7 and 10% critical damping.

The differences between the two sets of response spectra stated above might result in an underestimate of the responses of Seismic Category I structures should the damping values of Regulatory Guide 1.61 be used. However, with the use of more conservative (i.e., lower) damping values than those of Regulatory Guide 1.61, the two sets of spectra would lead to very nearly the same results, as is shown in Section 3.7.1.3.

As indicated in Section 3.7.1.4, some of the Seismic Category I structures are founded upon competent soils. Others are founded upon rock by means of caissons or lean concrete. The foundation elevation for each of the Seismic Category I structures is given in Tables 3.7-5 and 3.7-6. In the seismic analyses, with soil structure interaction effects included, the design spectra are applied at the various foundation locations of Seismic Category I structures. For the Reactor Building, Auxiliary Building, and Control Building, which are founded upon lean concrete bearing on rock, the design spectra in Figures 3.7-1 and 3.7-2 are applied in the respective lumped-mass-spring soil-structure interaction system at the foundation, as listed in Table 3.7-5. For the Diesel Generator Building, Fuel Handling Building, and Intermediate Building, which are founded upon caissons, the effective design spectra are applied throughout the elevation of the caissons in the lumped-mass-spring soil-structure interaction systems. Such effective design spectra are determined based upon equivalent energy input accounting for the design spectra at rock elevation (Figures 3.7-1 and 3.7-2) and the design spectra at soil elevation (Figures 3.7-3 and 3.7-4) as described in Section 3.7.2.4. For the Service Water Pumphouse, which is founded on competent soils, the design spectra (Figures 3.7-1 and 3.7-2) are applied at the base rock elevation, at 350 feet, in the finite element soil-structure interaction system (see Section 3.7.2.1.1). Since no structural response amplification was expected from the service water intake structure and service water discharge structure, design spectra were not used for these two structures. Instead, effective seismic loads, based upon the maximum ground accelerations, were conservatively used for design as is described in Section 3.8.4.4.8 and 3.8.4.4.9, respectively.

3.7.1.2 Design Time History

A synthetic earthquake ground motion time history was developed to simulate the SSE and OBE, based upon the design response spectra discussed in Section 3.7.1.1, for the time history analysis of structures, components, and equipment.

The time history is compatible with the corresponding response spectra. The “valleys” in the unsmoothed response spectra generated from the time history do not fall below the corresponding smoothed response spectra presented as Figures 3.7-1 through 3.7-4 for rock and soil foundation elevations. Figures 3.7-5 through 3.7-8 present comparisons between the smoothed response spectra and spectra derived from the synthetic earthquake time history for 2%, 5%, 7%, and 10% of critical damping, respectively.

The synthetic earthquake time history was developed with an equal time interval of 0.01 second. The period intervals at which the unsmoothed response spectra values were calculated ranged from 0.001 second to 0.2 second. A total of 108 points were used in generating each spectrum. The closest period intervals were used in the most critical portions of each spectrum. In Table Table 3.7-0, the frequency intervals used for calculating the unsmoothed response spectra (see Figures 3.7-5 and 3.7-8) from the synthetic earthquake time history are given.

3.7.1.3 Critical Damping Values

3.7.1.3.1 Balance of Plant Scope

The specific percentage of critical damping values used for Seismic Category I structures, systems, and components are presented in Table 3.7-1 and 3.7-2. The values were obtained from Reference 1. These values are equivalent to or provide less damping than the current values in Regulatory Guide 1.61 (see Appendix 3A). For example, the damping values provided in Table 3.7-1 for reinforced concrete structures are 2 and 5% critical for stress levels no more than about half the yield point and at or just below the yield point, respectively. The corresponding values in Regulatory Guide 1.61 are 4 and 7% critical for OBE and SSE, respectively. The damping values for stress levels beyond the yield point, as shown in Table 3.7-1, were not used in the analysis. A comparison of the design spectrum of 2% (Section 3.7.1.1) and the recommended spectrum of 4% in Regulatory Guide 1.60 indicates that, except in the range of frequencies below about 0.55 Hz, the design spectrum envelops the recommended spectrum with significant margin, especially in the frequency range from about 0.55 to 9 Hz. The 5% design spectrum is also compared with the 7% recommended spectrum with similar conclusion obtained.

In the case of prestressed concrete structures, such as the Reactor Building shell, the corresponding damping values required in Table 3.7-1 are equivalent to those in Regulatory Guide 1.61 which are 2 and 5% critical for OBE and SSE respectively. In actual design of the Reactor Building shell, however, a damping value of 2% was used for both OBE and SSE. This, coupled with the only slight unconservatism of the design spectra in comparison to the recommended spectra (see Section 3.7.1.1), suffices to assure the adequacy and conservatism of the structural responses under both OBE and SSE.

Based upon the above, the use of more conservative damping values, together with the design spectra, has provided a measure of the seismic responses of Seismic Category I structures, systems, and components which is equivalent to or more conservative than would be provided by using the damping values in Regulatory Guide 1.61 combined with the recommended spectra in Regulatory Guide 1.60.

For the soil-structure interaction system, the hysteretic damping values for the foundation media were taken to be 5% for the rocking mode and 10% for the swaying mode, regardless of the type of foundation media and frequency range. For conservatism, the radiation (viscous) damping due to wave propagation from a structure into the half-space, which is frequency dependent, was not considered.

In a typical classical modal analysis, different damping has been specified for each mode of the vibratory system. The method of weighted modal damping as described in Reference 2 was used to calculate the damping for each mode in the dynamic analysis of the soil-structure interaction system.

3.7.1.3.2 Components and Equipment Provided by the NSSS Vendor

The damping values given in Table 3.7-3 are used for the systems analysis of Westinghouse equipment. These are consistent with the damping values recommended in Regulatory Guide 1.61 except in the case of the primary coolant loop system components and large piping (excluding reactor pressure vessel internals) for which the damping values of 2% and 4% are used as established in testing programs reported in Reference 3. The damping values for control rod drive mechanisms (CRDM) and the fuel assemblies of the Nuclear Steam Supply System are in conformance with the values for welded and/or bolted steel structures as listed in Regulatory Guide 1.61.

Tests on fuel assembly bundles justified conservative component damping values of 7% for OBE and 10% for SSE to be used in the fuel assembly component qualification. Documentation of the fuel assembly tests is presented in Reference 4.

The damping values used in component analysis of CRDM and their seismic supports were developed by testing programs performed by Westinghouse. These tests were performed during the design of the CRDM support; the support was designed so that the damping in Table 3.7-3 could be conservatively used in the seismic analysis. The CRDM support system is designed with plates at the top of the mechanism and gaps between mechanisms. These are encircled by a box section frame which is attached by tie-rods to the refueling cavity wall. The test conducted was on a full size CRDM complete with rod position indicator coils, attachment to a simulated vessel head, and variable gap between the top of the pressure housing support plate and a rigid bumper representing the support. The internal pressure of the CRDM was 2250 psi and the temperature on the outside of the pressure housing was 400°F.

The program consisted of transient vibration tests in which the CRDM was deflected a specified initial amount and suddenly released. A logarithmic decrement analysis of the decaying transient provides the effective damping of the assembly. The effect on damping of variations in the drive shaft axial position, upper seismic support clearance, and initial deflection amplitude was investigated.

The upper support clearance had the largest effect on the CRDM damping with the damping increasing with increasing clearance. With an upper clearance of 0.06 inches, the measured damping was approximately 8%. The clearances in a typical upper seismic CRDM support are a minimum of 0.10 inches. The increasing damping with increasing clearances trend from the test results indicated that the damping would be greater than 8% for both the OBE and the SSE based on a comparison between typical deflections during these seismic events to the initial deflections of the mechanisms in the test. Component damping values of 5% are, therefore, conservative for both OBE and SSE.

The Replacement Service Structure, Integrated Head Assembly (IHA), was designed similarly to the original CRDM Seismic Support Assembly. Damping values used for the original design were applied to the IHA with the CRDM Support System designed with plates at the top of the CRDM mechanisms with gaps between the plates that approximate the original design.

These damping values are used and applied to CRDM component analyses by response spectra techniques. Where time history analyses are used, damping in the pressure housing is set at the levels stated in Table 3.7-3 for welded steel structures and impact damping is applied at the contact points in the upper seismic supports.

3.7.1.4 Supporting Media for Seismic Category I Structures

The Seismic Category I service water intake structure, Service Water Pumphouse, and service water discharge structure are supported by mats founded upon competent soil. Other Seismic Category I structures are founded upon rock by means of caissons or mats. For the Reactor Building, Auxiliary Building, and Control Building, soils below planned foundation grade have been excavated and replaced with lean concrete bearing on rock.

Dynamic engineering properties of the soil and bedrock at the site have been evaluated for use in foundation interaction analyses. These properties, presented in Table 3.7-4, were developed using field geophysical and geologic data and static and dynamic laboratory test data. These values are appropriate for design at strain levels corresponding to the SSE and OBE. The shear module and subgrade module developed from laboratory and geophysical data have been reduced using factors related to rock quality designation (RQD). More detailed information concerning the foundation media is provided in Section 2.5.

Descriptions of the supporting media for Seismic Category I structures are presented in Table 3.7-5

The foundation elevation and the foundation type for the Seismic Category I structures are presented in Table 3.7-5. Foundation material data for those structures supported on caissons is presented in Table 3.7-6.

Cross sections illustrating building foundation elevations, general subsurface conditions, and surface topography are presented in Figures 2.5-77 through 2.5-82. The locations of the sections are shown on Figures 2.5-46 and 2.5-47. The approximate dimensions, including height and top elevation, as well as the embedment depth of the Seismic Category I structures, as previously discussed, are presented in Table 3.7-7.

3.7.1.5 Effects of Reservoir Induced Seismicity

In addition to the seismic design data and procedures for the normal tectonic earthquake as presented within Section 3.7 herein, the effects of Reservoir Induced Seismicity were fully investigated in a separate study completed in 1983.

Shortly after filling of Monticello Reservoir in late 1977, a series of small earthquakes began occurring in the vicinity of the Virgil C. Summer Nuclear Station. These events, termed Reservoir Induced Seismicity (RIS), are still continuing to date but much less frequently than during the initial two years after filling the reservoir. The largest of the RIS events which have occurred are local magnitude ML 2.8 microearthquakes and are characterized by free field motions of very short duration, high frequency, and high peak accelerations.

As a result of this RIS phenomena, both the Advisory Committee on Reactor Safeguards (ACRS) and the Atomic Safety and Licensing Board (ASLB) expressed concerns on the impact that these small earthquakes would have on plant equipment and components required for the shutdown and continued removal of residual heat. The ACRS concern was with the largest postulated earthquake which might occur from Reservoir Induced Seismicity. The ASLB concern dealt with the shallow RIS events recorded at Monticello Reservoir. To address the ACRS and ASLB concerns, programs were set up to develop and establish envelope spectra for both the ACRS and ASLB type of events.

For the ACRS it was determined that the earthquake could be adequately represented by a 4.5 M_L event of normal tectonic depth anchored to a zero period acceleration of.22g. This response spectrum was considered by the NRC as conservative for the necessary evaluation. Comparing the ACRS response spectrum with the SSE response spectrum and considering the dominant frequencies of the structures, it was concluded that only buildings on rock had to be evaluated for the ACRS commitment. Buildings on rock include the Reactor Building, Auxiliary Building, Control Building, and Intermediate Building. The Intermediate Building, although on caissons, is so restrained that it was considered as a building on rock. Four Oroville aftershocks of magnitude 4.5 were used at nine varied time increments to generate 36 separate time history components for the ACRS. These components were applied to the seismic models of the appropriate plant structures to generate the necessary floor response spectra. This floor response spectra was required for use in the subsequent ACRS equipment margin study for safe shutdown equipment and components.

For the ASLB program, the envelope spectra for RIS events, as recorded by the USGS accelerograph located near the site, was used as a basis to further determine the response spectra which should be applied to the specific foundation types of the nuclear plant structures (i.e. rock, caissons, soil). The development of this specific response spectra included a program of explosion test experiments and resulted in a reduced envelope spectra for the three individual foundation types on rock, caissons, or soil.

This reduced enveloped spectra, as approved by the NRC, was compared to the SSE response spectra at the foundation level. It was concluded that for buildings on rock, the SSE foundation response spectra exceeded the ASLB reduced envelope spectra, except for the frequency region higher than 16 Hz. For buildings on caissons or on soil, the SSE response spectra exceeded the ASLB reduced response spectra essentially at all frequencies. Therefore only the structures on rock were required to be evaluated for the ASLB criteria.

The ASLB reduced envelope spectra was applied to the seismic models of the four buildings on rock to generate floor response spectra curves. These floor response spectra were the bases for performing the subsequent ASLB equipment margin study for the safe shutdown equipment and components.

Because of the similarities of the ACRS and the ASLB review procedures, it was determined that the equipment margin study could be concurrently performed for both the ACRS and ASLB criteria. This study was divided into two categories; one for active components and one for passive components.

Active components are defined as those components which require actuation or moving parts to perform their function for shutdown and residual heat removal. Passive components are defined as those components which do not require actuation or moving parts to perform this same function, but are required to maintain their structural integrity.

For the active equipment margin study, separate design margins were determined for both the ACRS and ASLB. The active components which were originally qualified by tests were evaluated for margin by comparison of the ACRS and ASLB floor response spectra and the original test response spectra (TRS).

For those active components originally qualified by analyses, the original design spectrum or ZPA value was compared to the ACRS and ASLB floor response spectra to determine the resulting margin. Results of the active equipment margin study showed that all active equipment and components possessed sufficient margin in original design to equal or exceed that required by the ACRS and ASLB criteria.

Passive components were generically addressed and qualified by using inelastic response spectra and ductility demand criteria as a more appropriate and accurate technique of measuring real damage potential. Results of the analysis for passive components showed that the SSE is a relatively more severe design criterion than either the ACRS and ASLB spectrum. Maximum ductility demands were well below the minimum capacity of the passive components, proving that neither the ACRS or the ASLB criteria pose a significant seismic risk to the passive components in the station.

Thus the equipment margin studies showed that both active and passive equipment and components possessed adequate design margins to withstand the affects of any imposed reservoir induced seismicity.

The overall conclusion of the program is that the ACRS and ASLB criteria do not affect the safe shutdown and residual heat removal equipment in the plant and that no plant modifications are required. Based on these positive results, both the ACRS requirement and the ASLB License Condition 2.C (Reference 25) are satisfied with no further actions required.

Detailed input, data, and conclusions for the ACRS and ASLB seismic programs are presented in the report, “Seismic Confirmatory Program, Equipment Margin Study, V. C. Summer Nuclear Station Unit 1, OL No. NPF-12, November 1983". (Reference 26)

3.7.2 Seismic System Analysis

3.7.2.1 Seismic Analysis Methods

3.7.2.1.1 Balance of Plant Scope

Seismic analyses of the Seismic Category I structures are performed using the method of normal mode. The design response spectra or synthetic time history, described in Section 3.7.1.2, are used as the input motion.

For the Reactor Building, including the interior concrete structure, the flexibility matrix of the structure system is first formulated using the STRUDL (Reference 5) computer program (see Section 3.8.4.4). This flexibility matrix is then combined with the mass matrix of the structure system to solve for the natural frequencies and mode shapes by the Jacobian diagonalization routine.

Each individual modal response is obtained by the numerical integration method of Nigam and Jennings (Reference 6). The total structural response is taken as the superposition of the responses of all significant modes. Significant modes for structural response are defined using the dominant modal participation factor as a base. Any mode with a modal participation factor greater than 10% of the dominant mode is considered a significant mode. Since all other modes lie within frequencies well above the rigid frequency and have small participation factors with response spectrum values much less than that of the dominant mode, they contribute less than 10% of the total response. For example, the participation factors of the Reactor Building, as shown in Table 3.7-7c, indicate that the significant modes are first through seventh mode. The frequency for the seventh mode is 45.87 cps. beyond which there is very little energy input in the time history.

Floor response spectra are calculated from the resulting floor acceleration time history using the method of Nigam and Jennings (Reference 6).

For the remaining Seismic Category I structures, except the service water intake structure, Service Water Pumphouse, and service water discharge structure, the seismic analysis is performed using the computer program DYNAL (Reference 7) (see Section 3.8.4.4). The Householder-Ortega-Wielandt method, described in (Reference 7), is used in the modal analysis to obtain the natural frequencies and mode shapes for the structure system. Structural responses are obtained by superposition of modal responses of all significant modes. The time histories of structural responses at mass points of interest are used to generate the floor response spectra.

Because of the embedment condition and the underlying foundation characteristics, the Service Water Pumphouse and associated supporting foundation media are analyzed for the soil-structure interaction effect (see Section 3.7.2.4) using the computer program FLUSH (Reference 8) (see Section 3.8.4.4). This program uses the plane-strain finite element method and is capable of taking into account the three-dimensional characteristics of the soil-structure system by use of viscous boundaries on planar sides of the plane-strain model. Additional features of FLUSH are discussed in (Reference 8) and Section 3.7.2.4. The analytical procedure used is two-dimensional. Material damping is included in stiffness matrices formed from complex modules of foundation media. The structural response is obtained by applying the method of complex response. This includes solving the displacements in the frequency domain through Gaussian elimination, followed by the inverse Fast Fourier Transform for the displacements in the time domain.

Typical lumped mass mathematical models used for seismic analysis are shown by Figure 3.7-9 for the Reactor Building which is founded upon rock. Figure 3.7-10 depicts a typical lumped mass mathematical model for the Intermediate Building which is supported by caissons seated in rock. The finite element model of the Service Water Pumphouse and its supporting medium is presented by Figure 3.7-11.

The mass points of a building are, as a rule, chosen at the major floor elevations of the building. In the case of the Reactor Building interior concrete structure, typical mass points are also selected at the supports of safety class equipment, such as the reactor vessel, steam generators, pressurizer, and reactor coolant pumps. The number of degrees of freedom is the same as the total number of modes. Since, for the Virgil C. Summer Nuclear Station Seismic Category I structure, the total number of modes is always greater than the number of significant modes and the significant modes contribute to more than 90% of the total response, the number of degrees of freedom selected is adequate.

For Seismic Category I structures founded upon rock (see Figure 3.7-9), the effects of foundation torsion, rocking, and translation with respect to the supporting media are represented by the effective linear foundation springs derived from the vibration of the rigid disc sitting upon an elastic half- space as described in Section 3.7.2.4. The stiffness members between floors are connected at stiffness centers, and the mass center and the stiffness center of each floor are connected by a rigid link to simulate torsional effects. The torsional spring is also attached to the bottom of the mat at the same point as the rocking and translational springs. The induced torsions, transverse shears, and bending moments at every section of the model are used in the design of the buildings. A typical torsional model is illustrated by Figure 3.7-11a. The torsional response is presented by Table 3.7-7b.

For Seismic Category I structures supported on caissons (see Figure 3.7-10), the effective stiffness of the surrounding soil medium is represented by lateral soil springs attached to the caissons in addition to the previously discussed foundation springs. The lateral soil springs are calculated in accordance with the method proposed by Penzien (Reference 9 (see Section Section 3.7.2.4).

The concrete structure element is assumed to have linear elastic properties.

3.7.2.1.2 Components and Equipment Provided by the NSSS Vendor

Those Seismic Category I components and systems that must remain functional in the event of the SSE are identified by applying the criteria of Section 3.2.1.

In general, the dynamic analyses are performed using a modal analysis plus either the response spectrum analysis or integration of the uncoupled modal equations as described in Sections 3.7.2.1.2.3 and 3.7.2.1.2.4 respectively, or by direct integration of the coupled differential equations of motion described in Section 3.7.2.1.2.5.

3.7.2.1.2.1 Dynamic Analysis - Mathematical Model

The first step in any dynamic analysis is to model the structure or component, i.e., convert the real structure or component into a system of masses, springs, and dashpots suitable for mathematical analysis. The essence of this step is to select a model so that the displacements obtained will be a good representation of the motion of the structure or component. Stated differently, the true inertia forces should not be altered so as to appreciably affect the internal stresses in the structure or component. Some typical modeling techniques are presented in Reference 10.

Equations of motion consider the multi-degree-of-freedom system shown in Figure 3.7-12. Making a force balance on each mass point r, the equations of motion can be written in the form:

$$m_r \ddot{y}_r + \sum^{i} c_{ri} u_i + \sum^{i} k_{ri} \dot{u}_i = 0 \qquad (3.7\text{-}1)$$

Where:

m_r = the value of the mass or mass moment of rotational inertia at mass point r.

$\ddot{y}_r$ = absolute translational or angular acceleration of mass point r.

c_{ri} = damping coefficient - external force or moment required at mass point r to produce a unit translational or angular velocity at mass point i, maintaining zero translational or angular velocity at all other mass points. Force or moment is positive in the direction of positive translational or angular velocity.

$\dot{u}_i$ = translational or angular velocity of mass point i relative to the base.

k_{ri} = stiffness coefficient - the external force (moment) required at mass point r to produce a unit deflection (rotation) at mass point i, maintaining zero displacement (rotation) at all other mass points.

Force (moment) is positive in the direction of the displacement (rotation).

u_i = displacement (rotation) of mass point i relative to the base.

Note that Figure 3.7-12 does not attempt to show all of the springs (and none of the dashpots) which are represented in Equation (3.7-1).

Since:

$$\ddot{y}_r = \ddot{u}_r + \ddot{y}_s \qquad (3.7\text{-}2)$$

Where:

$\ddot{y}_s$ = absolute translational (angular) acceleration of the base.

$\ddot{u}_r$ = translational (angular) acceleration of mass point r relative to the base.

Equation (3.7-1) can be written as:

$$m_r \ddot{u}_r + \sum^{i} c_{ri} \dot{u}_i + \sum^{i} k_{ri} u_i = m_r \ddot{y}_s \qquad (3.7\text{-}3)$$

For a single degree of freedom system with displacement u, mass m, damping c, and stiffness k, the corresponding equation of motion is:

$$m\ddot{u} + c\dot{u} + ku = -m\ddot{y}_s \qquad (3.7\text{-}4)$$

3.7.2.1.2.2 Modal Analysis

1. Natural Frequencies and Mode Shapes

The first step in the modal analysis method is to establish the normal modes, which were determined by eigen solution of Equation (3.7-3). The right hand side and the damping term are set equal to zero for this purpose as illustrated in Reference 11 (pp. 83 through 111). Thus, Equation (3.7-3) becomes:

$$m_r\ddot{u}_r + \sum^{i} k_{ri}\, u_{.i} = 0 \qquad (3.7\text{-}5)$$

The equation given for each mass point r in Equation (3.7-5) can be written as a system of equations in matrix form as:

$$[M]\ \{\ddot{\Delta}\} + [K]\ \{\Delta\} = 0 \qquad (3.7\text{-}6)$$

Where:

[M] = mass and rotational inertia matrix.

{Δ} = column matrix of the general displacement and rotation at each mass point relative to the base.

[K] = square stiffness matrix.

$\{\ddot{\Delta}\}$ = column matrix of general translational and angular accelerations at each mass point relative to the base, $d^2\{\Delta\}/dt^2$.

Harmonic motion is assumed and the {Δ} is expressed as:

$$\{\Delta\} = \{\delta\} \sin \omega t \qquad (3.7\text{-}7)$$

Where:

{δ} = column matrix of the spatial displacement and rotation at each mass point relative to the base.

ω = natural frequency of harmonic motion in radians per second.

The displacement function and its second derivative are substituted into Equation (3.7-6) and yield:

$$[K] \{\delta\} = \omega^2 [M] \{\delta\} \quad (3.7\text{-}8)$$

The determinant [K] - ω^2 [M] is set equal to zero and is then solved for the natural frequencies. The associated mode shapes are then obtained from Equation (3.7-8). This yields n natural frequencies and mode shapes where n equals the number of dynamic degrees of freedom of the system. The mode shapes are all orthogonal to each other and are sometimes referred to as normal mode vibrations. For a single degree of freedom system, the stiffness matrix and mass matrix are single terms and the determinant [K] - ω^2 [M] when set equal to zero yields simply:

$$k - \omega^2 [M] = 0$$

or:

$$\omega = \sqrt{\frac{k}{m}} \quad (3.7\text{-}9)$$

where ω is the natural angular frequency in radians per second. The natural frequency in cycles per second is therefore

$$f = \frac{1}{2\pi}\sqrt{\frac{k}{m}} \quad (3.7\text{-}10)$$

To find the mode shapes, the natural frequency corresponding to a particular mode, ωn, can be substituted in Equation (3.7-8), however, only n-1 of these equations are independent. This means that the elements of $\{\delta\}$ can be expressed only as multiples of one another. Normalizing $\{\delta\}$ such that the maximum displacement (rotation) of any element is unity gives:

ϕrn = displacement (rotation) of mass point r in mode n relative to the base.

2. Modal Equations

The response of a structure or component is always some combination of its normal modes. However, good accuracy can be obtained by using only the first few modes of vibration. In the normal mode method, the mode shapes are used as principal coordinates to reduce the equations

of motion to a set of uncoupled differential equations that describe the motion of each mode n. These equations may be written as (Reference 11, pp. 116-125):

$$\ddot{A}_n + 2\omega_n p_n \dot{A}_n + W_n^2 A_n = -\Gamma_n \ddot{y}_s \qquad (3.7\text{-}11)$$

where the modal displacement or rotation, A_n, is related to the displacement or rotation of mass point r in mode n, u_{rn}, by the equation:

$$u_{rn} = A_n \Phi_{rn} \qquad (3.7\text{-}12)$$

Where:

ω_n = natural frequency of mode n in radians per second.

p_n = critical damping ratio of mode n.

Γ_n = modal participation factor of mode n given by:

$$\Gamma_n = \frac{\sum^{n} m_r \phi'_{rn}}{\sum^{n} m_r \phi_{rn}^2} \qquad (3.7\text{-}13)$$

and:

ϕ'_{rn} = value of ϕ_{rn} in the direction of the earthquake.

The essence of the modal analysis lies in the fact that Equation (3.7-11) is analogous to the equation of motion for a single degree of freedom system that will be developed from Equation (3.7-4). Dividing Equation (3.7-4) by m gives:

$$\ddot{u} + \frac{c}{m}\dot{u} + \frac{k}{m}u = -\ddot{y}_s \qquad (3.7\text{-}14)$$

The critical damping ratio of a single degree of freedom system, p, is defined by the equation:

$$p = \frac{c}{c_c} \qquad (3.7\text{-}15)$$

where the critical damping coefficient is given by the expression:

$$c_c = 2m\omega \qquad (3.7\text{-}16)$$

Substituting Equation (3.7-16) into Equation (3.7-15) and solving for c/m gives:

$$\frac{c}{m} = 2\omega p \qquad (3.7\text{-}17)$$

Substituting this expression and the expression for k/m given by Equation (3.7-9) into Equation (3.7-14) gives:

$$\ddot{u} + 2\omega p\dot{u} + \omega^2 u = -\ddot{y}_s \qquad (3.7\text{-}18)$$

Note the similarity of Equations (3.7-11) and (3.7-18). Thus each mode may be analyzed as though it were a single degree of freedom system and all modes are independent of each other. By this method a fraction of critical damping, i.e., c/cc, may be assigned to each mode and it is not necessary to identify or evaluate individual damping coefficients, i.e., c. However, assigning only a single damping ratio to each mode has a drawback. Normally, there are two ways used to overcome this limitation when considering a slightly damped structure supported by a massive moderately damped structure.

The first method is to develop and analyze separate mathematical models for both structures using their respective damping values. The massive moderately damped support structure is analyzed first. The calculated response at the support points for the slightly damped structures is used as a forcing function for the subsequent detailed analysis. The second method is to inspect the mode shapes to determine which modes correspond to the slightly damped structure and then use the damping associated with the structure having predominant motion.

3.7.2.1.2.3 Response Spectrum Analysis

The response spectrum is a plot showing the variation in the maximum response (Reference 12, pp. 24-51) (displacement, velocity, and acceleration) of a single-degree-of-freedom system versus its natural frequency of vibration when subjected to a time history motion of its base. Examples of response spectra are shown in Figures 3.7-13 and 3.7-14.

The response spectrum concept can best be explained by outlining the steps involved in developing a spectrum curve. Determination of a single point on the curve requires that the response (displacement, velocity, and acceleration) of a single degree of freedom system with a given damping and natural frequency be calculated for a given base motion. The variations in response are established and the maximum absolute value of each response is plotted as an

ordinate with the natural frequency used as the abscissa. The process is repeated for other assumed values of frequency in sufficient detail to establish the complete curve. Other curves corresponding to different fractions of critical damping are obtained in a similar fashion. Thus, the determination of each point of the curve requires a complete dynamic response analysis, and the determination of a complete spectrum may involve hundreds of such analyses. However, once a response spectrum plot is generated for the particular base motion, it may be used to analyze each structure and component with that base motion. The spectral acceleration, velocity, and displacement are related by the equation:

$$S_{a_n} = \omega_n S_{v_n} = \omega_n^2 S_{d_n} \qquad (3.7\text{-}19)$$

There are two types of response spectra that must be considered. If a given building is shown to be rigid and to have a hard foundation, the ground response spectrum or ground time history is used. It is referred to as a ground response spectrum. If the building is flexible and/or has a soft foundation, the ground response spectra are modified to include these effects. The response spectrum at various support points must be developed. This is called a floor response spectrum. The specific response spectra used are discussed in Sections 3.7.1 and 3.7.2.5.

3.7.2.1.2.4 Integration of Modal Equations

This method can be separated into the following two basic steps:

1. Integration procedure for the uncoupled modal Equation (3.7-11) to obtain the modal displacements and accelerations as a function of time.
2. These modal displacements and accelerations are combined to obtain the total
3. displacements, accelerations, forces, and stresses.

Integration of these uncoupled modal equations is done by step-by-step numerical integration. The step-by-step numerical integration procedure (Reference 13) consists of selecting a suitable time interval, Δt, and calculating modal acceleration, $\ddot{A}_n$ modal velocity, $\dot{A}_n$ and modal displacement, An, at discrete time stations Δt apart, starting at t = 0 and continuing through the range of interest for a given time history of base acceleration.

From the modal displacements and accelerations, the total displacements, accelerations, forces, and stresses can be determined as follows:

1. Displacement of mass point r in mode n as a function of time is given by Equation (3.7-12) as:

$$u_{rn} = A_n \phi_{rn} \qquad (3.7\text{-}20)$$

with the corresponding acceleration of mass point r in mode n as:

$$\ddot{u}_{rn} = \ddot{A}_n \phi_{rn} \qquad (3.7\text{-}21)$$

2. The displacement and acceleration values obtained for the various modes are superimposed algebraically to give the total displacement and acceleration at each time interval.
3. The total acceleration at each time interval is multiplied by the mass to give an equivalent static force. Stresses are calculated by applying these forces to the model. Alternatively these stresses may be determined from the deflections at each time interval.

3.7.2.1.2.5 Integration of Coupled Equations of Motion

The dynamic transient analysis is a time history solution of the response of a given structure to known forces and/or displacement forcing functions. The structure may include linear or nonlinear elements, gaps, interfaces, plastic elements, and viscous and Coulomb dampers. Nodal displacements, nodal forces, pressure, and/or temperatures may be considered as forcing functions. Nodal displacements and elemental stresses for the complete structure are calculated as functions of time.

The basic equations for the dynamic analysis are as follows:

$$[M]\{\ddot{x}\}+[C]\{\dot{x}\}+[K]\{x\}=\{F(t)\} \qquad (3.7\text{-}22)$$

where the terms are as defined earlier and $\{F(t)\}$ and may include the effects of applied displacements, forces, pressures, temperatures, or nonlinear effects such as plasticity and dynamic elements with gaps. Options of translational accelerations input to a structural system and the inclusion of static deformation and/or preload may be considered in the nonlinear dynamic transient analysis. The option of translational input such as uniform base motion to a structural system is considered by introducing an inertia force term of $-[M]\{\ddot{z}\}$ to the right hand side of the basic Equation (3.7-22), i.e.,

$$[M]\{\ddot{x}\}+[C]\{\dot{x}\}+[K]\{x\}=\{F\}-[M]\{\ddot{z}\} \qquad (3.7\text{-}23)$$

The vector $\{\ddot{z}\}$ is defined by its components $\{\ddot{z}_i\}$ where i refers to each degree of freedom of the system. $\{\ddot{z}_i\}$ is equal to a_1, a_2, or a_3 if the i(th) degree of freedom is aligned with the direction of the system translational acceleration a_1, a_2, or a_3, respectively. $\{\ddot{z}_i\} = 0$ if the i(th) degree of freedom is not aligned with any direction of the system translational acceleration. Typical application of this option is a structural system subjected to a seismic excitation of a given ground acceleration record. The displacement {x} obtained from the solution of Equation (3.7-23) is the displacement relative to the ground.

The option of the inclusion of initial static deformation or preload in a nonlinear transient dynamic structural analysis is considered by solving the static problem prior to the dynamic analysis. At each stage of integration in transient analysis, the portion of internal forces due to static deformation is always balanced by the portion of the forces which are statically applied. Hence, only the portion of the forces which deviate from the static loads will produce dynamic effects. The output of this analysis is the total result due to static and dynamic applied loads.

One available method for the numerical integration of Equations (3.7-22) and (3.7-23) is the third order (cubic) integration scheme. In the third-order (cubic) integration scheme values of {x} are assumed to be a cubic function of time over a small time increment, i.e.,

$$\{x_t\} = \{a\} + \{b\}t + \{c\}t^2 + \{d\}t^3 \qquad (3.7\text{-}24)$$

The velocity and acceleration vectors are found by differentiating Equation (3.7-24) with respect to time:

$$\{\dot{x}_t\} = \{b\} + 2\{c\}t + 3\{d\}t^2 \qquad (3.7\text{-}25)$$

$$\{\ddot{x}_t\} = 2\{c\} + 6\{d\}t \qquad (3.7\text{-}26)$$

The unknown coefficients {a}, {b}, {c}, and {d} can be obtained from Equation (3.7-24) in terms of the displacements at time t, t-1, t-2, and t- 3 (i.e., present and three previous values of displacements). Thus for each time interval, the velocity and acceleration arrays may be expressed by:

$$\{\dot{x}_t\} = f_1(\{x_t\},\{x_{t-1}\},\{x_{t-2}\},\{x_{t-3}\}) \qquad (3.7\text{-}27)$$

$$\{\ddot{x}_t\} = f_2(\{x_t\},\{x_{t-1}\},\{x_{t-2}\},\{x_{t-3}\}) \qquad (3.7\text{-}28)$$

Substituting Equations (3.7-27) and (3.7-28) into Equation (3.7-22) and solving for the present value of displacement vector gives:

$$\frac{C_1}{(\Delta t)^2}[M] + \frac{C_2}{(\Delta t)}[C] + [K]\{x_t\} = \{F_t\} +$$

$$f([M],[C],\{x_{t-1}\},\{x_{t-2}\},\{x_{t-3}\}) \qquad (3.7\text{-}29)$$

The above set of simultaneous linear equations is solved to obtain the present values of nodal displacements $\{x_t\}$ in terms of the previous (known) values of the nodal displacements. Since {M}, {C}, and {K} are included in the equation, they can also be time or displacement dependent.

3.7.2.2 Natural Frequencies and Response Loads

A summary of significant frequencies and mode shapes for the representative Seismic Category I structures is presented by Figures 3.7-15 through 3.7-20 for the Reactor Building, Control Building, Auxiliary Building, Intermediate Building, Fuel Handling Building, and Diesel Generator Building, respectively.

Floor response spectra at critical Seismic Category I structure elevations and points of support are presented for the OBE by Figures 3.7-21 through 3.7-27 for the Reactor Building, Figures 3.7-28 and 3.7-29 for the Control Building, Figures 3.7-30 through 3.7-32 for the Auxiliary Building, Figures 3.7-33 and 3.7-34 for the Intermediate Building, Figures 3.7-35 and 3.7-36 for the Fuel Handling Building, Figures 3.7-37 through 3.7-39 for the Diesel Generator Building and Figures 3.7-40 and 3.7-41 for the Service Water Pumphouse. These floor response spectra are used for the

seismic qualification of Seismic Category I safety class equipment and components as described in Section 3.7.3. Response loads (displacements, accelerations and masses) are presented by Table 3.7-7a for the OBE.

In Table 3.7-7a and Figures 3.7-21 through 3.7-41, the x component corresponds to the plant East-West direction, the y component corresponds to the plant North-South direction and the z component corresponds to the plant vertical direction. One exception occurs in the case of the service water pumphouse where the x component is perpendicular to the shoreline and the y component is parallel to the shoreline. Both the actual, narrow and artificially broadened response spectra are drawn.

Since the artificial time history has frequency content around 20 cps and between 24 and 30 cps, as shown by Figure 3.7-5, and the building has a horizontal natural frequency at 29.2 cps, as shown by Figure 3.7-15, the secondary peak at 29 cps is higher than the spectrum value at 20 cps. However, the spectrum value at 20 cps is still higher than the maximum floor acceleration of 0.18g. For the vertical earthquake, there is a natural frequency at 22.5 cps. This natural frequency and the frequency content of the artificial time history caused the secondary peaks at 21 and 26 cps.

The SSE response spectrum envelope accelerations have been calculated by scaling the OBE response spectrum envelope accelerations. Since the SSE structured damping is conservatively assumed to be the same as the OBE structural damping, the SSE and OBE response ratio is proportional to the input acceleration value. For buildings on rock, the ratio of SSE to OBE acceleration is 1.5. For buildings on soil, the ratio is 1.67. For buildings on caissons the ratio varies from 1.62 to 1.55 as described by Figure 3.7-43. Scale factors for each of the buildings are as follows:

1. Reactor Building, 1.5 OBE.
2. Auxiliary Building, 1.55 OBE.
3. Control Building, 1.55 OBE.
4. Fuel Handling Building, 1.62 OBE.
5. Intermediate Building, 1.55 OBE.
6. Diesel Generator Building, 1.62 OBE.
7. Service Water Pumphouse, 1.67 OBE.

To properly account for amplification due to flexure of floor slabs, Υ a scaling factor, has been applied to the response spectrum envelopes for the vertical direction. The magnitude of the scaling factor depends upon the location of equipment, components, or systems on a particular building floor and is discussed in Section 3.7-3.

The maximum floor accelerations at the major building floor elevations and equipment supports correspond to the acceleration at the high frequency ends of the associated floor response spectra.

3.7.2.3 Procedure Used for Modeling

In the seismic analysis, Seismic Category I structures which form a soil-structure interaction system with foundation media are defined as “seismic systems.” Except for the Service Water Pumphouse, as mentioned in Section 3.7.2.2, these structures are simulated by lumped mass mathematical models. Other Seismic Category I structures, components, and equipment, defined as “seismic subsystems,” are decoupled from the “seismic system” in the mathematical models. The general uncoupling criterion is based upon the ratio of mass of the supported subsystem to that of the supporting system. If the total building mass is used as the supporting mass, the mass ratio is always small. However, if the modal mass is used as the supporting mass, the mass ratio can be greater than 0.01. Based upon the theory of random vibration, the effect of a large mass ratio is a decrease in the mean square responses of the supported subsystem and the supporting system (see Figure 2.12 and 2.13 of Reference 25). In the uncoupled analysis, the subsystem is analyzed using a floor response spectrum which is obtained by assuming that the subsystem is rigidly attached to the supporting system. This assumption of rigid attachment is equivalent to the zero mass ratio case discussed in Reference 25. Since the zero mass ratio case yields the highest subsystem response, the uncoupled analysis is always conservative.

The effects of such decoupling upon the dynamic response of the Reactor Building have been investigated in detail. Both the decoupled case and the case where the heavy equipment is incorporated into the “seismic system” mathematical model have been examined. It has been found that, for the interior concrete structure considered, decoupling of the heavy equipment from the supporting structure adds only slight additional conservatism to the structural response and is therefore justified. The criteria used for lumping masses is as described in Section 3.7.2.1.

Dynamic lumped mass models are constructed so that three-dimensional responses can be obtained. For the finite element model of the Service Water Pumphouse supporting medium, two separate, othogonal plane strain models are constructed. Three directions of earthquake ground motion are input to the dynamic models, one at a time, for the seismic analysis, including floor response spectra generation. The spatial combination of such responses is discussed in Section 3.7.2.6.

For analysis of NSSS supplied equipment, primary importance is given to the Reactor Coolant System. The analysis of this system can be performed using several different methods depending upon the level of seismic activity at the plant site. The possible methods include:

1. Linear modal analysis of the primary loop piping and components.
2. Coupled building/loop linear modal analysis.
3. Coupled building/loop non-linear time-history analysis.

Methods (2) and (3) are considered to be “seismic systems” in accordance with the guidance noted in Standard Review Plan 3.7.3. Method (1) and all other systems and components within the NSSS Vendor’s scope F, except primary loop piping, are analyzed independently and are classified as “seismic subsystems.” Examples of these are the primary system components, auxiliary pumps, branch piping, tanks, etc.

Method (3) was used for the seismic analysis of the Virgil C. Summer Nuclear Station Reactor Coolant Loop Piping System. All other analyses of NSSS vendor supplied equipment were performed as “seismic subsystem” analyses.

3.7.2.4 Soil-Structure Interaction

The effect of soil-structure interaction on the seismic response of lumped mass models is represented by six equivalent linear foundation springs: three translational; two rocking; and one torsional (see Section 3.7.2.1).

The validity of the foundation spring method used for the foundation-structure configuration has been investigated. This investigation is summarized as follows:

1. The Seismic Category I structures are supported either on rock supported fill concrete or caissons seated in rock. Therefore, the layering effect is insignificant.
2. Since the plant site has sufficiently deep and uniform overburden, frequency independent foundation springs are considered to be adequate for simulation of the soil-structure interaction phenomenon (Reference 14).
3. The effect of embedment depth (Section 3.7.1.4) on the foundation spring values has been considered and, for reasons of conservatism, is ignored.
4. For the Seismic Category I structures supported on caissons, the following considerations have been further investigated through modeling:
   a. The interaction between the caisson (and, if any, the underground portion of the structure) and the surrounding soil medium is accounted for by connecting effective lateral soil springs to the lumped mass of the caisson (and, if any, the underground portion of the structure). The soil springs are calculated based upon the work by Penzien (Reference 9) on pile foundations in which Midlin’s half-space formulas for the force-displacement relationship are utilized.

      The amplified free-field seismic motion at each elevation of interest in the soil medium has been considered. As shown by Figure 3.7-42, the acceleration time histories, A1 (t), A2 (t), . . . Ai (t), represent the amplified motions at the elevations of interest. However, in the lumped mass approach considered, a single acceleration time history with equivalent energy input has been conservatively estimated and applied throughout the elevation of the caisson as shown by Figure 3.7-43.
   b. Settlement of the soil underneath the mat is considered.
   c. The stress levels in the soil at the junction of the underground structures and the lateral soil medium are compared with the corresponding bearing capacity to check the stability of the entire soil-structure system.
   d. Caissons are drilled into competent rock for end bearing and frictional load transfer. Rock properties relative to caisson design and construction are described in Section 2.5.4.

e. The pertinent parameters used in the parametric study of soil-structure interaction are as follows:

(1) Soil shear modulus (G) is 1.0×10^4 to 3.5×10^4 psi. This range is based upon both in-situ dynamic wave tests and laboratory triaxial tests.

(2) Dynamic concrete Young's modulus ($E_{dynamic}$) is 1.0 E_{static} to 2.0 E_{static}.

(3) Settlement of soil underneath the mat: soil takes 0 to 50% of the vertical load.

5. The foundation mat of the caisson supported Intermediate Building is rigidly connected to the Control Building foundation mat for purposes of lateral stability. For such a structure-foundation configuration, both foundation soil springs and caisson soil springs are used in the combined dynamic lumped mass model of the two buildings.

As mentioned in Section 3.7.2.1, the Service Water Pumphouse is analyzed for the soil-structure interaction effect by using the finite element program, FLUSH (Reference 8). Approximate strain dependent shear modules of the foundation medium are first estimated for the expected level of ground motion and surface discharge pressure using the one-dimensional wave propagation theory. Final strain and frequency dependent soil properties and damping ratio are obtained through an iterative sequence of dynamic response calculations for the soil-structure system. The soil property curves presented in Section 2.5 are used.

It is considered that motions in the vicinity of the structure are due to vertical propagation of body waves from underlying, stiffer formations. Accordingly, the basic method for the dynamic response calculation can be illustrated as follows. A control motion compatible with the design response spectra, as presented in Section 3.7.2.1, is first specified. This control motion is then used as input to a finite element model of the soil-structure system and the response is computed at elevations and points of interest.

The computer program FLUSH (Reference 8) is also equipped with a transmitting boundary, simulating sufficient extent of the half-space. Furthermore, with use of a viscous boundary on the planar side of the plane-strain finite element model, three dimensional wave propagation phenomena of the foundation medium are taken into account.

3.7.2.5 Development of Floor Response Spectra

Floor response spectra are developed by applying the time history earthquake motion to the multi-degree of freedom models of the Seismic Category I structures with the various mass points representing the described elevation in each structure (see Section 3.7.2.1). Such floor response spectra take into consideration the effect of the three components of earthquake motion and reflect predominant response near the dominant frequencies of the structure.

Due to the general asymmetry of the configuration of the Seismic Category I structures, the responses of the structures are normally three-directional in nature even when subjected to only one component of earthquake motion.

To properly estimate floor response spectrum values, including the three-directional effects of both the earthquake (which would not be likely to produce maximum responses in all three directions simultaneously) and the structural behavior, the following equation is used:

$$S_x = (S^2_{x1} + S^2_{x2} + S^2_{x3})^{1/2}$$

Where:

S_x = the final spectrum value at any frequency point in the x direction.

S_{xk} = the spectrum value at the same frequency point in the x direction due to earthquake component in the k(th) direction (k = 1, 2, 3).

In the development of vertical floor response spectra, additional effects of vertical amplification other than those due to the overall structural response are considered. These are the amplification due to floor flexibility and rocking motion of the structure.

With the inclusion of the floor flexibility in the vertical response calculation, additional response spectrum peaks are determined at the characteristic frequencies of the floor. To account for the rocking motion of the Auxiliary, Control, and Intermediate Buildings, several nodal points are selected at the corners of the floor with which walls usually intersect. These corner points are connected to the lumped mass of the floor by rigid links as shown in the torsional model in Figure 3.7-11a. Additional amplifications are observed in the floor response spectrum. The final floor response spectrum is constructed to envelop the spectrum peaks attributable to the overall vertical structural response and the floor flexibility, as well as to the rocking motion of the structure.

The effect of torsional response on horizontal floor response spectra, due primarily to the eccentricity of the structural configuration, is discussed in Section 3.7.2.11.

3.7.2.6 Three Components of Earthquake Motion

3.7.2.6.1 Balance of Plant Scope

The time history method is employed in the seismic analysis of Seismic Category I structures. The maximum responses (e.g., accelerations) due to each of the three components of earthquake motion are first calculated separately at a particular point of a structure or of the corresponding mathematical model. These component responses are then combined by taking the square root of the sum of the squares of maximum codirectional responses caused by each of the three components of earthquake motion (see Section 3.7.2.5). This procedure is in conformance with Regulatory Guide 1.92, Revision 1.

3.7.2.6.2 Components and Equipment Provided by the NSSS Vendor

The seismic design of the piping and equipment includes the effect of the seismic response of the supports, equipment, structures, and components. The system and equipment response is determined using three earthquake components, two horizontal and one vertical. The design ground response spectra, specified in Section 3.7.1, are the bases for generating these three input components. Floor response spectra are generated for two perpendicular horizontal directions, (i.e., N-S and E-W) and the vertical direction. System and equipment analysis is performed with these input components applied in the N-S, E-W, and vertical directions. The damping values used in the analysis are those given in Table 3.7-3.

In computing the system and equipment response by response spectrum modal analysis the methods of Section 3.7.3.7 are used to combine all significant modal responses to obtain the combined unidirectional responses.

The combined total response is then calculated using the square root of the sum of the squares formula applied to the resultant unidirectional responses. For instance, for each item of interest such as displacement, force, stresses, etc., the total response is obtained by applying the above described method. The mathematical expression for this method (with R as the item of interest) is:

$$R_C = \left[\sum_{T=1}^{3} R_T^2\right]^{1/2} \qquad (3.7\text{-}30)$$

Where:

$$R_T = \left[\sum_{i=1}^{N} R_{Ti}^2\right]^{1/2} \qquad (3.7\text{-}31)$$

and:

R_C = total combined response at a point.

R_T = value of combined response of direction T.

R_{Ti} = absolute value of response for direction T, mode i.

N = total number of modes considered.

The subscripts can be reversed without changing the results of the combination.

For the case of closely spaced modes, RT in Equation (3.7-31) above is replaced with R_T as given by Equation (3.7-32) in Section 3.7.3.7, where the criteria and justification for meeting the intent of Regulatory Guide 1.92, Revision 1 are presented.

3.7.2.7 Combination of Modal Responses

3.7.2.7.1 Balance of Plant Scope

Since only the time history method is employed in the seismic (system) analysis of Seismic Category I structures, modal responses are algebraically combined, in the time domain, in the solution following the principle of superposition. Regulatory Guide 1.92, Revision 1, is, therefore, not applicable.

3.7.2.7.2 Components and Equipment Provided by the NSSS Vendor

Conformance with the recommendations of Regulatory Guide 1.92, Revision 1 for combination of modal responses is presented in Section 3.7.3.7.

3.7.2.8 Interaction of Noncategory I Structures with Seismic Category I Structures

Complete separation of Seismic Category I structures from adjacent Seismic Category I or non-Seismic Category I structures prevents interaction with or impact from adjacent structures. Seismic effects on non-Seismic Category I structures are investigated to prevent the possibility of damage to Seismic Category I structures due to possible collapse of non-Seismic Category I structures.

3.7.2.9 Effects of Parameter Variations on Floor Response Spectra

The peak width and period coordinates of the floor response spectra (see Section 3.7.2.5) are determined by parametric study based upon the variations of the soil springs and/or material properties of the structure and foundation. In any case, the peak width is assigned a minimum range of ±10% of the center frequency. For cases where the variation of calculated periods due to the various assumptions regarding material properties and soil-structure interaction change the spectrum values, the parametric study, coupled with the enveloping process, is used to conservatively estimate the floor response spectrum values.

3.7.2.10 Use of Constant Vertical Static Factors

Dynamic analyses with vertical earthquake motion are performed instead of using constant vertical load factors.

3.7.2.11 Methods Used to Account for Torsional Effects

A mathematical model with a rigid link connecting the center of mass and center of rigidity at each floor elevation is used to calculate the actual torsional responses. For typical asymmetric structures, such as the Intermediate Building, each floor in the model is taken as a rigid diaphragm with three translational and one torsional degree of freedom. Responses, including the amplification effect of the corner nodal points, as presented in Section 3.7.2.5, are obtained separately for the vertical and horizontal excitations. The combined response is obtained in the manner discussed in Section 3.7.2.6.

3.7.2.12 Comparison of Responses

Since the time history method is used throughout for seismic system analyses, no comparison of responses is needed.

3.7.2.13 Methods for Seismic Analysis of Dams

Methods for seismic analysis of dams are presented in Section 2.5.

3.7.2.14 Determination of Seismic Category I Structure Overturning Moments

Overturning moments for Seismic Category I structures are determined at the base of the Seismic Category I structures. Each of the three components of earthquake excitation is considered separately. The resultant overturning moment is obtained by combining the three earthquake components in accordance with Section 3.7.2.6. The vertical earthquake component is viewed as reducing the dead weight of the structure in counteracting the overturning moment. Soil reaction is calculated by adding to, or subtracting (whichever controls) the vertical earthquake component from, the dead weight and other loads on the structure. Safety factors of 1.1 and 1.5 are provided against overturning of Seismic Category I structures due to the SSE or OBE, respectively, combined with other appropriate design loads.

3.7.2.15 Analysis Procedure for Damping

3.7.2.15.1 Balance of Plant Scope

A classical modal analysis is applied to the lumped mass soil-structure interaction system. In the modal analysis, different modal damping is specified for each mode according to the concept of weighted average damping (References 15, 16). In this approach a higher damping value is specified for a mode in which soil deformation is predominant compared to structural deformation. The basic equation for the weighted average damping is as follows:

$$D_n = \frac{\sum_{i=1}^{N} (D_{H,i} + \frac{\omega_n}{\omega_i} D_{v,i}) E_{i,n}}{\sum_{i=1}^{N} E_{i,n}}$$

Where:

D_n = Weighted modal damping for the n(th) mode.

i = 1, 2, 3, . . . , S, S+1, ... , N.

S = The degree of freedom of the structure for which damping values are assigned.

N-S = The degree of freedom representing the soil springs.

$D_{H,i}$ = Hysteretic damping in the k(th) degree of freedom of the soil-structure interaction system.

$D_{v,i}$ = Viscous damping in the k(th) degree of freedom of the system.

ωn = Frequency of n(th) mode.

ωi = Frequency at which $D_{v,i}$ is defined.

$E_{i,n}$ = Energy stored in k(th) degree of freedom of the system in n(th) mode.

Damping in structural elements (of superstructure and caissons) generally is hysteretic in nature which shows frequency independent energy loss per cycle. The internal damping in soil is also hysteretic. Radiation damping due to wave propagation from a structure into the soil medium is viscous damping which shows frequency dependent energy loss per cycle. When a structure is founded upon caissons, the overall damping in rocking is primarily hysteretic. Theoretically, radiation damping in swaying is generally very large. However, such radiation damping is set to zero for conservatism. Typical choices for the damping ratios (see Section 3.7.1.3) are as follows:

1. For $i \leq s$
   a. $D_{H,i}$ = (see Table 3.7-1)
   b. $D_{v,i} = 0$
2. For Rocking Mode Soil Spring
   a. $D_{H,i} = 5\%$
   b. $D_{v,i} = 0$
3. For Swaying Mode Soil Spring
   a. $D_{H,i} = 10\%$
   b. $D_{v,i} = 0$

3.7.2.15.2 Components and Equipment Provided by the NSSS Vendor

For components and equipment provided by Westinghouse, either the lowest damping value associated with the elements of the system is used for all modes, or an equivalent modal damping value is determined according to the energy distribution in each mode. Testing programs for damping were done for the reactor coolant loop (Reference 3).

3.7.3 Seismic Subsystem Analysis

3.7.3.1 Seismic Analysis Methods

3.7.3.1.1 Balance of Plant Scope

Seismic analysis is performed for those subsystems that can be modeled to correctly predict the seismic response. A component is modeled as a multi-degree-of-freedom, lumped mass system with mass free interconnections and sufficient mass points to ensure adequate representation. The resulting system is analyzed using the response spectrum modal analysis technique. An alternative time history method may also be applied. The time history method, when used, conservatively simulates the response spectrum envelope of interest. A stress analysis is then performed using the inertia forces or equivalent static loads obtained from the dynamic analysis. Moments, shears, accelerations, deflections and stresses are calculated on a mode by mode basis. The total seismic response is obtained by combining each modal response using the square root of the sum of the squares method. The absolute sum of the responses is considered for closely spaced, in phase modes as set forth in Section 3.7.3.7. In cases for which some dynamic degrees of freedom do not contribute to the total response, kinematic condensation is employed in the analysis.

3.7.3.1.2 Components and Equipment Provided by the NSSS Vendor

Seismic analysis methods for subsystems within Westinghouse scope of responsibility are given in Section 3.7.2.1.

3.7.3.2 Determination of Number of Earthquake Cycles

3.7.3.2.1 Balance of Plant Scope

One SSE plus five OBE events are assumed to occur during the life of the plant. Ten (10) maximum stress cycles are assumed to occur during each event.

3.7.3.2.2 Components and Equipment Provided by the NSSS Vendor

For each OBE the system and component will have a maximum response corresponding to the maximum induced stresses. The effect of these maximum stresses for the total number of OBE’s must be evaluated to assure resistance to cyclic loading.

The OBE is conservatively assumed to occur 20 times over the life of the plant. The number of maximum stress cycles for each occurrence depends on the system and component damping values, complexity of the system and component, duration, and frequency content of the input earthquake. A precise determination of the number of maximum stress cycles can only be made using time history analysis for each item. Instead, a time history study has been conducted to arrive at a realistic number of maximum stress cycles.

To determine the conservative equivalent number of cycles of maximum stress associated with each occurrence, an evaluation was performed considering both equipment and its supporting building structure as single-degree-of-freedom systems. The natural frequencies of the building and the equipment are conservatively chosen to coincide. The damping in the equipment and building are equivalent to the damping values in Table 3.7-3.

The results of this study indicate that the total number of maximum stress cycles in the equipment having peak acceleration above 90% of the maximum absolute acceleration did not exceed eight cycles. If the equipment was assumed to be rigid in a flexible building, the number of cycles exceeding 90% of the maximum stress was not greater than three cycles.

This study was conservative since it was performed with single-degree-of-freedom models which tend to produce a more uniform and unattenuated response than a complex interacted system. The conclusions indicate that 10 maximum stress cycles for flexible equipment (natural frequencies less than 33 Hz) and 5 maximum stress cycles for rigid equipment (natural frequencies greater than 33 Hz) for each of 20 OBE occurrences should be used for fatigue evaluation.

3.7.3.3 Procedure Used for Modeling

Equipment within the balance of plant scope is modeled as a series of discrete mass points, connected by mass free members, having sufficient mass points to ensure adequate representation of dynamic behavior. Detailed modeling of piping systems is described in Section 3.7.3.8.

Procedures used for modeling the equipment and components provided by the NSSS vendor are described in Section 3.7.2.1.2.

3.7.3.4 Basis for Selection of Frequencies

3.7.3.4.1 Balance of Plant Scope

Where applicable for analysis of equipment, modes selected as significant include the following:

1. Natural frequencies less than 30 Hz.
2. Frequencies above 30 Hz with modal participation factors greater than 10% of the fundamental mode participation factor.

For piping systems where a detailed seismic analysis is performed, all modes with natural frequencies of less than 30 Hz are included in the response calculation.

For piping systems where the simplified seismic support spacing method is employed, the limits of seismic support spans are established under the condition that the fundamental frequencies are higher than those associated with the dominating peak of the floor response spectrum.

3.7.3.4.2 Equipment and Components Provided by the NSSS Vendor

The analysis of the equipment subjected to seismic loading involves several basic steps, the first of which is the establishment of the intensity of the seismic loading. Considering that the seismic input originates at the point of support, the response of the equipment and its associated supports based upon the mass and stiffness characteristics of the system, will determine the seismic accelerations which the equipment must withstand.

Three (3) ranges of equipment/support behavior which affect the magnitude of the seismic acceleration are possible:

1. If the equipment is rigid relative to the structure, the maximum acceleration of the equipment mass approaches that of the structure at the point of equipment support. The equipment acceleration value in this case corresponds to the low-period region of the floor response spectra.
2. If the equipment is very flexible relative to the structure, the equipment will show very little response.
3. If the periods of the equipment and supporting structure are nearly equal, resonance occurs and must be taken into account.

In the above cases, equipment under earthquake loadings is designed to be within code allowable stresses.

Also, as noted in Section 3.7.3.2.2, rigid equipment/support systems have natural frequencies greater than 33 Hz.

3.7.3.5 Use of Equivalent Static Load Method of Analysis

3.7.3.5.1 Balance of Plant Scope

If the fundamental frequency of the component is greater than 30 Hz, the component is analyzed statically. The equivalent static forces are obtained by multiplying the lumped mass of each mass point by the appropriate maximum floor acceleration. The maximum floor acceleration is obtained from the response spectra envelope at the high frequencies.

3.7.3.5.2 Equipment and Components Provided by the NSSS Vendor

The static load equivalent or static analysis method involves the multiplication of the total weight of the equipment or component member by the specified seismic acceleration coefficient. The magnitude of the seismic acceleration coefficient is established on the basis of the expected dynamic response characteristics of the component. Components which can be adequately characterized as single-degree-of-freedom systems are considered to have a modal participation factor of one. Seismic acceleration coefficients for multi-degree-of-freedom systems which may be in the resonance region of the amplified response spectra curves are increased by 50% to account conservatively for the increased modal participation.

3.7.3.6 Three Components of Earthquake Motion

For the balance of plant scope the responses to the two horizontal and the vertical component seismic inputs are calculated separately for the entire subsystem. The maximum value of a particular response due to simultaneous action of three components of earthquake were obtained by taking the square root of the sum of the squares of corresponding maximum response values to each of the three components calculated separately. This procedure is in conformance with Regulatory Guide 1.92. For components and equipment provided by the NSSS vendor, methods used to account for three components of earthquake motion are given in Section 3.7.2.6.2.

3.7.3.7 Combination of Modal Responses

3.7.3.7.1 Balance of Plant Scope

The combination of modal responses is limited to the response spectrum modal analysis technique.

Two consecutive modes are defined as closely spaced if their frequencies differ from each other by 10% or less of the lower frequency. For modes that are not closely spaced, the maximum value of the response of a given element of a system or component, subjected to a single independent spatial component (response spectrum) of a three-component earthquake, is obtained by taking the square root of the sum of the squares of corresponding maximum values of the response of the element attributed to individual significant modes of the system or component.

If some or all of the modes are closely spaced, they are divided into groups that include all modes having frequencies between the lowest frequency in the group and a frequency 10% higher. The representative maximum value of a particular response of a given element of a system or component attributed to each such group of modes is first obtained by taking the sum of the absolute values of the corresponding peak values of the response of the element attributed to individual modes in that group. The representative maximum value of this particular response attributed to all the significant modes of the system or component is then obtained by taking the square root of the sum of the squares of corresponding representative maximum values of the response of the element attributed to each closely spaced group of modes and the remaining modal responses for the modes that are not closely spaced.

This procedure is in conformance with Regulatory Guide 1.92.

3.7.3.7.2 Components and Equipment Supplied by the NSSS Vendor

For response spectra analysis, the total unidirectional seismic response is obtained by combining the individual modal responses utilizing the square root of the sum of the squares method. For systems having modes with closely spaced frequencies, this method is modified to include the possible effect of these modes. The groups of closely spaced modes are chosen such that the difference between the frequencies of the first mode and the last mode in the group does not exceed 10% of the lower frequency. Combined total response for systems which have such closely spaced modal frequencies is obtained by adding to the square root of the sum of the

squares of all modes the product of the responses of the modes in each group of closely spaced modes and a coupling factor ε. This can be represented mathematically as:

$$R_T^2 = \sum_{i=1}^{N} R_i^2 + 2\sum_{j=1}^{S}\sum_{K=M_j}^{N_j-1}\sum_{\ell=K+1}^{N_j} R_K R_\ell \varepsilon_{K\ell} \qquad (3.7\text{-}32)$$

Where:

R_T = total response.

R_i = absolute value of response of mode i.

N = total number of modes considered.

S = number of groups of closely spaced modes.

M_j = lowest modal number associated with group j of closely spaced modes.

N_j = highest modal number associated with group j of closely spaced modes.

$\varepsilon_{K\ell}$ = coupling factor with:

$$\varepsilon_{K\ell} = \left\{1 + \left[\frac{\omega'_K - \omega'_\ell}{\beta'_K \omega'_K \omega'_\ell}\right]^2\right\}^{-1} \qquad (3.7\text{-}33)$$

and:

$$\omega'_j = \omega_j[1-(\beta'_j)^2]^{1/2} \qquad (3.7\text{-}34)$$

$$\beta'_j = \beta_j + \frac{2}{\omega_j t_d} \qquad (3.7\text{-}35)$$

Where:

ω_j	=	frequency of closely spaced mode j.
β_j	=	fraction of critical damping in closely spaced mode j.
t_d	=	duration of the earthquake.

An example of this equation applied to a system can be supplied with the following considerations. Assume that the predominant contributing modes have frequencies as given below:

Mode	1	2	3	4	5	6	7	8
Frequency	5.0	8.0	8.3	8.6	11.0	15.5	16.0	20

There are two groups of closely spaced modes, namely with modes {2, 3, 4} and {6, 7}. Therefore:

S	=	2 number of groups of closely spaced modes.
M_1	=	2 lowest modal number associated with group 1.
N_1	=	4 highest modal number associated with group 1.
M_2	=	6 lowest modal number associated with group 2.
N_2	=	7 highest modal number associated with group 2.
N	=	8 total number of modes considered.

The total response for this system is, as derived from the expansion of Equation (3.7-32):

$$R_T^2 = [R_1^2 + R_2^2 + R_3^2 + ... + R_8^2] + 2R_2R_3\varepsilon_{23} + 2R_3R_4\varepsilon_{34} + 2R_6R_7\varepsilon_{67} \quad (3.7\text{-}36)$$

For time history analysis, each earthquake component direction is analyzed separately. For each of these analysis, at each time step, the global response of interest is obtained by superposition of the individual modal responses.

The preceding gives the criteria and justification for meeting the intent of Regulatory Guide 1.92, Revision 1.

3.7.3.8 Analytical Procedures for Piping

3.7.3.8.1 Balance of Plant Scope

The piping system geometry, cross sectional dimension and physical properties of each pipe segment and the restraint conditions are supplied as inputs to the PIPDYN II computer program during construction. During operations, the approved programs are specified in the VCSNS piping design guide. The mass of each piping segment is lumped at the element nodes by the computer. Additional concentrated masses are specified separately for valves, actuators, and other concentrated weights at the centers of gravity for the individual assembly or subassemblies to represent both bending and torsional effects of the assembly.

The restraint conditions of supports are specified in three translational and three rotational directions in the model, in either global or local coordinates for each support point. The restraints may be free, rigid, or elastic with a specified spring constant for each translational or rotational direction. When coupling effects between any two joint degrees of freedom are significant, a 6 by 6 stiffness matrix is used to describe an elastic foundation. Moment release at nodal points is used for pin connections or flexible joints whenever applicable.

The computer then formulates a discrete system of equations based upon the input data. The resulting homogeneous equations are solved as an eigenvalue problem. The floor response spectrum method is used in calculating the responses of each mode including nodal displacements, end forces, and moments and support loads. These modal responses are combined by the square root of the sum of the squares method for all modes with frequencies less than 30 Hz. In addition, the effects of the modes not included are added to the square root of the sum of the squares response as one term, using the highest frequency from the square root of the squares response under 30 Hz to obtain the total response. The definition and grouping method of combining close modes, described in Section 3.7.3.7 is applied in nodal deflection, element end forces and moments, acceleration, and support loads.

The responses from the two horizontal and the vertical component of an earthquake are calculated separately as described above. These responses are then combined using the square root of the sum of the squares method. The resultant end moments are finally used in the applicable ASME Code, Section III, equations for stress evaluation.

For certain 2 inch and smaller pipes or cold pipes of larger sizes, a simplified floor response spectrum dynamic analysis is performed. An iterative analytical procedure is followed for each pipe size, schedule, and response spectrum input, while using span length as a variable. The dynamic system equations are solved for the various span lengths and associated support reactions and pipe stresses are determined. Maximum allowable span lengths are then selected on the basis of a stress and/or natural frequency criteria for each of the various parameters. Seismic supports/restraints are then spaced to be within the allowable span limits established by this stress/frequency criteria. The pipe frequency is determined using a multi-span, simple supported model with the maximum spans established as described in Section 3.7.3.4. Justification for this approximate analysis method has been demonstrated by comparison of the results of detailed dynamic analyses of various piping systems with the results of the simplified method.

A scaling factor (gamma factor) is applied to the response spectrum envelopes for the vertical direction. This is used to account for amplification due to flexure of floor slabs and, therefore, is a function of the location of the components on a particular floor.

Typical scaling factors used for seismic analysis are presented in Table 3.7-8 and Figures 3.7-44 through 3.7-46.

Where relative structural movement exists within the same structure or where piping spans between adjacent structures, the effect of differential piping support movements are evaluated. The relative movements of pipe supports are considered separately in each of the spatial directions. The results are then combined by the square root of the sum of the squares method.

3.7.3.8.2 Components and Equipment Provided by the NSSS Vendor

The Class 1 piping systems are analyzed to the rules of the ASME Code, Section III, NB 3650. When response spectrum methods are used to evaluate piping systems supported at different elevations, the following procedures are used. The effect of differential seismic movement of piping supports is included in the piping analysis according to the rules of the ASME Code, Section III, Paragraph NB 3653. According to ASME definitions, these displacements cause secondary stresses in the piping system. The response quantity of interest induced by differential seismic motion of the support is computed statically by considering the building response on a mode-by- mode basis.

In the response spectrum dynamic analysis for evaluation of piping systems supported at different elevations, the most severe floor response spectrum corresponding to the support locations is used.

The selection, location, and use of snubbers for these systems is based upon the stress requirements of the ASME Code, Section III, Articles NB/NC/ND-3600 or other controlling design criteria.

3.7.3.9 Multiply Supported Equipment Components with Distinct Inputs

3.7.3.9.1 Balance of Plant Scope

Any equipment supported at different locations (elevations and/or floors) is analyzed by imposing a single conservative response spectrum at each location. This response spectrum is constructed in such a way that it conservatively envelopes the pertinent response spectra of the different locations.

3.7.3.9.2 Components and Equipment Provided by the NSSS Vendor

When response spectrum methods are used to evaluate Reactor Coolant System primary components interconnected between floors, the procedures of the following paragraphs are used. There are no components in the Westinghouse scope of analysis which are connected between

buildings. The primary components of the Reactor Coolant System are supported at no more than two floor elevations.

A response spectrum analysis is first made assuming no relative displacement between support points. The response spectra used in this analysis are the most severe floor response spectra.

Secondly, the effect of differential seismic movement of components interconnected between floors is considered statically in the integrated system analysis and in the detailed component analysis. The results of the building analysis are reviewed on a mode-by-mode basis to determine the differential motion in each mode. Per ASME Code rules, the stress caused by differential seismic motion is clearly secondary for piping (NB 3650) and component supports (NF 3231). For components, the differential motion is evaluated as a free end displacement, since, per NB 3213.19, examples of a free end displacement are motions "that would occur because of relative thermal expansion of piping, equipment, and equipment supports, or because of rotations imposed upon the equipment by sources other than the piping". The effect of the differential motion is to impose a rotation on the component by the building. This motion, then, being a free end displacement and being similar to thermal expansion loads, causes stresses which are evaluated with ASME Code methods including the rules of NB 3227.5 used for stresses originating from restrained free end displacements.

The results of these two steps, the dynamic inertia analysis and the static differential motion analysis, are combined absolutely with due consideration for the ASME classification of the stresses.

3.7.3.10 Use of Constant Vertical Static Factors

3.7.3.10.1 Balance of Plant Scope

The response spectrum method is used for the vertical seismic subsystem dynamic analysis. However, for the cases where the equipment's lowest frequency in the vertical direction is more than 30 Hz, the maximum floor acceleration is used for equipment design.

3.7.3.10.2 Components and Equipment Provided by the NSSS Vendor

Constant vertical load factors are not used as the vertical floor response load for the seismic design of safety-related components and equipment within Westinghouse's scope of responsibility.

3.7.3.11 Torsional Effects of Eccentric Masses

If the torsional effect of a valve operator or other eccentric mass is likely to have a significant effect upon the results of the analysis described in Section 3.7.3.1 for Seismic Category I systems, the eccentric mass and its moment arm are included in the mathematical model described in Sections 3.7.3.3 and 3.7.3.8.

3.7.3.12 Buried Seismic Category I Piping Systems

Seismic analysis of buried safety class piping is performed in three phases, as follows:

1. Calculation of maximum soil strain and curvature resulting from the propagation of seismic waves, considering an estimated relative contribution of each wave type (shear wave, compression wave, and Rayleigh wave).
2. Determination of the extent to which the pipe deforms elastically as a result of soil strain and curvature, or as a result of relative ground movement at building/soil interfaces, considering the influence of friction forces between soil and pipe and treatment of soil as a continuous elastic support.
3. Calculation of the stresses in the pipe which result from such elastic deformation and comparison with allowable stress as described by Table 3.9-2.

References 21 through 24 were used as the basis for the analytical determination of seismic stresses in buried safety class piping. Sources for various parameters used in the analysis are as follows:

1. Maximum acceleration for SSE, Section 2.5.2.10.
2. Fill surface elevations and subsoil conditions, Sections 2.5.4.4 and 2.5.4.8.
3. Properties (γ_t, $\bar{c}$, $\overline{Q}$, μ, and G_{max}) of Zone I and Zone II fill soils, Sections 2.5.4.5.2 and 2.5.6.4.
4. Properties (γ_t, $\bar{c}$, and $\overline{Q}$) of Zone III fill soil are assumed, based upon Section 2.5.4.5.2 and US Navy Design Manual, NAVDOCK DM-7, “Soil Mechanics, Foundations and Earth Structures” Bureaus of Yards and Docks, 1962.

3.7.3.13 Interaction of Other Piping with Seismic Category I Piping

A Seismic Category I piping system is analyzed by including the piping extending to at least the first restraint in each of the three mutually orthogonal directions beyond the defined Seismic Category I boundaries. Whenever necessary, piping segments and restraints beyond the region described above are included to ensure that both the elastic reaction and the effects of masses of the non-Seismic Category I piping on the Seismic Category I piping are adequately represented. Those portions of piping which form interfaces between Seismic Category I and non-Seismic Category I are designed to satisfy Seismic Category I requirements.

3.7.3.14 Seismic Analyses for Reactor Internals

Fuel assembly component stresses induced by horizontal seismic disturbances are analyzed through the use of finite element computer modeling. The time history floor response based on a standard seismic time history normalized to SSE levels is used as the seismic input. The reactor internals and the fuel assemblies are modeled as spring and lumped mass systems or beam elements. The component seismic response of the fuel assemblies is analyzed to determine design

adequacy. A detailed discussion of the analyses performed for typical fuel assemblies is contained in References 4 and 17.

Fuel assembly lateral structural damping obtained experimentally is presented in Figure 3-4 of Reference 18. The data indicate that no damping values less than 10% were obtained for fuel assembly displacements greater than 0.11 inches.

The distribution of fuel assembly amplitudes decreases as one approaches the center of the core. The average amplitude for the minimum displacement fuel assembly is well above 0.11 inches for the SSE.

Fuel assembly displacement time history for the SSE seismic input is illustrated in Figure 2-3 of Reference 18.

The control rod drive mechanisms (CRDM) are seismically analyzed to confirm that system stresses under the combined loading conditions as described in Reference 3.9.1 do not exceed allowable levels as defined by the ASME Code, Section III for Upset and Faulted conditions. The CRDM is mathematically modeled as a system of lumped and distributed masses. The model is analyzed under appropriate seismic excitation and the resultant seismic bending moments along the length of the CRDM are calculated. The corresponding stresses are then combined with the stresses from the other loadings required and the combination is shown to meet the ASME Code Section III requirements.

3.7.3.15 Analysis Procedure for Damping

3.7.3.15.1 Balance of Plant Scope

The composite modal damping approach is used to account for element-associated damping. This is based upon the use of the mass as a weighting function in generating the composite modal damping. The formulation leads to:

$$\overline{\beta}_j \{\phi\}^T[\overline{M}]\{\phi\}$$

Where:

$\overline{\beta}_j$ = Equivalent modal damping factor of the j(th) mode.

$[\overline{M}]$ = The modified mass matrix constructed from element matrix formed by the product of the damping factor as provided in Table 3.7-9 for the element and its mass matrix.

$\{\phi\}$ = The j(th) normalized model vector.

In the cases of equipment which consists of elements of the same damping factor, the above equation is reduced to a single damping factor.

3.7.3.15.2 Components and Equipment Provided by the NSSS Vendor

Analysis procedures for damping for subsystems in Westinghouse's scope of responsibility are given in Section 3.7.2.15.2.

3.7.4 Seismic Instrumentation

3.7.4.1 Comparison with Regulatory Guide 1.12

The seismic instrumentation provided is in general conformance with Regulatory Guide 1.12 (see Appendix 3A) for a maximum foundation acceleration of less than 0.3g.

Since the soil-structure interaction is negligible, the "Free Field" triaxial time-history accelerograph is omitted as permitted by ANSI N18.5 (Reference 19).

3.7.4.2 Location and Description of Instrumentation

The types and locations of seismic instrumentation are as follows:

1. Triaxial Time-History Accelerometer

   One triaxial accelerometer is located at each of the following locations

   a. Reactor Building foundation mat outside of the Reactor Building (see Figure 3.7-47).
   b. Reactor Building ring girder outside the Reactor Building (see Figure 3.7-48).

   The output of both triaxial sensor units (accelerometers) is recorded by a solid-state recording system in the Control Building. The accelerometer located on the Reactor Building foundation mat also functions as a seismic trigger for the actuation of the solid-state recording system. An alarm is sounded when the recording system is activated.

2. Triaxial Response Spectrum Recorder

   One triaxial response spectrum recorder, capable of permanently recording peak response as a function of frequency for both horizontal motions and vertical motion, is provided at each of the following locations:

   a. Reactor Building foundation mat outside the Reactor Building (see Figure 3.7-47).
   b. Steam generator support (see Figure 3.7-51).
   c. On the Intermediate Building roof at elevation 463'-0" (see Figure 3.7-52).
   d. On the foundation of the Auxiliary Building at elevation 374'-0" (see Figure 3.7-53).

Each triaxial response spectrum recorder will record 12 frequencies, 1/3 of an octave apart, beginning with 2 Hz and ending with 25.4 Hz.

3. Triaxial Seismic Switch

   A triaxial seismic switch, located at the Reactor Building foundation mat, is provided to actuate an alarm in the control room (see Figure 3.7-47).

   The seismic monitoring instrumentation shown in Table 3.7-11 should be maintained with a high level of availability. Each of these instruments shall be demonstrated operable by the performance of the channel check, channel calibration, and analog channel operational test as established in the appropriate test procedures.

   Each of the above seismic monitoring instruments actuated during a seismic event greater than or equal to 0.01g shall be restored within 24 hours and a channel calibration performed within 5 days following the seismic event. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. A Special Report shall be prepared and submitted to the Commission within 10 days describing the magnitude, frequency spectrum, and resultant effect upon facility features important to safety.

   The availability of the seismic instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the facility to determine if plant shutdown is required.

   Criteria for the selection of types and locations of seismic instrumentation are in accordance with Regulatory Guide 1.12 (see Appendix 3A). Where multiple locations for a particular instrument are possible, the location selected is based upon analytical results which show that an amplified response is expected at the selected location. If an earthquake occurs, the recorded responses of the previously discussed seismic instrumentation, except for the triaxial seismic switch, are compared to calculated responses as discussed in Section 3.7.4.4.

   For instruments using a plate as a mounting adapter, Table 3.7-10 presents the calculated lowest natural frequency (of three dimensions) of each mechanical system monitored (adapter plate, plus instrument). For instruments not using a plate adapter, the instruments are rigidly bolted to the concrete surface as a mounting accordance with the instrument manufacturer’s instructions.

   Instrument assemblies are specified and designed to be free of spurious resonances within the frequency range of the instrument.

3.7.4.3 Control Room Operator Notification

Control room signals available to the operator are as follows:

1. Indication and an audible alarm are actuated when the triaxial seismic switch at the Reactor Building foundation signals that the OBE peak ground acceleration has been exceeded in either of the horizontal directions or in the vertical direction.

2. Indication and a common alarm are actuated when any of the 12 elements of each triaxial section of the triaxial response spectrum recorder at the Reactor Building foundation mat exceeds the frequency setpoint. Two setpoints are provided for each element. Exceeding the first setpoint illuminates a yellow light at an acceleration equivalent to 2/3 OBE design response spectra. A red light is illuminated if acceleration exceeds the OBE design response spectra.
3. Indication and an audible alarm are actuated when the accelerometer at the Reactor Building foundation mat detects acceleration greater than 0.01g in either horizontal direction or greater than 0.0067g in the vertical direction signifying that the triaxial time-history accelerometer recording system has started. The recording system is located in the relay room below the control room.

3.7.4.4 Comparison of Measured and Predicted Responses

In the event of an earthquake, the control room supervision determines whether or not there are initial indications that the OBE acceleration level has been exceeded. This is accomplished by inspection of the indications and alarms described in Section 3.7.4.3. In the event of an earthquake, the control room supervision determines whether or not there are initial indications that the OBE acceleration level has been exceeded. This is accomplished by inspection of the indications and alarms described in Section 3.7.4.3. Data from the triaxial time history accelerometer located at the Reactor Building foundation mat will be analyzed and retrieved from the relay room recording/analysis system. The data is provided to control room supervision as soon as possible to meet approximately 4-hour target of performing the evaluation of the earthquake ground motion records against plant specific OBE exceedance. This is accomplished as follows:

1. The triaxial time history accelerometer on the Reactor Building foundation mat records acceleration as a function of time. The data is recorded in solid-state and then processed via computer analysis to produce:(a) comparisons of the recorded earthquake to the foundation OBE design for each directional component, (b) a calculation of the Cumulative Absolute Velocity as compared to a threshold criterion for each directional component, and (c) a summary determination of exceedance of the plant OBE design basis. The summary position on exceedance of the plant OBE design can then be used by the control room supervision to determine if shut down of the plant is warranted.
2. Plant operator walkdowns will also commence after the occurrence of an earthquake to evaluate any unusual plant conditions which might exist, such as, pump or valve leakages, excess equipment vibrations or deformations, structural cracking, fallen objects, etc. Reports on the extent of damage, or lack thereof, will be used by the control room supervision in conjunction with the seismic instrumentation results and other control room indications to establish a position on whether the plant OBE design has been exceeded and if shut down is required. This decision should be made within approximately eight (8) hours of the earthquake occurrence

3. If the decision to shut down the plant is made, it should be conducted in a controlled process using existing plant procedures.
4. As part of the evaluation of the effects of the earthquake, the measured responses from the other sensors located throughout the plant will be compared to the design response for their respective locations. These comparisons will be used to evaluate the overall impact of the earthquake as it relates to the design of the plant and components.

3.7.5 Seismic Design Control

3.7.5.1 Balance of Plant Scope

Safety class components and equipment are designed using floor response spectra as input with the exception of certain instruments, generally locally mounted devices, which are procured using fixed values of 1.5g (wall mounted devices) and 3.0g (pipe mounted devices) as conservative values for multiple locations. Vendors are responsible for the design and qualification by analysis or test of components and equipment within their scope. This responsibility includes review of the design, analyses, or tests by one or more qualified engineers other than the engineer(s) who originated the design, performed the analyses, or developed the tests.

Safety class piping systems are also designed using floor response spectra as input. Gilbert is responsible for design and qualification of piping systems by analysis during construction (see Section 3.7.3). This responsibility includes review of the design and analyses by one or more qualified engineers other than the engineer(s) who originated the design or performed the analyses. During operations, VCSNS staff is responsible for design and qualification of BOP piping systems by analyses which may be performed by various contractors per VCSNS piping design guides or their predecessors.

The snubber vendor maintains acceptance and qualification test reports on file for each type of snubber which has been used as a piping restraint for the Virgil C. Summer Nuclear Station.

The loading conditions and transients analyzed are described for each system in the piping system design specification. The analytical procedure described in Section 3.7.3.8 is followed and the results are compared to the applicable design Section of the ASME Code or other controlling design requirements.

For certain small diameter piping (2 inch and smaller), the seismic design is implemented by the application of simplified seismic support criteria which are subjected to independent review.

3.7.5.2 Components and Equipment Provided by the NSSS Vendor

The following procedure is implemented for Westinghouse supplied safety-related mechanical equipment that falls within one of the many categories which have been analyzed as described in Sections 3.7.2 and 3.7.3 and has been shown to be rigid with all natural frequencies greater than or equal to 33 Hz.

1. Equivalent static acceleration factors for the horizontal and vertical directions are included in the equipment specification. The vendor must certify the adequacy of the equipment to meet the seismic requirements as described in Section 3.7.3.
2. When the floor response spectra are developed the cognizant engineer responsible for the particular component checks to ensure that the acceleration factors are less than those given in the equipment specification. If accelerations exceed those in the equipment specifications, the designs are rechecked to verify equipment adequacy.

All other Westinghouse supplied safety-related equipment is analyzed or tested as described in Sections 3.7.2, 3.7.3, and 3.10.

3.7.6 References

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Table 3.7-0
Frequency Intervals Used For Calculation of Response Spectra

Frequency Range (Hz)	Increments (Hz)
0.2 - 3.0	0.0622
3.0 - 3.6	0.1425
3.6 - 5.0	0.1857
5.0 - 8.0	0.20
8.0 - 15.0	0.3532
15.0 - 18.0	0.5414
18.0 - 22.0	0.80
22.0 - 34.0	1.450

Table 3.7-1
Damping Factors Percent of Critical Damping[1]

Component or Structure	Value Used OBE & SSE	Regulatory Guide 1.61 Value	
		OBE	SSE
Reactor Building	2.0	2.0	5.0
Concrete Support Structures Inside the Reactor Building	2.0	4.0	7.0
Assemblies & Structures			
Bolted & Riveted	2.5	4.0	7.0
Welded	2.0	2.0	4.0
Vital Piping Systems			
Larger than 12 Inch Diameter	2.0/3.0 [2]	2.0	3.0
12 Inch Diameter and Smaller	1.0/2.0 [2]	1.0	2.0

(1) See Reference 1
(2) Code Class N-411, "Alternative Damping Values for Seismic Analysis of Class 1, 2 and 3 Piping Sections, Section III, Division 1," is acceptable for piping analyses for systems supported on all building structures per Regulatory Guide 1.84, Rev. 25.

Table 3.7-2
Damping Factors Percent of Critical Damping
For Structures With Soil Interaction

	Range of Shear Wave Velocity	Damping Factor
On Rock	C > 6000 fps	2-5
On Firm Soil	C ≥ 2000 fps	5-7
On Soft Soil	C < 2000 fps	7-10

NOTE: See reference 1.

Table 3.7-3
Damping Values Used For Seismic Systems
Analysis For Westinghouse Supplied Equipment [3]

Item	Damping (Percent of Critical) Upset Conditions (OBE)	Damping (Percent of Critical) Faulted Condition (SSE, DBA)
Primary Coolant Loop System - Components and Large Piping [1]	2 [2]	4 [2]
Small Piping	1 [2]	2 [2]
Welded Steel; Structures	2	4
Bolted and/or Riveted Steel Structures	4	7

(1) Generally applicable to 12 inch or larger diameter piping.
(2) Code Case N-411, “Alternative Damping Values for Seismic Analysis of classes 1, 2 and 3 Piping Sections, Section III, Division 1,” is acceptable for piping analyses for systems supported on all building structures per Regulatory Guide 1.84,Rev. 25.
(3) Damping values noted were applied to the design of the Integrated Head Assembly (IHA) which replaced the service structure on the original reactor vessel head. The IHA is installed on the replacement Reactor Vessel Closure Head.

Table 3.7-4
Foundation Seismic Design Parameters

Foundation Material	Compressional Wave Velocity (ft/sec)	In-Situ Density (lbs/cu ft)	Poisson's Ratio (μ)	Shear Modulus (G) or Modulus of Rigidity (lbs/sq in)	Modulus of Subgrade Reaction(1) (lbs/cu ft)
Saprolite	1000-3000	110-135	0.35	1×10^4 to 3.5×10^4	$\frac{5 \times 10^6}{\sqrt{BL}}$
Weathered and jointed rock	(12,000-13,000) (2)	(140-160) (2)	0.30	5×10^5	$\frac{2 \times 10^8}{\sqrt{BL}}$
Sound rock	15,000	165	0.20	2×10^6	$\frac{8 \times 10^8}{\sqrt{BL}}$

(1) "BL" is contact area of square foundation. For other contact area shapes, subgrade modulus must be modified (see Barkan, 1962).
(2) Numbers in parentheses are estimated values.
NOTE: Young's Modulus, $E = 2(1 + \mu)G$.

Table 3.7-5
Foundation Elevation and Foundation Type
Seismic Category I Structures

Structure	Foundation Elevation (ft)	Foundation Type
Reactor Building		
North	341 (1) to 396	Fill Concrete
East	348 (1) to 396	Fill Concrete
South	362 (1) to 396	Fill Concrete
West	367 (1) to 396	Fill Concrete
Entire Structure	396 to 408	Mat
Control Building		
North	366 (1) to 407	Fill Concrete
East	371 (1) to 407	Fill Concrete
South	366 (1) to 407	Fill Concrete
West	371 (1) to 407	Fill Concrete
Entire Structure	407 to 411	Mat
Diesel Generator Building		
Entire Structure	Table 3.7-6	Caissons
Service Water Pumphouse	386	Mat
Service Water Intake Structure	367	Mat
Service Water Discharge Structure	408	Mat
Auxiliary Building		
North	354(1) to 384	Fill Concrete
South	368(1) to 370	Fill Concrete
North	384 to 388	Mat
South	370 to 374	Mat
Fuel Handling Building		
Entire Structure	Table 3.7-6	Caissons

Table 3.7-5 (continued)
Foundation Elevation and Foundation Type
Seismic Category I Structures

Structure	Foundation Elevation (ft)	Foundation Type
Intermediate Building		
Entire Structure	Table 3.7-6	Caissons

(1) Bottom elevation determined in field to suit actual condition.

Table 3.7-6
Foundation Data For Safety Class Structures
Supported on Caissons

Structure	Elevation of Cap (ft)	Underlying Soil	Elevation in No. 3 Rock for Seismic Input
Diesel Gen. Building	394 to 421	Zone I, II, III fill and silty fine sand, medium dense to dense	369 to 363
Fuel Handling Building	409 to 430	Zone I, II, III fill and silty fine sand, medium dense to dense	345
Intermediate Building	394 to 409	Zone I, II, III fill and silty fine sand, medium dense to dense	375

Table 3.7-7
Dimensions of Seismic Category I Structures

Structure	Plan Dimensions (ft)	Height (ft)	Embedment Depth (ft)	Top Elevation (ft)
Reactor Building	134, OD	206	39	602
Control Building	84 x 141	98	28	505
Diesel Generator Building	66 x 67	83 and 56	41 and 14	477
Service Water Pumphouse	70 x 79	73	49	459
Service Water Intake Structure	166 x 18	21 and 30	--	388 and 396.5
Service Water Discharge Structure	35 x 33	6 to 15	15	425
Auxiliary Building	120 x 190	--	--	--
North	--	127	51	511
South	--	141	65	511
Fuel Handling Building	75 x 123	95 and 102	26 and 5	511
Intermediate Building	85 x 198	76 and 78	39 and 26	485

Table 3.7-7a
Response Loads For Seismic Category I Structures

Elevation (Ft)	Mass (Kip-Sec^2/Ft)	Acceleration (g)			Displacement (in)		
		X	Y	Vert.	X	Y	Vert.
Service Water Pumphouse							
390’	184.938	0.200	0.160	0.161	0.765	0.612	0.063
425’	211.736	0.235	0.188	0.173	0.899	0.719	0.068
436’	107.693	0.262	0.209	0.175	1.002	0.799	0.069
441’	55.416	0.276	0.220	0.186	1.055	0.841	0.073
459’	82.328	0.327	0.261	0.190	1.250	0.998	0.074
Control Building							
412’	257.93	0.144	0.168	0.078	0.015	0.027	0.010
425’	141.15	0.183	0.212	0.083	0.028	0.047	0.010
436	120.46	0.208	0.260	0.110	0.035	0.061	0.017
448’	95.91	0.263	0.309	0.124	0.055	0.074	0.019
463’	150.39	0.328	0.365	0.130	0.078	0.087	0.019
482’	191.86	0.429	0.433	0.137	0.100	0.103	0.020
505’	196.97	0.501	0.490	0.142	0.117	0.114	0.020
Auxiliary Building							
374’	490.55	0.117	0.117	0.082	0.011	0.009	0.014
388’	679.64	0.134	0.129	0.098	0.019	0.016	0.012
397’	227.16	0.150	0.203	0.089	0.028	0.038	0.015
412’	1086.12	0.232	0.268	0.106	0.055	0.057	0.015
436’	900.96	0.338	0.363	0.109	0.085	0.083	0.015
463’	658.05	0.501	0.444	0.116	0.137	0.104	0.016
485’	390.81	0.554	0.485	0.118	0.154	0.114	0.016
511’	50.15	0.650	0.498	0.120	0.175	0.120	0.016

Table 3.7-7a (continued)
Response Loads For Seismic Category I Structures

Elevation (Ft)	Mass (Kip-Sec^2/Ft)	Acceleration (g)			Displacement (in)		
		X	Y	Vert.	X	Y	Vert.
Intermediate Building							
412’	398.45	0.180	0.308	0.209	0.031	0.072	0.025
436’	432.54	0.274	0.461	0.222	0.043	0.111	0.026
463’	368.40	0.357	0.574	0.235	0.065	0.136	0.027
485’	106.24	0.372	0.541	0.242	0.065	0.140	0.027
Reactor Building Shell							
435’	203.54	0.161	0.157	0.157	0.040	0.040	0.005
462’	180.06	0.202	0.200	0.195	0.079	0.079	0.008
481’	148.76	0.243	0.242	0.220	0.109	0.109	0.009
500’	173.73	0.296	0.295	0.242	0.139	0.139	0.010
523’	180.06	0.350	0.350	0.267	0.176	0.176	0.012
546’	153.11	0.397	0.399	0.288	0.211	0.212	0.013
582’	517.95	0.476	0.475	0.301	0.257	0.258	0.014
Interior Concrete							
407’	468.51	0.118	0.114	0.112	0.005	0.005	0.002
427’	144.29	0.168	0.162	0.124	0.012	0.011	0.003
431’	59.24	0.180	0.170	0.126	0.014	0.013	0.003
435’	136.40	0.192	0.183	0.129	0.016	0.016	0.003
439’	47.11	0.201	0.195	0.130	0.018	0.017	0.003
445’	109.50	0.219	0.221	0.131	0.021	0.020	0.003
462’	330.75	0.298	0.304	0.134	0.028	0.027	0.004
475’	64.35	0.342	0.347	0.134	0.032	0.030	0.004
Diesel Generator Building							
427’	127.7	0.466	0.470	0.107	0.228	0.216	0.006
436’	117.2	0.474	0.478	0.111	0.264	0.240	0.006
463’	84.1	0.520	0.514	0.111	0.336	0.348	0.006

Table 3.7-7a (continued)
Response Loads For Seismic Category I Structures

Elevation (Ft)	Mass (Kip-Sec^2/Ft)	Acceleration (g)			Displacement (in)		
		X	Y	Vert.	X	Y	Vert.
476’	67.7	0.841	1.420	0.090	0.384	0.384	0.006
Fuel Handling Building							
436’	882.82	0.303	0.320	0.230	0.101	0.130	0.023
463’	6.78	0.304	0.328	0.230	0.209	0.279	0.036
495’	8.85	0.846	0.974	0.225	0.337	0.456	0.051
512’	6.18	0.814	0.884	0.225	0.405	0.550	0.059

Table 3.7-7b
Results of Transient Analysis - Typical Torsional Model

Transient Analysis Sum X-EQ

	System Accelerations (Total)					
	Translation			Bending Response	Torsional Response	Bending Response
Joint	X	Y	Z	X	Y	Z
701	0.174155E 02 0.968478E 01	-0.216468E 00 0.958479E 01	0.194451E 01 0.240496E 01	-0.339760E-02 0.232497E 01	0.317496E-01 0.216497E 01	-0.128979E-01 0.950479E 01
70102	0.151535E 02 0.968478E 01	-0.297819E 00 0.822482E 01	-0.166849E 01 0.682485E 01	-0.339760E-02 0.232497E 01	0.317496E-01 0.216497E 01	-0.128979E-01 0.950479E 01
70103	0.151535E 02 0.968478E 01	-0.135537E 01 0.950479E 01	-0.414053E 01 0.216497E 01	-0.339760E-02 0.232497 E 01	0.317496E-01 0.216497E 01	-0.128979E-01 0.950479E 01
70104	0.192796E 02 0.968478E 01	0.664329E 00 0.822482E 01	-0.386272E 01 0.216497E 01	-0.339760E-02 0.232497E 01	0.317496E-01 0.216497E 01	-0.128979E-01 0.950479E 01
70105	0.192796E 02 0.968478E 01	-0.795434E 00 0.992478E 01	-0.166849E 01 0.682485E 01	-0.339760E-02 0.232497E 01	0.317496E-01 0.216497E 01	-0.128979E-01 0.950479E 01
702	0.143161E 02 0.984478E 01	-0.200542E 00 0.950479E 01	-0.223558E 01 0.232497E 01	-0.339760E-02 0.232497E 01	0.270121E-01 0.216497E 01	-0.128978E-01 0.950479E 01
70202	0.125049E 02 0.984478E 01	-0.299360E 00 0.822482E 01	-0.143435E 01 0.232497E 01	-0.339960E-02 0.232497E 01	0.270121E-01 0.216497E 01	-0.128978E-01 0.950479E 01
70203	0.125049E 02 0.984478E 01	-0.135695E 01 0.950479E 01	0.377615E 01 0.224497E 01	-0.339760E-02 0.232497E 01	0.270121E-01 0.216497E 01	-0.128978E-01 0.950479E 01
70204	0.162128E 02 0.984478E 01	0.662784E 00 0.822482E 01	0.357268E 01 0.224497E 01	-0.339760E-02 0.232497E 01	0.270121E-01 0.216497E 01	-0.128978E-01 0.950479E 01
70205	0.162128E 02 0.984478E 01	-0.792828E 00 0.992478E 01	-0.143435E 01 0.232497E 01	-0.339760E-02 0.232497E 01	0.270121E-01 0.216497E 01	-0.128978E-01 0.950479E 01

Table 3.7-7b (continued)
Results of Transient Analysis - Typical Torsional Model

Transient Analysis Sum X-EQ

	System Accelerations (Total)					
	Translation			Bending Response	Torsional Response	Bending Response
Joint	X	Y	Z	X	Y	Z
703	0.130849E 02 0.984478E 01	-0.137671E 00 0.950479E 01	-0.197403E 01 0.232497E 01	-0.339755E-02 0.232497E 01	0.221927E-01 0.216497E 01	-0.128976E-01 0.950479E 01
70302	0.115773E 02 0.984478E 01	-0.303186E 00 0.822482E 01	-0.131435E 01 0.232497E 01	-0.339755E-02 0.232497E 01	0.221927E-01 0.215497E 01	-0.128976E-01 0.950479E 01
70303	0.115773E 02 0.984478E 01	-0.135311E 01 0.950479E 01	-0.320794E 01 0.216497E 01	-0.339755E-02 0.232497E 01	0.221927E-01 0.216497E 01	-0.128976E-01 0.950479E 01
70304	0.146807E 02 0.984478E 01	0.658934E 00 0.822482E 01	0.303730E 01 0.224497E 01	-0.339755E-02 0.232497E 01	0.221927E-01 0.216497E 01	-0.128976E-01 0.950479E 01
70305	0.146807E 02 0.984478E 01	-0.795415E 00 0.992478E 01	-0.131435E 01 0.232497E 01	-0.339755E-02 0.232497E 01	0.221927E-01 0.216497E 01	-0.128976E-01 0.950479E 01

Table 3.7-7c
Reactor Building Modal Participation Factors

Mode	Participation Factor	Frequency (cps)
*1 (dominant mode)	26.48	4.35
*2	22.68	11.47
*3	12.18	15.68
*4	22.25	29.15
*5	-8.03	32.96
*6	13.69	40.64
*7	-6.36	45.87
8	-0.97	56.10
9	-1.26	56.77
10	-0.11	66.38
11	0.06	76.14
12	-1.01	79.20
13	0.37	111.01
14	-1.79	147.12
15	-0.66	157.47
16	0.69	208.84
17	0.37	213.11
18	0.01	239.89
19	0.35	312.96
20	-0.12	385.35

* Significant modes

Table 3.7-8
Gamma Scaling Factors

	Gamma Scaling Factor
Reactor Building Shell and Interior Concrete	1.0
Control Building	See Figure 3.7-44
Diesel Generator Building	1.0
Fuel Handling Building	1.0
Auxiliary Building	See Figure 3.7-45
Intermediate Building	See Figure 3.7-46
Service Water Pumphouse	1.0

Table 3.7-9
Damping Factors Percent of Critical Damping[1]

Component or Structure	Working Stress, No More Than About One-Half Yield Point	At, or Just Below Yield Point	Beyond Yield Point with Permanent Strain Greater Than Yield Point Limit Strain
Reactor Building	2.0	5.0	Not applicable
Concrete Support Structures Inside the Reactor Building	2.0	5.0	
Assemblies L Structures			
a. Bolted & Riveted	2.5	5.0	
b. Welded	2.0	5.0	
Vital Piping Systems [2]			
Other Concrete Structures above Ground	2.0	5.0	

(1) Reference: "Seismic Design Criteria for Nuclear Reactor Facilities" by Nathan M. Newmark and William J. Hall, Proceedings, Fourth World Conference on Earthquake Engineering, January 13 - January 18, 1969, Santiago, Chile.
(2) Refer to Table 3.7-1 for damping factors.

Table 3.7-10
Seismic Instrument Sensing Elements[1]

Ident. No.	Sensing Element Description	Location	FSAR Figure Reference	Mounting Type	Lowest Natural Frequency of Mounting [2]
IYM-1780	Accelerometer	Reactor building, foundation mat, outside reactor building	3.7-47	Bolted to foundation	[3]
IYM-1782	Seismic switch	Reactor building, foundation mat, outside reactor building	3.7-47	Bolted to foundation	[3]
IYM-1783	Response spectrum recorder with switches	Reactor building, foundation mat, outside reactor building	3.7-47	Bolted to foundation	[3]
IYM-1784	Accelerometer	Reactor building, top of ring girder, outside reactor building	3.7-48	Bolted to ring girder concrete	[3]

Table 3.7-10 (continued)
Seismic Instrument Sensing Elements[1]

Ident. No.	Sensing Element Description	Location	FSAR Figure Reference	Mounting Type	Lowest Natural Frequency of Mounting [2]
IYM-1785	Response spectrum recorder	Steam generator C, upper lateral support, inside Reactor Building	3.7-51	Bolted to adapter plate	30.9 Hz
IYM-1786	Response spectrum recorder	Intermediate Building roof, elevation 463’	3.7-52	Bolted to concrete floor	[3]
IYM-1787	Response spectrum recorder	Auxiliary Building foundation elevation 374’	3.7-53	Bolted to foundation	

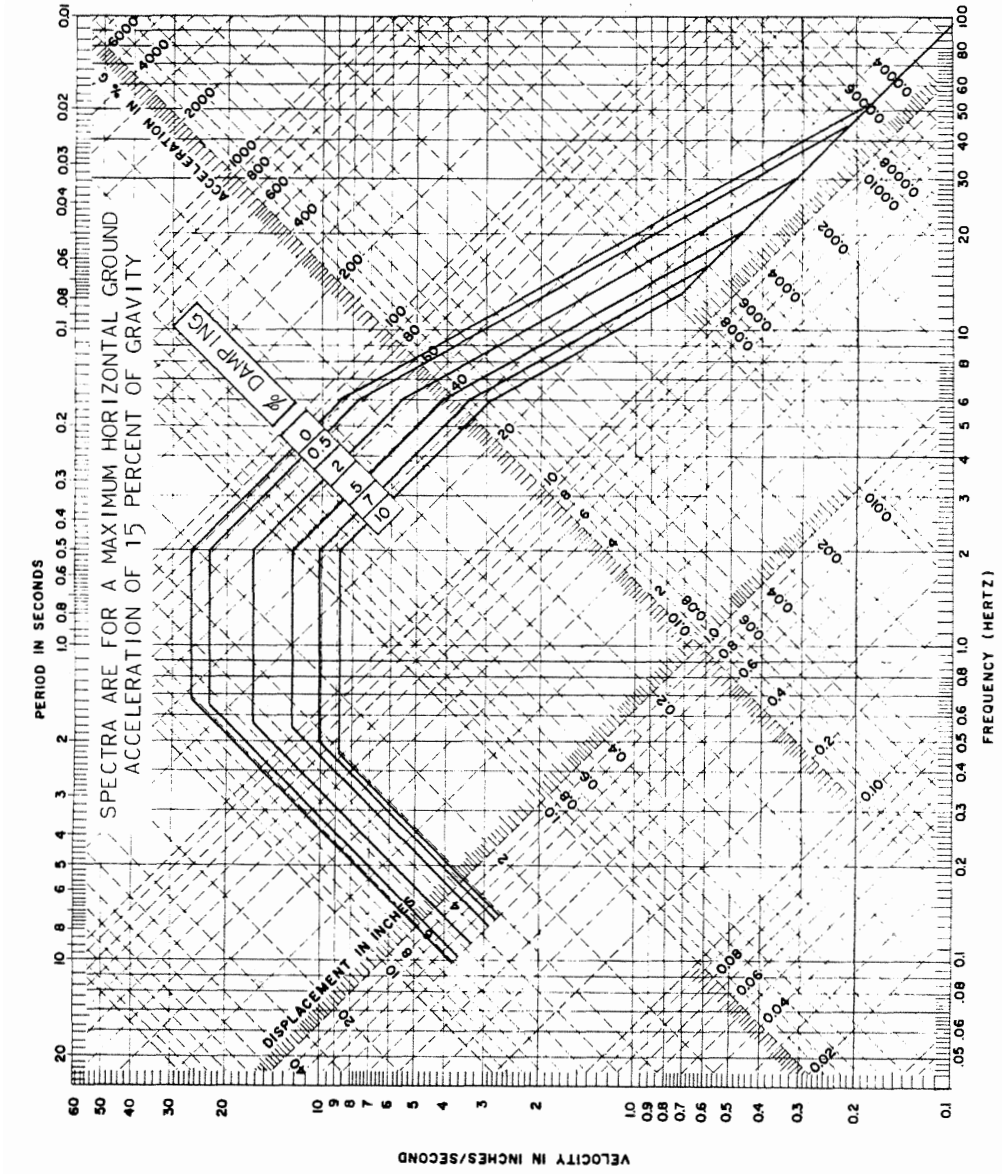
(1) All listed sensing elements are triaxial sensors.
(2) Lowest natural frequency, in three dimensions, of mounting plate.
(3) This instrument does not use a plate as a mounting adapter. The instrument is bolted rigidly to the concrete surface that it monitors. The instrument is free from spurious resonances within its frequency range.

Table 3.7-11
Seismic Monitoring Instrumentation

	Instruments and Sensor Locations	Measurement Range	Minimum Instruments Operable
1.	Triaxial Time-History Accelerographs System, including the following components:		
	a. IYM-1780 Reactor Building Foundation Mat Accelerometer/Trigger	0.1 to 40 Hz 0.01 to 1.0g	1*
	b. IYM-1784 Reactor Building Ring Girder Accelerometer	0.1 to 40 Hz 0.01 to 1.0g	1
2.	Triaxial Seismic Switch		
	a. IYM-1782 Reactor Building Foundation Mat	0.1 to 30 Hz 0.01 to 0.25g	1*
3.	Triaxial Response-Spectrum Recorders		
	a. IYM-1783 - Reactor Building Foundation Mat	(1)	1*
	b. IYM-1785 - Steam Generator Support	(1)	1
	c. IYM-1786 - Intermediate Bldg., Elev. 463’	(1)	1
	d. IYM-1787 - Auxiliary Bldg. Foundation	(1	1

(1) Range varies for the multiple elements of the instrument, i.e., 1.6g at 2 Hz, 10g at 5 Hz, 34g at 10 Hz, 12g at 16 Hz.
.* With control room indication and/or alarm.

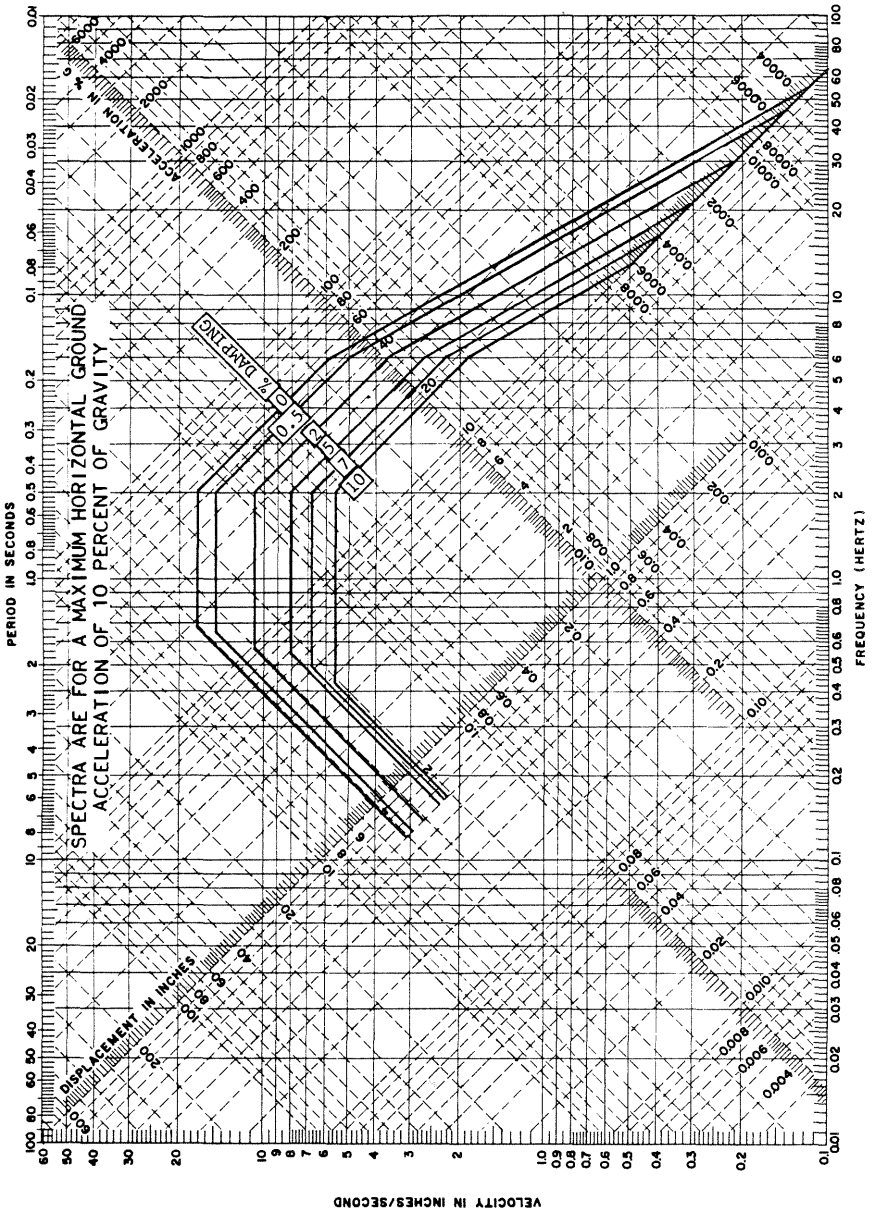
Figure 3.7-1
RESPONSE SPECTRA SAFE SHUTDOWN EARTHQUAKE, STRUCTURES FOUNDED ON ROCK



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectra Safe Shutdown Earthquake, Structures Founded on Rock Figure 3.7-1

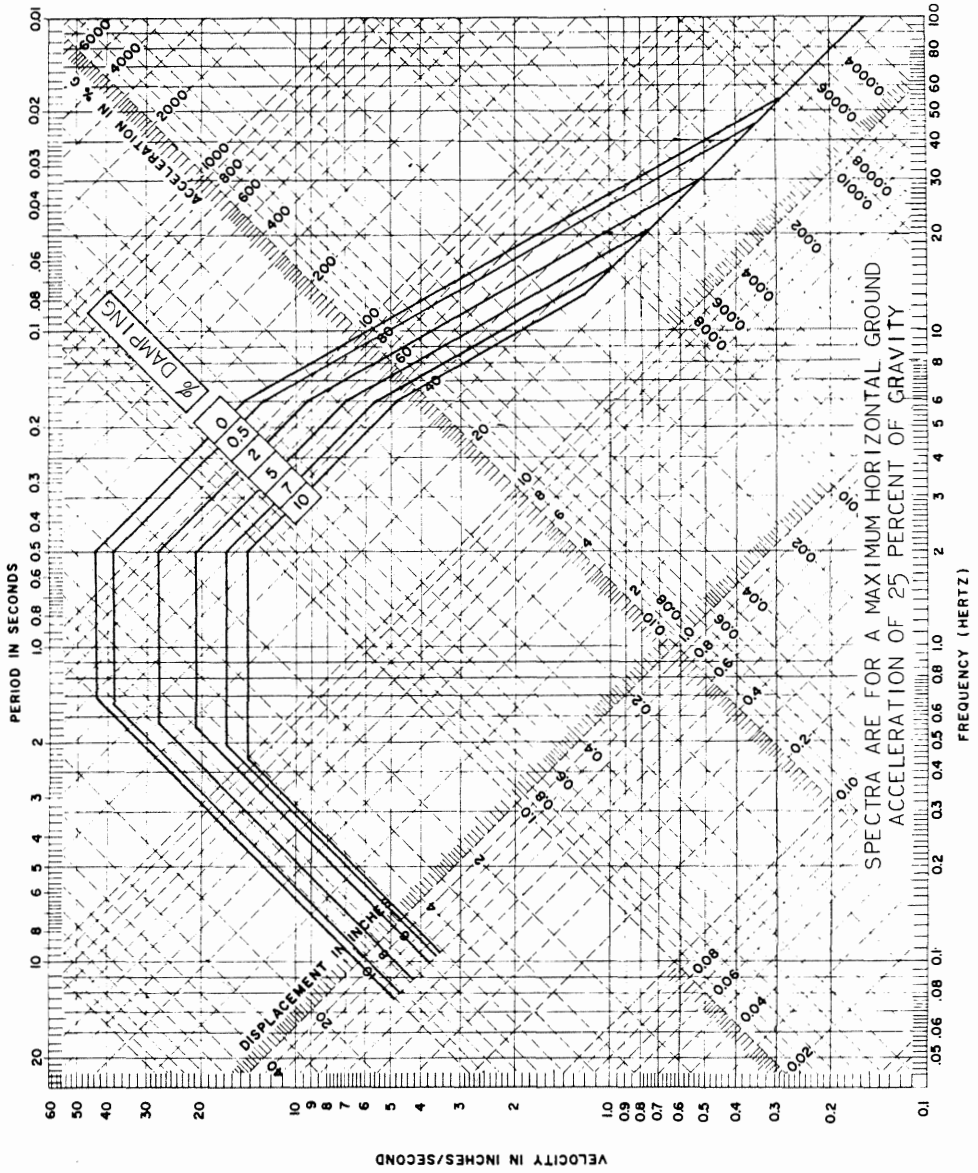
Figure 3.7-2

RESPONSE SPECTRA OPERATING BASIS EARTHQUAKE, STRUCTURES FOUNDED ON ROCK



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectra Operating Basis Earthquake, Structures Founded on Rock Figure 3.7-2

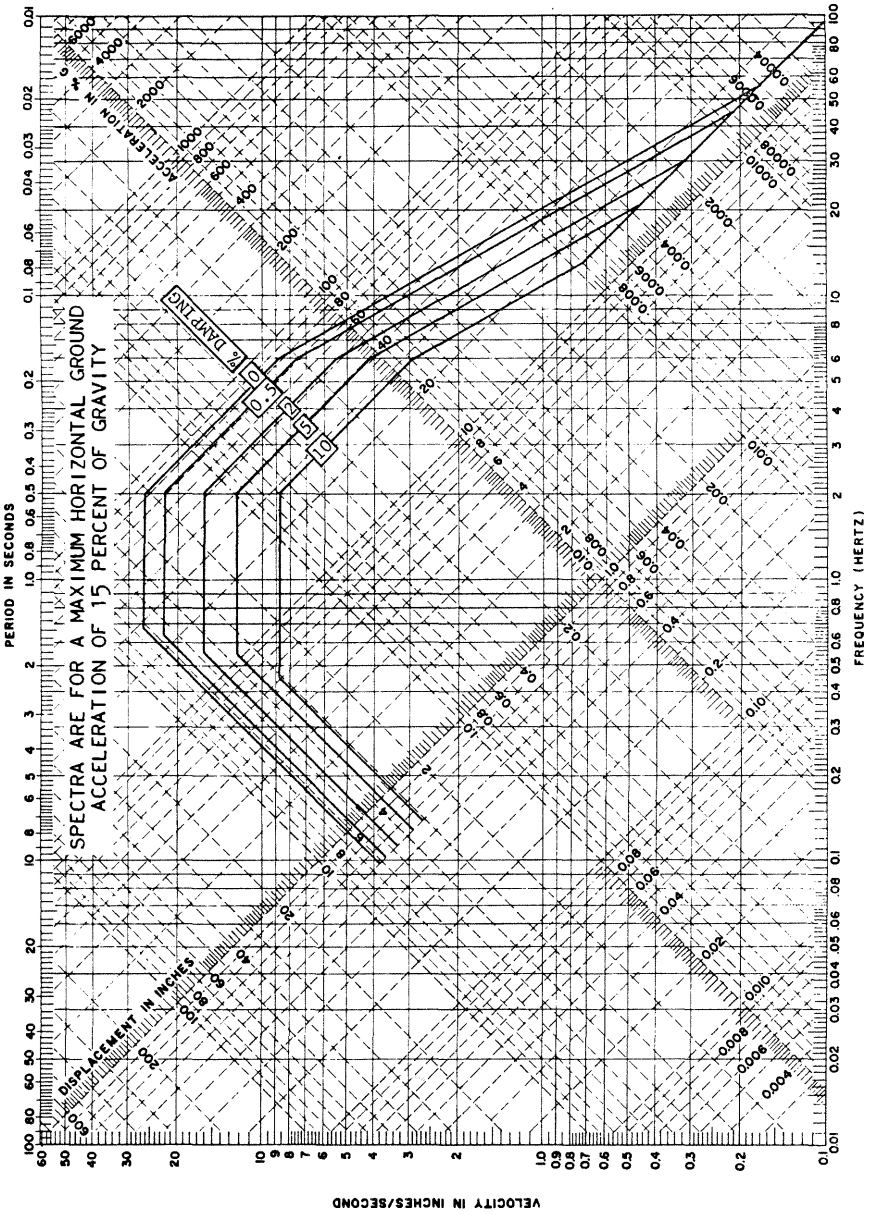
Figure 3.7-3
RESPONSE SPECTRA SAFE SHUTDOWN EARTHQUAKE, STRUCTURES FOUNDED ON SOIL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectra Safe Shutdown Earthquake, Structures Founded on Soil
Figure 3.7-3

Figure 3.7-4

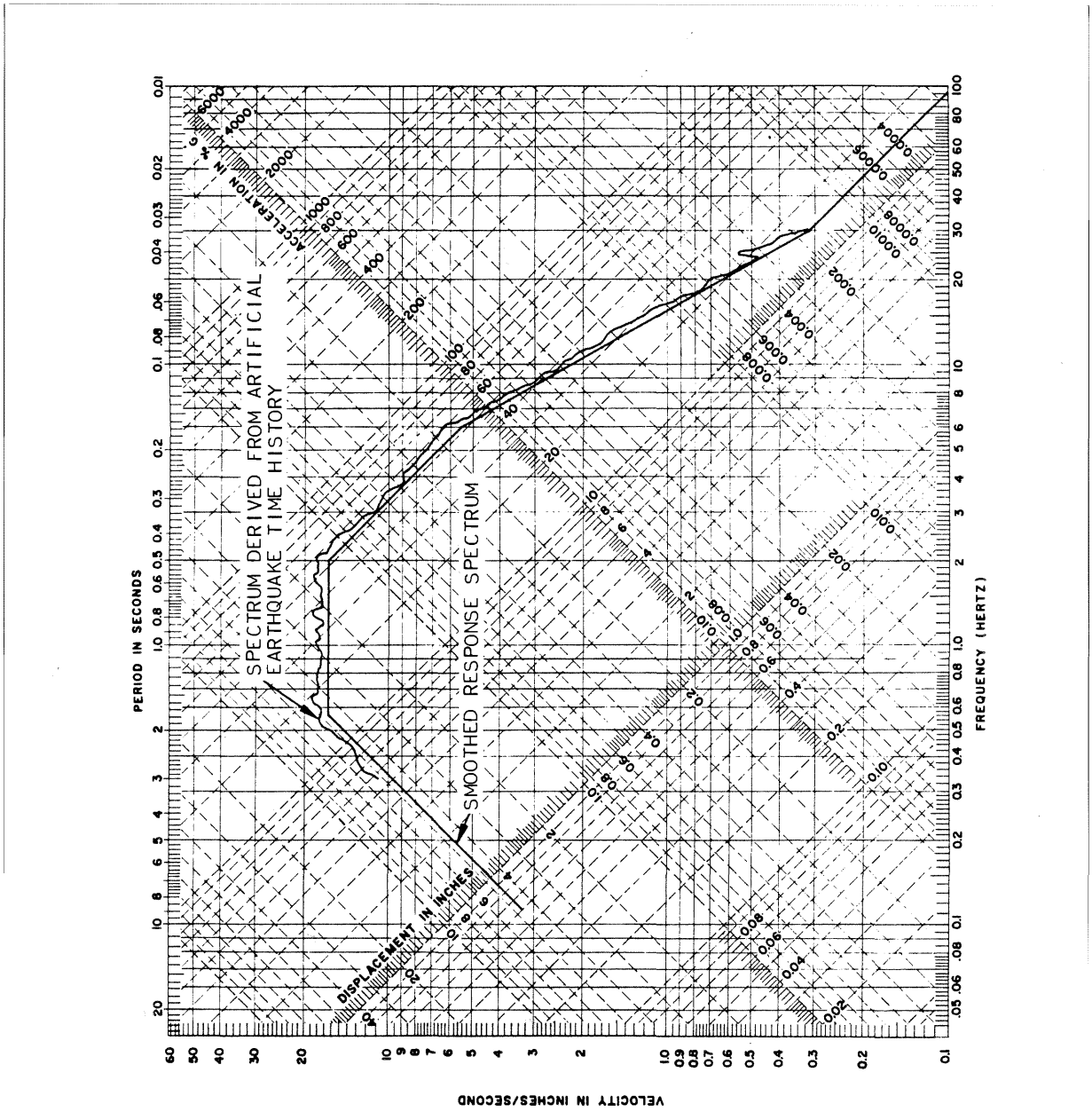
RESPONSE SPECTRA OPERATING BASIS EARTHQUAKE, STRUCTURES FOUNDED ON SOIL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectra Operating Basis Earthquake, Structures Founded on Soil Figure 3.7-4

Figure 3.7-5

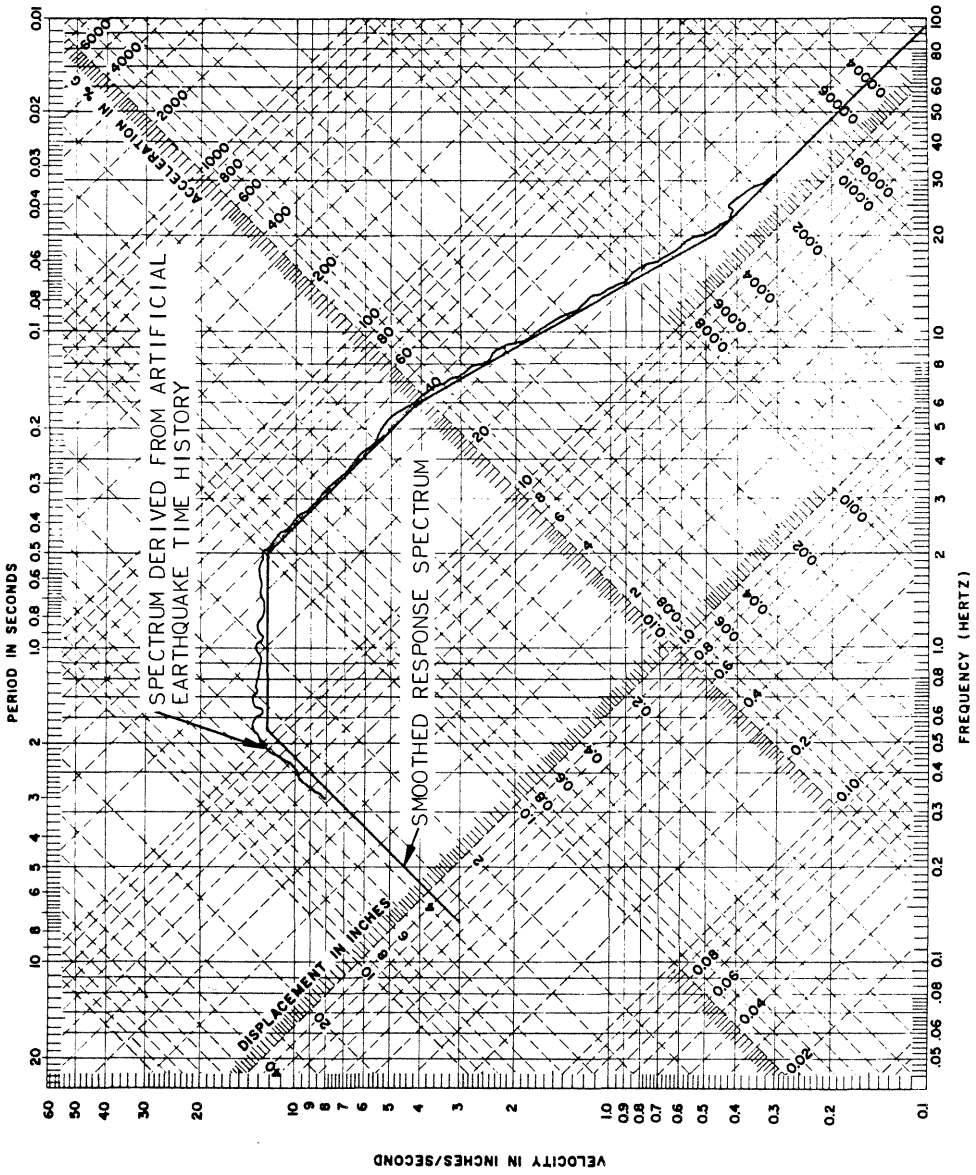
COMPARISON OF RESPONSE SPECTRA AT 2 PERCENT CRITICAL DAMPING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Comparison of Response Spectra at 2 Percent Critical Damping Figure 3.7-5

Figure 3.7-6

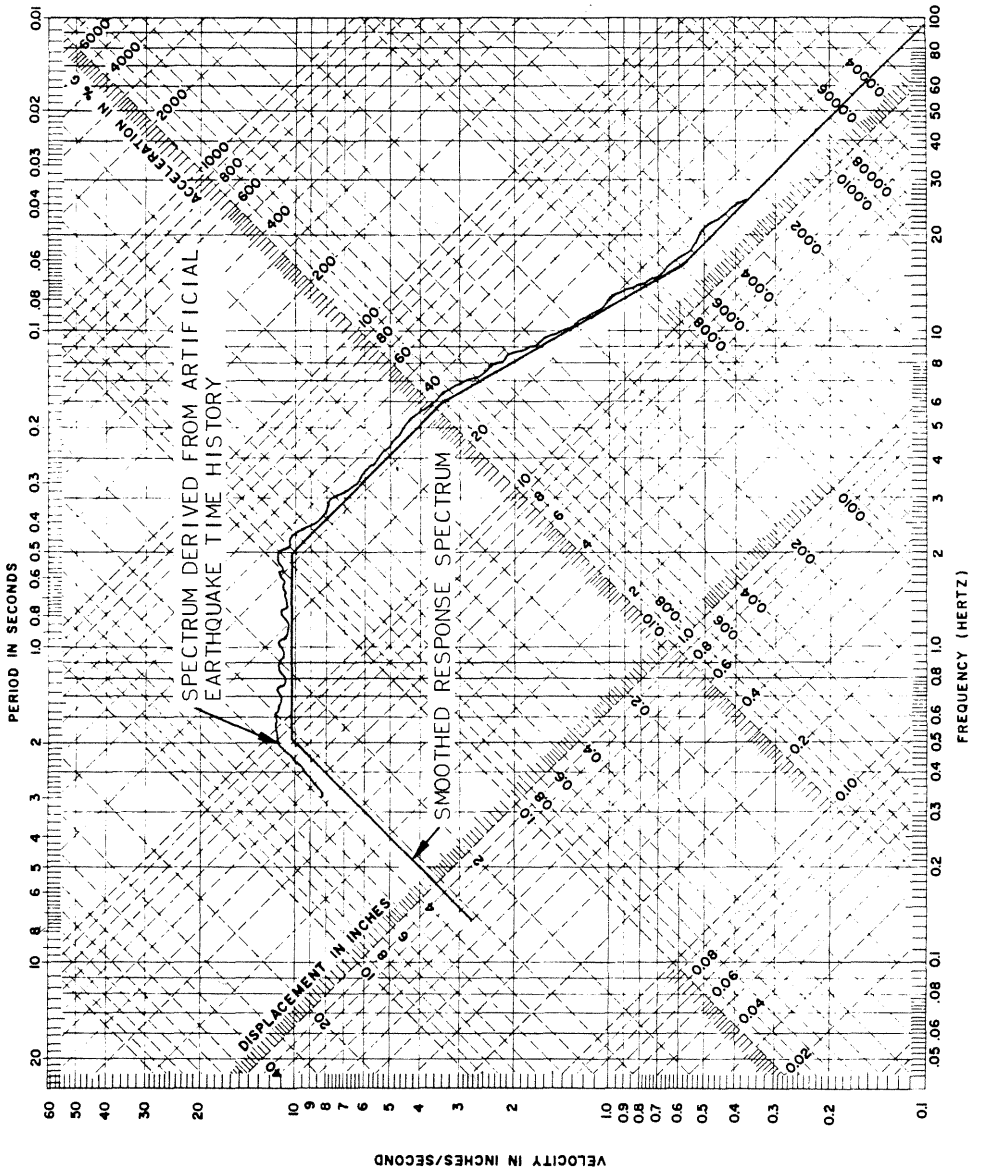
COMPARISON OF RESPONSE SPECTRA AT 5 PERCENT CRITICAL DAMPING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Comparison of Response Spectra at 5 Percent Critical Damping Figure 3.7-6

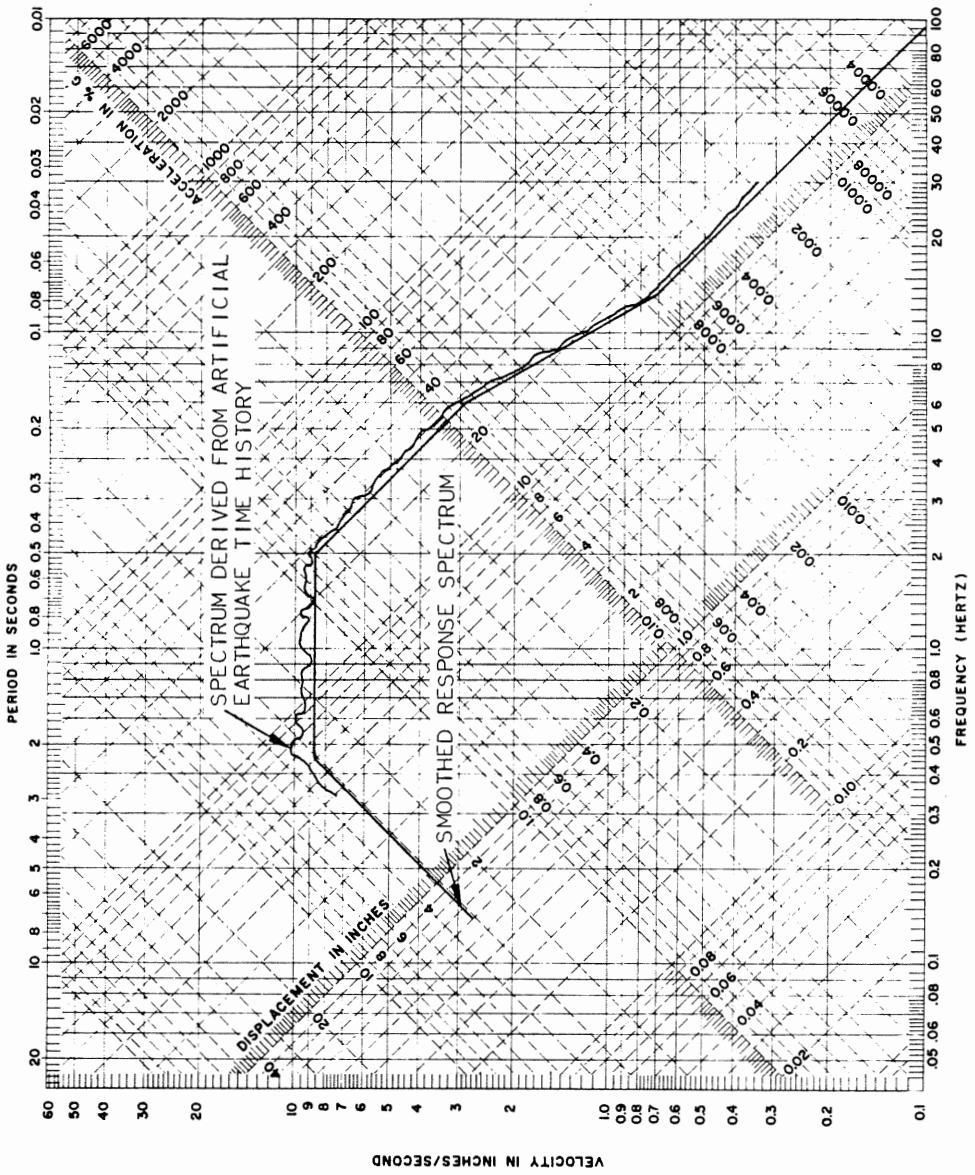
Figure 3.7-7

COMPARISON OF RESPONSE SPECTRA AT 7 PERCENT CRITICAL DAMPING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Comparison of Response Spectra at 7 Percent Critical Damping Figure 3.7-7

Figure 3.7-8
COMPARISON OF RESPONSE SPECTRA AT 10 PERCENT CRITICAL DAMPING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Comparison of Response Spectra at 10 Percent Critical Damping
Figure 3.7-8

Figure 3.7-9

LUMPED MASS MODEL REACTOR BUILDING SHELL AND INTERIOR CONCRETE

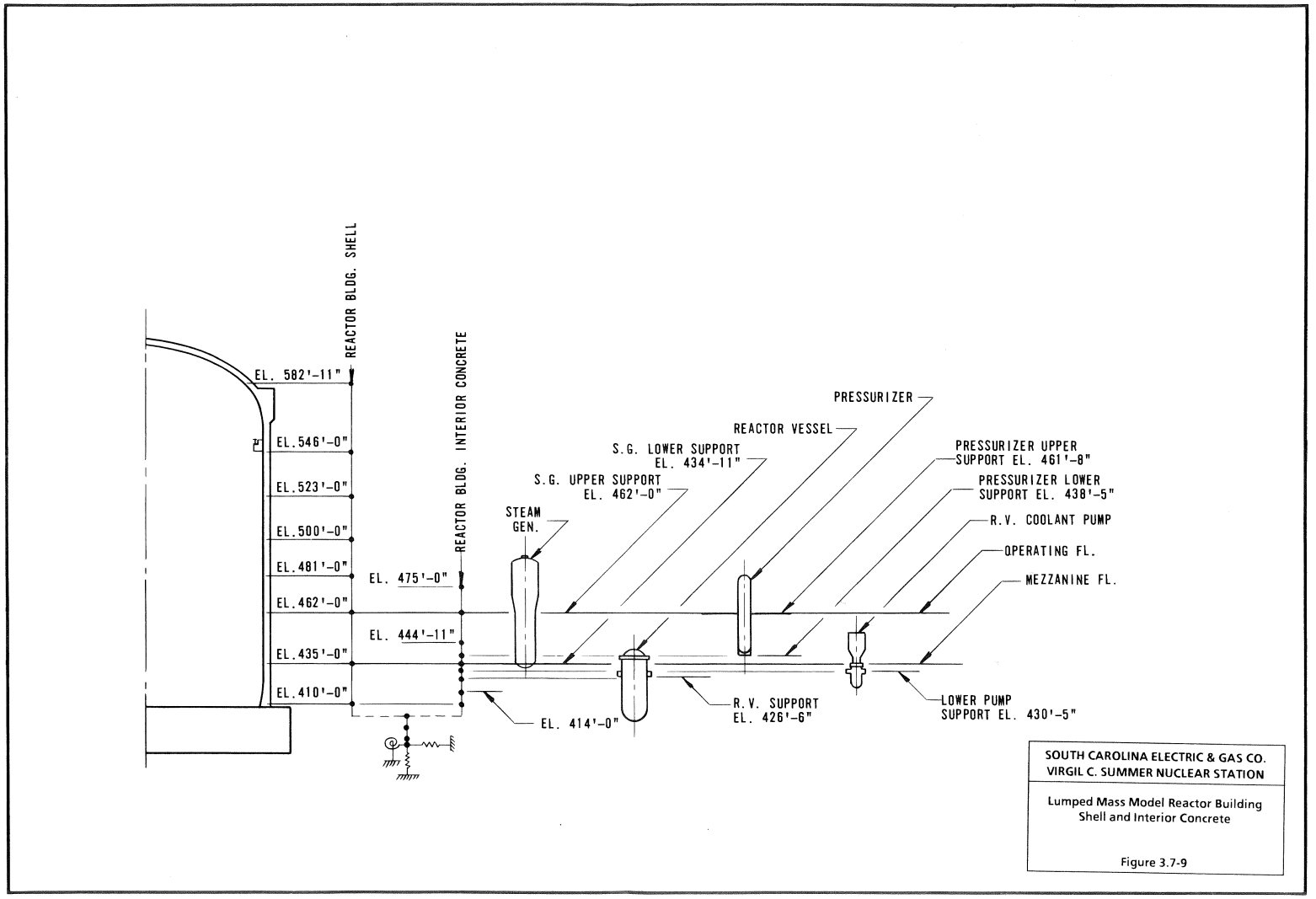
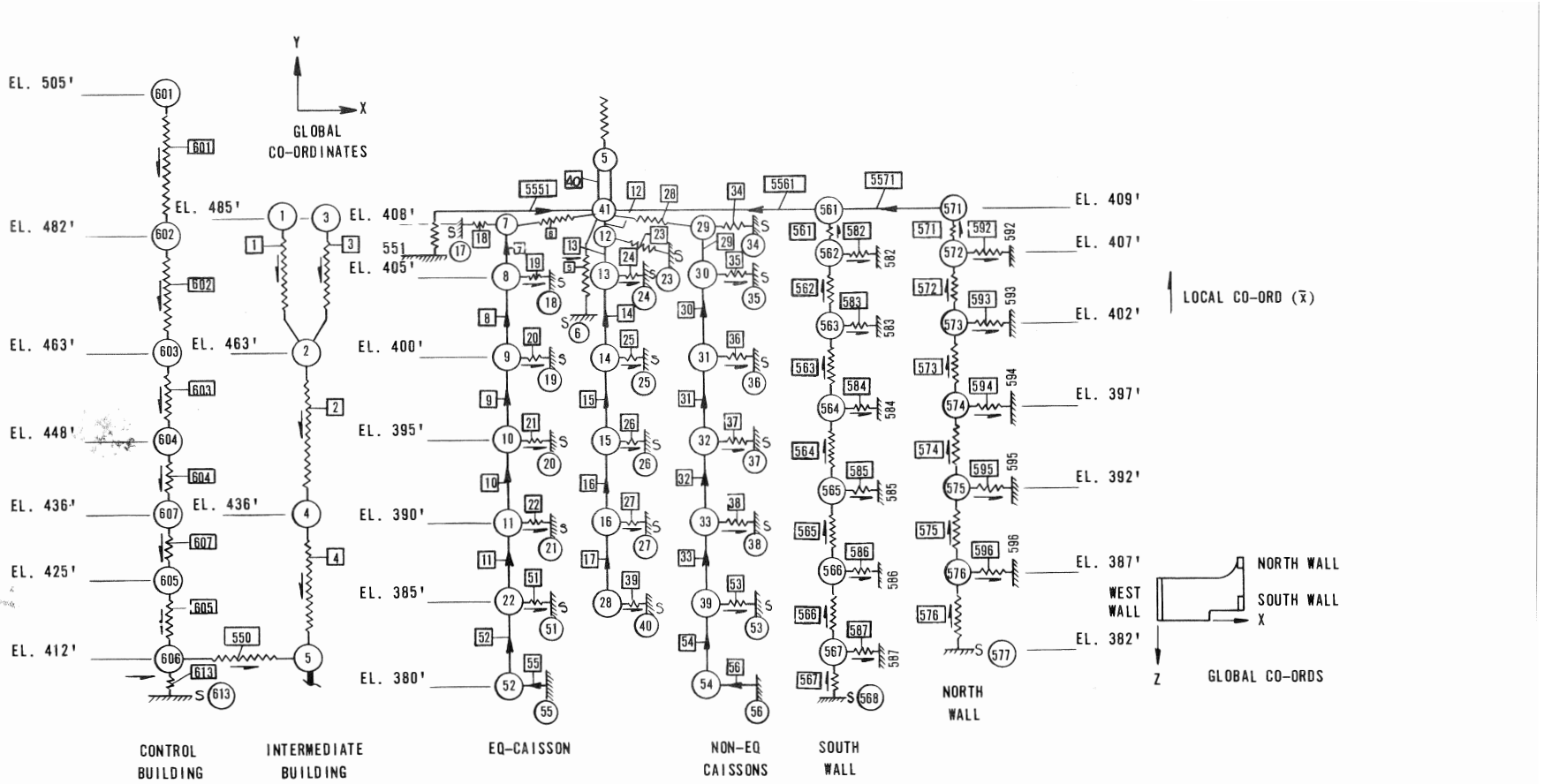


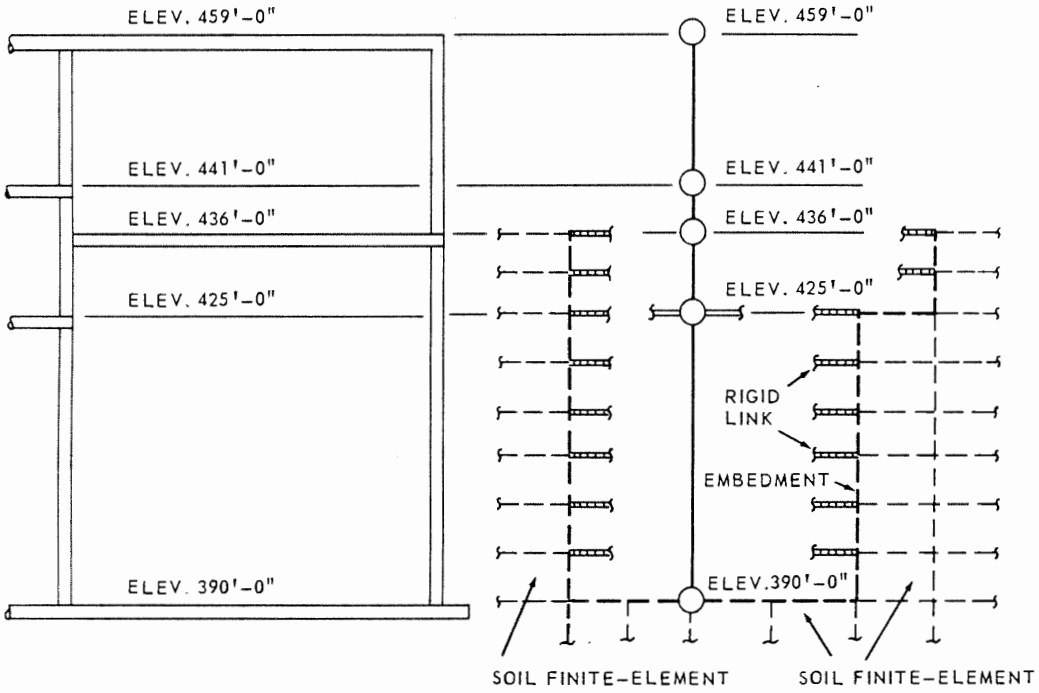
Figure 3.7-10

LUMPED MASS MODEL OF INTERMEDIATE BUILDING



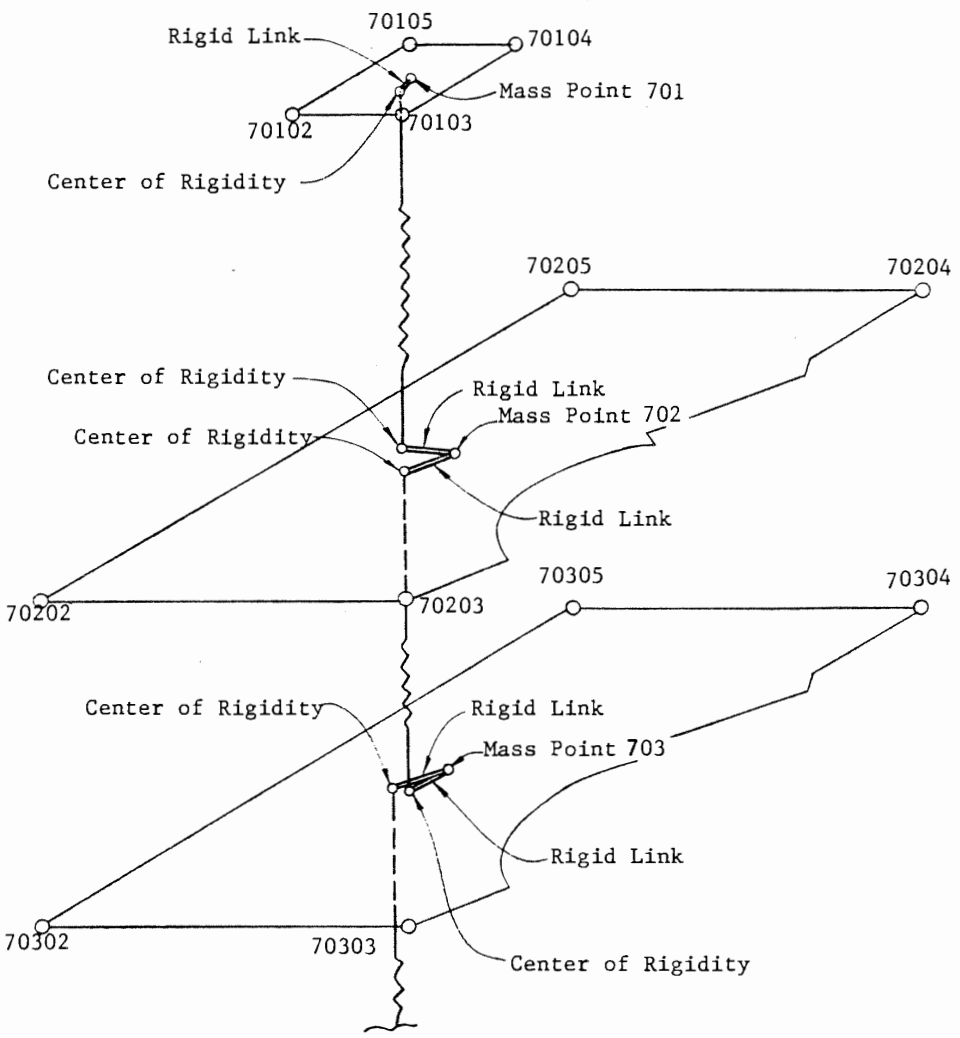
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Lumped Mass Model of Intermediate Building Figure 3.7-10

Figure 3.7-11
FINITE ELEMENT MODEL OF THE SERVICE WATER PUMPHOUSE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Finite Element Model of the Service Water Pumphouse Figure 3.7-11

Figure 3.7-11a
TYPICAL TORSIONAL MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Torsional Model Figure 3.7-11a

Figure 3.7-12
MULTI-DEGREE-OF-FREEDOM SYSTEM

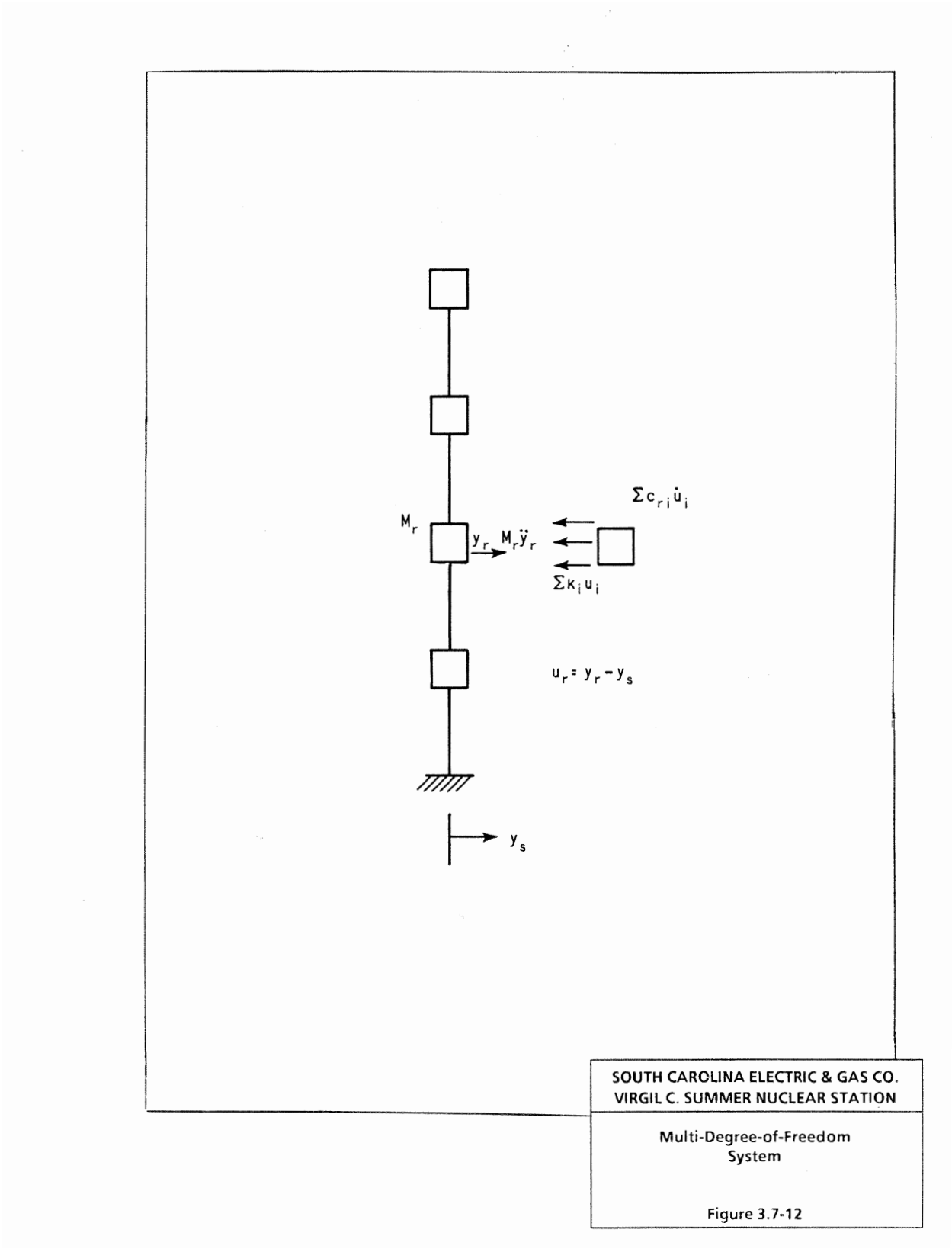
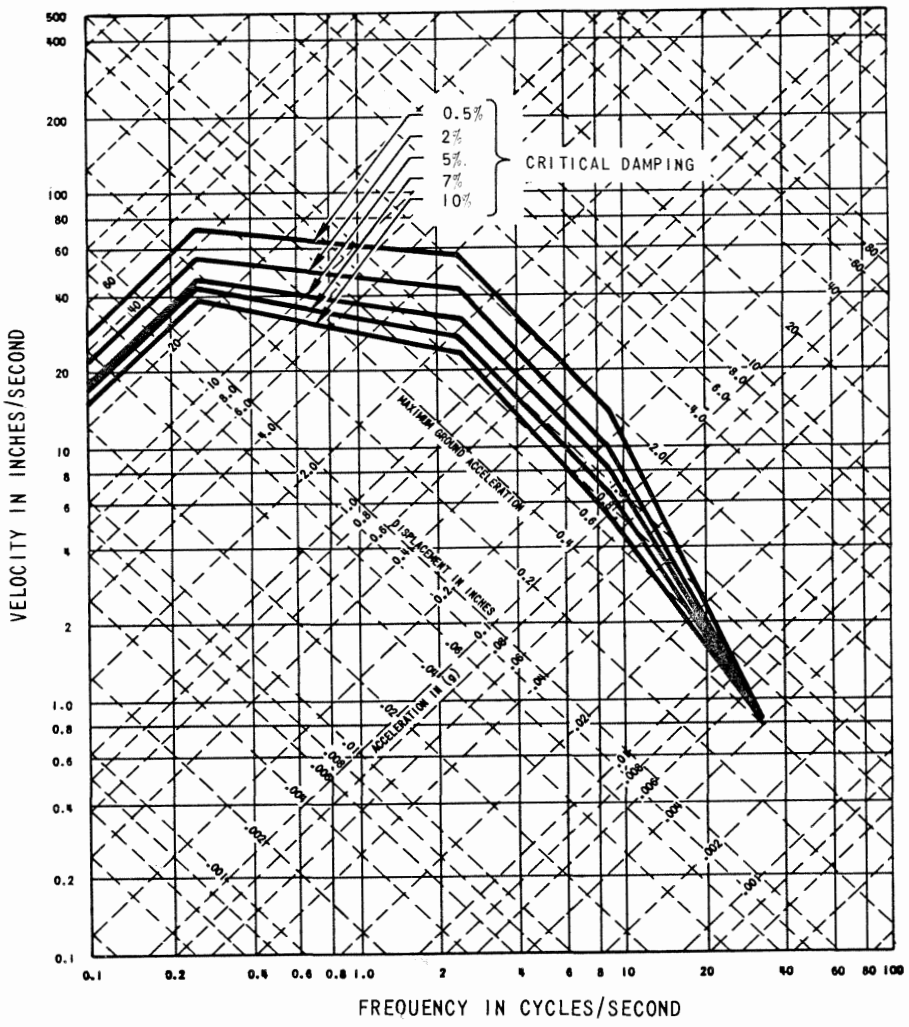


Figure 3.7-13

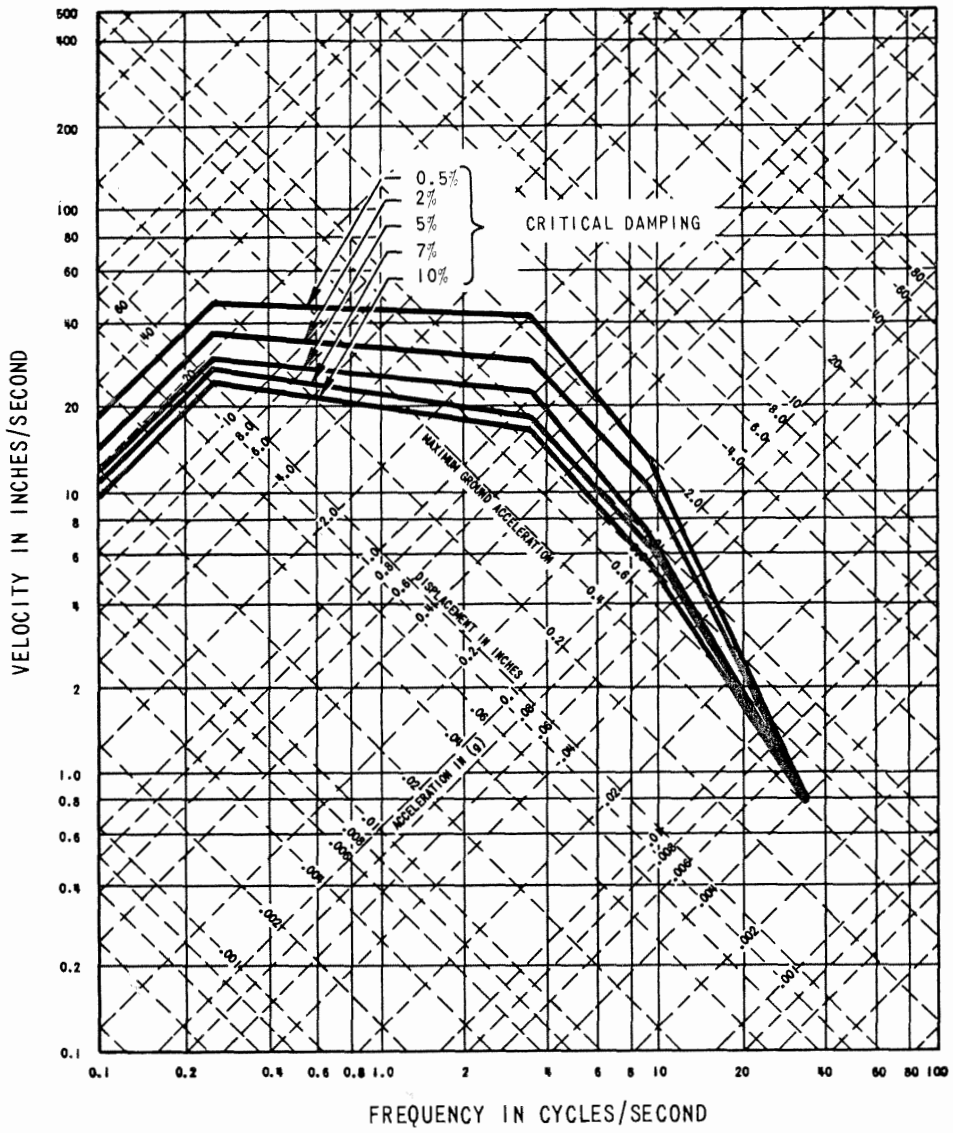
HORIZONTAL DESIGN RESPONSE SPECTRA-
SCALED TO 0.4G HORIZONTAL GROUND ACCELERATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Horizontal Design Response Spectra - Scaled to 0.4g Horizontal Ground Acceleration Figure 3.7-13

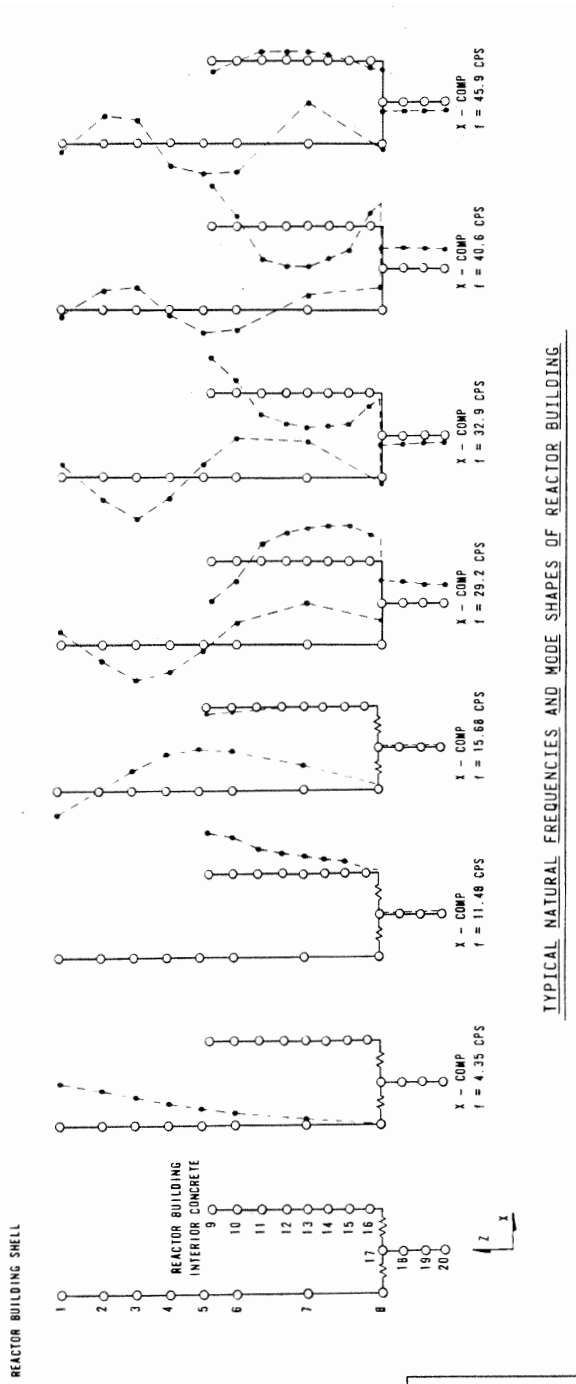
Figure 3.7-14

VERTICAL DESIGN RESPONSE SPECTRA-
SCALED TO 0.4G HORIZONTAL GROUND ACCELERATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Vertical Design Response Spectra - Scaled to 0.4g Horizontal Ground Acceleration Figure 3.7-14

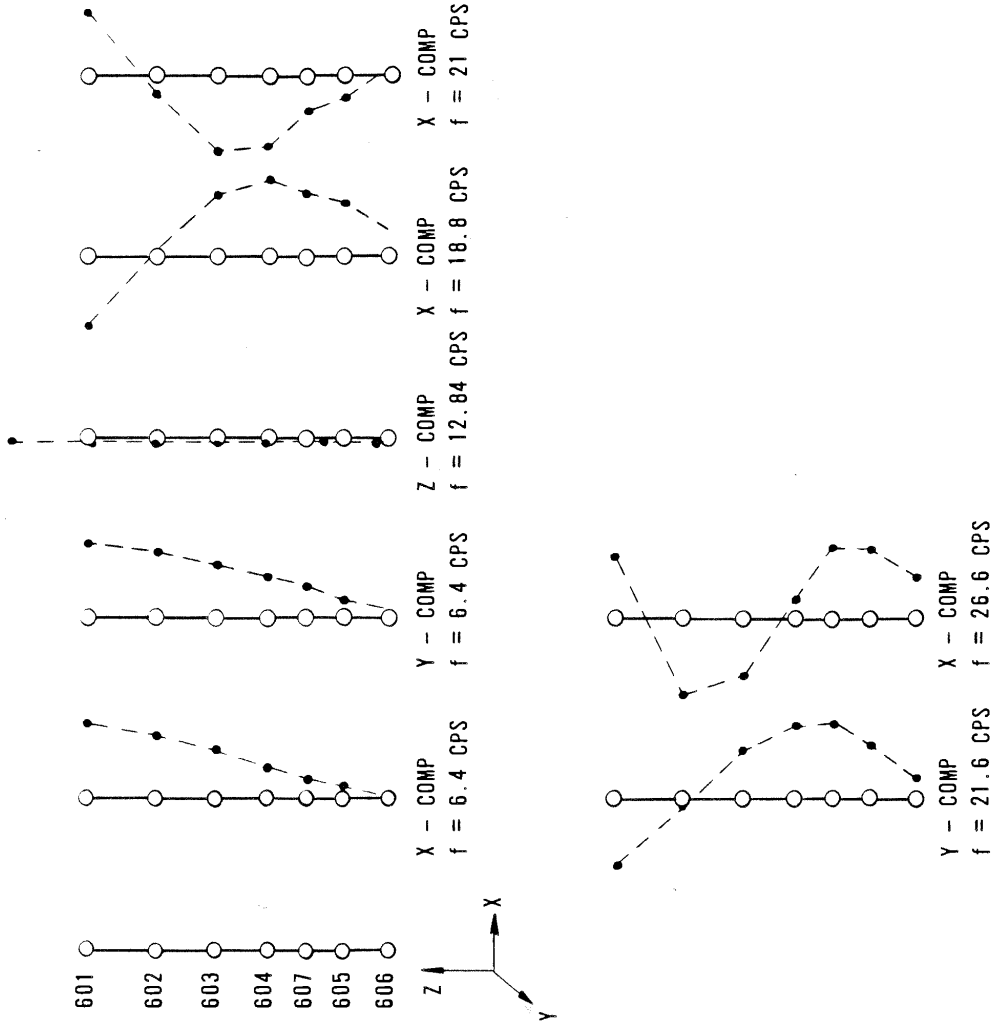
Figure 3.7-15
TYPICAL NATURAL FREQUENCIES AND MODE SHAPES OF THE REACTOR BUILDING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Natural Frequencies and Mode Shapes of the Reactor Building
Figure 3.7-15

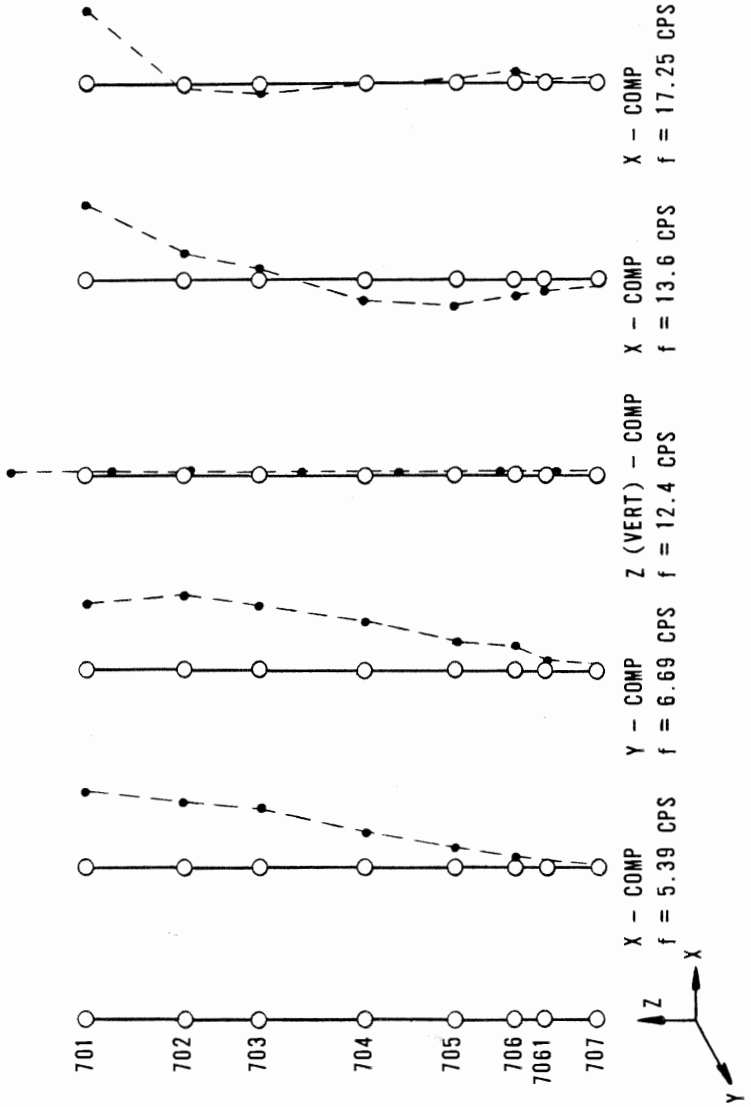
Figure 3.7-16

TYPICAL NATURAL FREQUENCIES AND MODE SHAPES OF THE CONTROL BUILDING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Natural Frequencies and Mode Shapes of the Control Building Figure 3.7-16

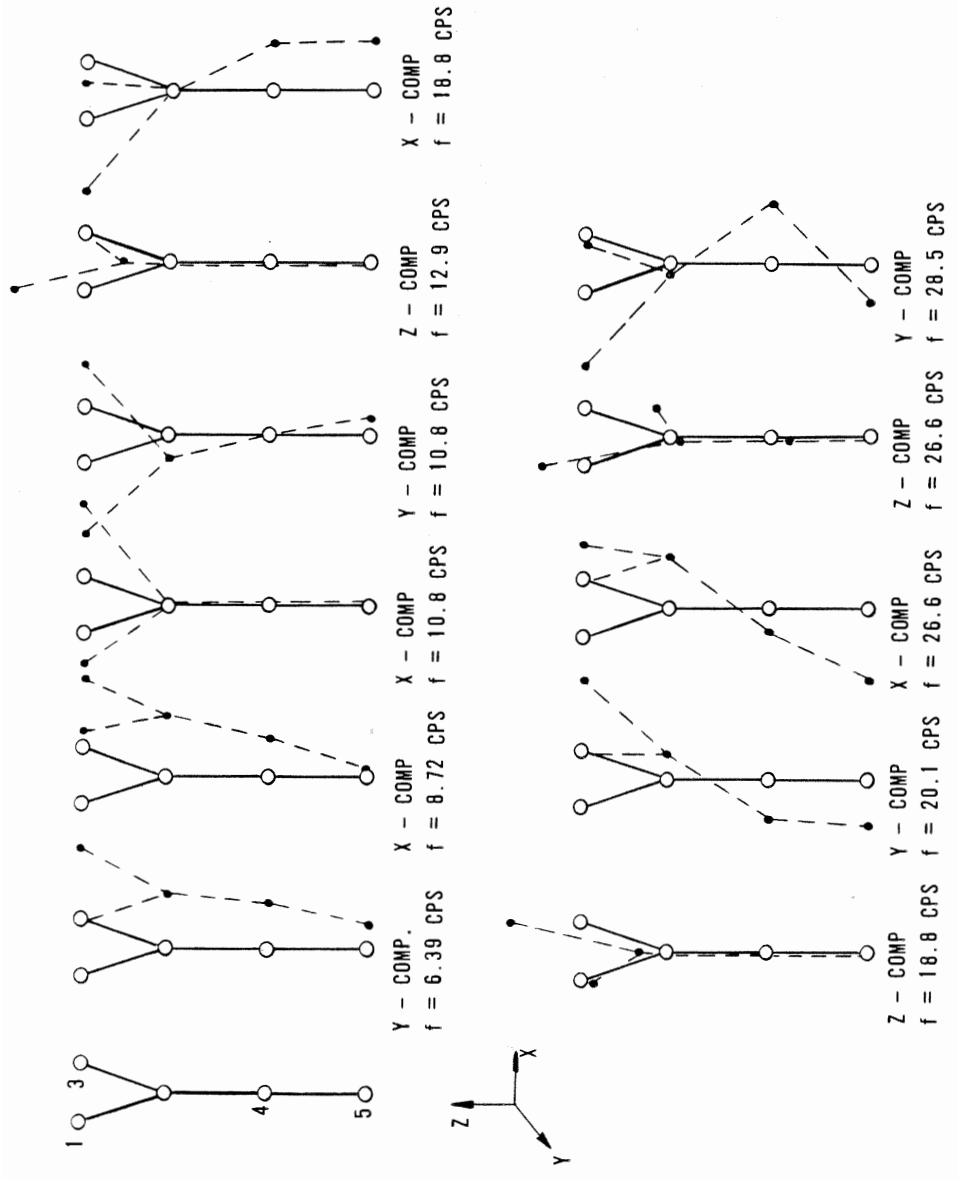
Figure 3.7-17
TYPICAL NATURAL FREQUENCIES AND MODE SHAPES OF THE AUXILIARY BUILDING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Natural Frequencies and Mode Shapes of the Auxiliary Building Figure 3.7-17

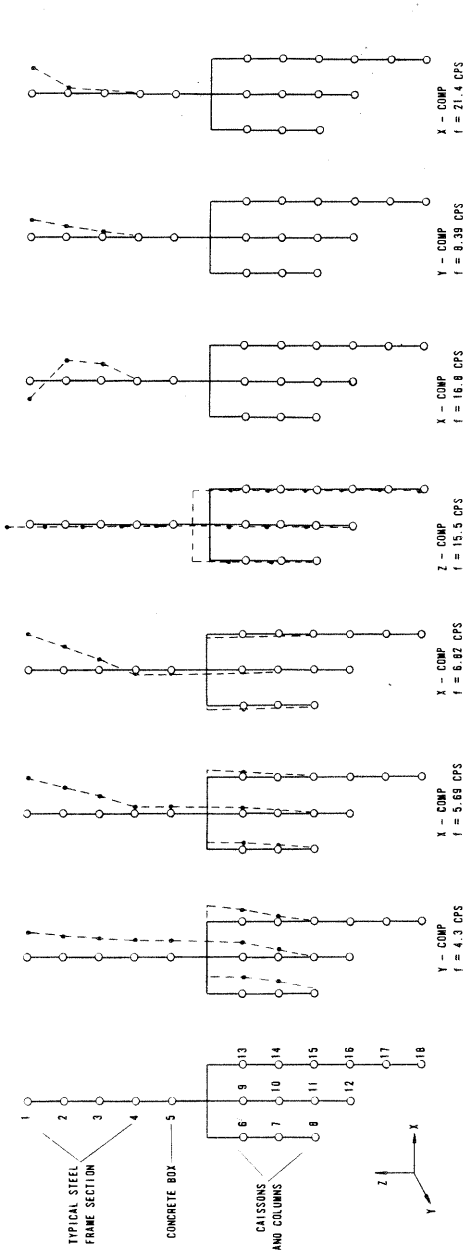
Figure 3.7-18

TYPICAL NATURAL FREQUENCIES AND MODE SHAPES OF THE INTERMEDIATE BUILDING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Natural Frequencies and Mode Shapes of the Intermediate Building
Figure 3.7-18

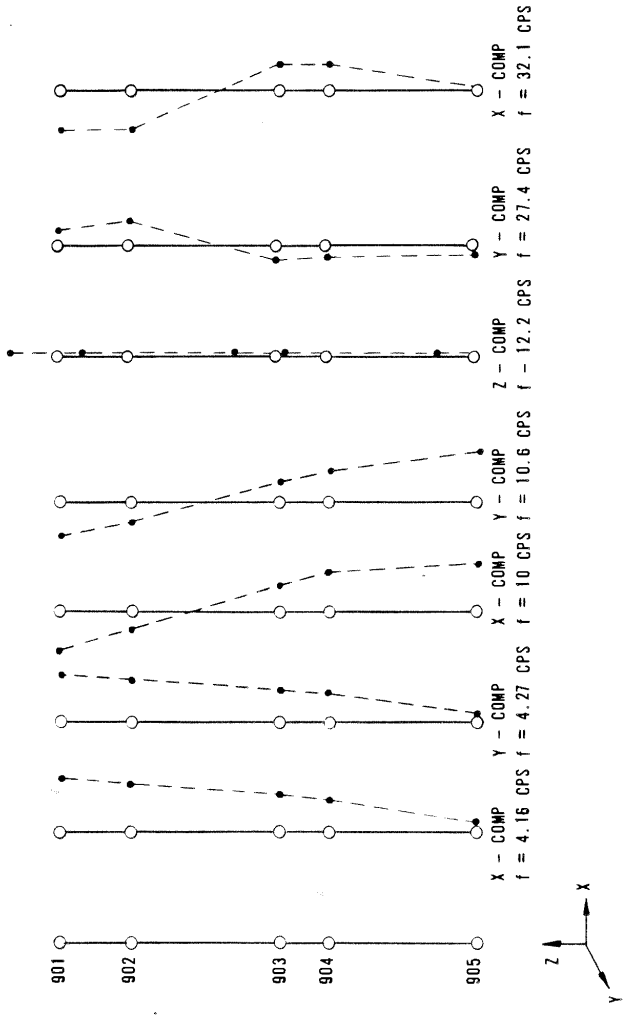
Figure 3.7-19
TYPICAL NATURAL FREQUENCIES AND MODE SHAPES OF THE FUEL HANDLING BUILDING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Natural Frequencies and Mode Shapes of the Fuel Handling Building
Figure 3.7-19

Figure 3.7-20

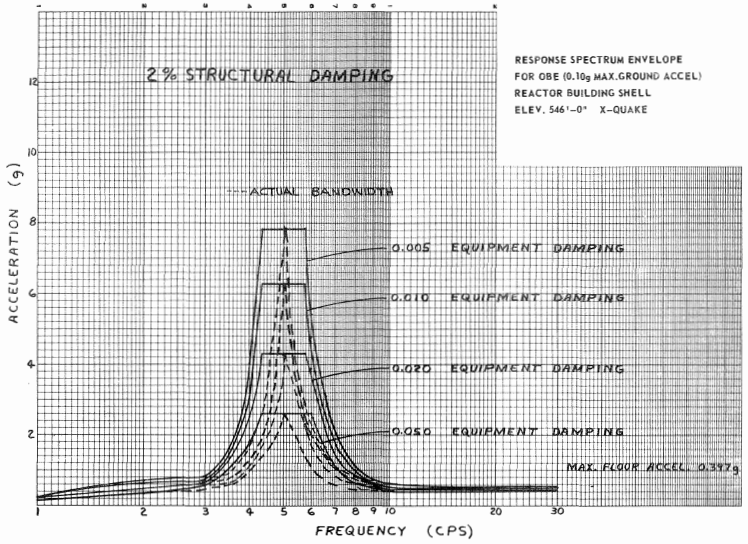
TYPICAL NATURAL FREQUENCIES AND MODE SHAPES OF THE DIESEL GENERATOR BUILDING

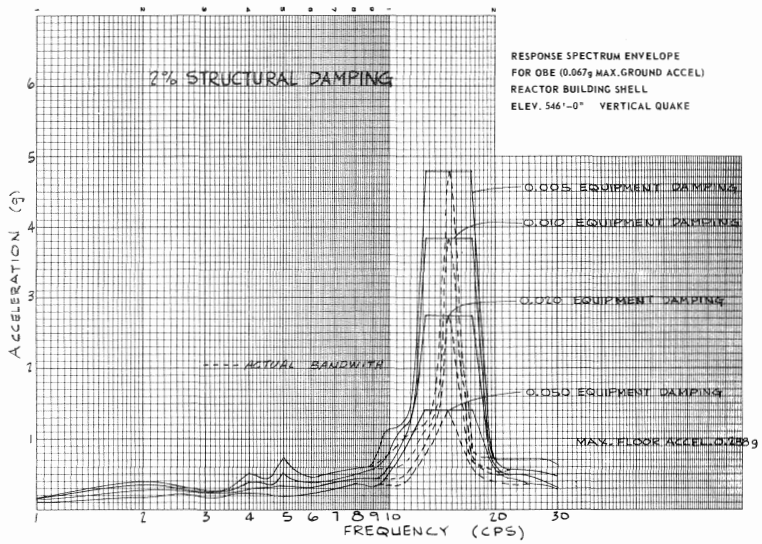


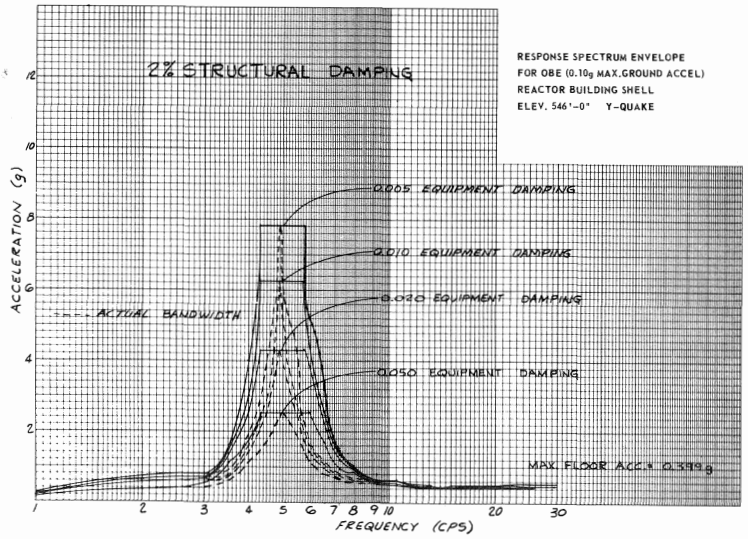
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Natural Frequencies and Mode Shapes of the Diesel Generator Building Figure 3.7-20

Figure 3.7-21

RESPONSE SPECTRUM ENVELOPES REACTOR BUILDING SHELL ELEVATION 546' - 0"



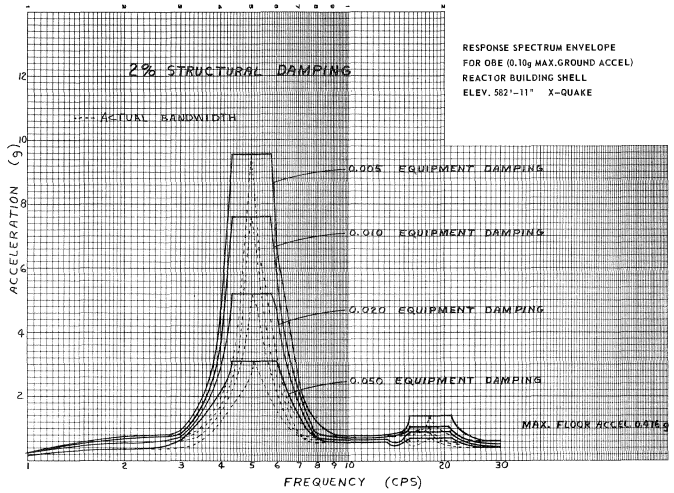


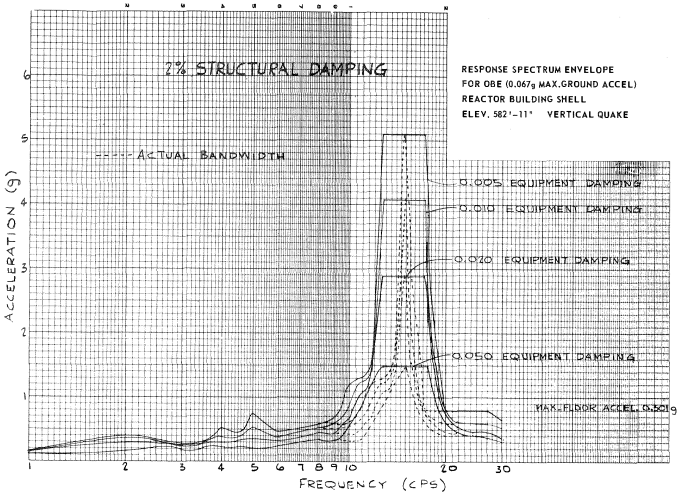


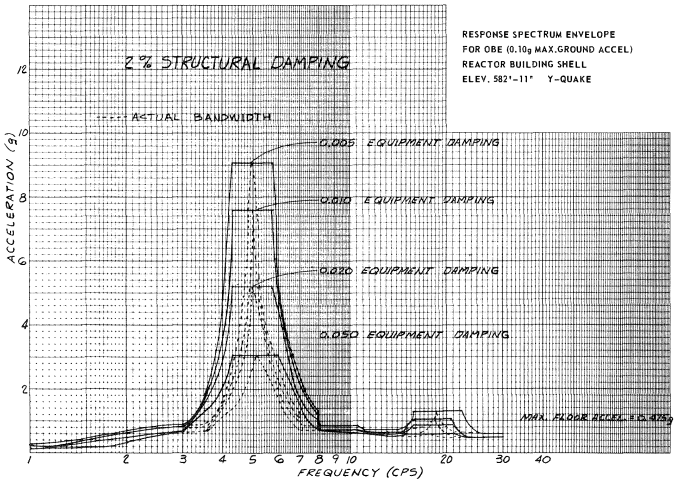
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Reactor Building Shell Elevation 546' - 0" Figure 3.7-21

Figure 3.7-22

RESPONSE SPECTRUM ENVELOPES REACTOR BUILDING SHELL ELEVATION 582' - 11"



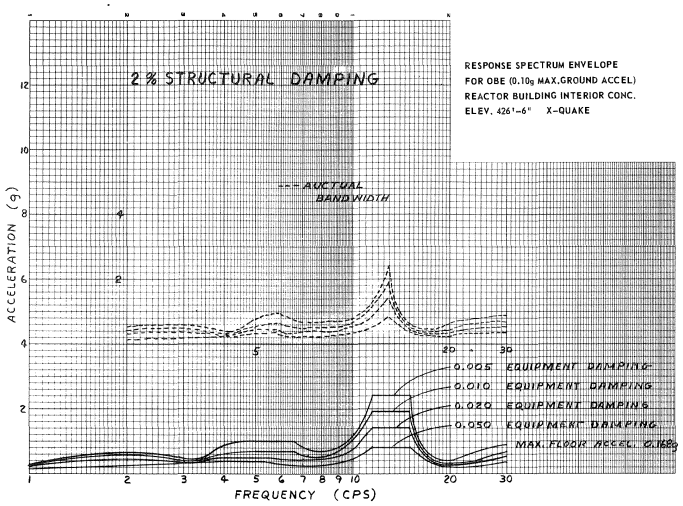


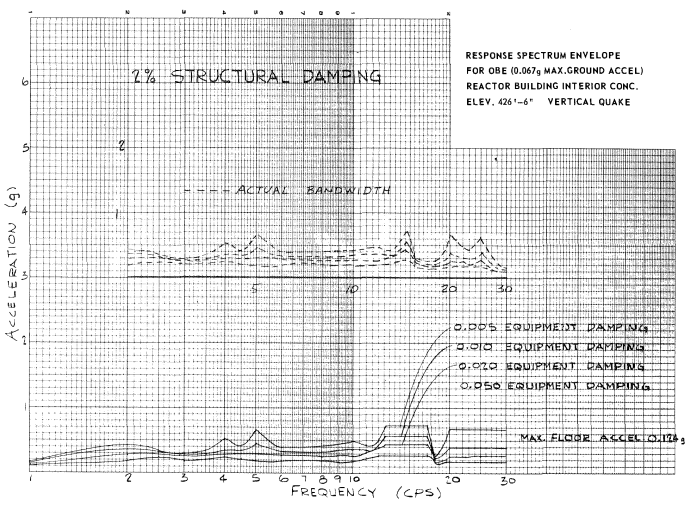


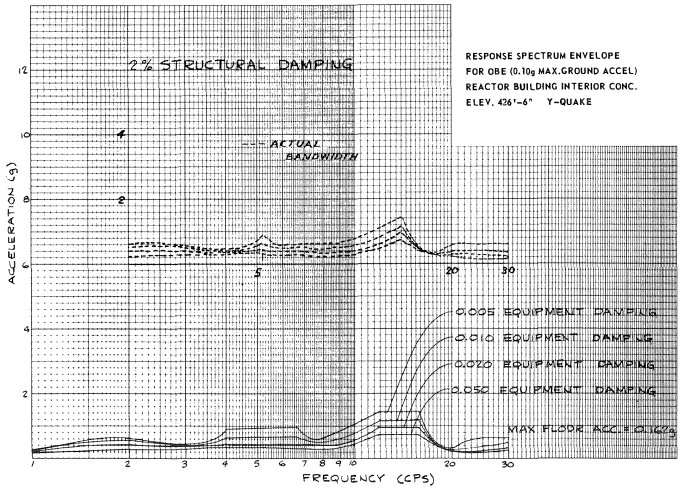
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Reactor Building Shell Elevation 582' - 11" Figure 3.7-22

Figure 3.7-23

RESPONSE SPECTRUM ENVELOPES REACTOR BUILDING INTERIOR CONCRETE 426' - 6"



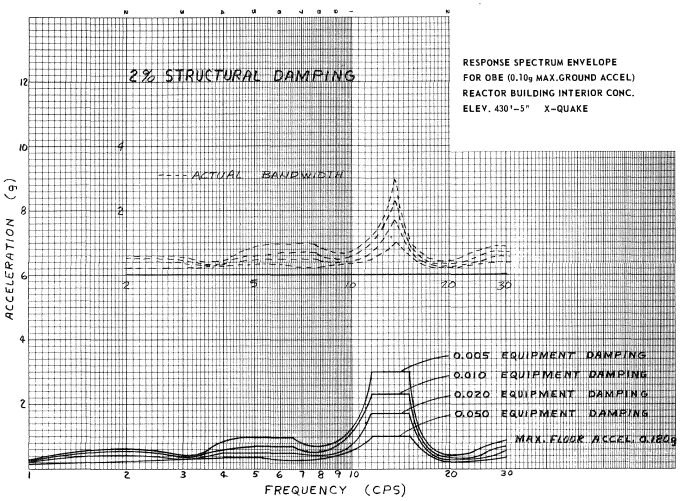


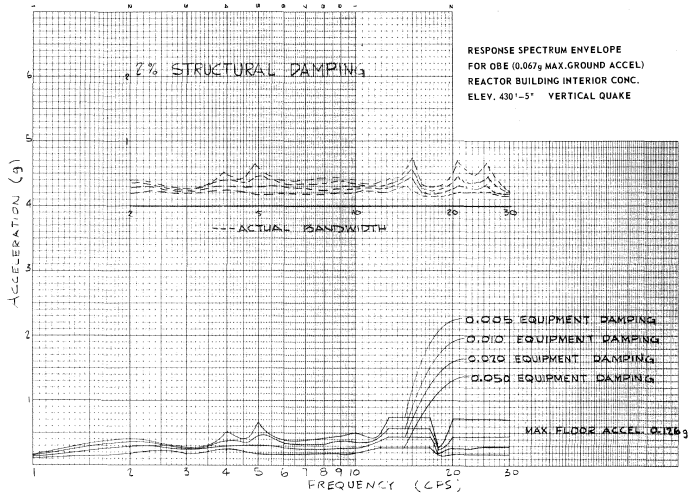


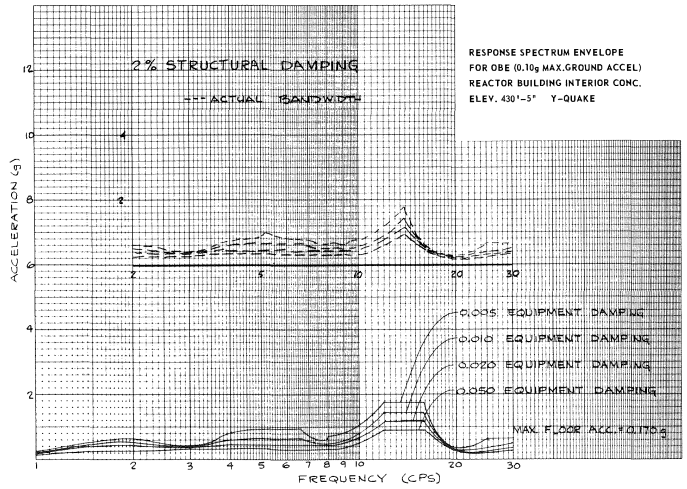
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Reactor Building Interior Concrete Elevation 426' - 6" Figure 3.7-23

Figure 3.7-24

RESPONSE SPECTRUM ENVELOPES REACTOR BUILDING INTERIOR CONCRETE 430' - 5"



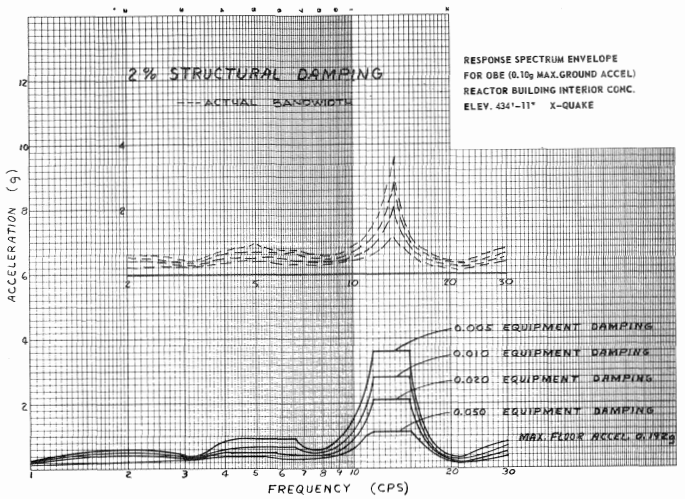


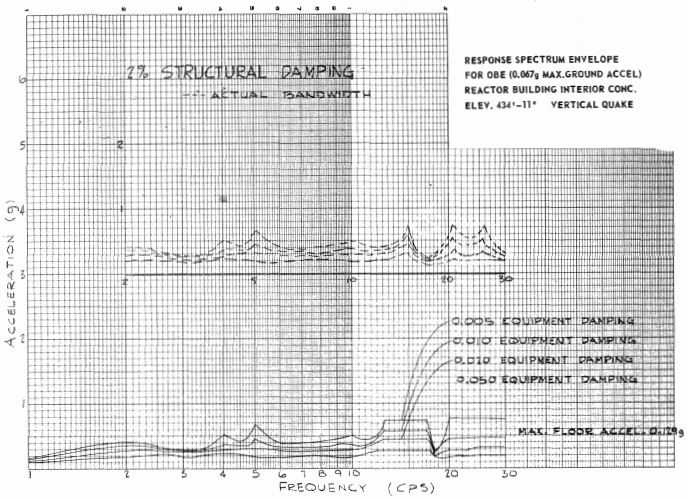


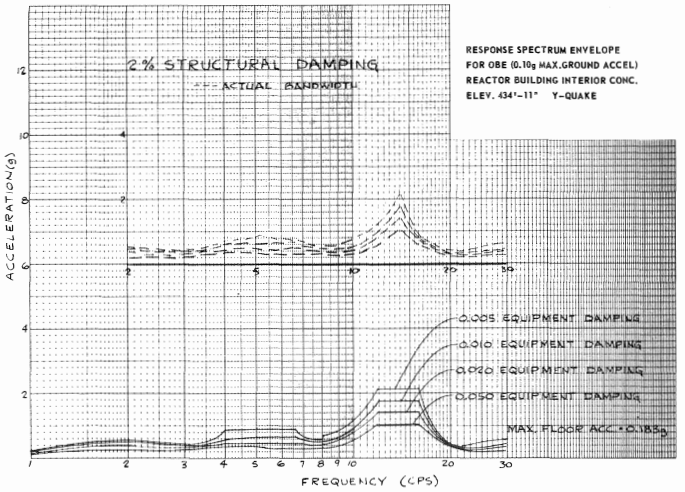
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Reactor Building Interior Concrete Elevation 430' - 5"
Figure 3.7-24

Figure 3.7-25

RESPONSE SPECTRUM ENVELOPES REACTOR BUILDING INTERIOR CONCRETE 434' - 11



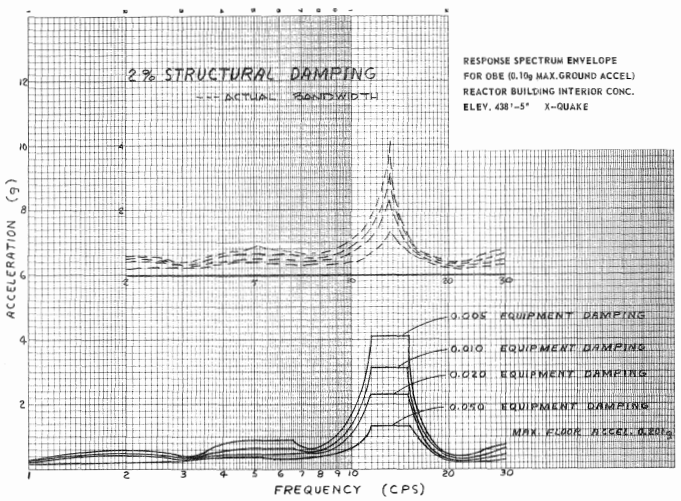


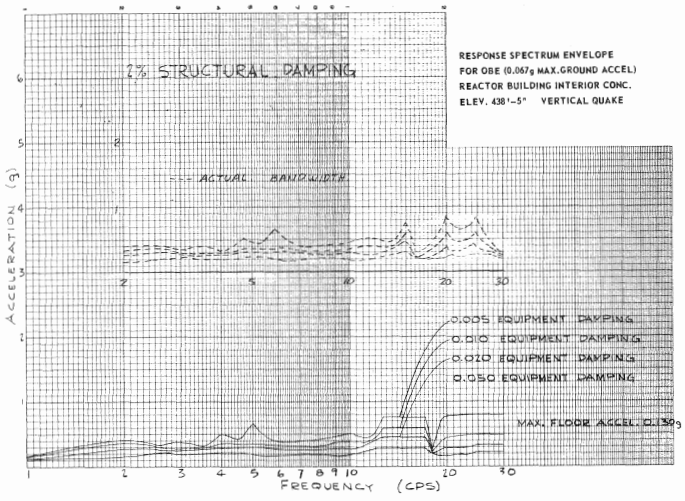


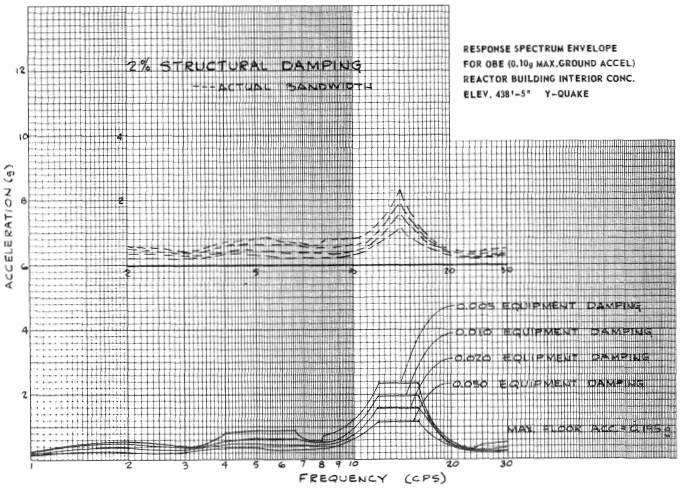
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Reactor Building Interior Concrete Elevation 434' - 11" Figure 3.7-25

Figure 3.7-26

RESPONSE SPECTRUM ENVELOPES REACTOR BUILDING INTERIOR CONCRETE 438' - 5"



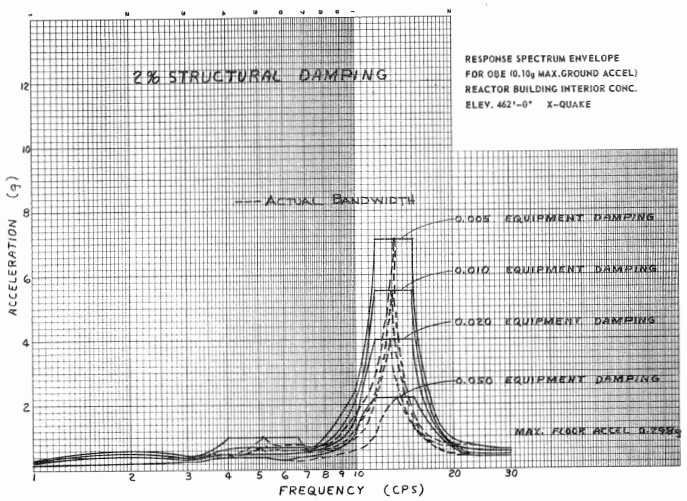


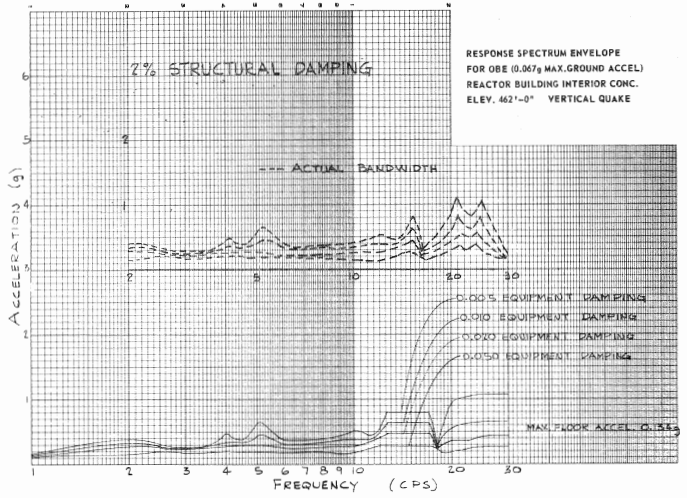


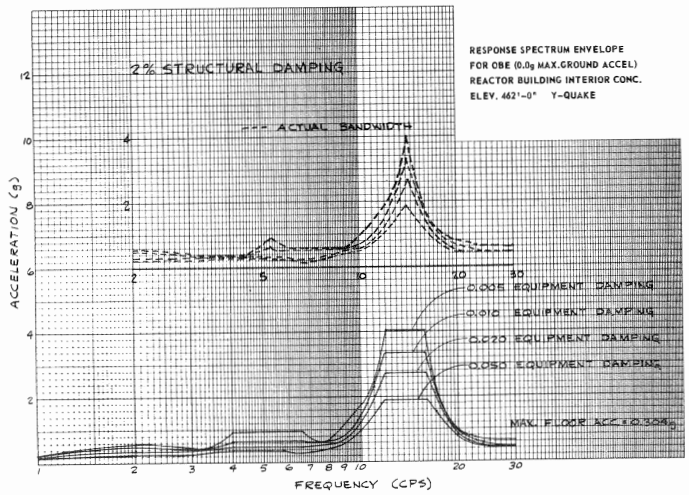
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Reactor Building Interior Concrete Elevation 438' - 5" Figure 3.7-26

Figure 3.7-27

RESPONSE SPECTRUM ENVELOPES REACTOR BUILDING INTERIOR CONCRETE 462' - 0"



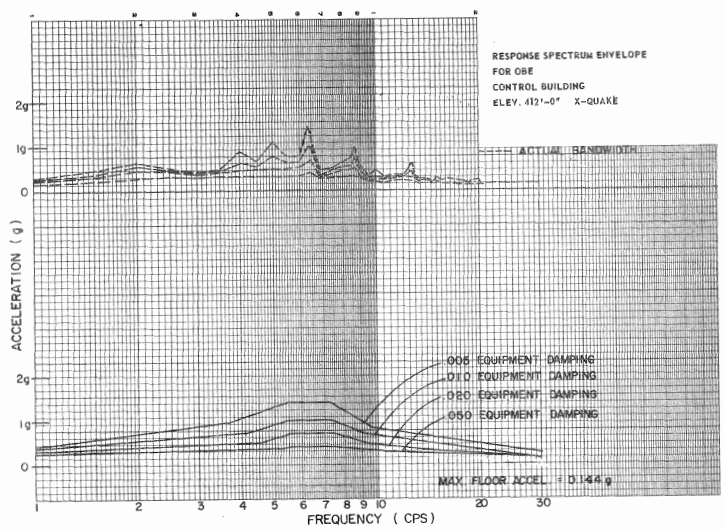


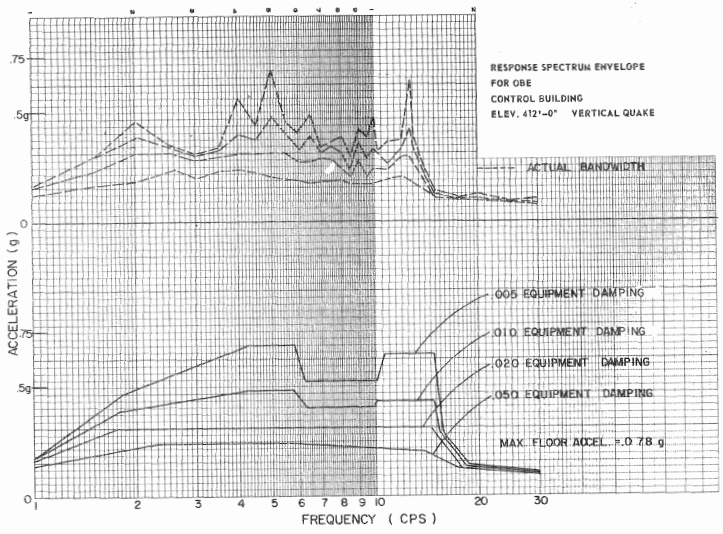


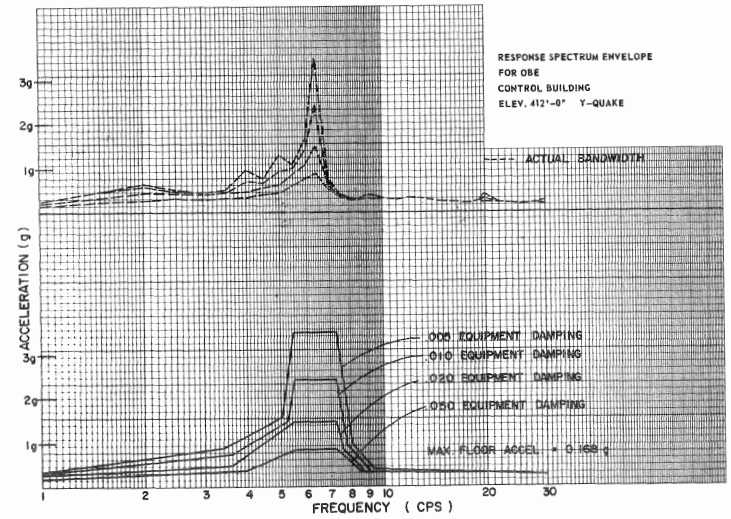
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Reactor Building Interior Concrete Elevation 462' - 0" Figure 3.7-27

Figure 3.7-28

RESPONSE SPECTRUM ENVELOPES CONTROL BUILDING ELEVATION 412' - 0"







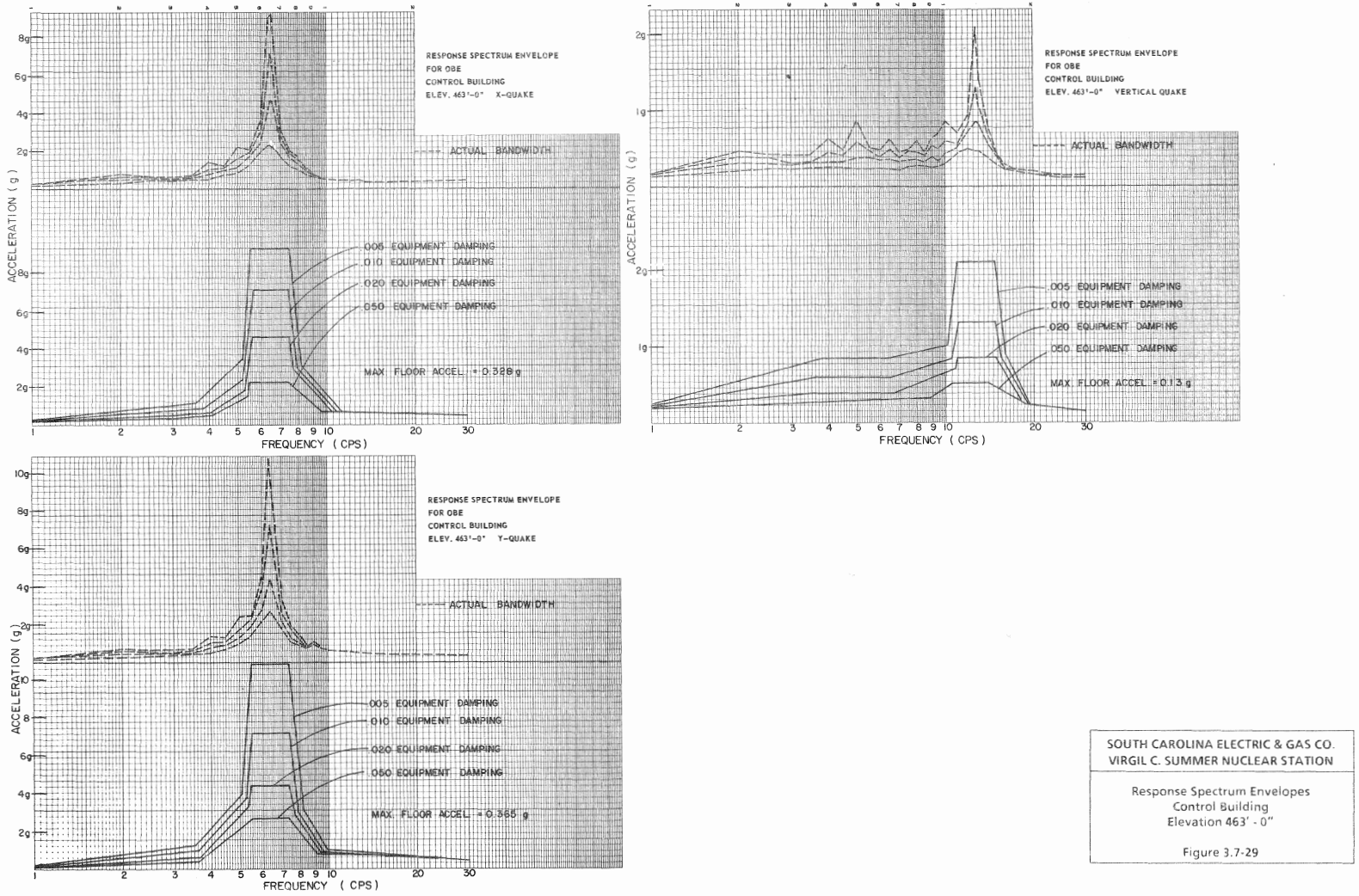
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Response Spectrum Envelopes
Control Building
Elevation 412' - 0"

Figure 3.7-28

Figure 3.7-29

RESPONSE SPECTRUM ENVELOPES CONTROL BUILDING ELEVATION 463' - 0"



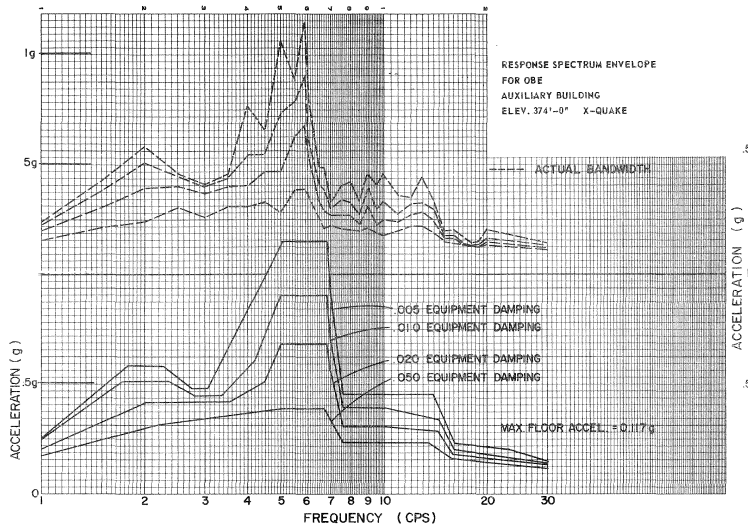
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

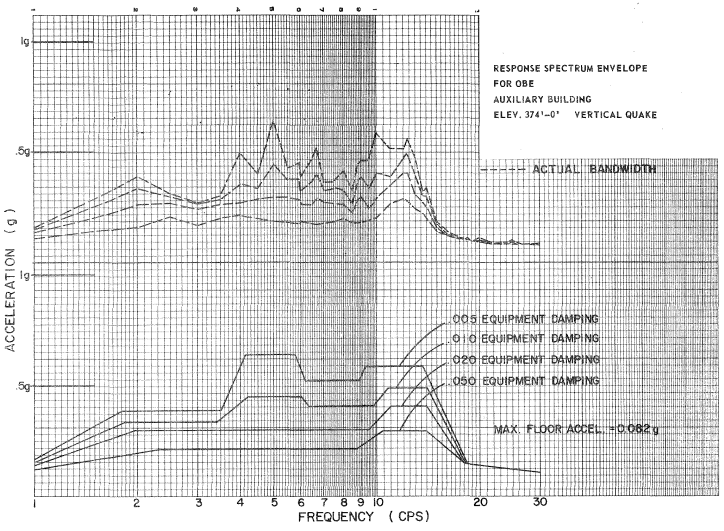
Response Spectrum Envelopes
Control Building
Elevation 463' - 0"

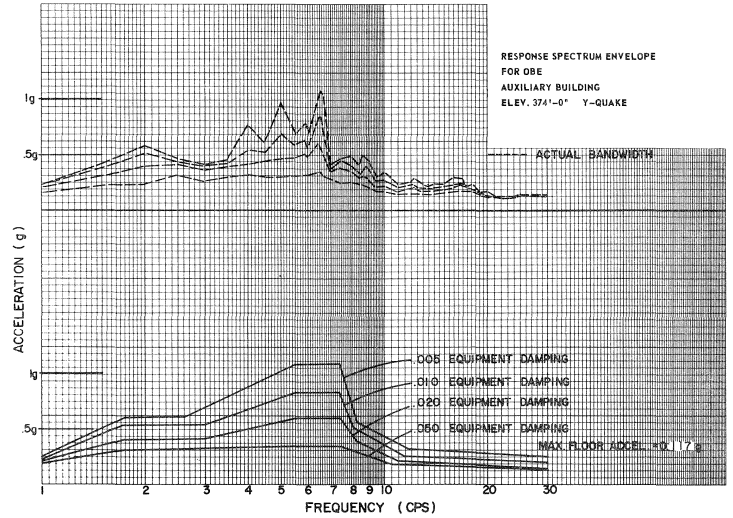
Figure 3.7-29

Figure 3.7-30

RESPONSE SPECTRUM ENVELOPES AUXILIARY BUILDING ELEVATION 374' - 0"



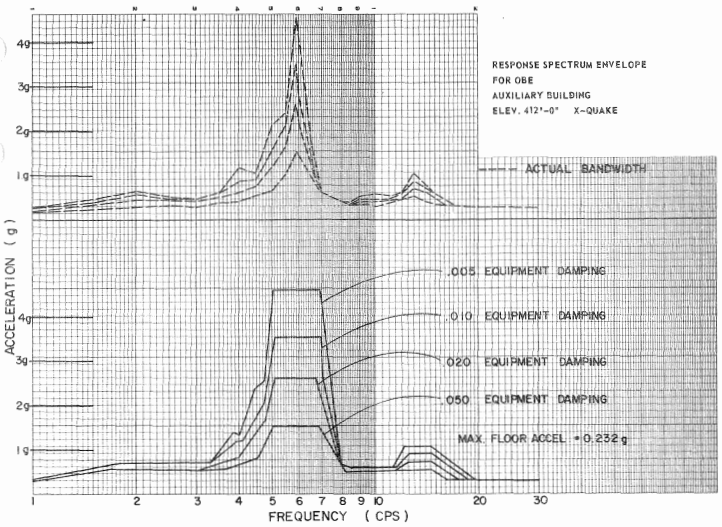


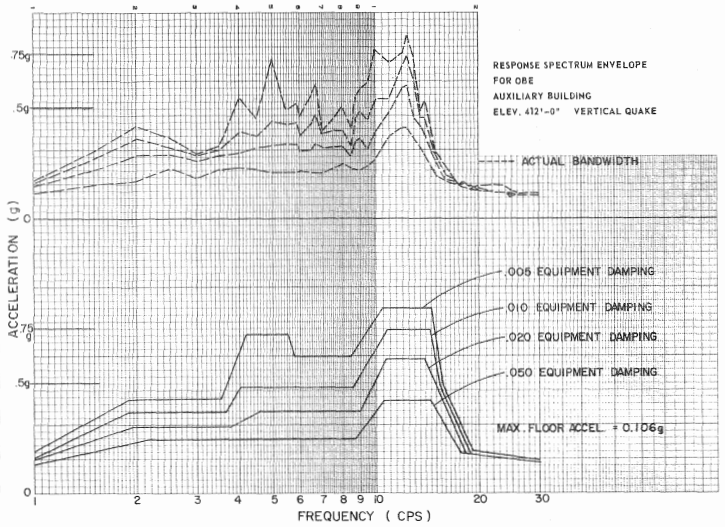


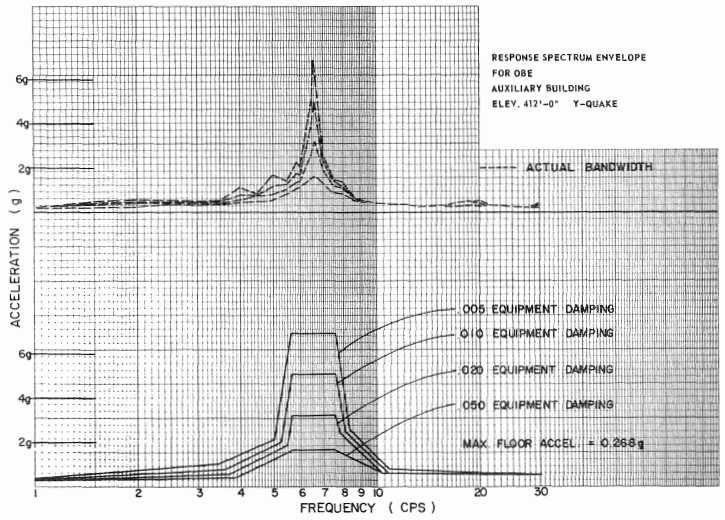
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Auxiliary Building Elevation 374' - 0" Figure 3.7-30

Figure 3.7-31

RESPONSE SPECTRUM ENVELOPES AUXILIARY BUILDING ELEVATION 412' - 0"







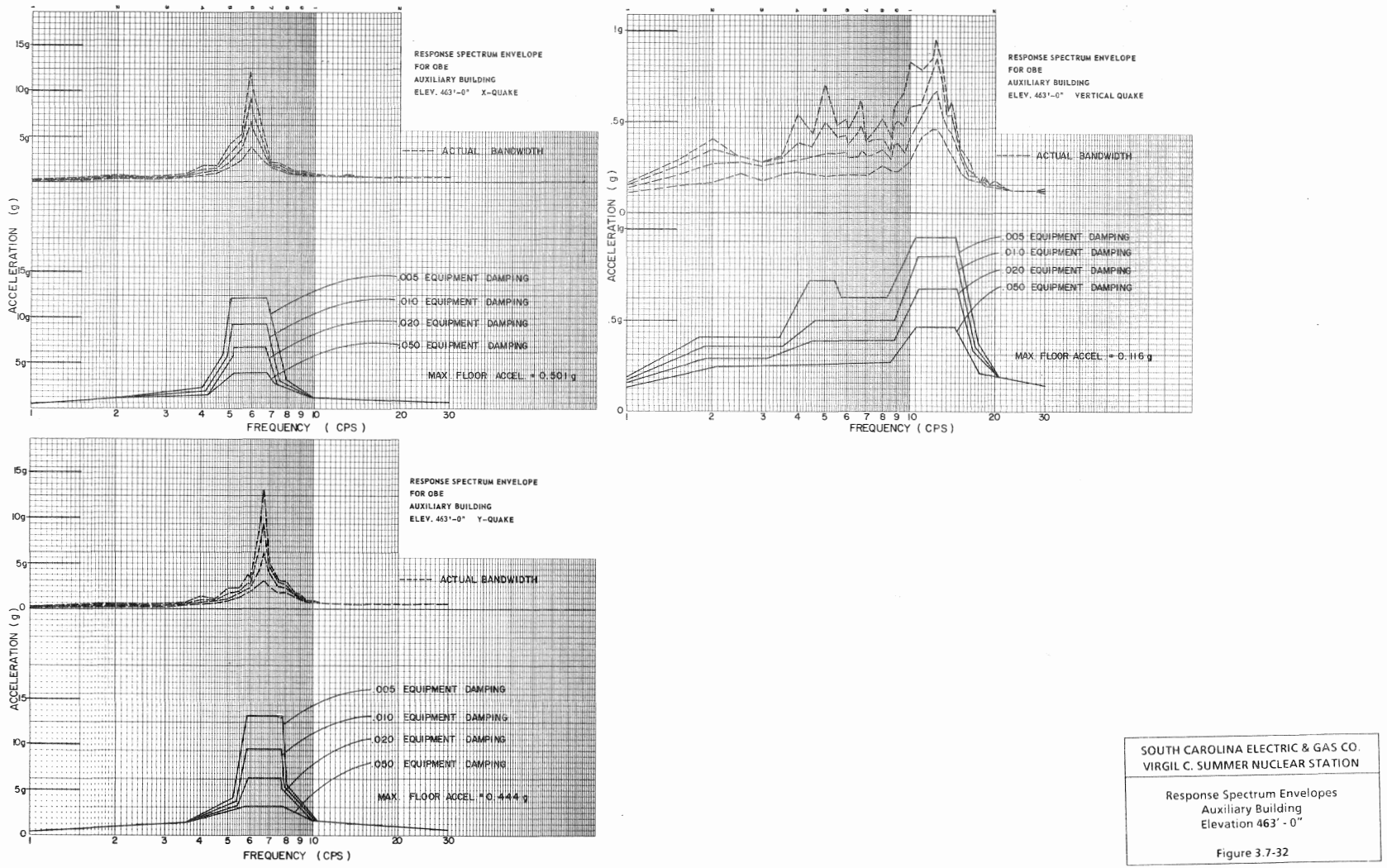
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Response Spectrum Envelopes
Auxiliary Building
Elevation 412' - 0"

Figure 3.7-31

Figure 3.7-32

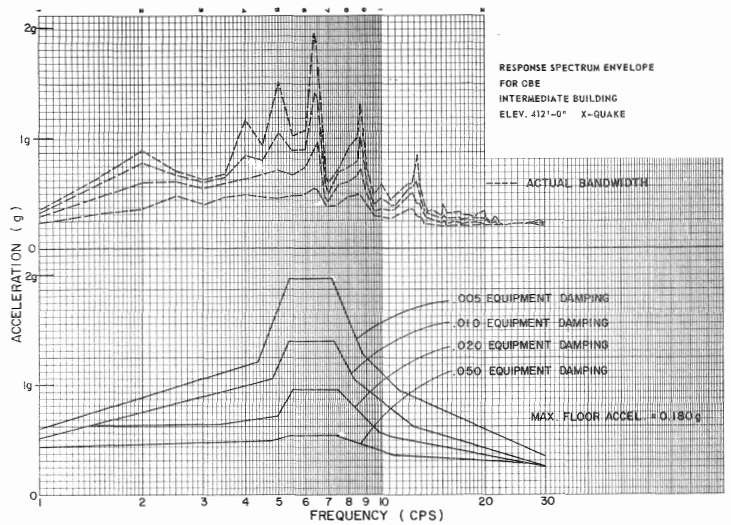
RESPONSE SPECTRUM ENVELOPES AUXILIARY BUILDING ELEVATION 463' - 0"

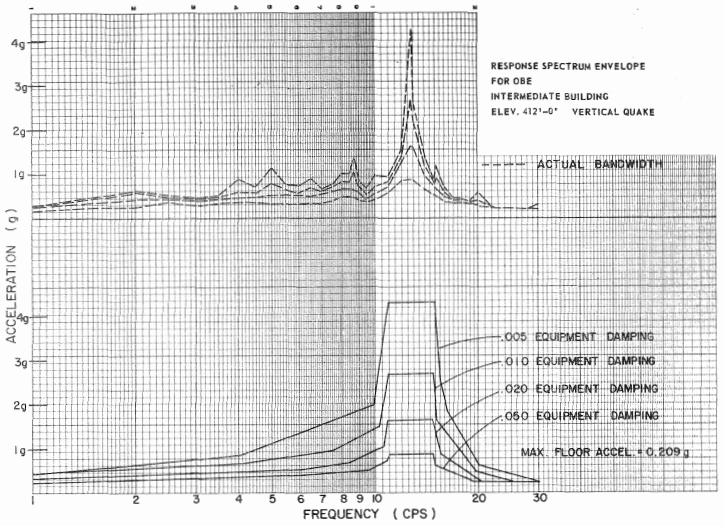


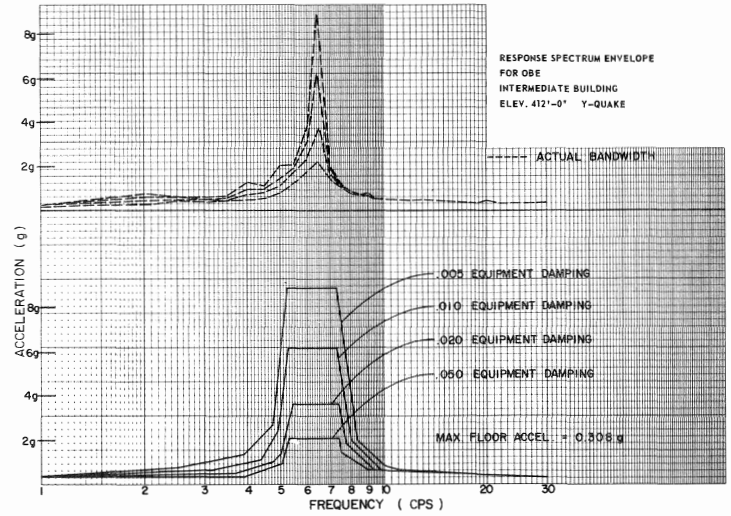
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Auxiliary Building Elevation 463' - 0" Figure 3.7-32

Figure 3.7-33

RESPONSE SPECTRUM ENVELOPES INTERMEDIATE BUILDING ELEVATION 412' - 0"



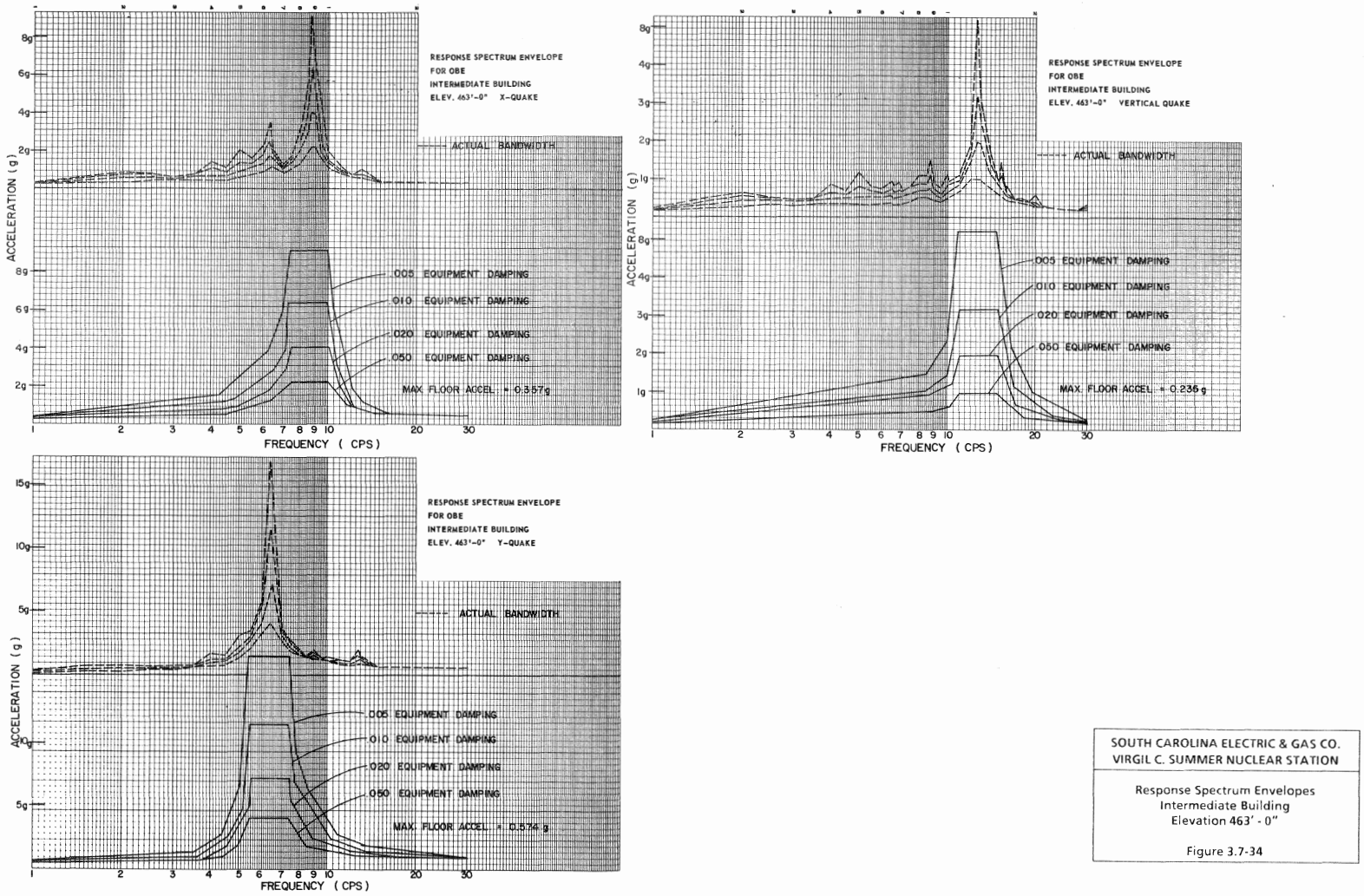




SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Intermediate Building Elevation 412' - 0" Figure 3.7-33

Figure 3.7-34

RESPONSE SPECTRUM ENVELOPES INTERMEDIATE BUILDING ELEVATION 463' - 0"



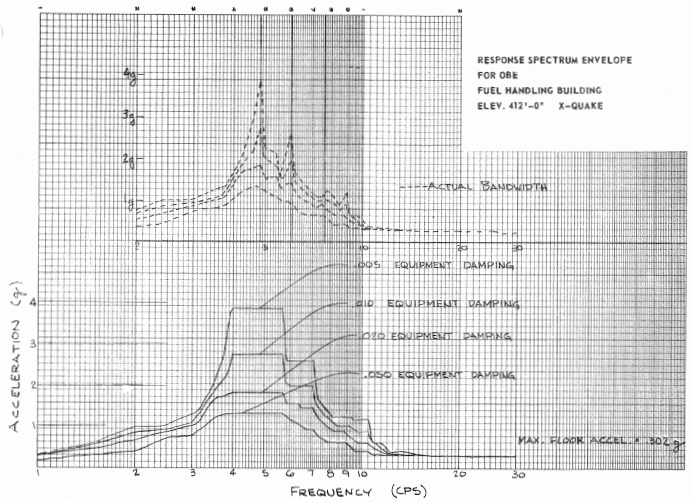
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

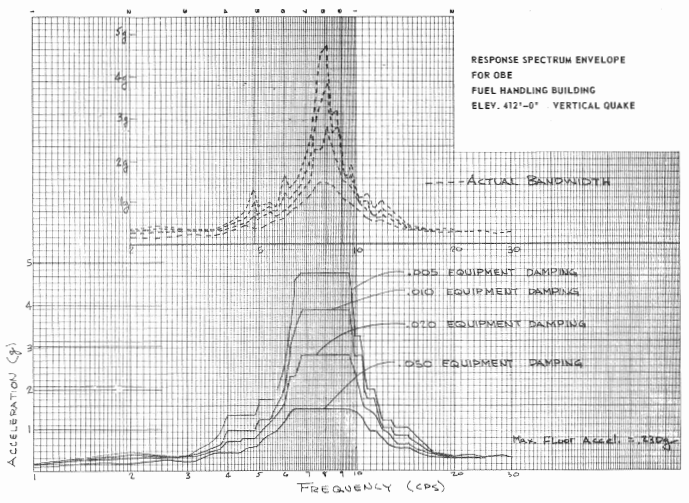
Response Spectrum Envelopes
Intermediate Building
Elevation 463' - 0"

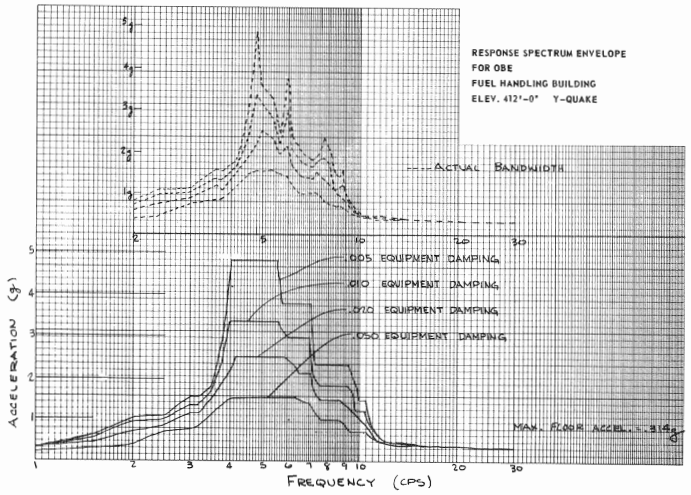
Figure 3.7-34

Figure 3.7-35

RESPONSE SPECTRUM ENVELOPES FUEL HANDLING BUILDING ELEVATION 412' - 0"



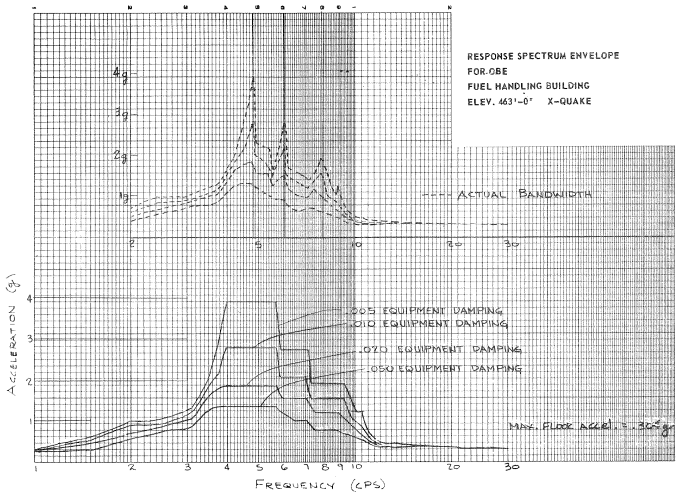


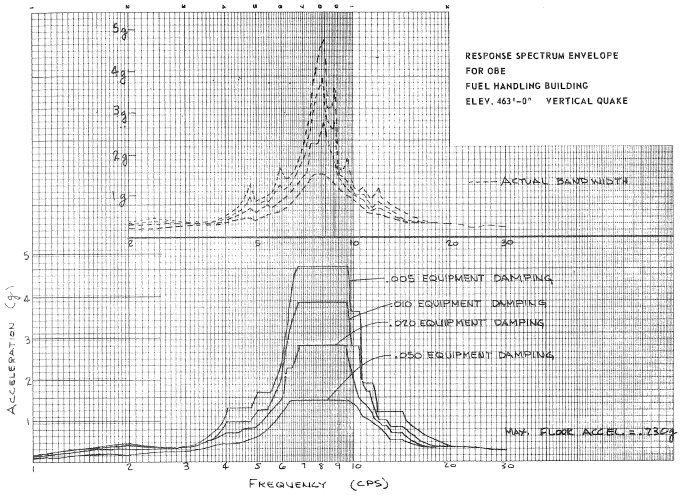


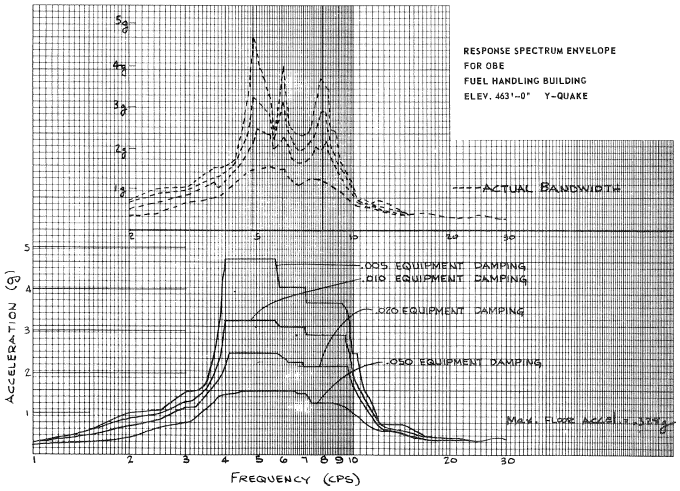
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Fuel Handling Building Elevation 412' - 0" Figure 3.7-35

Figure 3.7-36

RESPONSE SPECTRUM ENVELOPES FUEL HANDLING BUILDING ELEVATION 463' - 0"



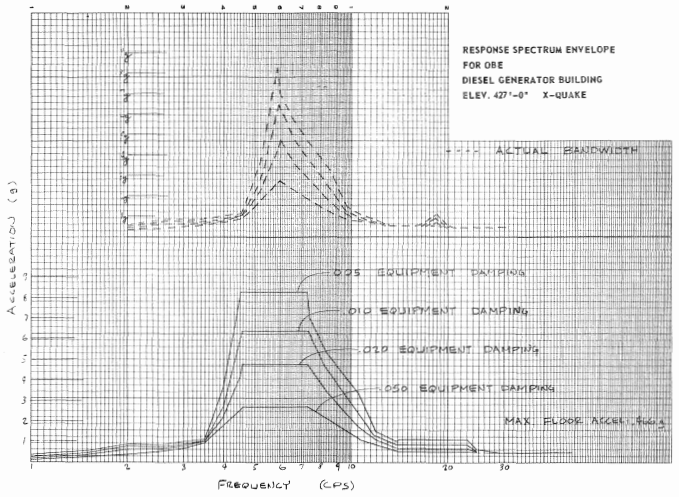


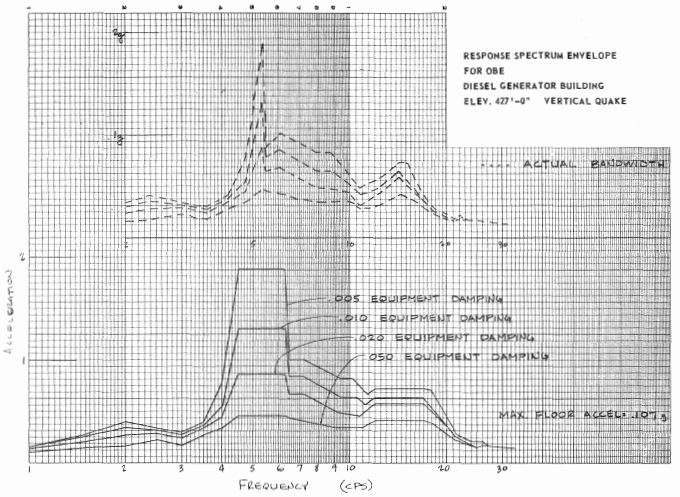


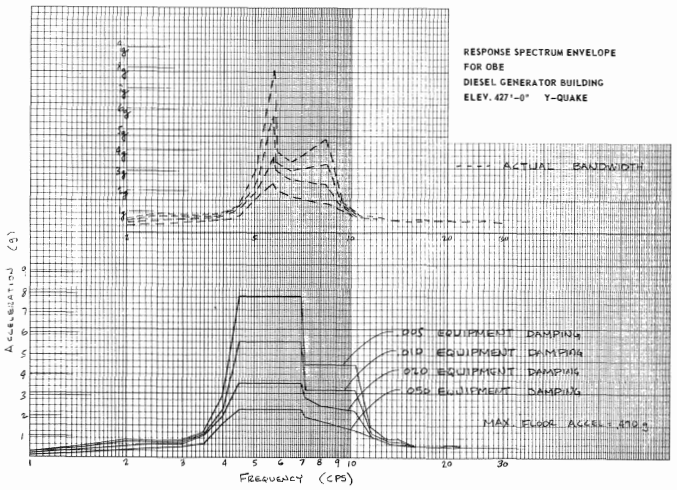
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Fuel Handling Building Elevation 463' - 0" Figure 3.7-36

Figure 3.7-37

RESPONSE SPECTRUM ENVELOPES DIESEL GENERATOR BUILDING ELEVATION 427' - 0"



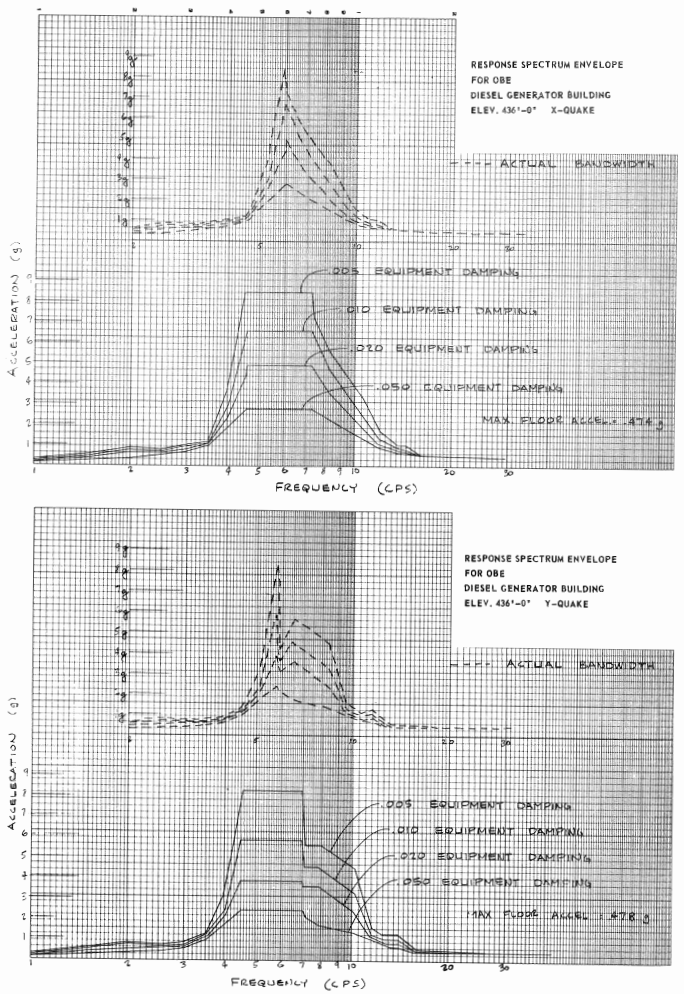


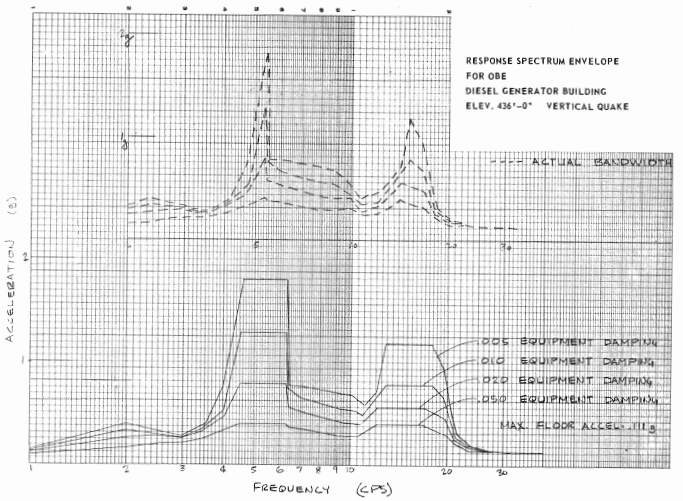


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Diesel Generator Building Elevation 427' - 0" Figure 3.7-37

Figure 3.7-38

RESPONSE SPECTRUM ENVELOPES DIESEL GENERATOR BUILDING ELEVATION 436' - 0"





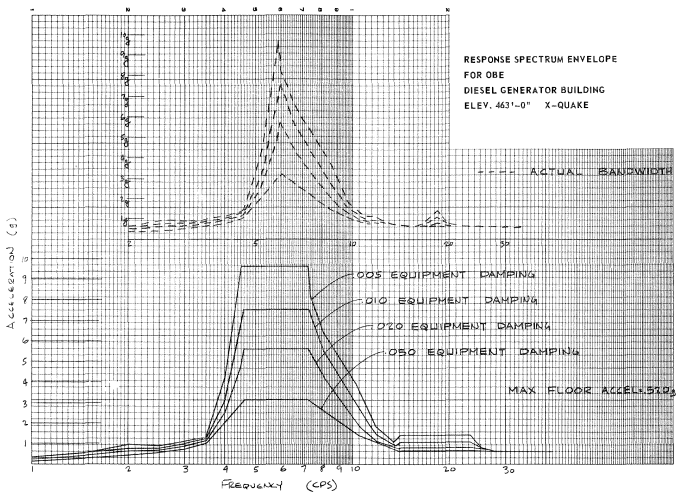
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

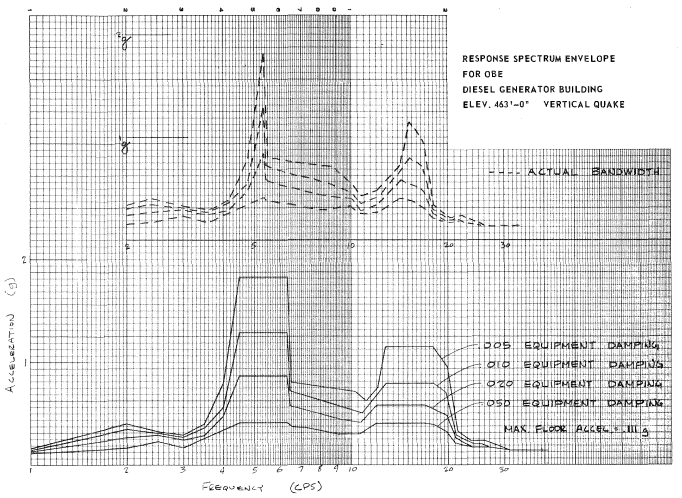
Response Spectrum Envelopes
Diesel Generator Building
Elevation 436' - 0"

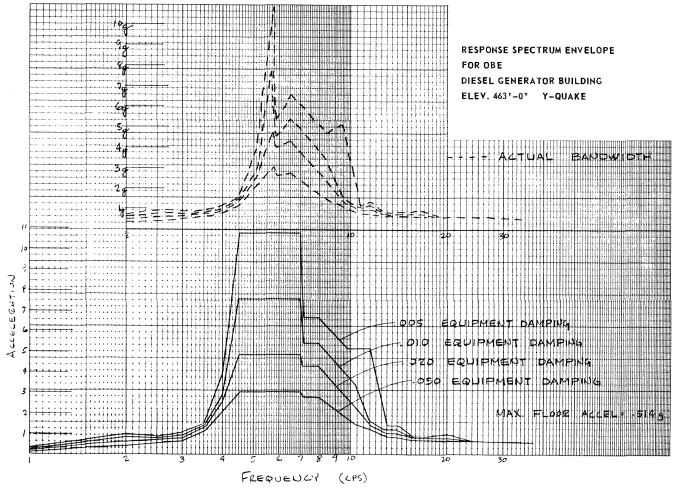
Figure 3.7-38

Figure 3.7-39

RESPONSE SPECTRUM ENVELOPES DIESEL GENERATOR BUILDING ELEVATION 463' - 0"



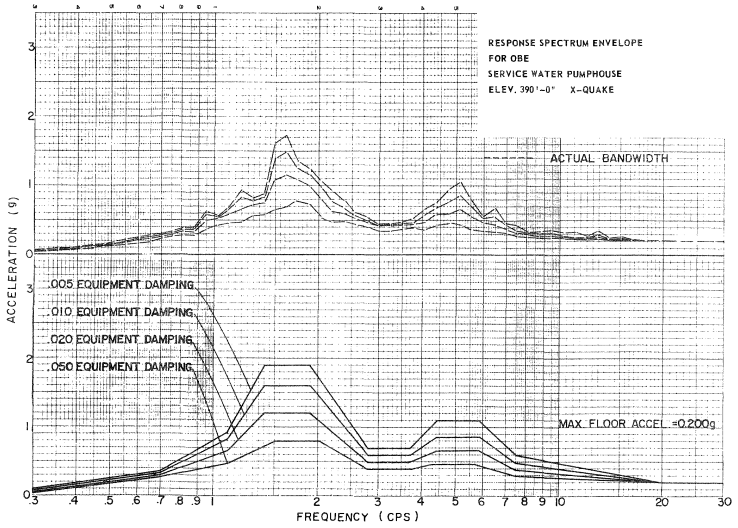


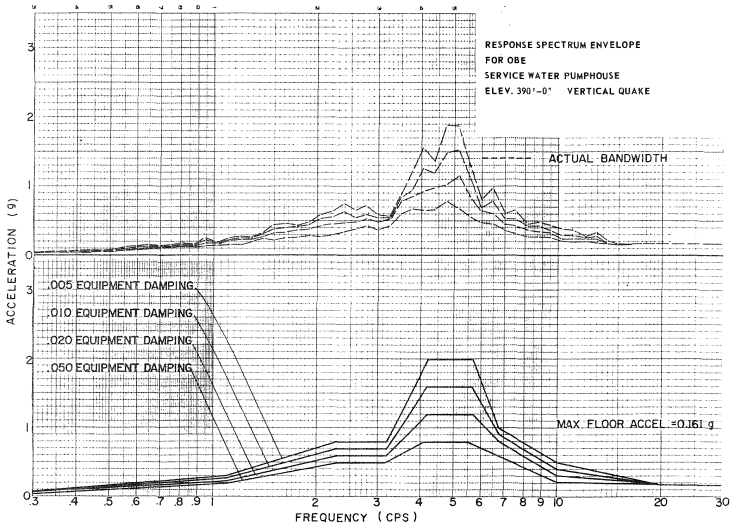


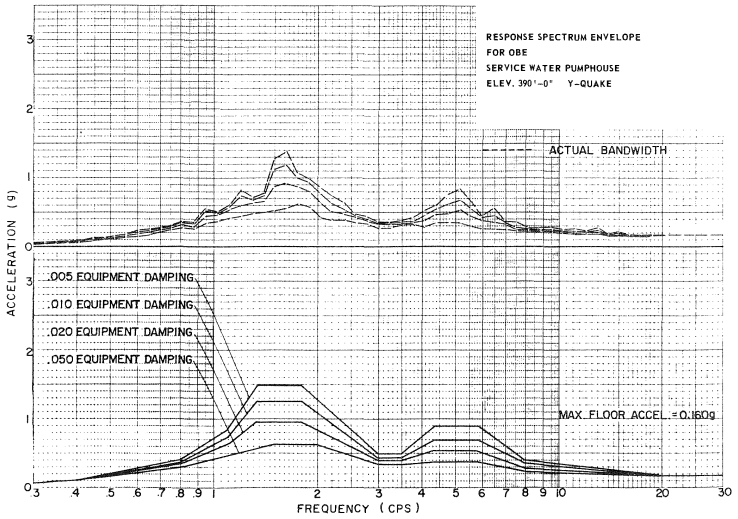
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Diesel Generator Building Elevation 463' - 0" Figure 3.7-39

Figure 3.7-40

RESPONSE SPECTRUM ENVELOPES SERVICE WATER PUMPHOUSE ELEVATION 390' - 0"



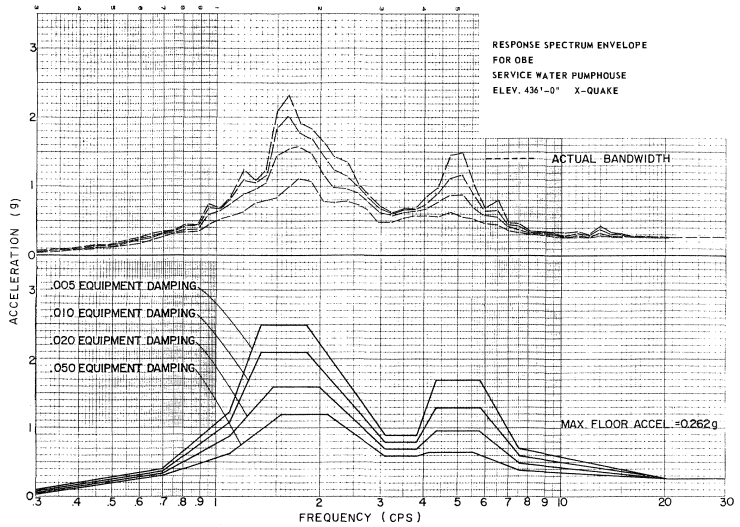


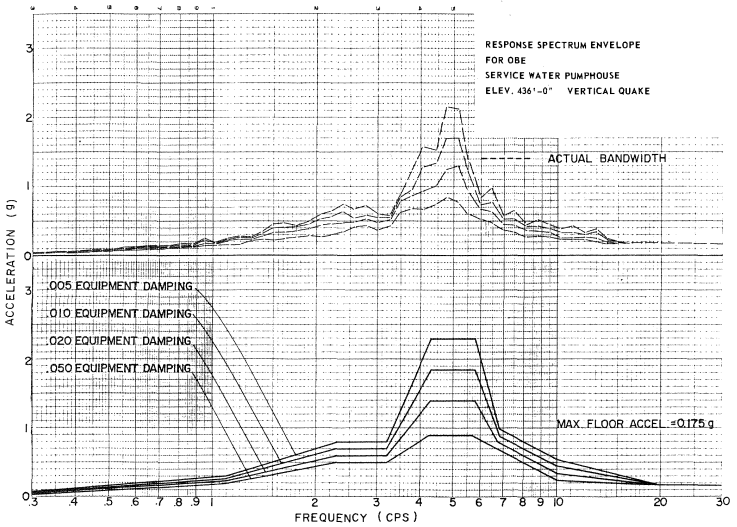


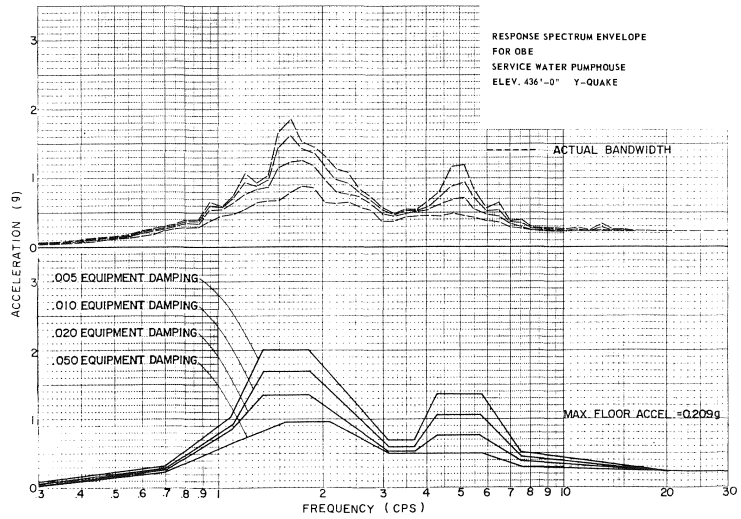
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Response Spectrum Envelopes Service Water Pumphouse Elevation 390' - 0" Figure 3.7-40

Figure 3.7-41

RESPONSE SPECTRUM ENVELOPES SERVICE WATER PUMPHOUSE ELEVATION 436' - 0"





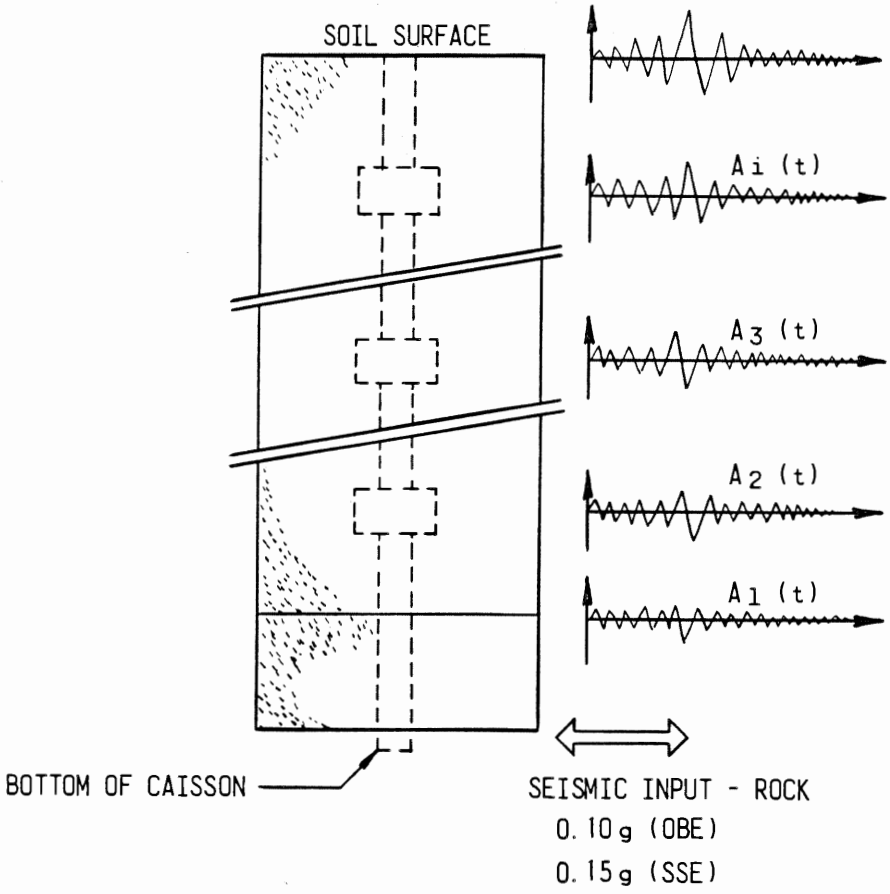


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Response Spectrum Envelopes
Service Water Pumphouse
Elevation 436' - 0"

Figure 3.7-41

Figure 3.7-42
SOIL SHEAR BEAM MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Soil Shear Beam Model
Figure 3.7-42

Figure 3.7-43
EQUIVALENT ACCELERATOR BASED UPON EQUALIZED ENERGY

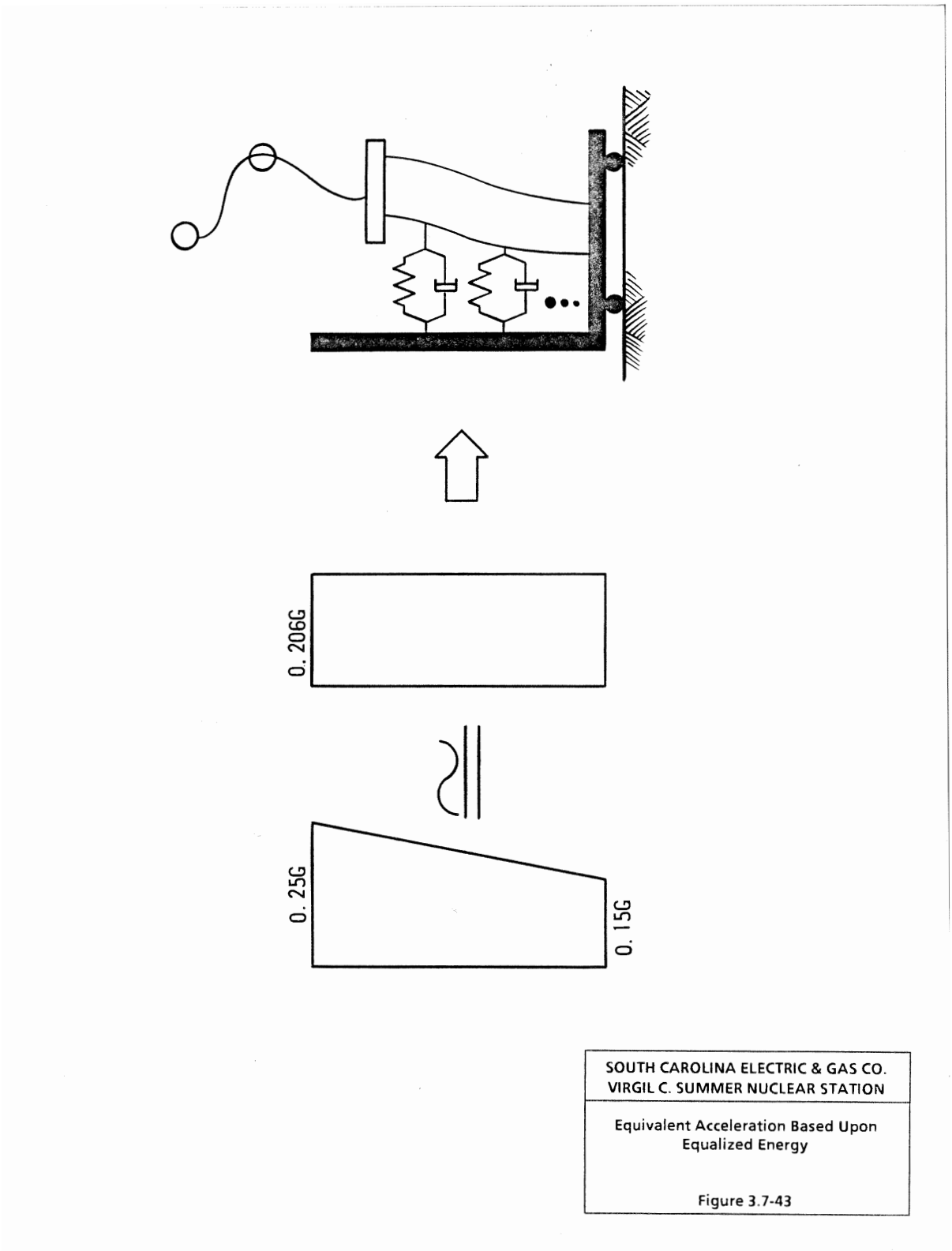
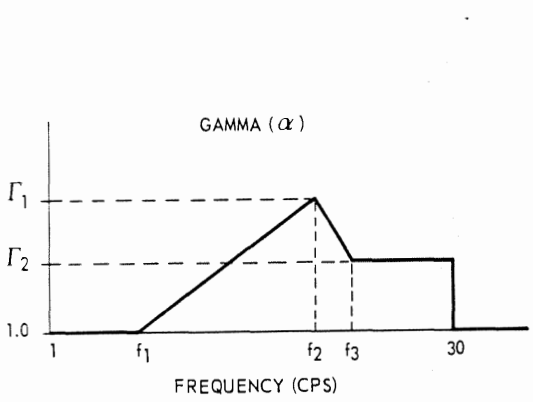
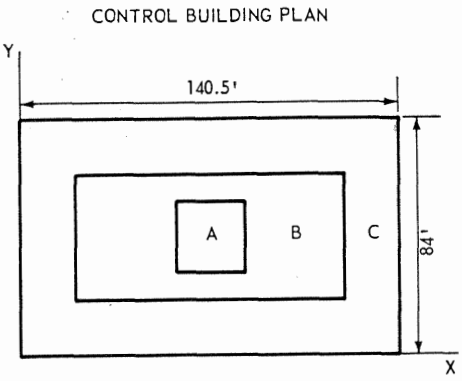


Figure 3.7-44

GAMMA SCALING FACTOR CONTROL BUILDING





ZONE	COORDINATES (FT.)	
	X	Y
A	57.5 ~ 82.5	29.5 ~ 54.5
B	20.0 ~ 57.5 82.5 ~ 120.5	20.0 ~ 29.5 54.5 ~ 64.0
C	REMAINING AREA	

ELEV.	ZONE	Γ_1	Γ_2	f_1	f_2	f_3
505'	A	9.5	3.6	5.0	12.0	16.0
	B	6.9	2.9	5.0	12.0	16.0
	C	1.8	1.8	5.0	12.0	–
482'	A	4.0	1.8	5.5	16.0	19.0
	B	3.0	1.6	5.5	14.0	19.0
	C	1.2	1.2	5.5	14.0	–
463'	A	4.0	1.5	5.5	13.0	19.0
	B	3.7	1.3	5.5	12.5	19.0
	C	1.1	1.1	5.5	12.5	–
452'	A	4.0	1.3	5.5	12.0	17.0
	B	3.0	1.1	5.5	12.5	17.0
	C	1.0	1.0	–	–	–

ELEV.	ZONE	Γ_1	Γ_2	f_1	f_2	f_3
436'	A	2.2	1.0	6.0	12.5	15.0
	B	2.2	1.0	9.0	12.5	15.0
	C	1.0	1.0	–	–	–
412'	A	1.0	1.0	–	–	–
	B	1.0	1.0	–	–	–
	C	1.0	1.0	–	–	–

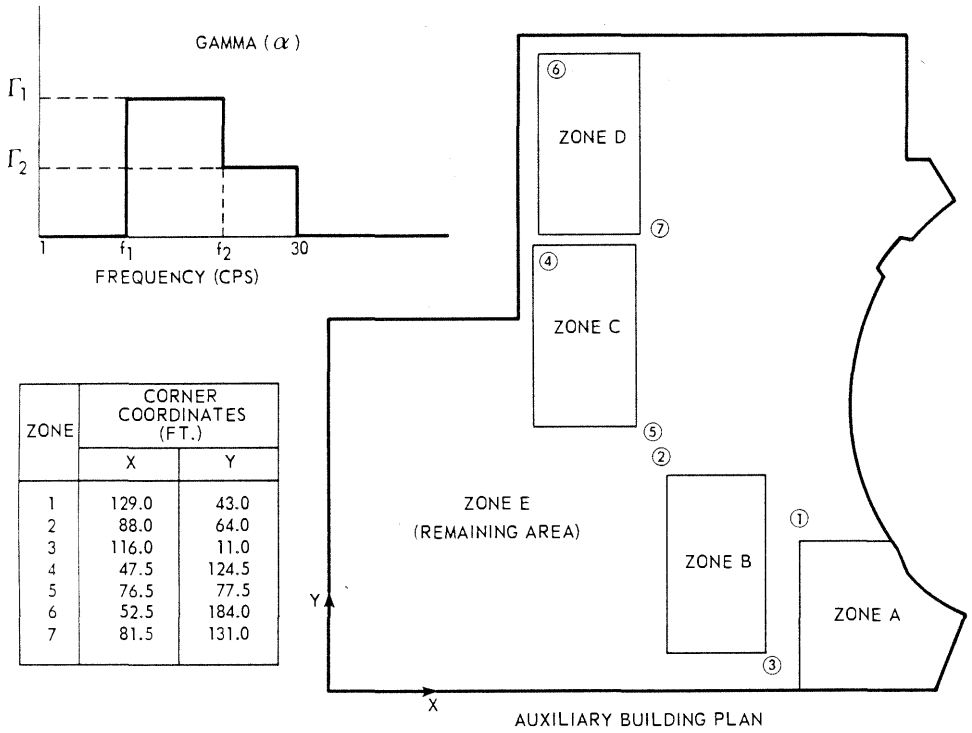
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Gamma Scaling Factor
Control Building

Figure 3.7-44

Figure 3.7-45

GAMMA SCALING FACTOR AUXILIARY BUILDING



ZONE	CORNER COORDINATES (FT.)	
	X	Y
1	129.0	43.0
2	88.0	64.0
3	116.0	11.0
4	47.5	124.5
5	76.5	77.5
6	52.5	184.0
7	81.5	131.0

ELEV.	ZONE	Γ_1	f_1	f_2	Γ_2
511'	C	2.6	19	30	–
	E	1.0	–	–	1.0
485'	A	8.9	15	26	2.0
	B	4.4	19	30	–
	C	2.6	19	30	–
	D	7.9	12	24	2.7
	E	1.0	–	–	1.0
463'	A	8.9	15	26	2.0
	E	1.0	–	–	1.0
436'	A	8.7	15	26	2.0
	E	1.0	–	–	1.0
412'	A	8.6	15	26	2.0
	E	1.0	–	–	1.0
397' 388' 374'	E	1.0	–	–	1.0

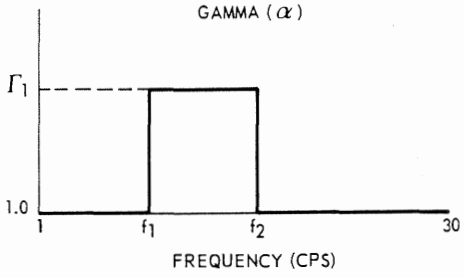
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

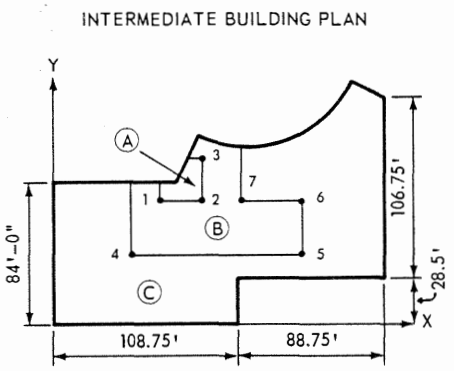
Gamma Scaling Factor
Auxiliary Building

Figure 3.7-45

Figure 3.7-46

GAMMA SCALING FACTOR INTERMEDIATE BUILDING





ELEV.	ZONE	Γ_1	f_1	f_2
483	ALL	1.0	–	–
463	A	4.1	8	19
	B	2.2	8	19
	C	1.0	–	–
450	A	3.1	7.5	19
	B	2.1	8	19
	C	1.0	–	–
436	A	2.5	8	19
	B	1.5	8	19
	C	1.0	–	–
412	A	1.4	9	10.5
	B	1.0	–	–
	C	1.0	–	–

ZONE	CORNER COORDINATES (FT.)	
	X	Y
1	64	75
2	89	75
3	89	95
4	41	41.5
5	150	41.5
6	150	70
7	110	70

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Gamma Scaling Factor
Intermediate Building

Figure 3.7-46

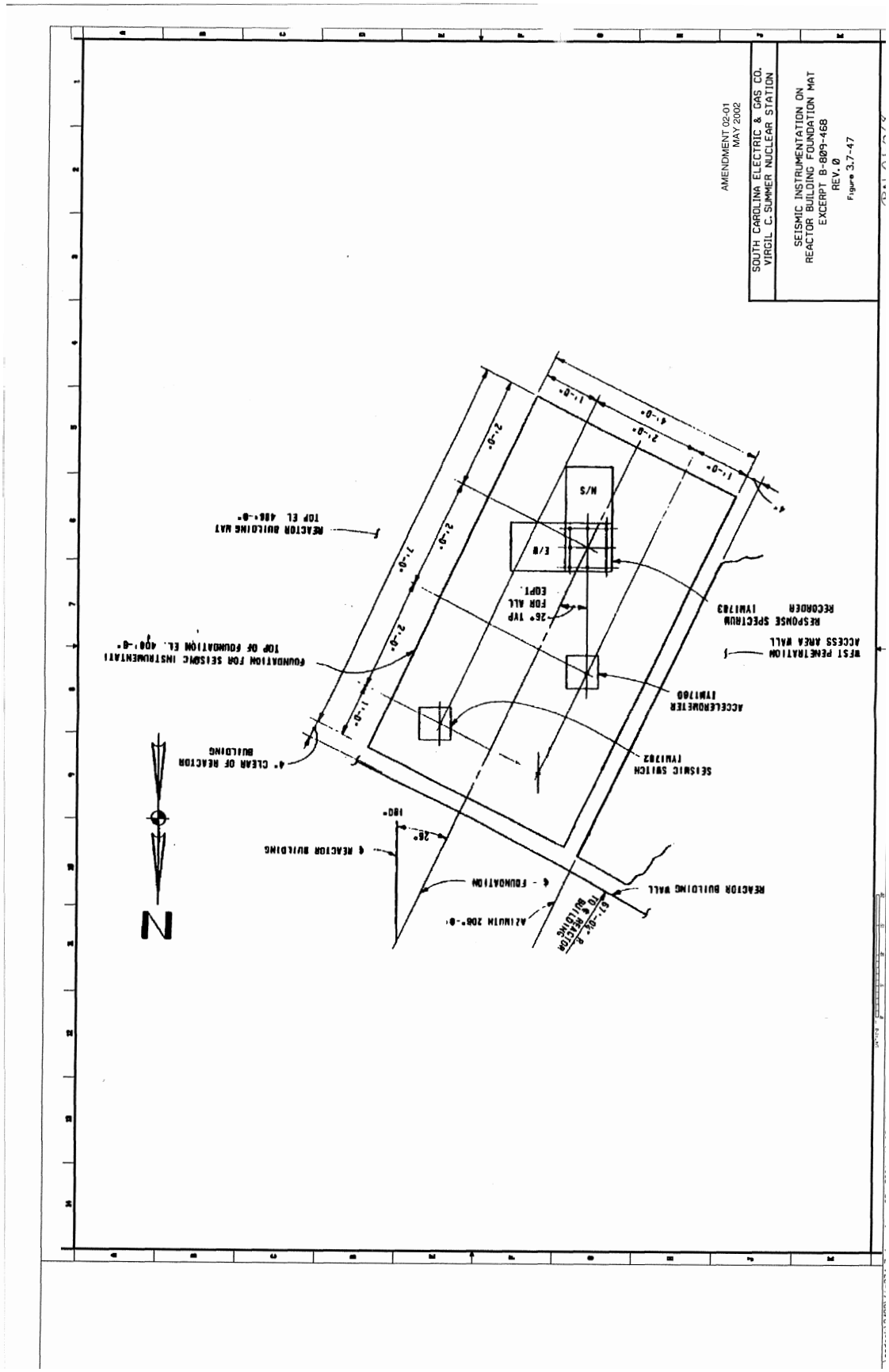


Figure 3.7-47
SEISMIC INSTRUMENTATION ON REACTOR BUILDING FOUNDATION MAT EXCERPT B-809-46B REV. 0

Figure 3.7-48

SEISMIC INSTRUMENTATION ON TOP OF RING GIRDER MAT EXCERPT B-809-469 REV. 0

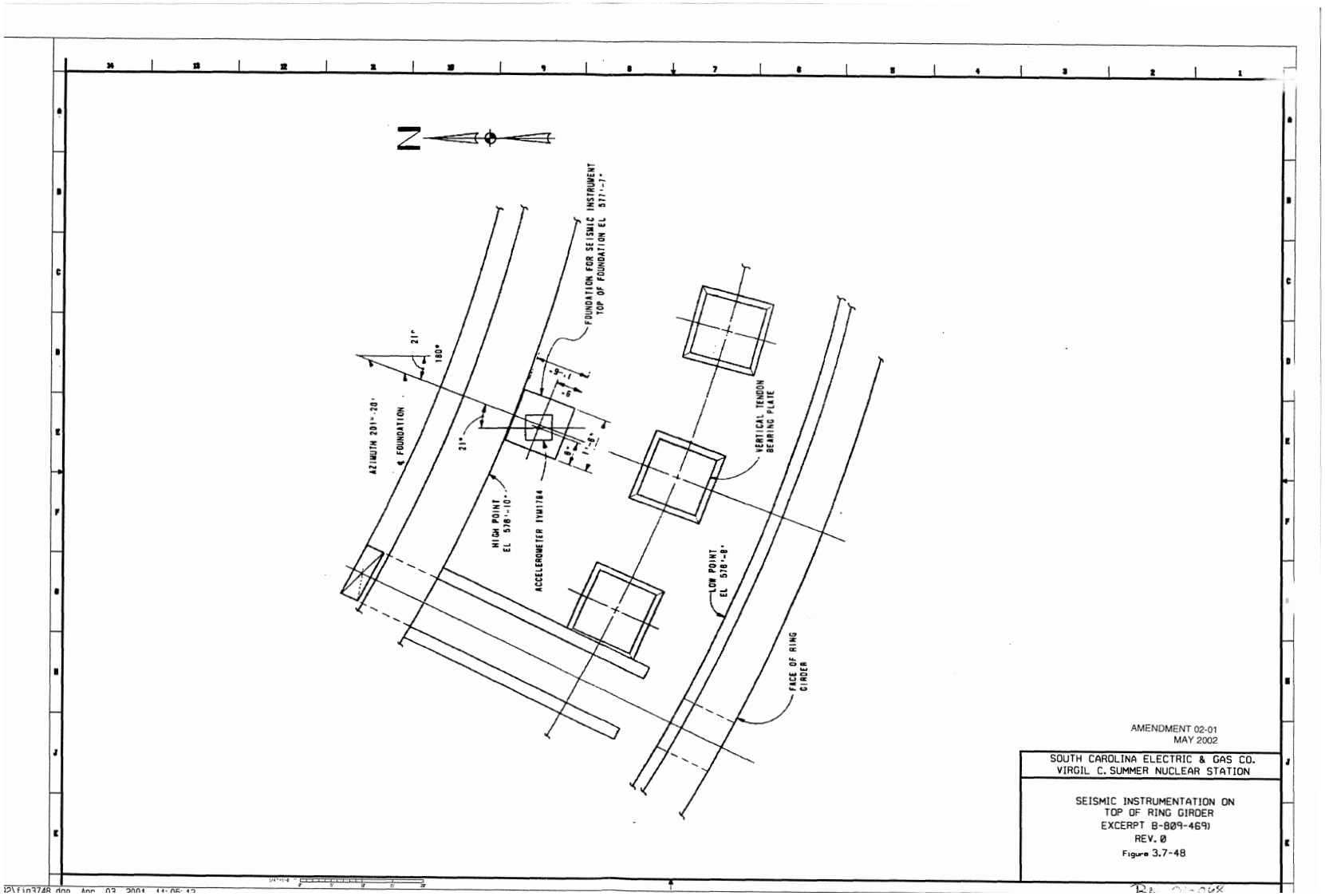


Figure 3.7-49
DELETED BY AMENDMENT 96-03

Figure 3.7-50
DELETED BY AMENDMENT 96-03

Figure 3.7-51
DRAWING B-809-473
FSAR FIGURE REFERENCE
Figure 3.7-52
DRAWING B-809-470
FSAR FIGURE REFERENCE
Figure 3.7-53
DRAWING B-809-471
FSAR FIGURE REFERENCE

3.8 DESIGN OF CATEGORY I STRUCTURES

3.8.1 Concrete Reactor Building

3.8.1.1 Description of the Reactor Building

The Reactor Building is a post tensioned, reinforced concrete structure with an integral steel liner. The Reactor Building consists of a cylindrical wall, a shallow dome roof and a foundation mat with a depressed incore instrumentation pit under the reactor vessel. The foundation mat bears on fill concrete which extends to competent rock. At the underside of the Reactor Building foundation mat a tendon access gallery is formed into the top of the fill concrete. A retaining wall, extending approximately 1/4 of the way around the Reactor Building, protects the below grade portions of the Reactor Building wall from the subgrade. Adjacent buildings surround the remaining three quarters of the Reactor Building.

The Reactor Building is lined on the inside face with a steel plate liner which forms a leaktight membrane. The liner is not considered to provide structural reinforcement. Figures 1.2-2 through 1.2-7, 1.2-9, and 1.2-10 show overall plans and sections of the Reactor Building and its relationship to adjacent structures.

3.8.1.1.1 Reactor Building Concrete

3.8.1.1.1.1 Foundation Mat

The Reactor Building foundation consists of a 12 foot thick structural mat, which supports the Reactor Building shell, and the concrete and steel internal structures. The structural mat is supported by fill concrete which extends down to competent rock. Thickness of the fill concrete varies from 27 feet to 52 feet, approximately. See Figure 3.8-1.

The structural mat is circular in plan with a diameter of 154 feet and extends 10 feet beyond the Reactor Building shell cylindrical wall. The mat concrete has a specified minimum compressive strength, f_c, of 5000 psi and is reinforced with ASTM 615 Grade 60 reinforcing bars. The incore instrumentation pit is located near the center of the mat and is “keyhole” in shape in plan. The base of the pit is 13 feet thick and the walls vary in thickness from 8 feet to 13 feet.

The uppermost fill concrete, extending from elevation 384' to elevation 396', has a diameter of 154 feet. A 6 foot wide by 8 foot high tendon access gallery is formed into the fill concrete directly under the Reactor Building shell cylindrical wall. This gallery provides access to the vertical tendon anchorages. The fill concrete has a specified minimum compressive strength of 3000 psi and is reinforced around the gallery with ASTM 615 Grade 60 reinforcing bars.

The remaining fill concrete, extending from elevation 340' - 365' (varies) to elevation 384', has a diameter of 174 feet. This concrete has a specified minimum compressive strength of 1500 psi and is lightly reinforced on its vertical face with ASTM 615 Grade 60 reinforcing bars.

Refer to Section 3.8.5.1 for additional discussion of the Reactor Building foundation.

3.8.1.1.1.2 Cylindrical Wall and Dome

The Reactor Building shell consists of concrete with a specified minimum compressive strength of 5000 psi and is reinforced with ASTM 615 Grade 60 reinforcing bars. The 4 foot thick cylindrical wall has an inside diameter of 126 feet and a height of 149 feet from the top of the structural mat (elevation 408') to the spring line (elevation 557'). The 3 foot thick shallow dome roof has an inside central radius of 81'-4-1/2" and a transition inside radius of 30 feet. The apex of the outside face of the dome is located at elevation 602'-0-1/4". The shell is post tensioned by ungrouted tendons. Each tendon consists of 170, 1/4 inch diameter, stress relieved wires. The wire is in accordance with ASTM A421. The cylindrical wall contains 115 vertical tendons and 150 hoop tendons. The wall employs the 3 buttress-240 degree hoop tendon concept. The dome contains a total of 99 tendons arranged in a three-way system with 33 tendons per band. Components of the tendon system are identified in Figure 3.8-2.

The Reactor Building shell is provided with a 16 foot ID equipment hatch, a 9 foot OD personnel airlock and a 5 foot OD personnel emergency air-lock. The wall is thickened to 7'-6" in the areas of the equipment hatch and personnel airlock. Reinforcement around the hatch and airlocks is shown in Figures 3.8-3 and 3.8-4. Other major penetrations in the shell include three 56 inch OD sleeves for the main steam lines, three 38 inch OD sleeves for the feedwater lines, and a 24 inch OD sleeve for the fuel transfer tube. Reinforcement around typical main steam line and feedwater line penetrations is shown in Figures 3.8-5 through 3.8-8. The adjacent set of main steam and feedwater line penetrations is reinforced as shown in Figures 3.8-9 and 3.8-10.

The general wall reinforcement layout is shown in Figure 3.8-11. The hoop bars are 1 layer of #14 bars at 12 inch centers on each face for most of the wall height. The vertical bar sizes vary up the wall. On the inside face, the vertical bars (1 layer at 12 inches, center to center) consist of #14 bar Cadwelded to #18 dowels in the lower portion of the wall height. Numbers 11 and 14 bars are used in the upper portion. On the outside face, the vertical bars (1 layer at 12 inches, center to center) consist of #18 bars in the lower portion of the wall and #14 bars in the top portion of the wall. The Cadweld splices are generally arranged in a 3 foot minimum, 4 bar stagger pattern for both hoop and vertical bars. In penetration areas, vertical bars are either deflected around the penetration sleeve; or, in those cases where the deflection would be too large, bars are terminated at each face and a U bar connects the inside face and outside face vertical bars.

Radial shear reinforcement is provided in the lower 20 feet of the wall, in the upper 20 feet of the wall under the spring line, and in the dome above the ring girder. In the bottom 10 feet of the wall, typically #7 ties at 9 inch centers vertically by 12 inch centers horizontally are used. In the next 10 feet, #5 ties varying from 6 inches to 12 inches vertically by 12 inches horizontally are used. Radial shear reinforcement in the upper 20 feet of the wall consists of #7, #6, and #5 ties. The vertical spacing of these bars varies between 8, 12, and 18 inches. Depending upon design requirements, the bars are spaced horizontally so as to enclose either each set of inside-outside face vertical bars or every other set of inside-outside face vertical bars. In the areas surrounding the polar crane brackets, #5 ties at 6 inch centers vertically by 12 inch centers horizontally are used. For those areas of the Reactor Building wall that are not provided with radial shear reinforcement, #5 radial tension ties are provided, having an average spacing horizontally of 3 feet 6 inches and within 1 inch clear, above and below, each hoop tendon.

Reinforcement details for the dome are shown in Figure 3.8-11a. Meridional reinforcement consists of #11 bars on each face. The spacing of these bars varies as they extend radially toward the apex to Cadweld with a square reinforcement grid of #10 bars. The hoop reinforcement consists of #14 and #11 bars spaced as shown. Radial shear reinforcement consisting of #9 and #7 bars is provided in the dome for a distance of 16 feet above the ring girder. Radial tension ties consisting of #5 bars exist over the remainder of the dome. These ties provide an area density of 0.25 square inches per square foot of dome surface.

Three (3) buttresses, spaced 120° apart and extending full height from the top of the foundation mat to the underside of the ring girder, serve as anchorage points for the hoop tendons. The buttresses are nominally 12'-10" wide and 6'-6" thick. The inside face of each buttress is flush with the inside face of the cylindrical wall.

Buttresses are reinforced in both the meridional (vertical) and hoop directions. Inside face vertical reinforcement is #14 bar at 12 inches and extends full height. Outside face vertical reinforcement consists of #18 bar at 12 inches for the lower half and #14 bar at 12 inches for the upper half. In the hoop direction, inside face reinforcement is identical to that for the cylindrical wall. Outside face hoop reinforcement consists of #11 bar at 11-1/2 inches. In addition to the reinforcement described, shear and bursting reinforcement is also provided around the tendon anchorage. Number 9 U-shaped bars are used for shear reinforcement and spirals (2 sets behind each tendon base plate) for bursting reinforcement. The spirals have an outside diameter of 15 inches and 21 inches each and are made from #5 bar at 3 inch pitch. Typical buttress details are shown in Figure 3.8-12.

3.8.1.1.1.3 Ring Girder

The junction of the dome and cylinder wall is thickened to provide space for the anchorage of the dome and vertical prestressing tendons. This thickened junction is referred to as the ring girder and serves as a transfer block for the prestressing forces. The ring girder is 9 feet wide at its top and approximately 19 feet in overall depth. Its outside vertical face is flush with the outside face of the buttresses on the cylindrical wall and is notched at various angles to accept seating of the dome tendon bearing plates. To minimize the depth of these side notches, a fully rotated system of dome bearing plates is employed.

The ring girder is reinforced in both meridional and hoop directions as shown by Figure 3.8-13. Inside face meridional reinforcement is #18 bar at 12 inches center to center. Shear reinforcement consists of #9 bars, shaped, oriented, and spaced as shown by Figure 3.8-13. A set of bursting reinforcement consisting of rings cut from 20 inch OD ASTM A-106 pipe with 1 inch nominal thickness is provided behind each tendon anchorage.

3.8.1.1.2 Steel Liner and Penetrations

3.8.1.1.2.1 Liner Plate

The liner plate is designed to function as a leaktight membrane sealing the entire Reactor Building for any postulated conditions to be encountered throughout the operating life of the plant. In

general, the liner plate is made from ASME SA516, Grade 60, carbon steel (see Figures 3.8-1 and 3.8-14).

The cylindrical wall liner plate is made from carbon steel. At its base, in the haunch area, a truncated conical transition section tapers inward to accommodate the thickened concrete of the cylindrical shell. This truncated conical section extends approximately 10 feet above the floor plate. The cylindrical portion of the liner is 139 feet high and has an inside diameter of 126 feet.

The top of the cylindrical portion of the liner is closed by a dome with a minor radius of 30 feet and a major radius of 81'-4-1/2". The ratio of Reactor Building ID to dome height is 3 to 1.

The interior vertical height from the top of the floor liner plate to the interior apex of the dome is 190'-11-3/4". The floor, cylindrical, and dome portions of the liner plate are 1/4 inch thick.

The bottom of the liner consists of flat, floor liner plates, welded to anchors which are embedded in the mat concrete (see Figure 3.8-14).

The liner plate extends downward into the foundation mat to line the incore instrumentation pit, 2 residual heat removal sumps, 2 Reactor Building spray sumps, 1 Reactor Building sump, and 1 incore instrumentation pit sump. The incore instrumentation pit is lined with stainless steel plates and carbon steel plates. Carbon steel plate, 1/4 inch thick, is used to line the incore instrumentation pit walls. Stainless steel, 1/2 inch thick, is used to line the bottom and 1/4 inch thick stainless steel is used to line the walls of the incore instrumentation tunnel. The residual heat removal sump, Reactor Building spray sumps, and Reactor Building sump floors and sidewalls are lined with 1/4 inch thick stainless steel plate (see Figure 3.8-1). The carbon steel is ASME SA516, Grade 60, material. the stainless steel is ASME SA240, type 304 material.

Weld seams which are inaccessible for inspection following construction of the plant are covered with test channels. These test channels are welded continuously along the edge of their flanges to the liner to provide leaktight enclosures for pneumatic leak testing of the liner welds (see Figure 3.8-14). The test channels are zoned into test areas by plates welded to the ends of sections of the channels. Small diameter tubing is connected to the test channels and extends to accessible areas for leak testing after concrete placement.

3.8.1.1.2.2 Penetrations

All Reactor Building penetrations are anchored to the concrete Reactor Building wall or foundation mat so that loads are transferred from the penetrations to the concrete. All penetrations satisfy the requirements of 10 CFR 50, Appendix J. Penetrations are classified into the following groups:

1. Piping Penetrations

   All piping penetrations consist of a sleeve around the outside of the piping. The piping is joined to the sleeve inside the Reactor Building by an attachment plate (see Figure 3.8-15). Outside the Reactor Building, piping is attached to the sleeve by an attachment plate or by a bellows assembly. The attachments at both the inside and outside ends of the sleeve create an interspace between the sleeve and piping. This interspace is tested to ensure that leak rate requirements are satisfied. The bellows and sleeve are designed to withstand the containment design pressure and temperature.

   Each sleeve is integrally welded to a surrounding, thickened liner reinforcing plate. The weld between the sleeve and reinforcing plate is covered by a circular test channel which is used for testing the leak tightness of the weld.

   Anchorage attachments, provided on the outside of the embedded portion of each sleeve, transfer the piping loads into the Reactor Building wall (see Figure 3.8-15).

   All hot piping penetrations are insulated as required to prevent the temperature in the concrete adjacent to the sleeve from exceeding 200°F during normal operation.

   Insulation is provided around the attachment plate and portions of the exposed sleeve, as well as around the process pipe, resulting in a smooth transition in temperature gradients from the pipe through the attachment plate and into the sleeve. This prevents unacceptable thermal stress concentrations in the sleeve, as well as in the hot process pipe.

   The containment boundary and weld locations, typical for all piping penetrations, in the main steam line penetration are shown byFigure 3.8-15.

   The main steam penetration materials and inspection requirements are listed in Table 3.8-0.

   Containment boundary welds to process pipe are accessible for inservice inspection per the ASME Code, Section XI. Welds are examined to the requirements of ASME Section XI as required by 10CFR50.55a.

   The welds attaching the stiffeners and cooling fins to the penetration assembly and the weld between the bellows assembly and the process pipe are examined either by the liquid penetrant or magnetic particle method.

2. Mechanical System Penetrations

   A fuel transfer tube penetrates the Reactor Building connecting the refueling canal in the Reactor Building and the fuel transfer canal in the Fuel Handling Building. This penetration consists of a stainless steel pipe installed inside a sleeve (see Figure 3.8-16). This pipe functions as the transfer tube connecting the refueling canals in the Reactor and Fuel Handling Buildings.

An attachment plate is welded to the transfer tube and the end of the sleeve. A protective cover is placed over the attachment plate and sleeve. The cover is welded to the transfer tube and Reactor Building liner to provide an interspace for local leak rate testing of the welds which are part of the containment system.

Details of the residual heat removal sump and penetration are shown in Figure 3.8-17.

3. Electrical System Penetrations

Sleeves through the Reactor Building wall are provided to accommodate electrical and instrumentation cables which pass through the wall (see Figure 3.8-15). The sleeves are welded to the Reactor Building inner reinforcing plates. A leak test channel is placed over the sleeve to liner weld to provide leak test capability.

The electrical leads are installed in the penetration assemblies which are bolted to the electrical penetration sleeve. Each assembly has provisions for leak testing to comply with 10 CFR 50, Appendix J.

4. Spare Penetrations

Spare penetrations consist of sleeves passing through the reactor wall with the liner reinforced around the sleeve (see Figure 3.8-15). Both ends of the sleeve are sealed with butt welded pipe caps to provide an interspace within the sleeve for leak testing. A test channel assembly over the sleeve to liner plate weld is provided to allow leak testing.

Spare penetrations #602-18, #600-12, and #505-18 are fitted with bolted removable blank flanges and Flexitallic type or equal gaskets in place of butt welded end caps. This penetration is for temporary services into Reactor Building as required during shut-down. Leakage rate testing is performed on the penetration as discussed in Chapter 6.2.6, Containment Leakage Testing.

3.8.1.1.2.3 Access Openings

1. Equipment Hatch

The equipment hatch has an inside diameter of 16 feet as shown in Figure 3.8-18. The hatch is equipped with a hatch cover, mounted on the inside of the Reactor Building.

The hatch cover is double O-ring gasketed and has a leakage test tap between the O-rings. The enclosed space between the O-rings is capable of being leak tested as discussed in Chapter 6.2.6, Containment Leakage Testing. A monorail and hoist are provided inside the Reactor Building for removal of the hatch cover. The hatch cover is suspended from 2 points.

Two (2) legs with rollers are provided on the hatch cover. The rollers move within a channel anchored to the floor slab to prevent pivoting as the door is moved into the open position.

A concrete shield located outside the Reactor Building acts as a missile and biological shield.

2. Personnel Airlocks

Two (2) personnel airlocks are provided for access to the Reactor Building (see Figures 3.8-19 through Figure 3.8-20b). Each airlock has 2 doors which are sealed with double O-rings. Independent connections are provided between each double O-ring door seal and the handwheel shaft seals for leak testing in accordance with the requirements of Technical Specifications Section 3/4.6.1.3. For leak testing, the personnel airlocks can be independently pressurized to the Reactor Building design pressure.

During normal operation the outer and inner doors are interlocked so that neither door can be opened unless the other door is closed and latched. The inner door can be operated manually from inside the Reactor Building and from inside the airlock. The outer door can be operated manually from inside the airlock and from the outer side of the outer bulkhead.

In addition to the capabilities described above, the emergency personnel airlock has a remote operational capability for both doors from the opposite side.

The mechanical interlocking system can be deactivated to allow both doors to be left open when the plant is shut down. Doors are mechanically latched and are swung by manual means. Each door is furnished with a pressure equalizing valve which is operated by the latching mechanism.

Balanced magnetic switches provide input on airlock position to the Integrated Fire and Security System. Each airlock has position indication on a CRT in the Control Room as follows:

a. Alarm, if either of the 2 airlock doors is not shut.

b. Trouble, if the magnetic switch circuit has a ground or a break.

Additionally, an audible alarm is given upon a change in status.

3.8.1.1.2.4 Structural Attachments

1. Polar Crane Brackets

The polar crane brackets are located on an angular spacing of 11°-15' around the circumference of the Reactor Building with a top elevation of 548'-4-3/4". These brackets provide vertical and lateral support for the polar crane steel runway girders which are described in Section 3.8.3.

The brackets extend through the Reactor Building liner and are anchored into the concrete wall. The liner plate in the area of the brackets is 1/2 inch thick.

Forces and moments created by the crane wheel loads are carried into the brackets and thence to the concrete. See Figure 3.8-21 for details of the crane runway girders and brackets.

The crane and trolley bridge are prevented from being dislodged during an earthquake by lugs on the trolley and on the bridge trucks which extend below the supporting girders. These details are shown in Figure 3.8-22.

2. Pad Overlay Plates

   Small diameter circular overlay plates are fillet welded to the liner plate to support piping, ducts, conduit, and electric cable trays. Studs or angle anchors are provided on the liner behind the attachment plates to transfer loads on the pads into the concrete shell.

3. Equipment Supports

   The Reactor Building cooling units, charcoal filter units, and associated platforms are supported on the inside of the cylindrical shell of the Reactor Building by steel framing members which terminate at brackets located on the liner. The brackets consist of plate sections welded to the liner or to the thicker liner insert plates. The load is transferred into the concrete shell by the embedded portion of the bracket located on the outside of the liner plate. The embedded portions of the bracket consist of welded plate sections and headed concrete anchors.

3.8.1.2 Applicable Codes, Standards, and Specifications

3.8.1.2.1 General

Structural design, fabrication, construction, testing, and inservice inspection of the Reactor Building conform to the following documents unless noted otherwise herein:

1. Southern Standard Building Code, 1969 Edition.
2. American Concrete Institute, “Building Code Requirements for Reinforced Concrete,” ACI 318-71.
3. American Concrete Institute, “Criteria for Reinforced Concrete Nuclear Power Containment Structures,” ACI Committee 349 report, ACI Journal, January, 1972.
4. American Concrete Institute, “Specification for Structural Concrete for Buildings,” ACI 301-72, revised 1975.
5. American Institute of Steel Construction, “Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings,” February 12, 1969.
6. American Institute of Steel Construction, “Code of Standard Practice for Steel Buildings and Bridges,” July 1, 1970.
7. American Welding Society, “Structural Welding Code,” AWS D1.1-72.

8. Nuclear Regulatory Commission, Regulatory Guides, as discussed in Appendix 3A and listed below:
   a. Regulatory Guide 1.12, “Instrumentation for Earthquakes.”
   b. Regulatory Guide 1.18, “Structural Acceptance Test for Concrete Primary Reactor Containments.”
   c. Regulatory Guide 1.29, “Seismic Design Classification.”
   d. Regulatory Guide 1.76, “Design Basis Tornado for Nuclear Power Plants.”
   e. Regulatory Guide 1.94, “Quality Assurance Requirements for Installation, Inspection and Testing of Structural Concrete and Structural Steel during the Construction Phase of Nuclear Power Plants.”
9. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criteria 2, 4, 16, 50, 51, 52, and 53.

3.8.1.2.2 Concrete

The following codes, standards, and specifications are used to establish the properties of concrete and concrete coatings and to control concrete placement and concrete coating applications:

1. American Concrete Institute
   a. “Specification for Structural Concrete for Buildings,” ACI 301-72, revised 1975.
   b. “Building Code Requirements for Reinforced Concrete,” ACI 318-71.
   c. “Mass Concrete for Dams and Other Massive Structures,” ACI Title No. 67-17, a report by ACI Committee 207.
2. American Society for Testing and Materials
   a. “Standard Method of Test for surface Moisture in Fine Aggregate,” C70-73.
   b. “Standard Method of Test for Specific Gravity and Absorption of Coarse Aggregate,” C127-73.”
   c. Standard Method of Test for Specific Gravity and Absorption of Fine Aggregate,” C128-73.
   d. “Standard Method of Test for Length Change of Hardened Cement Mortar and Concrete,” C157-75.
   e. “Standard Method of Test for Thermal Conductivity of Materials by Means of the Guarded Hot Plate,” C177-71.
   f. “Manual of Coating Work for Nuclear Power Plant Primary Containment Facilities,” D01.43.
   g. “Standard Method of Test for Total Moisture Content of Aggregately by Drying,” C566-67.

h. "Standard Method of Test for Chloride Ion in Water and Waste Water," D512-67.

i. "Standard Method of Test for Sulfate Ion in Water and Waste Water," D516-68.

j. ASTM C109-08, Standard Test Method for Compressive Strength of Hydraulic Cement Mortars (Using 2-in Cube Specimens).

k. ASTM C1107-11, Standard Specification for Packaged Dry Hydraulic-Cement Grout (Nonshrink).

3. U.S. Army Corps of Engineers

   a. "Method of Test for Coefficient of Linear Expansion of Concrete," CRD-C39-55.

   b. "Method of Test for Flow of Grout Mixtures (Flow Cone Method)," CRD-C79-58.

   c. "Method of Test for Flat and Elongated Particles in Coarse Aggregate," CRD-C119-53.

   d. "Methods of Sampling and Testing Expansive Grouts," CRD-C589-70.

   e. CRD C621-93, Standard Specification for Packaged Dry Hydraulic-Cement Grout (Nonshrink).

4. National Association of Corrosion Engineers, "Coatings and Linings for Immersion Service," TPC No. 2.

5. Concrete Plant Manufacturers Bureau, "Concrete Plant Standard," Revision 5, March, 1973.

6. Truck Mixer Manufacturers Bureau, "Truck Mixer and Agitator Standards," Revision 9, November, 1971.

7. American National Standards Institute

   a. "Protective Coatings (Paints) for the Nuclear Industry," ANSI N5.12-74.

   b. "Quality Assurance for Protective Coatings Applied to Nuclear Facilities," (Proposed) ANSI N101.4-72.

8. Nuclear Regulatory Commission, Regulatory Guide 1.55, "Concrete placement in Category 1 Structures" as discussed in Appendix 3A.

3.8.1.2.3 Reinforcing Steel

The following codes and specifications are used to establish the properties of and to control the fabrication and placement of reinforcing steel:

1. American Society for Testing and Materials

   a. "Standard Specification for Deformed Billet Steel Bars for concrete Reinforcement," ASTM A615-72.

   b. "Standard Methods and Definitions for Mechanical Testing of Steel Products," ASTM A370-72.

2. American Concrete Institute

   a. "Specification for Structural Concrete for Buildings," ACI 301-72, Revision 1975. Bars of Category 1 Concrete Structures."

b. "Building Code Requirements for Reinforced Concrete," ACI 318-71.

3. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," Division 2, 1975.
4. Nuclear Regulatory Commission, Regulatory Guides, as discussed in Appendix 3A and listed below:
   a. Regulatory Guide 1.10, "Mechanical (Cadweld) Splices in Reinforcing Bars of Category 1 Concrete Structures."
   b. Regulatory Guide 1.15, "Testing of Reinforcing Bars for Category 1 Concrete Structures."

3.8.1.2.4 Post Tensioning System

The following codes, standards and specifications are used to establish the properties of and control the placement of the post tensioning system.

1. American Concrete Institute, "Criteria for Reinforced Concrete Nuclear Power Containment Structures," ACI Committee 349 report, ACI Journal, January, 1972.
2. Prestressed Concrete Institute, "Tentative Specification for Post Tensioning Materials," PCI Journal, January-February, 1971.
3. American Society for Testing and Materials
   a. "Specification for Uncoated Stress Relieved Wire for Prestressed Concrete," ASTM A421-65.
   b. "Specification for Conducting Drop Weight Test to Determine Nil-Ductility Transition Temperature of Ferritic Steels," ASTM E208-69.
   c. "Specification for Welded and Seamless Steel Pipe," ASTM A53-72a.
   d. "Specification for Zinc (Hot-Galvanized) Coatings on Products Fabricated from Rolled, Pressed and Forged Steel Shapes, Plates, Bars and Strip," ASTM A123-73.
   e. "General Requirements, Specification for Steel Sheet, Zinc-Coated Galvanized by the Hot-Dip Process," ASTM A525-71.
4. American Welding Society, "Structural Welding Code," AWS D1. 1-72.
5. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code,
6. Nuclear Regulatory Commission, Regulatory Guides, as discussed in Appendix 3A and listed below:
   a. Regulatory Guide 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures."
   b. Regulatory Guide 1.103, "Post-Tensioned Prestressed Systems for Concrete Reactor Vessels and Containments."
7. American Welding Society, "Code for Welding and Building Construction," AWS D1.0-69.

3.8.1.2.5 Steel Liner, Penetrations, and Attachments

The following codes, standards, and specifications are used to establish the properties of and control the placement of the steel liner, penetrations, and attachments:

1. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code
   a. Section II, “Material Specification Parts A and C"
   b. Section V, “Non-Destructive Examination”
   c. Section IX, “Welding Qualifications”
2. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, “Nuclear Power Plant Components,” Division 1.
   a. Including Winter 1972 Addenda for personnel airlocks and equipment hatch.
   b. Including Summer 1972 Addenda for liner, penetration sleeves, overlay pads, brackets, and insert plates.
   c. Including Winter 1975 Addenda for piping penetration assemblies.
   d. Including 1974 Edition for electrical penetration assemblies.
3. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, “Nuclear Power Plant Components,” Division 2, 1975.
4. American Welding Society, “Structural Welding Code,” AWS D1.1-72, Section 4, Part VI, “Stud Welding.”
5. American National Standards Institute
   a. “Safety Standard for Design, Fabrication and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors,” ANSI N6.2-1965; approved by American Nuclear Society and American Society of Mechanical Engineers.
   b. “Protective Coatings (Paints) for the Nuclear Industry,” ANSI N5.12-74.
   c. “Protective Coatings (Paints) for Light Water Nuclear Reactor Containment facilities,” (Proposed) ANSI N101.2-74.
   d. “Quality Assurance for Protective Coatings to Nuclear facilities,” (Proposed) ANSI N101.4-72.
6. American Nuclear Society, “Proposed Standard for Leak Rate Testing of Containment Structures for Nuclear Reactors,” ANS 7.60, Appendix A.
7. Institute of Electrical and Electronics Engineers, “Standards for Electrical Penetration Assemblies in Containment Structures for Nuclear Generating Stations,” IEEE-317-1972.
8. Title 10, Code of Federal Regulations, Part 50, Appendix J, “Reactor Containment Leakage Testing for Water Cooled Power Reactors.”
9. Steel Structures Painting Council, “Near White Metal,” SSPC-SP10.

10. Nuclear Regulatory Commission, Regulatory Guides, as discussed in Appendix 3A and listed below:
    a. Regulatory Guide 1.19, “Non-Destructive Examination of Primary Containment Liner Welds.”
    b. Regulatory Guide 1.63, “Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants.”

3.8.1.3 Loads and Load Combinations

3.8.1.3.1 Concrete Reactor Building

3.8.1.3.1.1 Load Definitions

Fundamental design loads for the Reactor Building are defined as follows:

1. D - Dead load of structure, hydrostatic loads, and permanent equipment loads.
2. L - Conventional floor and roof live loads and movable equipment loads, including piping, cables, etc. Other loads which vary intensity, such as soil pressures and polar crane loads are all included.
3. F - Post tensioning forces for any given loading condition.
4. P - Design accident pressure load. This pressure is based upon peak calculated pressure with appropriate margin provided for calculational uncertainties as described in Section 6.2.1.
5. R - Local force or pressure on structure or penetration caused by rupture of any one pipe.
6. T_o - Thermal effects under normal operating conditions, including liner expansion, equipment and pipe reactions, and temperature gradients.
7. T_a - Added thermal effects (over and above operating thermal effects) which may occur during a design basis accident and which correspond to a factored design accident pressure (i.e., 1.25P or 1.5P).
8. Earthquake
    a. E - Operating basis earthquake (OBE).
    b. E' - Safe shutdown earthquake (SSE). Vertical and horizontal earthquake accelerations are assumed to act simultaneously if appropriate for determination of maximum stress. Dynamic response characteristics of the structure, supporting rock, and rock pressures are considered in determination of forces due to earthquakes (E and E').
9. Z - External pressure resulting from internal pressure drop due to spray cooling.
10. Z' - Internal pressure resulting from atmospheric pressure drop due to a tornado.
11. W - Design wind load.
12. W' - Tornado wind load and tornado missiles.

3.8.1.3.1.2 Design Loads

1. Dead Load, Hydrostatic Loads, and Permanent Equipment Loads - D

   a. Dead load consists of the weight of the complete structure. A reinforced concrete density of 150 lb/ft^3 is used.

   b. Hydrostatic loads due to groundwater at elevation 423' are used in the design of the structural foundation mat. This results in a height of 27 feet of water acting at the bottom of the mat.

   c. Permanent equipment and piping loads on the Reactor Building shell under service loads (S) and factored loads (U) as follows:

      (1) Pipe penetration - normal reaction (D and To) - pipe break and earthquakes (R, E, and E').

      (2) Pipe supports - normal reactions (D and To) - pipe break and earthquakes (R, E, and E').

      (3) Polar crane - normal reactions (D and To) - earthquakes (E and E').

      (4) Air handling units - normal reactions (D and To) - earthquakes (E and E').

2. Snow, Ice, and Polar Crane Loads - L

   The Reactor Building is designed to withstand snow or ice loads of 20 lb/ft2. Polar crane lifted loads consist of 360 tons during construction and 157.5 tons during normal plant shutdown.

3. Post Tensioning Forces - F

   Forces on the Reactor Building at 40 years (original plant operating license), after the majority of post tensioning losses have occurred, are as follows:

   a. The 115 vertical tendons produce a vertical stress resultant of 335 kips/ft in the cylindrical wall.

   b. The 150 hoop tendons produce:

      (1) An external pressure of 5768 lb/ft^2 corresponding to 375 kip/ft hoop stress resultant in the 10 foot haunch

      (2) An external pressure of 11,535 lb/ft^2 corresponding to 750 kip/ft hoop stress resultant in the remaining wall height.

   c. The 99 dome tendons (33 per layer) produce an external pressure of approximately 13,835 lb/ft2 (varies over the dome).

   Initial post tensioning forces for the vertical, hoop, and dome tendons are 1.14, 1.18, and 1.15 times the above values, respectively.

The foregoing minimum required level of applied external prestress on the containment was calculated based upon the effects of prestress alone. Subsequent evaluations showed this external prestress could be reduced by including the effects of increased tendon forces due to expansion of the containment shell under accident pressure conditions. Subsequent evaluation of the dome tendon minimum required post tensioning force was performed utilizing the as-built reinforcement configuration, which resulted in reduction of the minimum required dome tendon group average anchorage force to 1025 kips.

4. Design Accident Pressure Load - P

   The Reactor Building design pressure, P, is 57 psig.

5. Operating Temperature - T_o

   Temperature profiles, shown by Figure 3.8-23, are based upon the following boundary conditions:

   a. Reactor Building Internal Temperature

      (1) Maximum, 120°F

      (2) Minimum, 50°F

   b. Average Monthly Ambient Temperature Outside the Reactor Building

      (1) Highest, 83.6°F

      (2) Lowest, 35.3°F

      These values are the highest and lowest average monthly ambient temperatures ever recorded in the vicinity of the site by the U.S. Weather Bureau.

   In addition to the above temperature conditions, the design includes a maximum thermal gradient based upon a 20°F outside temperature. The winter design dry-bulb temperature is expected to be 20°F or higher for 99% of the hours for the months of December, January, and February. The use of 20°F as an equilibrium outside air temperature is a conservative approach in that the Reactor Building wall thermal gradient will be maximized. The effects of the various temperature gradients and the thermal force exerted on the concrete by the Reactor Building liner are considered in the Reactor Building design. The effect of adjacent building temperatures (104°F, maximum; 65°F, minimum) is also considered in the design.

6. Added Thermal Effects - T_a

   The accident temperature gradients throughout the concrete wall of the Reactor Building are shown by Figure 3.8-24. The effects from these gradients are considered in the design of the Reactor Building. Thermal forces exerted on the concrete by the Reactor Building liner are also considered.

7. Earthquake Loads - E and E'

   Site seismology and response spectra are described in Section 2.5. Seismic design of the Reactor Building is based upon the response to ground accelerations described in Section 3.7.

8. External Pressure - Z

   The Reactor Building is designed for an internal vacuum, Z, of 3.5 psig which would result from inadvertent actuation of the Reactor Building Spray System.

9. Internal Pressure - Z'

   The Reactor Building is designed to withstand an internal pressure, Z' , equal to 3 psig occurring at a rate of 2 psi per second as a result of an atmospheric pressure drop due to a tornado.

10. Wind Load - W

    The Reactor Building is designed to withstand wind pressures corresponding to the design wind velocity discussed in Section 3.3.1.

11. Tornado Wind Load - W'

    The Reactor Building is designed to withstand tornado wind pressures and tornado generated missiles as discussed in Section 3.3.2.

12. Structural Acceptance Test

    Following completion of construction, the Reactor Building is subjected to an internal pressure test at 65.6 psig to verify structural integrity.

3.8.1.3.1.3 Load Combinations

The Reactor Building is designed to withstand various combinations of the loads defined in Section 3.8.1.3.1.1 and discussed in Section 3.8.1.3.1.2. These load combinations are presented in Table 3.8-1.

3.8.1.3.2 Reactor Building Liner and Attachments

3.8.1.3.2.1 Reactor Building Liner and Anchor Design Loads

Load definitions for loads used to design the Reactor Building liner and anchors are in accordance with the ASME Code, Section III, Division 2, Article CC-3220.

Specific loadings applicable to design of the Reactor Building liner and anchors are delineated by the load combinations presented in Table 3.8-2. The following loads apply to the design of the Reactor Building liner and anchors in addition to those discussed in Section 3.8.1.3.1.2.

1. Dead Load - D

   The Reactor Building liner is designed for the dead load of the liner, all bracing, scaffolds, and supports attached to the liner which are used during liner erection and construction.

2. Live Load - L

   The Reactor Building liner is designed for a 100 lb/ft^2 live load on the dome liner plates to account for loads on the dome liner due to reinforcing steel, tendon conduit, personnel, and equipment during construction of the concrete shell. A reduced live load is used during erection of the polar crane.

   The cylindrical portion of the liner also serves as the inside formwork for fresh concrete loads which occur during concrete placement. Live loads due to fresh concrete are calculated in accordance with ACI Publication SP-4, “Formwork for Concrete.” A pour rate of 2 feet per hour and a concrete temperature of 60°F are conservatively assumed.

   To support the fresh concrete, the dome liner is supported at close intervals by tying to the rigid system of dome tendon conduits as described in Section 3.8.1.6.1.3. The design of the dome liner to withstand fresh concrete loads takes this support system into account.

3. Wind Load - W

   During construction the Reactor Building liner is designed for wind loads resulting from a wind velocity of 70 mph at 30 feet above grade (based upon a 10 year recurrence interval) in accordance with ASCE Paper 3269 (Reference 1).

4. Operating Temperatures - T_o

   An operating temperature range of 50°F to 120°F inside the Reactor Building is considered in the design of the Reactor Building liner. An operating temperature range of 12°F to 92°F outside the Reactor Building is considered in the specification of materials and material properties. Local thermal effects at hot penetrations are also considered. However, these effects do not contribute to the controlling Reactor Building liner design loads since concrete temperature is limited to 200°F, maximum, at such local spots.

   Thermal effects at the time of the structural acceptance test are considered. These temperatures inside the Reactor Building are controlled during such testing.

   Transient thermal effects resulting from temperature changes within the Reactor Building during normal operation as well as during startup and shutdown are also considered.

5. Normal Pipe Reactions - R_o

   Load combinations applicable to Reactor Building liner and anchor design, as well as design of insert plates are presented in Table 3.8.2. These load combinations comply with the applicable portions of the ASME Code, Section III, Division 2, Table CC-3230-1.

   Fatigue effects are considered based upon the criteria stated in the ASME Code, Section III, Division 1, Class MC. Operating conditions involving cyclic application of loads and thermal conditions are considered.

6. Design Accident Pressure Load - P_a

   The Reactor Building design pressure, P_a, is 57 psig.

7. Structural Acceptance Test Pressure Load - P_t

   The Reactor Building structural acceptance test pressure load, P_t, is 65.6 psig.

8. Differential Pressure Load - P_v

   The Reactor Building differential pressure load, P_v, is 3.5 psig below atmospheric pressure and 3 psig above atmospheric pressure.

9. Earthquake Loads - E_o and E_{ss}

   Site seismology and response spectra are described in Section 2.5. Seismic design of the Reactor Building is based upon the response to ground accelerations described in Section 3.7.

10. Tornado Wind Load - W_t

    The Reactor Building is designed to withstand tornado wind pressures and tornado missiles as discussed in Section 3.3.2.

3.8.1.3.2.2 Bracket, Attachment, and Pad Overlay Plate Design Loads

Load Definitions for loads used to design brackets, attachments pad overlay plates, and assorted embedments are in accordance with the ASME Code, Section III, Division 2, Article CC-3220.

Specific loadings applicable to the design of these components are delineated by the load combinations presented in Table 3.8-3. The following loads apply to the design of brackets, attachments, and overlay plates in addition to those discussed in Section 3.8.1.3.2.1:

1. Dead Load - D

   Dead load consists of the weight of specific equipment and its associated support structure.

2. Live Load - L

   Polar crane bracket live load consists of a lifted load of 360 tons during construction or 157.5 tons during normal plant shutdown. Impact loads, as a percentage of wheel load, are also considered as live loads. Access platform live load is 150 lb/ft^2.

3. Earthquake Loads - E_o and E_{ss}

   Earthquake loads are obtained from system analyses of ducts and piping or from the seismic analysis performed by the vendors of equipment such as the polar crane.

These load combinations are in compliance with the ASME Code, Section III, Division 2, Article CC-3750.

3.8.1.4 Design and Analysis Procedures

3.8.1.4.1 Concrete Reactor Building

For structural analysis purposes, the Reactor Building geometry is idealized in various structural models depending upon the particular structural component to be analyzed. These components are: the structural foundation mat, the general shell, the thickened openings, the ring girder, and the buttresses.

3.8.1.4.1.1 Structural Foundation Mat

Two (2) finite element models are used depending upon whether the load combination creates symmetrical or unsymmetrical uplift of the mat. The models are shown by Figures 3.8-25 and 3.8-26, respectively. The analytical method used is the ELAD (S014) computer program described in Section 3.8.4.4.

3.8.1.4.1.1.1 Symmetrical Uplift

Load combination 4a in Table 3.8-1 causes a symmetrical uplift condition. However, the mat reinforcement is generally controlled by the unsymmetrical uplift condition described in Section 3.8.1.4.1.1.2. The forces and tractions resulting from load combination 4a are applied over the top of the mat and on the portion of the Reactor Building wall included in the model. The forces for the wall at elevation 438' are obtained from an analysis of the general shell which is described in Section 3.8.4.1.2. Hydrostatic pressures due to ground water at elevation 423' are applied along the bottom of the mat at the mat-fill concrete interface. A thin row of elements exists at this interface. These elements are assigned a zero shear modulus, G_{RZ}, to conservatively calculate the radial stress resultant, N_R, which is produced by the mat radial expansion, caused by the 1.5P term of the load combination.

Accommodation of the symmetrical uplift of the mat from the fill concrete is accomplished by removing interface elements which exhibit tensile vertical stresses, σ_z, under the total forces

resulting from the load combination 4a. Removal of these elements is an iterative process. The results of the first iteration indicate that tensile σ_z stresses occur in the outermost rings of interface elements and compressive σ_z stresses exist in the remaining elements which are located radially inside these rings. For the second iteration, the tensile stressed elements are removed. The results of the first iteration indicate that the outermost rings of elements which were previously compressive are now tensile. These tensile elements are removed for the next iteration. This process is continued until all the interface elements exhibit compressive σ_z stresses. In this condition, the computed symmetrical uplift occurs from radius 38 feet to 77 feet and the mat is supported by the fill concrete in bearing from radius 0 to 38 feet.

The displacement boundary conditions for the model are applied to the boundaries of the fill concrete as shown by Figure 3.8-25. These boundaries are of sufficient extent so that the specified displacement boundary conditions do not affect the mat stresses.

3.8.1.4.1.1.2 Unsymmetrical Uplift

Unsymmetrical forces on the Reactor Building can result from load combinations 3c, 4b, 5a, and 5b of Table 3.8-1. However, only those load combinations including the seismic forces E or E' are sufficient to produce uplift of the mat. These load combinations produce the largest reinforcement requirements. The extent of uplift is calculated from static overturning analyses which include the hydrostatic uplift force due to ground water at elevation 423'. Structural analyses of the mat are performed for load combinations 4b and 5a.

For analytical purposes each load combination is separated into symmetrical and unsymmetrical parts:

Load Combination	Symmetrical	Unsymmetrical
1. 4b	$(D + F + T_o + T_a + 1.25P)$	$+ (D + 1.25E)$
2. 5a	$(D + F + T_o + T_a + P)$	$+ (D + E')$

These terms are defined in Section 3.8.1.3, except that D represents the reduced effective dead load of the structure that results from the vertical acceleration corresponding to 1.25E or E' in addition to hydrostatic uplift pressures. The terms L and R are not applicable for mat design and are, therefore, not included.

The structural analysis of the symmetrical parts is performed using the ELAD model presented by Figure 3.8-25 in accordance with the iteration procedure previously described. The ELAD Model presented by Figure 3.8-26 is used to analyze the mat for the unsymmetrical parts. The internal stress resultants in the mat obtained from the 2 ELAD models are combined, except where larger rebar requirements result from exclusion of the LOCA. When this occurs, rebar requirements are controlled by D + E'. The stress resultants are obtained by integrating the output stresses across the mat section thickness.

The loads on the mat for the unsymmetrical parts of the load combinations consist of applied loads and reactor loads. The applied loads consist of the hydrostatic pressures plus the dead weight and seismic forces from the internal concrete structures, major equipment, and the Reactor Building shell. The hydrostatic pressures are applied to the mat at elevation 396' and elevation 374'. The seismic forces are determined from the lumped-mass model, time-history analysis of the Reactor Building using the dynamic analysis procedure described in Figure 3.7.2.1. From this analysis, the total vertical and horizontal forces and overturning moment are obtained separately for the internal concrete and the shell. Their combined effect is largest at a time when the response accelerations of the shell are largest. The seismic forces at this time for the internal concrete are distributed to the primary and secondary shield walls and steel column ring according to their respective stiffnesses. Tractions and nodal point forces are applied to the top of the mat at their respective radii such that the vertical and horizontal forces and overturning moment of each are represented. The forces and overturning moment for the shell are obtained from the seismic analysis at elevation 438'. These are represented as tractions and nodal point forces on the shell at the corresponding elevation in the ELAD model. The seismic acceleration of the shell from elevation 438' to elevation 408' and of the 12 foot mat are described through the use of body forces on the model. All applied loads can be represented by the 0th and 1st Fourier harmonics for input into ELAD.

The applied loads and the reaction loads are simultaneously applied to the model shown by Figure 3.8-26. The model is in static equilibrium under these loads and displacement boundary conditions are not required. For the ELAD analysis, however, zero displacement boundary conditions must be specified to remove rigid body displacements. For the load equilibrated mat, these zero displacements must be specified at nodes such that internal stresses are not affected. This is accomplished by incorporating a low stiffness column, located at the mat centerline and extending 30 feet below the incore base, into the model. The zero displacement boundary conditions are specified at lower nodes in the column. A review of the results at the interface of the column and incore base indicates that the stresses are practically zero. Hence, incorporation of the column in the model allows for removal of rigid body displacements without influencing mat stiffness or stresses.

The reaction loads are normal and shear tractions which occur at the mat-fill concrete interface to equilibrate the applied loads. These tractions are linearly distributed over the nonuplifted part of the mat. They are zero at the start of uplift and maximum at the mat perimeter. These tractions are accurately described by a 10 term Fourier Series for input to the ELAD analysis.

3.8.1.4.1.1.3 Mat Design

The mat is designed to resist the stress resultants obtained from the analysis previously described. The main reinforcement (radial and hoop) is designed based upon the linear stress and strain distributions discussed in Section 3.8.1.5.1.1. The resulting reinforced concrete section satisfies the criteria of Section 3.8.1.5.1.

The temperature distributions shown by Figures 3.8-23 and 3.8-24 were considered in the mat design. This information was used to establish linear thermal gradients in the incore base, walls, and mat. The design procedure for these gradients is described in Section 3.8.1.4.1.2. The linear

gradients were included in the design if a larger reinforcement requirement resulted. This occurred for the bottom reinforcement in the incore base and mat and for the outside reinforcement in the incore walls. In areas of the mat where the liner is exposed (incore base and part of incore walls) the active force of the liner on the concrete due to To and Ta was included. The allowance for a cracking reduction of the thermal stresses is described in Section 3.8.1.4.1.2. The design for transverse shear is in accordance with Chapter 11 of ACI 318-71 [2], except that Section 11.2.2 of ACI 318-71 is not applicable. The calculated nominal shear stress, V_u, is obtained from the transverse shear stress resultant, V_u, using Equation (11-3) of ACI 318-71. Wherever V_u exceeds the permissible shear stress, v_c, of ACI 318-71, Section 11.4, shear reinforcement in the form of closed ties is sized using Equation (11-13) of ACI 318-71. Wherever V_u is less than v_c but greater than 1/2 v_c, minimum closed tie shear reinforcement is provided in accordance with Equation (11-1) of ACI 318-71.

Transverse shear transfer across construction joints is provided by the keys described in Section 3.8.1.6.1.3.

The portion of the mat spanning over the incore pit was considered as a deep beam using References 3 and 4 and the shear provisions of Section 11.9 of ACI 318-71. Because the seismic response of the internal concrete produced a torsion on this portion of the mat, the provisions of Sections 11.7 and 11.8 of ACI 318-71 were also applied.

To ensure the ability of the mat to develop its design capacity, diagonal bars extending from the incore walls through the mat were provided based upon information reported in Reference 5.

Concrete cover of reinforcement is not less than that specified in Table 3.8-4.

The effects of shrinkage, creep and material property variation are discussed in Section 3.8.1.4.1.2.

3.8.1.4.1.2 General Shell

Design of the Reactor Building wall and dome is based upon stress resultants obtained from 2 computer programs:

1. KALNINS Static Program (S043)
2. KALNINS Dynamic Program (S032)

These programs are discussed in Section 3.8.4.4.

The model for the analyses is shown by Figure 3.8-27. The design of additional reinforcement around the unthickened penetrations, including main steam and feedwater, is based upon stress concentration factors applied to the stresses from the KALNINS analyses. The additional effects of pipe rupture are included, as discussed in subsequent paragraphs of this section.

KALNINS static computer program is used to obtain stresses and stress resultants for the individual fundamental loads D, F, P, T_o, T_a, Z, Z', W, and W', defined in Section 3.8.1.3. The unsymmetrical fundamental loads W and W' are discussed in Section 3.3. Their effective pressures, shown by Figures 3.3-2 and 3.3-3, are represented in the computer program using a 10 term Fourier Series. Design procedures for tornado missile loads are described in Section 3.5.1.

KALNINS dynamic computer program is used to obtain the stresses and stress resultants in the shell due to E and E'. In these analyses, the 2% structural damping curves of Figures 3.7-1 and 3.7-2 are used.

Stress results from this analysis are increased by 20% based upon a comparison of shell overturning moments from KALNINS dynamic computer program and the time history seismic analysis discussed in Section 3.7.2.1.

The stresses and stress resultants for the load combinations were obtained by applying the appropriate load factors to the fundamental load results combined according to the load combination listed in Table 3.8-1. Since the shell model is fixed at the base, the results near the base were modified to account for the effect of the mat uplift under load combinations 4a, 4b, and 5a. For the remainder of the load combinations, the fixed base model yields conservative results. In cases where the combined stresses are entirely compressive through the shell thickness, those stresses are compared with the allowable criteria in Section 3.8.1.5. Where tensile concrete stresses exist, uncracked stress resultants are used in a cracked section design of reinforcement according to the criteria specified in Section 3.8.1.5.1.1.

The resulting concrete section satisfies the criteria stated in Section 3.8.1.5.1. Such reinforcement satisfies the crack control requirements of Paragraph 2.5.4 of Reference 6. The splice requirements of Paragraph 2.5.3 of Reference 6 are also satisfied through use of Cadweld splices for all main vertical and hoop reinforcement in the wall. Cadweld splices are also used for dome reinforcement which is required to resist tensile forces while subjected to perpendicular tensile stresses and for the #14 hoop bars.

Concrete cover of reinforcement is not less than that specified in Table 3.8-4.

3.8.1.4.1.2.1 Prestress

The level of prestress at 40 years (original plant operating license), accounting for the majority of losses, is established using the minimum requirements of load combination 6, Table 3.8-1. These losses are identified as follows:

1. Friction

   The friction losses used in the design are based upon the following wobble, K, and curvature, μ, coefficients:

   a. For hoop and dome tendons

(1) K = 0.0003

(2) $\mu = 0.16$

b. For vertical tendons:

(1) K = 0.0003

(2) $\mu = 0.16$

2. Elastic Shortening

The prestress loss due to elastic shortening is based upon 1/2 of the elastic shortening due to initial prestress forces.

3. Creep of Concrete

Prestress loss due to creep is based upon the following calculated 40 year concrete creep strains:

a. Vertical, 210 micro in/in.

b. Hoop, 390 micro in/in.

c. Dome, 330 micro in/in.

These values are used in an interaction prestress loss analysis (Reference 7).

4. Shrinkage

Prestress loss due to shrinkage is based upon a conservative 40 year value of 100 micro in/in.

5. Steel Relaxation

Prestress loss due to tendon wire relaxation is based upon a 40 year stress relaxation value of 8.5%. This is used in an interaction prestress loss analysis (Reference 7).

The results of the third tendon surveillance indicated that loss in prestress force was occurring at a faster rate than originally predicted. Wire stress relaxation testing was performed at Lehigh University Fritz Engineering Laboratory to verify the 8.5% stress relaxation value assumed for the original design. Testing was performed on samples of wire from actual tendons in the containment. Samples were tested at several temperatures including the temperature representative of the average temperature at the location of the tendons within the containment shell. Based on the results, a wire stress relaxation value of 12.8% for 40 years is used to predict prestress losses for the fourth and subsequent surveillances.

The level of initial prestress, which is necessary to satisfy the 40 year requirements, does not exceed the criteria stated in Section 3.8.1.5.1.2.

The design procedures for tendon anchorages are presented in Section 3.8.1.4.1.4.

3.8.1.4.1.2.2 Temperatures T_o and T_a

The T_o temperature distributions, shown in Figure 3.8-23 and the T_a temperature distributions shown in Figure 3.8-24 for winter and summer startup and shutdown conditions, are included in the design. At sections in the shell where stresses due to these actual distributions do not cause concrete tension when combined with stresses for the remaining part of the load combination, the uncracked stresses are compared with the criteria stated in Section 3.8.1.5.1

In cases where the combination of these stresses produces a concrete tensile stress, a cracking reduction of the thermal stress only is permitted. If the temperature distribution under consideration is nonlinear, an effective linear distribution is obtained. The effective linear gradient is such that it has the same average temperature and produces the same moment about the center of gravity of the uncracked section as does the actual nonlinear temperature distribution. The steady-state temperature distributions are linear. The linear gradients are then used in the design as follows:

1. The uncracked thermal stress resultants produced by the average temperature across the section plus the liner expansion are combined with the uncracked stress resultants for the remaining part of the load combination. The combined stress resultants are N and M.
2. The balance of the temperature distribution is a linear gradient, ΔT, which has a zero average temperature. The additional effects of this gradient are determined using the following procedure:
   a. Analyze the section for N plus M based upon a cracked section and a linear strain.
   b. Determine the location of the neutral axis, the slope, S_L, of the strain diagram, and the resulting stresses as determined by N and M above.

$$S_L = \frac{f_c}{kd\,E_c}$$

where:

f_c = Maximum concrete stress

kd = The neutral axis

E_c = Modulus of elasticity of concrete

c. Determine the slope, S_T, of the strain diagram due to the applied temperature gradient based upon an uncracked section:

$$S_T = \frac{\alpha \Delta T}{t}$$

where:

α = Coefficient of thermal expansion

ΔT = Temperature differential across the wall

t = Thickness of the wall

d. Equate the slope of the final strain diagram, S_c, to S_L plus S_T. Strain due to the applied load plus thermal gradient is then:

$$S_c = \frac{f_c}{kd\, E_c} + \frac{\alpha \Delta T}{t}$$

e. Knowing the slope of the final strain diagram, Sc, and equating the sum of the forces of the final stress diagram to the applied axial force, the location of the neutral axis for the combined loading of N plus M plus temperature gradient can be determined as follows:

(1) Net axial load, N, excluding thermal gradient:

$N = A_{sfs} - 1/2\ f_c\ kd$

(2)Net axial load, N, plus thermal gradient:

$N = A_{sfst} - 1/2\ f_{ct} kd_t$

(3) By equating the above 2 expressions for N and substituting:

$f_{ct} = S_c kd_t\ E_c$, and

$f_{st} = S_c\ (d - kd_t)\ n\ E_c$, and solve for kd_t

where:

f_s = Tensile stress in reinforcing steel due to N and M

f_{st} = Tensile stress in reinforcing steel due to N and M plus thermal gradient

f_{ct} = Compressive stress in concrete due to N and M plus thermal load.

kd_t = Distance from compressive face of concrete to the neutral axis.

f. Calculate the resulting stresses by back substitution into the equations for f_{ct} and f_{st}, above.

The design includes the effects of the following:

1. Adjacent building temperatures.
2. Average temperature differences between the shell and ring girder during startup and shutdown.

The active force of the liner on the concrete under T_a produces a tensile axial stress resultant which is limited by the compressive yield capacity of the liner plate material. For purposes of reinforcement design, a liner compressive yield strength of 45 ksi is used based upon the average strength from mill test reports. The tensile axial stress resultant in the concrete is determined from the difference between 45 ksi and the liner stress under normal operating conditions. This tensile force is combined directly with stress resultants on the section without regard to time differences between P and T_a. These time differences are considered, however, in determining the effects of the nonlinear accident temperature distribution on concrete stress.

3.8.1.4.1.2.3 Radial Shear

Radial shear acts perpendicular to the wall of the Reactor Building.

Reinforcement for radial shear is in accordance with Chapter 11 of ACI 318-71, except that Section 11.2.2 of ACI 318-71 is not applicable.

The calculated nominal shear stress v_u, is obtained from the radial shear stress resultant, v_u, using Equation (11-3) of ACI 318-71. Wherever v_u exceeds the permissible shear stress, v_c, shear reinforcement is provided using Equation (11-13) of ACI 318-71. The permissible shear stress, v_c, is described in Section 3.8.1.5.1.

Radial shear transfer across construction joints is provided by the keys described in Section 3.8.1.6.1.3.

3.8.1.4.1.2.4 Tangential Shear

Tangential (membrane) shear acts tangential to the wall of the Reactor Building. The provisions of Section 11.16 of ACI 318-71, are not applicable to design for this shear. Load combinations 4a and 5b of Table 3.8-1 produce tangential shear along with membrane tensile stress resultants which are resisted by vertical and hoop reinforcement. The design criteria for the reinforcement is that the steel ratio, p_v, provided for tangential shear, both vertically and horizontally, is at least

$$p_v = \frac{A_v}{ta} = \frac{v_u}{\phi f_y},$$

and that this steel ratio is in addition to that required to resist membrane tensile forces where:

A_v = Area of reinforcement within distance a

t = Thickness of the wall

a = spacing measured perpendicular to bars

v_u = Nominal tangential shear stress

ϕ = 0.85

f_y = Minimum specified yield strength of reinforcement

The value of the nominal shear stress, v_u, does not exceed $8\sqrt{f'_c}$.

Tangential shear transfer across construction joints is provided by the roughening of these joints as described in Section 3.8.1.6.1.3.

3.8.1.4.1.2.5 Radial Tension Under Post Tensioning

To prevent lamination under prestress, radial ties are provided to resist the forces caused by the curvature of the hoop and dome tendons.

In the dome, the ties enclose both the top surface reinforcing and extend past the lower layer of prestressing tendons, and conform to the larger of Criterion (a) or Criterion (b). For the cylindrical shell, the ties enclose the reinforcing of both surfaces and conform to Criterion (a).

1. Criterion (a)

   The area of the ties shall be sufficient to resist, at 0.5 f_y, the radial components of all prestress forces multiplied by the distance from the outside surface to the centroid of the tendon system and divided by the total shell thickness.

2. Criterion (b)

   The area of the ties shall be sufficient to resist, at 0.5 f_y, the radial components of the prestress forces in the innermost layer of tendons.

The maximum tie spacing does not exceed the thickness of the shell.

3.8.1.4.1.2.6 Penetrations

The following discussion pertains to the reinforced concrete design around all penetrations except the equipment hatch and personnel air locks which are discussed in Section 3.8.1.4.1.3.

The stress concentration increase of shell stresses and the resulting reinforcement requirements are determined for all penetrations using the information in References 8 and 9. The additional

concrete stress resultants due to pipe rupture effects from the main steam and feedwater lines are determined using References 10, 11, and 12 in conjunction with results of an ELAD analysis of the main steam penetration.

The main steam and feedwater pipe rupture loads, R, on the Reactor Building include reactions from the penetration sleeve and jet impingement. Impact of the ruptured pipe is prevented by the restraints described in Section 3.6. The forces on the sleeve are calculated axial loads, shears, and moments from the pipe. The moment on the sleeve is the ultimate moment the pipe is capable of developing. The axial load and shear on the sleeve are based upon thrust forces which have been increased to account for dynamic effects.

The reinforcement around penetrations consists of the general shell vertical and hoop bars supplemented by additional vertical, horizontal, and diagonal bars. This system of reinforcement is designed to resist the forces in the concrete as discussed above. The general shell bars are deflected around the penetration sleeves except where prohibited by the penetration size. In such cases, the shell bars terminate in a 90 degree bend that is continuous with the opposite face bar. The deflected shell bars are provided with tie-back bars which are designed to resist calculated forces caused by the change of direction of the deflected bars. In the areas of the main steam and feedwater penetrations it was necessary to increase the size of the general shell reinforcement in addition to providing the supplemental bars.

Pipe rupture forces from the main steam line are large enough to produce a punching shear requirement for radial shear ties. These ties are based on Equation (11-13) of ACI 318-71 with $v_c = 2\sqrt{f'_c}$. The nominal shear stress, v_u, is less than the $6\sqrt{f'_c}$ allowable stress appearing in Section 3.8.1.5.1.

Pipe rupture forces for the feedwater line are not large enough to cause v_u to exceed the $4\sqrt{f'_c}$ allowable stress given in Section 3.8.1.5.1. However, shear ties are provided to resist the axial thrust on the penetration sleeve.

3.8.1.4.1.2.7 Shrinkage and Creep

The effect of concrete shrinkage on the design stress resultants is insignificant due to the large volume-to-surface ratios of the Reactor Building elements. Rapid drying of the Reactor Building exterior was minimized by use of the 14 day water curing process described in Section 3.8.1.6.1.3. However, the main reinforcement is located sufficiently close to the surface to adequately control shrinkage cracking. Any stresses which may have been produced in the reinforcement due to surface drying tend to be compressive and thus, do not reduce the capacity of the reinforcement since the reinforcement is provided to resist tensile forces.

For purposes of calculating prestress losses, a conservative value for 40 year shrinkage strain of 100 micro in/in is used as discussed previously. This is approximately 10 times greater than would be calculated using the information in Reference 13.

The effect of concrete creep under dead and prestress loads is included in the prestress loss calculations and in the structural analysis. Concrete creep with time sheds compressive stress from the concrete to the liner. This results in less concrete compressive stress available to resist the design accident and extreme environmental load combinations and increases reinforcement requirements. The increased liner stress is accompanied by increased strains.

Both of these effects are considered in the design through the use of an effective Young's Modulus, E'_c. This modulus is obtained from the creep curves in Reference 13. From these curves, specific creep strains, sc, are obtained, considering both concrete age at loading and duration of loading. The effective modulus is expressed in terms of specific creep as:

$$E'_c = \frac{E_c}{1 + scE_c}$$

where:

E_c = Instantaneous Young's Modulus = 4×10^6 psi

sc = Specific creep (micro in/in/psi)

3.8.1.4.1.2.8 Material Property Variations

Material quality control, described in Section 3.8.1.6, assures that minimum strength material requirements are achieved. Overstrength of the liner and mechanical property variation of the concrete materials are considered in the design.

As discussed previously, the liner, during a temperature increase, exerts a tensile force on the concrete. For design purposes, the magnitude of this force is assumed to be limited by the compressive yield strength of the liner. The liner material identified in Section 3.8.1.6 has a minimum specified yield strength of 32 ksi. However, for the design of reinforcement, a liner compressive yield strength of 45 ksi was used. This is based upon the average yield strength of the same grade of liner material as obtained from mill tests.

The effect of variations of Young's Modulus between concrete pours was considered. Testing laboratory data on the design mix and the field compression test data were reviewed. Based upon this review, it was concluded that the variations of the mechanical properties were sufficiently close to the design values to have an inconsequential effect on structural analysis results.

3.8.1.4.1.3 Access Openings

The design of the thickened Reactor Building wall in the vicinity of the equipment hatch and personnel airlock is based upon the stress resultants obtained from a finite element analysis of the local areas. A doubly curved, quadrilateral shell element is used. The boundary conditions for the local model, shown by Figure 3.8-28, are obtained from the general shell analysis discussed in Section 3.8.1.4.1.2. The local model is arranged so that the appropriate horizontal and vertical symmetries are used with the applied load and displacement boundary conditions. The local model extends into the surrounding normal 4 foot wall to the extent that effects of the thickened

portions have dissipated and the general shell boundary conditions are valid. In the preliminary analysis phase, a course mesh finite element model of the overall cylindrical shell, including buttresses and thickened openings, is used to provide the appropriate dimensional extent of the finer mesh localized model.

Analyses are performed for the individual fundamental loads. Stress resultants are then combined according to the load combinations determined to be critical in the general shell analysis. Internal pressure load on the access hatch door is applied to the perimeter of the opening as a distributed shear load. Hoop prestressing forces are applied as an equivalent external pressure. The added local effects of the tendon draping pattern are considered. The treatment of thermal loads is the same as that descried for the general shell.

In the design, the tangential shear stresses due to earthquake loading are based upon the course mesh model results. The model consists of the entire cylindrical shell with the thickened access areas, fixed at the base. Displacements at the top, obtained from the general shell analysis, are introduced as boundary conditions. The thickened access opening is oriented 90° to the earthquake direction.

Other aspects of the design procedure are the same as described for the general shell.

3.8.1.4.1.4 Buttresses

The buttresses are designed to resist local tendon anchorage forces, as well as the meridional and hoop stress resultants induced by the load combinations in Table 3.8-1.

The concrete bearing stresses behind the anchorage plates are based upon initial prestress at lockoff.

Local bursting stresses due to tendon anchorage forces are conservatively calculated assuming an isolated equivalent block and using the three independent analysis procedures described in References 14, 15, and 16. The results obtained from the 3 methods are evaluated to arrive at the amount of bursting reinforcement required.

Spalling stresses are considered in accordance with Guyon’s recommendation and further investigated on the basis of a “bending away” mechanism as described in Reference 17.

Requirements for ties connecting the buttress to the shell wall are obtained by hypothesizing a vertical failure plane at the Interface of the wall and buttress. An unbalanced hoop tendon force is assumed to exist which is resisted by the ties according to the shear friction provisions of Section 11.15 of ACI 318-71.

The design of the buttress reinforcement is based upon the results of the course mesh finite element model described in Section 3.8.1.4.1.3 and the results of a plane stress finite element analysis using Wilson’s Program (SO66), described in Section 3.8.4.4. The discontinuity effect of the mat in the vertical direction is considered using classical shell theory and accounting for the buttress thickness.

The model for the plane stress analysis is shown by Figure 3.8-29. The boundaries of the model, at the buttress centerline, and midway between buttresses, are lines of symmetry with respect to Displacements. Roller Displacement boundary conditions are applied at these boundaries. The internal accident pressure and hoop tendon forces are applied as normal tractions. The action of the liner under a temperature increase is represented as an equivalent internal pressure.

Other aspects of the design procedures are the same as described for the general shell.

3.8.1.4.1.5 Ring Girder

The design of the ring girder is based upon the stress results obtained from the computer programs ELAD, KALNINS Static, and KALNINS Dynamic. All 3 programs are used specifically for the analysis of axisymmetric structures subjected to both axisymmetric and nonaxisymmetric load cases. These computer programs are described in Section 3.8.4.4.

The ELAD model, shown by Figure 3.8-30, represents the entire Reactor Building above elevation 497'. This boundary is far enough below the ring girder (60 feet) so that only membrane stresses occur. Hence, the specification of “roller” Displacement boundary conditions is applicable for the fundamental loads used on the model. The ELAD model includes the 2 layers of anchorage pockets for the dome prestress tendons. The model is used to obtain stress results for the fundamental loads:

D, L, F, P, T_o, T_a, Z, and Z'.

These stresses are integrated across the concrete section to obtain the stress resultants used in the reinforcement design. They are combined with the general shell stress resultants for W, W', E, and E' to construct the load combinations in Table 3.8-1.

The prestress fundamental load, F, is sub-divided into 3 separate load cases:

1. Vertical Prestress, F_v
2. Dome prestress, F_d
3. Hoop prestress, F_h

The dome prestress load, F_d, is a nonaxisymmetric load in that, within 60 degree dome segments, the anchorage forces may vary in magnitude depending upon whether 1 or 2 tendon layers are anchored. Because of this it was necessary to consider stress results at 2 azimuths in the ring girder. These are the locations where the anchorage forces are maximum and minimum.

The remaining part of the dome prestress load is represented by meridionally varying normal and meridional shear tractions applied to the appropriate dome elements. These occur simultaneously with nonuniform anchorage forces at the lower and upper anchorage pockets which are represented by a 2 term Fourier Series.

The treatment of operating and accident temperature loads T_o and T_a is discussed in Section 3.8.1.4.1.2.2. Differential heating and cooling between the ring girder and the wall and dome, as measured by the average temperatures in these sections, are examined. The resulting stresses are included in reinforcement design for the ring girder.

At normal operating conditions, the effective linear thermal gradients in the ring girder, the calculation basis of which has been previously discussed, are less than the steady-state gradients. Hence, for such conditions the steady-state values are used in the reinforcement design. At accident temperature conditions, higher equivalent linear thermal gradients are obtained. These values are used in the design.

The design for tendon anchorage forces is discussed in Section 3.8.1.4.1.4.

Other aspects of the design procedures are the same as described for the general shell.

3.8.1.4.2 Liner Plate

Reactor Building liner plate design and analytical procedures are in accordance with the ASME Code, Section III, Division 2, Article CC-3600.

3.8.1.4.2.1 Cylinder and Dome Liner Plate

Since the concrete Reactor Building shell is much stiffer than the liner plate, strains in the liner are compatible with the strains in the Adjacent shell concrete to which the liner is attached at close intervals. The strains in the liner are obtained from the analyses of the Reactor Building shell described in Section 3.8.1.4.1.

Strains in the liner due to localized conditions and transients associated with design basis accident temperature are computed separately based upon the equation

$$\varepsilon = \alpha \Delta T$$

where:

ε = Strain

α = Coefficient of thermal expansion for the liner

ΔT = Change in temperature of the liner

These strains are combined with the strains due to the other loadings in the load combinations, including design basis accident or localized thermal loadings due to postulated pipe rupture.

3.8.1.4.2.2 Floor Liner Plate

The thickened knuckle plate at the floor to sidewall transition of the liner is analyzed using KALNINS Static Program (see Section 3.8.4.4). Boundary conditions are taken from the analyses of the cylindrical wall and the mat analyses described in Sections 3.8.1.4.1 and 3.8.5.4.

The floor liner and the portions of the liner extending into the incore instrumentation pit are analyzed with the surrounding mat and interior concrete structures using the ELAD finite element computer program (see Section 3.8.4.4). The mat analyses are discussed in Sections 3.8.1.4.1 and 3.8.5.4. Analysis of interior concrete structures is described in Section 3.8.3.4.

3.8.1.4.2.3 Brackets, Attachments, Pad Overlay Plates, and Inserts

Manual calculations are employed in the analyses of pad overlay plates and inserts. Brackets and attachments together with their anchorages into the Reactor Building wall are designed in accordance with the provisions of AISC, “Specification for the Design, Fabrication and Erection of Structural Steel for Buildings” (Reference 18).

3.8.1.4.2.4 Anchors

The analysis and design of the liner anchors considers the effects of the following:

1. Unbalanced loads resulting from the variation of liner curvature.
2. Variation in anchor Spacing.
3. Misalignment of liner plate seams.
4. Liner thickness greater than nominal due to tolerances specified by ASME SA20.
5. Variation in liner plate yield stress higher than the specified minimum.
6. Local concrete crushing in the anchor zone.
7. Variation in anchor stiffness due to variation of concrete modulus.
8. Voids in the concrete behind the liner.

The liner anchorage system consists of meridional angles (3 by 3 by 1/4 inch) Spaced at 15 inch centers. The effects of Adjacent panel buckling are considered in the design of the anchor to liner welds and the anchors.

The design and analysis of the steel liner and anchor system was based upon the considerations and approaches described in Reference (Reference 19). The referenced approach considers a liner anchorage system utilizing the same basic parameters as were used for this design.

The analysis considers a 1 inch wide strip of liner plate and angle anchor. The mathematical model consists of a simplified spring-node system as shown by Figure 3.8-30a. Anchorage Displacements have been determined based upon the solution of the equilibrium equations for Displacement at each node.

The following simplifying and conservative assumptions have been considered in the analysis. Internal pressure accompanying the high temperature for accident conditions has been disregarded. Buckling inward, in a direction opposite to initial outward curvature, has been disregarded. The model considers initially straight panels with the exception of the buckled panel.

The stable panels are assumed to exert an in-plane shear force corresponding to their yield stress although the critical load, considering an initially straight member, may be less than the load corresponding to yield stress.

Certain material, fabrication, and construction variables affect the liner-anchor system design. Initial inward curvature of the assumed buckled panel and variation in anchor Spacing decrease the post buckling strength of the buckled panel. Liner thicknesses in the unbuckled panels of 16% greater than nominal due to rolling tolerances result in increased anchor forces and deformations. However, this effect is considerably less than an increase in yield stress above the minimum yield stress (Reference 19).

For this design, an increase in the yield stress of 35% over the nominal yield stress (43 ksi used versus 32 ksi nominal yield SA516, Grade 60 material) is conservatively adequate to account for material yield, as well as liner thickness variation.

ASME Code Class MC tolerances are adhered to for alignment of liner plate seams. Nominal weld reinforcement at the weld seams assure no decrease in panel strength due to misalignment within specified tolerances.

Local concrete crushing in the anchor zone may occur. Any crushing is expected to occur at the corners where the anchor is welded to the liner. This local crushing is accounted for in the design by using a load-Displacement relation for the anchor based upon tests of the liner-anchor system to the ultimate load (Reference 19). Concrete modulus is relatively uniform for the Reactor Building shell concrete and, therefore, does not affect the liner anchor design. Small local voids in the vicinity of an anchor will not affect the overall stability of the liner-anchor system. The anchor load carrying ability will decrease only in the local area with resulting redistribution of liner forces to the Adjacent area of anchorage, assuring against gross instability of the inner-anchor system in the area.

In summary, certain material and fabrication variables will tend to decrease the load carrying capability of the buckled panel while, on the other hand, certain variables will increase the strength of the unbuckled panels, resulting in greater in-plane forces across the liner anchors. For the limiting case, the post buckling Capacity of the buckled panel was assumed to be zero while the yield stress in the unbuckled panel was considered to be 35% greater than the minimum specified yield, as shown in Table 4 of Reference 19.

For this limiting case, the factor of safety for the maximum computed deflection versus the ultimate deflection is 8. Ultimate deflections are obtained through tests described in (Reference 19) for a liner-anchor system utilizing the same variables.

Anchors around insert plates are designed using manual calculations. Anchors at brackets and penetration sleeves serve as anchorages for equipment of piping loads transmitted into the concrete shell. In addition, these embedments anchor the insert plates, assuring liner stability in these local areas.

3.8.1.5 Structural Acceptance Criteria

3.8.1.5.1 Concrete Structure

To keep the Reactor Building basically elastic under Service Load Combinations, S, and below the range of general yield under Factored Load Combinations, U, the Allowable (S) and Permissible (U) stresses and strains specified in this section are used. These allowables apply to the load combinations given in Table 3.8-1.

3.8.1.5.1.1 Permissibles for Factored Load Combinations, U

The concrete, nonprestressed reinforcement and tendon stresses do not exceed the permissible values specified in this section. The permissible values for concretestresses and nonprestressed reinforcement stresses and strains are based upon the Capacity reduction factors, ϕ of ACI 318-71, except that $\phi = 0.9$ is used for axial compression occurring either with or without bending.

1. Axial Forces and Moments

   The concrete maximum compressive stress is limited to $\phi\ (0.85\ f'_c) = 0.765\ f'_c$. The nonprestressed reinforcement is subject to a $\phi\ f_y = 0.90\ f_y$ stress limit and to a strain limit of 1.5 times its yield strain. The section has a Capacity to resist the controlling design forces and moments without exceeding these permissible values. In evaluation of this Capacity, the section is kept below a general yield state by taking the concrete stress distribution to be linear from the cracked section neutral axis to the extreme compression fiber. The distribution of the strain across the section is taken as linear.

   The tensile strength of the concrete is not relied upon to resist the design forces and moments.

2. Radial and Transverse Shear

   The shear forces which are oriented in the thickness direction of the Reactor Building are termed “transverse shear” for the structural foundation mat and “radial shear” for the wall, ring girder, and dome.

   For the structural foundation mat, if the calculated transverse shears exceed the permissible values given in ACI 318-71, Sections 11.4 and 11.9, shear reinforcement is provided. Design of the reinforcement is in accordance with the requirements noted in Section 3.8.1.4.

For the wall, ring girder, and dome, if the calculated radial shears exceed the permissible values given in ACI 318-71, Section 11.5, as modified below, shear reinforcement is provided. Design of the reinforcement is in accordance with the requirements noted in Section 3.8.1.4.

The exceptions to ACI 318-71, Section 11.5, are as follows:

a. Equation (11-10) of ACI 318-71 is not applicable.

b. Equation (11-11) of ACI 318-71 is replaced by

$$v_{ci} = K\sqrt{f'_c} + \left[\frac{M_{cr}\dfrac{V}{M'} + V_i}{b'd}\right]$$

Where:

$$K = 1.75 - \frac{0.036}{np} + 4.0np$$

but is not less than 0.6 for $p \geq 0.003$. For $p < 0.003$, the value of K is zero.

$$M_{cr} = \frac{I_g}{y_t}\left[6\sqrt{f'_c} + f_{pe}\right]$$

but is not less than zero. However, in case the section has been cracked earlier, the term $6\sqrt{f'_c}$ is replaced by zero.

c. The value of v_{ci} is calculated using alternate Methods A and B, as specified below. The smaller value of v_{ci} thus obtained is used in accordance with ACI 318-71, Section 11.6. The lower limit of $1.7\sqrt{f'_c}$ placed on v_{ci} by ACI 318-71 does not apply.

(1) Method A

Each live load is applied independently, in turn. All other live loads comprising the loading condition are treated as existing dead loads. Each such individually considered live load is designated “Q”.

The following definitions are used:

(a) f_{pe} - Compressive stress in concrete (due to all loads except “Q”) at the extreme fiber of a section at which tension stresses are caused by “Q”; f_{pe} is calculated at a distance d/2 from the section being investigated for shear, measured in the direction of decreasing moment. Relaxation and creep losses are considered if this leads to more conservative design.

(b) V - Shear caused by "Q" only at the section under consideration.

(c) M' - Maximum moment caused by "Q" only at a distance d/2 from the section under consideration, measured in the direction of decreasing moment.

(d) V_i - Shear caused by prestress and load at the section under consideration.

(2)Method B

All live loads comprising a given loading condition are applied simultaneously.

The following definitions are used:

(a) f_{pe} - Compressive concrete stress caused by post tensioning and dead load at the extreme fiber of a section at which tensile stresses are caused by the live loads; f_{pe} is calculated at a distance d/2 from the section being investigated for shear, in the direction of decreasing moment. Relaxation and creep stresses are considered if this leads to a more conservative design.

(b) v - Shear caused by the live loads at the section under consideration.

(c) M' - Maximum moment caused by the live loads at a distance d/2 from the section under consideration, measured in the direction of decreasing moment.

(d) v_i - Shear caused by prestress and dead load at the section under consideration.

d. Equation (11-12) of ACI 318-71 is replaced by

$$v_{cw} = 3.5\sqrt{f'_c}\left[1+\frac{f_{pc}}{3.5\sqrt{f'_c}}\right]^{1/2}$$

Where:

f_{pc} is positive for compression.

3. Radial Tension under Post Tensioning

The radial forces caused by the curvature of the hoop and dome tendons are resisted entirely by ties. Design of the ties is discussed in Section 3.8.1.4.

4. Tangential Shear

This shear occurs in the Reactor Building wall during earthquake motion. It is oriented in the plane of the wall. The provisions of ACI 318-71, Section 11.16, are not applicable. Reinforcement is provided to resist the entire value of tangential shear. Design of the reinforcement is in accordance with the requirements noted in Section 3.8.1.4. The value of the nominal shear stress, v_u, is not allowed to exceed $8\sqrt{f'c}$.

5. Punching Shear

   This shear occurs in the Reactor Building wall around piping penetrations and the large access openings under specific load combinations. The local shears produced by the polar crane bracket supports also fall under this classification. The nominal shear stress, v_u, is not allowed to exceed $4\sqrt{f'_c}$. unless shear reinforcement is provided. If shear reinforcement is designed in accordance with the requirements noted in Section 3.8.1.4, v_u is not allowed to exceed $6\sqrt{f'_c}$.

6. Torsion

   Under a specific load combination, the primary shield wall produces a torsional force upon the portion of the structural foundation mat which spans over the incore instrumentation pit. For this condition, the provisions of ACI 318-71, Section 11.7, are applicable.

7. Bearing

   The provisions of ACI 318-71, Section 10.14, are applicable. The permissible bearing stress is 0.60 f'_c.

8. Tendon Stresses

   The axial tensile capacity of the tendons is not allowed to exceed 0.9 f_{py}, where f_{py} is the minimum specified tensile yield strength of the prestressing steel.

9. Thermal Limitations

   Internal concrete surface temperatures are limited to 350°F, except in local areas exposed to steam jets, where 575°F is the limitation.

3.8.1.5.1.2 Allowables for Service Load Combinations, S

The concrete, nonprestressed reinforcement and tendon stresses do not exceed the allowable values specified herein. These allowables apply to all S Load Combinations in Table 3.8-1, including the initial prestress condition. For this condition, the effects of the prestressing sequence are considered. This includes consideration of stresses and deformations before prestressing, as well as at intermediate stages of the prestressing operation. The concrete stresses are such that:

1. Membrane compressive stresses do not exceed $0.45f'_c$.
2. Extreme fiber compressive stresses due to membrane plus bending do not exceed $0.60f'_c$.
3. The tensile strength of the concrete is not relied upon to resist the design forces and moments. It is a serviceability requirement, however, that the membrane tensile stresses at transfer of prestress do not exceed $\sqrt{f'_c}$.

4. Compressive stress under the tendon anchor bearing plates does not exceed either $0.60f'_{ci}\sqrt[3]{A_2/A_1}$ or f'_{ci}, where f'_{ci} is the compressive strength of the concrete at the time of initial prestress. The bearing plate area is A1 and A2 is the maximum area of the portion of the anchorage surface that is geometrically similar to, and concentric with, the area of the bearing plate.
5. Bearing stresses, excluding those for the tendon anchor bearing plates, do not exceed 35% of those permitted for factored loads.
6. The allowable shear and torsion stresses are taken as 55% of those permitted for factored loads.
7. The nonprestressed reinforcement stresses are such that tensile and compressive stresses do not exceed 24,000 psi, except for shear reinforcement, in which case these stresses do not exceed 30,000 psi.
8. The tendon stresses are such that:
   a. The tension stress during stressing is limited to 0.80 f_{pu}, where f_{pu} is the minimum specified ultimate tensile strength of the wire.
   b. The tension stress immediately after anchoring does not exceed 0.70 f_{pu}.
9. The temperature in the concrete is limited to 150°F, except in local areas such as pipe penetration locations where 200°F is the limitation.

3.8.1.5.2 Reactor Building Liner and Attachments

3.8.1.5.2.1 Liner and Anchors

Structural acceptance criteria for the Reactor Building liner are in accordance with the allowable stresses and strains stated in the ASME Code, Section III, Division 2, Table CC-3720-1. These allowables apply to the corresponding load combinations presented in Table 3.8-2.

Acceptance criteria for the Reactor Building liner anchors are in accordance with the allowable displacements stated in the ASME Code, Section III, Division 2, Table CC-3730-1. These allowables apply to the corresponding load combinations presented in Table 3.8-2.

3.8.1.5.2.2 Brackets, Attachments, and Pad Overlay Plates

Structural acceptance criteria for brackets, attachments, and pad overlay plates are presented in Table 3.8-3.

3.8.1.6 Materials, Quality Control, and Special Construction Techniques

3.8.1.6.1 Concrete

3.8.1.6.1.1 Material

1. Cement

Cement used is Type II, moderate heat of hydration, with the following additional requirements:

a. Maximum 58% sum of tricalcium aluminate and tricalcium silicate for 7 and 28 day cube strengths.

b. Minimum compressive cube strength of 4800 psi at 28 days or 3000 psi at 7 days.

c. Maximum fineness of 4000 cm^2/gm for 7 and 28 day cube strengths.

d. Air content of cement mortar: 7% minimum; 12% maximum.

e. Loss on ignition of the cement: 2% maximum.

f. Minimum fineness of 2800 cm^2/gm for 7 day cube strengths.

g. For 7 day cube strength, the minimum limit of tricalcium aluminate is 42%.

Cement complies with the requirements of the ASME Code, Section III, Division 2, Article CC-2221.

2. Aggregates

a. Fine Aggregate

Fine aggregate complies with the requirements of ACI 301-72 (Reference 20) and ASTM C33. The fine aggregate complies with the ASME Code, Section III, Division 2, Article CC-2222.1(a), (e), and (g).

b. Course Aggregate

Course aggregate complies with the requirements of ACI 301-72 and ASTM C33. Based upon compressive strength tests, tolerance of ±5% on each sieve size of standard No. 67 gradation is allowed. South Carolina State Highway Department (SCSHD) Course Aggregate gradation 8M size and the gradation of ASTM C33 No. 8 is used. Course aggregate complies with the ASME Code, Section III, Division 2, Article CC-2222, with respect to potential reactivity, petrographic examination, and aggregate shapes and sizes. Course aggregate shapes are tested in accordance with CRD-C119, “Method of Test for Flat and Elongated Particles in Course Aggregate” using the “count” method which is more conservative than the “weight” method.

3. Water

Mixing water complies with the requirements of the ASME Code, Section III, Division 2, Article CC-2223 and the following additional requirements:

a. Sulfate ion, 250 ppm

b. Total solids content, 1000 ppm

4. Admixtures

The following admixtures are used:

a. Air entraining admixture complying with ASTM C260.

b. Water reducing admixture complying with ASTM C494, Types A and D.

Admixtures comply with the requirements of the ASME Code, Section III, Division 2, Article CC-2224.

3.8.1.6.1.2 Concrete Mixes

1. Specified Properties

The specified properties are as follows:

a. Concrete compressive strength of 5000 psi at 90 days.

Fly ash is not used in the concrete mix. The schedule of testing to verify that concrete reaches a compressive strength of 5000 psi at 90 days is as follows: one cylinder is tested at 7 days for information; 1 at 28 days for information; and 2 at 90 days for verification of 90 day strength.

b. Maximum slump of 4 inches

c. Air content, 4 to 8%

d. Unit weight, 142.1 lb/ft^3

e. Confirmatory tests for modulus of elasticity, Poisson's ratio, coefficient of thermal expansion, shrinkage, uniaxial creep, tensile strength, and thermal conductivity were performed to provide actual property values for comparison with assumed design values. These values compare favorably with those assumed for the design and, as such, are confirmatory.

2. Concrete Mix Proportioning

Concrete mix proportioning complies with the requirements of the ASME Code, Section III, Division 2, Article CC-2232.

3.8.1.6.1.3 Concrete Construction

1. Formwork

For the wall the steel liner is used as an inside form with conventional formwork on the outside face. Special precautions are taken to limit the stress in the steel liner. These precautions consist of ties between the formwork and a concrete maximum pour rate of 24 inches per hour. Also, the liner is locally stiffened by temporary bracing to hold it within tolerance.

The dome liner serves as an inside form. It is supported at intervals by means of ties attached to a system of rigid dome tendon conduit.

Formwork design complies with the requirements of the ASME Code, Section III, Division 2, Article CC-4251.

2. Construction Joints

   a. Structural Foundation Mat

      The vertical joints for the 8 pie shaped concrete placements consist of nominal 3 inch by 12 inch keys extending through the entire mat thickness and are sufficient to resist the calculated transverse shears at the joints. These keys are performed with expanded metal (1/4 by No. 18) which is cast in place to serve as a bulkhead for the concrete placement. The remaining mat joints are provided with removable, wood formed keys. Keys are sized to resist calculated transverse shears where applicable.

   b. Wall and Dome

      Joints are designed to resist calculated radial (transverse) and tangential shears. Horizontal joints in the wall are provided with nominal 3 inch by 12 inch keys in addition to being roughened to 1/4 inch amplitude using water under pressure. Horizontal joints are provided with a 1/2 inch layer of mortar just prior to placement of the next lift. In the upper and lower part of the wall, key sizes are provided based upon calculated shear requirements. Vertical joints in the wall are provided with nominal 3 inch by 12 inch keys and are roughened to 1/4 inch amplitude. Vertical joints in the wall are formed using a combination of a 12 inch wide section of expanded metal (cast-in-place) and removable wood bulkheads. Both extend the height of the pour. The expanded metal is centered at the horizontal conduit radius. Construction joints in the ring girder are roughened to 1/4 inch amplitude and are sufficiently reinforced to transfer shears by shear friction. Construction joints in the dome are formed using cast-in-place expanded metal.

Construction joints comply with the requirements of the ASME Code, Section III, Division 2, Article CC-4252.

3. Batching of Concrete

   Batching of concrete complies with the requirements of the ASME Code, Section III, Division 2, Article CC-4222. The batch plant is calibrated to ASTM C94 on a 90 day frequency by the testing laboratory.

4. Mixing of Concrete

   Mixing of concrete complies with the requirements of the ASME Code, Section III, Division 2, Article CC-4223.

5. Conveying of Concrete

   Conveying of concrete complies with the requirements of the ASME Code, Section III, Division 2, Article CC-4224.

6. Placing of Concrete

   Placing of concrete complies with the requirements of the ASME Code, Section III, Division 2, Article CC-4225.

   Placement of concrete under cold and hot weather conditions complies with the requirements of the ASME Code, Section III, Division 2, Article CC-4260.

7. Consolidation

   Consolidation complies with the requirements of the ASME Code, Section III, Division 2, Article CC-4226.1. Designed mixes using 3/8 inch maximum size aggregate are provided for use in areas of congestion.

8. Curing

   Elements of the concrete Reactor Building, including structural foundation mat, wall, ring girder, and dome are cured in accordance with Chapter 14, “Massive Concrete,” of ACI 301-72, except that only continuous water curing is permitted for the foundation mat. In addition, the requirements of ACI 306-66 [21] are followed instead of ACI 301-72, Section 14.5.4.

   Curing of concrete complies with the requirements of the ASME Code, Section III, Division 2, Article 4240.

9. Mass Concrete

   Sections 3'-9" or larger in the smallest dimension are considered as mass concrete. Such sections are placed and cured in accordance with the mass concrete provisions of ACI 301-72, with the following additional requirements:

   a. Section 14.5.4 of ACI 301-72, which discusses the drop of temperature at the end of the curing period is replaced by the more complete requirements of ACI 306-66.
   b. The time between placement of abutting concrete segments was a minimum of 3 days for the shell and a minimum of 7 days for the foundation mat.
   c. The temperature in the Reactor Building structural foundation mat was monitored throughout the curing period until a downward trend in temperature was observed. In addition, at no time during the curing period did the concrete exceed the predetermined design value of 175°F.
   d. Continuous wet curing was the method of curing for the Reactor Building foundation mat.

3.8.1.6.1.4 Quality Control

1. Cement

Quality controls for cement comply with the requirements of the ASME Code, Section III, Division 2, Article CC-5221, with respect to ASTM C150 as modified in Section 3.8.1.6.1.1 for physical and chemical properties. In addition, the temperature of the cement was limited to a maximum of 170°F.

2. Aggregates

   Quality control for aggregates complies with the requirements of the ASME Code, Section III, Division 2, Article CC-5224, for flat and elongated particles, friable particles, lightweight particles, Los Angeles abrasion, potential reactivity, and soundness. Absorption is tested using ASTM C127 or ASTM C128 procedures prior to approval for use. Gradation is tested using ASTM C136 procedures within 1 day of use. Moisture content is determined at least daily in accordance with ASTM C566 or ASTM C70 prior to production with a minimum frequency of 500 tons. The quantity of material finer than No. 200 sieve per ASTM C117 is determined within 1 day of use. Organic impurities are determined in accordance with ASTM C40 weekly during production.

3. Water and Ice

   The following tests are performed every 6 months:

   a. Effect on compressive strength, in accordance with ASTM C109
   b. Setting time, in accordance with ASTM C191
   c. Soundness, in accordance with ASTM C151
   d. Chloride content, in accordance with ASTM D512
   e. Sulfates, in accordance with ASTM D516

4. Admixtures

   The admixture supplier is required to submit a certificate of compliance with ASTM C260 or ASTM C494 prior to or with each delivery of admixture.

5. Concrete

   Quality control requirements for concrete comply with the requirements of the ASME Code, Section III, Division 2, Article CC-5230 for the following:

   a. Mixer uniformity
   b. Sampling method
   c. Compression cylinder
   d. Compressive strength
   e. Slump

f. Air content

g. Temperature

h. Unit weight/yield

Test to confirm the validity of the engineering design for the following parameters were initiated upon approval of the concrete mix designs:

a. Modulus of elasticity, in accordance with ASTM C469

b. Poisson's ratio, in accordance with ASTM C469

c. Coefficient of thermal expansion, in accordance with CRD-C39

d. Shrinkage, in accordance with ASTM C157

e. Uniaxial creep, in accordance with ASTM C512

f. Splitting tensile strength, in accordance with ASTM C496

g. Thermal conductivity, in accordance with ASTM C177

Regulatory Guide 1.55 is addressed in Appendix 3A.

3.8.1.6.2 Reinforcing Steel and Cadweld Splices

3.8.1.6.2.1 Material

Reinforcing steel is Grade 60 billet steel which conforms to the requirements of ASTM A615. Materials for reinforcing steel and for Cadweld splices (mechanical splice sleeves) comply with the requirements of the ASME Code, Section III, Division 2, Article CC-2310. Regulatory Guide 1.15 is addressed in Appendix 3A.

3.8.1.6.2.2 Cadweld Splices

Reinforcing bars, sizes #11, #14, and #18, are spliced using Cadweld splices in specified locations. The Cadweld splices develop the tensile strength of the reinforcement. Cadwelding is performed in accordance with the ASME Code, Section III, Division 2, Article CC-4333. Regulatory Guide 1.10 is discussed in Appendix 3A.

3.8.1.6.2.3 Quality Control

1. Reinforcing Steel

   a. Tensile Tests

Testing frequency complies with the requirements of the ASME Code, Section III, Division 2, Article CC-2331.1. Where the producing mill had not determined tensile properties at the frequency required by Article CC-2331.1 of the Code, user tests were performed by a testing laboratory at a frequency that satisfies Article CC-2331.1 requirements.

b. Acceptance Standards for Tensile Tests

(1) Where the producing mill determined tensile properties, acceptance standards for such tests complied with the requirements of Article CC-2331.2 of the Code.

(2)Where user tests were performed by a testing laboratory, acceptance standards were as follows:

(a) If a test specimen failed to satisfy the tensile requirements of ASTM A615-72, Table 2, 4 random specimens were selected and tested.

(b) If all 4 specimens satisfied the ASTM A615-72, Table 2, requirements, the reinforcement was accepted. If one of the 4 specimens failed to satisfy these requirements, a second set of 4 random specimens was selected and tested. If 2 or more of the original 4 specimens failed to satisfy these requirements, the material represented by the specimens was rejected.

(c) If one or more of the second set of 4 specimens fail to satisfy the ASTM A615-72, Table 2, requirements, the material represented by the specimens is rejected.

c. Bend Tests

Bend tests comply with the requirements of the ASME Code, Section III, Division 2, Article CC-2332.

d. Chemical Analyses

Chemical analyses comply with the requirements of the ASME Code, Section III, Division 2, Article CC-2333.

e. Traceability

Reinforcing steel traceability complied with Article CC-2320 of the ASME Code, Section III, Division 2.

2. Cadweld Splices

Cadweld splice testing and acceptance criteria are in accordance with Article CC-4333 of the ASME Code, Section III, Division 2.

3.8.1.6.3 Post Tensioning System

The Post Tensioning System generally conforms to the intent of the requirements of the ASME Code, Section III, Division 2. Minor deviations from the Code exist because procurement and part of the fabrication of components predate issuance of this portion of the Code. However, these deviations either exceed Code requirements or satisfy the intent of the Code. Where deviations

exist, they are explained. Applicable cross references to articles of the Code are provided at ends of paragraphs in Sections 3.8.1.6.3.1 through 3.8.1.6.3.4.

3.8.1.6.3.1 Material

Materials for the components of the Post Tensioning System are as follows:

1. Semi-Rigid Conduit and Screw Couplings

   Semi-rigid conduit and screw couplings, for wall tendons, are fabricated from sheet steel, galvanized on both surfaces and manufactured in accordance with ASTM A 525-71. This galvanized sheet steel is spirally formed into circular tube (Article CC-2441(a)).

2. Rigid Conduit and Sleeve Couplings

   Schedule 40 conduit and Schedule 60 couplings, for dome tendons, are fabricated from piping conforming to ASTM A53-72a, Type S, Grade B, requirements. Both surfaces of Schedule 40 pipe are galvanized in accordance with the requirements of ASTM A123-73 (Article CC-2441(a)).

3. Trumpets

   Trumpets are manufactured from hot rolled electric welded (HREW) steel tubing (Article CC-2441(a)).

4. Transition Funnels

   Transition funnels are spun from cold rolled sheet steel (Article CC-2441(a)).

5. Permanent End Caps, Shims, and Gaskets

   Materials for these components are as follows:

   a. Permanent end caps are fabricated from hot rolled steel conforming to the requirements of ASTM A36-70a and HREW tubing.
   b. Permanent end cap shims are fabricated from hot rolled steel conforming to ASTM A36-70a.
   c. Permanent end cap gaskets are manufactured from Neoprene durometer 60.

6. Wire

   Wire is manufactured in accordance with ASTM A421-65 using type BA anchorage (Article CC-2421).

7. Anchorage Components

a. Bearing plates are fabricated from steel plate conforming to ASTM A36-70a with S2 supplementary requirements (Article CC-2432).

b. Anchor heads are fabricated from AISI 4142 steel, heat treated to Rockwell hardness 42 (Article CC-2433).

c. Bushings are fabricated from AISI 4142 steel, heat treated to Rockwell hardness 42 (Article CC-2433).

d. Shims are fabricated from steel plate conforming to ASTM A36-70a with S2 supplementary requirements.

8. Corrosion Protection Grease

a. Temporary corrosion protection grease applied to tendon wires is Visconorust 1702 with an overcoating of Visconorust 1601 or their equivalents (Article CC-2442.2.2).

b. Permanent corrosion protection grease pumped into the conduit is Visconorust 2090P-4 or its equivalent (Article CC-2442.3.2(a) and (b)).

9. Tendon Performance Test

Tendon qualification by performance tests is reported in the Three Mile Island Nuclear Station Unit 1 Final Safety Analysis Report.

The Post Tensioning Tendon System is qualified in accordance with Regulatory Guide 1.103 (see Appendix 3A).

The Post Tensioning Tendon System also satisfies the requirements of the ASME Code, Section III, Division 2, Article CC-2460.

The tendon system has been tested without failure at -73°F for 500 cycles of load range of 60% to 80% of guaranteed ultimate tensile strength. This test is above and beyond the requirements of the ASME Code.

3.8.1.6.3.2 Fabrication

1. Conduit

a. Semi-Rigid

Semi-rigid conduit is fabricated from sheet steel formed into tubing by the “Spiro” process. This tubing is then cut into lengths suitable for shipment to the construction site.

b. Rigid

Rigid conduit is fabricated from Schedule 40 pipe. The conduit is cut and bent in the shop to dimensions indicated by the shop drawings.

2. Anchorage Components

Anchorage components are fabricated in accordance with shop drawings and fabrication procedures of the tendon manufacturer.

3. Permanent End Caps and Shims

Permanent end caps and shims are fabricated in accordance with the shop drawings and fabrication procedures of the tendon manufacturer.

4. Tendons

a. Buttonheads

Buttonheads are of the cold upset type. The tendon manufacturer is required to develop dimensional and split (crack) criteria to ensure that buttonhead strength exceeds that of the wire (Article CC-4432.3).

b. Tendons

The individual wires of a tendon are cut to “as measured” length, then threaded through the anchor heads and buttonheaded on one end of the wire in the shop. When all wires for a particular tendon are cut, threaded through the anchor head and buttonheaded, the tendon is coated with the corrosion protection greases, twisted, banded, coiled, and protected for shipment to the construction site (Article CC-4432).

3.8.1.6.3.3 Installation

1. Conduit

a. Semi-Rigid

Semi-rigid conduit is cut to length onsite and placed in the Reactor Building structure in the positions shown by the construction drawings. Any required bending is accomplished by hand. Joints are formed by threading an oversize coupling from one conduit section onto the next. Joints are taped to prevent intrusion of concrete.

b. Rigid

Each section of shop bent, Schedule 40 conduit for the Reactor Building dome carries an identification mark placed on it by the conduit supplier. This mark corresponds to the conduit section mark on the approved construction drawings. The constructor places each dome tendon conduit section in the location designated by the construction drawings.

2. Bearing Plate/Trumpet Embedded Anchorages

   Bearing plate/trumpet embedded anchorages are cast into the Reactor Building structure. The embedded anchorages required a steel frame for temporary support before being cast in concrete. No form of welding or heating of the bearing plate portion of embedded anchorages is allowed. When an embedded anchorage is erected, the constructor attaches a temporary end cover to it. This temporary end cover remains in position until tendon placement to prevent entrance of debris and water.

3. Conduit Cleaning

   The internal surface of the conduit is first cleaned by pulling cloths through to remove debris. The internal surface is then coated with Visconorust 209OP-4 corrosion protection grease or its equivalent.

4. Tendon Installation

   Tendons are removed from onsite storage, unwrapped, and, placed on an uncoiler. After attaching a “Vellums Grip,” the tendon is pulled through the conduit by means of a winch connected to the “Vellums Grip” attachment.

5. Buttonheading

   Field formed buttonheads are formed on the wires of each tendon in accordance with the same criteria used for shop formed buttonheads.

6. Tendon Stressing

   Tendons are not stressed until all concrete for the complete Reactor Building shell has been placed and has reached a minimum strength of 5000 psi. The tendon manufacturer is required to calculate, for each tendon, the anticipated elongation at each stressed end. These elongation calculations are based upon established friction and wobble coefficients.

   a. Force and Strain Measurements

      (1) Each tendon is initially stressed to a maximum of 80% of the minimum guaranteed ultimate capacity of the tendon. The jacking force is then reduced to 70% of ultimate capacity and locked off. Stress-strain curves prepared by the wire manufacturer for production lots of the material are used to establish tendon elongation. These curves are then used by the tendon manufacturer to establish the final gage reading and elongation of each stressed tendon. If loss of prestress force in any tendon due to broken wires and/or unacceptable buttonheads exceeds either 3% for 1 tendon or 2% for 2 adjacent tendons, the tendon is rejected and either repaired or replaced.

      (2) After taking up initial slack by jacking to a maximum jack pressure of 2000 psig, force strain measurements are taken. These measurements are obtained by measuring the tendon elongation and comparing it with the force indicated by the jack pressure

gage. Prior to being sent to the site, all pressure gages are calibrated using a deadweight tester, traceable to the National Bureau of Standards. Once at the site, one of the gages is set aside for purposes of calibration verification. Calibration of each gage is verified after every 24 hours operation for that gage. Prior to being sent to the site, stressing rams are calibrated for ram area by use of a load cell, traceable to the National Bureau of Standards. The pressure gage-stressing ram system indicates tensioning force within an accuracy of ±2%. During stressing, records are made of elongation, as well as pressure obtained for each tendon. At the pressure gage reading equivalent to 80% of the guaranteed ultimate capacity of the tendon, the tendon elongation is measured simultaneously at each stressing end. The measured elongation is compared to that calculated by the contractor (using average load-elongation curves). If the maximum differential between measured and calculated elongation exceeds -5%, or +10% the contractor is required to immediately report the discrepancy in writing (Article CC-4464.1).

b. Stressing Sequence

The tendon stressing sequence is as follows (Article CC-4462):

(1) Vertical tendons

(2)Dome tendons

(3) Horizontal tendons

The contractor is required to develop a complete, detailed stressing sequence for each type of tendon. This detailed sequence is required to comply with the requirements given below. Tendons are stressed simultaneously, as described below:

(1) Vertical Tendons

Vertical tendons are stressed from the top end only, using 6 sets of stressing equipment equally spaced around the ring girder, stressing 6 vertical tendons simultaneously. As an alternate to stressing a group of 6 equally spaced vertical tendons simultaneously, the group of 6 tendons is divided into 2 subgroups with 3 tendons in each subgroup. The 3 tendons within each subgroup are equally spaced and simultaneously stressed. The 2 subgroups may be stressed independently but stressing of both subgroups must be completed prior to stressing the next group of 6 equally spaced tendons.

(2)Dome Tendons

Except where prevented by jacking equipment interferences, dome tendons are stressed from both ends using 6 sets of stressing equipment to stress these tendons simultaneously. The set of 3 tendons for which simultaneous stressing is specified is defined as a sequence. Where the 3 tendons in a sequence cannot be stressed simultaneously because of an interference between the stressing equipment for one tendon and that of another, consecutive stressing is permitted. In this event, the 3 tendons are stressed within 8 hours; that is, the attainment of overstress pressure on

the third tendon of a sequence occurs within 8 hours of the attainment of a jack pressure of 2000 psi, the preliminary tensioning level, for the first tendon in that sequence.

(3) Horizontal Tendons

Horizontal tendons are stressed from both ends using 6 sets of stressing equipment. Three (3) horizontal tendons are stressed simultaneously.

7. Corrosion Protection

After the tendons are installed, the permanent corrosion protection grease, Visconorusts 2090P-4 or its equivalent is pumped into the tendon conduit to completely fill the remaining air space. When all air is displaced, signified by a solid stream of grease at the discharge end, pumping is stopped and the conduits are sealed at 0 psig. To facilitate pumping the grease, it is heated so that minimum grease temperature at discharge end is 115°F.

8. Vertical Tendon Retensioning

Because of increased wire relaxation losses as described in Section 3.8.1.4.1.2.1, retensioning of the vertical tendons was implemented in early 1990. The vertical tendons were restored close to their initial lock-off force of 1402 kips without detensioning in order to maintain the minimum average required vertical prestress force for the life of the plant. The loading on the containment structure from retensioning vertical tendons does not impose any additional or combination of loads not previously considered in the original analysis and design. The sequence for retensioning vertical tendons was selected to provide even application of the incremental vertical prestress around the containment walls during the retensioning process.

3.8.1.6.3.4 Quality Control

1. Wire

Certified physical and chemical mill test reports for each reel of wire are obtained by the tendon manufacturer (Article CC-2423). Only full diameter test pieces are used in the physical tests (Article CC-2422). Load strain curves certifying physical properties of each mill heat of material are obtained by the tendon manufacturer.

In addition to the requirements of ASTM A421-65, stress relaxation property information is required by the construction specification. In the early stage of the contract, stress relaxation properties of the wire were obtained by the tendon manufacturer from the steel producer (Article CC-2424). These properties were based upon tests performed on material previously manufactured under the same ASTM or other specification and produced in the same plant, utilizing the same procedures that were employed to produce material for the production tendons. Data furnished with the test results includes (Article CC-2424):

a. Detailed test method

b. Initial stress

c. Final stress

d. Test time

e. Temperature limits

f. Mathematical tools used to interpret test results

g. Percentage stress relaxation properties for design life.

In view of the fact that the tendon manufacturer had wire of differing stress relaxation properties in storage, stress relaxation property tests are required to ensure that the correct material is used to fabricate tendons. The frequency of testing is, as a minimum, one test per 50 tons of steel or per heat produced, whichever is smaller. Test specimens are selected at random.

Details of this test, are given in the quality control program of the tendon manufacturer. The tendon manufacturer is required to have the test results available for inspection and to forward applicable test results with each shipment of tendons to the job site.

The wire is inspected for rust, splits, cuts, and bends in accordance with the requirements set forth in the tendon manufacturer's quality assurance manual.

2. Anchorage Components

The tendon manufacturer obtains certified physical and chemical mill test reports to verify compliance with the material specification. The frequency of testing is, as a minimum, one test per mill heat or heat treatment batch, whichever is applicable. The tendon manufacturer is required to obtain copies of the certified test reports and to forward applicable copies with each shipment of anchorage components to the job site.

Heat treated components, such as anchor heads, are hardness tested after heat treating (Article CC-2433.2).

The tendon manufacturer fabricates the load carrying anchorage components in accordance with the following requirements:

a. Components, excluding shims, are low stress stamped with unique identifying numbers which give complete tractability from manufacture of the steel to delivery to the job site.

b. Documentation sheets are developed to record the manufacturing record of each individual component. Copies of the applicable, completed sheets accompany each shipment of anchorage components to the job site.

c. Certified copies of physical and chemical mill test results are obtained to verify compliance with the tendon manufacturer's specification requirements. As a minimum, certified test results are provided for each heat of material or heat treatment batch, whichever is applicable.

d. At least 10% of all anchorage components are inspected for hole and thread tolerances, alignment, dimensional control, weld porosity, notches, etc. The tolerances, methods of inspection, frequency of inspection, and acceptance criteria are stated on the tendon manufacturer's shop drawings and in the quality control manual. Inspection records are forwarded with each shipment to the job site.

e. Weld and welder qualification are accomplished prior to commencement of the work. Both qualifications are in accordance with the requirements of AWS D1.0-69 (Reference 23).

3. Conduit

Certified copies of the mill certificates for the chemical and physical properties of each heat of steel used in the manufacture of each type of conduit are obtained.

The semi-rigid conduit, when continuously supported on a flat surface, is sufficiently strong to withstand the weight of a 200 pound man without permanent deformation (Article CC-2441(b)).

To determine that the fabricated conduit has minimum required internal dimension, a "pig" of diameter 1/4 inch less than the conduit inside diameter is pulled through the conduit.

After cutting and bending (where applicable), a minimum of 10% of the sections of conduit in each shipment, selected at random, are inspected to verify compliance with the above requirements.

Dimensional tolerances for cutting and bending conduit are checked against established tolerances.

Upon receipt at the job site, the conduit and couplings are visually inspected for damage. If the conduit is damaged or there is evidence of conduit damage, the conduit is inspected for detrimental dents and other defects. To determine if a dent is detrimental, a cylindrical unpainted steel pig, free of corrosion and sharp edges, and having a diameter of either 4 3/4 inches (Schedule 40 conduit) or 4 1/2 inches (semi-rigid conduit) by approximately 20 inches long with tapered ends and lead and tail lanyards, is pulled through the conduit. If a dent or dents prevent passage of the pig, the conduit is rejected and replaced.

After the conduit is placed in the Reactor Building structure, location is checked against established tolerances.

Before and after placement of concrete around conduit, the conduit is checked for dents and restrictions by pulling through 24 inch long, untapered pig. For rigid (Schedule 40) conduit, a cylindrical steel pig of 4 1/2 inch diameter is used. For the semi-rigid conduit, a 4 1/4 inch diameter pig is used (Article CC-5423).

Coupling welds joining sections of rigid conduit are made in accordance with the following:

a. Welders are qualified in accordance with the requirements of AWS D1.1-72 (Reference 24).

b. Welds are made in accordance with approved welding procedures.

c. Ten percent (10%) of the welds, selected at random, are liquid penetrant inspected using the solvent removable process.

d. The weld is subjected to pneumatic pressure testing to ensure leak tightness.

4. Bearing Plate/Trumpet Assemblies

Bearing plate/trumpet assemblies are examined for dimensional accuracy in accordance with the criteria given in the tendon manufacturer's fabrication procedures and shop drawings (Article CC-5422.1).

5. Permanent End Caps

Permanent end caps are inspected in accordance with the criteria given in the tendon manufacturer's fabrication and quality assurance procedures.

6. Tendon Fabrication

a. Buttonheads

The tendon manufacturer is required to develop buttonhead criteria by means of tests. The wire used in the tests is required to be of the same size and manufacture as that used in the production of tendons. These tests are required to demonstrate that buttonheads conforming to the buttonhead criteria develop the full strength of the wire and that failure takes place in the wire, not the buttonhead. As a minimum, buttonhead criteria include:

(1) Wire - manufacturer, type, quality, etc.

(2) Shape - spherical, flat topped, etc.

(3) Diameter with tolerances

(4) Eccentricity of head and seat surfaces

(5) A bearing surface for 360° of the buttonhead

(6) Hardness range of anchor on which the buttonhead bears

(7) Allowable number of splits in any one buttonhead

(8) Size, inclination, and location of splits (cracks), including maximum values for a single split (crack) and a total value for the maximum number of allowable splits (cracks) in any one buttonhead.

The tendon manufacturer inspects buttonheads in accordance with the following requirements utilizing the buttonhead criteria:

(1) All buttonheads are visually inspected for malformation. Any buttonheads which appear to be malformed due to size or eccentricity are included in the random check noted in items (3) and (4), below. All double buttonheads are inspected for compliance with acceptance criteria for size, eccentricity, slips, and splits.

(2)The frequency of visual inspection for splits is 100%. Any buttonhead found to have a split or splits is checked to determine if it complies with the split criteria.

(3) A random check of buttonhead size using “Go” and “No-Go” gages is made for a minimum of 10% of the buttonheads of each tendon.

(4) Buttonhead eccentricity is checked for a minimum of 5% of the buttonheads per tendon, selected at random, to ensure compliance with the criteria.

(5) All wires in a tendon are cut to the same length by cutting the wires under the same conditions.

(6) As the wire for each tendon is cut, the tendon manufacturer inspects it for rust. Rust grade inspection criteria are noted in the construction specification.

a. Tendons

After fabrication and before twisting and banding, the tendons are inspected to ensure that each wire is coated with corrosion protection grease.

Each tendon is inspected prior to shipping to ensure that it consists of 170 wires, is twisted and banded and is wrapped in protective material (Article CC-5424).

7. Corrosion Protection Grease

Both temporary and permanent corrosion protection greases are checked to ensure that water soluble chloride, nitrate, and sulfide content is less than 10 ppm each (Article CC-2442.3.2).

The following requirements apply to bulk filling of conduit with permanent corrosion protection grease:

a. For vertical tendons, bulk filling is completed within 8 1/2 months of tendon installation and within 7 months for hoop and dome tendons.

b. Bulk filling sealing pressure is 0 psig.

c. Minimum grease discharge temperature is 105°F.

d. Determination that conduit is completely filled is based upon observation of a solid stream of grease at the discharge point.

3.8.1.6.4 Steel Liner, Penetrations, and Attachments

3.8.1.6.4.1 Material

1. Liner Plate

   Material for the liner shell, dome, and floor conforms to ASME SA516, Grade 60, impact tested at minus 25°F in accordance with the ASME Code, Section III, Division 1, Article NE-2300, and Division 2, Article CC-2511. In addition, all liner materials thicker than 3/8 inch are ultrasonically examined in accordance with the requirements of ASME SA578, including supplementary requirements S1, S3, and S4.

   Material for the incore instrumentation pit floor and walls and for sumps in the structural foundation mat conforms to ASME SA240, Grade 304. The finish on the plates is hot rolled, annealed, and pickled as specified in ASME SA480.

2. Liner Attachments

   Liner attachments include angle anchors, studs, brackets, and overlay plates. Material for these items conforms to the following requirements:

   a. Plate

      (1) Carbon steel material conforms to ASME SA516, Grade 60 or Grade 70, impact tested at minus 25°F in accordance with the ASME Code, Section III, Division 1, Article NE-2300, and Division 2, Article CC-2522. In addition, material thicker than 3/8 inch which is stressed in the through thickness direction satisfies the ultrasonic examination requirements of ASME SA578, including supplementary requirements S1, S3, and S4.

      (2) Stainless steel material conforms to ASME SA240, Grade 304. The finish on plates is hot rolled, annealed, and pickled as specified in ASME SA480.

   b. Rolled Structural Sections

      Rolled structural sections conform to ASME SA36 or ASTM A36.

   c. Studs

      Material for studs conforms to ASTM A108, Grade 1015 or Grade 1018 of ASTM A276, Type 304.

3. Penetrations

   Materials for different components of penetrations are as follows:

   a. Carbon Steel Pipe Sleeves

      Material for penetration sleeves of less than 30 inch diameter conforms to ASME SA333, Grade 6 (seamless), impact tested at minus 30°F or below.

Material for penetration sleeves of 30 inch diameter and larger conforms to ASME SA155, Grade KCF 70, Class 1 (welded) impact tested at minus 25°F in accordance with the ASME Code, Section III, Division 1, Article NE-2300, and Division 2, Article CC-2523.

b. Stainless Steel Pipe Sleeves

Material for stainless steel pipe sleeves conform to ASME SA312, Grade 304.

c. Carbon Steel Plates

(1) Liner insert plates conform to ASME SA516, Grade 60, normalized, ultrasonically examined and impact tested at minus 25°F in accordance with the ASME Code, Section III, Division 1, Article NE-2300, and Division 2, Article CC-2523.

(2)Plate material attached to penetration sleeves for concrete anchorage conforms to ASME SA516, Grade 70, normalized, ultrasonically examined and impact tested at minus 25°F in accordance with the ASME Code, Section III, Division 1, Article NE-2300.

d. Penetration Pipe Fittings

Penetration pipe fitting material conforms to ASME SA420, Grade WPL-6 (seamless), impact tested at minus 50°F.

a. Spare Penetrations with Removable End Caps

Spare electrical penetrations #505-18, #600-12, and #602-18 have removable end caps of the following materials:

(1) Securing Studs: ASME SA320 GR L43.

(2)Slip-on Flanges:

#505-18, #600-12 (Outside and Inside) ASME SA350 GR LF2.

#602-18 (Outside) ASME SA350 GR LF2.

#602-18 (Inside) ASME SA 105 C.S.

(3) Blind Flanges: ASME SA350 GR LF2.

(4) Gaskets: Flexitallic type or equal.

4. Access Openings

Materials listed below are used for the equipment hatch, personnel access airlock, and personnel emergency airlock:

a. Carbon Steel

(1) Plate

Carbon steel plates, except liner insert plates, are ASME SA516, Grade 70, normalized and impact tested at minus 25°F in accordance with the ASME Code, Section III, Division 1, Article NE-2300.

Liner insert plates are ASME SA516, Grade 60, normalized and impact tested at minus 25°F in accordance with ASME Code, Section III, Division 1, Article NE-2300.

(2)Structural Shapes

Structural shapes are ASME SA36.

(3) Pipe

Pipe is ASME SA333, Grade 6, seamless.

(4) Pipe Fittings

Pipe fittings are ASME SA420, Grade WPL-6 (seamless) and impact tested at minus 50°F.

(5) Bars

Bars are ASTM A108, Grade 1015.

b. Stainless Steel

(1) Plate

Plate is ASME SA240, Type 304.

(2)Bar and Structural Shapes

Bars and structural shapes are ASME SA479, Type 304.

(3) Pipe

Pipe is ASME SA312, Type 304 (seamless).

(4) Pipe Fittings

Pipe fittings are ASME SA182, Grade F, Type 304 or ASME SA403, Type 304.

3.8.1.6.4.2 Fabrication

The steel liner, penetration sleeves, reinforced insert plates and attachments are fabricated and installed in accordance with the ASME Code, Section III, Division 1, Article NE-4000, and Division 2, Articles CC-4122, 4521 (except item e), 4523 (except 4523.2), 4532, and 4533 (except 4533.2).

3.8.1.6.4.3 Construction

1. Liner Plate

   After the concrete structural foundation mat is placed to the base floor elevation, the 1/4 inch thick floor liner plates are installed by welding to embedments in the mat. During this period, the transition section at the lower portion of the 1/4 inch thick cylindrical liner wall plate is also erected. The liner serves as the internal form for placement of the shell concrete. Liner seams are double butt welds, except for the first 2 horizontal welds. On these welds, backing plates are used. The liner plate is continuously anchored to the shell by vertical angle anchors spaced at the maximum center to center distance of 15 inches and horizontal angles spaced at approximately 5 foot centers.

   After completion of the cylindrical liner wall, the 1/4 thick dome liner is erected on and supported by a steel space frame consisting of interconnected trusses. This space frame is located within the Reactor Building and is supported from the previously erected dome transition segment of the liner. When erection is complete the space frame is removed.

   Careful attention is given to the erection of the shell to ensure that all rings match properly. Fitting and alignment are in accordance with the ASME Code, Section III, Division 1, Article NE-4230. Dimensional tolerances for welded joints are as follows:

   a. Root face (land), ±1/16 inch
   b. Groove angle, ±10°
   c. Groove radius, ±1/32 inch
   d. Root opening (without backup), +1/8 inch, -1/16 inch
   e. Root opening (with backup), +1/4 inch, 0 inch
   f. The following tolerances apply to the as-built liner:

   a. Cylindrical Liner

      Tolerance is ±2 inches with respect to the horizontal radius from the center of the Reactor Building and ±2 inches with respect to elevation. Plumbness must be within 1/2 inch in 10 feet. Maximum out of plumb condition is 2 inches at any elevation. This complies with the ASME Code, Section III, Division 2, Article CC-4522.1.

   b. Dome Liner

      Tolerance is ±3 inches with respect to the design radius in compliance with the ASME Code, Section III, Division 2, Article CC-4522.2.

   c. Local Bulges

      Local bulges, flat spots, or discontinuities in the cylindrical liner are within the tolerances presented in Table 3.8-5 at the center of a stringline chord.

2. Penetrations

Penetration assemblies are shop fabricated and field installed by welding to larger diameter penetration sleeves. The penetration sleeves, with reinforcing plates, are installed in the liner prior to concrete placement.

Tolerances for location of penetration sleeves and attachments are ± 1/2 inch, measured at the inside face to the liner, with respect to azimuth and elevation. The location tolerance for the outside end of the penetration sleeve is ± 1/2 inch with respect to the actual location at the inner face of the liner.

3.8.1.6.4.4 Quality Control

1. Codes and Standards

   Welding operator qualification and weld procedure qualification are in accordance with the ASME Code, Section IX. Stud welding procedure qualification and operator qualification are in accordance with AWS D1.1-72 (Reference 24)], Part VI, Section 4.

   Fabrication and installation comply with the requirements of the ASME Code, Section III, Division 1, Article NE-4000 and with portions of Division 2.

   Non-Destructive examination of welds complies with the ASME Code, Section III, Division 1, as well as with Regulatory Guide 1.19 (see Appendix 3A).

2. Non-Destructive Examination and Testing

   a. Complete Penetration Welds

      Liner welds are examined by 2% spot radiography in accordance with Regulatory Guide 1.19 (see Appendix 3A) and the ASME Code, Section III, Division 2, Article CC-5531.2. Liner welds not capable of being radiographed are examined by 100% magnetic particle detection.

      Liner welds accessible to vacuum box testing are 100% tested. Where vacuum box testing is not possible, welds are examined by 100% magnetic particle, liquid dye penetrant, or ultrasonic methods in addition to required radiography.

      All welds are 100% visually examined.

      Welds provided with test channels are pressure tested for leak tightness to the design pressure in accordance with the ASME Code, Section V, Article T-1020.

   b. Attachment Welds

      Full penetration attachment welds are examined by 100% magnetic particle, ultrasonic, or liquid dye penetrant methods.

      Fillet welds are examined by magnetic particle or liquid dye penetrant methods. Twenty percent (20%) of these welds, selected at random, are examined.

   c. Stud Welds

Stud welds are examined using stud welding test method specified by AWS D1.1-72, Paragraph 4.29.

3. Acceptance Standards

   a. Radiography is performed in accordance with the ASME Code, Section III, Division 1, Article NE-5320, and Division 2, Article CC-5542. In addition, surface pinholes are removed by grinding.

   b. Magnetic particle examination is performed in accordance with the ASME Code, Section III, Division 1, Article NE-5340, and Division 2, Article CC-5545.

   c. Liquid dye penetrant examination is performed in accordance with the ASME Code, Section III, Division 1, Article NE-5350, and Division 2, Article CC-5544.

   d. Ultrasonic testing is performed in accordance with the ASME Code, Section III, Division 1, Article NE-5330.

   e. Vacuum box testing reveals through thickness discontinuities by formation of a continuous stream of bubbles in the bubble solution. Formation of single, small bubbles is not considered relevant. Defects revealed by a continuous stream of bubbles are unacceptable. Refer to the ASME Code, Section III, Division 2, Article CC-5546.1.1.

   f. Stud weld acceptance standards are in accordance with AWS D1.1-71, Paragraphs 4.29 and 4.30, and the ASME Code, Section III, Division 2, Article CC-5547.

4. Preliminary Tests

   a. Test channels are shop tested for structural integrity at 115% of design pressure. In addition, such test channels are leak tested at 100% of design pressure.

   b. Test channels located over butt welds in the liner are leak tested at 100% of design pressure before and after concrete placement.

3.8.1.7 Testing and Inservice Inspection Requirements

3.8.1.7.1 Structural Acceptance Test

The structural acceptance test complies with the requirements of Regulatory Guide 1.18 (see Appendix 3A) for prototype containments and satisfies the criteria of the ASME Code, Section III, Division 2, Article CC-6000, except as noted in subsequent paragraphs of this section.

3.8.1.7.1.1 General

During structural acceptance testing, the Reactor Building is subjected to internal air pressures ranging from 0 psig to 65.6 psig (115% of the design pressure of 57 psig) and back to 0 psig. Pressurization and depressurization of the Reactor Building is accomplished in 10 increments: 0 psig to 12 psig, 12 psig to 30 psig, 30 psig to 45 psig, 45 psig to 55 psig, 55 psig to 65.6 psig, 65.6 psig to 55 psig, 55 psig to 45 psig, 45 psig to 30 psig, 30 psig to 12 psig, and 12 psig to 0 psig. Incremental pressurization and depressurization during testing is necessary to allow strain gage readings, deflection measurements, and other observations to be made and also to allow for

evaluation and comparison of data with the predicted results as a function of internal pressure as the test proceeds.

When pressurizing and depressurizing the Reactor Building, the pressure change is stopped within -0, +0.10 psig of the desired pressure level increment, except for 65.6 psig and 0 psig.

After the desired pressure has been reached, a wait of at least 60 minutes is required. This permits Reactor Building strains and stresses to adjust before strains, deflection, and other observed data are recorded.

The locations at which displacement measurements are obtained are listed in Table 3.8-6. Four (4) radial and 1 vertical displacement measurements are made at 6 meridians on the cylindrical wall, plus a vertical displacement measurement at the apex of the Reactor Building dome. Radial, vertical, and tangential displacements are measured at 6 equally spaced and symmetrically aligned points on the horizontal and vertical center axes of the equipment hatch.

The design locations of strain gages for strain measurements are listed in Table 3.8-7. Minor variations from these locations occurred in field placement of the gages and are documented. Strain measurements are made at the base, at 4 intermediate points, and at the spring line of the cylindrical wall on the meridian. Strain measurements are also made around the equipment hatch at 4 points symmetrically aligned on the horizontal and vertical axes. The strain measurements are made at 3 positions within the cylindrical wall: inside face, middle, and outside face. Horizontal, vertical, and shear strain in the concrete is measured under the bearing plate of one vertical tendon post tensioning anchor (see Figures 3.8-31 through 3.8-34).

The test program includes visual examination of the accessible exterior concrete surface of the Reactor Building. The locations of areas for crack pattern charts are listed in Table 3.8-8 and shown by Figures 3.8-35 through 3.8-37. Concrete cracking is charted in these designated exterior areas of the Reactor Building. These areas include the structural foundation mat and cylindrical wall intersection, mid-height of the cylindrical wall, one quadrant around the equipment hatch, the buttress and cylindrical wall intersection and the intersection cylindrical wall, ring girder, top shelf of ring girder, and dome of Reactor Building. The remaining exterior concrete surface which is accessible from existing floors and platforms is visually examined for cracks.

3.8.1.7.1.2 Preparation of Testing

The installation of all optical instrument targets, direct current displacement transducers (DCDT’s), white wash for crack pattern charting, tapes, strain gages, junction boxes, conduit, wires, readout instruments, instrument support structures, and platforms is completed, checked, and tested prior to initiating pressurization of the Reactor Building.

During construction, strain gages are attached to reinforcing bars and waterproofed; also, the lead wires are installed. The waterproofed strain gages and the lead wires are protected against damage during construction. It is recognized that prior to the test, when each strain gage is being checked out, malfunction of gages may occur. Therefore, to avoid having to remove concrete to regain access to the gage, 2 gages are installed at each specified location. The primary and redundant

strain gages are attached to a 4'-10" long #6 reinforcing bar with 180 degree hook on each end. This bar is called a sister bar. The gages are placed as close together as practical on the reinforcing bar.

The cable leads from the primary and redundant strain gages are kept separate to prevent a single accident from causing malfunction of both strain gages.

Prior to and during the structural acceptance test, the inside air temperature of the Reactor Building is controlled within limits.

Outside air temperature varies, but due to the relatively short period of time involved in the performance of the structural acceptance test, normal fluctuations of the outside air temperature do not appreciably affect the temperature in the concrete shell.

Both inside and outside air temperature readings are taken and recorded at least twice daily for 2 weeks prior to the start of the structural acceptance test and at each pressure level during the test. The locations of thermocouples for temperature measurement are listed in Table 3.8-9.

3.8.1.7.1.3 Interpretation of Test Data

Test data obtained during the structural acceptance test is interpreted and compared with the analytical values obtained during the analysis and design of the Reactor Building (see Figure 3.8-38). If the test data does not show good agreement with the analytical values, the discrepancies are resolved.

If the test data include any displacements which exceed the predicted extremes, such discrepancies are resolved by means which could include a review of the design, evaluation of measurement errors or material variability, and, possibly, an exploration of the structure.

3.8.1.7.1.4 Calculated Responses

Displacements of the Reactor Building under pressure are computed at several points on the structure. A graph for each of these points shows the limiting displacement for a pressure of 65.6 psig. Pressure versus displacements is plotted at the 0 psig, 30 psig, 45 psig, 55 psig, and 65.6 psig levels during both pressurization and depressurization of the Reactor Building.

Stress cracking from the applied pressure loading is not anticipated due to the residual compressive stress remaining in the shell at the maximum pressure of 65.6 psig. However, existing shrinkage cracks will propagate in length and enlarge slightly in width when the Reactor Building is pressurized. Also, some new hairline cracks may occur that were not initially observed. The crack pattern will be random and the crack width enlargement should be less than 0.010 inch.

3.8.1.7.2 Post Tensioning System Inservice Inspection

The VCSNS inservice inspection program for the Post Tensioning System tendons is performed in accordance with the requirements of the Code of Federal Regulation (10CFR50.55a) and by reference therein, the requirements of ASME Section XI, Subsection IWL. The program was initially developed in compliance with Regulatory Guide 1.35. Inspections were conducted under this program until the NRC incorporated the requirements of Subsection IWL into its regulations, with specified modifications and limitations, in an amendment to section 50.55a.

The VCSNS inservice inspection program additionally utilizes the guidance provided in Regulatory Guide 1.35.1, (see Appendix 3A) for determining the prestressing forces used for inservice inspections. By following the minimum standards presented in Regulatory Positions 1 through 4, the small-sample inspection program of ASME Section XI Subsection IWL (and Regulatory Guide 1.35) provide better confidence in the integrity of the prestressed tendons.

3.8.1.8 Assessment of Design Criteria

A review of Sections 3.8.1.1 through 3.8.1.7 and of the ASME Code (Reference 28), Article CC-3000, indicates that most likely areas for significant differences in design criteria would be in Section 3.8.1.3.1.3, “Load Combinations,” and in Section 3.8.1.5, “Structural Acceptance Criteria,” as it relates to membrane and bending stress conditions in the Reactor Building. These 2 areas are addressed by Items 1 and 2, below. Finally, specific differences are investigated at 4 locations in the Reactor Building.

1. Load Combinations

   a. Comparison

      The load combinations appearing in ASME Code Table CC-3230-1 are compared to the load combinations presented by Table 3.8-1.

      (1) The Test load combination of the ASME Code is represented by load combination 2 of Table 3.8-1.

      (2) The Construction load combination of the ASME Code is represented by load combination 1 of Table 3.8-1, except that the design wind, W, is not included. However, the design wind, W, does appear in the Construction load combination 1 of Table 3.8-2, which is applicable to the free standing liner. For the concrete Reactor Building structure, inclusion of the design wind, W, in the Construction load combination, with the requirement of a Service condition, is not expected to control design. Consequently, the difference between Section 3.8.1 and the ASME Code is insignificant.

      (3) The Normal load combination of the ASME Code is represented by load combination 3.a of Table 3.8-1.

(4) The Service Severe Environmental load combination of the ASME Code which includes E_o is not represented. This is investigated later. The ASME Code Service Severe Environmental load combination including W is not represented. However, the load combination including W is expected to be less severe than that including E_o.

(5) The Factored Severe Environmental load combination of the ASME Code which includes $1.5E_o$ is effectively represented by load combination 5.a of Table 3.8-1 because E' equals 1.5E equals $1.5E_o$. However, P_v (denoted as Z in Table 3.8-1) is not included in load combination 5.a of Table 3.8-1. This is investigated later.

The Factored Severe Environmental load combination of the ASME Code which includes 1.5W is not represented. However, this load combination is expected to be less significant than either the ASME load combination including $1.5E_o$ or the tornado wind load combination (load combination 5.b) of Table 3.8-1.

(6) The Factored Extreme Environmental load combination of the ASME Code which includes E_{ss} is represented by load combination 5.a of Table 3.8-1. However, P_v is not included in load combinations 5.a of Table 3.8-1. The addition of P_v tends to increase concrete compressive stresses and liner strains. However, since E' equals 1.5E equals $1.5E_o$, investigation of this ASME Code load combination is addressed by Item (5), above.

The Factored Extreme Environmental load combination of the ASME Code which includes W_t is represented by load combination 5.b of Table 3.8-1.

(7) The Factored Abnormal load combination of the ASME Code which includes 1.5P is represented by load combination 4.a of Table 3.8-1.

The Factored Abnormal load combination of the ASME Code which includes $1.25R_a$ is not represented due to the absence of a 1.25 factor on R in the load combinations of Table 3.8-1. Consideration of R_a would be of potential significance only in the evaluation of localized areas at high energy piping penetrations rather than the overall design of the Reactor Building shell.

(8) The first 2 Factored Abnormal/Severe Environmental load combinations of the ASME Code are represented by load combination 4.b of Table 3.8-1. The third ASME Code load combination is not represented in the load combinations of Table 3.8-1. This is investigated later.

(9) The Factored Abnormal/Extreme Environmental load combination of the ASME Code is represented by load combination 5.a of Table 3.8-1.

b. Conclusions

Based upon the above comparisons of the ASME Code and Section 3.8.1 load combinations, the following ASME Code load combinations would be candidates for investigation of compliance with the ASME Code flexural and membrane stress/strain acceptance criteria:

(1) Service - Severe Environmental
$D + L + F + T_o + E_o + R_o + P_v$

(2)Factored - Severe Environmental
$D + 1.3L + F + T_o + 1.5E_o + R_o + P_v$

(3) Factored - Extreme Environmental
$D + L + F + T_o + E_{ss} + R_o + P_v$

(4) Factored - Abnormal/Extreme Environmental
$D + L + F + T_o + E_o + 0.5E_{ss} + W + H_a$

Since E_{ss} equals $1.5E_o$ and since the live load, L, is inconsequentially small relative to other loads appearing in the above load combinations, it is necessary only to investigate either one of the Factored load combinations, under items (2) and (3), above. The Factored Extreme load combination, Item (3), above, is selected.

In the load combination of Item (4), above, H_a has a value of zero.

2. Structural Acceptance Criteria

a. Comparison

The criteria which would limit Reactor Building membrane and bending stress conditions are compared.

(1) Concrete

The most significant differences between the ASME Code and Section 3.8.1.5 appear in the allowable compressive stresses as shown byTable 3.8-16.

(2)Reinforcing Steel

The allowable stresses and strains of Section 3.8.1.5 are more conservative than those of the ASME Code as shown by Table 3.8-17.

(3) Liner

As noted in Section 3.8.1.5.2.1, the ASME Code allowables of ASME Code Table CC-3720-1 are used.

b. Conclusions

From the above comparisons it is determined that the Section 3.8.1.5 acceptance criteria for some compressive stresses are not as stringent as the ASME Code criteria. These include Service primary membrane stresses, Service primary membrane plus bending stresses, and Factored primary membrane stresses. Consequently, it is necessary to investigate the FSAR load combinations which produce large compressive stresses in addition to the ASME Code load combinations previously identified (see 1.b, above).

The total load combinations to be investigated, along with the allowable concrete compressive stresses, are presented byTable 3.8-18. These allowable stresses depend upon the conditions appearing in ASME Code Table CC-3136.5-1.

3. Investigation of Reactor Building at Four Locations

Tables 3.8-19 through 3.8-22 show the predicted Reactor Building concrete stresses and linear strains at 4 locations. Also shown are the corresponding ASME Code allowables. It should be noted that all predicted values are less than the allowables.

Concrete compressive stresses for those load combinations including To are conservatively large because a cracking reduction of the thermal stresses was not used.

4. Summary and Conclusion

The assessment of the Virgil C. Summer Nuclear Station Reactor Building has consisted of:

a. Comparing the ASME Code load combinations with those appearing in Table 3.8-1 of the FSAR. From this comparison the ASME Code load combinations which differ from those in Table 3.8-1 were identified.

b. Comparing the ASME Code structural acceptance criteria governing membrane and flexural stress conditions in the Reactor Building shell with those appearing in Section 3.8.1.5. From this comparison the ASME Code allowable concrete compressive stresses were identified as being generally more stringent than those in Section 3.8.1.5.

c. Identifying those load combinations in Table 3.8-1 which would be impacted by the more stringent ASME Code allowables.

d. For the load combinations identified as described in items a and c, above, determining at 4 locations on the Reactor Building shell, the flexural and membrane stresses in the concrete and the stresses and strains in the liner.

e. Comparing these stresses and strains with the ASME Code allowables, in Tables 3.8-19 through 3.8-22.

A review of Tables 3.8-19 through 3.8-22 indicates that the Virgil C. Summer Nuclear Station Reactor Building design is conservative with respect to a design based upon the use of the ASME Code and the Standard Review Plan. It is noted that minimum specified values for material properties, rather than actual material properties, were used in this evaluation.

3.8.2 Steel Containment

The Virgil C. Summer Nuclear Station design does not employ a steel containment structure.

3.8.3 Concrete and Steel Internal Structures of Steel or Concrete Containments

3.8.3.1 Description of the Internal Structures

The internal structures of the Reactor Building consist of the following:

1. Primary shield wall surrounding and supporting the reactor vessel.
2. Secondary shield walls, surrounding and laterally supporting the steam generator.
3. Refueling cavity and fuel transfer canal.
4. Mezzanine floor, at elevation 436' and an operating floor, at elevation 463', both consisting of 2 foot thick concrete slabs supported by structural steel framing.
5. Polar crane supports.
6. Concrete basement slab (4 feet thick) at elevation 412' is supported by the structural foundation mat.

The general arrangement of these structures is shown by Figures 3.8-39 through 3.8-42 and the structures are described below.

3.8.3.1.1 Reactor Support System

The reactor vessel supports are described in Section 5.5.14.

3.8.3.1.2 Steam Generator Support System

The steam generator supports are described in Section 5.5.14.

3.8.3.1.3 Reactor Coolant Pump Support System

The reactor coolant pump supports are described in Section 5.5.14.

3.8.3.1.4 Pressurizer Support System

The pressurizer supports are described in Section 5.5.14.

3.8.3.1.5 Primary Shield Wall

3.8.3.1.5.1 Description

The primary shield wall is a reinforced concrete wall surrounding and supporting the reactor vessel. The wall varies in thickness as shown by Figure 3.8-43. The inside diameter is approximately 16 feet. The lower portion of the wall, below the base slab (elevation 412') is a 4 foot thick cylindrical section surrounded by structural foundation mat concrete. Vertical support of the primary shield wall is provided by the Reactor Building foundation mat.

The inside of the primary shield wall is basically circular throughout its height. The outside is circular from the structural foundation mat to the top of the basement slab where it becomes polygonal to accommodate surrounding structures, such as secondary shield walls, fuel transfer canal slab, and fuel canal walls.

Between the base slab (elevation 412') and the fuel transfer canal (elevation 437'-2-1/2") steel assemblies are embedded into the primary shield wall. Their functions are described in Section 3.8.3.1.5.2. The general arrangement of these steel assemblies is shown in Figure 3.8-43.

3.8.3.1.5.2 Primary Shield Wall and Embedded Steel Assemblies

Embedded steel assemblies provide support for the reactor vessel support system, provide pipe rupture restraint for the reactor coolant piping, and restrict the buildup of pressure and temperature on the primary shield wall and on the reactor vessel, should a loss of coolant accident (LOCA) occur.

The functions performed by the steel assemblies are described in detail below:

1. Sleeves around Reactor Coolant Piping

   Each reactor coolant pipe between the reactor vessel and steam generator passes through a double walled sleeve (displacement restrictor) embedded in the primary shield wall (see Figure 3.8-44). The double walled sleeves consist of 2 cylindrical sleeves interconnected with radial ribs. Reactor coolant pipe break displacement limiters are attached to the inside of the inner sleeve. The annular space between the 2 sleeves functions as an air flow duct during normal operation, limiting the surrounding concrete temperature. See Figures 3.8-45 and 3.8-46.

2. Baffle Assemblies

   Baffle assemblies are installed around the primary coolant pipes at the inside face of the primary shield wall. These assemblies limit effluent flow into the reactor cavity from a postulated pipe break. Each baffle directs the flow into the double walled sleeve and into the inservice inspection hatch. The baffles are internally ribbed steel box structures embedded in the primary shield wall. See Figures 3.8-47 and 3.8-48.

   The baffle assemblies are interconnected circumferentially. This circumferentially shaped assembly transmits postulated pipe break effluent loads to the primary shield wall.

3. Anchor Assemblies under Reactor Vessel Supports

   Anchorage assembly embedments are provided under each reactor vessel support to transfer loads from the reactor vessel support to the primary shield wall. See Figures 3.8-43, 3.8-49, and 3.8-50.

Each assembly functions as a bearing shear lug assembly supported by wide flange sections cast into the primary shield wall. The anchorage assembly attachments transfer vertical, radial, and tangential loads from the reactor vessel support to the primary shield wall.

4. Neutron Detector Block Outs

   Eight (8) blockouts are provided at the inside periphery of the primary shield wall to accommodate installation and inspection of neutron detector equipment around the reactor vessel. See Figures 3.8-43, 3.8-44, and 3.8-51.

3.8.3.1.6 Secondary Shield, Refueling Cavity, and Fuel Transfer Canal Walls

The secondary shield wall forms 3 compartments which are located adjacent to and are connected with the primary shield wall. These compartments are of polygonal shape in plan and form enclosures for the reactor coolant system equipment.

The function of these enclosures is to protect the Reactor Building from the effects of a postulated pipe break, provide biological shielding, and provide lateral support for the reactor coolant system equipment. The pressurizer is enclosed in a separate compartment.

The refueling cavity/fuel transfer canal is located above and adjacent to the reactor vessel and is a stainless steel lined reinforced concrete structure. The walls of the refueling cavity/fuel transfer canal form part of the secondary shield wall system. For details of the secondary shield wall and the refueling cavity/fuel transfer canal, see Figures 3.8-39 through 3.8-42.

3.8.3.1.7 Operating and Mezzanine Floors

The operating floor slab at elevation 463' and the mezzanine floor slab at elevation 436' are supported by a structural steel framing system and the secondary shield walls. The inner edge of these reinforced concrete slabs is keyed and doweled into the secondary shield walls. The outer edge stops short of the Reactor Building liner to provide separation from the Reactor Building.

The structural steel framing system consists of radially oriented girders supported on the inboard ends by concrete corbels or steel brackets attached to the secondary shield wall. The outboard ends are supported by steel columns. The columns are spaced along a 59 foot radius, with base plates supported on piers cast in the basement floor slab at elevation 412'. Perimeter girders between the columns support the outboard portion of the operating and mezzanine floor slabs. Steel beams frame between the girders to support the floor slabs. Plans and sections showing the structural steel framing system are shown by Figures 3.8-39 through 3.8-42.

3.8.3.1.8 Polar Crane Supports

The polar crane is supported by perimeter runway girders around the Reactor Building at elevation 552' approximately (top of rail). The circular crane rail is attached to the top flange of the perimeter runway girders. The runway girders include a weldment to engage the polar crane seismic uplift lugs. The runway girders are shown by Figures 3.8-21 and 3.8-22

3.8.3.1.9 Concrete Basement Slab

A 4 foot thick concrete basement slab, located at elevation 412', is supported by the Reactor Building foundation mat. This slab supports and anchors all the internal structures and equipment. The Reactor Building base mat liner is not penetrated for anchorage of any internal structure or equipment.

3.8.3.2 Applicable Codes, Standards, and Specifications

3.8.3.2.1 General

Structural design and materials for the internal concrete and steel structures conform to the following documents unless noted otherwise herein:

1. “Southern Standard Building Code,” 1969 Edition.
2. American Concrete Institute, “Building Code Requirements for Reinforced Concrete,” ACI 318-71.
3. American Concrete Institute, “Specification for Structural Concrete for Buildings,” ACI 301-72, revised 1975.
4. American Institute of Steel Construction, “Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings,” February 12, 1969.
5. American Institute of Steel Construction, “Code of Standard Practice for Steel Buildings and Bridges,” July 1, 1970.
6. American Welding Society, “Structural Welding Code,” D1.1-72.
7. Regulatory Guides, as discussed in Appendix 3A and listed below:
   a. Regulatory Guide 1.12, “Instrumentation for Earthquakes.”
   b. Regulatory Guide 1.29, “Seismic Design Classification.”
   c. Regulatory Guide 1.94, “Quality Assurance Requirements for Installation, Inspection and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants.”
8. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criteria 2 and 4.

3.8.3.2.2 Concrete

The following codes, standards, and specifications are used to establish the properties of concrete and to control concrete placement:

1. American Concrete Institute
   a. “Specification for Structural Concrete for Buildings,” ACI 301-72, revised 1975.
   b. “Building Code Requirements for Reinforced Concrete,” ACI 318-71.

c. "Mass Concrete for Dams and Other Massive Structures," ACI Title No. 67-17, a report by ACI Committee 207.

2. American Society for Testing and Materials

a. "Standard Method of Test for surface Moisture in Fine Aggregate," C70-73.

b. "Standard Method of Test for Specific Gravity and Absorption of Coarse Aggregate," C127-73.

c. "Standard Method of Test for Specific Gravity and Absorption of Fine Aggregate," C128-73.

d. "Standard Method of Test for Length Change of Hardened Cement Mortar and Concrete," C157-75.

e. "Standard Method of Test for Thermal Conductivity of Materials by Means of the Guarded Hot Plate," C177-71.

f. "Standard Method of Test for Total Moisture Content of Aggregate by Drying," C566-67.

g. "Standard Method of Test for Chloride Ion in Water and Waste Water," D512-67.

h. "Standard Method of Test for Sulfate Ion in Water and Waste Water," D516-68.

i. ASTM C109-08, Standard Test Method for Compressive Strength of Hydraulic Cement Mortars (Using 2-in Cube Specimens).

j. ASTM C1107-11, Standard Specification for Packaged Dry Hydraulic-Cement Grout (Nonshrink).

3. U.S. Army Corps of Engineers

a. "Method of Test for Coefficient of Linear Expansion of Concrete," CRD-C39-55.

b. "Method of Test for Flow of Grout Mixtures (Flow Cone Method)," CRD-C79-58.

c. "Method of Test for Flat and Elongated Particles in Coarse Aggregate," CRD-C119-53.

d. "Methods of Sampling and Testing Expansive Grouts," CRD-C589-70.

e. CRD C621-93, Standard Specification for Packaged Dry Hydraulic-Cement Grout (Nonshrink).

4. Concrete Plant Manufacturers Bureau, "Concrete Plant Standards," Revision 5, March, 1973.

5. Truck Mixer Manufacturers Bureau, "Truck Mixer and Agitator Standards," Revision 9, November, 1971.

6. Regulatory Guide 1.55, "Concrete placement in Category 1 Structures," (see Appendix 3A).

3.8.3.2.3 Reinforcing Steel

The following codes and specifications are used to establish the properties of and to control the fabrication and placement of reinforcing steel:

1. American Society for Testing and Materials
   a. "Standard Specification for Deformed Billet Steel Bars for Concrete Reinforcement," ASTM A615-72.
   b. "Standard Methods and Definitions for Mechanical Testing of Steel Products," ASTM A370-72.
2. American Concrete Institute
   a. "Specification for Structural Concrete for Buildings," ACI 301-72, revised 1975.
   b. "Building Code Requirements for Reinforced Concrete," ACI 318-71.
3. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," Division 2, 1975.

3.8.3.2.4 Structural Steel

Codes and specifications for design, fabrication, and erection of structural steel are as stated in Section 3.8.3.2.1, items 5 and 6.

3.8.3.3 Loads and Load Combinations

3.8.3.3.1 Load Definitions

Loads used in the design of the interior concrete and steel structures are defined as follows:

1. Normal Loads
   a. D - Dead load of the structure, including any permanent equipment loads.
   b. L - Live loads, including any movable equipment loads which may vary in intensity.
   c. To - Thermal effects and loads under normal operating or shutdown conditions.
   d. R_o - Pipe reactions under normal operation or shutdown conditions.
   e. F - Hydrostatic loads due to pressure of liquid under shutdown conditions.
2. Severe Environmental Loads

   E - Loads generated by an OBE

3. Extreme Environmental Loads

   E' - Loads generated by an SSE

4. Abnormal Loads
   a. P_a - Pressure equivalent static load within or across a compartment due to a pipe break, including dynamic factors.

b. T_a - Thermal loads due to thermal conditions occurring during a pipe break.

c. R_a - Pipe reactions due to thermal conditions during a pipe break.

d. Y_r - Equivalent static load due to the reaction on a broken pipe during a postulated break, including dynamic load factors, except where time history analysis is performed.

e. Y_j - Jet impingement equivalent static load due to the jet from a broken pipe during a postulated break, including dynamic load factors.

f. Y_m - Missile equivalent static load due to impact of any postulated missile, including dynamic load factors.

3.8.3.3.2 Design Loads

1. Normal Loads

   a. Dead Load, D

      A reinforced concrete density of 150 lb/ft^3 is used. Density of structural steel is 490 lb/ft^3. Permanent equipment loads and cable tray loads are used in the design.

   b. Live Loads, L

      The live loads considered in the design are the weight of any equipment or systems not permanently attached, plus an allowance for transient loads during construction, operation, or maintenance.

   c. Thermal Effects, T_o

      Temperature induced forces are evaluated for the various sections of the interior structures based upon the most adverse temperature gradients predicated upon normal plant operation temperature ranges (Refer to Section 6.2.1).

   d. Pipe Reactions, R_o

      Pipe Load reactions are considered, as appropriate, for the design of the internal structures. Thus reactions are considered as live loads.

   e. Hydrostatic Loads, F

      Hydrostatic loads are based upon a water density of 62.4 lb/ft^3.

2. Severe Environmental Loads, E

   Seismic design of the internal structures is based upon the response to OBE ground accelerations as described in Section 3.7.

3. Extreme Environmental Loads, E'

   Seismic design of the internal structures is based upon the response to SSE ground accelerations as described in Section 3.7.

4. Abnormal Loads

   a. Design Accident Pressure, P_a, and Temperature, T_a

      The various components of interior structures are designed for the worst applicable postulated accident conditions. These conditions vary with different components and are dependent upon the postulated accident; for a discussion of the accident types investigated, see Section 6.2.1.

   b. Pipe Break Effects, R_a, Y_r, Y_j

      The reactions from pipe break are considered in the design of the interior structures where applicable. See Section 3.6.

   c. Missile Impact, Y_m

      The effect of interior missile impact on the internal structures is considered (see Section 3.5).

3.8.3.3.3 Load Combinations

3.8.3.3.3.1 Interior Concrete Structures

The internal concrete structures, including primary shield walls, secondary shield walls, and floor slabs are designed for the load combinations presented in Table 3.8-10.

3.8.3.3.3.2 Structural Steel Structures

The floor framing system and polar crane runway girders are designed for the load combinations presented in Table 3.8-11.

3.8.3.4 Design and Analysis Procedure

3.8.3.4.1 Reactor Coolant System Supports

Description of the models and analytical methods, loads and loading combinations, and allowable limits for the Reactor Coolant System supports are given in Section 5.2.1.10.

3.8.3.4.2 Primary Shield Wall

3.8.3.4.2.1 Structural Model

The primary shield was analyzed in 2 phases:

1. The entire wall from the base (elevation 387'-8") to the top (elevation 437'-2-1/2") was analyzed as an axisymmetric thick cylinder using the finite element computer program ELAD for axisymmetric solids of revolution (see Section 3.8.4.4).
2. Due to major penetration discontinuities and the restraint effects of the secondary shield walls above the basement slab, that portion of the primary shield wall was modeled using the

finite element computer program MRI/STARDYNE (see Section 3.8.4.4) with thick element criteria.

The boundary condition assumed for the first phase analysis at the basement floor slab and the structural base mat was one of radial restraint. Design loads were applied at their point of application to the primary shield wall and results were combined in accordance with the load combinations given in Table 3.8-10.

The structural boundary at the top of the basement floor slab (elevation 412') was assumed to be fixed for the second phase analysis. The effects of the secondary shield walls, fuel transfer canal walls, and fuel transfer canal slab were modeled as displacement boundaries. Actual penetrations were modeled. Loads were applied individually at their point of application and results were combined in accordance with the load combinations given in Table 3.8-10.

The structural behavior predicted by both models at the assumed boundary of the second phase model (top of basement slab) was found to be compatible. The resultant stresses from both models were used to determine the concrete and reinforcing steel requirements in accordance with the strength design method given in ACI 318-71.

3.8.3.4.2.2 Application of Loads and Analytical Procedure

The elastic analysis was performed by applying the basic loads listed in Section 3.8.3.3. These loads were applied separately and the resultant forces obtained from each analysis are combined with appropriate load factors according to the load combinations listed in Table 3.8-10.

From the results of these combinations, the maximum stress resultants to which an element under investigation is subjected were determined.

The reinforcement area was then calculated according to ACI 318-71 using the strength design method. Earthquake, temperatures, and accident loads were treated as follows:

1. Earthquake

   The accelerations of the primary shield wall in horizontal and vertical directions at different elevations of the wall were calculated as described in Section 3.7.

   The absolute value of the seismic forces was added to the applicable load combinations.

2. Thermal Loads

   Thermal gradients were generated from the time history studies of the accident conditions (see Section 6.2.1). The thermal gradients occurring at various hours after startup, shutdown, and accident were used as input in the analyses. The forces obtained from these analyses were superimposed separately on load combinations to determine the maximum effect.

3. Loss of Coolant Accidents

a. Pressure Loads

A postulated guillotine break at the weld connecting the reactor coolant pipe with the reactor vessel nozzle for the cold leg (see Figures 3.8-43 and 3.8-44) was considered as described in Chapter 6. The reactor coolant released by this postulated break is directed toward the steam generator compartment through the penetration and toward the refueling cavity through the inservice inspection hatch due to the baffle assembly flow restriction as described in Section 3.8.3.1.5.1. The flow back into the primary cavity is limited by the narrow gap between the nozzle and the steel baffle assembly surrounding the nozzle.

The pressure in the annulus of the primary shield wall caused by the limited back flow of reactor coolant is maximum at the postulated break location and decreases away from it, creating a spatial distribution of accident pressure which is applied to the inside of the primary shield wall structure model. The pressure buildup in the penetration at the location of the postulated break is also applied simultaneously with the reactor cavity pressures. The transient pressure includes a dynamic factor for the static input on the structural model.

b. Pipe Reactions and Jet Forces

The forces associated with postulated reactor coolant pipe ruptures, such as pipe reactions and jet forces are also considered. The reactor coolant pipes pass through double walled steel sleeves embedded in the primary shield wall. Lateral movement of the pipe in the event of an accident is restricted by shims between the pipe periphery and the sleeve inner wall along the passage of the pipe through the primary wall thickness. Due to this restriction of lateral movement of the pipe in the event of a rupture near reactor vessel nozzle, the loss of reactor coolant and the dynamic reaction of the pipe are limited. The restricted flow also limits the jet impingement force. Axial movement of the pipe is limited by the reactor coolant loop geometry. The vertical reaction of the hot leg pipe in case of a break at the steam generator elbow is taken by a vertical support column located outside the primary shield wall. Lateral movement of the hot leg pipe in case of a break is resisted by shims between the pipe periphery and the sleeve in the wall. Lateral and vertical movement of the cold leg pipe is resisted by shims as described above. The loads transmitted to the primary shield wall from the reactor vessel supports due to accident, thermal, and seismic effects are applied to the model separately and are combined in accordance with Table 3.8-10.

3.8.3.4.3 Secondary Shield Walls, Refueling Cavity Walls, Fuel Transfer Canal Walls and Slab, and Mezzanine and Operating Floor Slabs

The interior structures were modeled using the finite element technique with the computer program MRI/STARDYNE (see Section 3.8.4.4). A composite finite element model was generated which included all of the significant interior structures, including the primary shield wall, secondary shield wall, fuel transfer canal walls and slab, the adjacent mezzanine and operating floor slabs, the 4 foot thick basement floor slab, and steel columns. Due to the completeness of the model, the only boundary condition was the contact surface between the

basement floor slab and the Reactor Building structural foundation mat which was simulated by springs. The spring constants were determined in accordance with the half space theory.

The element size and number of nodes were determined by parametric studies and the ASCE publication, “Guidelines for Finite Element Idealization.” Loads were applied to the model individually at their point of application and the results were combined in accordance with Table 3.8-10. Associated pipe break loads were applied to the model using a dynamic load factor. Based upon the results of the combined stresses, the concrete was checked against allowable stresses and the area of reinforcing required was determined utilizing the strength design method given in ACI 318-71. Horizontal shears were reacted at the basement slab through friction and by bearing of the embedded portion of the primary shield wall below the basement slab. Local effects of jet impingement forces were investigated using yield line theory.

3.8.3.4.4 Interior Structural Steel (Operating and Mezzanine Floor Framing)

The mezzanine and operating floors are supported by beam and girder steel framing. The girders are supported by the secondary shield walls and outboard perimeter columns as described in Section 3.8.3.1.7.

The concrete slabs are designed to transfer horizontal forces to the secondary shield walls.

The structural steel is designed for the temperature increase caused by the postulated accidents. The thermal gradient between the structural steel frame and the concrete slab was incorporated in this design. Structural steel is designed for the pipe break pressure, jet forces, and LOCA differential pressures by application of a dynamic load factor to the resultant loads.

The pipe reactions associated with pipe breaks were determined by a dynamic analysis of the affected structural steel. Hand calculations were used for the design, except for column design where computer program S027 was used. (See Section 3.8.4.4).

3.8.3.4.5 Polar Crane Supports

The polar crane runway girders are designed as simply supported beams spanning between the brackets described in Section 3.8.1.

Crane wheel loads, determined for the various loads and load combinations listed in Table 3.8-3, are applied to the polar crane runway girders at different locations to determine maximum shears, moments, and reactions.

Girders are provided with slotted holes in one end to allow thermal growth under operating and accident conditions. Rail splices are also provided with gaps and slotted holes. Polar crane wheels are designed to allow for expansion of polar crane runway girders.

Vent openings are provided in the girders to prevent collapse during pressurization of the Reactor Building.

3.8.3.4.6 Basement Floor Slab

The 4 foot thick basement floor slab at elevation 412' was analyzed in conjunction with the analysis of the secondary shield wall. The model used is discussed in Section 3.8.3.4.3. Loads were applied independently at their point of application in the entire model and results were combined in accordance with the load combinations given in Table 3.8-10. Associated pipe break loads were applied to the model using a dynamic load factor. The total horizontal shear was reacted by the embedded portion of the primary shield wall in bearing and friction between the basement slab and the Reactor Building liner and base mat.

The entire interior structure, including the basement slab, was analyzed to determine adequate stability. Consideration of stiffness of the primary shield wall, secondary shield walls, and basement slab was included in the overturning analysis.

3.8.3.5 Structural Acceptance Criteria

3.8.3.5.1 Reactor Coolant System Supports

The loads and loading combinations considered in the analysis of the Reactor Coolant System supports and allowable stress criteria are given in Section 5.2.1.10.

3.8.3.5.2 Interior Concrete Structures

Allowable stresses were maintained within the limits shown in Table 3.8-10.

3.8.3.5.3 Steel Structures and Supports

Allowable stresses were maintained within the limits shown in Table 3.8-11.

3.8.3.6 Materials, Quality Control, and Special Construction Techniques

3.8.3.6.1 Concrete

Information regarding interior structure concrete materials, quality control, and special construction techniques is identical to that presented in Section 3.8.1.6.1. The compressive strength of the concrete is 5000 psi at 90 days.

3.8.3.6.2 Reinforcement

Information regarding interior concrete structure reinforcement materials, quality control, and special construction techniques is the same as that presented in Section 3.8.1.6.2.

3.8.3.6.3 Structural Steel

Materials for interior steel structures conform to the following requirements:

1. Structural Steel Shapes and Plates
   a. ASTM A36-70a
   b. ASTM A572-70a, Grade 50
2. High Strength Bolts

   ASTM A325-71

3. Ordinary Bolts

   ASTM A307-68, Grade A

4. Welding Rods

   AWS D1.1-72, Type E7015, E7016, and E7018

5. Concrete Anchor Studs

   ASTM A108, Grades 1010, 1015, 1017, or 1020

6. Anchor Bolts

   ASTM A36-70a

7. Nuts for Anchor Bolts

   ASTM A307-68, Grade A

8. Polar Crane Rails

   ASTM A1-68a

9. Embedded Steel Assemblies
   a. Reactor Vessel Support Assemblies
      (1) ASTM A302-B plate steel with supplemental requirements S1, S3, and S4, and ultrasonic inspection for internal discontinuities in accordance with ASTM A578, acceptance level 1.

   (2)ASTM A588 wide flanges and plates

      (3) ASTM A441 bar

   b. Neutron Detector Liner Boxes
      (1) ASTM A302-B plate steel with supplemental requirements S1, S3, and S4, and ultrasonic inspection for internal discontinuities in accordance with ASTM A578, acceptance level 1.

(2)SAE C-1012 threaded coupling, 9-1/2 inch OD (non-nuclear safety class).

(3) ASTM A53 or ASTM A106 pipe (non-nuclear safety class).

c. Reactor Cavity Liners

(1) The liner serves as a concrete form and provides close tolerances for optimum air passage around the reactor vessel ASTM A302-B plate steel with supplemental requirements S1, S3, and S4, and ultrasonic inspection for internal discontinuities in accordance with ASTM A578, acceptance level 1. Alternatively, ASTM A709, Grade 36, as required.

(2)ASTM A588 angles

d. Pipe Sleeve Assemblies

(1) ASTM A302-B plate steel with supplemental requirements S1, S3, and S4, and ultrasonic inspection for internal discontinuities in accordance with ASTM A578, acceptance level 1.

(2)Headed concrete anchor studs, 3/4 inch by 3-3/8 inch.

(3) Headed concrete anchor studs, 7/8 inch by 7-3/16 inch.

(4) ASTM A36 threaded rod, 3/8 inch (non-nuclear safety class).

(5) ASTM A213, type 316 stainless steel tubing, 1/2 inch OD (non-nuclear safety class).

(6) ASTM A36 angle, 1-1/4 inch by 1-1/4 inch by 1/8 inch (non-nuclear safety class).

e. Cover Plates

(1) ASTM A302-B plate steel with supplemental requirements S1, S3, and S4, and ultrasonic inspection for internal discontinuities in accordance with ASTM A578, acceptance level 1.

(2)ASTM A307 bolts, 3/4 inch diameter (non-nuclear safety class).

(3) ASTM A588 angle, 4 inch by 4 inch by 1/2 inch

(4) Threaded studs, 3/4 inch diameter

(5) Headed concrete anchor studs, 3/4 inch by 3-7/8 inch

Material and quality control requirements conform to AISC, “Specification for the Design, Fabrication and Erection of Structural Steel for Buildings,” 1969 Edition.

Fabrication and erection of structural steel, installation and inspection of high strength bolts, and welding and welding inspection are in accordance with ANSI N45.2.5 (Reference 25).

3.8.3.7 Testing and Inservice Inspection Requirements

Except for testing required to comply with material specifications, no testing or inservice inspection of internal structures is planned.

3.8.4 Other Seismic Category 1 Structures

3.8.4.1 Description of the Structures

3.8.4.1.1 General

With the exception of the Service Water Pumphouse, intake and discharge structure, the Seismic Category 1 structures surround the Reactor Building. These structures are seismically independent of the Reactor Building and of each other. However, the Control and Intermediate Building foundations are tied together, while the superstructures are separated (see Figure 3.8-52).

The separation of the structures, typical joints at foundation level, and typical floor and roof levels are indicated by Figure 3.8-52. The relative motions of adjacent Seismic Category 1 structures at critical elevations were determined to establish the required seismic separation.

The Non-Seismic Category 1 Hot Machine Shop and Turbine Building are designed to withstand earthquake loads and tornado wind loads to the extent required for prevention of damage to Seismic Category 1 structures. General materials of construction are concrete with a compressive strength of 3000 psi; ASTM A615, grade 60, reinforcing steel; and ASTM A36 structural steel.

Both rubber (styrene-butadiene) and polyvinyl chloride waterstops are used. Polyvinyl chloride waterstop locations and expected radiation levels are listed in Table 3.8-11a.

3.8.4.1.2 Auxiliary Building

The Auxiliary Building is a reinforced concrete shear wall (box type) structure with 6 main floor levels. It is approximately 110 feet wide by 190 feet long. The lowest level, a sub-basement, is located 61 feet below grade and the roof level is 50 feet above grade. The roof and exterior walls are of 2 foot thick reinforced concrete designed to prevent damage to safety-related equipment areas from tornado missiles and their effects. The floors are reinforced concrete supported on concrete walls. Areas immediately adjacent to the Reactor Building utilize steel framing and concrete slabs tied into the adjacent Auxiliary Building concrete walls.

A Non-Seismic Category 1 structure of steel frame, metal siding, and metal roof deck is located on the roof of the Auxiliary Building. The basic details of this steel structure are provided by Figures 3.8-72 and 3.8-73. This structure is classified as Non-Seismic Category 1 because the equipment contained in it is nonsafety related, primarily HVAC components, such as plenums and fans, as well as a number of electrical panels. Generally, this equipment is bolted to the slab at Elevation 485'-0". This structure was designed to withstand earthquake forces, based upon the “Uniform Building Code,” 1973 Edition, and 100 mph design wind loads. The elastic method of

analysis was used for the design. The loads are applied to the braced frame structure, using conventional frame analysis methods. The steel roof deck is used as a diaphragm to transfer the lateral loads due to earthquake or wind to the braced frame and supports. Load combinations and acceptance criteria are as stated in Table 3.8-14, Section 1.a, with a 1/3 increase in allowable stresses for seismic and wind loads in accordance with Reference 18, where applicable. In addition, this Non-Seismic Category 1 structure is designed to withstand the SSE and tornado wind. The elastic method of analysis was used and loading combinations are as stated in Table 3.8-14, Section 2.a. The acceptance criterion used is that forces in the structure do not exceed the ultimate capacity of the structure. This method is considered conservative in comparison with a full plastic analysis.

The steel roof structure has been checked for its response to missile impact. Specifically, calculations indicate that impact by the design missile, a steel rod, with a diameter of 1 inch, a length of 3 feet, and weight of 8 pounds, cannot render the structure, or any portion of the structure, unstable. Impact by this missile cannot cause a structural steel component to become detached from the overall structure such that a secondary missile is generated. Potential impact by a utility pole was not considered for this particular structure since the base of the steel, at Elevation 485'-0", is more than 30 feet above plant grade, at Elevation 435'-0".

Demonstration of the capability of the structure to withstand impact of the indicated missile satisfies the provisions of Standard Review Plan, Section 3.5.1.4, Paragraph III-4.

The Seismic Category 1 portion of the Auxiliary Building has a roof and external walls of 2 foot thick reinforced concrete designed to prevent damage to safety related equipment areas from tornado missiles and tornado missile effects. This design was developed in accordance with ACI 318-71 and ACI 349, using the loads and load combinations of Table 3.8-12. Therefore, the Seismic Category 1 portion of the Auxiliary Building will not be damaged by either an earthquake or a tornado.

The Auxiliary Building is separated from other buildings by a space to prevent load transfer during an OBE or SSE. See Figures 3.8-53 and 3.8-54 for details.

3.8.4.1.3 Intermediate Building

The Intermediate Building is an L-shaped, box type structure with 2 main floors and a partial third floor. It is approximately 90 feet wide by 200 feet long. The lower level of the structure is 23 feet below grade. The low roof is 28 feet above grade and the high roof is 70 feet above grade. The 2 story area has steel columns and beams supporting concrete slabs. The 3 story area, approximately 84 feet by 30 feet in plan, on the west side of the structure consists of concrete walls, roof, and floor slabs. The 2 story structure houses the main steam and feedwater lines. The roof structure is designed in specific areas to provide pressure relief by means of steel sacrificial panels in case of a pipe rupture. Equipment or systems essential for safe shutdown are not located on the floor under these sacrificial panels. The exterior walls and roofs are reinforced concrete, designed to prevent tornado missile damage to Seismic Category 1 equipment. The Intermediate Building is separated from other buildings above the foundation to prevent load transfer during an OBE or SSE. See Figures 3.8-54 and 3.8-55 for details.

3.8.4.1.4 Diesel Generator Building

The Diesel Generator Building is a reinforced concrete structure approximately 67 feet long, 65-1/2 feet wide and 42 feet above grade, as shown by Figure 3.8-56. The general basement level is 8 feet below grade. The cable and piping pit area extends down to 35 feet below grade. The structure is founded in a caisson system, as described in Section 3.8.5.1.6.

The walls and roof of the Diesel Generator Building are designed to prevent damage to safety-related equipment from tornado missiles and their effects. Removable missile shields are provided in front of external equipment access openings. Labyrinth shields are provided at external access doors. The Diesel Generator Building is separated from other buildings to prevent load transfer during an OBE or SSE. See Figure 3.8-56.

3.8.4.1.5 Control Building

The Control Building is a steel framed structure with concrete exterior shear walls and a concrete roof. This building has 4 main levels and is approximately 84 feet wide by 140 feet long. The lower 3 levels are further divided into upper cable spreading and plenum areas and lower rooms. The basement floor is 23 feet below grade. The concrete roof is approximately 70 feet above grade. The exterior walls and roof are reinforced concrete designed to prevent tornado missiles from damaging safety-related equipment within the building. The main interior framing consists of steel columns, steel girders in the north-south direction, and steel beams in the east-west direction. Horizontal forces are transferred to the exterior walls by diaphragm action of the concrete floor slabs. The Control Building is separated from other buildings above the foundation by a space to prevent load transfer during an OBE or SSE. See Figures 3.8-55 and 3.8-57 for details.

3.8.4.1.6 Fuel Handling Building

The Fuel Handling Building is a steel frame superstructure founded on a reinforced concrete substructure. This building has 2 main floor levels and a roof. It is approximately 120 feet long by 68 feet wide. The lowest level of the structure is approximately 23 feet below grade. The roof is approximately 76 feet above grade.

The principle elements of the building are the stainless steel lined spent fuel pool, the cask loading pit, the decontamination area, excess liquid waste processing areas, the fuel transfer canal which connects the cask loading pit and spent fuel pool, the railroad access area (floor elevation 436'), and the new fuel storage area. The upper floor level consists of a concrete slab supported by concrete walls and structural steel framing. A 125 ton overhead traveling fuel handling crane which spans 62'-8" is provided. The main hook of the crane lifts and handles the spent fuel cask. The 125 ton main hoist incorporates a single-failure-proof design as discussed in Section 3.12.4.3. The auxiliary hook (15 ton capacity) lifts and handles new fuel and new fuel containers. The fuel handling crane is physically restrained from traveling over the spent fuel pool by bumper stops mounted on the crane rails (see Section 9.1) and by posts which are welded to the ends of the fuel handling crane runway beams. The Fuel Handling Building is separated from other buildings by a

space to prevent load transfer during an OBE or SSE. See Figures 3.8-58 through 3.8-60 for details.

3.8.4.1.7 Service Water Pumphouse

The Service Water Pumphouse is a reinforced concrete building adjacent to the service water pond. The structure consists of a forebay and pump chamber which is approximately 54 feet by 51 feet. The pump chamber extends from elevation 390' to the operating floor at elevation 436'. A reinforced concrete superstructure and roof approximately 79 feet by 70 feet extends from operating floor to elevation 459'. The roof covers the forebay/pump chamber, the control area, and the discharge pipe pits. The main intake structure enters the forebay at elevation 390'. Monorails are provided on the underside of the roof structure. The concrete walls and roof are designed to protect Seismic Category 1 equipment from damage due to tornadoes and their effects. See Figures 3.8-61 and 3.8-62.

3.8.4.1.8 Service Water Intake Structure

The Service Water Intake Structure is a reinforced concrete rectangular box culvert with 2 reinforced concrete wing walls at the intake end. The structure is mostly buried within the West Embankment as shown by Figures 1.2-1 and 3.8-63. The portion which is not covered with soil is submerged within the service water pond. The function of the Service Water Intake Structure is to draw water from the service water pond into the Service Water Pumphouse. The connection between the Service Water Intake Structure and the Service Water Pumphouse is described in Section 3.8.5.1. The Service Water Intake Structure is designed to withstand loads applied under normal operating conditions, as well as under the extreme environmental conditions.

The Service Water Intake Structure (SWIS) is designed as a 2 dimensional structure in the transverse direction. The loads are primarily sustained by sections normal to the longitudinal axis. All load combinations and loads specified in Standard Review Plan (SRP) 3.8.4 for reinforced concrete strength design were satisfied.

The controlling load combination included dead, hydrostatic, and soil pressure loads for the unique conditions of the SWIS being dewatered, via stop logs, and the Service Water Pond being completely filled. Provisions for stop logs have been made at the intake end of the SWIS and at the entrance to the pump chamber.

A comparison of factored internal forces and moments to the acceptance limits of SRP 3.8.4 results in the most critical section having a strength which is 20% in excess of that required. The load combinations which included OBE and SSE result in the most critical section having a strength of 150% and 230% respectively in excess of those required.

As far as the longitudinal direction of the SWIS is concerned, the original design of the SWIS included longitudinal reinforcing steel for distribution of cracks associated with thermal and shrinkage effects. The original design did not include consideration of the differential settlement that occurred. Since the unanticipated settlement has occurred, and the cracks have been grouted, the longitudinal reinforcing steel now serves exactly the same purpose as originally intended.

The longitudinal direction could crack due to a seismic event. It is conservatively calculated using Newark's theory that the actual maximum crack width that could occur due to an SSE is 0.16 inches. The safety margin in the longitudinal direction can only be based upon the degree of cracking and its effect on safe function of the SWIS. It was determined that the SWIS will function satisfactorily with a crack width of 1/2 inch. The 1/2 inch is a lower bound number, but nevertheless could be used to determine a safety margin by comparing it with the actual calculated crack width of 0.16 inches. On this basis, the safety margin of the structure in the longitudinal direction can be said to be at least 3.0.

3.8.4.1.9 Service Water Discharge Structure

The Service Water Discharge Structure is located on the southeast edge of the West Embankment of the service water pond. The discharge structure, as shown by Figure 3.8-64, is a reinforced concrete structure which consists of an expansion chamber and a sill with crest at elevation 414'. The crowns of two 30 inch diameter discharge pipes which terminate at the Service Water Discharge Structure are at elevation 412'-6". The pipes are connected to the Service Water Discharge Structure by flexible connections.

3.8.4.2 Applicable Codes, Standards, and Specifications

The design, materials, fabrication, erection, inspection, and testing of Seismic Category 1 structures are covered by codes, standards, and guides which are applicable in whole or in part. A list of such documents is as follows:

3.8.4.2.1 General

1. Southern Standard Building Code, 1969 Edition.
2. American Concrete Institute, “Building Code Requirements for Reinforced Concrete,” ACI 318-71.
3. American Concrete Institute, “Code Requirements for Nuclear Safety Related Concrete Structures,” ACI 349-76.
4. American Concrete Institute, “Specification for Structural Concrete for Buildings,” ACI 301-72, revised 1975.
5. American Institute of Steel Construction, “Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings,” February 12, 1969.
6. American Institute of Steel Construction, “Code of Standard Practice for Steel Buildings and Bridges,” July 1, 1970.
7. American Welding Society, “Structural Welding Code,” AWS D1.1-72.
8. American National Standards Institute, “Supplementary Quality Assurance Requirements for Installation and Testing of Concrete Structural Steel, Soils and Foundations during the Construction Phase of Nuclear Power Plants,” ANSI N45.2.5.

9. Nuclear Regulatory Commission, Regulatory Guides, as discussed in Appendix 3A listed below:
    a. Regulatory Guide 1.13, “Spent Fuel Storage Facility Design Basis.”
    b. Regulatory Guide 1.29, “Seismic Design Classification.”
    c. Regulatory Guide 1.55, “Concrete placement in Category 1 Structures.”
    d. Regulatory Guide 1.76, “Design Basis Tornado for Nuclear Power Plants.”
    e. Regulatory Guide 1.94, “Quality Assurance Requirements for Installation and Testing of Structural Concrete and Structural Steel during the Construction Phase of Nuclear Power Plants.”
10. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criteria 2 and 4.

3.8.4.2.2 Concrete

The following codes, standards, and specifications are used to establish the properties of concrete and to control concrete placement:

1. American Concrete Institute
    a. “Specification for Structural Concrete for Buildings,” ACI 301-72, Revised 1975.
    b. “Building Code Requirements for Reinforced Concrete,” ACI 318-71.
    c. “Mass Concrete for Dams and Other Massive Structures,” ACI Title Number 67-17, a report by ACI Committee 207.
2. American Society for Testing and Materials
    a. “Standard Method of Test for surface Moisture in Fine Aggregate,” C70-73.
    b. “Standard Method of Test for Specific Gravity and Absorption of Coarse Aggregate,” C127-73.
    c. “Standard Method of Test for Specific Gravity and Absorption of Fine Aggregate,” C128-73.
    d. “Standard Method of Test for Length Change of Hardened Cement Mortar and Concrete,” C157-75.
    e. “Standard Method of Test for Thermal Conductivity of Materials by Means of the Guarded Hot Plate,” C177-71.
    f. “Standard Method of Test for Total Moisture Content of Aggregate by Drying,” C566-67.
    g. “Standard Method of Test for Chloride Ion in Water and Waste Water,” D512-67.
    h. “Standard Method of Test for Sulfate Ion in Water and Waste Water,” D516-68.
    i. ASTM C109-08, Standard Test Method for Compressive Strength of Hydraulic Cement Mortars (Using 2-in Cube Specimens).

j. ASTM C1107-11, Standard Specification for Packaged Dry Hydraulic-Cement Grout (Nonshrink).

3. U. S. Army Corps of Engineers
   a. "Method of Test for Coefficient of Linear Expansion of Concrete," CRD-C39-55.
   b. "Method of Test for Flow of Grout Mixtures (Flow Cone Method)," CRD-C79-58.
   c. "Method of Test for Flat and Elongated Particles in Coarse Aggregate," CRD-C119-53.
   d. "Methods of Sampling and Testing Expansive Grouts," CRD-C589-70.
   e. CRD C621-93, Standard Specification for Packaged Dry Hydraulic-Cement Grout (Nonshrink).
4. Concrete Plant Manufacturers Bureau, "Concrete Plant Standard," Revision 5, March, 1973.
5. Truck Mixer Manufacturers Bureau, "Truck Mixer and Agitator Standard," Revision 9, November, 1971.

3.8.4.2.3 Reinforcing Steel

The following codes and specifications are used to establish the properties of and to control the fabrication and placement of reinforcing steel:

1. American Society for Testing and Materials
   a. "Standard Specification for Deformed Billet Steel Bars for Concrete Reinforcement," ASTM A615-72.
   b. "Standard Methods and Definitions for Mechanical Testing of Steel Products," ASTM A370-72.
2. American Concrete Institute
   a. "Specification for Structural Concrete for Buildings," ACI 301-72, Revision, 1975.
   b. "Building Code Requirements for Reinforced Concrete," ACI 318-71.

3.8.4.3 Loads and Load Combinations

3.8.4.3.1 Load Definitions

All the major loads encountered or postulated in the plant are listed below. The loads listed are not necessarily applicable to all the structures and their elements. Loads and the applicable load combinations for which each structure is designed depend upon the conditions to which that particular structure may be subjected.

1. Normal Loads

Normal loads, which are those loads encountered during normal plant operation and shutdown include:

a. D - Dead loads or their related internal moments and forces, including any permanent equipment loads and hydrostatic loads.

b. L - Live loads or their related internal moments and forces, including any movable equipment loads and other loads which vary with intensity and occurrence, such as soil pressure.

c. T_o - Thermal effects and loads under normal operating or shutdown conditions, based upon the most critical transient or steady-state condition.

d. R_o - Pipe reactions under normal operating or shutdown conditions, based upon the most critical transient or steady-state condition.

2. Severe Environmental Loads

Severe environmental loads include:Extreme Environmental Loads

a. E - Loads generated by the OBE

b. W - Loads generated by the design wind specified for the plant.

Extreme environmental loads include:

a. E' - Loads generated by the SSE

b. W_t - Loads generated by the design tornado specified for the plant. Tornado loads include loads due to the tornado wind pressure, the tornado created differential pressure, and tornado generated missiles.

3. Abnormal Loads

Abnormal loads are those loads generated by a postulated high energy pipe break accident, including:

a. P_a - Pressure equivalent static load within or across a compartment generated by the postulated break, including an appropriate dynamic load factor to account for the dynamic nature of the load.

b. T_a - Thermal loads under thermal conditions generated by the postulated break, including T_o.

c. R_a - Pipe reactions under thermal conditions generated by the postulated break, including R_o.

d. Y_r - Equivalent static load on the structure generated by the reaction on the broken high energy pipe during the postulated break, including an appropriate dynamic load factor to account for the dynamic nature of the load.

e. Y_j - Jet impingement equivalent static load on a structure generated by the postulated break, including an appropriate dynamic load factor to account for the dynamic nature of the load.

f, Y_m - Missile impact equivalent static load on a structure generated by or during the postulated break, as from pipe whipping, including an appropriate dynamic load factor to account for the dynamic nature of the load.

In determining an appropriate equivalent static load for Y_r, Y_j, and Y_m, elastoplastic behavior is assumed where applicable with appropriate ductility ratios, provided excessive deflections do not result in loss of function of any safety-related system.

3.8.4.3.2 Load Combinations for Concrete Structures

Load combinations for concrete structures are listed in Table 3.8-12.

For service load conditions, either the working stress design method or the strength design method is used. Where soil and hydrostatic pressures are present, in addition to all service load condition load combinations listed in Table 3.8-12, where they are included in L and D, respectively, the requirements of Sections 9.3.4 and 9.3.5 of ACI 318-71 (Reference 12) are also satisfied (i.e., dead load and liquid levels are varied).

For factored load conditions, which represent extreme environmental, abnormal, abnormal/severe environmental, and abnormal/extreme environmental conditions, the strength design method is used.

In load combinations c, d, and e of Table 3.8-12, the maximum values of P_a, T_a, R_a, Y_j, Y_r, and Y_m, including an appropriate dynamic load factor, are used unless a time-history analysis is performed to justify otherwise. Load combinations b, d, and e of Table 3.8-12 and the corresponding structural acceptance criteria, presented in Table 3.8-12, are first satisfied without

the tornado missile load in load combination b and without Y_j, Y_r, and Y_m in load combinations d and e. When considering these concentrated loads, local strength capacities are occasionally permitted to be exceeded where it is demonstrated that there is no loss of function of any safety-related system.

The criteria for loads and load combinations used in the designs of the Service Water Intake and Service Water Discharge Structures are summarized in Table 3.8-13. Since the structures are buried and/or submerged, no live, wind, or tornado loads were considered. The loads considered included the dead weight of the structures, lateral, and vertical earth pressure, lateral fluid pressure, and dynamic forces imparted by the OBE and the SSE. Different loading combinations were investigated so that the structures could resist the most critical load combination without distress.

3.8.4.3.3 Load Combinations for Steel Structures

Load combinations for steel structures are listed in Table 3.8-14.

For service load conditions, either the elastic working stress design methods of Part 1 of the AISC Specification (Reference 18) or the plastic design methods of Part 2 of the AISC Specification are used.

In the load combinations listed in Table 3.8-14 for factored load conditions, thermal loads are neglected when it is shown that they are secondary and self-limiting in nature.

In load combinations (3), (4), and (5) of Table 3.8-14 for factored load combinations for either elastic working stress design methods or plastic design methods, the maximum values of P_a, T_a, R_a, Y_j, Y_r, and Y_m, including an appropriate dynamic load factor, are used unless a time-history analysis is performed. Load combinations (2), (4), and (5) of Table 3.8-14 for factored load combinations for either elastic working stress design methods or plastic design methods and the corresponding structural acceptance criteria, presented in Table 3.8-14, are first satisfied without the tornado missile load in load combination (2) and without Y_j, Y_r, and Y_m in load combinations (4) and (5). When considering these concentrated loads, local section strengths are occasionally permitted to be exceeded where it is demonstrated that there is no loss of function of any safety related system.

3.8.4.4 Design and Analysis Procedures

3.8.4.4.1 General

The design and analytical procedures utilized for Seismic Category 1 structures are in accordance with the following codes:

1. For concrete structures, ACI 318-71 and ACI 349.
2. For steel structures, AISC Specification.

The computer programs utilized are described in Section 3.8.4.4.10. Methods used for seismic analysis are discussed in Section 3.7.

3.8.4.4.2 Auxiliary Building

The concrete floor slabs and roof were designed as one or two way slabs, or a combination of both, using geometry aspect ratio as a criterion. The floors and roof were analyzed using plate theory or computer program MASS 01. Where the plate theory was used, parametric studies were performed on the boundary conditions to obtain upper bound solutions. The computer program used modeled the slabs as a series of discrete nodes. The number of nodes used was determined from previous studies. The boundary conditions included in the model were based upon stiffness considerations.

Lateral slab loads were carried in diaphragm action to the walls. The vertical slab loads were transmitted to columns and walls and the lateral loads, including torsional slab loads were transmitted to the shear walls. The shear walls were analyzed with consideration for shear and flexural requirements, including the effects of penetrations.

The loads were applied independently to the walls and slabs and the results were combined in accordance with the load combinations given in Table 3.8-11 and Table 3.8-12. Pipe break forces were applied using dynamic load factors. Based upon the results of the analysis, the concrete and reinforcement requirements were obtained using the strength design method of ACI 318-71. Those portions of the Auxiliary Building where steel framing was used were designed in accordance with the AISC Specification. The roof slab and exterior walls were designed for local load conditions, i.e., missile penetration, utilizing the techniques described in Section 3.5.3.

3.8.4.4.3 Intermediate Building

With the exception of the 3 story tower, the roof and floors of the Intermediate Building were analyzed and designed as described in Section 3.8.4.4.2 for the Auxiliary Building. The application of the MASS 01 computer program, as described in Section 3.8.4.4.2, considered the stiffness contribution of the concrete slabs and the structural steel members and their mutual participation.

The 3 story concrete tower was analyzed and designed using plate theory. Parametric studies were performed on the boundary conditions to obtain upper bound solutions.

Lateral loads on both portions of the structure were carried by floors and roofs acting as diaphragms. The 3 story tower portion is tied to the balance of the structure by diaphragm action which carries all horizontal loads, including torsion.

The roof slab and exterior walls were designed for local load conditions, i.e., missile penetration, utilizing the techniques described in Section 3.5.3.

The loads were applied independently to the walls and slabs and the results were combined in accordance with the load combinations given in Tables 3.8-12 and 3.8-14. Pipe break forces were

applied using dynamic load factors. Based upon the results of the analysis, concrete and reinforcement requirements were obtained using the strength design method of ACI 318-71. Where steel framing was used, it was designed in accordance with the AISC Specification.

3.8.4.4.4 Diesel Generator Building

The concrete walls and slabs were analyzed by moment distribution or moment coefficient methods. The floor and roof slabs were analyzed and designed as diaphragms to transmit lateral loads to the vertical shear walls and subsequently to the foundations. The loads were applied independently and the results were combined in accordance with the load combinations given in Table 3.8-12. Based upon the results of the analysis, concrete and reinforcement requirements were obtained using the strength design method of ACI 318-71.

The roof slab and exterior walls were designed for local load conditions i.e., missile penetration, utilizing the techniques described in Section 3.5.3.

3.8.4.4.5 Control Building

The interior structural steel frame was analyzed and designed in accordance with the provisions of the AISC Specification using the working stress method. The concrete floor slabs were analyzed utilizing moment coefficients and were designed in accordance with ACI 318-71 using the strength design method.

The floor and roof slabs were designed as diaphragms to transmit lateral loads to the exterior shear walls. The exterior walls were analyzed and designed as shear walls. Reinforcing steel was provided in accordance with the provisions of ACI 318-71. Loads were individually applied at their point of application and were combined in accordance with the load combination of Tables 3.8-12 and 3.8-14.

The roof slab and exterior walls were designed for local load conditions, i.e., missile penetration, utilizing the techniques described in Section 3.5.3.

3.8.4.4.6 Fuel Handling Building

The concrete spent fuel pool of the Fuel Handling Building was analyzed utilizing the computer programs MASS 01 and Slabs and Mats (S092) (see Section 3.8.4.4.10). The structure was idealized as a series of contiguous structural models utilizing boundary conditions which are based upon stiffness considerations employing parametric studies. The analytical results from these models were checked at the assumed boundaries to assure compatible structural behavior. Additional evaluations were performed to assess the impact of the new high-density fuel storage racks on the floor, walls and substructure of the Spent Fuel Pool. These evaluations were performed using the public domain, general-purpose finite element analysis program ANSYS (version 5.4). The structure was idealized using finite element models constructed to ensure realistic boundary conditions that do not perturb the internal forces and bending moments local to the spent fuel pool. Thermal finite element analysis assessed the stresses generated in the pool

reinforced concrete structure by the normal operating pool water temperature loads and accident boiling temperature loads.

The balance of the concrete portion of the Fuel Handling Building was analyzed using moment coefficients and plate theory.

The structural steel portions of the Fuel Handling Building were analyzed using classic hand calculational approaches and were designed in accordance with the AISC Specification. Diagonal bracing in the roof and wall was designed to transfer lateral load to the foundations.

Loads were independently applied to the structures at their point of application and the results were combined in accordance with the load combinations given in Tables 3.8-12 and 3.8-14.

The concrete portions of the structure were designed in accordance with the strength design method of ACI 318-71.

3.8.4.4.7 Service Water Pumphouse

The analysis and design procedures used for the Service Water Pumphouse are similar to those used for the Diesel Generator Building, with the exception that the seismic soil loads on the embedded portion of the structure were determined by use of the FLUSH computer program, as described in Section 3.7.

The roof slab and exterior walls were designed for local load conditions, i.e., missile penetration, utilizing the techniques described in Section 3.5.3.

3.8.4.4.8 Service Water Intake Structure

The Service Water Intake Structure was assumed to be an infinitely long rectangular tube-like structure subjected to different load combinations as described in Section 3.8.4.3. Thus, the effects of loads act mainly in the plane of the cross section of the structure, which is shown by Figure 3.8-63. The structure was further assumed to be elastic and the moment distribution method was used for analysis. The foundation of the structure is the bottom slab. Dynamic lateral earth loadings were determined using the solution of Seed and Whitman (Reference 26).

The wing walls at the intake end are free standing walls with no earth behind them. Under operating conditions, they are submerged and do not experience unbalanced forces. The loading which would be imparted to the walls during seismic events due to the inertia of the water was also considered using the Westergaard (Reference 27) solution. The static loading case was found to control. The wing walls are tied together with a bottom slab which serves as a foundation as shown by Figure 3.8-63. This slab also provides the lateral stability of the walls.

The ultimate strength design method was used to proportion and determine the amount of reinforcing steel required for the structure. All design procedures and allowable stresses are in compliance with ACI 318-71.

3.8.4.4.9 Service Water Discharge Structure

The different loads and load combinations used for the Service Water Discharge Structure are similar to those used for the Service Water Intake Structure and are shown by Table 3.8-13. The dynamic lateral earth pressure loading on abutment and wing walls was determined using the solution of Seed and Whitman (Reference 26). The design computes the dynamic pressure considering saturated unit weight of soil below water level.

The abutment wall is designed as a slab spanning between 2 wing walls. The wing walls are designed as slabs spanning between counterfort walls. The heel slab between the counterforts is designed for the weight of soil downward. The base slab (the basin slab) is designed for the maximum uplift pressure due to differential water pressure. The base slab is also designed for soil pressure from overturning moment.

The stability against sliding is provided by the weight of the structure, weight of the soil on the heel slab, shearing resistance of the soil medium, and by shear keys under the abutment wall and the sill wall. The passive pressure at the toe of the structure provides added safety against sliding. The stability against overturning is adequately provided by the weight of the structure and the soil. The stability factors for overturning, sliding, and flotation are in accordance with the minimum factors of safety specified in Table 3.8-15.

The strength design method of ACI 318-71 was adopted for the design of the Service Water Discharge Structure.

3.8.4.4.10 Description of Computer Programs

Listed below are descriptions of the computer programs used in the analysis and design of plant structures.

1. STRUDL (S084)

   STRUDL is a widely used, well known, analytical program developed by Massachusetts Institute of Technology that was released to the public domain in November, 1968. This program has a wide range of usage for static and dynamic analysis of frame members and reinforced concrete structures. STRUDL includes the capability for linear and nonlinear, static and dynamic analysis.

   The program was run on the Gilbert Associates, Inc., Reading, PA IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2 and the McDonnell Douglas, St. Louis, Mo., IBM 360/195 dual processor computer system under operating system OS/MVT/ASP release 21.8.

2. MRI/STARDYNE

   The MRI/STARDYNE analysis system consists of a series of compatible computer programs designed to analyze linear elastic structural models. The system can be used to evaluate a wide variety of static and dynamic problems. Only the static version was used for Virgil C. Summer Nuclear Station. The static capability includes the computation of structural deformations and member loads and stresses caused by an arbitrary set of thermal conditions, nodal applied loads, and/or prescribed displacements. MRI/STARDYNE was developed by the Mechanics Research Institute and used by Control Data Corporation since 1971. It is a large capacity finite element program which is designed for the analysis of truss, frame, and plate structures. Based upon the direct stiffness method, the program assembles the individual element stiffnesses into a global structure stiffness matrix, using appropriate matrix transformation and combination techniques. This system of equations is then solved for the generalized coordinates by Cholesk decomposition. A complete discussion of the theory used in STARDYNE and the theoretical and analytical verification is provided in the "STARDYNE Theoretical Manual," Control Data Corporation (Publication No. 86616300).

   This program has been widely used for analysis of complex structures since its release for commercial use in 1971. The program was run under revision E, dated May, 1973, on the Control Data Corporation CYBERNET system in New York on a CDC 6600 computer under version 3.3 of the SCOPE operating system.

3. ELAD (S014)

   ELAD is a computer program designed to determine elastic deformations, stresses, strains, and principal values of stress within axisymmetric solid structures of arbitrary shape subjected to axisymmetric or nonaxisymmetric pressure, concentrated loads and temperatures. All boundary conditions consistent with the theory of elasticity are permitted. A linear, elastic stress-strain relationship is assumed throughout the model. ELAD was developed by the Service Bureau Corporation, Inglewood, CA, under contract to the Air Force Weapons Laboratory, Kirtland AFB and is published as Technical Report No. AFWL-TR-69-70, dated October, 1969, available from the U. S. Government Document Clearing House.

   This program is widely available in the public domain and was run on the McDonnell Douglas, St. Louis, MO, IBM 360/195 dual processor computer system under OS/MVT/ASP release 21.8 and also on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

4. DYNAL (S085)

   DYNAL was developed by the Computer Science Department of McDonnell Douglas Automation Company and was operated under release 3.2, dated February 2, 1973, updated to September 10, 1973. The structural dynamic analyses available in DYNAL are based upon the modal superposition method using time history analysis. A simplified set of equations is formed in terms of "normal coordinates" and then solved. These "normal coordinates" are obtained by forming the stiffness and mass matrices of the structural system and solving for the normal modes and frequencies by the HOW method. The program capabilities for analysis using shock spectrum excitation or response spectrum were not utilized. Output obtained includes structural response in terms of displacement, velocity and accelerations at selected nodal points, maximum accelerations, and floor response curves.

   DYNAL is available in the public domain and has been widely used since its commercial release in 1970. The program is written in the same language as STRUDL and was run on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2 and on the McDonnell Douglas, St. Louis, MO. IBM 360/195, dual processor computer system under operating system OS/MVT/ASP release 21.8.

5. KALNINS Static Program (S043)

   KALNINS uses a multisegment method of direct numerical integration of boundary value problems and was developed by Arturs Kalnins and published in the Journal of Applied Mechanics, Volume 31, September, 1964, pages 467-476, and in the Journal of the Acoustical Society of America, Volume 36, July, 1964, pages 1355-1365. The program calculates elastic deflections and stresses in a thin walled, axisymmetric shell when subjected to any arbitrary surface, edge, and/or ring loads. The solution is based upon the linear theory of elasticity and takes into consideration bending, as well as membrane action of the shell in response to applied load. Results are in terms of resultant forces and couples with stresses calculated by assuming a linear distribution through the thickness.

   This program has been widely used for thin shell analysis since its release to the public domain in 1968. The program was run on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

6. Column Design Program (SO27)

   This Column Design Program selects steel columns for axial load plus end moments about major and/or minor axes per the allowable stress provisions in Part 1 of the AISC, "Specification for the Design, Fabrication and Erection of Structural Steel for Building," 1969 Edition.

The program accepts and combines axial loads and end moments for gravity load and lateral (wind and seismic) loads causing major and/or minor axis bending. Column height and support conditions about both axes complete the input for each column. Support condition options include either assumed effective length (K) factors or standard support conditions of beam and column stiffness factors that are used to calculate K factors.

This program has been verified by hand calculations and comparison to other previously verified programs.

The program was run on Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

7. KALNINS Dynamic Program (S032)

The program calculates the natural frequencies and mode shapes (stresses as well as displacements) of symmetric or nonsymmetric free vibration of rotationally symmetric elastic shells using the method of analysis published by Arturs Kalnins in the *Journal of the Acoustical Society of America*, Volume 36, July, 1964, pages 1355-1365. The program is applicable to axially symmetric shells to which any number of axisymmetric branches are attached.

The program determines either all natural frequencies within a prescribed frequency interval or a specified number of consecutive natural frequencies above a given frequency. The mode shapes of all displacements and stresses (or stress-resultants) are calculated and printed out for any desired number of points.

KALNINS Dynamic Program is available in the public domain and has been widely used since its commercial release in 1969.

The program was run on the Gilbert Associates, Inc., Reading, PA IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

8. Center of Gravity and Mass Moment (S042)

This program computes the center of mass, the total mass, and the mass moment of inertia about 3 axes for floor and wall systems. These values are computed for use in the dynamic analyses of buildings.

This program has been verified by hand calculations.

The program was run on the Gilbert Associates, Inc., Reading, PA IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

9. Spring Constants of Piles (S046)

   This program calculates the Winkler continuous spring constants for soil-caisson interaction. The Mindline equation, which defines the displacement components produced by a concentrated force within an isotropic half-space, is employed to evaluate the weighted average displacements of all the caissons in the group, to account for group action of the caissons, and to evaluate the Winkler continuous spring constants for the caisson group at specific depths.

   This program has been verified by hand calculations.

   The program was run on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operation system O/S 21.8 MVT with HASP 3.2.

10. DYREC (S061)

    The DYREC program calculates dynamic responses of 2 dimensional lumped mass systems for translational and/or rotational motion. The program allows translation in one direction and inplace rotation. The response is calculated by direct numerical integration of the equations of motion. The program allows nonlinear material properties and gaps between elements. DYREC has been used primarily to model and analyze pipe whip problems.

    This program has been verified by hand calculations and comparison to another widely used, generally accepted program (ANSYS).

    The program was being run on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

11. Wilson’s Program (S066)

    Wilson’s Program is a finite element program for stress analysis of 2 dimensional elastic solids and axisymmetric bodies of revolution. The program calculates stresses and strains for inplane pressure, displacement and concentrated type loading. Thermoelastic effects are included.

    Wilson’s Program was obtained from the University of Pennsylvania. This program has been widely used since its release to the public domain in 1961.

    The program was run on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

12. Wall Stiffness (SO73)

    The program calculates individual wall stiffnesses in 2 perpendicular directions, sums the wall stiffnesses in the 2 directions, locates the center of rotation (rigidity) for the entire wall system, and calculates the total rotational stiffness, Ip, about the center of rigidity.

This program has been verified by hand calculations.

The program was run on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

13. Slabs and Mats (S092)

This program was developed to solve slab and foundation mat problems. The program generates and solves a set of finite difference equations for mat deflections. Moments and shears are calculated from the deflections at user selected grid points.

The method of solution is the Finite Difference Technique applied to the Lagrange-Germain Biharmonic Equation.

This program has been verified by comparison to a program in the public domain (NASTRAN) and published information.

The program was run on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

14. Fourier/Wind (G019)

This program calculates coefficients to represent the variation of wind pressure with respect to circumferential coordinates by a Fourier Series. The program is also applicable to any even function with a period of 2π as long as the approximation of the integrals for the Fourier coefficients is sufficiently accurate for the function.

This program has been verified by hand calculations.

The program is being run on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operating system O/S 21.8 MVT with HASP 3.2.

15. MASS-01 (S106)

The computer program, MASS-01, “MAT AND SLAB SOLVER,” is utilized to analyze mat, slab, and wall bending problems. The program is based upon finite difference theory, to form a symmetrical matrix, to solve the uncoupled Lagrange-Germain-Huber variable thickness form of the biharmonic partial differential equation for static transverse slab loading. The slab is divided into a discrete number of node points so that the resulting network forms the basis of the matrix.

The boundary conditions which MASS-01 can analyze are not limited to the classical boundaries (i.e., clamp, simple, and free). A slope deflection approach to the boundary conditions also enables the user to obtain solutions to elastic boundaries. Thus, the user can specify, for both interior and exterior boundaries, a geometry consisting of walls and columns perpendicular to the slab and composite or noncomposite beam framing. The effect of interaction, both bending and torsion, is also included so that the computer model effectively represents the structure.

This program has been verified by comparison to a program in the public domain (STARDYNE) and to published information.

The program was executed on the Gilbert Associates, Inc., Reading, PA, IBM 370/155 computer under IBM operation system O/S 21.8 MVT with HASP 3.2.

16. FLUSH (S115)

The computer program FLUSH is a further development of the complex response finite element program LUSH (released to public domain in 1974). FLUSH includes new features such as transmitting boundaries, beam elements, an approximate 3 dimension ability, deconvolution within the program, and out-of-code equation solver.

The program is based upon a recognized public domain program (LUSH) and has been compared to published sample problems.

The program was executed at United Computing Systems, Inc., Kansas City, MO, on multiple CDC mainframes (i.e., - 6600, CYBER 7418, CYBER 175) under APEX/SL.

17. ANSYS

ANSYS is a general purpose finite element computer program for the solution of diversified analysis problems. Analysis capabilities include static and dynamic; plastic, creep and swelling; small and large deflections; and steady-state and transient heat transfer. ANSYS structural analysis capabilities include static, elastic, plastic, creep, dynamic, seismic, large deflection, and stability analysis. ANSYS has an extensive finite element library, including gaps, friction interfaces, springs, cables (tension only), and direct interfaces (compression only), with many of the elements containing complete plastic, creep and swelling capabilities. The ANSYS program is used in both the linear and nonlinear analysis of special two and three dimensional components and structures subject to loads such as: shear, axial, bending, torsion, pressure, and temperature. Output consists of nodal displacements, stresses, temperatures, etc., for use in evaluating the component or structure against specified acceptance criteria. Versions 5.4, 10.0A1, 13.0 and 14.0 of the ANSYS computer program have been used to analyze components and structures at VCSNS Unit 1.

3.8.4.5 Structural Acceptance Criteria

Structural acceptance criteria for each of the loading combinations considered in the design of other Category 1 structures are presented in Tables 3.8-12, for concrete structures other than the Service Water Intake Structure, and 3.8-14, for steel structures. For the Service Water Intake and Discharge Structures, all allowable stresses are in accordance with ACI 318-71.

3.8.4.6 Materials, Quality Control and Special Construction Techniques

3.8.4.6.1 Materials

3.8.4.6.1.1 Concrete

1. Cement

   Cement for other Seismic Category 1 structures may be ASTM C150, Type II cement, described in Section 3.8.1.6.1.1 or it may be ASTM C150, Type I cement. Type I cement conforms to ASTM C150 and also to the optional ASTM C150 requirements for having 0.60% maximum alkalais and 50% minimum final penetration for false set. Type I cement can also be accepted having a compressive cube strength of 3000 psi minimum, at 7 days, but must also satisfy the above mentioned optional ASTM C150 requirements.

   Cement complies with ACI 349, Section 3.2.

2. Aggregates

   Aggregates comply with ACI 349, Section 3.3.

3. Water

   Water complies with ACI 349, Section 3.4.

4. Admixtures

   Admixtures used comply with ACI 349, Section 3.6.

5. Grout

   Grout for base plates is either a factory premixed, nonshrink, nonmetallic or metallic grout or a laboratory designed, field mixed, nonshrink grout. Grout has no linear contraction and a maximum of 0.30% linear expansion in accordance with Corps of Engineers Standard CRD C-621 or ASTM C1107. The compressive strength of the grout is 6,000 psi minimum cube strength at 28 days when made and tested in accordance with ASTM C109. The grout specimens for strength and linear expansion testing are mixed to a flowable consistency measured by the time of the efflux from a standardized flow cone between 20 and 30 seconds. The flow cone shall conform to the requirements of ASTM C 939.

3.8.4.6.1.2 Concrete and Grout Mixes

1. Concrete Mix Proportioning

   Concrete mix proportioning complies with ACI 349, Section 4.2.

   Fly ash is not used in the concrete mix. Concrete compressive strength is at least 3000 psi at 28 days, except in the following locations where concrete compressive strength is at least 5000 psi at 90 days:

   a. Intermediate Building

      Concrete compressive strength is 5000 psi at 90 days in the column pads, the east penetration access area, and in concrete surrounding pipe restraint embedments.

   b. Fuel Handling Building

      Concrete compressive strength is 5000 psi at 90 days in all walls and slabs above elevation 463' and in the spent fuel pool walls.

   The schedule of testing to verify that concrete reaches a compressive strength of 5000 psi at 90 days is as follows: One (1) cylinder is tested at 7 days for information; 1 at 28 days for information; and two at 90 days for verification of 90 day strength.

2. Grout Mix Proportioning

   Premixed grout is combined with water to provide a minimum 6000 psi strength at 28 days.

   Laboratory designed, field mixed, nonshrink grouts are proportioned and tested in accordance with ASTM C109 to provide a minimum 6000 psi at 28 days in a workable, flowable consistency.

3.8.4.6.1.3 Reinforcing Steel and Cadweld Splices

1. Material

   Reinforcing steel is Grade 60 billet steel which conforms to the requirements of ASTM A615. Materials for reinforcing steel and for Cadweld splices (mechanical splice sleeves) comply with the requirements of Section 3.5 of ACI 349 for reinforcing and Section 7.5 of ACI 349 for Cadweld splices.

2. Cadweld Splices

   Reinforcing bars, sizes S14 and S18 are spliced using Cadweld splices. The sleeves develop the tensile strength of the reinforcement. Cadwelding is performed in accordance with Section 7.5 of ACI 349.

3.8.4.6.1.4 Structural Steel

Structural steel conforms to ASTM A36-70a.

3.8.4.6.1.5 Non-Bearing Plates

Non-Bearing column splice fill plate steel complies with ASTM A569 and ASTM A659 and has a maximum carbon content of 0.16 to 0.25%. These fill plates are classified as Non-Seismic Category 1.

3.8.4.6.1.6 Stainless Steel

Stainless steel plate material conforms to ASTM A240, Grade 304, is cold rolled and subsequently annealed and pickled to produce a surface finish of 75 RMS, maximum.

3.8.4.6.2 Quality Control

3.8.4.6.2.1 Concrete

Quality control requirements for concrete comply with ANSI N45.2.5 (Reference 25). Specific requirements for components are as follows:

1. Cement

   Quality control requirements for cement comply with ANSI N45.2.5.

2. Aggregates

   Quality control requirements for aggregates comply with ANSI N45.2.5 for moisture content (ASTM C566), potential reactivity (ASTM C289), and soundness (ASTM C88). In addition, the following tests are required at the frequency indicated:

   a. Flat and elongated particles (CRD C-119), monthly.
   b. Gradation (ASTM C136), within 1 day of use.
   c. Material finer than No. 200 sieve (ASTM C117), within 1 day of use.
   d. Organic impurities (ASTM C40), weekly during production.
   e. Friable particles (ASTM C142), monthly during production.
   f. Lightweight pieces (ASTM C123), monthly during production.
   g. Los Angeles abrasion (ASTM C131 or C535), every 6 months.

3. Water and Ice

   Quality control requirements for water and ice comply with ANSI N45.2.5.

4. Admixtures

   The admixture supplier is required to submit a certificate of compliance with ASTM C260 or C494 prior to or with each delivery of admixture.

5. Grout

   Quality control requirements for grout comply with ANSI N45.2.5, except that, as a minimum, during production grout is tested weekly. In addition, grout is tested at a minimum rate of 4 specimens for every 2000 pounds of grout material used.

3.8.4.6.2.2 Steel

The quality control requirements for steel structures comply with ANSI N45.2.5.

3.8.4.6.2.3 Reinforcing Steel and Cadweld Splices

Quality control provisions for reinforcing steel and Cadweld splices are discussed in Section 3.8.1.6.2.3.

3.8.4.6.3 Construction

There are no special construction techniques employed. Concrete construction complies with ACI 301-72 and steel construction complies with (Reference 18).

3.8.4.7 Testing and Inservice Surveillance Requirements

Minimum testing requirements for the Service Water Pumphouse and the Service Water intake structure are provided in Section 2.5.4.10.6.2.

There is no testing or inservice surveillance planned for other Seismic Category 1 structures.

3.8.5 Foundations

Foundation types and arrangements of Seismic Category 1 structures surrounding the Reactor Building are shown by Figure 3.8-65. These Seismic Category 1 structures are separated by a seismic gap which extends through the foundations except between the Control Building and the Intermediate Building foundations. The relationship of adjacent, separated structures and details of typical seismic separation are shown by Figure 3.8-52.

With the exception of the Reactor Building, the structural concrete has a compressive strength of 3000 psi. Reinforcing steel is ASTM A615, Grade 60.

Structural fill concrete, caissons, mats on existing soil, or compacted fill are used as foundation media for the Seismic Category 1 structure to transmit loads to competent rock.

Structural fill concrete is under the Reactor Building, Auxiliary Building, and Control Building as shown in Figure 3.8-65. The fill concrete extends from approximately elevation 340' to the undersides of the Seismic Category 1 structural mats. The fill concrete was placed in 5 foot thick layers, utilizing mass concrete construction techniques. The compressive strength of the fill concrete was 1500 psi, with the exception of the 12 foot thick layer immediately under the Reactor Building base mat and the uppermost 2 foot layer under the Auxiliary Building which had a compressive strength of 3000 psi. Fill concrete segments were keyed to each other on their vertical faces and the horizontal interfaces were roughened to assure shear friction resistance.

The Intermediate, Fuel Handling, and Diesel Generator Buildings are supported on caissons as shown in Figure 3.8-65.

Existing soil or compacted fill supported structures are the Service Water Intake Structure, the Service Water Discharge Structure, and the Service Water Pumphouse as shown in Figures 3.8-62, 3.8-63, and 3.8-64.

3.8.5.1 Description of Foundations

3.8.5.1.1 Reactor Building Foundation

A description of the physical characteristics of the structural foundation mat and fill concrete is presented in Section 3.8.1.1.1.1. Structural aspects are discussed in Section 3.8.1.4.1 and the following sections.

3.8.5.1.1.1 Structural Foundation Mat

The 12 foot thick structural foundation mat is reinforced with ASTM A615, Grade 60 reinforcement. Pertinent details of the reinforcement are as follows:

1. A radial and hoop grid of bars located at the top and bottom of the mat.
2. A rectangular grid of bars located at the top and bottom of the incore base.
3. A grid of vertical and horizontal bars at each face in the incore wall which is dowelled into the incore base and the mat.
4. Shear ties in the mat and incore walls.
5. Inclined bars spaced along the perimeter of the incore wall which are dowelled into the mat.

Figure 3.8-66 shows the bar sizes used and the spacing of this reinforcement. This reinforcement is designed to resist the load combinations presented in Table 3.8-1. All reinforcement except shear ties consists of No. 14 and No. 18 bars. Splicing of bars is accomplished by the use of Cadweld splices. The splices are staggered so that splices on adjacent bars are not less than 2 feet apart.

The structural foundation mat is constructed in the following sequence:

1. The incore base is placed in a single 13 foot pour.
2. The incore wall is placed in a single 8 foot pour.
3. The mat is placed in 12 foot thick, pie shaped sections.

Keys are used to transmit shear between these elements.

Horizontal shear transfer between the structural foundation mat and fill concrete is provided by both of the following:

1. The lateral bearing of the incore pit on the fill concrete.
2. The friction of the structural mat against the fill concrete at elevation 396' which is roughened to 1/4 inch amplitude.

Either of the above conditions acting alone is adequate to transfer the horizontal shear force.

3.8.5.1.1.2 Foundation Details

The joint at elevation 396' is continuously sealed along the perimeter of the structural foundation mat from external groundwater. This seal consists of a continuous 8 foot wide mortar joint external to the tendon gallery and continuous water stops, one external and one internal to the tendon gallery. The main function of these seals is to prevent entrance of groundwater into the tendon gallery. The structural mat and liner are designed to resist the full hydrostatic force.

Horizontal shear transfer between the 5 foot high sections of fill concrete and competent rock is provided by friction between the lists. Prior to placement of a lift, a layer of mortar is applied to the top of the previous lift which has been roughened to approximately 1/4 inch amplitude.

3.8.5.1.2 Auxiliary Building Foundation

The Auxiliary Building is founded on a 4 foot thick structural reinforced concrete mat which is supported on fill concrete extending down to competent rock. A waterproofing membrane is provided between the fill concrete and structural mat. Horizontal shears are transferred to the fill concrete through a series of shear keys. The shear keys are 6 feet square in plan and extend 1 foot deep into the fill concrete.

The Auxiliary Building mat is stepped from elevation 374' to elevation 388'. The plan and details of the Auxiliary Building foundation mat are shown by Figures 3.8-67 through 3.8-70.

3.8.5.1.3 Intermediate Building Foundation

The Intermediate Building foundation consists of a 3 foot thick basement floor slab which acts in conjunction with a series of grade beams to transfer vertical loads to the reinforced concrete caissons and shear/bearing walls and to concrete piers. The shear/bearing wall foundations and the reinforced concrete caissons are founded on competent rock. The piers are founded on fill concrete which extends beyond the Reactor Building and Auxiliary Building. Horizontal shears

are transferred through the basement floor slab to the shear/bearing walls and to the Control Building base mat.

The Control Building base mat and the Intermediate Building basement floor and grade beam system are structurally tied together so that they act in concert through diaphragm action to transfer horizontal shears, including torsion, from the Intermediate Building.

Plans and details are shown by Figures 3.8-67, 3.8-70, and 3.8-71.

3.8.5.1.4 Control Building Foundation

The Control Building foundation consists of a 4 foot thick reinforced concrete mat, the function of which is the transfer of vertical load from the superstructure columns to the fill concrete supporting the structural mat. The exterior shear walls are supported by the fill concrete through the 4 foot thick base mat. The fill concrete extends approximately 45 feet down to competent rock. Vertical reinforcing steel extends from the exterior shear walls approximately 25 feet into the layers of fill concrete. These vertical reinforcing bar anchorages are designed to resist the Control Building seismic uplift overturning forces, as well as the horizontal shears through shear friction.

Plans and details are shown by Figures 3.8-67 and 3.8-71.

3.8.5.1.5 Fuel Handling Building Foundation

The foundation system for the Fuel Handling Building consists of a concrete mat formed by the bottom of the spent fuel pool and fuel cask pit and is stepped up at the railroad bay. This mat is supported by reinforced concrete piers which extend to the fill concrete adjacent to the Reactor and Auxiliary Buildings and by reinforced concrete caissons which extend to competent rock on the north and east sides of the Fuel Handling Building mat. These caissons are outboard of the Reactor and Auxiliary Buildings. The reinforced concrete piers are attached to the fill concrete by reinforcing steel dowels and shear key sockets into the fill concrete. The caissons are socketed into the competent rock. Perimeter grade beams are provided at the outboard edges of the railroad bay mat.

Horizontal shears are transmitted from the base mat to the piers and caissons. The piers and caissons share the horizontal load with the piers resisting the major portion of the load.

Plans and details are shown by Figures 3.8-58, 3.8-59, 3.8-60, and 3.8-67.

3.8.5.1.6 Diesel Generator Building

The Diesel Generator Building is founded on a basement slab and grade beam system which is supported by reinforced concrete caissons extending to competent rock. Horizontal forces are resisted by caissons shear and soil-structure interaction. The reinforced concrete caissons also resist seismic overturning moments. Foundation plans and details are shown by Figures 3.8-56 and 3.8-67.

3.8.5.1.7 Service Water Pumphouse

The Service Water Pumphouse is founded on a structural foundation mat at elevation 390'. The valve pit and control areas at elevation 425' are supported by columns which extend to the supporting foundation mat at elevation 390'. The mat is founded on compacted fill which extends from the underside of the base mat to elevation 354'. The compacted fill is supported on in-situ soils (saprolite) from elevation 354' to elevation 350' where decomposed rock exists. Competent rock exists at approximately elevation 300'.

The Service Water Pumphouse structure is separated from the Service Water Intake Structure and from the connecting pipes and conduits by flexible joints, which accommodate relative settlement and seismic movement.

Foundation plan and details are shown on Figures 3.8-61 and 3.8-62.

3.8.5.1.8 Service Water Intake Structure

The base of the Service Water Intake Structure is at elevation 367'. The structure bears on fill material except for a portion of the inlet which rests on in-situ soils.

The structural features of the base slab are shown by Figure 3.8-63.

3.8.5.1.9 Service Water Discharge Structure

The base slab of the Service Water Discharge Structure bears at elevation 408' partly on the decomposed rock and partly on the fill concrete that extends to the decomposed rock.

The structural features of the base slab are shown by Figure 3.8-64.

3.8.5.2 Applicable Codes, Standards, and Specifications

Codes, standards, and specifications applicable to the Reactor Building foundation are discussed in Section 3.8.1.2. Those applicable to the foundations of other Seismic Category 1 structures are discussed in Section 3.8.4.2.

3.8.5.3 Loads and Load Combinations

3.8.5.3.1 Load Definitions

The loads considered for the Reactor Building foundation include those defined in Section 3.8.1.3.1. Loads considered for other Seismic Category 1 structure foundations include those defined in Section 3.8.4.3.1 plus those defined below.

Additional loads considered are as follows:

1. H - lateral earth pressure

2. F' - buoyant force resulting from the probable maximum flood.

3.8.5.3.2 Load Combinations

Load combinations considered for the Reactor Building foundation are listed in Table 3.8-1. Those considered for other Seismic Category 1 structure foundations are listed in Tables 3.8-12 and 3.8-13, for reinforced concrete structures, and 3.8-14, for steel structures. In addition to the load combinations presented in Tables 3.8-1, 3.8-12, 3.8-13, and 3.8-14, the load combinations listed in Table 3.8-15 are used to assure that sliding and overturning due to earthquake, wind, and tornado, as well as flotation do not exceed allowable factors of safety.

3.8.5.4 Design and Analysis Procedures

3.8.5.4.1 Reactor Building

The Reactor Building foundation design and analytical procedures are described in Section 3.8.1.4.

3.8.5.4.2 Auxiliary Building

The Auxiliary Building mat foundation was analyzed using plate coefficient methods and by use of the computer program STRUDL (see Section 3.8.4.4). The base mat was divided into representative equivalent frames and was analyzed using the STRUDL computer program. In both methods the supporting foundation medium was idealized as an elastic support.

The lateral loads were transmitted by diaphragm action of the base mat and were resisted by the shear keys which are integral with the base mat and supporting fill concrete. The shear keys and the local effects to the base mat were analyzed and designed using hand calculations.

The loads were independently applied at their point of application and the results were combined in accordance with the load combinations given in Table 3.8-14. Overall stability was checked to assure conformance with the load combinations given in Table 3.8-15.

The concrete stresses were checked and reinforcing steel requirements were determined in accordance with the strength design method of ACI 318-71 (Reference 2).

3.8.5.4.3 Intermediate Building

The base mat of the Intermediate Building was analyzed using the MASS 01 computer program (see Section 3.8.4.4) for vertical loads. The base mat was modeled as a structurally supported slab system with the structural stiffness of the supports included in the model.

Boundary conditions were the foundation medium (competent rock) and the first superstructure level where appropriate stiffnesses were determined.

The base mat was analyzed for horizontal shear using Wilson's finite element computer program (S066) (see Section 3.8.4.4). The boundary conditions were modeled at the shear walls, caissons, and the Control Building base mat. Structural stiffnesses of the boundary conditions were determined and included in the model.

The loads were applied independently at their point of application and the results were combined in accordance with the load combinations given in Table 3.8-12. Overall foundation stability was checked to assure conformance with the load combinations given in Table 3.8-15.

The concrete stresses were checked and the reinforcing steel requirements were determined in accordance with the strength design method of ACI 318-71.

3.8.5.4.4 Control Building

The base mat of the Control Building was analyzed using the finite difference computer program, Slabs and Mats (S092) (see Section 3.8.4.4). Boundary conditions included in the model were the foundation medium (fill concrete) and the first level of superstructure above the base mat. The vertical reinforcing steel, which extends from the perimeter concrete walls and is embedded into the fill concrete, was modeled as tension springs.

Loads were applied independently at their point of application and the results were combined in accordance with the load combinations given in Table 3.8-12. Overall foundation stability was checked to assure conformance with the load combinations given in Table 3.8-15.

The concrete stresses were checked and reinforcing steel requirements were determined in accordance with the strength design method of ACI 318-71.

3.8.5.4.5 Fuel Handling Building

The Fuel Handling Building base mat and grade beam system was analyzed using the Slabs and Mats (S092) and MASS 01 (S106) computer programs (see Section 3.8.4.4). The base mat system was modeled as a structurally supported slab with the supporting piers and caissons as the foundation boundaries. The superstructure boundaries were the structural steel interfaces and the top elevations of the fuel pool walls. The structural stiffnesses of these boundary conditions were included in the model.

Portions of the base mat were analyzed using hand calculations to confirm the structural behavior predicted by the computer programs and/or to study local effects.

Horizontal shears were distributed through the base mat to the piers and caissons based upon stiffness considerations.

Additionally, the spent fuel pool was analyzed for thermal gradients associated with operating and accident conditions. Computer programs MASS 01 (S106) and Wilson's finite element program (S066) (see Section 3.8.4.4) were used in the analysis. The spent fuel pool was initially modeled utilizing substructure techniques. Wilson's finite element program (S066) was employed for the

analysis of axial deformation. The MASS 01 (S106) computer program was used to analyze the flexural deformation. The substructures were joined by applying restoring forces to the individual substructures to ensure the compatibility of displacements. The resulting stresses were combined with other stresses. The spent fuel pool was re-analyzed to assess the impact of the new high-density fuel storage racks on the floor, walls and substructure. These evaluations were performed using the general-purpose finite element analysis program ANSYS. The structure was idealized using finite element models constructed to ensure realistic boundary conditions that do not perturb the internal forces and bending moments local to the spent fuel pool. Thermal finite element analysis assessed the stresses generated in the pool reinforced concrete structure by the normal operating pool water temperature loads and accident boiling temperature loads.

The loads were applied individually at their point of application and the results were combined in accordance with the load combinations given in Table 3.8-12. Overall foundation stability was checked to ensure conformance with load combinations given in Table 3.8-15.

Concrete stresses were checked and reinforcing steel requirements were determined in accordance with the strength design method of ACI 318-71.

3.8.5.4.6 Diesel Generator Building

The basement slab and grade beam system was analyzed as a rigid mat supported by caissons. The axial loads induced by seismic rocking moments were distributed to the caissons by the moment-area method. Grade beams are provided to span between walls where required, to transfer caisson reactions into the superstructure. The STRUDL computer program (see Section 3.8.4.4) was used for grade beam analysis wall and caisson connections to the beam were assumed to be pinned for the model.

The caisson were analyzed for lateral loads utilizing the STRUDL computer program. The caissons were fixed at the base and were restrained against rotation at the top. The surrounding soil was idealized as soil springs. Caisson moments and shears were determined by applying top displacements consistent with the dynamic analysis.

The loads were applied independently and the results were combined in accordance with the load combinations given in Table 3.8-12. Overall foundation stability was checked to ensure conformance with the load combinations given in Table 3.8-15.

The concrete stresses were checked and the reinforcing steel requirements were determined in accordance with the strength design method of ACI 318-71.

3.8.5.4.7 Service Water Pumphouse

The Service Water Pumphouse base mat was assumed to be rigid and was analyzed using plate theory and moment coefficients.

Loads were independently applied at their point of application and the results were combined in accordance with the load combinations given in Table 3.8-12. Overall foundation stability was

checked to assure conformance with the load combinations and acceptance criteria given in Table 3.8-15. Horizontal shears are transferred from the structure to the soil through friction.

The concrete stresses were checked and the reinforcing requirements were determined in accordance with the strength design method of ACI 318-71.

Based on the settlement analysis described in Section 2.5.4.10.6.2, differential settlement across the structure is found to be within acceptable limits for the structure and within the working tolerances of the equipment for satisfactory operation of the plant.

Flexible joints are designed for the relative settlement between the structure and the soil embedded services, as well as the Service Water Intake Structure.

3.8.5.4.8 Service Water Intake Structure

The structural design of the Service Water Intake Structure foundation is described in Section 3.8.4.4.8.

Settlement of the Service Water Intake Structure is described in Section 2.5.4.10.6.2. The post construction relative settlement between the intake structure and the Service Water Pumphouse is accommodated by a flexible connection, as discussed in Section 3.8.5.4.7.

3.8.5.4.9 Service Water Discharge Structure

The design and analysis procedure for the Service Water Discharge Structure base slab is described in Section 3.8.4.4.9.

The settlement of the Service Water Discharge Structure, bearing on decomposed rock is negligible, as noted in Section 2.5.4.

3.8.5.5 Structural Acceptance Criteria

For the Reactor Building the allowable limits which constitute the acceptance criteria are discussed in Section 3.8.1.5. Structural acceptance criteria for all other foundations are listed in Tables 3.8-12, for concrete Seismic Category 1 structures other than the Service Water Intake Structure and 3.8-14 for steel Seismic Category 1 structures. For the Service Water Intake Structure foundation, allowable stresses used in the design are in accordance with ACI 318-71. In addition, for the additional load combinations discussed in Section 3.8.5.3, the factors of safety against overturning, sliding, and flotation are presented in Table 3.8-15.

3.8.5.6 Materials, Quality Control, and Special Construction Techniques

Materials, quality control, and construction of the Reactor Building foundation are discussed in Section 3.8.1.6. Materials and quality control for foundations of other Seismic Category 1 structures are discussed in Section 3.8.4.6. No special construction techniques are employed in the construction of other Seismic Category 1 foundations.

3.8.5.7 Testing and Inservice Surveillance Requirements

There are no special testing or inservice surveillance requirements for Seismic Category 1 foundations.

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26. Seed, H. B., and Whitman, R. V., *Design of Earth Retaining Structures for Dynamic Loads*, Proceedings, American Society of Civil Engineers Specialty Conference, Lateral Stresses in the Ground and Design of Earth Retaining Structures, 1970.

27. Westergaard, H. M., *Water Pressures on Dams During Earthquakes,* Transactions, American Society of Civil Engineers, Vol. 98, 1933.

28. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Division 2, *Concrete Reactor Vessels and Containment,* 1977 Edition, including Winter, 1978 Addenda.

Table 3.8-0
Main Steam Penetration Materials and Inspection Requirements

Item	Material	Inspection Requirements
Process Pipe	33" OD, 1.70" wall, SA 106, Grade C	Ultrasonic examination, ASTM 213; impact tested
Sleeve	56" OD, 1.25" wall, SA 155 KCF 70, Class 1	Longitudinal butt welds radio-graphed; impact tested
Spacer Rings	56" OD, 1.25" wall, SA 516, Grade 70	Longitudinal butt welds radio-graphed; impact tested
Attachment Plates	2" thick, SA 516, Grade 70	Impact tested
Spacer Plate	1" thick, SA 516, Grade 70	Impact tested
Bellows Assembly		
Bellows	0.037" thick, SA 240, T304	Longitudinal butt weld radiographed
Ring	46" ID, 0.50" wall, SA 516, Grade 70	
Plate	1" thick, SA 516, Grade 70	
Stiffeners	1" thick, SA 516, Grade 70	
Cooling Fins	1/4" thick, SA 516, Grade 70	

Table 3.8-1
Reactor Building Concrete Load Combinations

1. Preoperation

   $S = D + L + F + T_o$

2. Structural Acceptance Test

   $S = D + L + F + 1.15P$ + thermal effects anticipated at time of test.

3. Normal Operation

   a. $S = D + L + F + To + Z$

   b. $U = 1.4D + 1.7L + F + T_o + Z$

   c. $U = D + 1.25L + F + T_o + Z + 1.256$ (E or W)

4. Design Accident

   a. $U = D + L + F + T_o + T_a + 1.5P + R$

   b. $U = D + L + F + T_o + T_a + 1.25P + R + 1.25$ (E or W)

5 Extreme Environmental

   a. $U = D + L + F + T_o + T_a + P + E' + R$

   b. $U = D + L + F + T_o + W' + Z'$

6. Post Tensioning Level

   The post tensioning level is such that the membrane stress resultants remain compressive for two load combinations:

   a. $D + F + P + T_o + T_a$

   b. $D + F + 1.2P + T_o$

Table 3.8-2
REACTOR BUILDING LINER AND ANCHOR LOAD COMBINATIONS

1. Construction

   $D + L + T_o + W$

2. Test

   $D + L + F + P_t$ + thermal effects anticipated at time of test.

3. Normal

   $D + L + F + T_o + R_o + P_v$

4. Environmental

   a. Severe, $D + L + F + T_o + R_o + (E_o \text{ or } W) + P_v$

   b. Extreme, $D + L + F + T_o + R_o + (E_{ss} \text{ or } W_t) + P_v$

5 Abnormal

   $D + L + F + P_a + T_a + R_a$

6. Abnormal/Severe Environmental

   $D + L + F + P_a + T_a + E_o + R_a$

7. Abnormal/Extreme Environmental

   $D + L + F + P_a + T_a + E_{ss} + R_a + R_r$

NOTE:

Wind load was considered during erection of reactor building liner. For definition of terms, refer to the ASME Code, Section III, Division 2.

Table 3.8-3
Attachment, Bracket, and Pad Overlay Plate Load Combinations

1. Construction

   $S = D + L$

2. Normal

   $S = D + L + R_o$

3. Severe Environmental

   $S = D + L + R_o + E_o$

4. Abnormal/Extreme Environmental

   $1.5S = D + L + R_a + E_{ss}$

NOTE:

"Specification for Design, Fabrication, and Erection of Structural Steel for Buildings," American Institute of Steel Construction.

Table 3.8-4
Minimum Concrete Cover For Reinforcement

Location		Minimum Cover
Dome		18 and 14S - 2-1/4 inches
		Others - 2 inches
Cylinder		18 and 14S - 2-1/4 inches
		Others - 2 inches
Foundation Mat	Bottom Reinforcing	18 and 14S - 3 inches
		Others - 3 inches
	Top Reinforcing	18 and 14S - 2-1/4 inches
		Others - 2-1/4 inches

Table 3.8-5
Tolerances For Local Bulges, Flatspots, or Discontinuities
in Cylindrical Portion of Reactor Building Liner

Chord Length	Centerline Theoretical Offset (in)	Tolerance Measured in One Plate More Than 12 Inches from Weld (in)	Tolerance Measured across Weld (in)
10' - 0"	2-3/8	± 7/16	± 5/8
15' - 0"	5-1/2	± 1	± 1-1/2
20' - 0"	9-5/8	± 1-3/4	± 2-5/8

Table 3.8-6
Displacement Measurement Locations for Reactor Building
Structural Acceptance Test

Instrument No. & Gage	Elevation	Azimuth	Notes
Cylinder Base and Cylinder Wall Radial Displacement - Direct Current Displacement Transducer (DCDT) Locations			
DCDT 1, 2, 3	420'-0"	59°, 101°, 162°-30'	Radial displacement
DCDT 4, 5, 6	420'-0"	243°-20', 308°, 347°	Radial displacement
DCDT 7, 8, 9	483'-0"	243°-20', 308°, 347°	Radial displacement
Cylinder Wall and Dome Radial Displacement - Scale and Jig Transit Locations			
Scale 10, 11	483'-0"	59°, 162°-30'	Radial displacement
Scale 12, 13, 14	557'-0"	59°, 101°, 162°-30'	Radial displacement
Scale 15, 16, 17	557'-0"	243°-20', 308°, 347°	Radial displacement
Scale 18, 19, 20	576'-5"	59°, 101°, 162°-30'	Radial displacement
Scale 21, 22, 23	576'-5"	243°-20', 308°, 347°	Radial displacement
Cylinder Ledge Vertical Displacement - Invar Tape and DCDT Locations			
DCDT 30, 31, 32	576'-5"	59°, 101°, 162°-30'	Vertical displacement
DCDT 33, 34, 35	576'-5"	243°-20', 308°, 347°	Vertical displacement
Dome Apex Vertical Displacement Invar Tape and DCDT Locations			
DCDT 36	599'-0"	-	Vertical displacement
DCDT 37, 40, 43, 46, 49, 52	472'-6"	-	Vertical displacement
DCDT 38, 41, 44, 47, 50, 53	472'-6"	-	Radial displacement
DCDT 39, 42, 45, 48, 51, 54	472'-6"	-	Tangential displacement

Table 3.8-6 (continued)
Displacement Measurement Locations for Reactor Building
Structural Acceptance Test

Equipment Hatch Displacement - (DCDT) Locations

Instrument No. & Gage	Elevation	Azimuth	Notes
DCDT 55	492'-6"	101°	Vertical displacement
DCDT 58	486'-6"	101°	Vertical displacement
DCDT 61	480'-6"	101°	Vertical displacement
DCDT 64	464'-6"	101°	Vertical displacement
DCDT 67	458'-6"	101°	Vertical displacement
DCDT 70	452'-6"	101°	Vertical displacement
DCDT 56	492'-6"	101°	Radial displacement
DCDT 59	486'-6"	101°	Radial displacement
DCDT 62	480'-6"	101°	Radial displacement
DCDT 65	464'-6"	101°	Radial displacement
DCDT 68	458'-6"	101°	Radial displacement
DCDT 71	452'-6"	101°	Radial displacement
DCDT 57	492'-6"	101°	Tangential displacement
DCDT 60	486'-6"	101°	Tangential displacement
DCDT 63	480'-6"	101°	Tangential displacement
DCDT 66	464'-6"	101°	Tangential displacement
DCDT 69	458'-6"	101°	Tangential displacement
DCDT 72	452’6”	101°	Tangential displacement

Table 3.8-7
Strain Gage Locations For Reactor Building
Structural Acceptance Test

Cylinder Wall and Base Junction - Strain Gage and Rebar Locations

Instrument No. & Gage	Elevation	Azimuth	Notes
Primary Strain Gage 73, 75, 77	410'-6"	8°	Meridional strain
Redund. Strain Gage 1073, 1075, 1077	410'-6"	8°	Meridional strain
Primary Strain Gage 74, 76, 78	410'-6"	8°	Hoop strain
Redund. Strain Gage 1074, 1076, 1078	410'-6"	8°	Hoop strain
Primary Strain Gage 79, 81, 83	412'-6"	8°	Meridional strain
Redund. Strain Gage 1079, 1081, 1083	412'-6"	8°	Meridional strain
Primary Strain Gage 80, 82, 84	412'-6"	8°	Hoop strain
Redund. Strain Gage 1080, 1082, 1084	412'-6"	8°	Hoop strain
Cylinder Wall and Dome Junction - Strain Gage and Rebar Locations			
Primary Strain Gage 85, 87, 89	553'-6"	8°	Meridional strain
Redund. Strain Gage 1085, 1087, 1089	553'-6"	8°	Meridional strain
Primary Strain Gage 86, 88, 90	553'-6"	8°	Hoop strain
Redund. Strain Gage 1086, 1088, 1090	553'-6"	8°	Hoop strain
Primary Strain Gage 91, 93, 95	557'-0"	8°	Meridional strain

Table 3.8-7 (continued)
Strain Gage Locations For Reactor Building
Structural Acceptance Test

Cylinder Wall and Base Junction - Strain Gage and Rebar Locations

Instrument No. & Gage	Elevation	Azimuth	Notes
Redund. Strain Gage 1091, 1093, 1095	557'-0"	8°	Meridional strain
Primary Strain Gage 92, 94, 96	557'-0"	8°	Hoop strain
Redund. Strain Gage 1092, 1094, 1096	557'-0"	8°	Hoop strain

Equipment Access Opening - Strain Gage and Rebar Locations

Primary Strain Gage 97, 99, 101, 103, 105, 107, 109, 111, 113, 115, 117, 119	472'-6"	-	Meridional strain
Redund. Strain Gage 1097, 1099, 1101, 1103, 1105, 1107, 1109, 1111, 1113, 1115, 1117, 1119	472'-6"	-	Meridional strain
Primary Strain Gage 98, 100, 102, 104, 106, 108, 110, 112, 114, 116, 118, 120	472'-6"	-	Hoop strain
Redund. Strain Gage 1098, 1100, 1102, 1104, 1106, 1108, 1110, 1112, 1114, 1116, 1118, 1120	472'-6"	-	Hoop strain
Primary Strain Gage 121, 123, 125	488'-6"	101°	Meridional strain
Redund. Strain Gage 1121, 1123, 1125	488'-6"	101°	Meridional strain

Table 3.8-7 (continued)
Strain Gage Locations For Reactor Building
Structural Acceptance Test

Instrument No. & Gage	Elevation	Azimuth	Notes
Main Strain Gage 122, 124, 126	488'-6"	101°	Hoop strain
Redund. Strain Gage, 1122, 1124, 1126	488'-6"	101°	Hoop strain
Main Strain Gage, 127, 129, 131	484'-10"	101°	Meridional strain
Redund. Strain Gage 1127, 1129, 1131	484'-10"	101°	Meridional strain
Main Strain Gage 128, 130, 132	484'-10"	101°	Hoop strain
Redund. Strain Gage 1128, 1130, 1132	484'-10"	101°	Hoop strain
Main Strain Gage 133, 135, 137	460'-9"	101°	Meridional strain
Redund. Strain Gage 1133, 1135, 1137	460'-9"	101°	Meridional strain
Main Strain Gage 134, 136, 138	460'-9"	101°	Hoop strain
Redund. Strain Gage 1134, 1136, 1138	460'-9"	101°	Hoop strain
Main Strain Gage 139, 141, 143	454'-9"	101°	Meridional strain
Redund. Strain Gage 1139, 1141, 1143	454'-9"	101°	Meridional strain
Main Strain Gage 140, 142, 144	454'-9"	101°	Hoop strain
Redund. Strain Gage 1140, 1142, 1144	454'-9"	101°	Hoop strain

Table 3.8-7 (continued)
Strain Gage Locations For Reactor Building
Structural Acceptance Test

Cylinder Wall - Strain Gage and Rebar Locations

Instrument No. & Gage	Elevation	Azimuth	Notes
Main Strain Gage 165, 167, 169	420'-6"	8°	Meridional strain
Redund. Strain Gage 1165, 1167, 1169	420'-6"	8°	Meridional strain
Main Strain Gage 166, 168, 170	420'-6"	8°	Hoop strain
Redund. Strain Gage 1166, 1168, 1170	420'-6"	8°	Hoop strain
Main Strain Gage 171, 173, 175	450'-6"	8°	Meridional strain
Redund. Strain Gage 1171, 1173, 1175	450'-6"	8°	Meridional strain
Main Strain Gage 172, 174, 176	450'-6"	8°	Hoop strain
Redund. Strain Gage 1172, 1174, 1176	450'-6"	8°	Hoop strain
Main Strain Gage 177, 179, 181	483'-0"	8°	Meridional strain
Redund. Strain Gage 1177, 1179, 1181	483'-0"	8°	Meridional strain
Main Strain Gage 178, 180, 182	483'-0"	8°	Hoop strain
Redund. Strain Gage 1178, 1180, 1182	483'-0"	8°	Hoop strain
Main Strain Gage 183, 185, 187	520'-6"	8°	Meridional strain

Table 3.8-7 (continued)
Strain Gage Locations For Reactor Building
Structural Acceptance Test

Instrument No. & Gage	Elevation	Azimuth
Redund. Strain Gage 1183, 1185, 1187	520'-6"	8°
Main Strain Gage 184, 186, 188	520'-6"	8°
Redund. Strain Gage 1184, 1186, 1188	520'-6"	8°
Under Vertical Tendon Anchorage at 7° 32' 20"		
Primary Strain Gage 189	Refer to Figure 3.8-33	Vertical
Redund. Strain Gage 1189	Refer to Figure 3.8-33	Vertical
Primary Strain Gage 190	Refer to Figure 3.8-33	Horizontal
Redund. Strain Gage 1190	Refer to Figure 3.8-33	Horizontal
Primary Strain Gage 191	Refer to Figure 3.8-33	45°
Redund. Strain Gage 1191	Refer to Figure 3.8-33	45°

Adjustment in location of instruments and gages may be made in the field to clear interferences.

Table 3.8-8
Crack Pattern Area Locations For Reactor Building
Structural Acceptance Test

Area No.	Center Line Elevation	Center Line Azimuth	Dimensions
145	~563'-9-1/2"	266°	7'-0" x ~41'-0"
146	488'-6"	266°	7'-0" x 7'-0"
147	415'-6"	266°	7'-0" x 7'-0"
148	483'-0"	~302°-27'	7'-0" x ~12'-2"
149	485'-0"	~111°-42'	25'-10" x 27'-2"

NOTE:

Adjustment in location of whitewash areas may be made in the field to clear interferences.

Table 3.8-9
Thermocouple Locations For Reactor Building
Structural Acceptance Test

Thermocouple No.	Elevation	Azimuth
150, 153	412'-0"	59°, 308°
151, 152, 154	416'-0"	162°-30', 243°-20', 347°
155, 156, 157, 158, 159	~483'-0"	59°, 162°-30', 243°-20', 308°, 347°
160, 161, 162, 163, 164	576'-0"	59°, 162°-30', 243°-20', 308°, 347°

NOTE:

Adjustment in the location of thermocouples may be made in the field to clear interferences.

Table 3.8-10
Load Combinations For Internal Concrete Structures

1. Load Combinations for Service Load Conditions

   a. $U = 1.4D + 1.7L$

   b. $U = 1.4D + 1.7L + 1.9E$

   c. $U = (0.75)\ (1.4D + 1.7L + 1.7T_o + 1.7R_o)$

   d. $U = (0.75)\ (1.4D + 1.7L + 1.9E + 1.7T_o + 1.7R_o)$

   e. $U = 1.2D + 1.9E$

   f. $U = 1.4D + 1.7L + 1.4F$

2. Load Combinations for Factored Load Conditions

   a. $U = D + L + T_o + R_o + E'$

   b. $U = D + L + T_o + R_o + 1.5P_o$

   c. $U = D + L + T_o + R_o + 1.25P_o + 1.0\ (Y_r + Y_j + Y_m) + 1.25E$

   d. $U = D + L + T_o + R_o + 1.0P_a + 1.0\ (Y_r + Y_j + Y_m) + 1.0E'$

"U" is the section strength required to resist the loads based upon the strength design methods of ACI 318-71.

Table 3.8-11
Load Combinations For Internal Structural Steel Structures

1. Load Combinations for Service Load Conditions

   a. $S = D + L$

   b. $S = D + L + E$

   c. $1.5S = D + L + R_o + T_o + E$

2. Load Combinations for Factored Load Conditions

   a. $1.6S = D + L + T_o + R_o + E'$

   b. $1.6S = D + L + T_a + R_a + P_a$

   c. $1.6S = D + L + T_a + R_a + P_a + Y_r + Y_j + Y_m + E$

   d. $1.7S = D + L + T_a + R_a + P_a + Y_r + Y_j + Y_m + E'$

"S" is the required section strength based upon the elastic stress design method and allowable stresses defined in AISC, "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," 1969 Edition.

Table 3.8-11a
Polyvinyl Chlorine Waterstops

Building	Elevation	Expected Normal Operation Radiation Level
Auxiliary Building (1)	386'-0"	< 10^4 to 10^6 Rad, TID (2), 40 yr
	410'-0"	< 10^6 Rad, TID, 40 yr
	412'-0"	< 10^4 to 10^6 Rad, TID, 40 yr
Control Building (1)	411'-0"	Negligible
Intermediate Building (1)	407'-0"	< 10^4 Rad, TID, 40 yr
	411'-0"	< 10^4 Rad, TID, 40 yr
	412'-0"	< 10^6 Rad, TID, 40 yr
Fuel Handling Building (1)	412'-9"	< 10^4 to 10^6 Rad, TID, 40 yr
	416'-8"	< 10^4 to 10^6 Rad, TID, 40 yr
Diesel Generator Building (1)	400'-0"	Negligible
	421'-0"	Negligible
Reactor Building (3)	387'-0" to 387'-8"	< 6.5 x 10^3 Rad, TID, 40 yr
	388'-0"	< 6.5 x 10^3 Rad, TID, 40 yr
	394'-10"	< 6.5 x 10^3 Rad, TID, 40 yr
	396'-0"	< 6.5 x 10^3 Rad, TID, 40 yr

(1) Radiation levels are from Table 3.11-3. Shielding provided by concrete cover on waterstops is neglected.
(2) TID - Total integrated dose.
(3) Shielding provided by concrete cover on waterstops is considered.

Table 3.8-12
Load Combinations and Acceptance
Criteria for Concrete Structures

1. Load Combinations for Service Load Conditions

a. Load Combinations Considered when Working Stress Design Method is Used

	Acceptance Criteria
(1) D + L	S[1]
(2) D + L + E	S
(3) D + L + W	S

When thermal stresses due to T_o and R_o are present, the following load combinations are also considered:

	Acceptance Criteria
(4) D + L + T_o + R_o	1.3S
(5) D + L + T_o + R_o + E	1.3S
(6) D + L + T_o + R_o + W	1.3S

Both cases of L having its full value or being completely absent are checked.

b. Load Combinations Considered when Strength Design Method is Used

	Acceptance Criteria
(1) 1.4D + 1.7L	U[2]
(2) 1.4D + 1.7L + 1.9E	U
(3) 1.4D + 1.7L + 1.7W	U

Table 3.8-12 (continued)
Load Combinations and Acceptance
Criteria for Concrete Structures

When thermal stresses due to T_o and R_o are present, the following load combinations are also considered:

	Acceptance Criteria
(4) $(0.75)(1.4D + 1.7L + 1.7T_o + 1.7R_o)$	U
(5) $(0.75)(1.4D + 1.7L + 1.9E + 1.7T_o + 1.7R_o)$	U
(6) $(0.75)(1.4D + 1.7L + 1.7W + 1.7T_o + 1.7R_o)$	U

Both cases of L having its full value or being completely absent area checked.
In addition, the following load combinations are considered:

	Acceptance Criteria
(7) $1.2D + 1.9E$	U
(8) $1.2D + 1.7W$	U

2. Load Combinations for Factored Load Conditions

	Acceptance Criteria
a. $D + L + T_o + R_o + E'$	U
b. $D + L + T_o + R_o + Wt$	U
c. $D + L + T_a + R_a + 1.5Pa$	U
d. $D + L + T_a + R_a + 1.25P_a + 1.0(Y_j + Y_r + Y_m) + 1.25E$	U
e. $D + L + T_a + R_a + 1.0P_a + 1.0(Y_j + Y_r + Y_m) + 1.0E'$	U

Both cases of L having its full value or being completely absent are checked.

(1) S - For concrete structures, S is the required section strength based upon the working stress design method and the allowable stresses defined in Section 8.10 of ACI 318-71. Increases in allowable stresses for concrete due to seismic or wind loadings are not used.
(2) U - For concrete structures, U is the section strength required to resist design loads based upon the strength design methods described in ACI 318-71.

Table 3.8-13
Loads and Load Combinations for the Service Water
Intake and Discharge Structures

1. Definitions and Nomenclature

D = dead weight of concrete and weight of soil above the Intake Structure

E = is the Operating Basis Earthquake

E' = is the Safe Shutdown Earthquake

H = is the lateral earth pressure

F = hydrostatic pressure

2. Load Combinations

U is defined as required strength to resist design loads.

a. End of Construction

U = 1.4D + 1.7H

U = 0.9D + 1.7H, where D reduces the effect of H

b. Operating Condition

U = 1.4D + 1.7H

U = 1.4D + 1.7H + 1.9E

U = 0.9D + 1.7H, where D reduces the effect of H

U = 1.4D + 1.4F + 1.7H

U = 1.4D + 1.4F + 1.7H + 1.87E (Critical Loading Combination)

U = 0.9D + 1.87E

c. Extreme Environmental Conditions

U = D + H + E'

U = D + H

U = D + H + 1.25E + $F^{(1)}$

U = 0.9D + H + E' + $F^{(1)}$, where D reduces effect of H

(1) F for discharge structure only.

Table 3.8-14
Load Combinations and Acceptance Criteria for Steel Structures

1. Load Combinations for Service Load Conditions

a. Load Combinations Considered when Elastic Working Stress Design Methods are Used

	Acceptance Criteria
(1) D + L	S [1]
(2) D + L + E	S
(3) D + L + W	S

When thermal stresses due to T_o and R_o are present, the following load combinations are also considered:

	Acceptance Criteria
(4) D + L + T_o + R_o	1.5S
(5) D + L + T_o + R_o + E	1.5S
(6) D + L + T_o + R_o + W	1.5S

Both cases of L having its full value or being completely absent are checked.

b. Load Combinations Considered when Plastic Design Methods are Used

	Acceptance Criteria
(1) 1.7D + 1.7L	Y [2]
(2) 1.7D + 1.7L + 1.7E	Y
(3) 1.7D + 1.7L + 1.7W	Y

When thermal stresses due to To and Ro are present, the following load combinations are also considered:

	Acceptance Criteria
(4) 1.3 (D + L + T_o + R_o)	Y
(5) 1.3 (D + L + E +T_o + R_o)	Y
(6) 1.3 (D + L + W +T_o + R_o)	Y

Both cases of L having its full value or being completely absent are checked.

Table 3.8-14 (continued)
Load Combinations and Acceptance Criteria for Steel Structures

2. Load Combinations for Factored Load Combinations

a. Load Combinations Considered when Elastic Working Stress Design Methods are Used. (3)

	Acceptance Criteria
(1) $D + L + T_o + R_o + E'$	1.6S
(2) $D + L + T_o + R_o + W_t$	1.6S
(3) $D + L + Ta + Ra + Pa$	1.6S
(4) $D + L + T_a + R_a + P_a + 1.0\ (Y_j + Y_r + Y_m) + E$	1.6S
(5) $D + L + T_a + R_a + P_a + 1.0\ (Y_j + Y_r + Y_m) + E'$	1.7S

b. Load Combinations Considered when Plastic Design Methods are Used

	Acceptance Criteria
(1) $D + L + T_o + R_o + E'$	0.9Y
(2) $D + L + T_o + R_o + W_t$	0.9Y
(3) $D + L + T_a + R_a + 1.5P_a$	0.9Y
(4) $D + L + T_a + R_a + 1.25P_a + 1.0\ (Y_j + Y_r + Y_m) + 1.25E$	0.9Y
(5) $D + L + T_a + R_a + 1.0P_a + 1.0\ (Y_j + Y_r + Y_m) + E'$	0.9Y

(1) S - For structural steel, S is the required section strength based upon the elastic design methods and the allowable stresses defined in Part I of the AISC, “Specification for the Design, Fabrication and Erection of Structural Steel for Buildings,” 1969 Edition. Increases in allowable stresses for steel due to seismic or wind loadings are not used.

(2) Y - For structural steel, Y is the required section strength required to resist design loads and is based upon plastic design methods described in Part 2 of the AISC, “Specification for the Design, Fabrication and Erection of Structural Steel for Buildings,” 1969 Edition.

(3) For these combinations, the plastic modulus of steel shapes is used in computing the required section strength, S.

Table 3.8-15
Load Combinations Used to Check Against
Sliding, Overturning, and Flotation

		Minimum Factors of Safet		
	Load Combination	Overturning	Sliding	Flotation
1.	D + H + E	1.5	1.5	-
2.	D + H + W	1.5	1.5	-
3.	D + H + E'	1.1	1.1	-
4.	D + H + Wt	1.1	1.1	-
5.	D + F	-	-	1.5

Table 3.8-16
Comparison of Allowable Compressive Stresses

	Service		Factored	
	Membrane	Membrane plus Bending	Membrane	Membrane plus Bending
Section 3.8.1.5	$0.4f_{c'}$[1]	$0.60f_{c'}$[1]	$0.765f_{c'}$[2]	$0.765f_{c'}$[2]
ASME Code	Table CC-3431-1		Table CC-3421-1	

(1) Section 3.8.1.5.1.2, Items 1 and 2.
(2) Section 3.8.1.5.1.1, Item 1.

Table 3.8-17
Reinforcing Steel Comparison of Allowable Stresses and Strains

	Service		Factored	
	Stress	Strain	Stress	Strain
Section 3.8.1.5	24 ksi (1)	-	$0.9f_y$ (2)	$0.9_{\varepsilon y}$ (2)
ASME Code	30 ksi	-	$0.9f_y$	$\geq \varepsilon_y$ (3)

(1) Section 3.8.1.5.1.2, Item 7.
(2) Section3.8.1.5.1.1, Item 1. Note that the FSAR strain limit of 1.5åy results from Reference 3 of Section 3.8.1.2.1. However, due to use of a linear concrete stress distribution in conjunction with 0.9fy, the reinforcing steel strain is actually limited to 0.9åy.
(3) ASME Code CC-3422.1.

3.

Table 3.8-18
Load Combination Allowable Stresses FROM ASME Code Tables CC 3421-1 and CC 3431-1

Load Combination	Type	Code Allowable Concrete Compression Stresses (PSI)			
		At Discontinuities - Base and Spring Line of Wall		Away From Discontinuities - Wall Mid-Height and Dome Apex	
		Membrane	Membrane + Bending	Membrane	Membrane + Bending
INITIAL PRESTRESS $D + F_I$	S	0.35 fc' = 1750	0.60 fc' = 3000	0.35 fc' = 1750	0.45 fc' = 2250
NORMAL WINTER OPERATION					
$D + F$	S	0.30 fc' = 1500	0.60 fc' = 3000	0.30 fc' = 1500	0.45 fc' = 2250
$D + F + P_v$	S	0.30 fc' = 1500	0.60 fc' = 3000	0.30 fc' = 1500	0.45 fc' = 2250
$D + F + T_o$	S	0.45 fc' = 2250	0.60 fc' = 3000	0.45 fc' = 2250	0.60 fc' = 3000
$D + F + T_o + P_v$	S	0.45 fc' = 2250	0.60 fc' = 3000	0.45 fc' = 2250	0.60 fc' = 3000
SEVERE ENVIRONMENTAL					
$D + F + E_o$	S	0.40 fc' = 2000	0.60 fc' = 3000	0.40 fc' = 2000	0.45 fc' = 2250
$D + F + E_o + P_v$	S	0.40 fc' = 2000	0.60 fc' = 3000	0.40 fc' = 2000	0.45 fc' = 2250
$D + F + E_o + T_o$	S	0.45 fc' = 2250	0.60 fc' = 3000	0.45 fc' = 2250	0.60 fc' = 3000
$D + F + E_o + T_o + P_v$	S	0.45 fc' = 2250	0.60 fc' = 3000	0.45 fc' = 2250	0.60 fc' = 3000

Table 3.8-18 (continued)
Load Combination Allowable Stresses FROM
ASME Code Tables CC 3421-1 and CC 3431-1

Load Combination	Type	Code Allowable Concrete Compression Stresses (PSI)			
		At Discontinuities - Base and Spring Line of Wall		Away From Discontinuities - Wall Mid-Height and Dome Apex	
		Membrane	Membrane + Bending	Membrane	Membrane + Bending
EXTREME ENVIRONMENTAL					
$D + F + E_{ss}$	U	0.60 fc' = 3000	0.85 fc' = 4250	0.60 fc' = 3000	0.75 fc' = 3750
$D + F + E_{ss} + P_v$	U	0.60 fc' = 3000	0.85 fc' = 4250	0.60 fc' = 3000	0.75 fc' = 3750
$D + F + E_{ss} + T_o$	U	0.75 fc' = 3750	0.85 fc' = 4250	0.75 fc' = 3750	0.85 fc' = 4250
$D + F + E_{ss} + T_o + P_v$	U	0.75 fc' = 3750	0.85 fc' = 4250	0.75 fc' = 3750	0.85 fc' = 4250
ABNORMAL/EXTREME ENVIRONMENTAL					
$D + F + E_o + 0.5E_{ss} + W$	U	0.60 fc' = 3000	0.85 fc' = 4250	0.60 fc' = 3000	0.75 fc' = 3750
$D + F + E_o + 0.5E_{ss} + W + T_o$		0.75 fc’ = 3750	0.85 fc' = 4250	0.75 fc' = 3750	0.85 fc' = 4250

F_I IS INITIAL PRESTRESS; F IS PRESTRESS AT STARTUP

Table 3.8-19
Comparison of Predicted Stresses and Strains with ASME Code Allowables at Base

LOAD COMBINATION	TYPE	CONCRETE STRESSES (PSI)								MEMBRANE LINER STRESSES (PSI)		LINER STRAINS (MICRO IN/IN)		
		CODE ALLOWABLE		PREDICTED								CODE PREDICTED ALLOW. MEMBRANE		
				MERIDIONAL			HOOP							
		MEM-BRANE	MEMB +BEND	I.F.	0.F.	MEMB.	I.F.	O.F.	MEMB	MERID-IONAL	HOOP	MEM-BRANE	MERID-IONAL	HOOP
INITIAL PRESTRESS					O									
D+F	S	-1750	-3000	-1477	391	-543	-252	67	-93	-17982	-4855	-2000	-572	12
NORMAL WINTER OPERATION														
D+F	S	-1500	-3000	-1368	330	-519	-234	56	-94	-16658	-4499	-2000	-529	11
D+F+P_v	S	-1500	-3000	-1430	360	-539	-245	61	-92	-17124	-4624	-2000	-544	12
D+F+T_o	S	-2250	-3000	-2153	1177	-488	-1492	944	-274	-25558	-16516	-2000	-716	-314
D+F+T_o+P_v	S	-2250	-3000	-2215	1207	-504	-1503	949	-277	-26024	-16641	-2000	-731	-314
SEVERE ENVIRONMENTAL														
D+F+E_o	S	-2000	-3000	-1344	-78	-711	-230	-13	-122	-16475	-4449	-2000	-524	11
D+F+E_o+P_v	S	-2000	-3000	-1406	-48	-727	-241	-8	-125	-16941	-4574	-2000	-538	12
D+F+E_o+T_o	S	-2250	-3000	-2129	739	-695	-1388	875	-257	-25375	-16466	-2000	-710	-314
D+F+E_o+T_o+P_v	S	-2250	-3000	-2191	799	-696	-1499	880	-310	-25841	-16591	-2000	-725	-314

Table 3.8-19 (CONTINUED)
Comparison of Predicted Stresses and Strains
with ASME Code Allowables at Base

LOAD COMBINATION	TYPE	CONCRETE STRESSES (PSI)								MEMBRANE LINER STRESSES (PSI)		LINER STRAINS (MICRO IN/IN)		
		CODE ALLOWABLE		PREDICTED								CODE PREDICTED ALLOW. MEMBRANE		
				MERIDIONAL			HOOP							
		MEM-BRANE	MEMB +BEND	I.F.	I.F.	MEMB.	I.F.	I.F.	MEMB	MERID-IONAL	HOOP	MEM-BRANE	MERID-IONAL	HOOP
EXTREME ENVIRONMENTAL														
$D+F+E_{ss}$	U	-3000	-4250	-1332	-282	-807	-228	-48	-138	-16485	-4424	-5000	-524	12
$+F+E_{ss}+P_v$	U	-3000	-4250	-1394	-252	-823	-239	-48	-141	-16849	-4549	-5000	-536	12
$D+F+_{ss}+T_o$	U	-3750	-4250	-2117	565	-776	-1486	840	-323	-25283	-16441	-5000	-707	-314
$D+F+E_{ss}+T_o+P_v$	U	-3750	-4250	-2179	595	-792	-1497	845	-326	-25749	-16566	-5000	-713	-314
ABNORMAL/EXTREME ENVIRONMENTAL														
$D+F+E_o+ 0.5E_{ss}+W$	U	-3000	-4250	-1326	-386	-856	-227	-66	-147	-16336	-4411	-5000	-519	11
$D+F+E_o+ 0.5E_{ss}+W+T_o$	U	-3750	-4250	-2111	-461	-825	-1485	822	-332	-25236	-16428	-5000	-706	-334

Table 3.8-20
Comparison of Predicted Stresses and Strains with ASME Code Allowables at Wall Mid-Height

		CONCRETE STRESSES (PSI)								MEMBRANE LINER STRESSES (PSI)		LINER STRAINS (MICRO IN/IN)		
		CODE ALLOWABLE		PREDICTED								CODE PREDICTED ALLOW. MEMBRANE		
				MERIDIONAL			HOOP							
LOAD COMBINATION	TYPE	MEM-BRANE	MEMB +BEND	I.F.	O.F.	MEMB.	I.F.	O.F.	MEMB	MERID-IONAL	HOOP	MEM-BRANE	MERID -IONAL	HOOP
INITIAL PRESTRESS														
D+F	S	-1750	-2250	-791	-757	-774	-1445	-1439	-1442	-11244	-18237	-2000	-205	-516
NORMAL WINTER OPERATION														
D+F	S	-1500	-2250	-751	-720	-736	-1335	-1329	-1332	-10625	-16871	-2000	-198	-476
D+F+P_v	S	-1500	-2250	-777	-744	-761	-1387	-1370	-1379	-10853	-17270	-2000	-202	-487
D+F+T_o	S	-2250	-3000	-1821	462	-680	-2407	-148	-1278	-21417	-27675	-2000	-462	-740
D+F+T_o+P_v	S	-2250	-3000	-1847	438	-705	-2459	-199	-1329	-21648	-28074	-2000	-466	-752
SEVERE ENVIRONMENTAL														
D+F+E_o	S	-2000	-2250	-890	-865	-878	-1319	-1311	-1315	-11637	-16940	-2000	-232	-468
D+F+E_o+P_v	S	-2000	-2250	-916	-889	-903	-1371	-1352	-1362	-11865	-17339	-2000	-235	-479
D+F+E_o+T_o	S	-2250	-3000	-1960	317	-822	-2391	-130	-1261	-22429	-27744	-2000	-496	-732
D+F+E_o+T_o+P_v	S	-2250	-3000	-1962	293	-834	-2443	-181	-1312	-22657	-28143	-2000	-500	-744

Table 3.8-20 (continued)
Comparison of Predicted Stresses and Strains
with ASME Code Allowables at Wall Mid-Height

LOAD COMBINATION	TYPE	CONCRETE STRESSES (PSI)								MEMBRANE LINER STRESSES (PSI)		LINER STRAINS (MICRO IN/IN)		
		CODE ALLOWABLE		PREDICTED								CODE PREDICTED ALLOW. MEMBRANE		
				MERIDIONAL			HOOP							
		MEM-BRANE	MEMB +BEND	I.F.	O.F.	MEMB.	I.F.	O.F.	MEMB	MERID-IONAL	HOOP	MEM-BRANE	MERID -IONAL	HOOP
EXTREME ENVIRONMENTAL														
$D+F+E_{ss}$	U	-3000	-3750	-960	-938	-949	-1311	-1302	-1309	-12143	-16975	-5000	-249	-464
$D+F+E_{ss}+P_v$	U	-3000	-3750	-986	-962	-974	-1363	-1353	-1358	-12371	-17374	-5000	-253	-475
$D+F+_{ss}+T_o$	U	-3750	-4250	-2030	244	-893	-2383	-121	-1252	-22995	-27779	-5000	-515	-728
$D+F+E_{ss}+T_o+P_v$	U	-3750	-4250	-2056	220	-918	-2435	-172	-1304	-23163	-28178	-5000	-517	-740
ABNORMAL/EXTREME ENVIRONMENTAL														
$D+F+E_o+ 0.5E_{ss}+W$	U	-3000	-3750	-996	-975	-986	-1307	-1297	-1302	-12402	-16993	-5000	-258	-462
$D+F+E_o+ 0.5E_{ss}+W+T_o$	U	-3750	-4250	-2066	207	-930	-2379	-116	-1248	-23193	-27797	-5000	-522	-726

Table 3.8-21
Comparison of Predicted Stresses and Strains with ASME Code Allowables at Wall Spring Line

		CONCRETE STRESSES (PSI)								MEMBRANE LINER STRESSES (PSI)		LINER STRAINS (MICRO IN/IN)		
		CODE ALLOWABLE		PREDICTED								CODE PREDICTED ALLOW. MEMBRANE		
				MERIDIONAL			HOOP							
LOAD COMBINATION	TYPE	MEM-BRANE	MEMB +BEND	I.F.	O.F.	MEMB.	I.F.	O.F.	MEMB	MERID-IONAL	HOOP	MEM-BRANE	MERID-IONAL	HOOP
INITIAL PRESTRESS														
D+F	S	-1750	-3000	-1101	-264	-683	-670	-606	-638	-14023	-9373	-2000	-390	-183
NORMAL WINTER OPERATION														
D+F	S	-1500	-3000	-1034	-255	-645	-617	-557	-587	-13149	-8656	-2000	-367	-167
D+F+P_v	S	-1500	-3000	-1071	-268	-670	-639	-575	-607	-13456	-8846	-2000	-376	-170
D+F+T_o	S	-2250	-3000	-2107	932	-588	-1702	612	-545	-24043	-19625	-2000	-633	-436
D+F+T_o+P_v	S	-2250	-3000	-2144	919	-613	-1724	594	-565	-24330	-19815	-2000	-641	-440
SEVERE ENVIRONMENTAL														
D+F+E_o	S	-2000	-3000	-1073	-271	-672	-586	-521	-554	-13410	-8459	-2000	-378	-158
D+F+E_o+P_v	S	-2000	-3000	-1110	-284	-697	-608	-539	-574	-13637	-8649	-2000	-384	-162
D+F+E_o+T_o	S	-2250	-3000	-2146	916	-615	-1671	648	-512	-24304	-19428	-2000	-644	-427
D+F+E_o+T_o+P_v	S	-2250	-3000	-2177	903	-637	-1693	630	-532	-24591	-19618	-2000	-652	-431

Table 3.8-21 (continued)
Comparison of Predicted Stresses and Strains
with ASME Code Allowables at Wall Spring Line

LOAD COMBINATION	TYPE	CONCRETE STRESSES (PSI)								MEMBRANE LINER STRESSES (PSI)		LINER STRAINS (MICRO IN/IN)		
		CODE ALLOWABLE		PREDICTED								CODE PREDICTED ALLOW. MEMBRANE		
				MERIDIONAL			HOOP							
		MEM-BRANE	MEMB +BEND	I.F.	O.F.	MEMB.	I.F.	O.F.	MEMB	MERID-IONAL	HOOP	MEM-BRANE	MERID-IONAL	HOOP
EXTREME ENVIRONMENTAL														
$D+F+E_{ss}$	U	-3000	-4250	-1093	-279	-686	-570	-503	-537	-13541	-8360	-5000	-383	-153
$D+F+E_{ss}+P_v$	U	-3000	-4250	-1130	-292	-711	-592	-521	-557	-13828	-8380	-5000	-391	-158
$D+F+_{ss}+T_o$	U	-3750	-4250	-2166	908	-629	-1656	666	-495	-24435	-19329	-5000	-649	-422
$D+F+E_{ss}+T_o+P_v$	U	-3750	-4250	-2203	895	-634	-1677	648	-515	-24712	-19519	-5000	-657	-426
ABNORMAL/EXTREME ENVIRONMENTAL														
$D+F+E_o+ 0.5E_{ss}+W$	U	-3000	-4250	-1103	-283	-693	-562	-494	-528	-13608	-8310	-5000	-386	-150
$D+F+E_o+ 0.5E_{ss}+W+T_o$	U	-3750	-4250	-2176	904	-636	-1647	675	-486	-24502	-19279	-5000	-652	-420

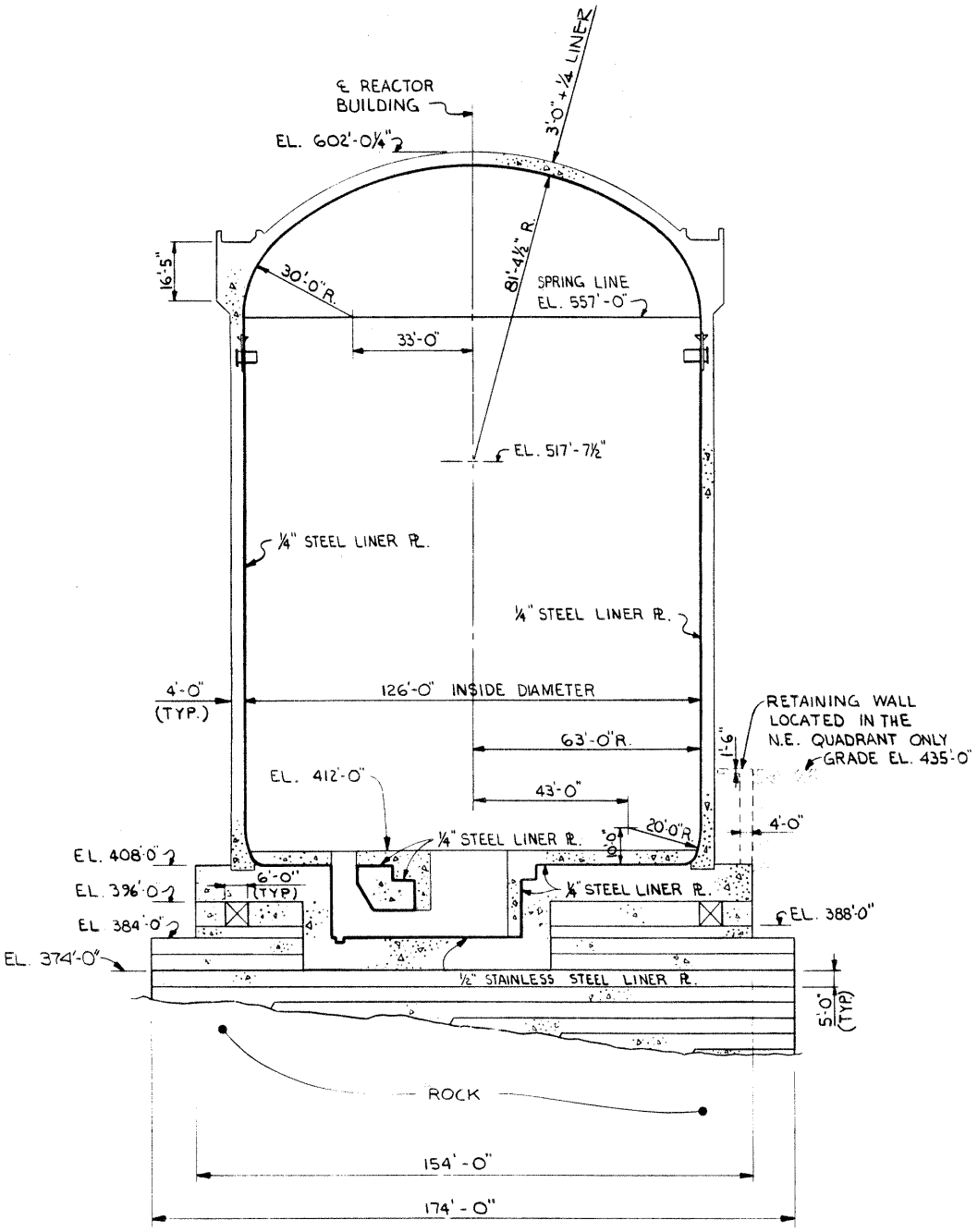
Table 3.8-22
Comparison of Predicted Stresses and Strains with ASME Code Allowables at Wall Dome Apex

LOAD COMBINATION	TYPE	CONCRETE STRESSES (PSI)								MEMBRANE LINER STRESSES (PSI)		LINER STRAINS (MICRO IN/IN)		
		CODE ALLOWABLE		PREDICTED								CODE PREDICTED ALLOW. MEMBRANE		
				MERIDIONAL			HOOP							
		MEM-BRANE	MEMB +BEND	I.F.	O.F.	MEMB.	I.F.	O.F.	MEMB	MERID-IONAL	HOOP	MEM-BRANE	MERID-IONAL	HOOP
INITIAL PRESTRESS														
D+F	S	-1750	-2250	-1380	-1508	-1444	-1470	-1494	-1482	-18295	-19272	-2000	-438	-482
NORMAL WINTER OPERATION														
D+F	S	-1500	-2250	-1293	-1412	-1353	-1377	-1399	-1388	-17132	-18046	-2000	-410	-451
D+F+P_v	S	-1500	-2250	-1339	-1452	-1396	-1422	-1443	-1433	17503	-18410	-2000	-419	-459
D+F+T_o	S	-2250	-3000	-2345	-212	-1279	-2432	-198	-1315	-27781	-28713	-2000	-671	-712
D+F+T_o+P_v	S	-2250	-3000	-2391	-252	-1322	-2447	-242	-1344	-28152	-29077	-2000	-680	-721
SEVERE ENVIRONMENTAL														
D+F+E_o	S	-2000	-2250	-1293	-1413	-1353	-1356	-1372	-1364	-17119	-17895	-2000	-411	-446
D+F+E_o+P_v	S	-2000	-2250	-1339	-1453	-1396	-1401	-1416	-1409	-17496	-18259	-2000	-421	-455
D+F+E_o+T_o	S	-2250	-3000	-2345	-213	-1279	-2401	-171	-1286	-27768	-28562	-2000	-672	-707
D+F+E_o+T_o+P_v	S	-2250	-3000	-2391	-253	-1322	-2456	-215	-1336	-28079	-28926	-2000	-679	-717

Table 3.8-22 (continued)
Comparison of Predicted Stresses and Strains
with ASME Code Allowables at Wall Dome Apex

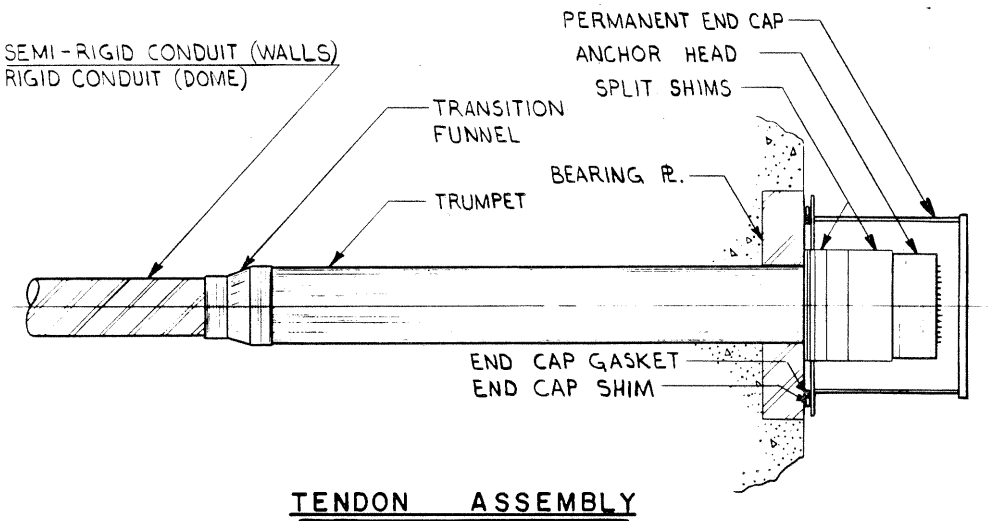
LOAD COMBINATION	TYPE	CONCRETE STRESSES (PSI)								MEMBRANE LINER STRESSES (PSI)		LINER STRAINS (MICRO IN/IN)		
		CODE ALLOWABLE		PREDICTED								CODE PREDICTED ALLOW. MEMBRANE		
				MERIDIONAL			HOOP							
		MEM-BRANE	MEMB +BEND	I.F.	O.F.	MEMB.	I.F.	O.F.	MEMB	MERID-IONAL	HOOP	MEM-BRANE	MERID-IONAL	HOOP
EXTREME ENVIRONMENTAL														
$D+F+E_{ss}$	U	-3000	-3750	-1293	-1414	-1354	-1345	-1358	-1352	-17112	-17819	-5000	-412	-443
$D+F+E_{ss}+P_v$	U	-3000	-3750	-1339	-1454	-1397	-1390	-1402	-1396	-17423	-18123	-5000	-419	-453
$D+F+_{ss}+T_o$	U	-3750	-4250	-2345	-214	-1280	-2400	-159	-1279	-27761	-28486	-5000	-672	-704
$D+F+E_{ss}+T_o+P_v$	U	-3750	-4250	-2391	-254	-1323	-2445	-201	-1323	-28132	-28850	-5000	-682	-713
ABNORMAL/EXTREME ENVIRONMENTAL														
$D+F+E_o+ 0.5E_{ss}+W$	U	-3000	-3750	-1293	-1414	-1354	-1340	-1351	-1346	-17109	-17780	-5000	-412	-442
$D+F+E_o+ 0.5E_{ss}+W+T_o$	U	-3750	-4250	-2345	-214	-1280	-2395	-150	-1273	-27758	-28447	-5000	-672	-703

Figure 3.8-1
REACTOR BUILDING AND FOUNDATION

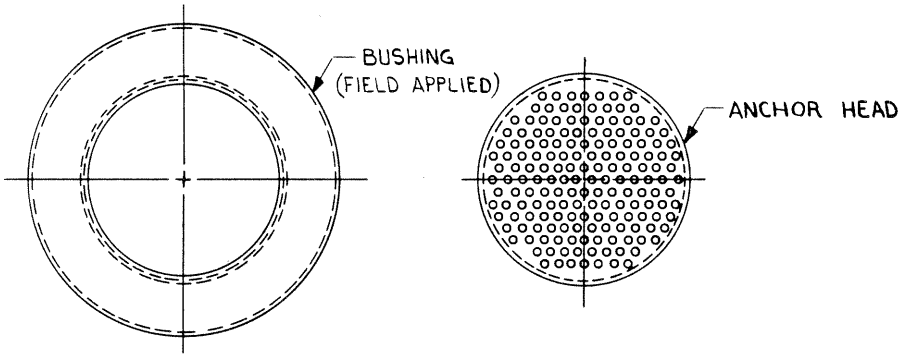


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Building and Foundation Figure 3.8-1

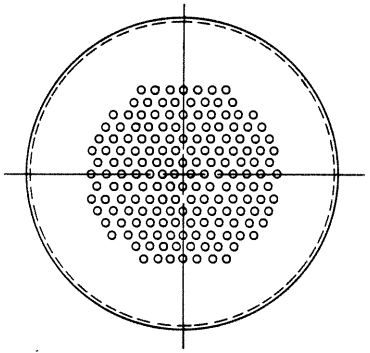
Figure 3.8-2
TENDON COMPONENTS



TENDON ASSEMBLY



SHOP ANCHOR HEAD ASSEMBLY

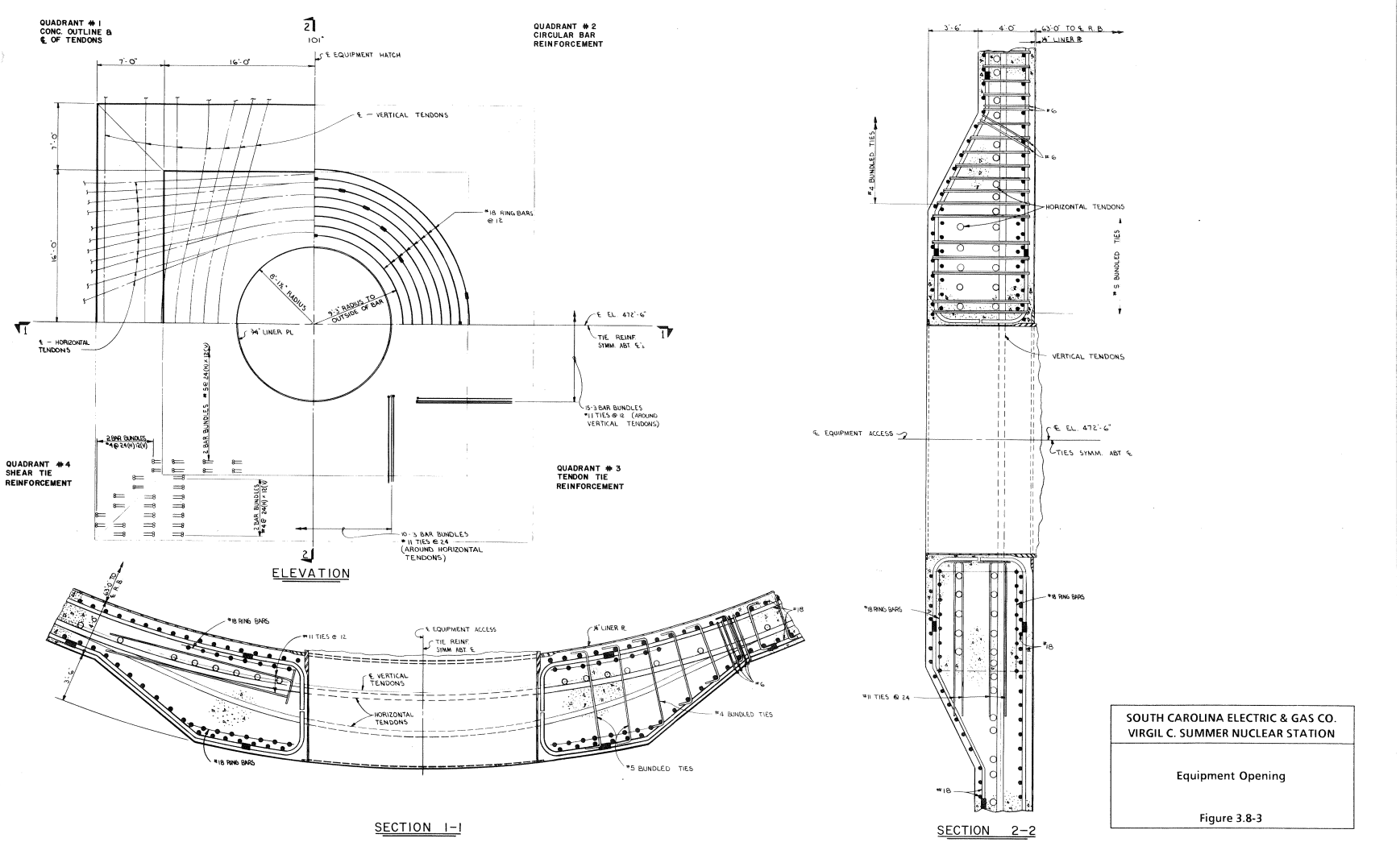


FIELD ANCHOR HEAD

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Tendon Components
Figure 3.8-2

Figure 3.8-3

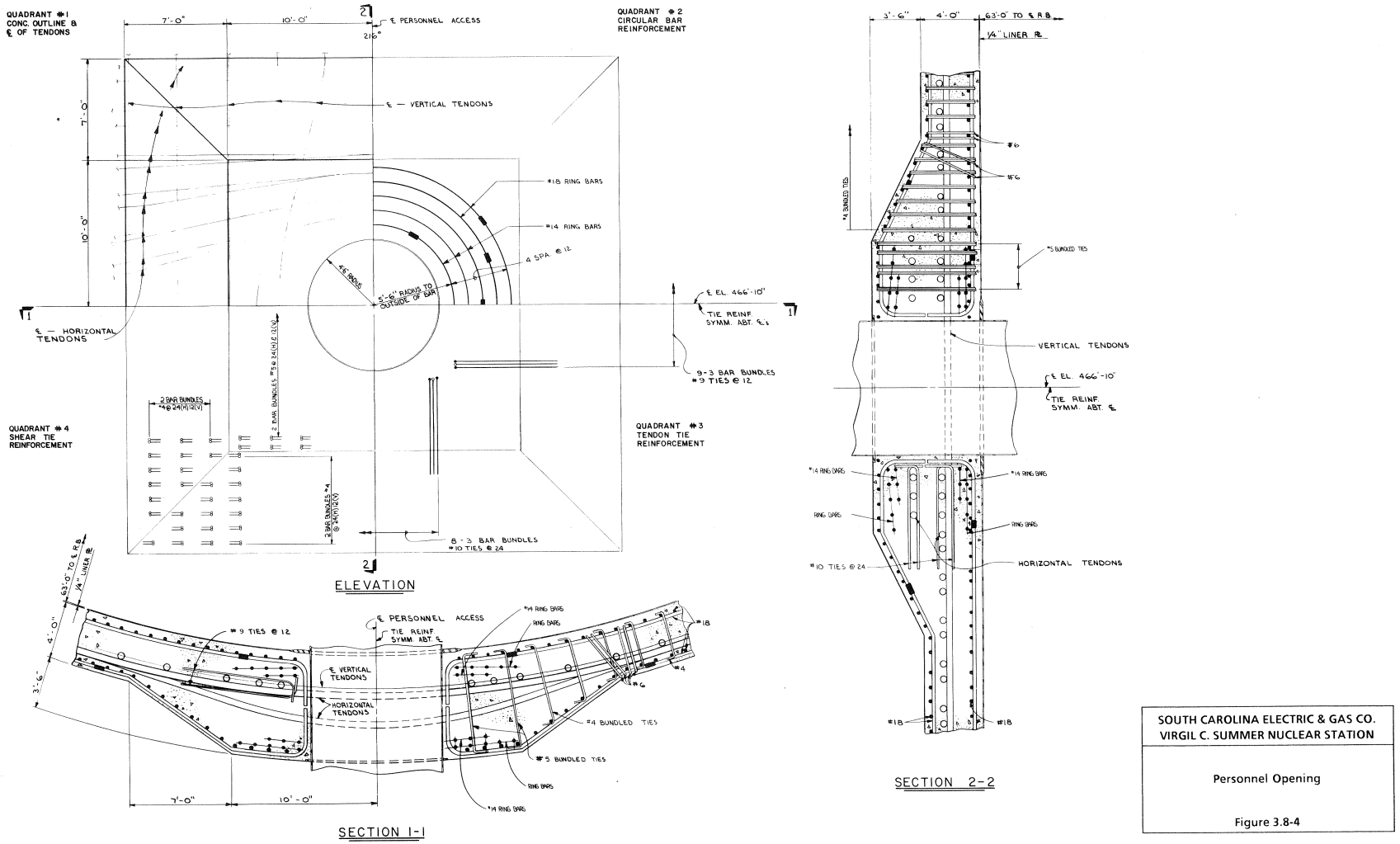
EQUIPMENT OPENING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Equipment Opening
Figure 3.8-3

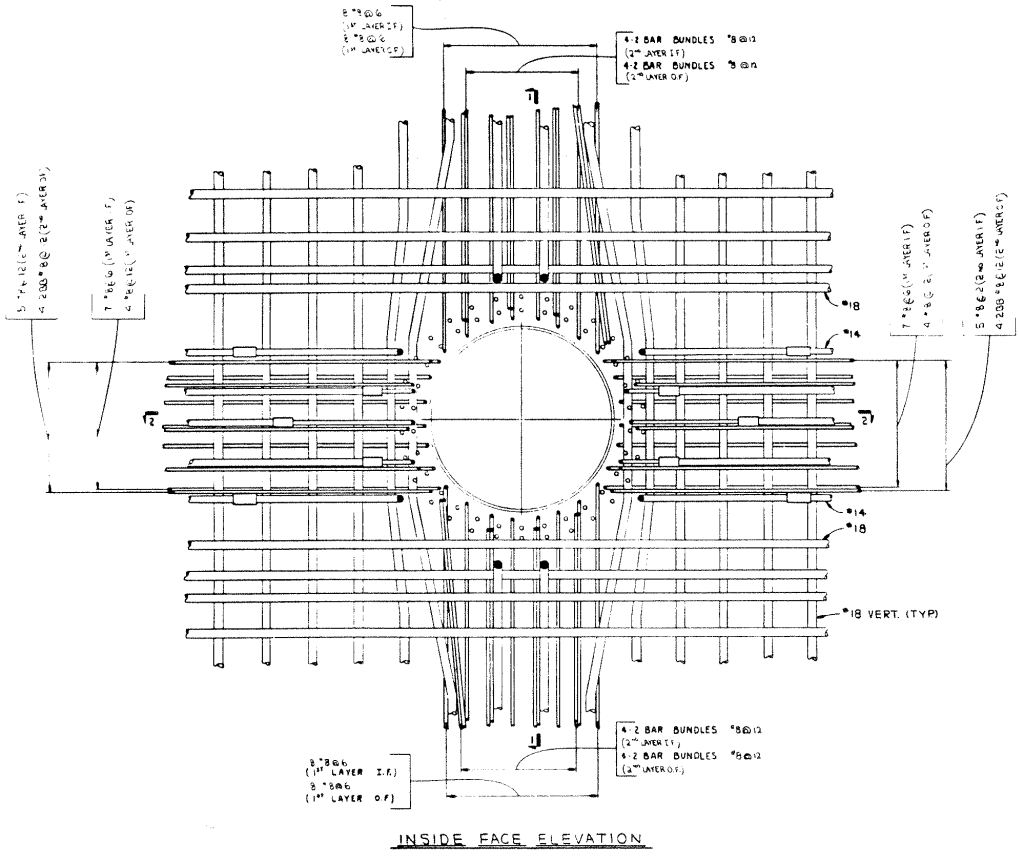
Figure 3.8-4

PERSONNEL OPENING



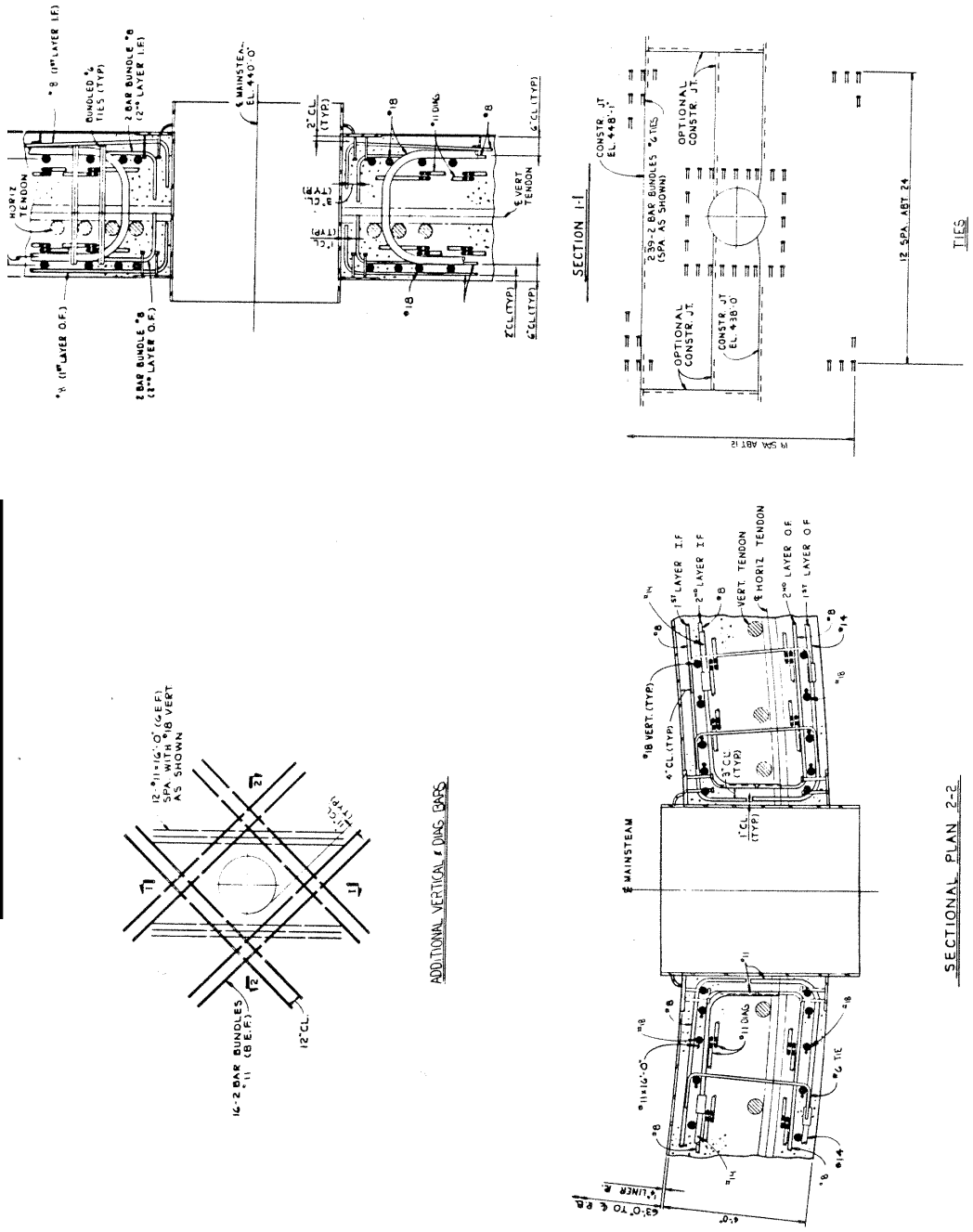
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Personnel Opening
Figure 3.8-4

Figure 3.8-5
MAIN STEAM PENETRATION



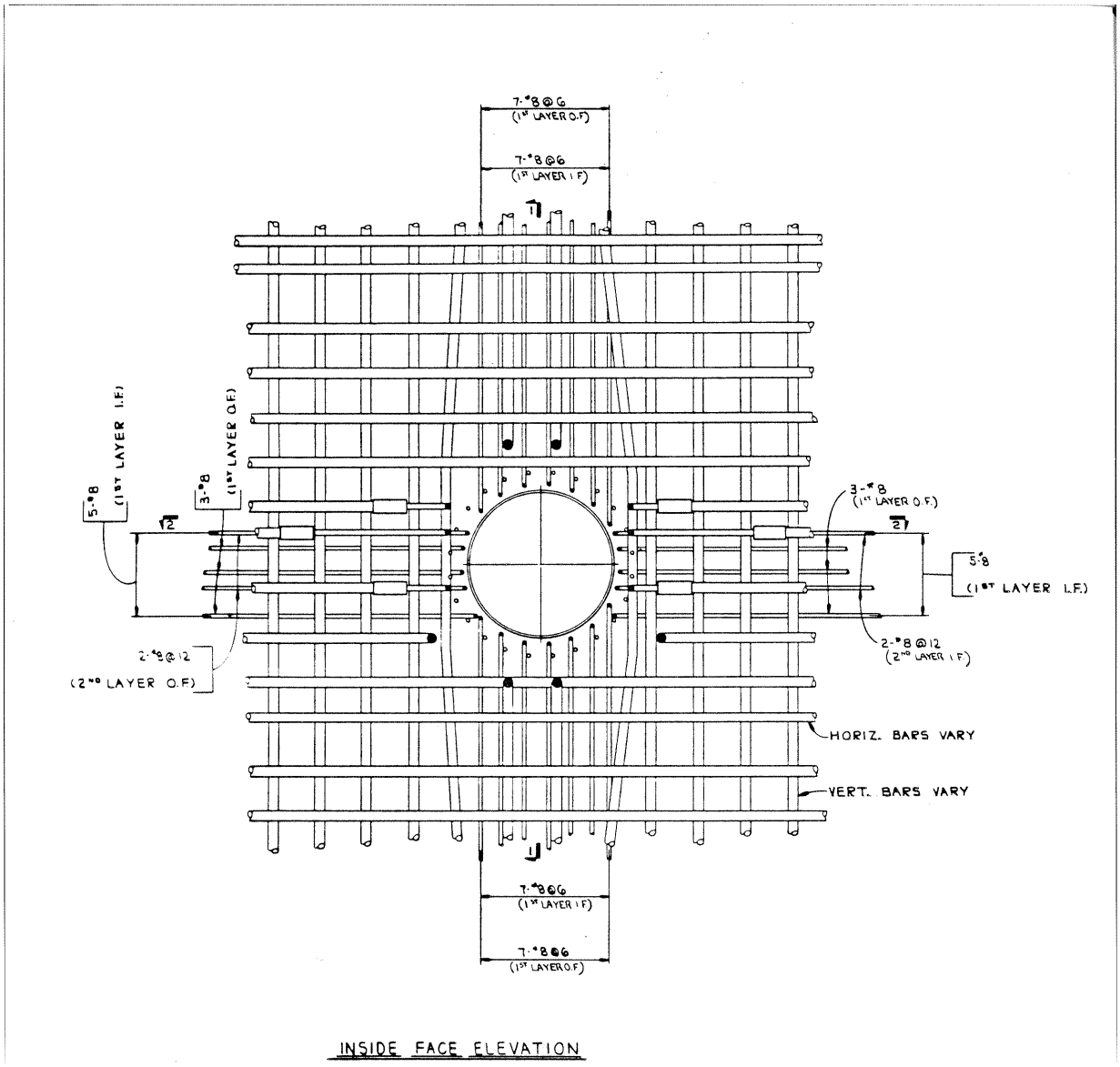
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Penetration Figure 3.8-5

Figure 3.8-6
MAIN STEAM PENETRATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Penetration
Figure 3.8-6

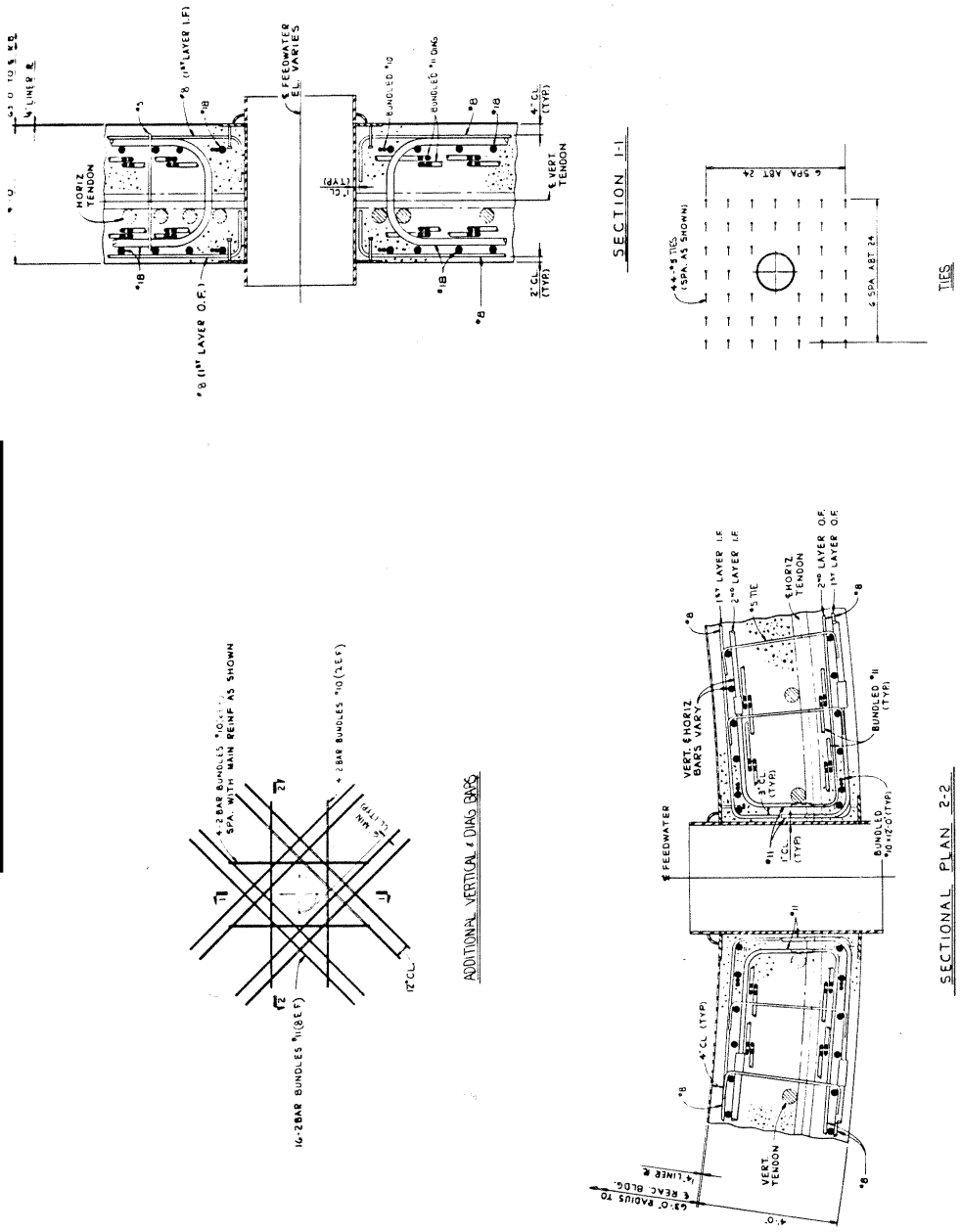
Figure 3.8-7
FEEDWATER PENETRATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Feedwater Penetration
Figure 3.8-7

Amendment 5
August 1989

Figure 3.8-8
FEEDWATER PENETRATION



Amendment 1
August 1985

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Feedwater Penetration
Figure 3.8-8

Figure 3.8-9

MAIN STEAM AND FEEDWATER PENETRATION

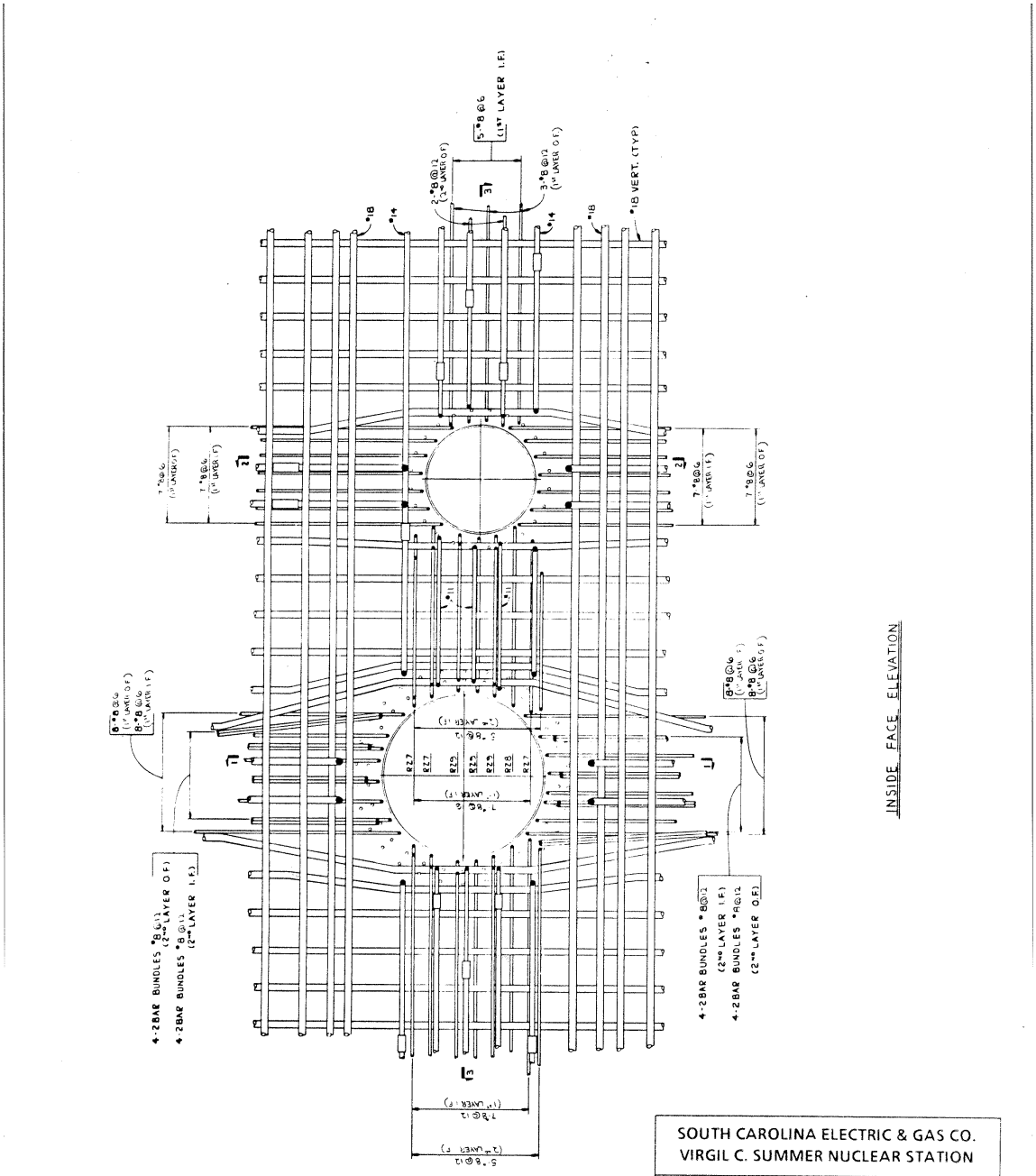
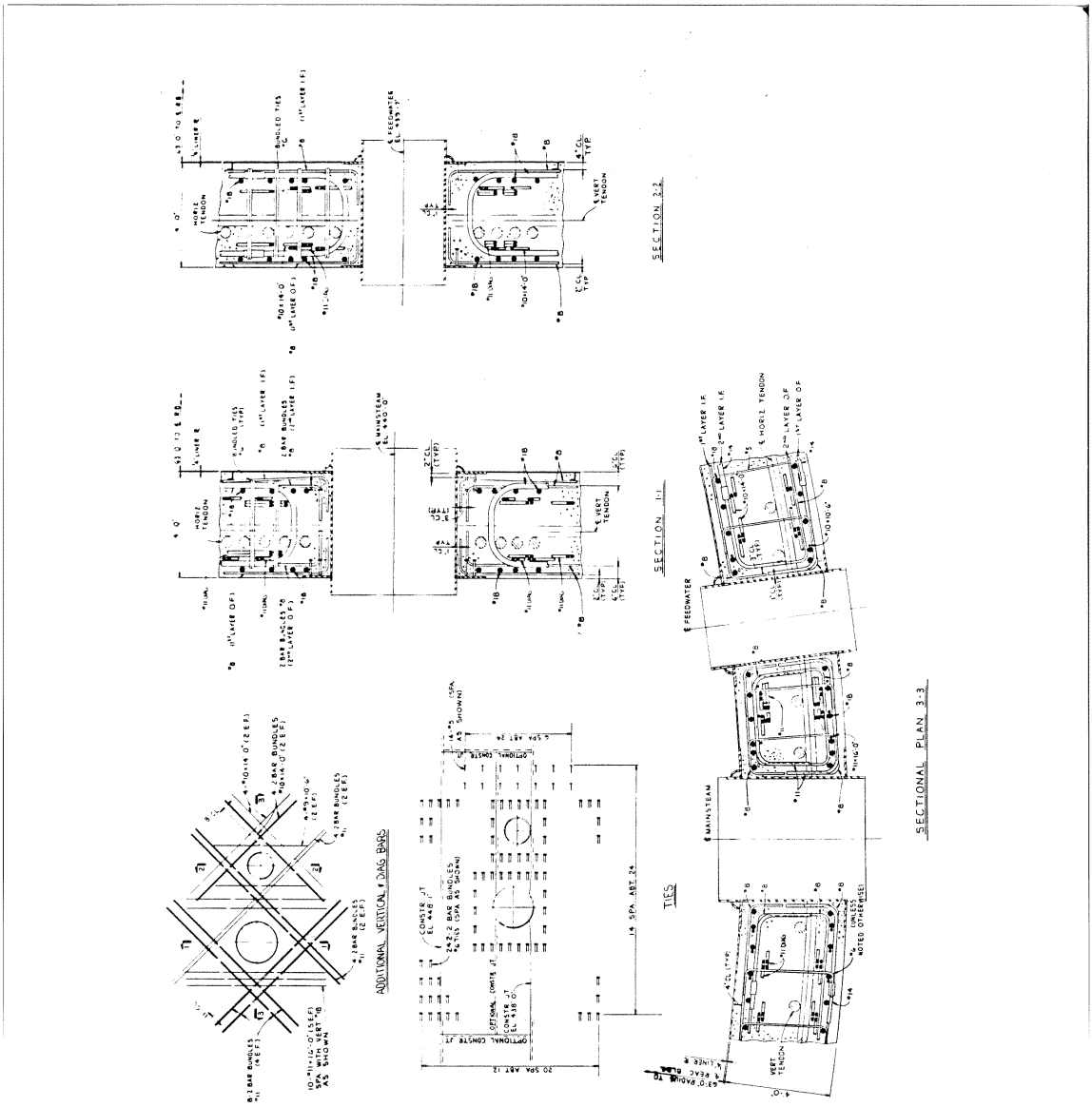


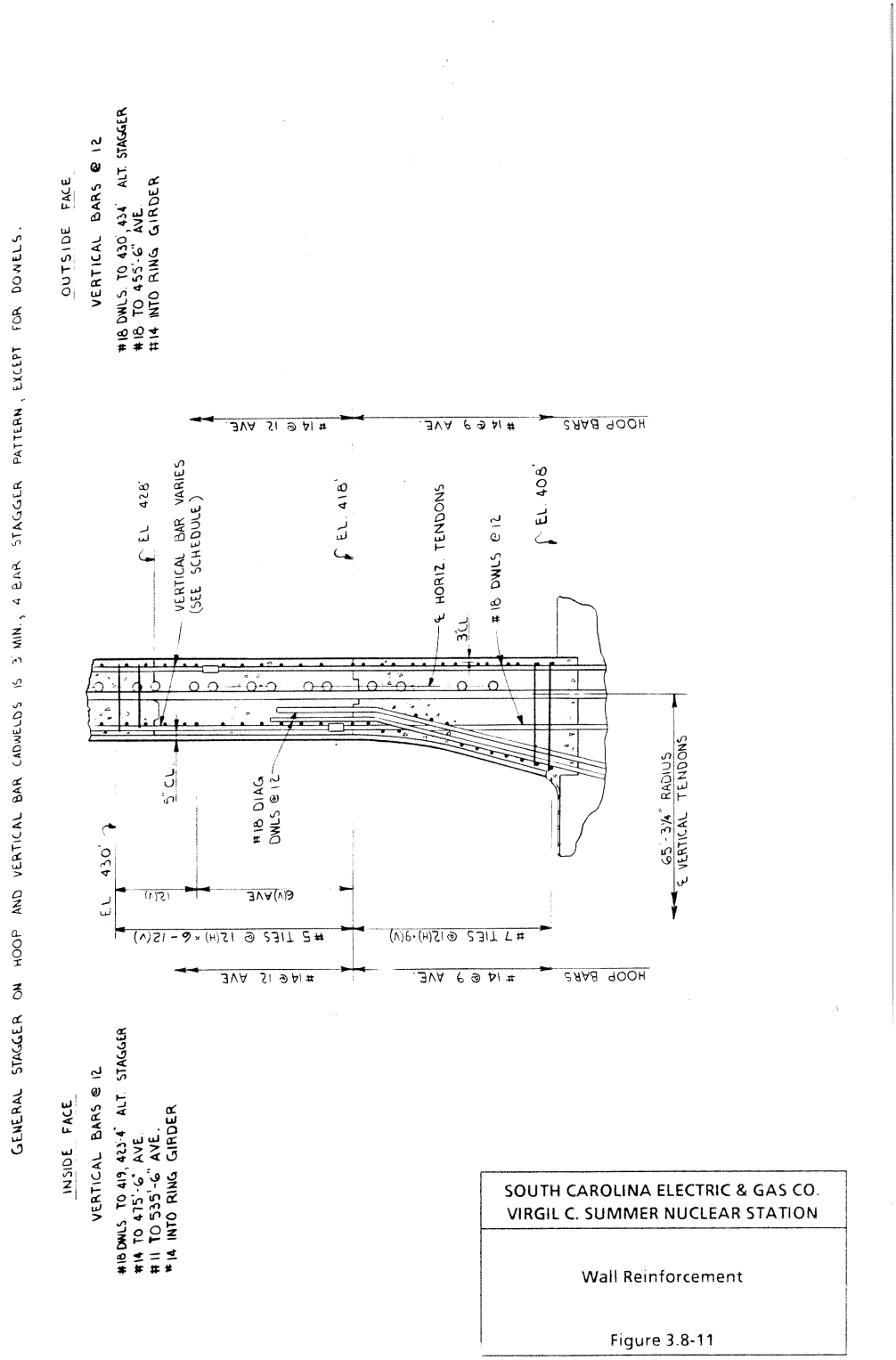
Figure 3.8-10

MAIN STEAM AND FEEDWATER PENETRATION



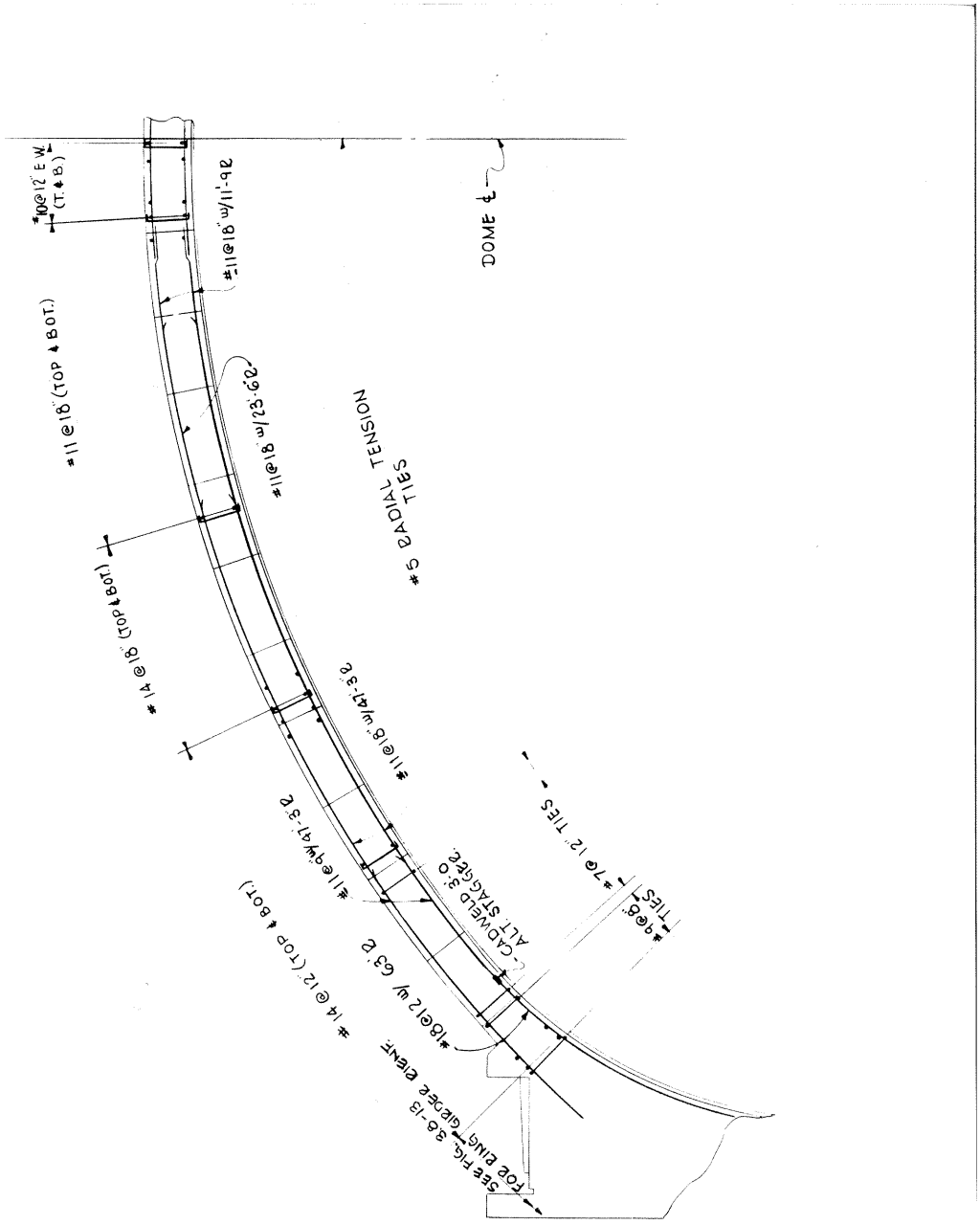
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam and Feedwater Penetration Figure 3.8-10

Figure 3.8-11
WALL REINFORCEMENT



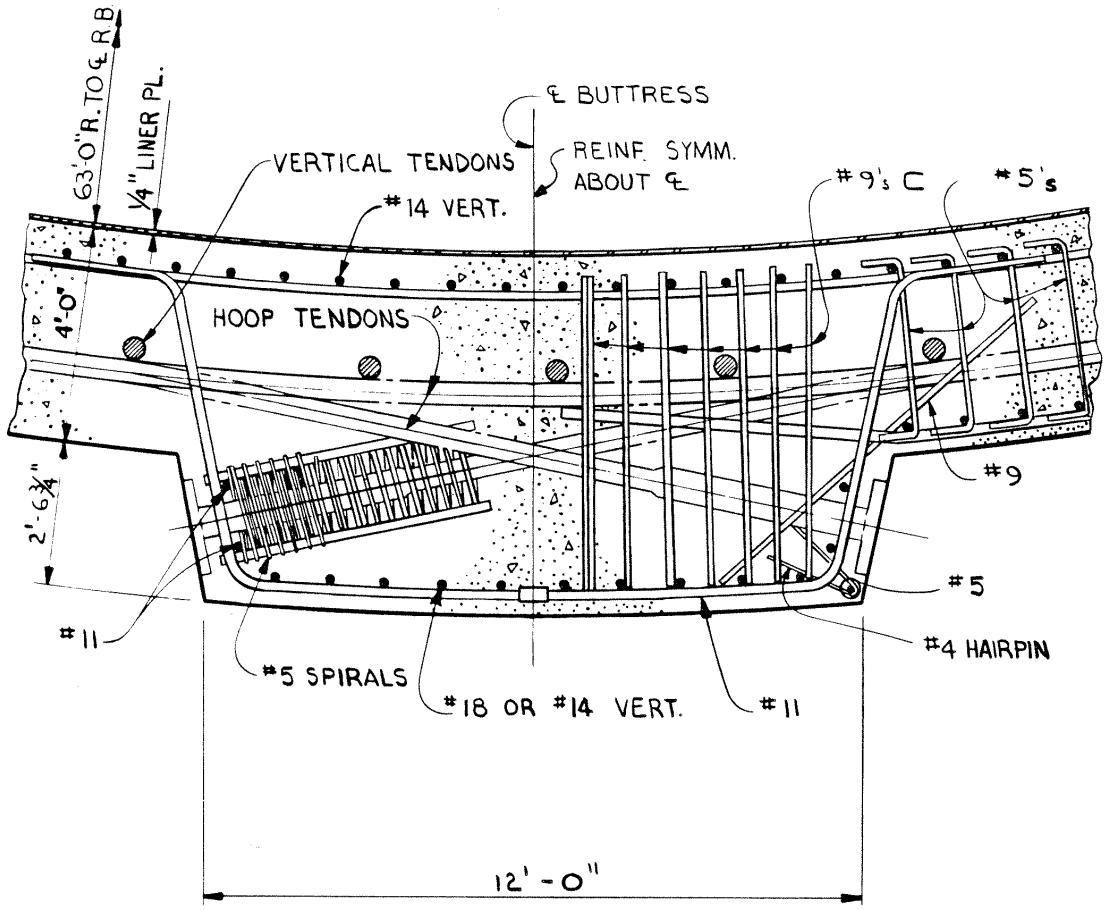
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Wall Reinforcement
Figure 3.8-11

Figure 3.8-11a
DOME REINFORCEMENT



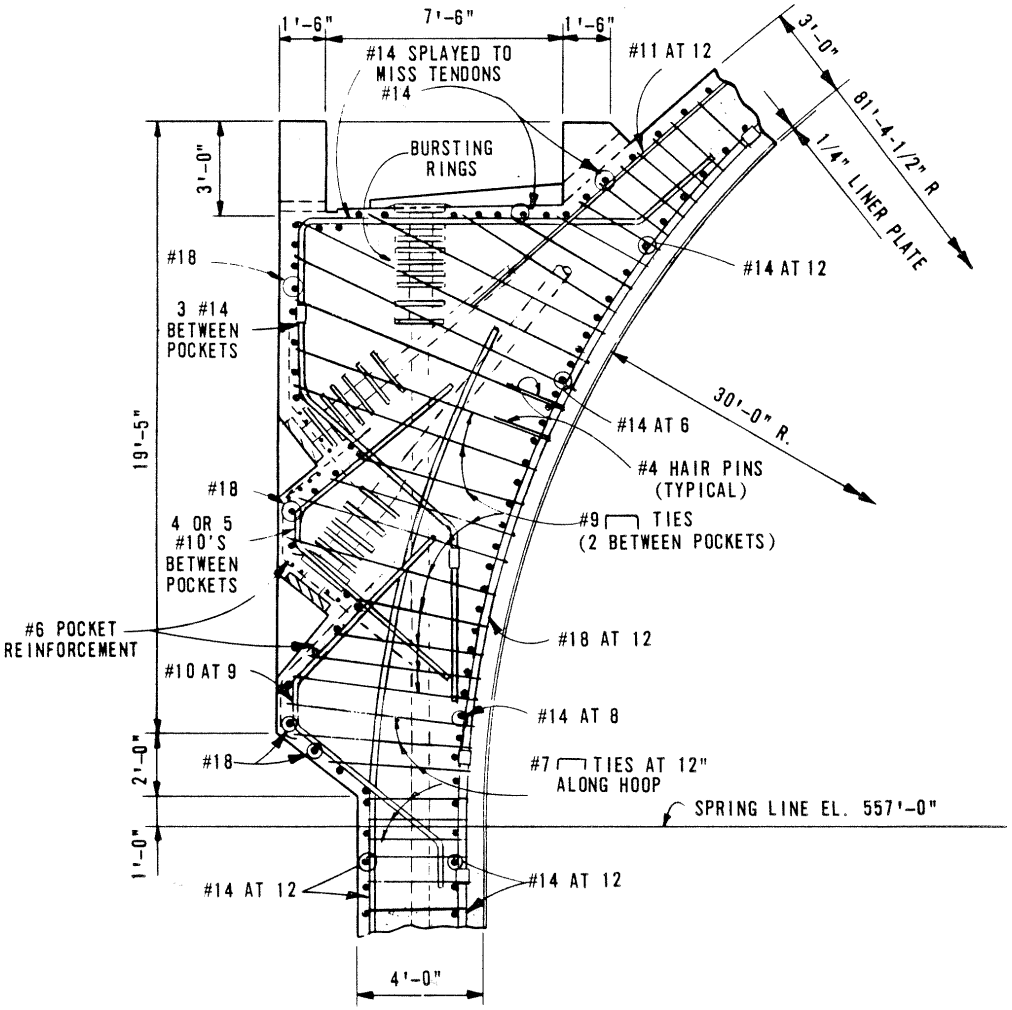
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Dome Reinforcement
Figure 3.8-11a

Figure 3.8-12
BUTTRESS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Buttress
Figure 3.8-12

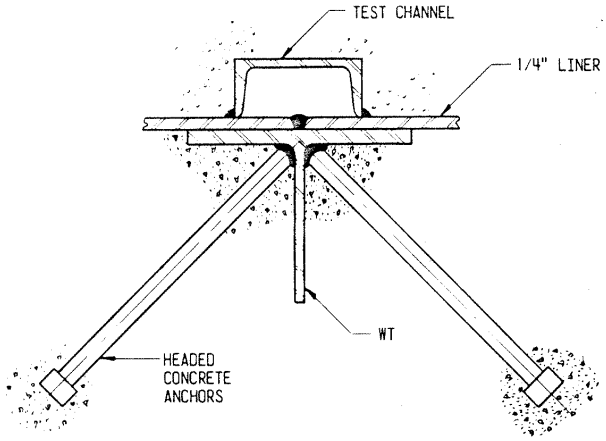
Figure 3.8-13
RING GIRDER



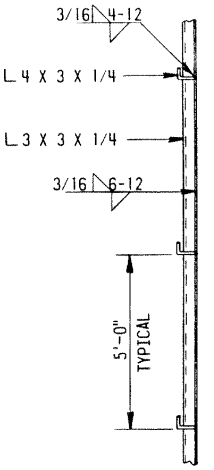
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Ring Girder
Figure 3.8-13

Figure 3.8-14

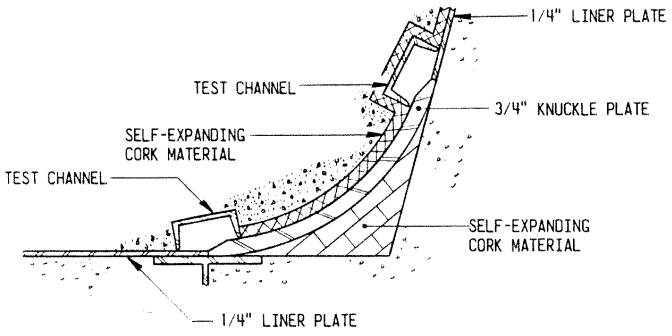
LINER CYLINDER TO BASE PLATE TRANSITION DETAILS



LINER FLOOR PLATE JOINT DETAIL



TYPICAL SECTION WALL ANCHORS

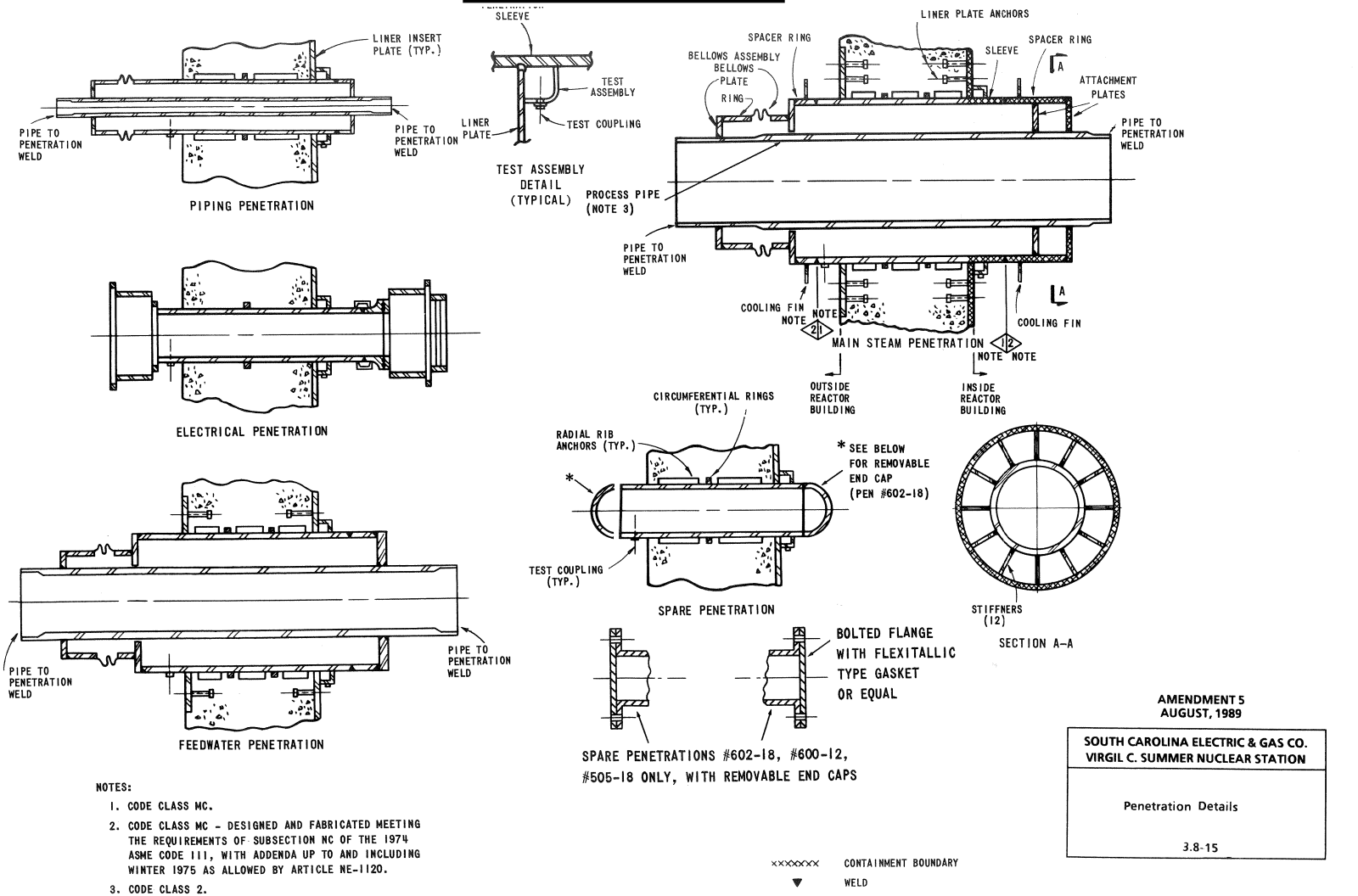


LINER CYLINDER TO BASE PLATE TRANSITION DETAIL

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Liner Cylinder to Base Plate Transition Details Figure 3.8-14

Figure 3.8-15

PENETRATION DETAILS



NOTES:

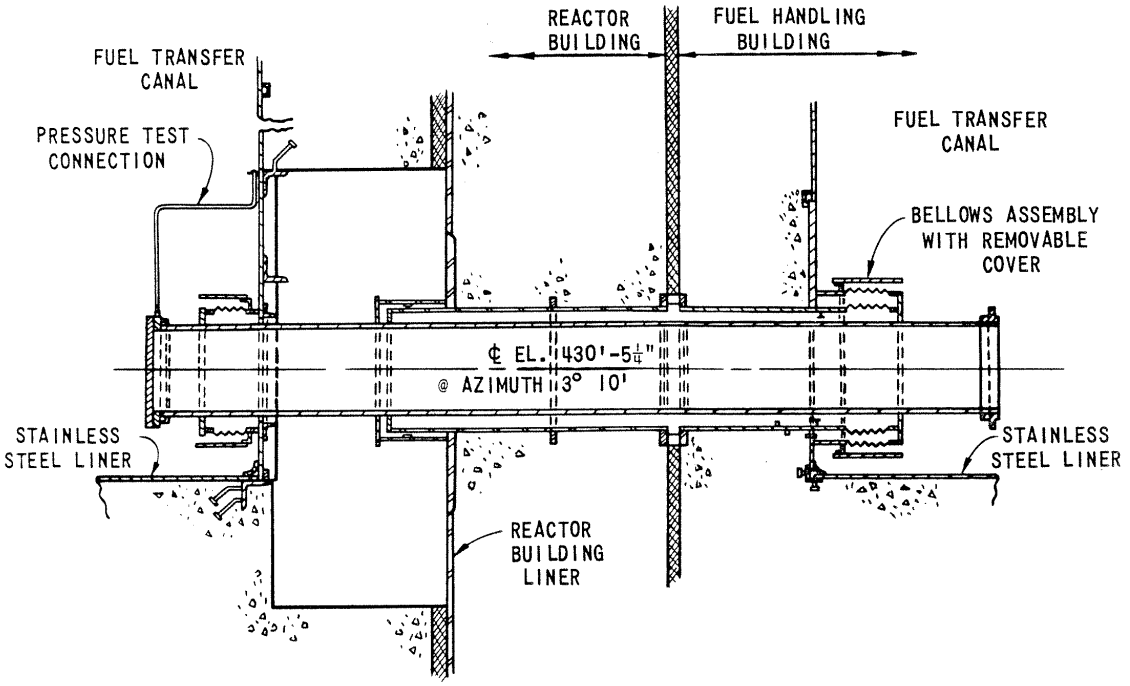
1. CODE CLASS MC.
2. CODE CLASS MC - DESIGNED AND FABRICATED MEETING THE REQUIREMENTS OF SUBSECTION NC OF THE 1974 ASME CODE III, WITH ADDENDA UP TO AND INCLUDING WINTER 1975 AS ALLOWED BY ARTICLE NE-1120.
3. CODE CLASS 2.

AMENDMENT 5
AUGUST, 1989

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Penetration Details
3.8-15

Figure 3.8-16

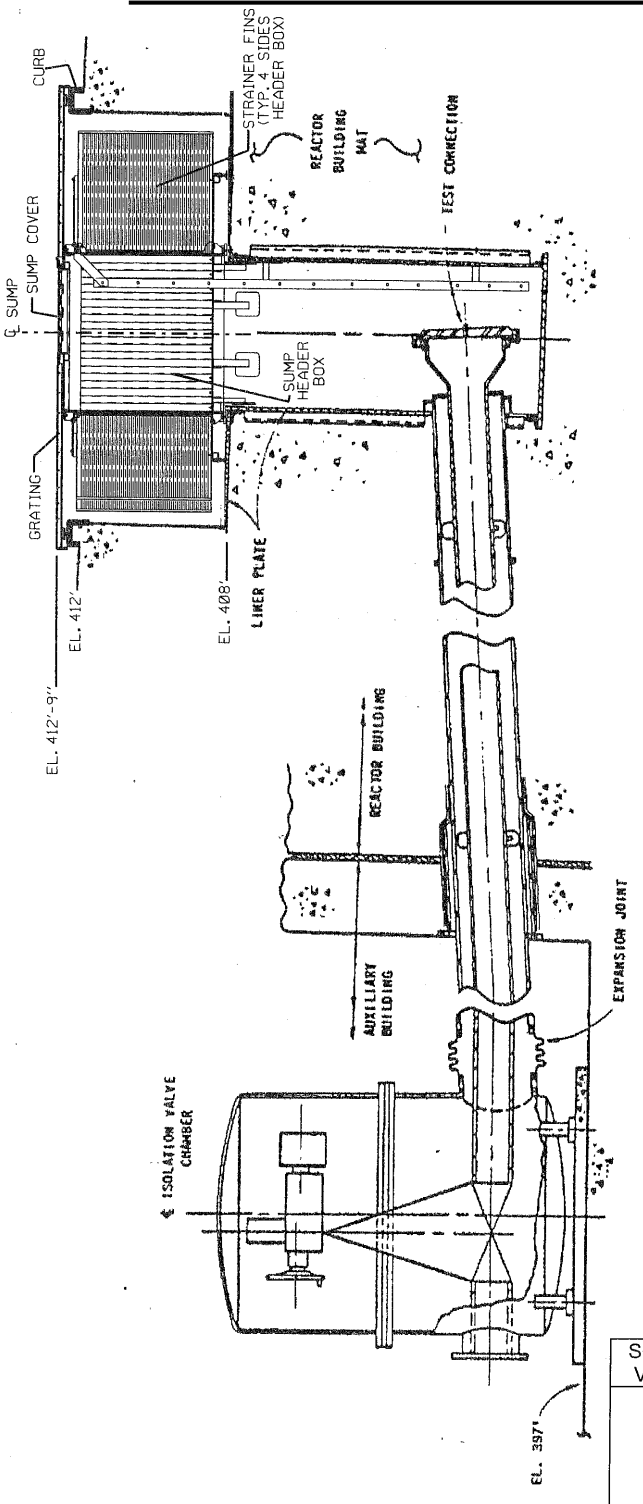
FUEL TRANSFER TUBE PENETRATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Fuel Transfer Tube Penetration Figure 3.8-16

Figure 3.8-17

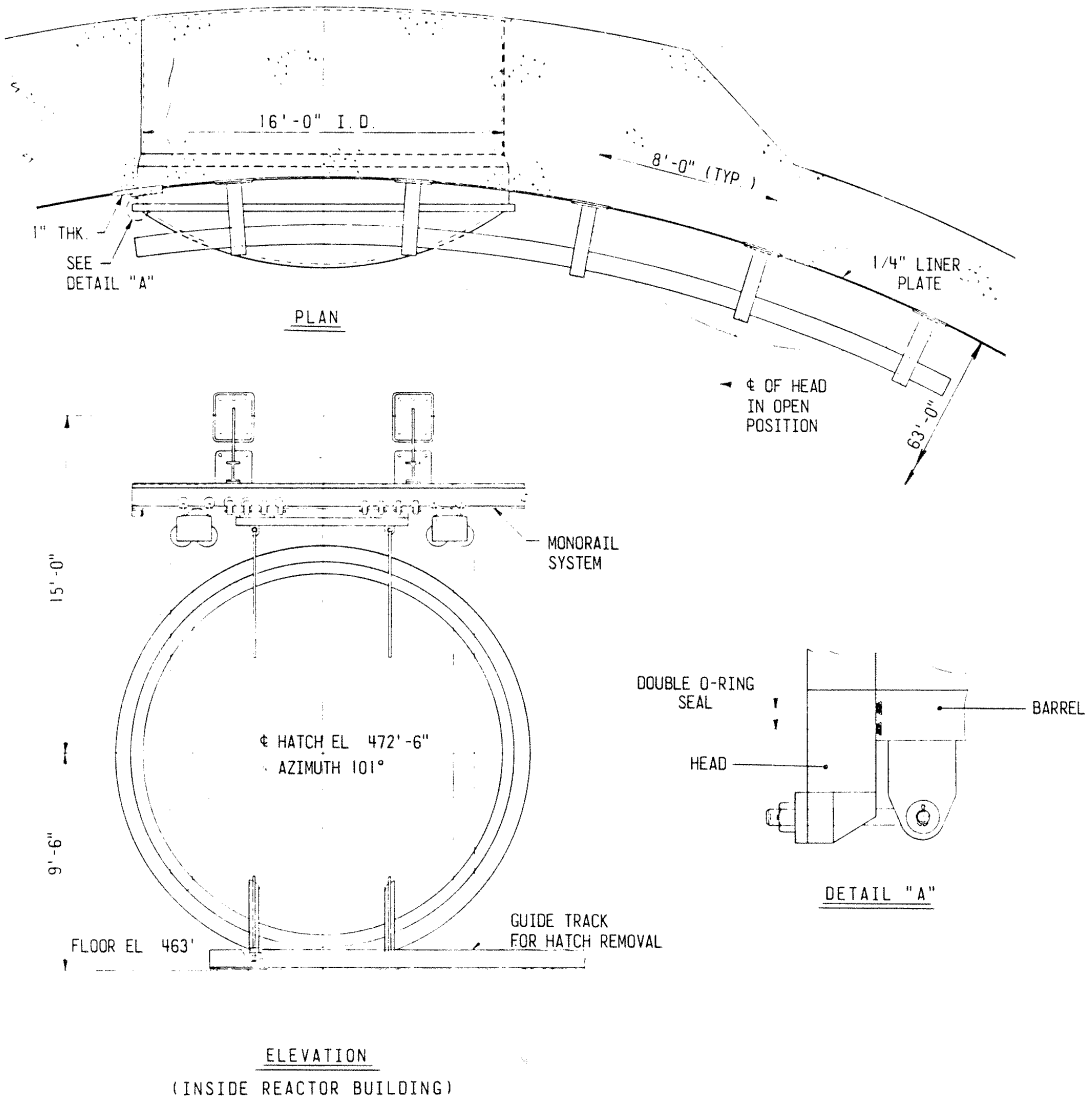
RB RECIRCULATION SUMPS FOR RESIDUAL HEAT REMOVAL AND RB SPRAY PUMPS



RN 13-022

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
RB Recirculation Sumps for Residual Heat Removal and RB Spray Pumps Figure 3.8-17

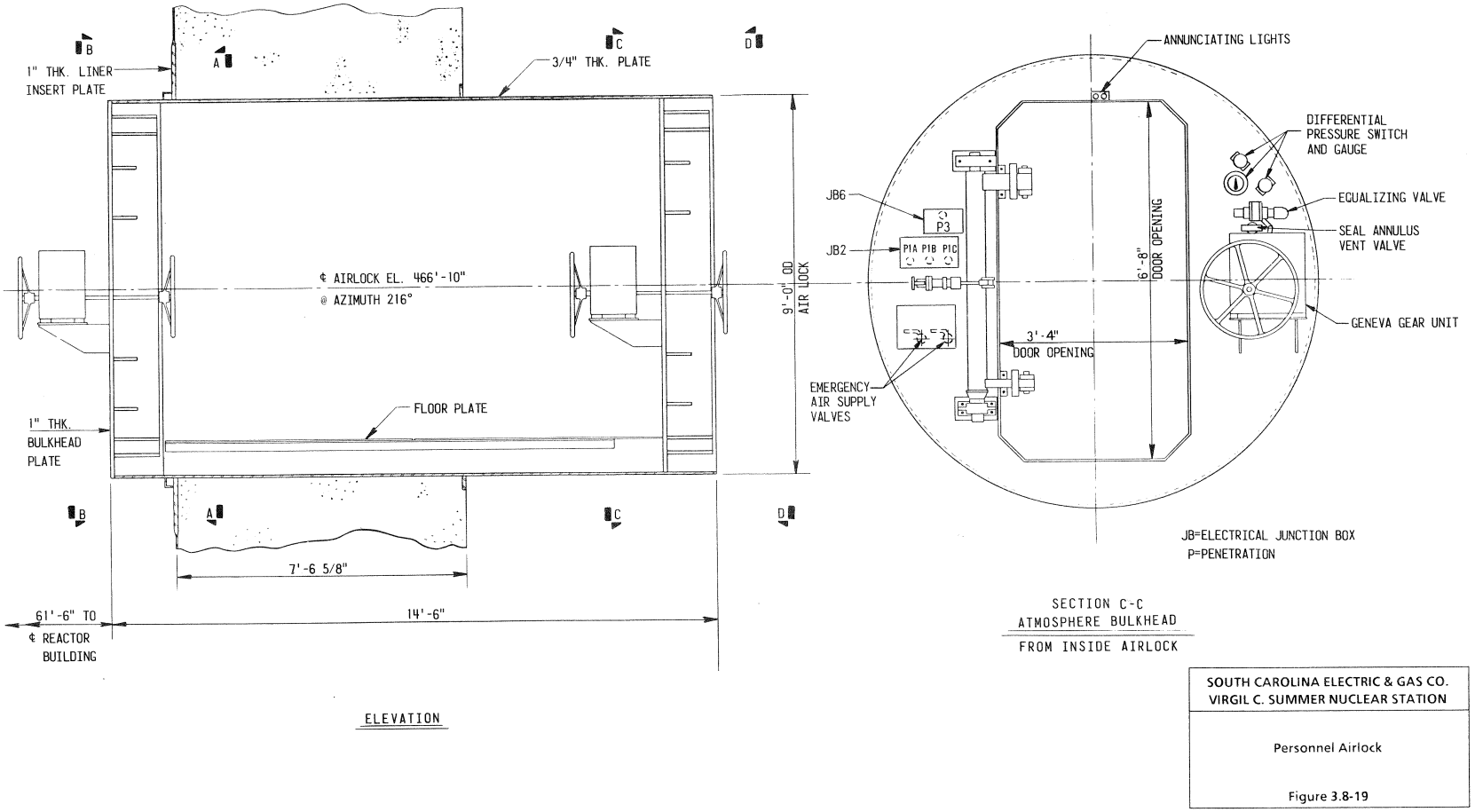
Figure 3.8-18
EQUIPMENT HATCH



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Equipment Hatch
Figure 3.8-18

Figure 3.8-19

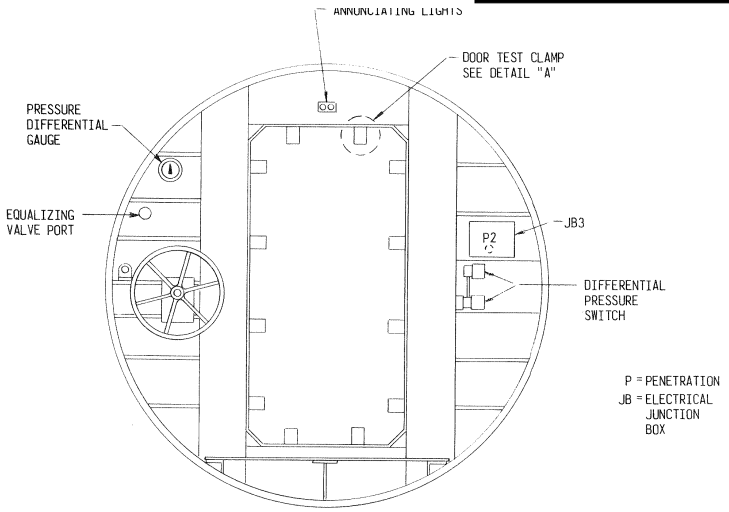
PERSONNEL AIRLOCK



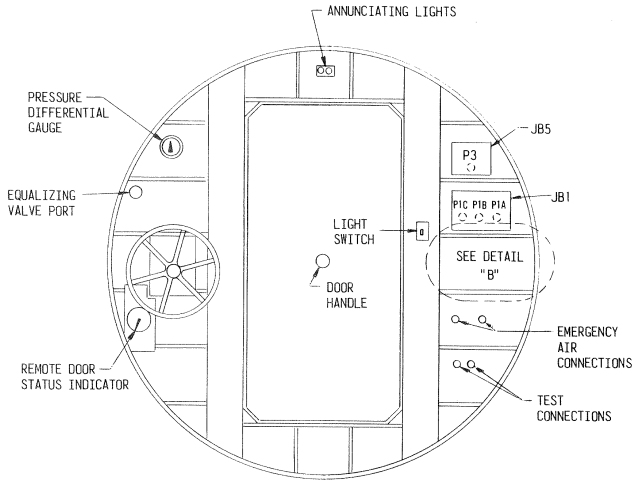
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Personnel Airlock
Figure 3.8-19

Figure 3.8-19a

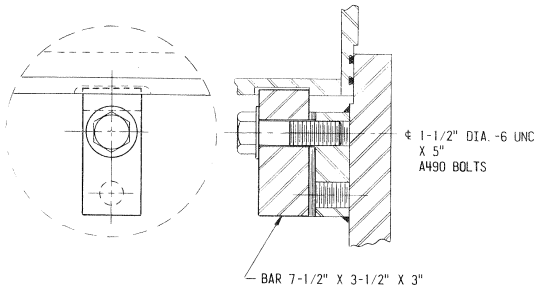
PERSONNEL AIRLOCK SECTIONS AND DETAILS



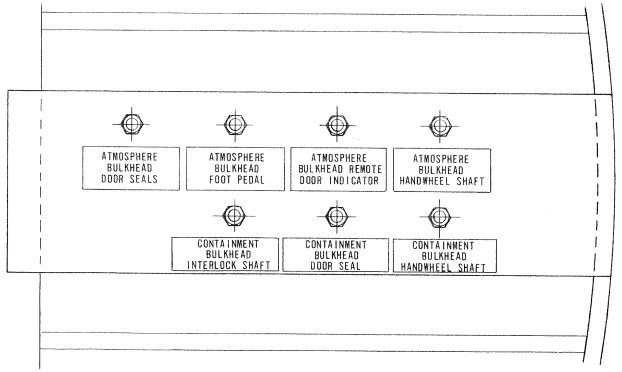
SECTION A-A
CONTAINMENT BULKHEAD
FROM INSIDE AIRLOCK



SECTION D-D
ATMOSPHERE BULKHEAD
FROM ATMOSPHERE



DETAIL "A"
DOOR TEST CLAMPS

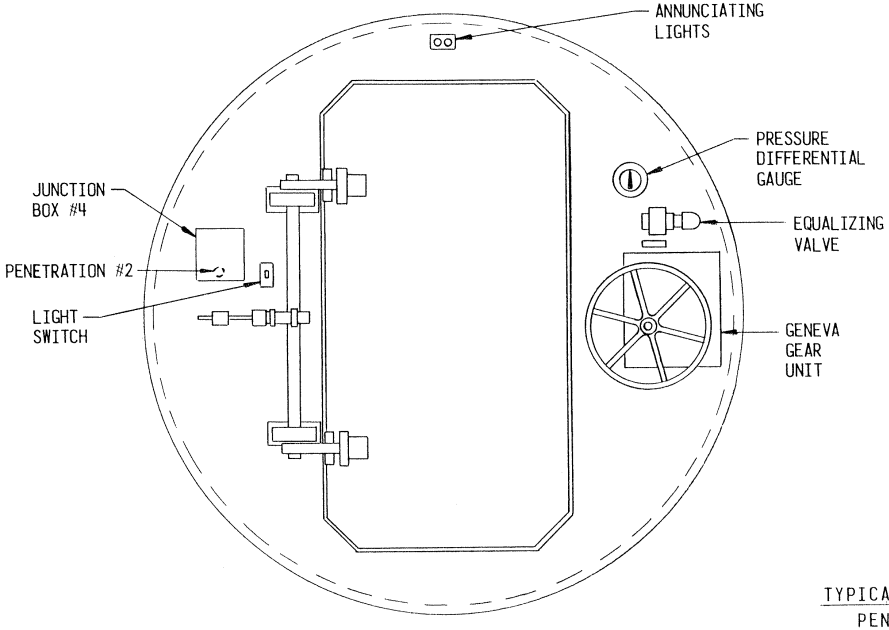


DETAIL "B"
REMOTE TEST PANEL

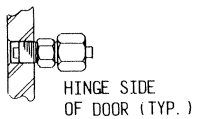
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Personnel Airlock Sections and Details
Figure 3.8-19a

Figure 3.8-19b

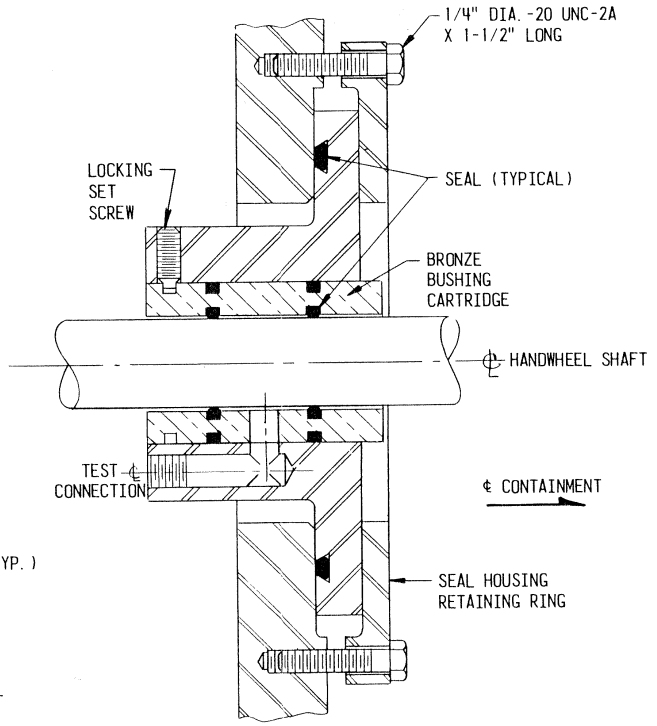
PERSONNEL AIRLOCK SECTIONS AND DETAILS



SECTION B-B
CONTAINMENT BULKHEAD
FROM INSIDE CONTAINMENT



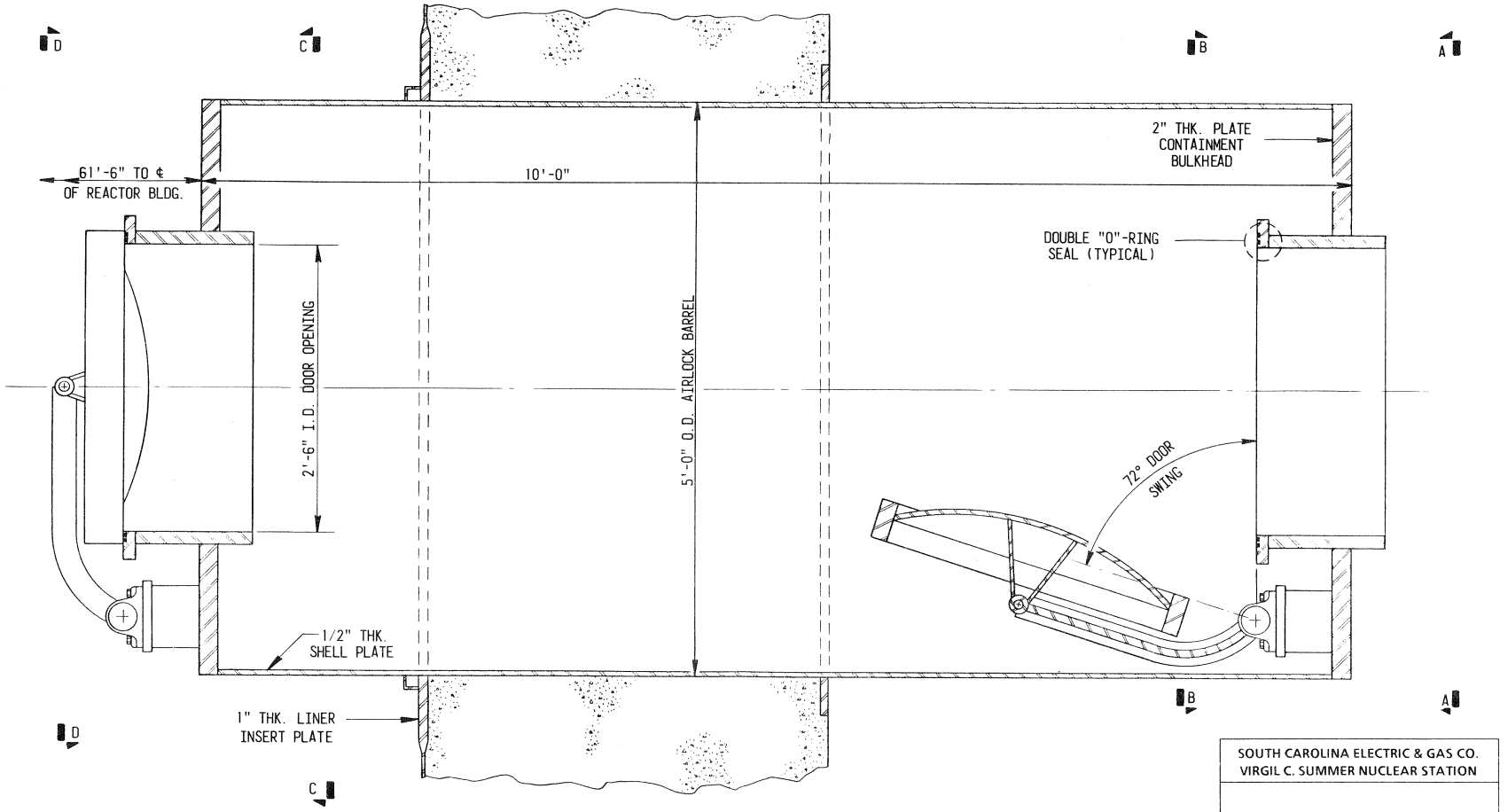
TYPICAL ELECTRICAL PENETRATION
CONAX FITTING-TYPE PL



HANDWHEEL SHAFT SEAL

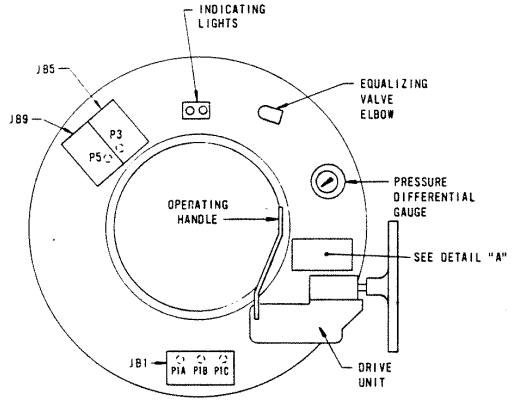
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Personnel Airlock Sections and Details
Figure 3.8-19b

Figure 3.8-20
EMERGENCY AIRLOCK



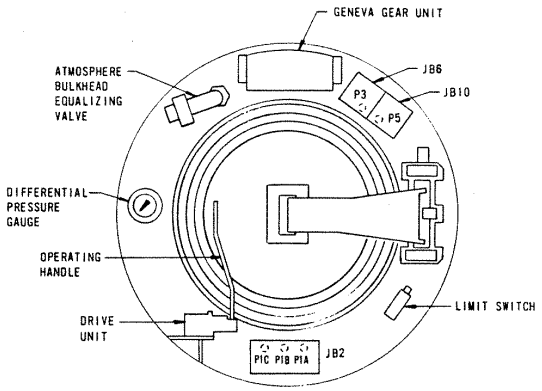
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Emergency Airlock
Figure 3.8-20

Figure 3.8-20a
EMERGENCY AIRLOCK SECTIONS

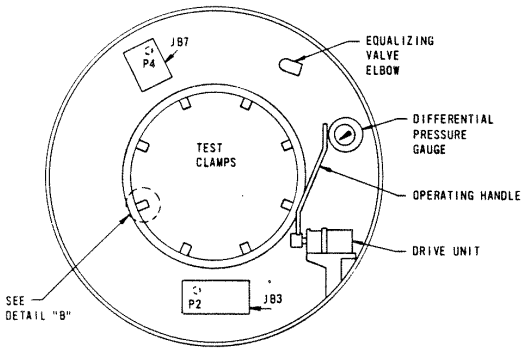


SECTION A-A
ATMOSPHERE BULKHEAD
FROM ATMOSPHERE

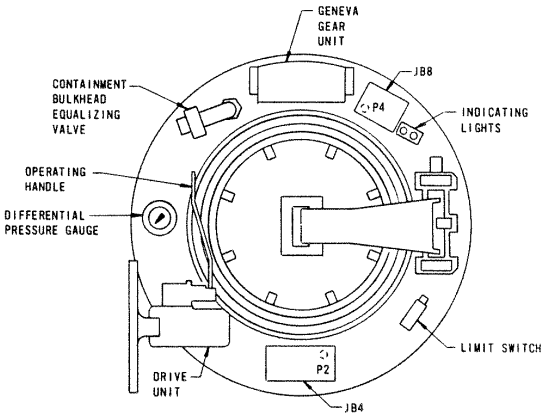
P = PENETRATION
JB = ELECTRICAL JUNCTION BOX



SECTION B-B
ATMOSPHERE BULKHEAD
FROM INSIDE AIRLOCK



SECTION C-C
CONTAINMENT BULKHEAD
FROM INSIDE AIRLOCK

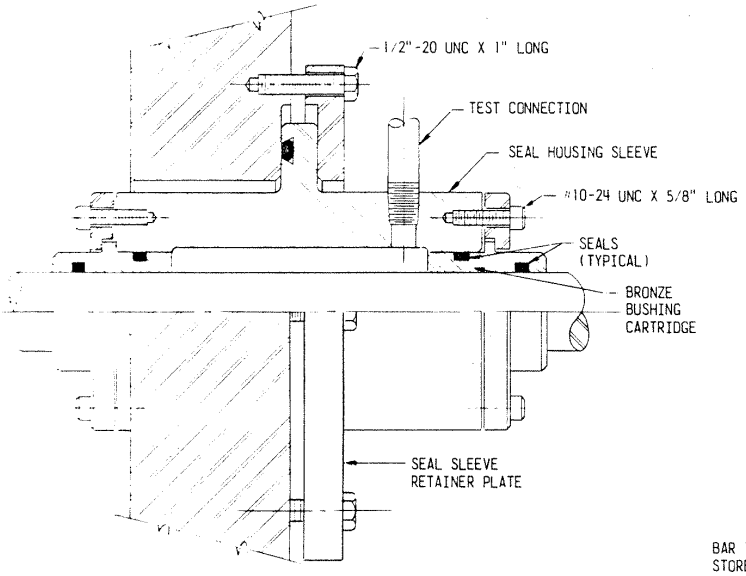


SECTION A-A
CONTAINMENT BULKHEAD
FROM INSIDE CONTAINMENT

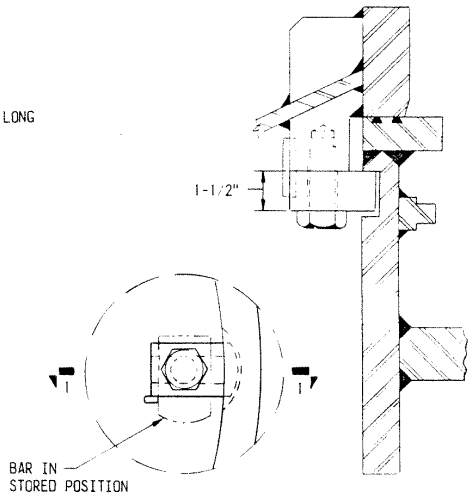
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Emergency Airlock Sections
Figure 3.8-20a

Figure 3.8-20b

EMERGENCY AIRLOCK SECTIONS AND DETAILS

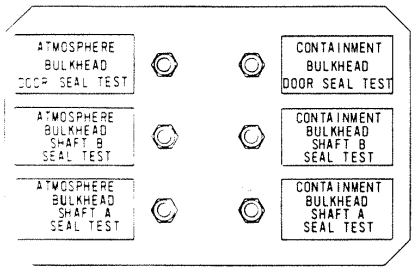


HANDWHEEL SHAFT SEAL

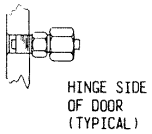


DETAIL "B" SECTION 1-1

DOOR TEST CLAMP



DETAIL "A"
REMOTE TEST PANEL

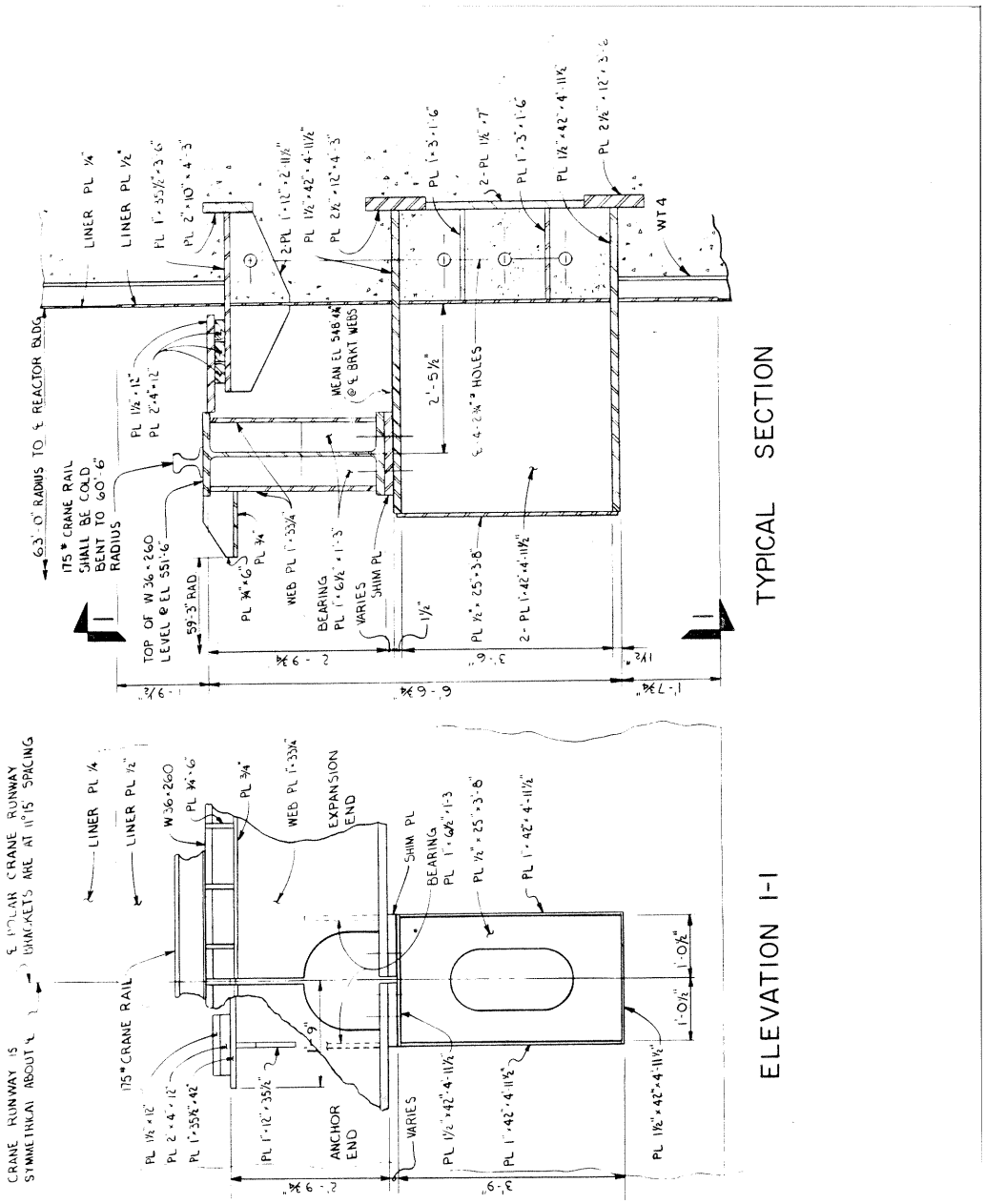


TYPICAL ELECTRICAL PENETRATION
CONAX FITTING TYPE PL

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Emergency Airlock Sections and Details Figure 3.8-20b

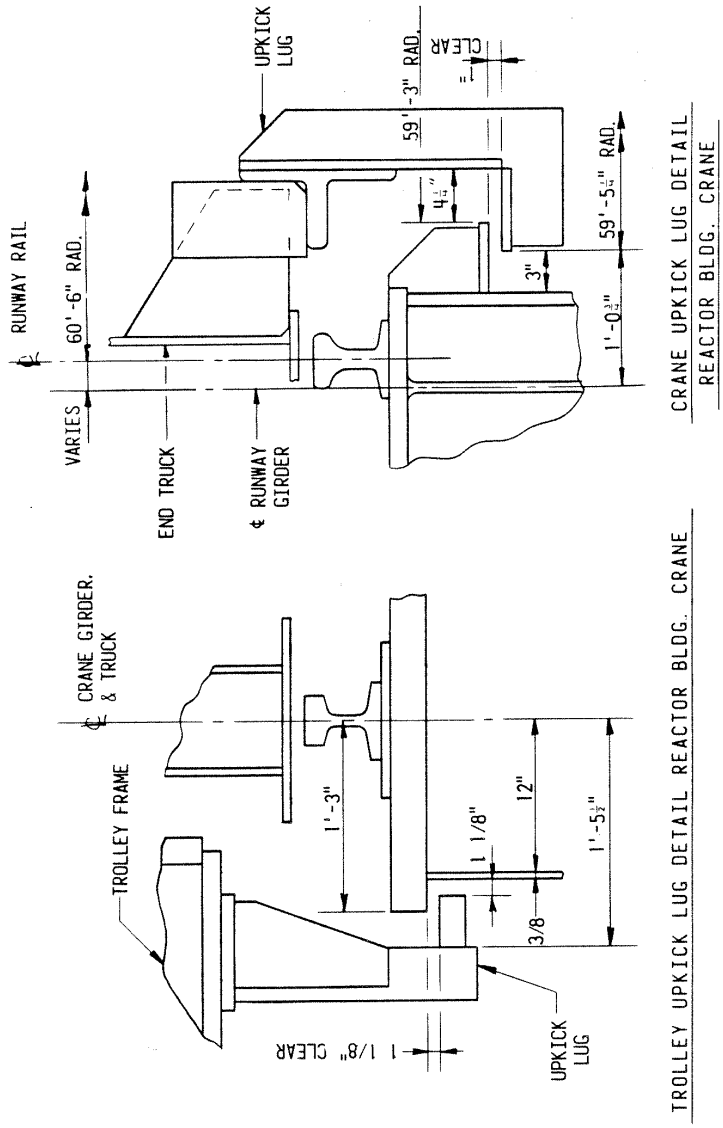
Figure 3.8-21

POLAR CRANE BRACKETS AND RUNWAY BEAMS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Polar Crane Brackets and Runway Beams
Figure 3.8-21

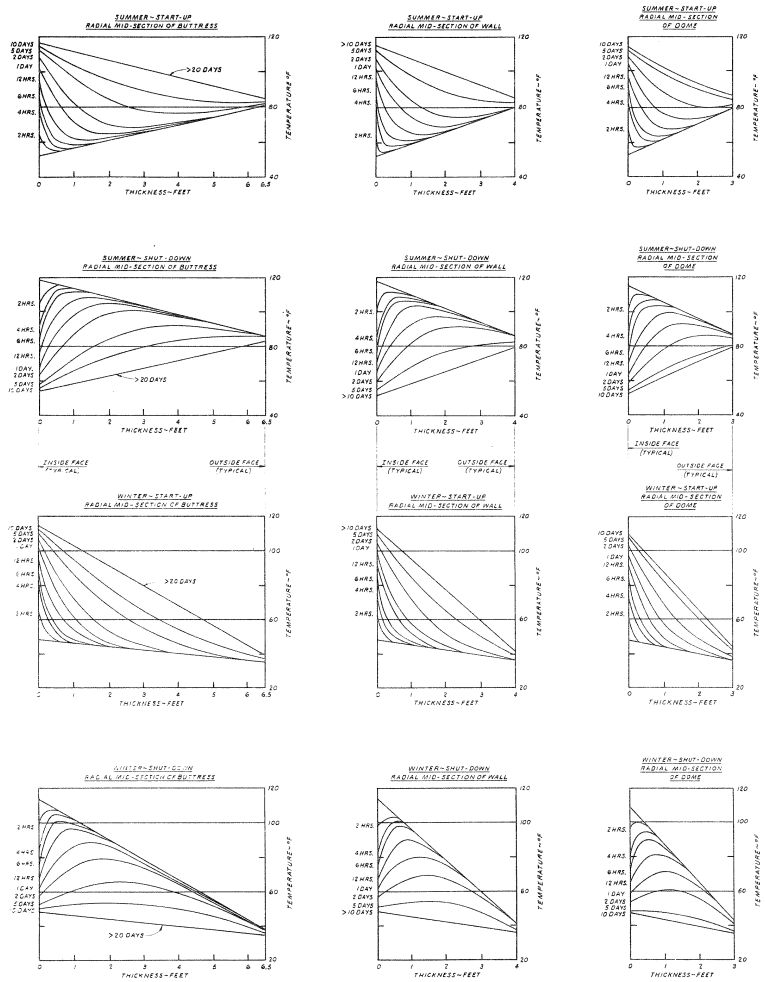
Figure 3.8-22
TROLLEY AND CRANE UPLIFT LUGS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Trolley and Crane Uplift Lugs Figure 3.8-22

Figure 3.8-23

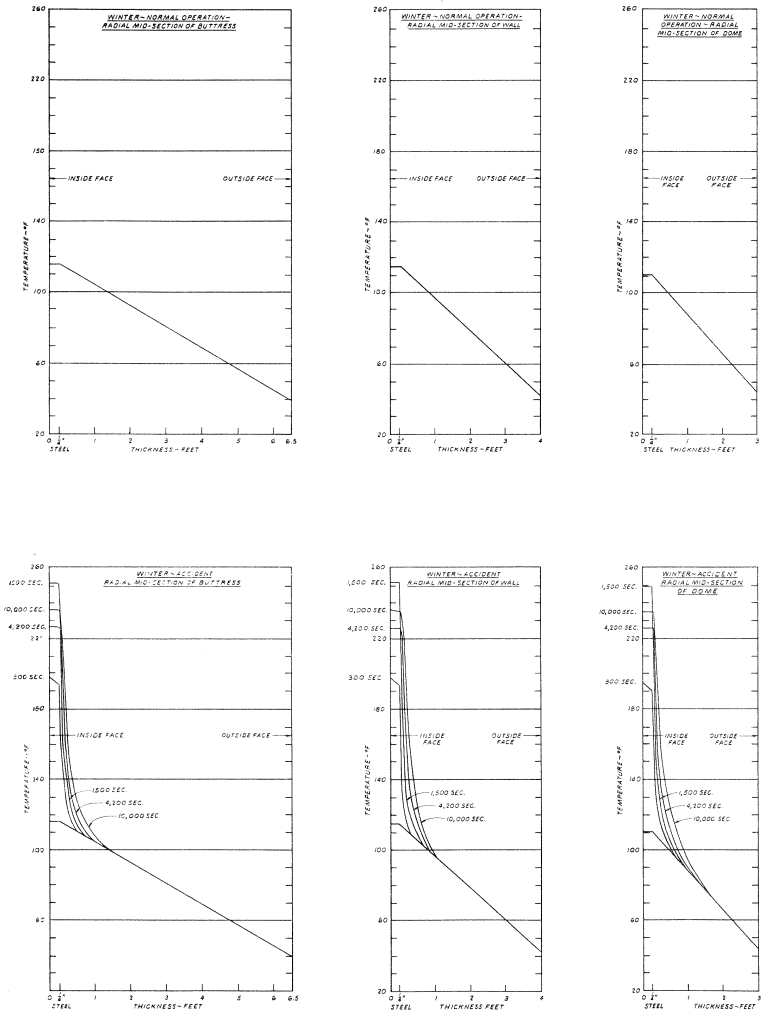
TEMPERATURE PROFILES THROUGH BUTTRESS, WALL AND DOME SUMMER AND WINTER START-UP AND SHUT-DOWN



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Temperature Profiles Through Buttress, Wall and Dome Summer and Winter Start-up and Shut-down Figure 3.8-23

Figure 3.8-24

TEMPERATURE PROFILES THROUGH BUTTRESS, WALL AND DOME WINTER NORMAL AND ACCIDENT

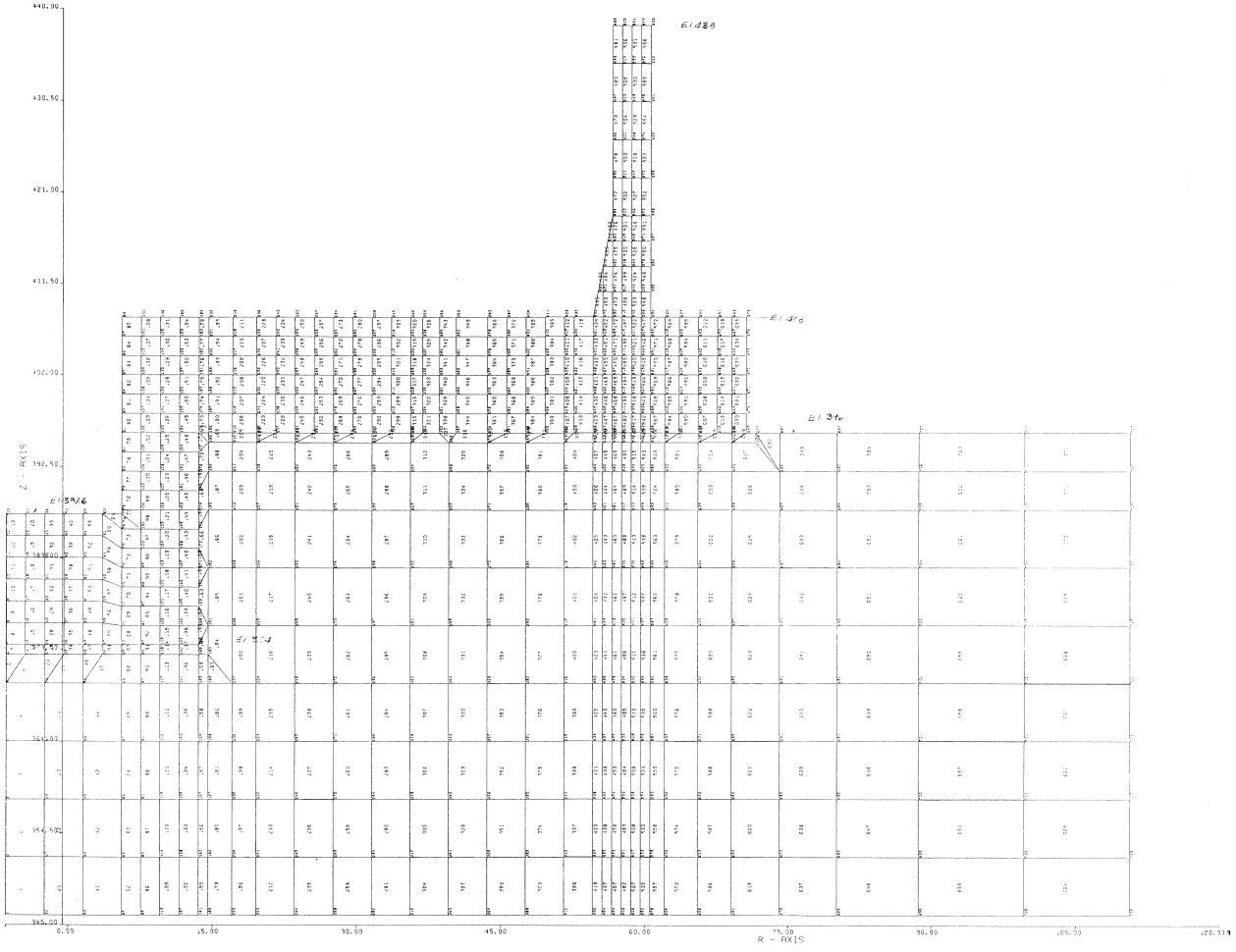


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Temperature Profiles Through Buttress, Wall and Dome Winter Normal and Accident

Figure 3.8-24

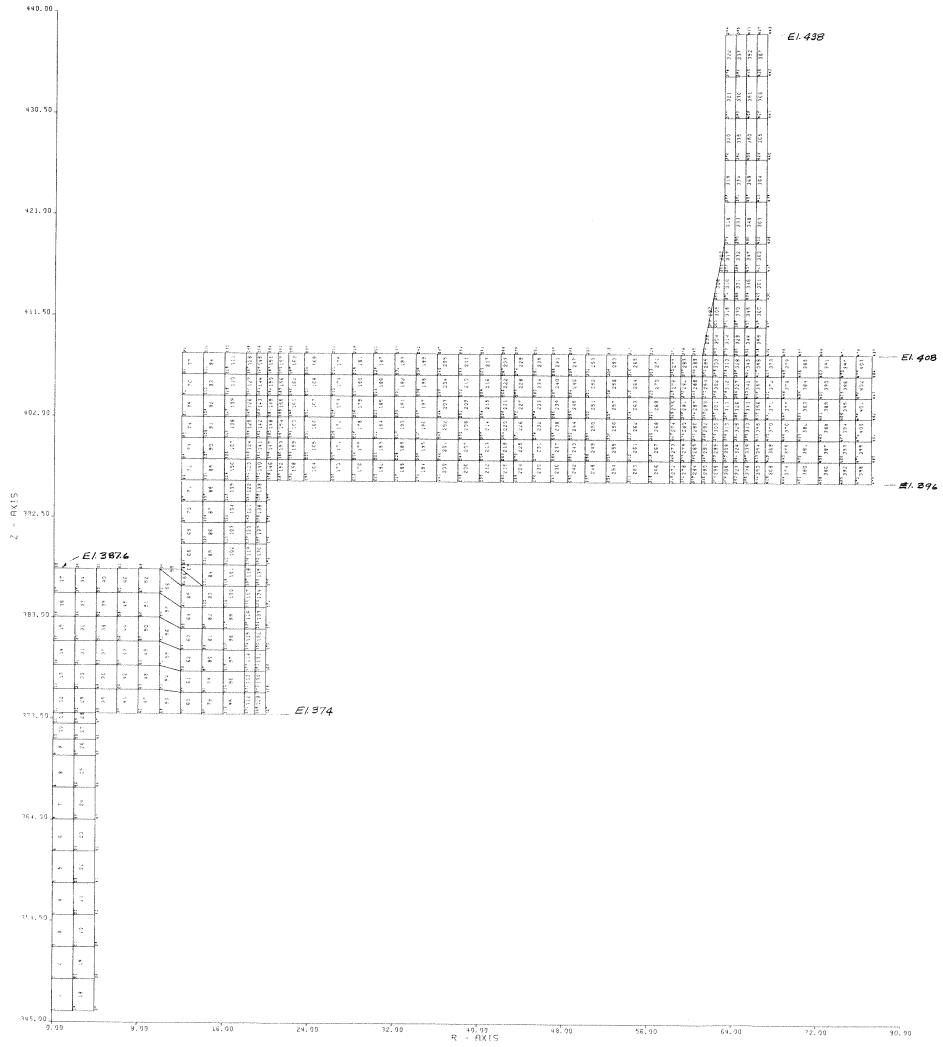
Figure 3.8-25
ELAD MODEL FOR SYMMETRICAL LOADS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
ELAD Model For Symmetrical Loads
Figure 3.8-25

Figure 3.8-26

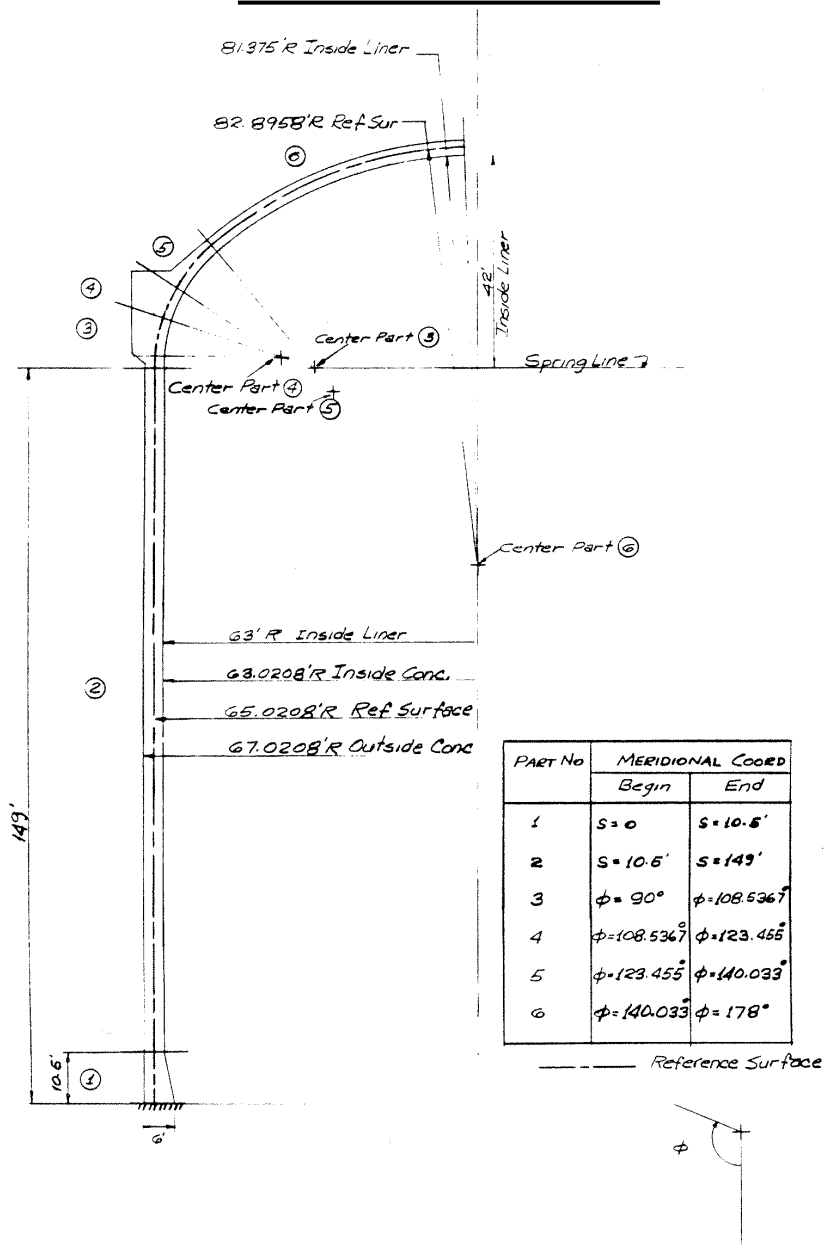
ELAD MODEL FOR UNSYMMETRICAL LOADS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
ELAD Model For Unsymmetrical Loads Figure 3.8-26

Figure 3.8-27

REACTOR BUILDING MODEL FOR USE WITH KALNINS PROGRAM



PART No	MERIDIONAL COORD	
	Begin	End
1	S = 0	S = 10.6'
2	S = 10.6'	S = 149'
3	φ = 90°	φ = 108.5367°
4	φ = 108.5367°	φ = 123.455°
5	φ = 123.455°	φ = 140.033°
6	φ = 140.033°	φ = 178°

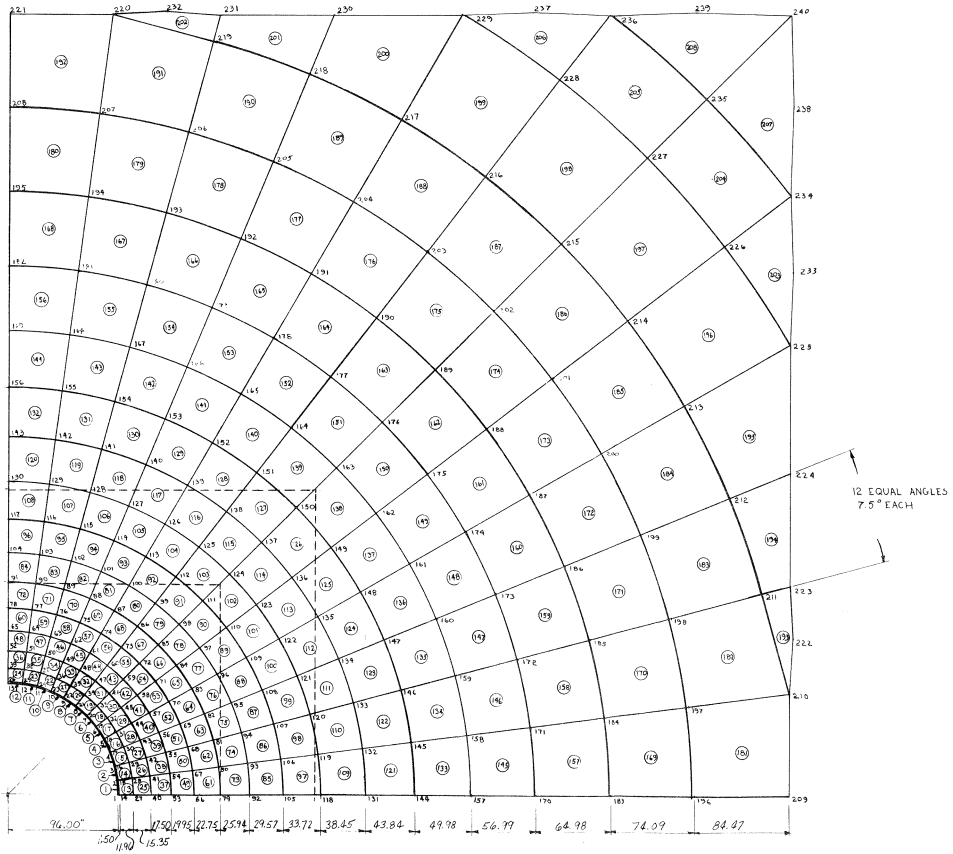
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Reactor Building Model For Use With KALNINS Program

Figure 3.8-27

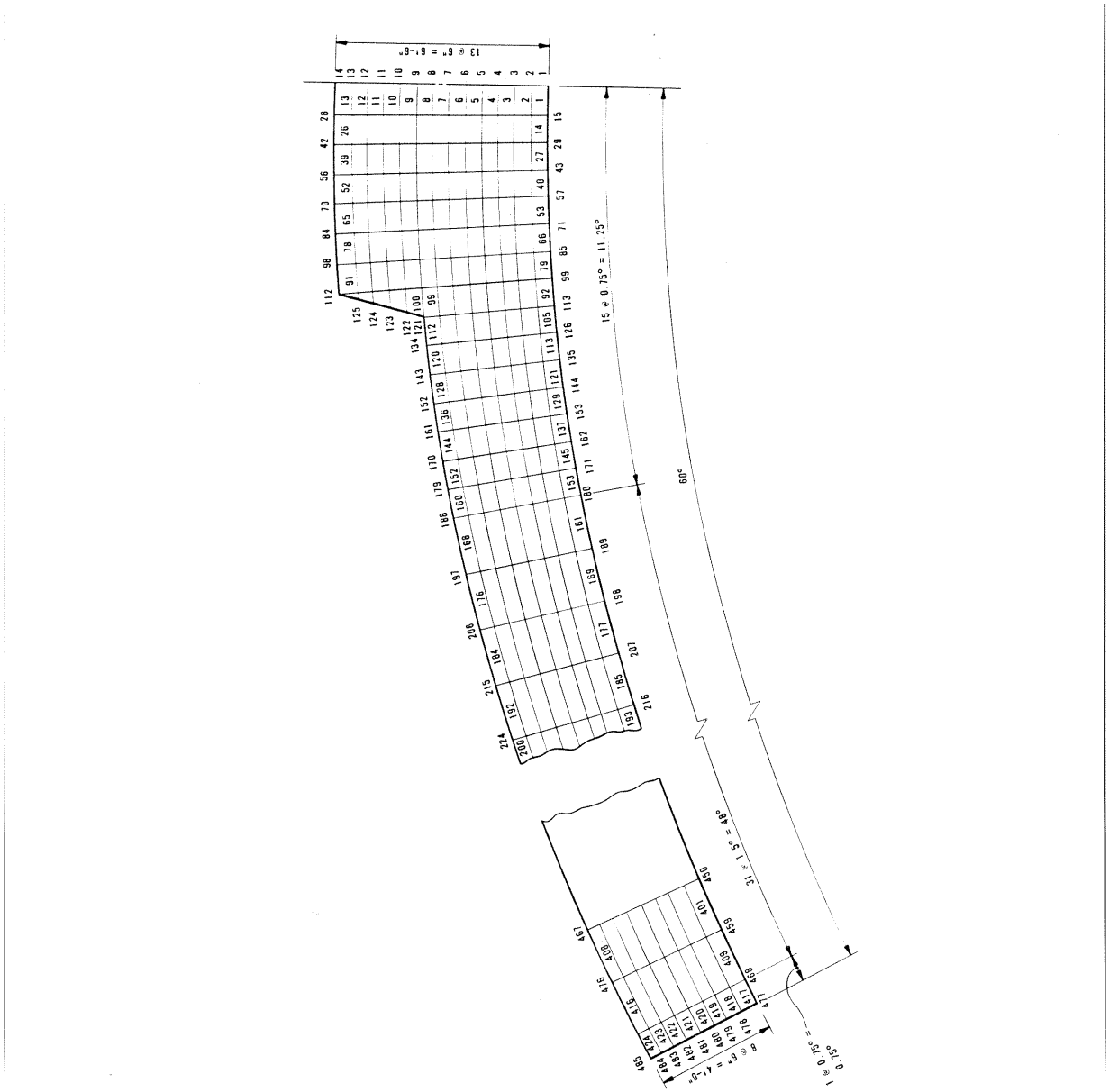
Figure 3.8-28

FINITE ELEMENT MODEL OF ACCESS OPENINGS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Finite Element Model of Accesss Openings
Figure 3.8-28

Figure 3.8-29
PLAIN STRESS FINITE ELEMENT MODEL
FOR BUTTRESS ANALYSIS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Plain Stress Finite Element Model For Buttress Analysis Figure 3.8-29

Figure 3.8-30

ELAD MODEL FOR RING GIRDER ANALYSIS

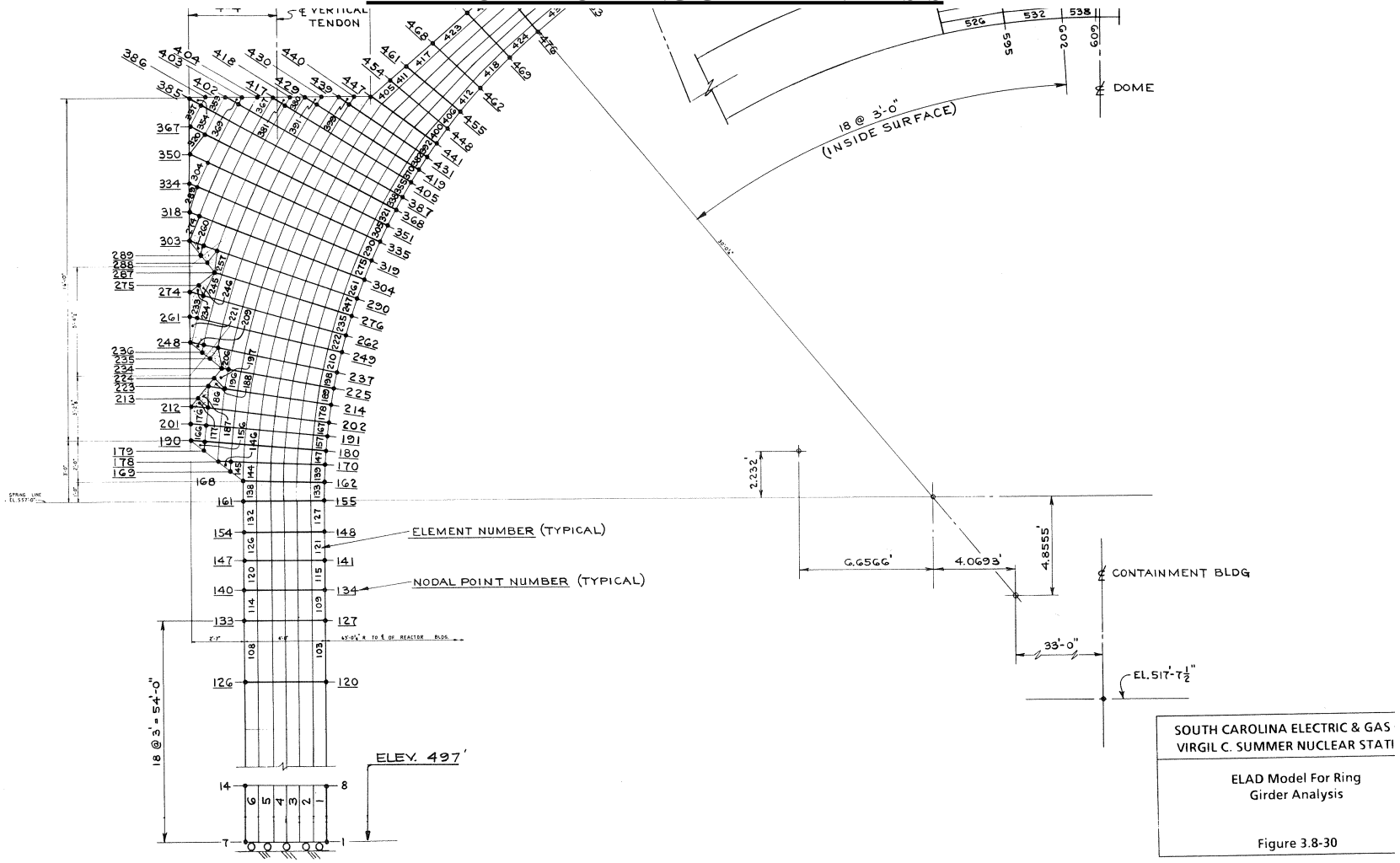
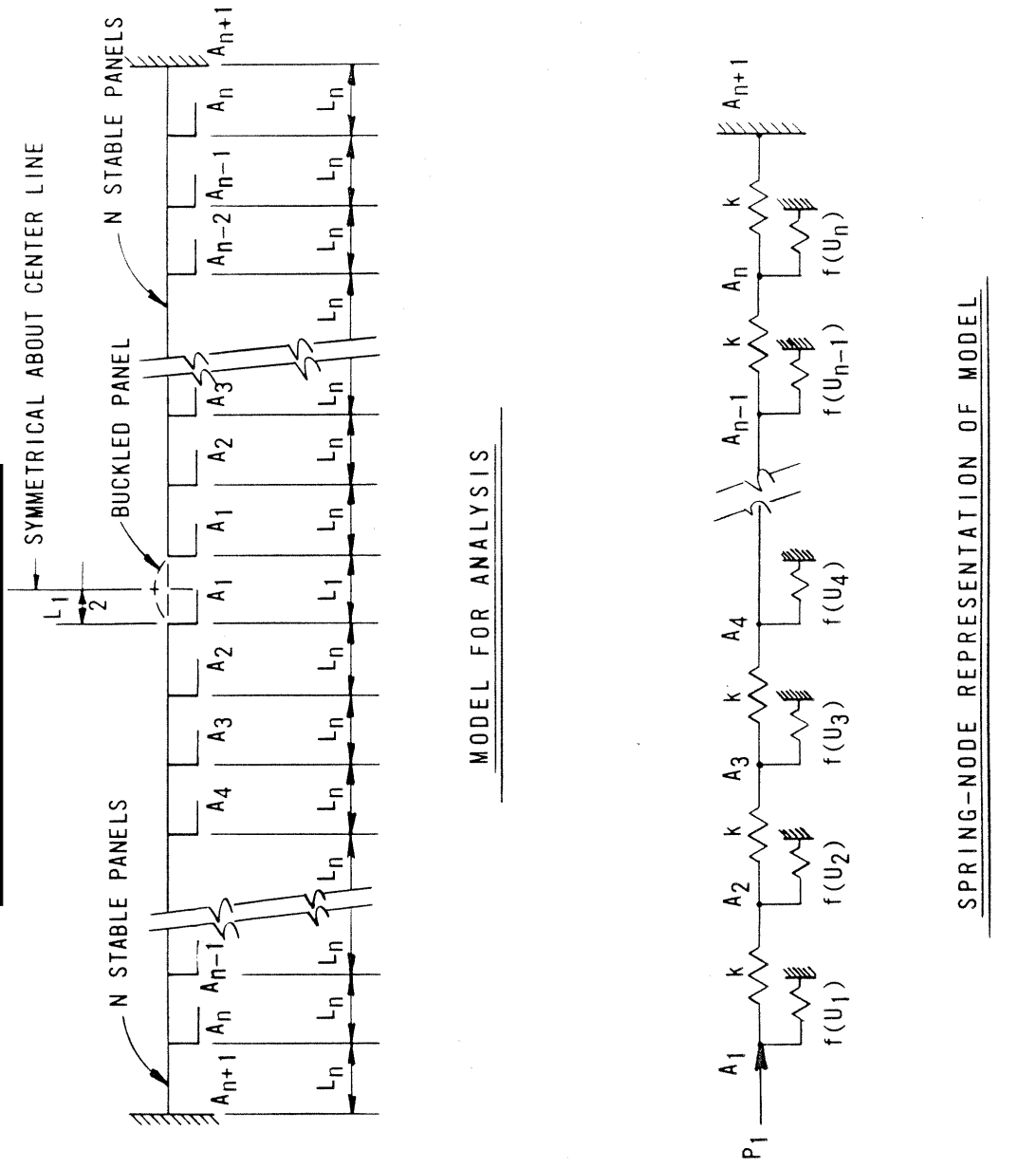


Figure 3.8-30a

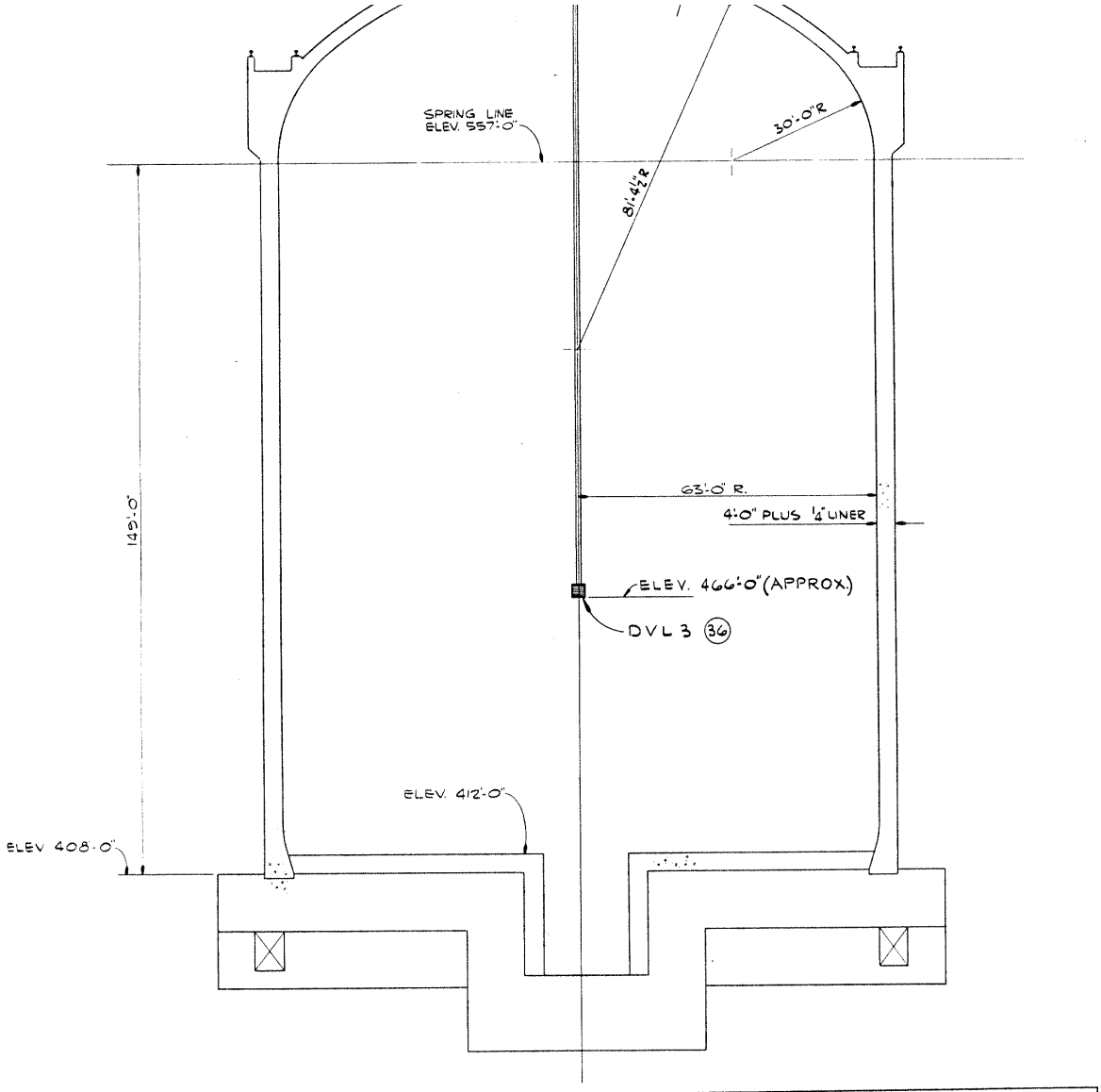
LINER - ANCHORAGE MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Liner - Anchorage Model Figure 3.8-30a

Figure 3.8-31

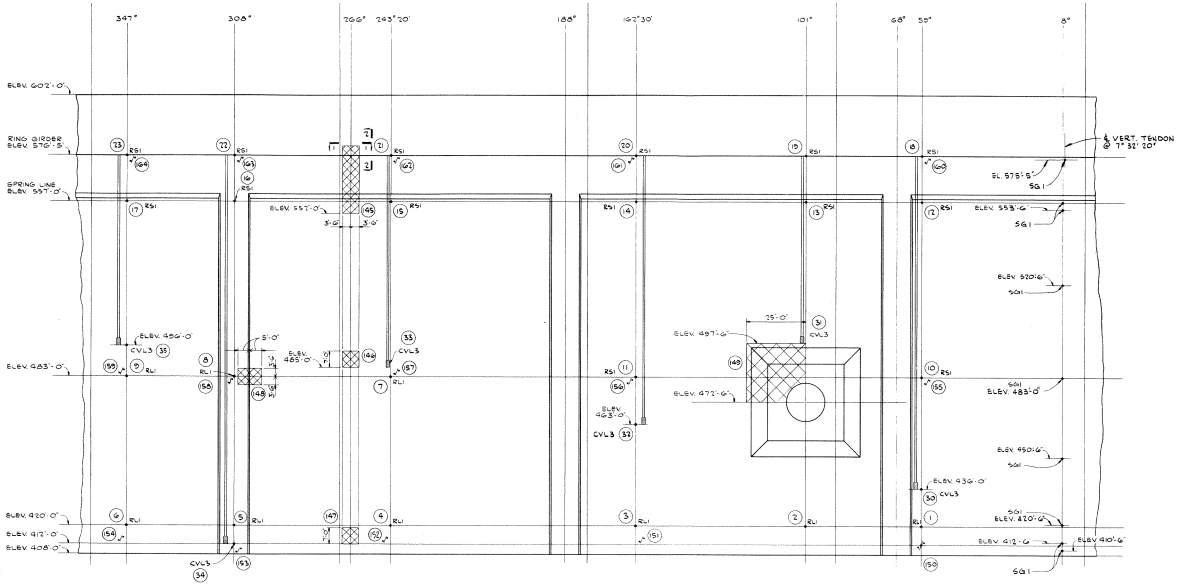
STRUCTURAL ACCEPTANCE TEST
INSTRUMENTATION REACTOR BUILDING
CROSS SECTION AND LOCATION

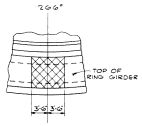


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Structural Acceptance Test Instrumentation Reactor Building Cross Section and Location Figure 3.8-31

Figure 3.8-32

STRUCTURAL ACCEPTANCE TEST
INSTRUMENTATION - LAYOUT AND LOCATION -
REACTOR BUILDING EXTERIOR STRETCHOUT
(GAI DWG. NO D-400-223)





SECTION 1-1

SECTION 2-2
FOR CRACK PATTERN

NOTES: -
A. CYLINDER AND DOME RADIAL DISPLACEMENTS
1. BOBT'S RL1
2. SCALE AND TRANSITS RSI
B. EQUIPMENT ACCESS RADIAL, TANGENTIAL, AND VERTICAL DISPLACEMENT
1. BOBT'S RL2, RL3, TL2, (RVEL2)
C. CYLINDER AND DOME VERTICAL DISPLACEMENT
1. INVAR TAPE AND BOBT RVL3
2. INVAR TAPES AND BOBT'S CVL3

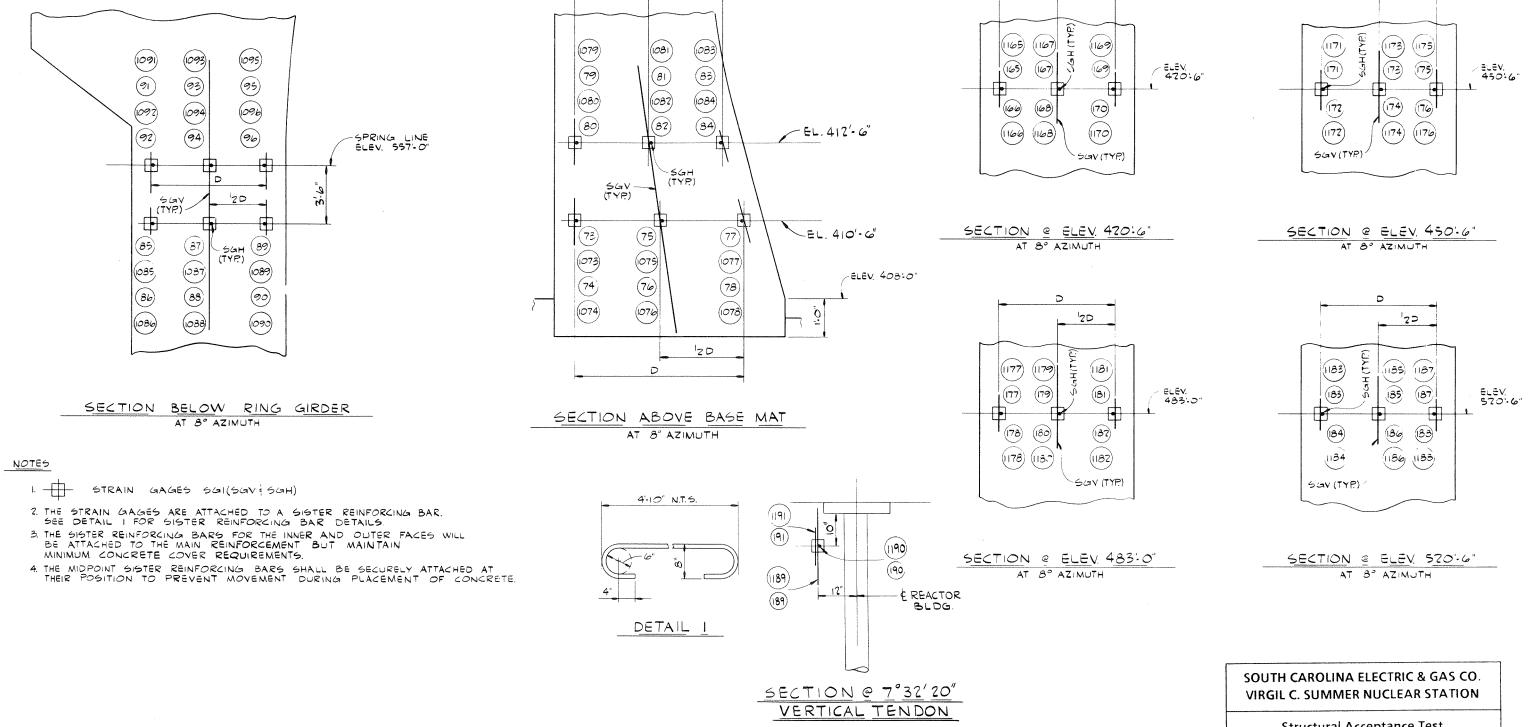
NOTES: - (CONTINUED)
D. CRACK PATTERN
1. SPECIAL PAINT
E. STRAIN MEASUREMENTS OF CYLINDER, EQUIPMENT ACCESS, RING GIRDER, AND CONCRETE UNDER VERTICAL TENDON
1. STRAIN GAGES SG
F. TEMPERATURE MEASUREMENTS
1. THERMOCOUPLES

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Structural Acceptance Test
Instrumentation - Layout and Location -
Reactor Building Exterior Stretchout
(GAI Dwg. No. D-400-223)
Figure 3.8-32

Figure 3.8-33

STRUCTURAL ACCEPTANCE TEST
INSTRUMENTATION - LAYOUT AND LOCATION -
REACTOR BUILDING SECTION AT 8° AZIMUTH



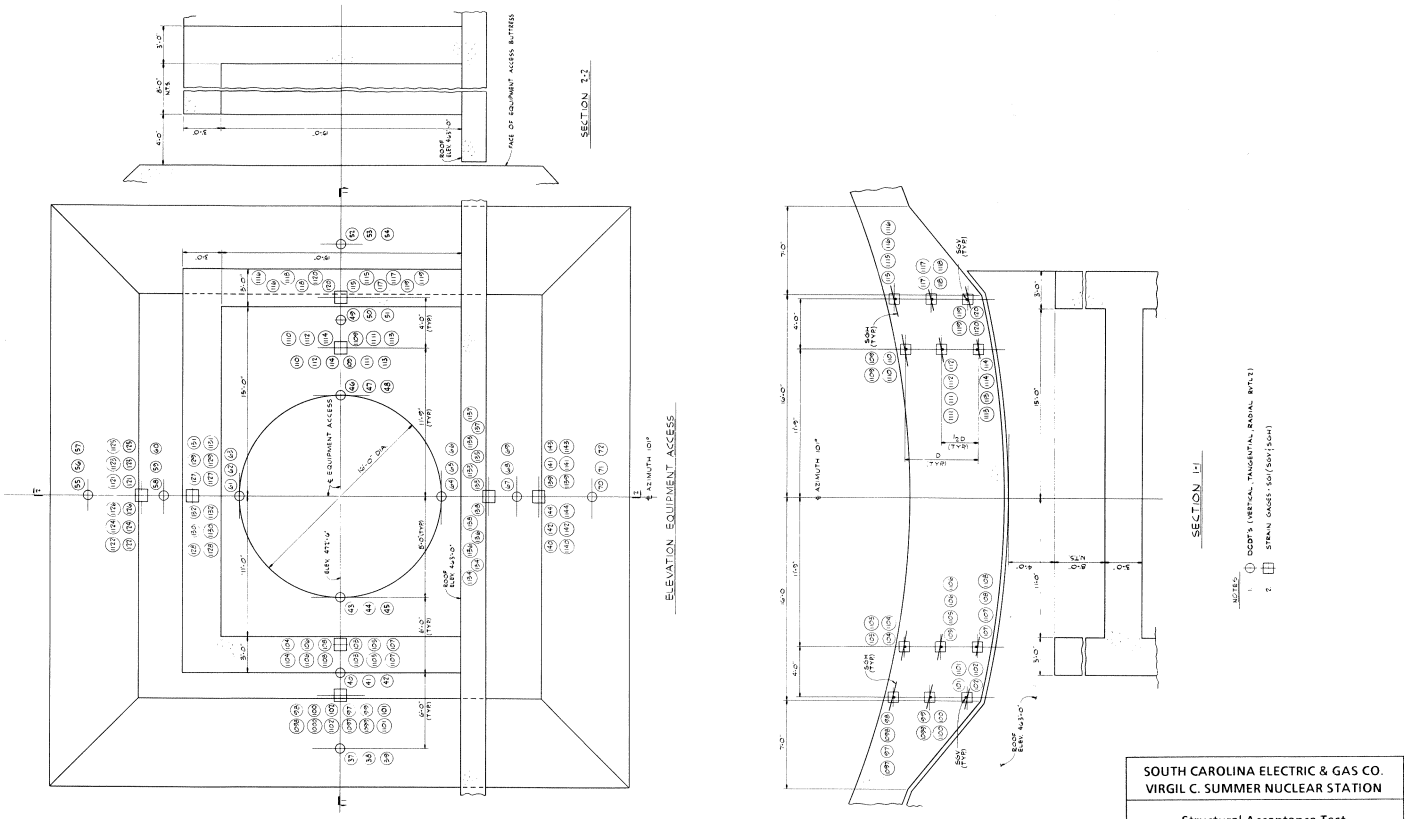
NOTES

1. ⊕ STRAIN GAGES SGI(SGV ; SGH)
2. THE STRAIN GAGES ARE ATTACHED TO A SISTER REINFORCING BAR. SEE DETAIL 1 FOR SISTER REINFORCING BAR DETAILS.
3. THE SISTER REINFORCING BARS FOR THE INNER AND OUTER FACES WILL BE ATTACHED TO THE MAIN REINFORCEMENT BUT MAINTAIN MINIMUM CONCRETE COVER REQUIREMENTS.
4. THE MIDPOINT SISTER REINFORCING BARS SHALL BE SECURELY ATTACHED AT THEIR POSITION TO PREVENT MOVEMENT DURING PLACEMENT OF CONCRETE.

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Structural Acceptance Test Instrumentation - Layout and Location - Reactor Building Section at 8° Azimuth Figure 3.8-33

Figure 3.8-34

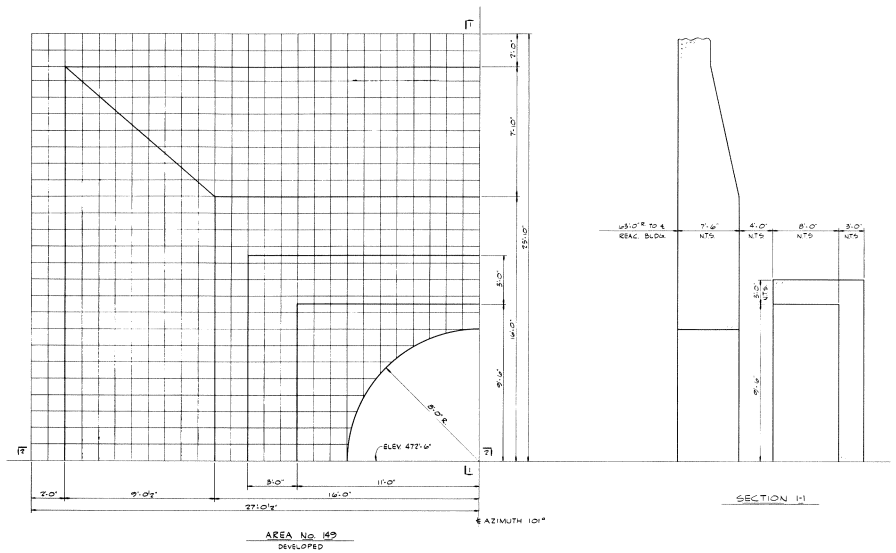
STRUCTURAL ACCEPTANCE TEST
INSTRUMENTATION - LAYOUT AND LOCATION
EQUIPMENT ACCESS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Structural Acceptance Test Instrumentation - Layout and Location Equipment Access Figure 3.8-34

Figure 3.8-35

STRUCTURAL ACCEPTANCE TEST
INSTRUMENTATION - LAYOUT AND LOCATION
CRACK PATTERNS - EQUIPMENT ACCESS



NOTES:
1. 1'-0" x 1'-0" GRID SHOWN TO AID SKETCHING OF CRACK PATTERNS
2. CRACK PATTERN WILL ESSENTIALLY BE THAT OF EXISTING HAIRLINE SHRINKAGE CRACKS. CRACK WIDTHS SHOULD BE LESS THAN .010

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Structural Acceptance Test Instrumentation - Layout and Location Crack Patterns - Equipment Access Figure 3.8-35

Figure 3.8-36

STRUCTURAL ACCEPTANCE TEST
INSTRUMENTATION - LAYOUT AND LOCATION
CRACK PATTERNS - WALL AND DOME JUNCTION

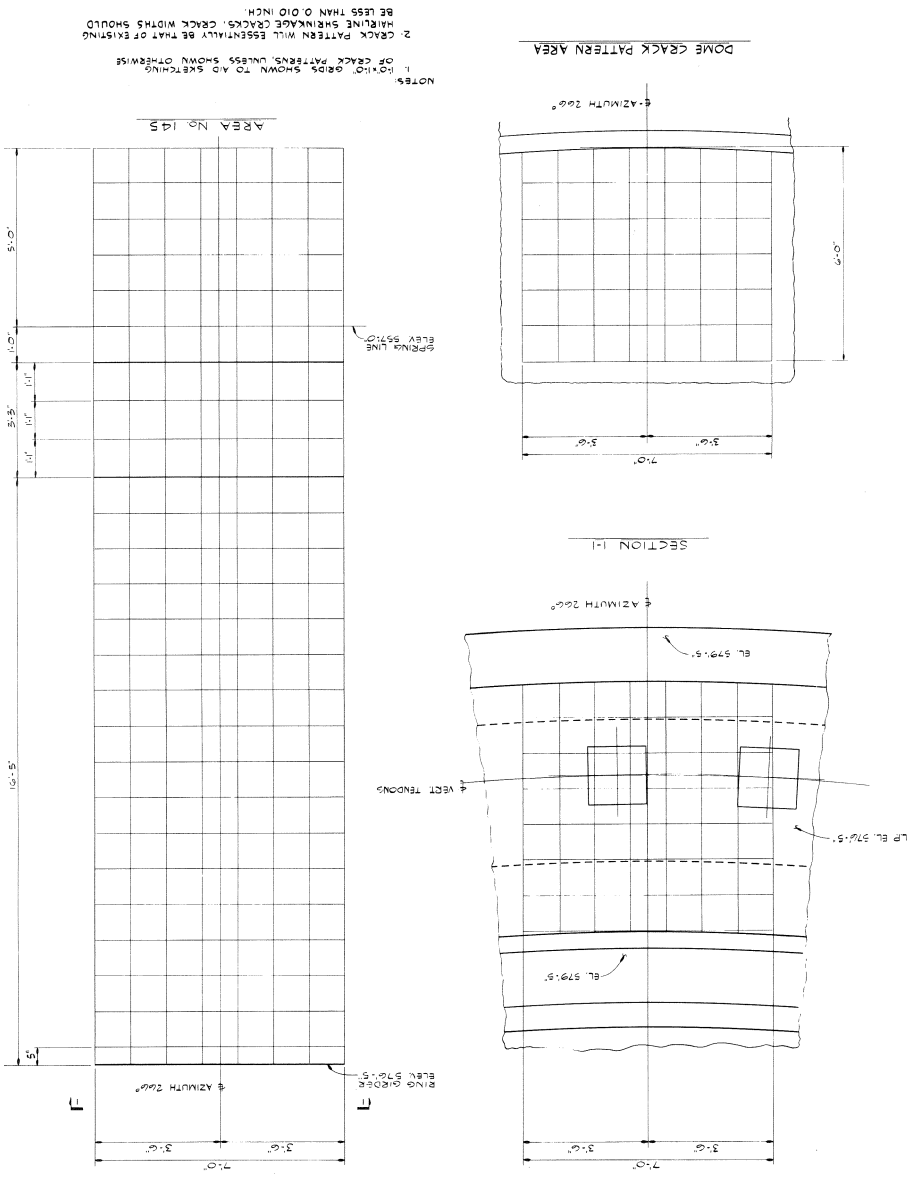
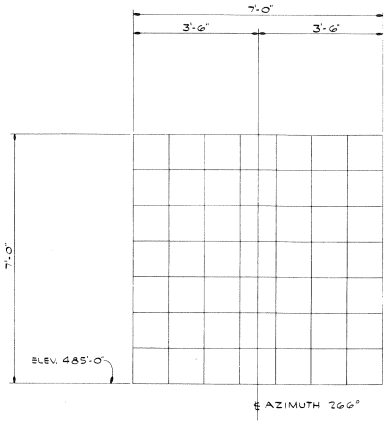
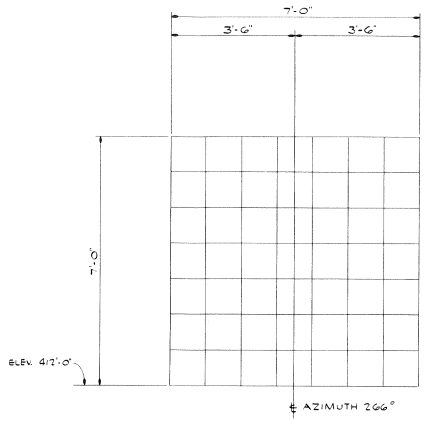


Figure 3.8-37

STRUCTURAL ACCEPTANCE TEST
INSTRUMENTATION - LAYOUT AND LOCATION
CRACK PATTERNS - WALLS



AREA No. 146



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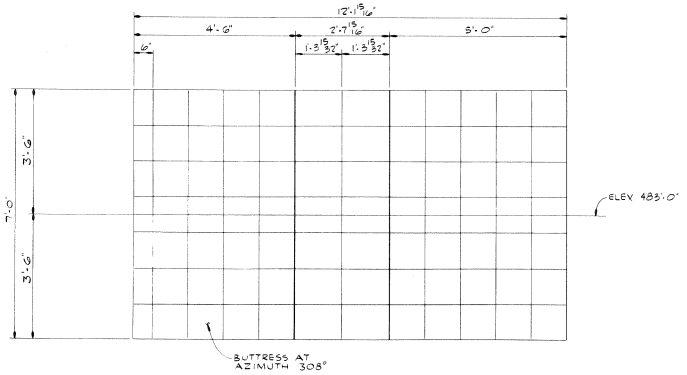


AREA No. 148

NOTES:

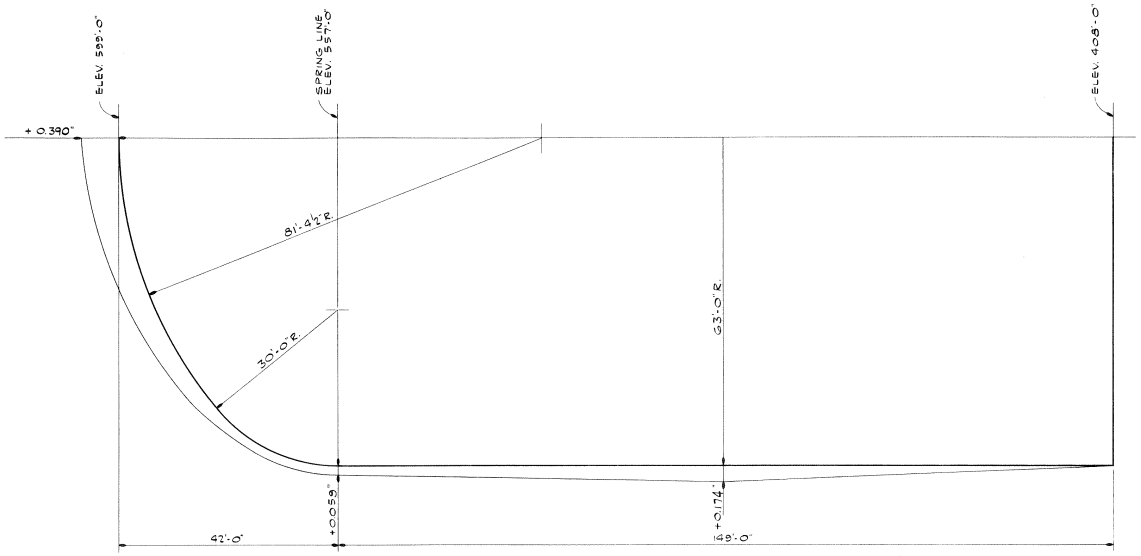
1. 1'-0" x 1'-0" GRID SHOWN TO AID SKETCHING OF CRACK PATTERN

2. CRACK PATTERN WILL ESSENTIALLY BE THAT OF EXISTING HAIRLINE SHRINKAGE CRACKS. CRACK WIDTHS SHOULD BE LESS THAN 0.010 INCH.

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Structural Acceptance Test Instrumentation Layout and Location Crack Patterns - Walls Figure 3.8-37

Figure 3.8-38

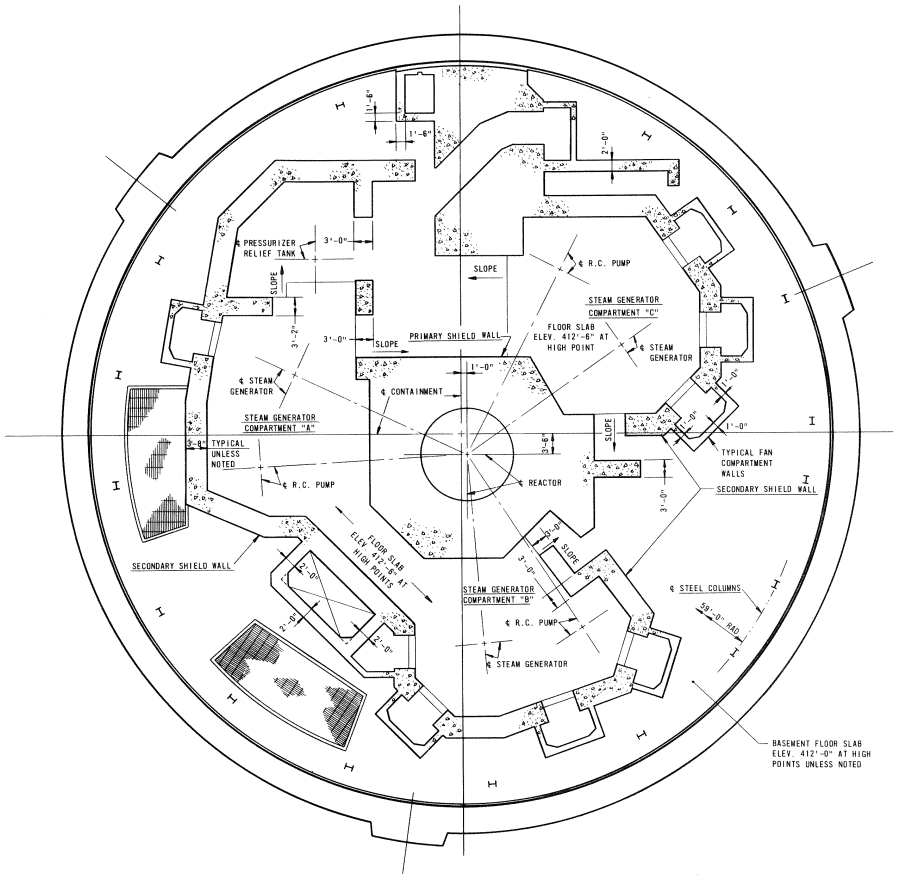
STRUCTURAL ACCEPTANCE TEST TYPICAL RADIAL DISPLACEMENTS - REACTOR BUILDING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Structural Acceptance Test Typical Radial Displacements - Reactor Building Figure 3.8-38

Figure 3.8-39

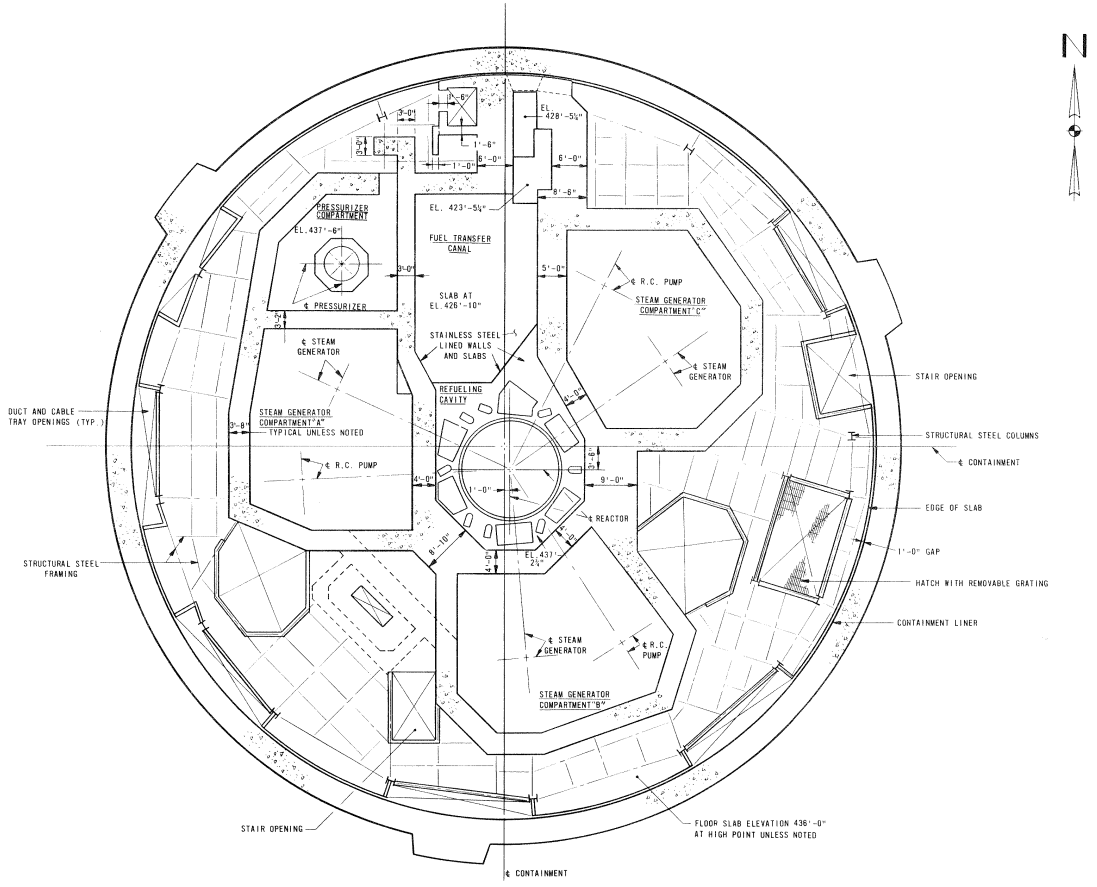
REACTOR BUILDING INTERIOR STRUCTURES PLAN ABOVE ELEVATION 412' - 0"



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Building Interior Structures Plan Above Elevation 412' - 0" Figure 3.8-39

Figure 3.8-40

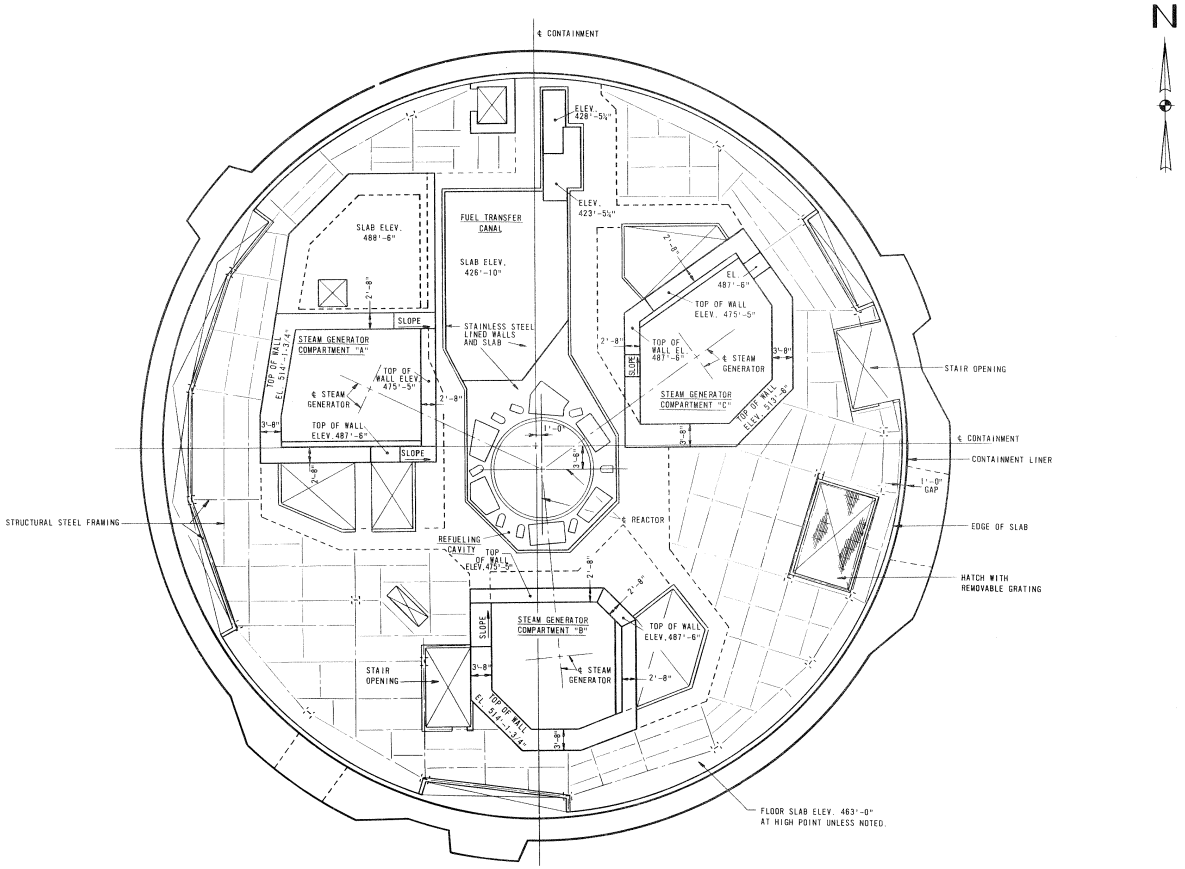
REACTOR BUILDING INTERIOR STRUCTURES PLAN ABOVE ELEVATION 436' - 0"



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Building Interior Structures Plan Above Elevation 436' - 0" Figure 3.8-40

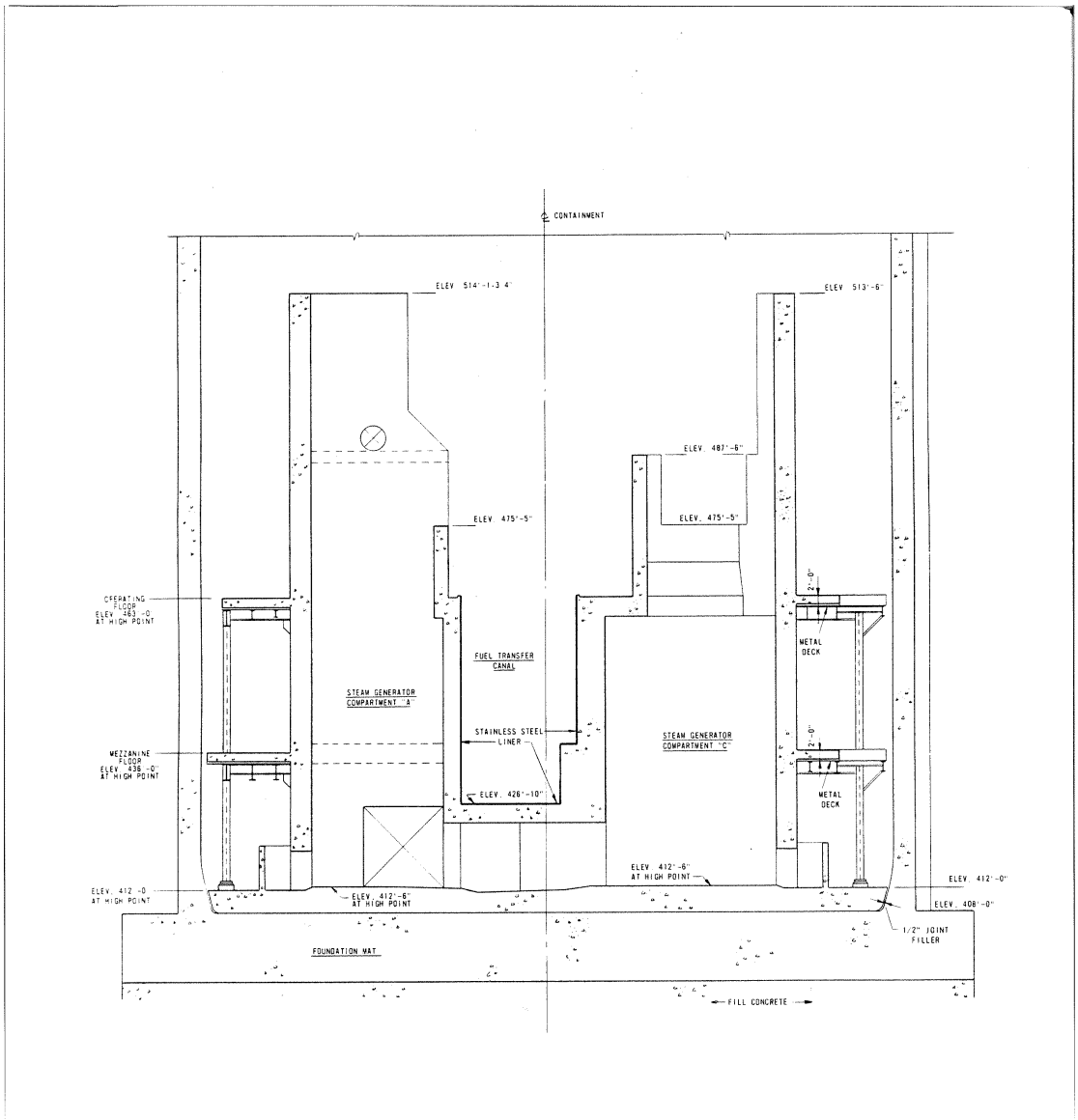
Figure 3.8-41

REACTOR BUILDING INTERIOR STRUCTURES PLAN ABOVE ELEVATION 463' - 0"



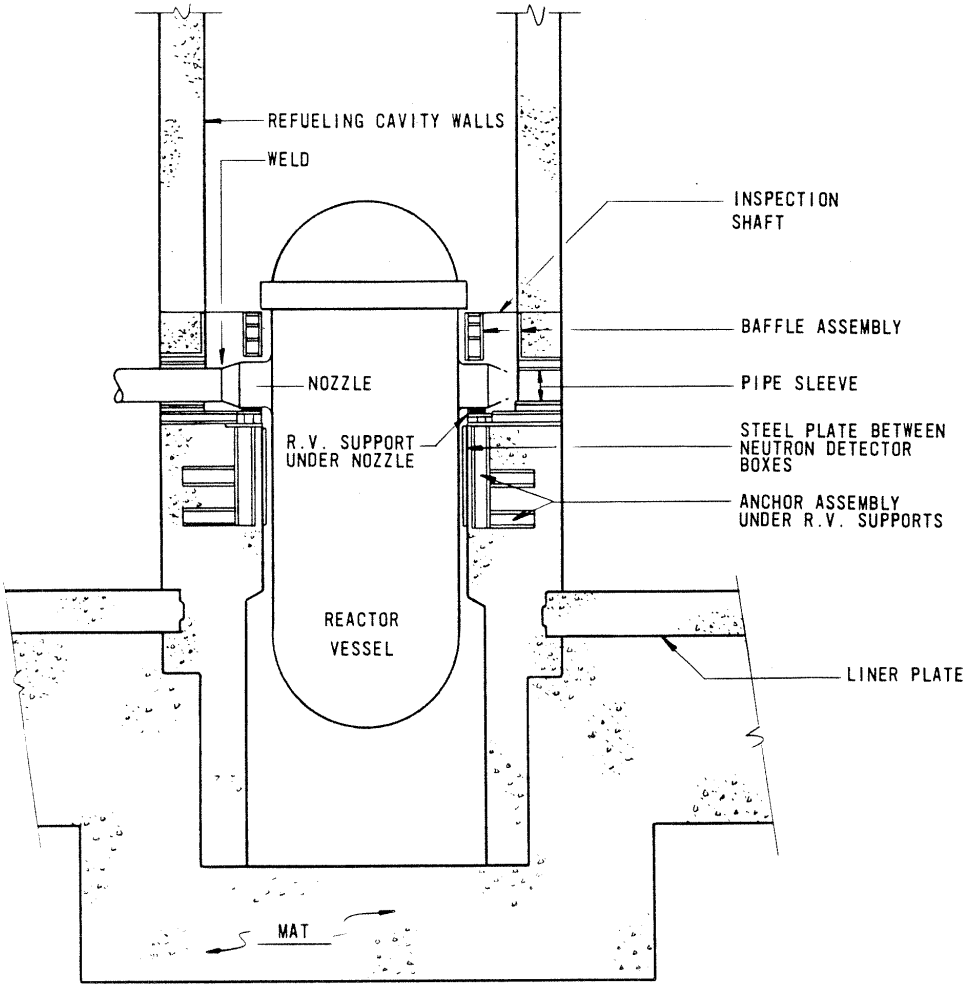
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Building Interior Structures Plan Above Elevation 463' - 0" Figure 3.8-41

Figure 3.8-42
SECTION THROUGH REACTOR BUILDING
LOOKING NORTH



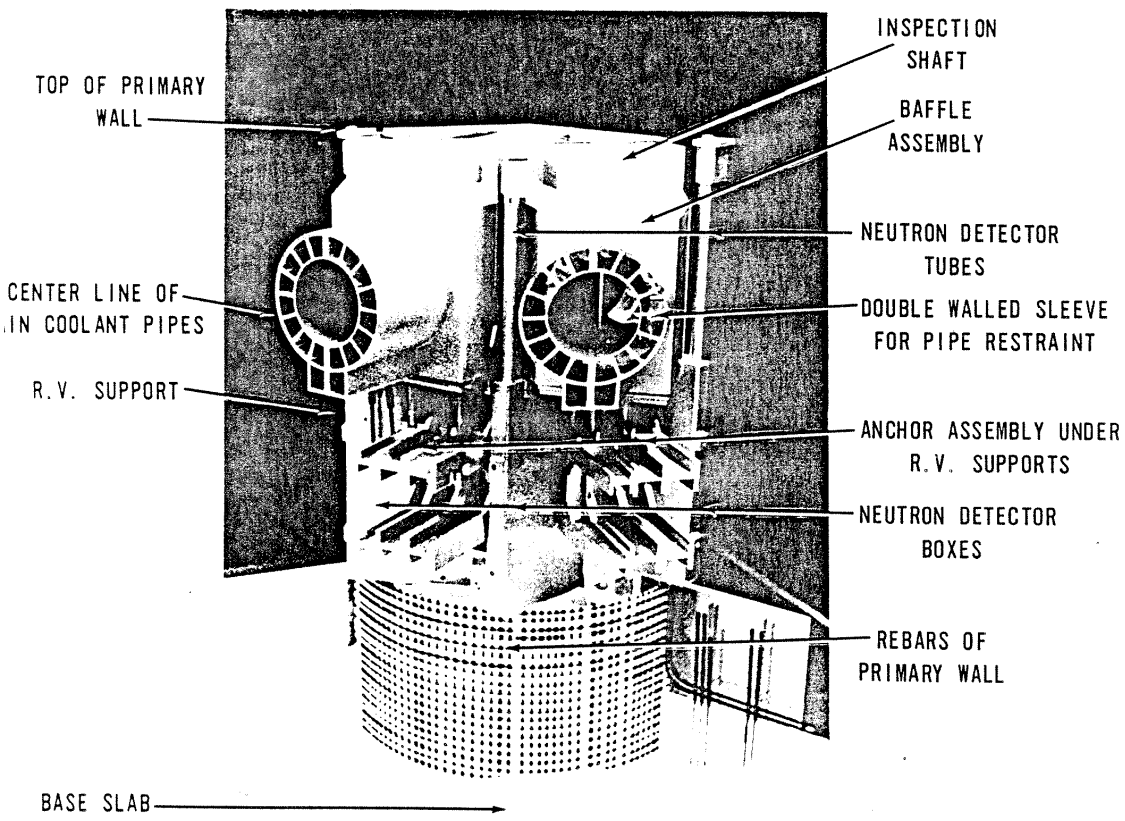
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Section Through Reactor Building Looking North
Figure 3.8-42

Figure 3.8-43
SECTION THROUGH PRIMARY SHIELD WALL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Section Through Primary Shield Wall Figure 3.8-43

Figure 3.8-44
OUTSIDE VIEW OF PRIMARY WALL

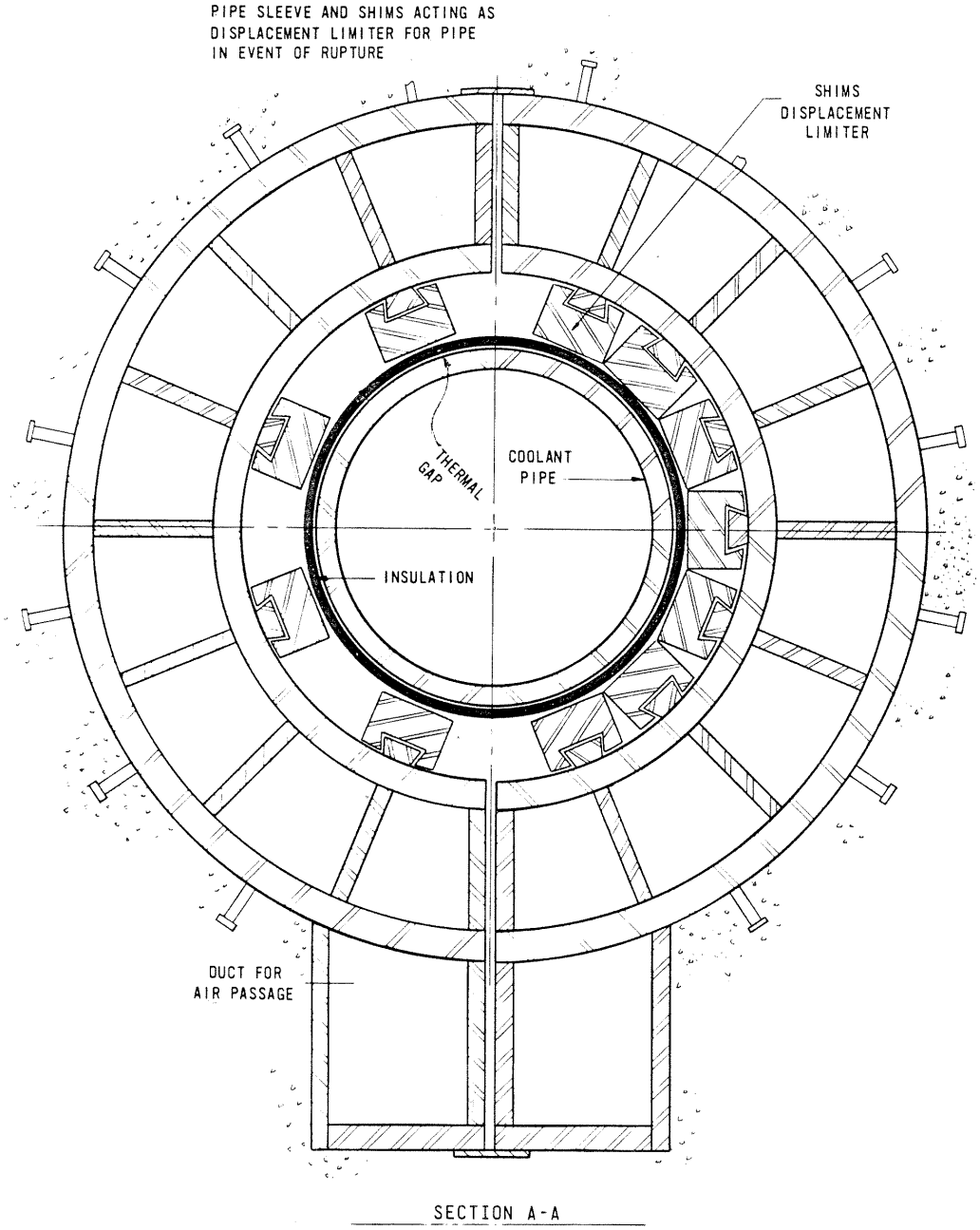


(CONCRETE NOT SHOWN FOR CLARITY)

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Outside View of Primary Wall Figure 3.8-44

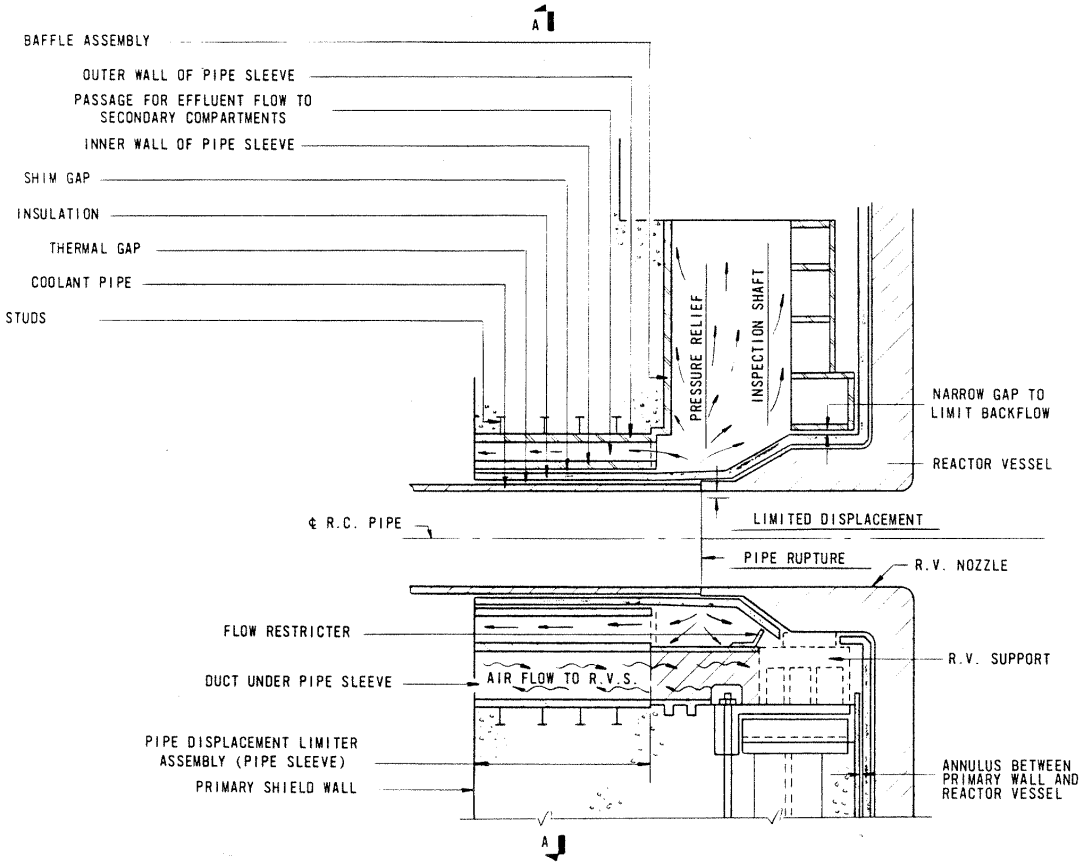
Figure 3.8-45

PRIMARY COOLANT PIPE SLEEVE



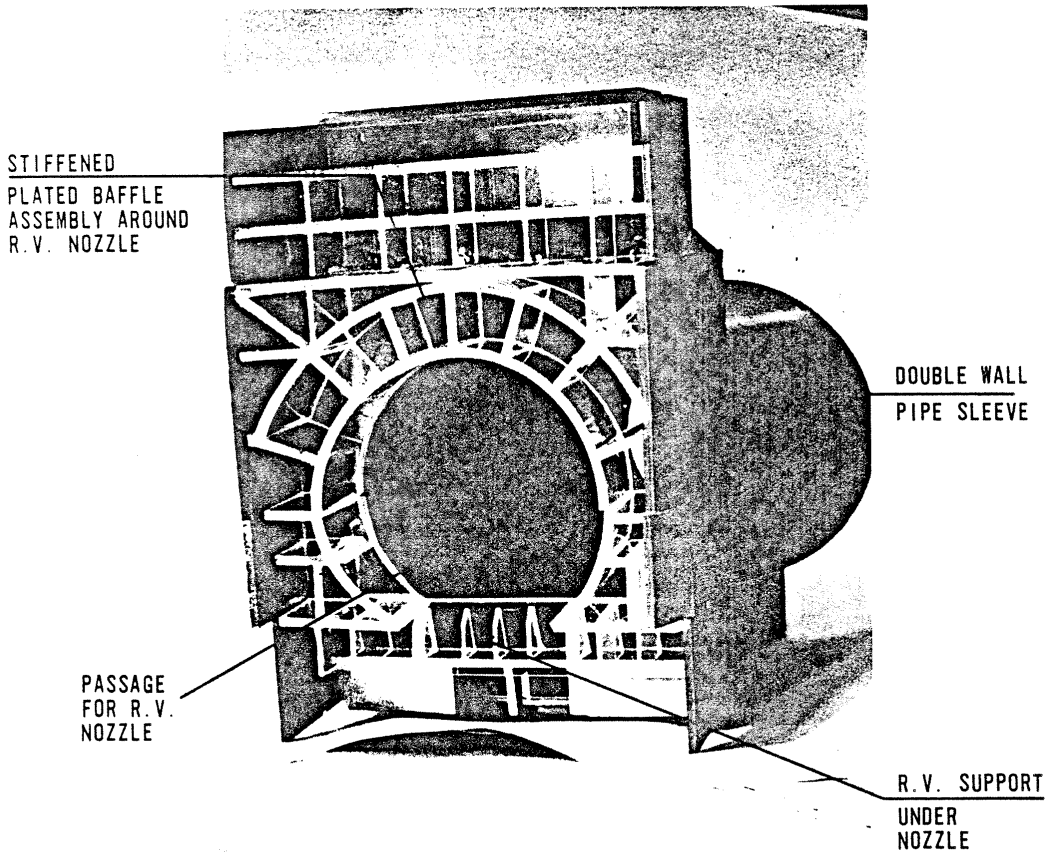
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Primary Coolant Pipe Sleeve Figure 3.8-45

Figure 3.8-46
SECTION THROUGH BAFFLE AND SLEEVE



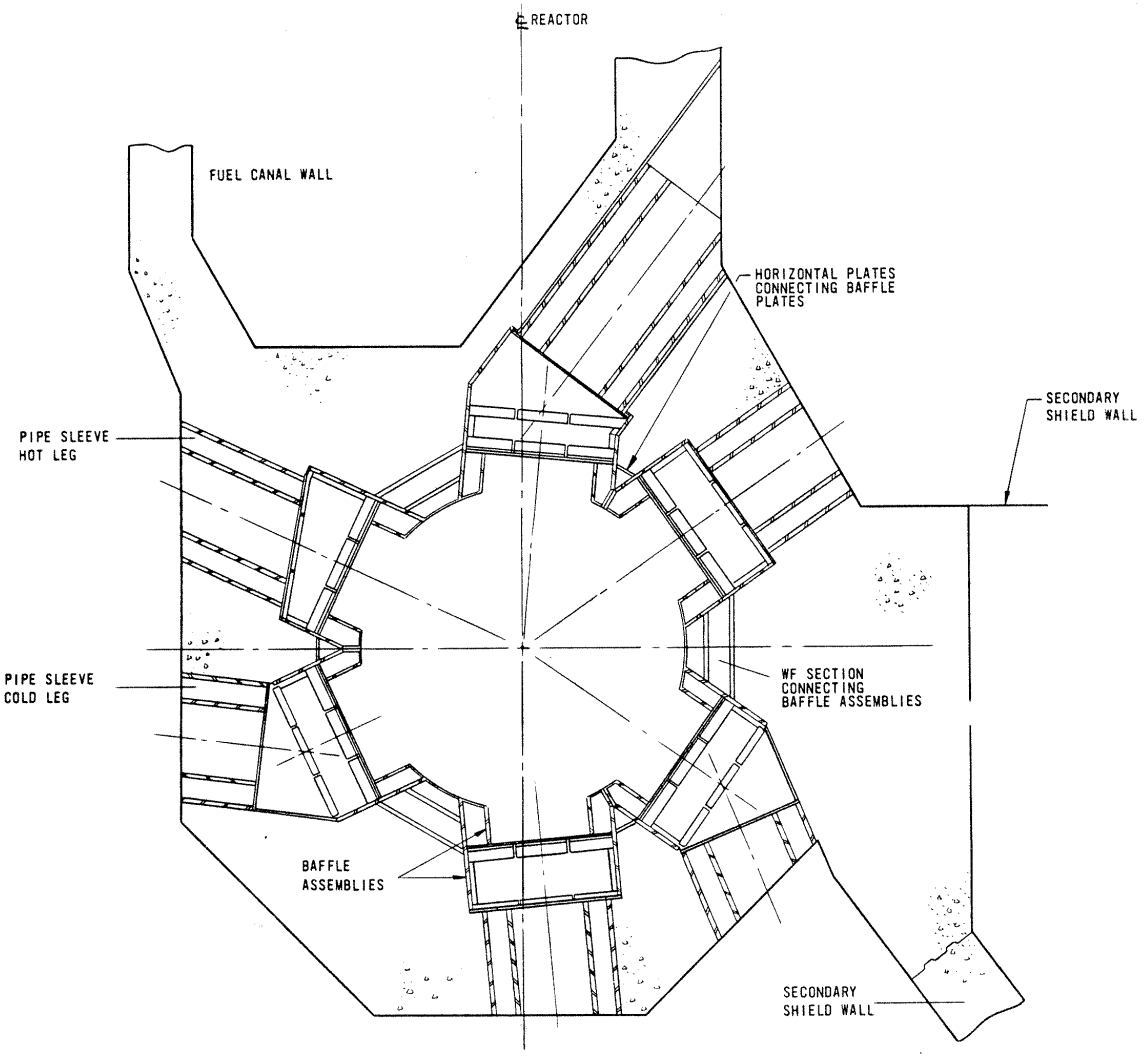
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Section Through Baffle and Sleeve Figure 3.8-46

Figure 3.8-47
INSIDE VIEW OF BAFFLE ASSEMBLY AROUND REACTOR VESSEL NOZZLE



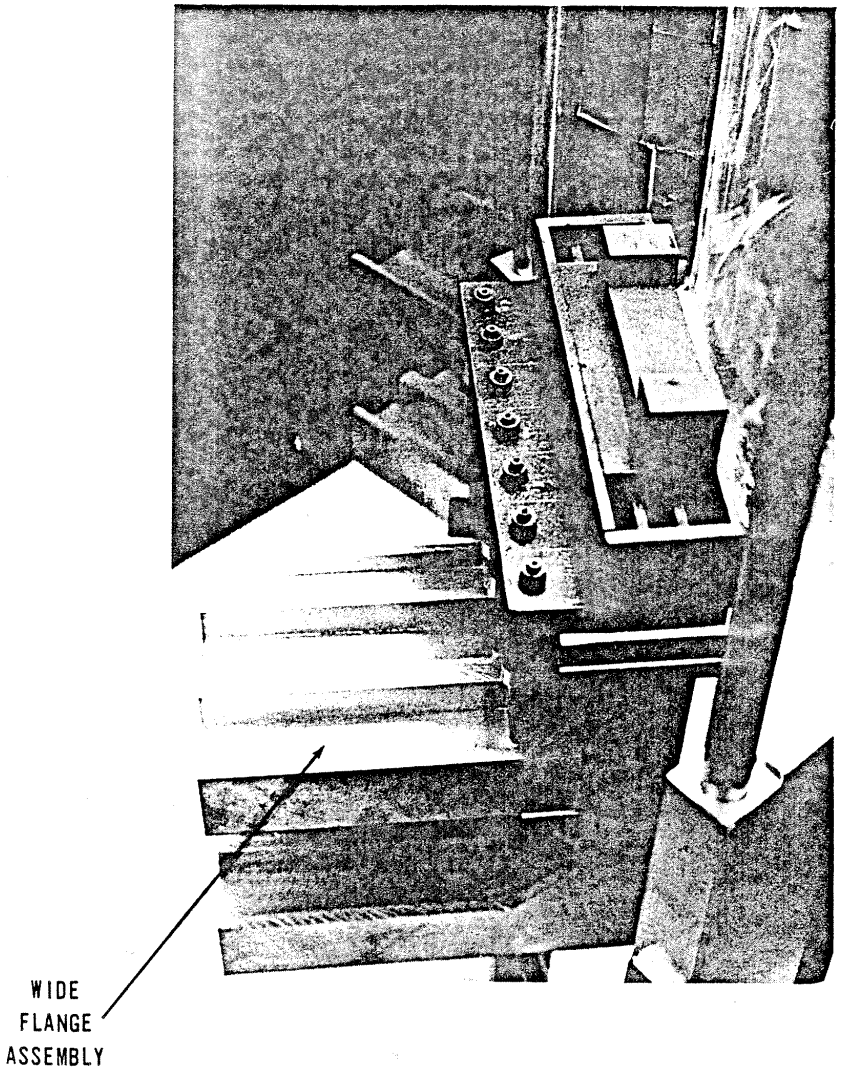
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Inside View of Baffle Assembly Around Reactor Vessel Nozzle Figure 3.8-47

Figure 3.8-48
PLAN VIEW OF BAFFLE ASSEMBLIES



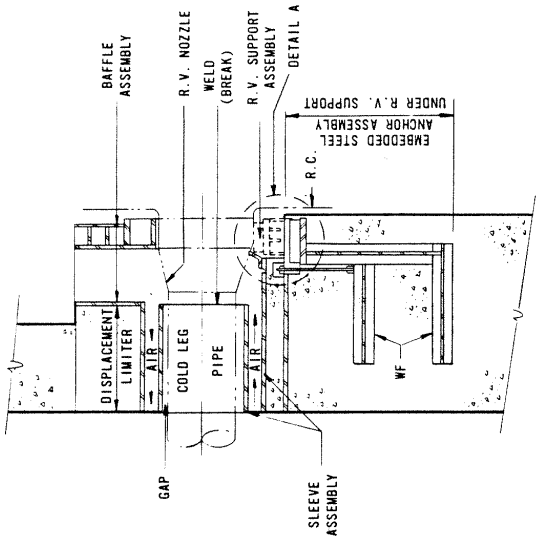
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Plan View of Baffle Assemblies Figure 3.8-48

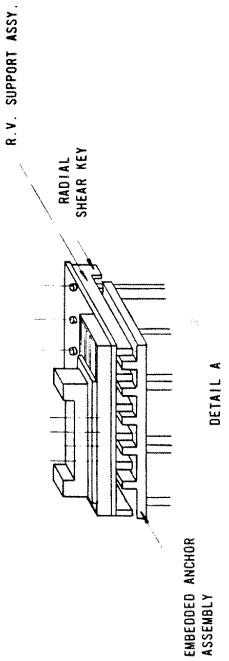
Figure 3.8-49
REACTOR VESSEL SUPPORT AND WIDE FLANGE ANCHOR ASSEMBLY



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Vessel Support and Wide Flange Anchor Assembly Figure 3.8-49

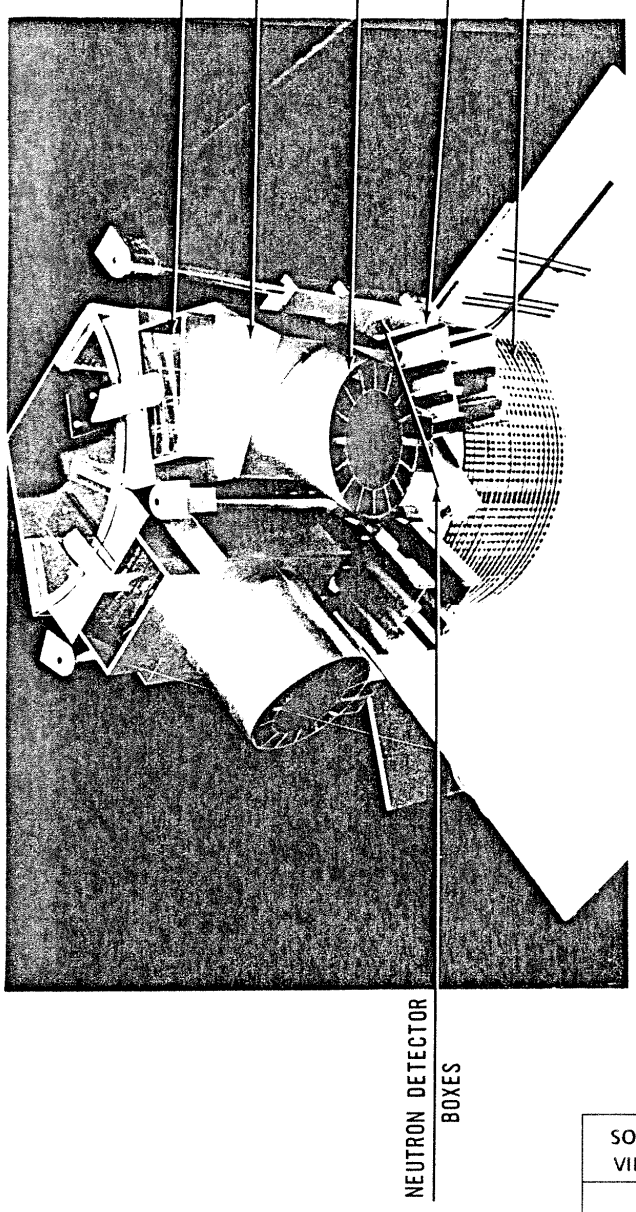
Figure 3.8-50
REACTOR PRESSURE VESSEL ANCHORAGE ASSEMBLY





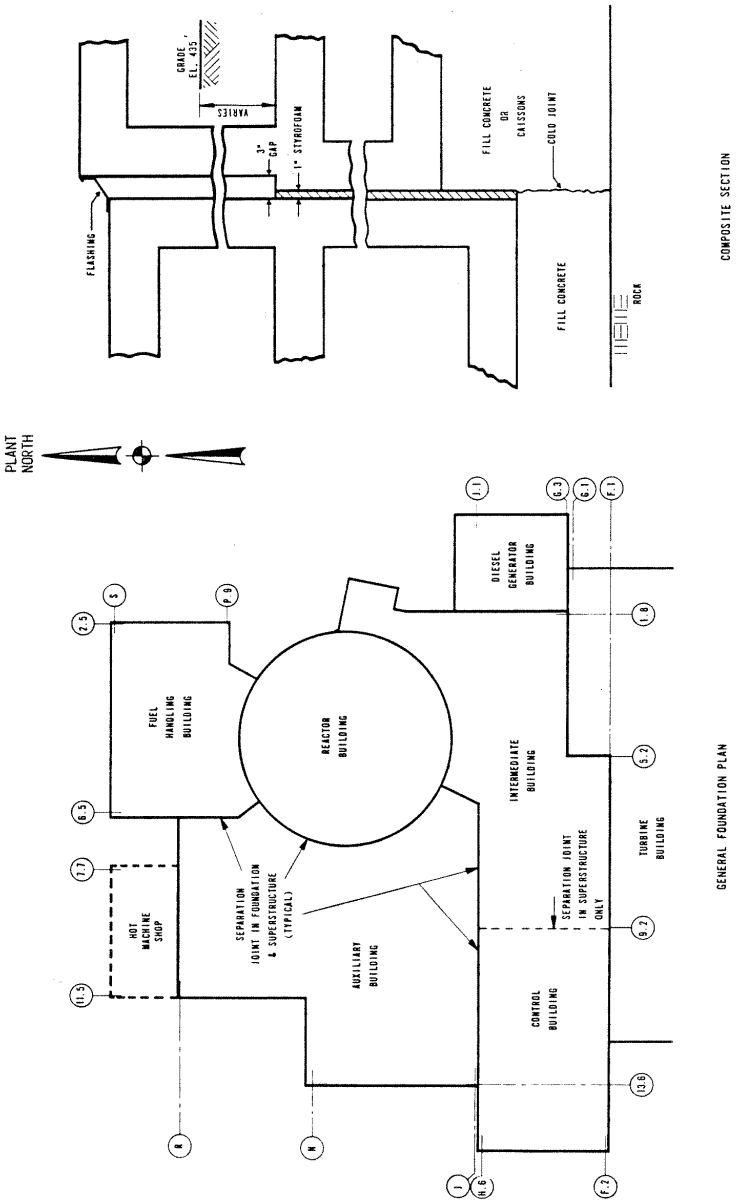
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Pressure Vessel Anchorage Assembly
Figure 3.8-50

Figure 3.8-51
OUTSIDE VIEW OF PRIMARY WALL



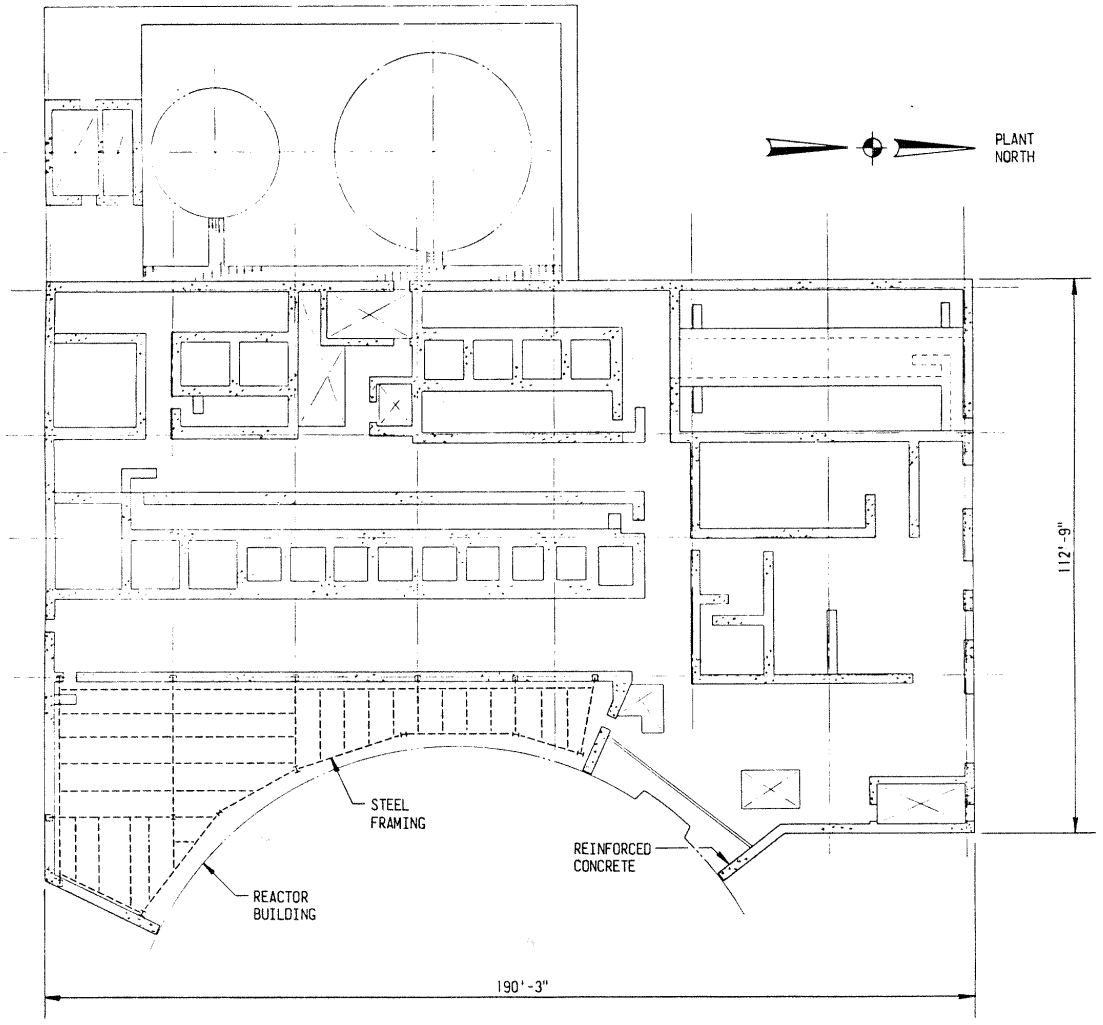
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Outside View of Primary Wall
Figure 3.8-51

Figure 3.8-52
GENERAL FOUNDATION PLAN AND COMPOSITE SECTION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
General Foundation Plan and Composite Section
Figure 3.8-52

Figure 3.8-53
PLAN AUXILIARY BUILDING MEZZANINE
FLOOR ELEVATION 436' - 0"

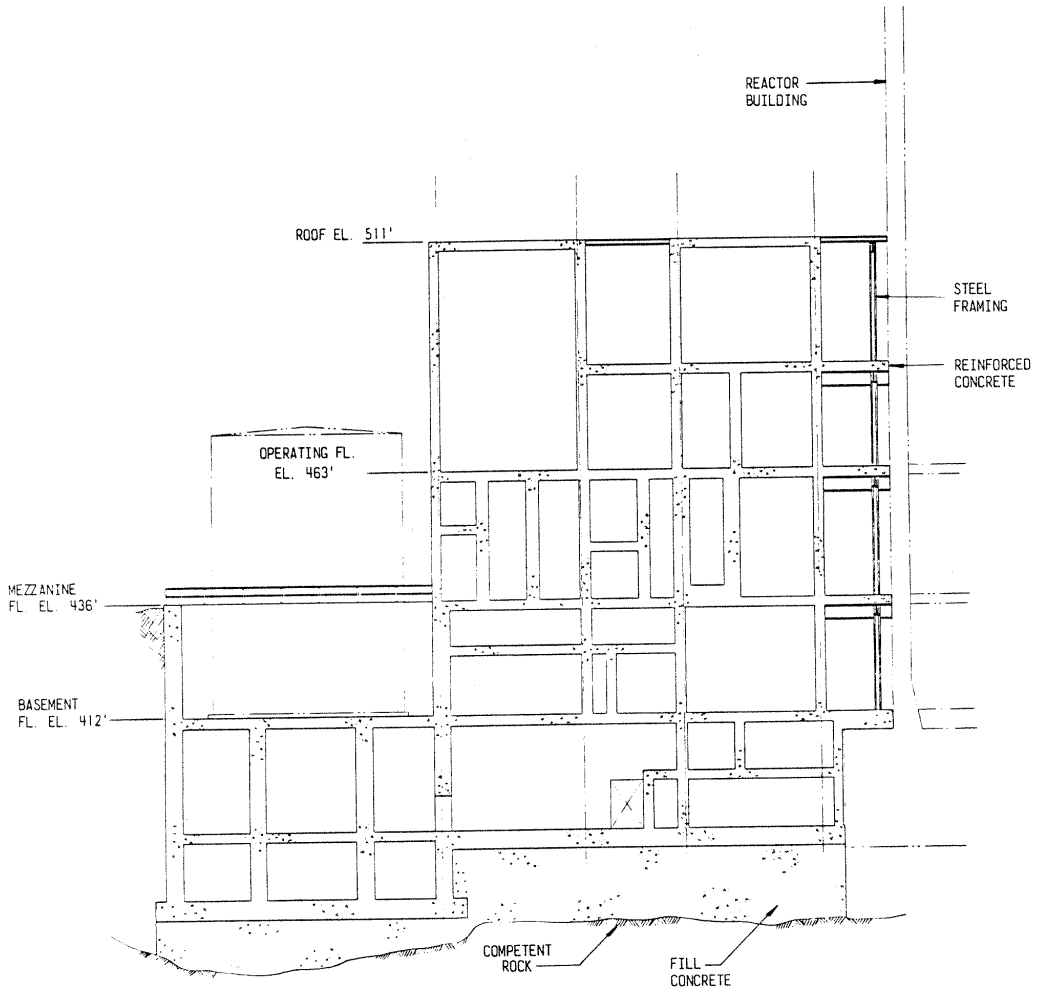


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Plan Auxiliary Building Mezzanine
Floor Elevation 436' - 0"

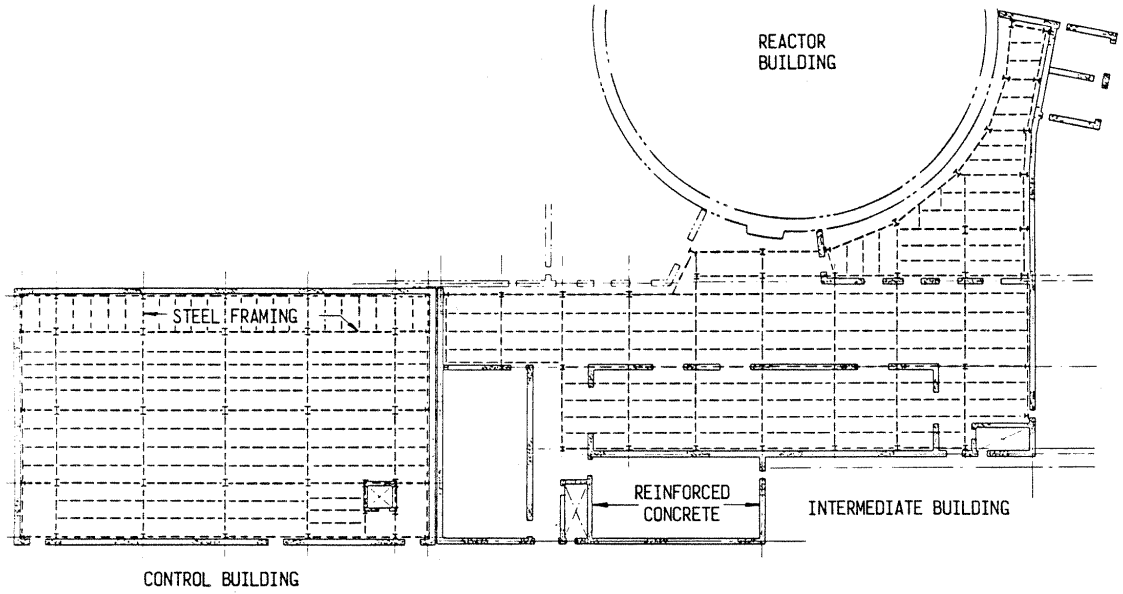
Figure 3.8-53

Figure 3.8-54
SECTION LOOKING NORTH THROUGH AUXILIARY BUILDING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Section Looking North Through Auxiliary Building Figure 3.8-54

Figure 3.8-55
PLAN CONTROL BUILDING AND INTERMEDIATE BUILDING MEZZANINE FLOOR ELEVATION 436' - 0"

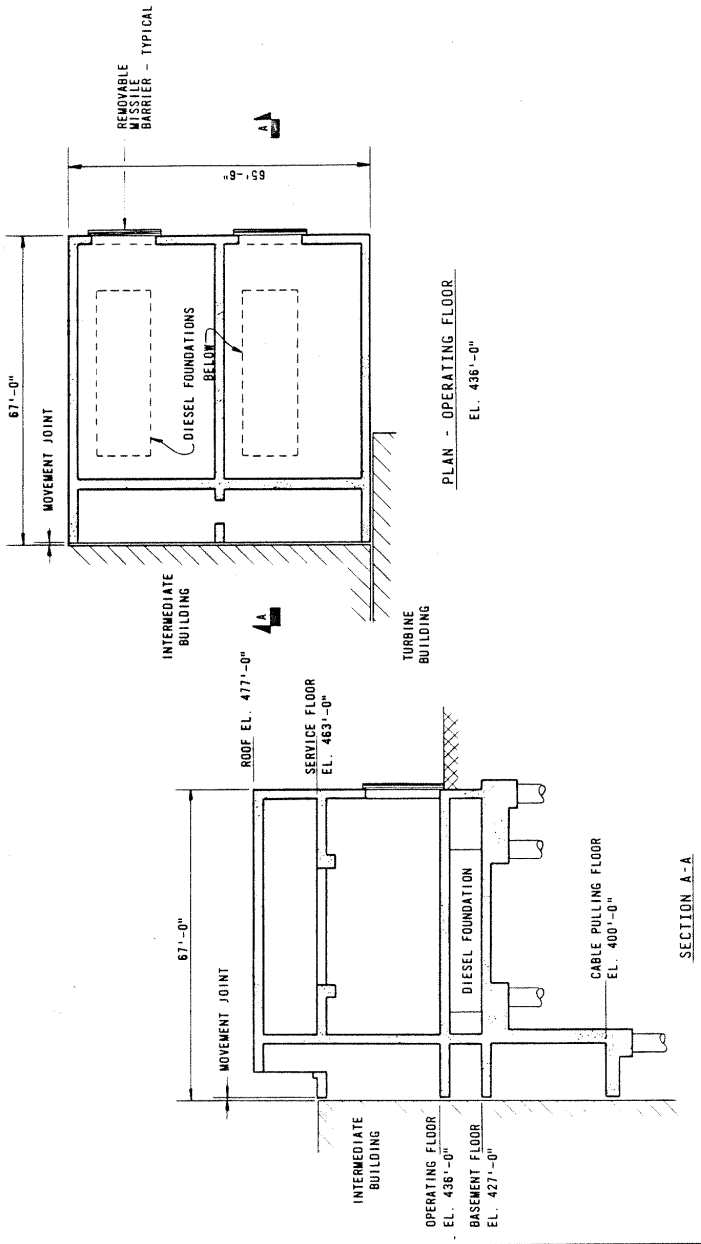


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Plan Control Building and Intermediate Building Mezzanine Floor Elevation 436' - 0"

Figure 3.8-55

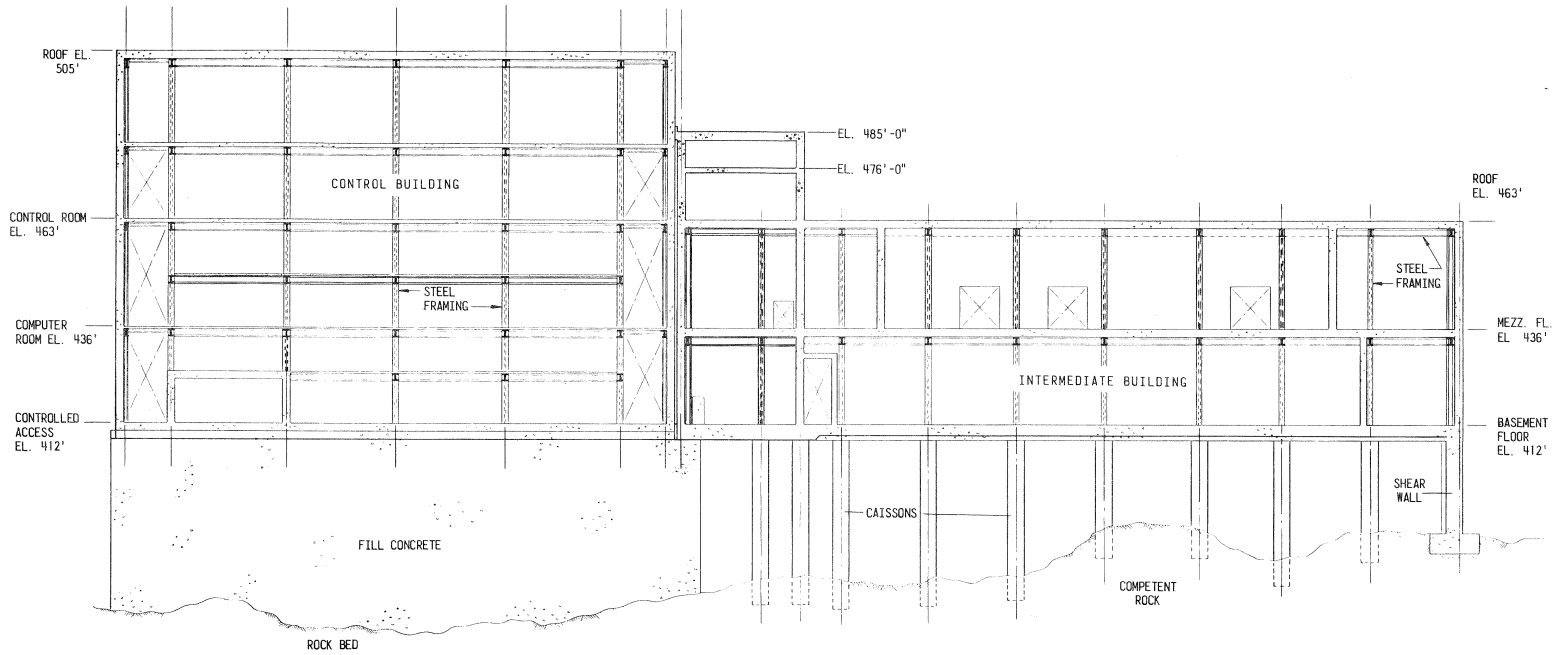
Figure 3.8-56
DIESEL GENERATOR BUILDING PLAN AND FOUNDATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Diesel Generator Building Plan and Foundation Figure 3.8-56

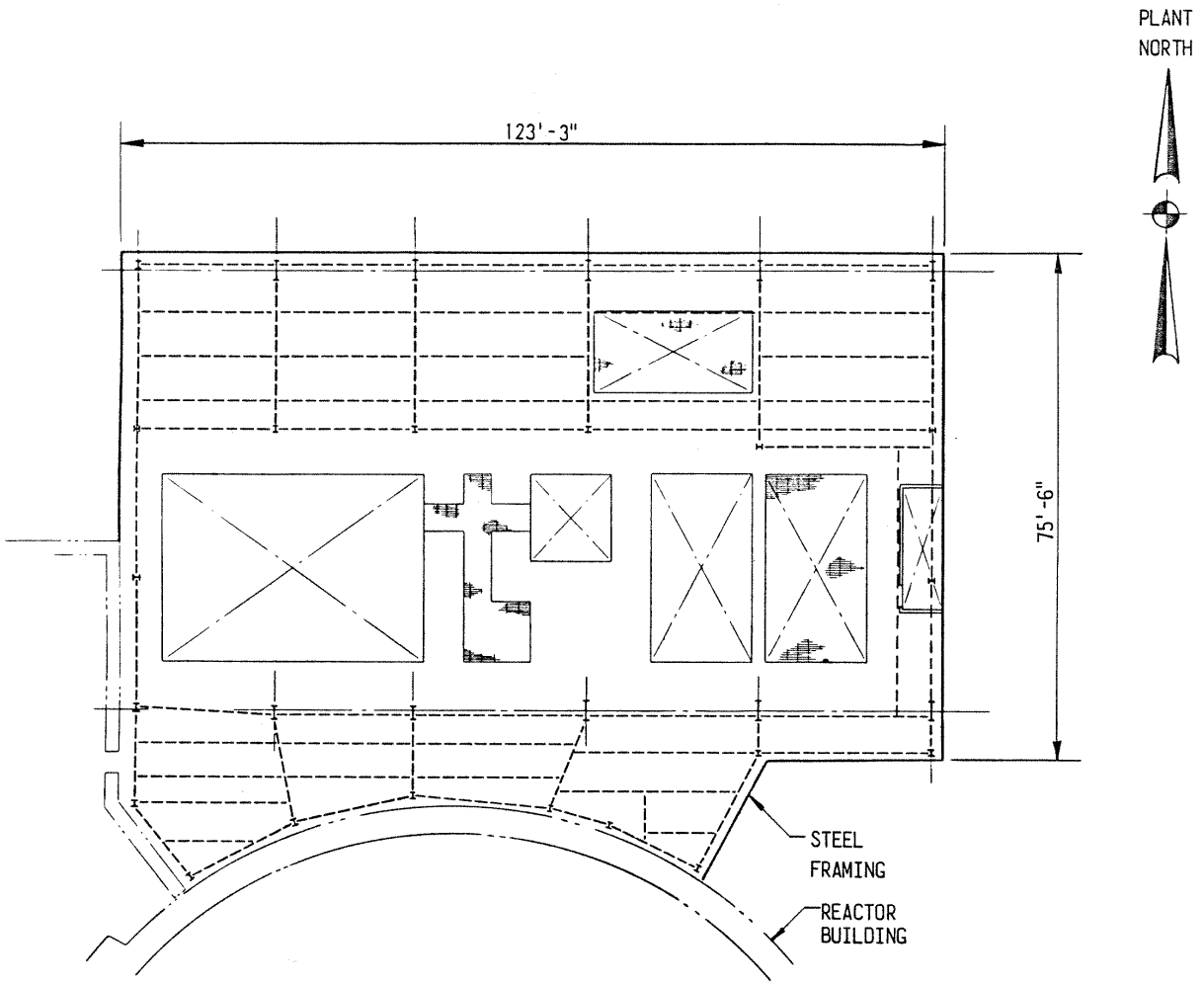
Figure 3.8-57

SECTION THROUGH INTERMEDIATE BUILDING AND CONTROL BUILDING LOOKING NORTH



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Section Through Intermediate Building and Control Building Looking North Figure 3.8-57

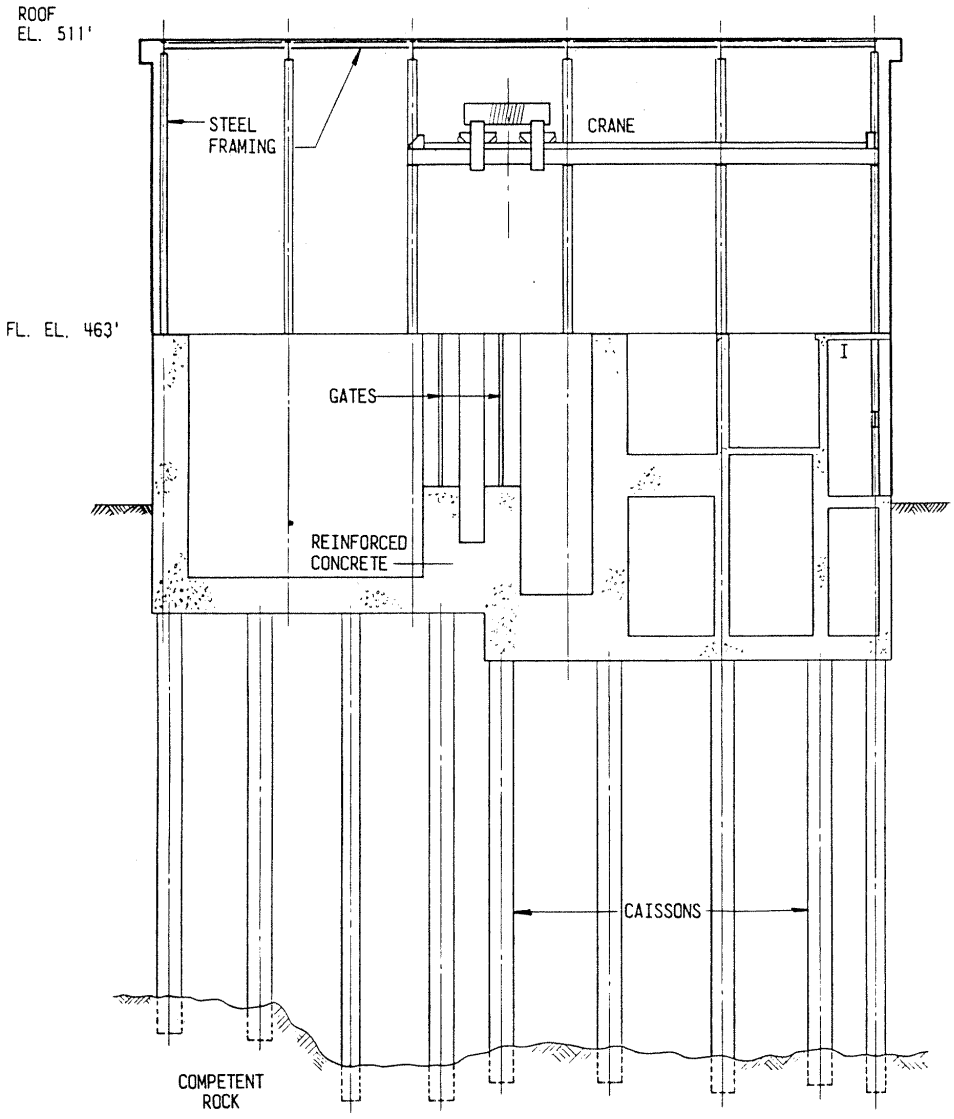
Figure 3.8-58
PLAN FUEL HANDLING BUILDING
OPERATING FLOOR



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Plan Fuel Handling Building Operating Floor Figure 3.8-58

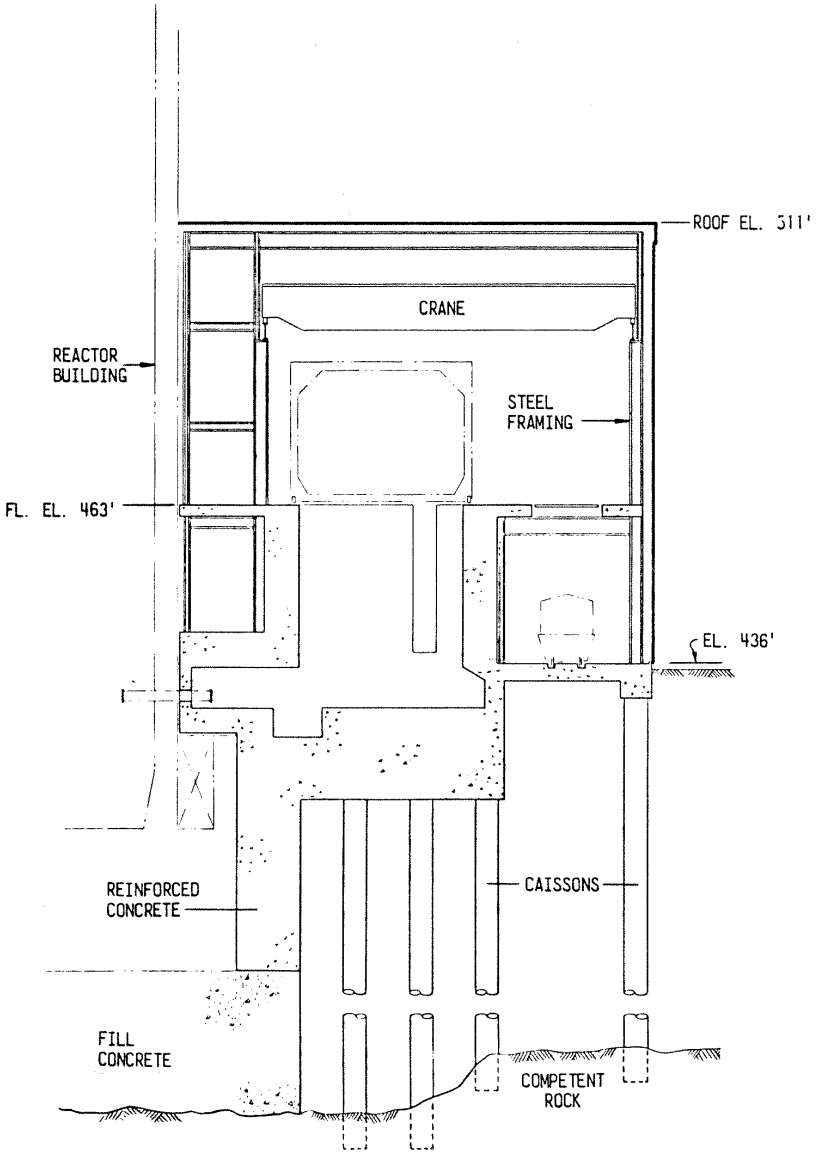
Figure 3.8-59

SECTION THROUGH FUEL HANDLING BUILDING
LOOKING NORTH



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Section Through Fuel Handling Building Looking North Figure 3.8-59

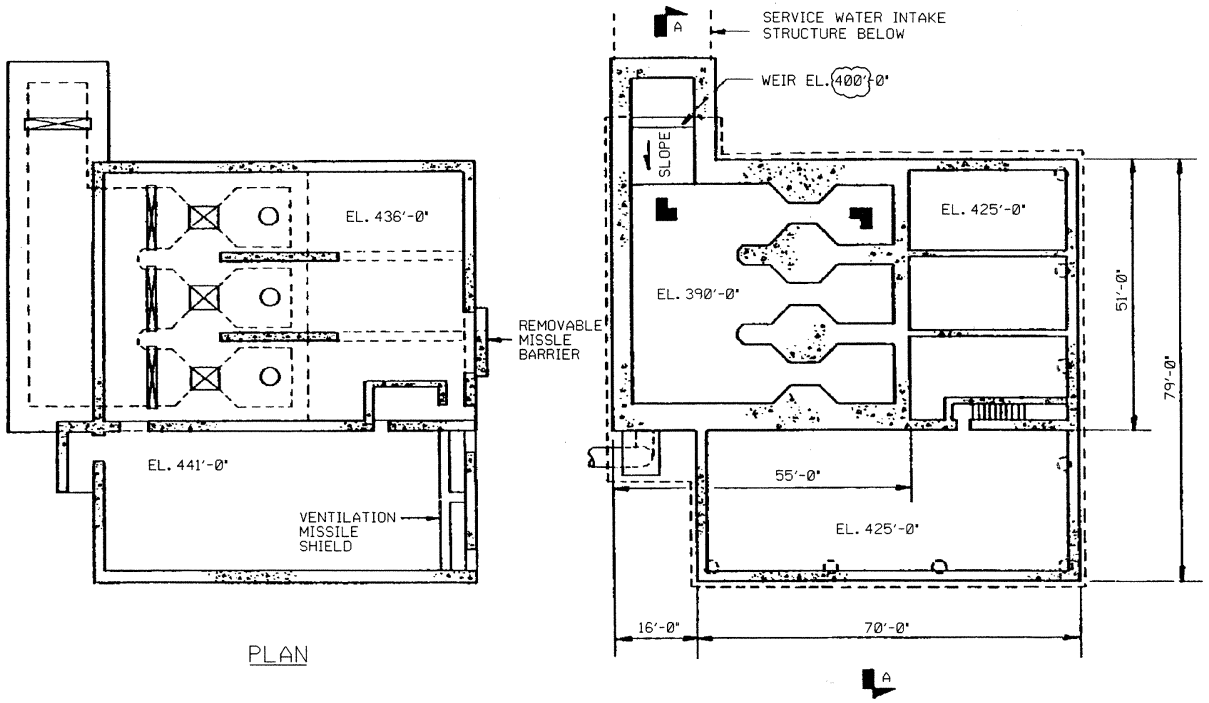
Figure 3.8-60
SECTION THROUGH FUEL HANDLING BUILDING
LOOKING WEST



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Section Through Fuel Handling Building Looking West Figure 3.8-60

Figure 3.8-61

PLAN SERVICE WATER PUMPHOUSE



NOTE:

REFER TO FIGURE 3.8-62 FOR NOTE ON SPECIFIED ELEVATIONS.

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
PLAN SERVICE WATER PUMPHOUSE Figure 3.8-61

Figure 3.8-62

SERVICE WATER PUMPHOUSE SECTION

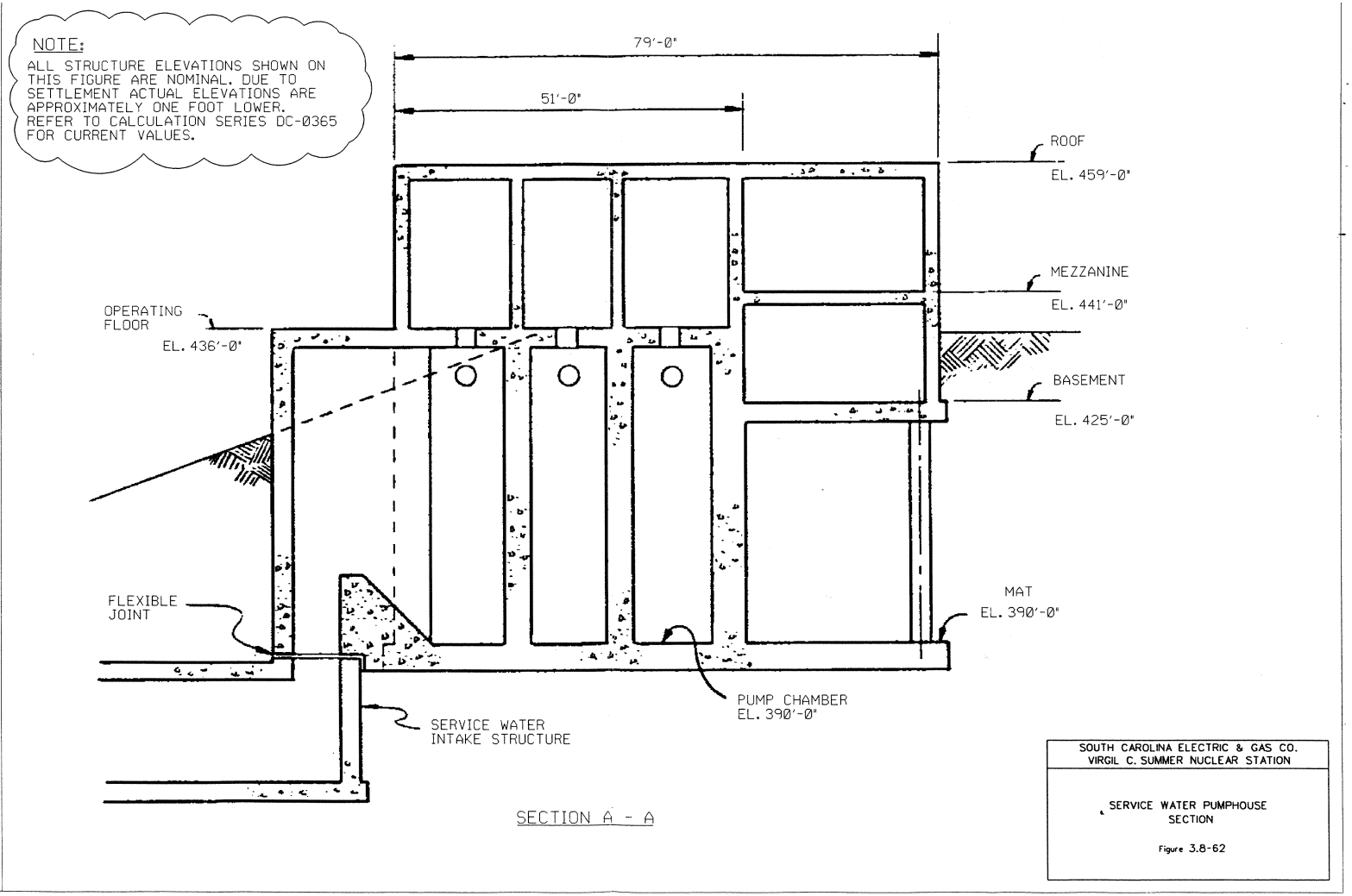
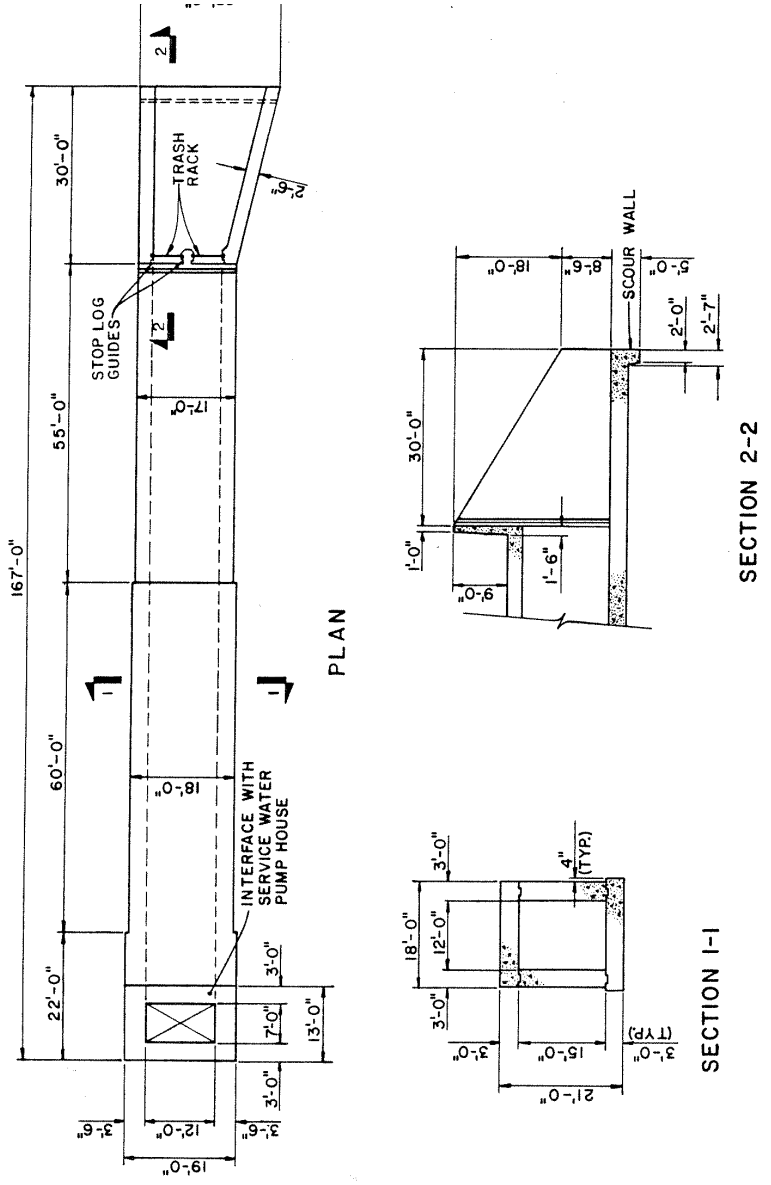


Figure 3.8-63

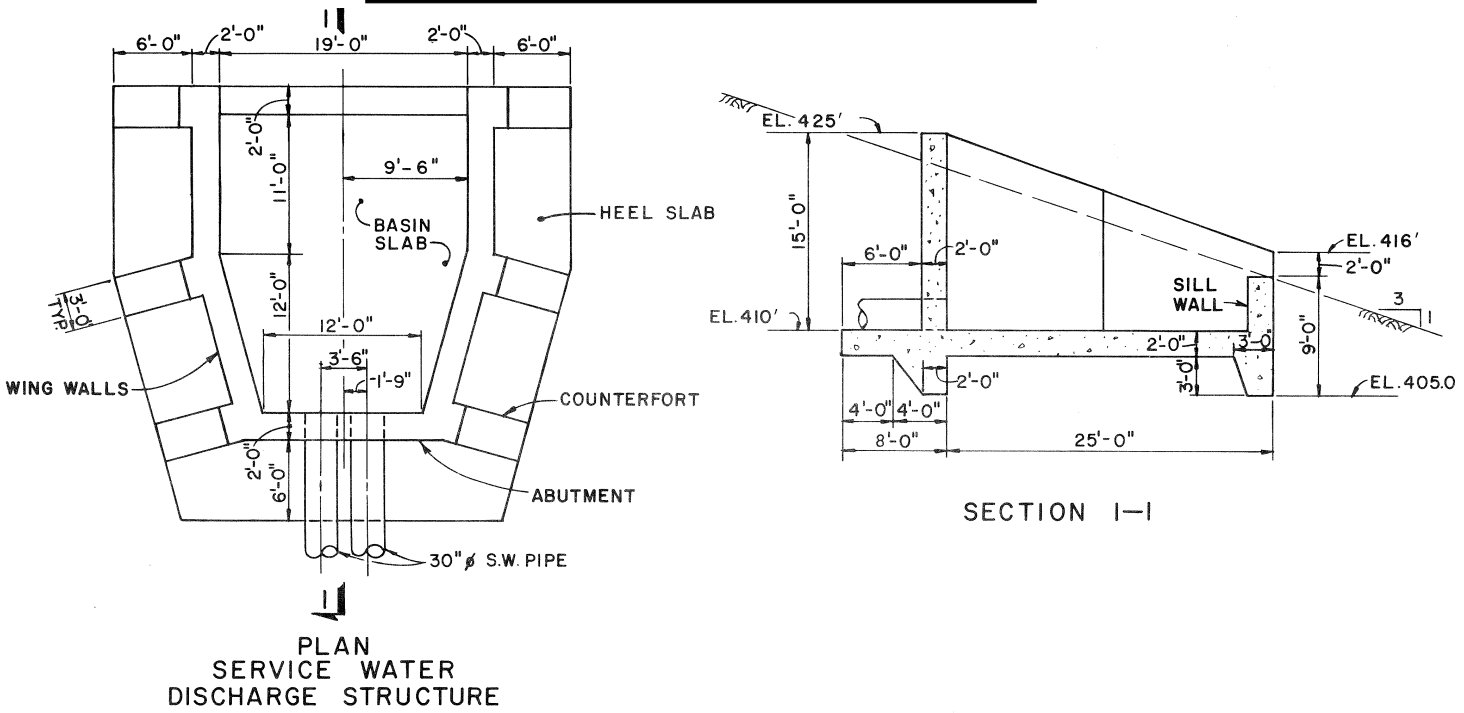
SERVICE WATER INTAKE STRUCTURE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Service Water Intake Structure Figure 3.8-63

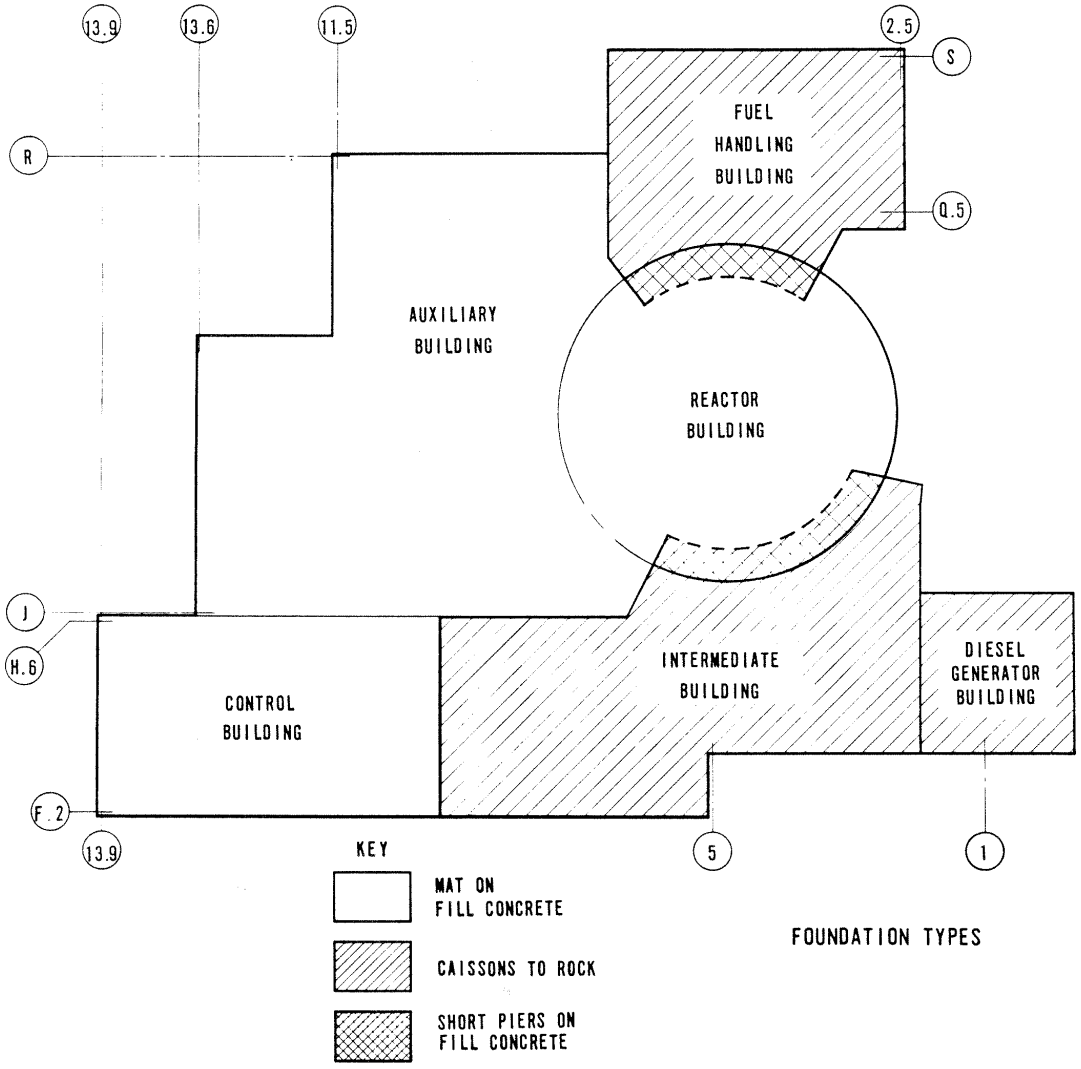
Figure 3.8-64

SERVICE WATER DISCHARGE STRUCTURE



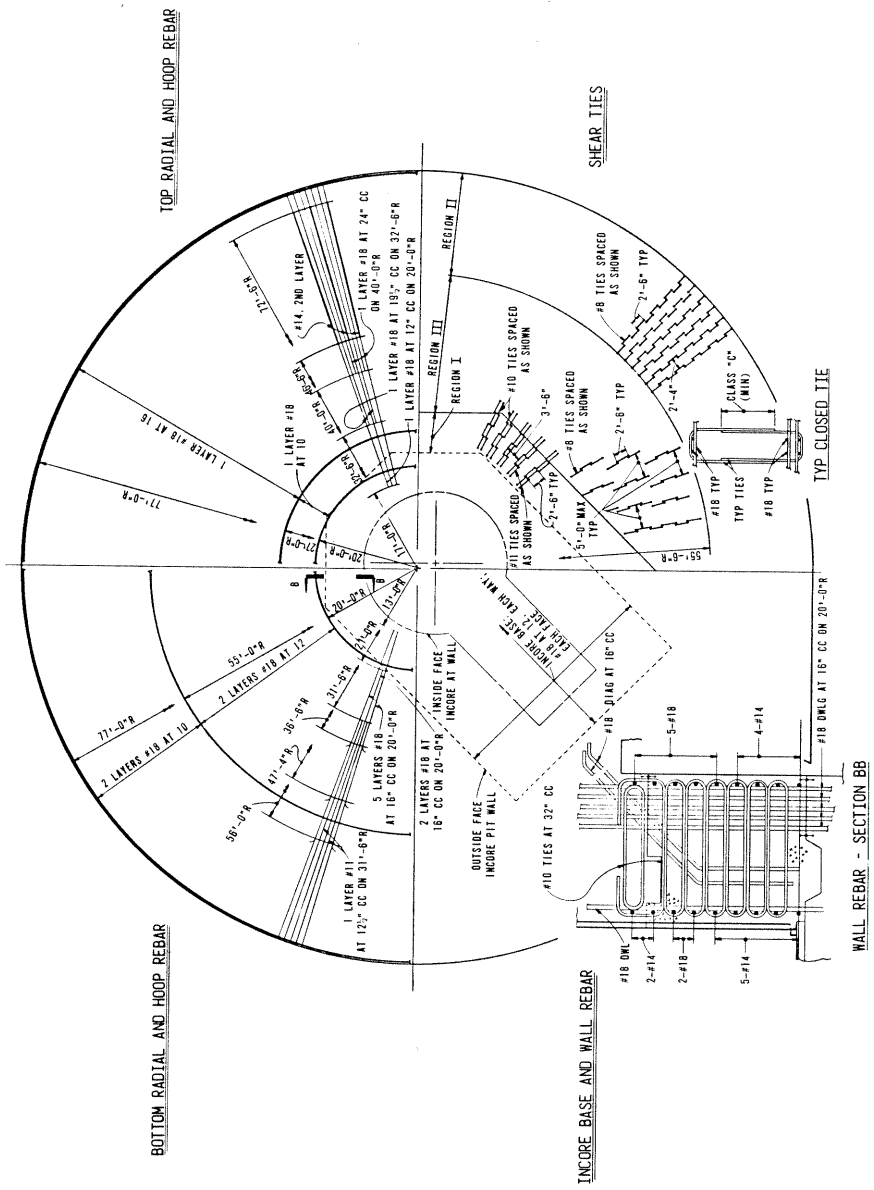
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Service Water Discharge Structure
Figure 3.8-64

Figure 3.8-65
FOUNDATION TYPES



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Foundation Types
Figure 3.8-65

Figure 3.8-66
REACTOR BUILDING STRUCTURAL MAT REINFORCEMENT



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Building Structural Mat Reinforcement
Figure 3.8-66

Figure 3.8-67

FOUNDATION PLAN REV. 0

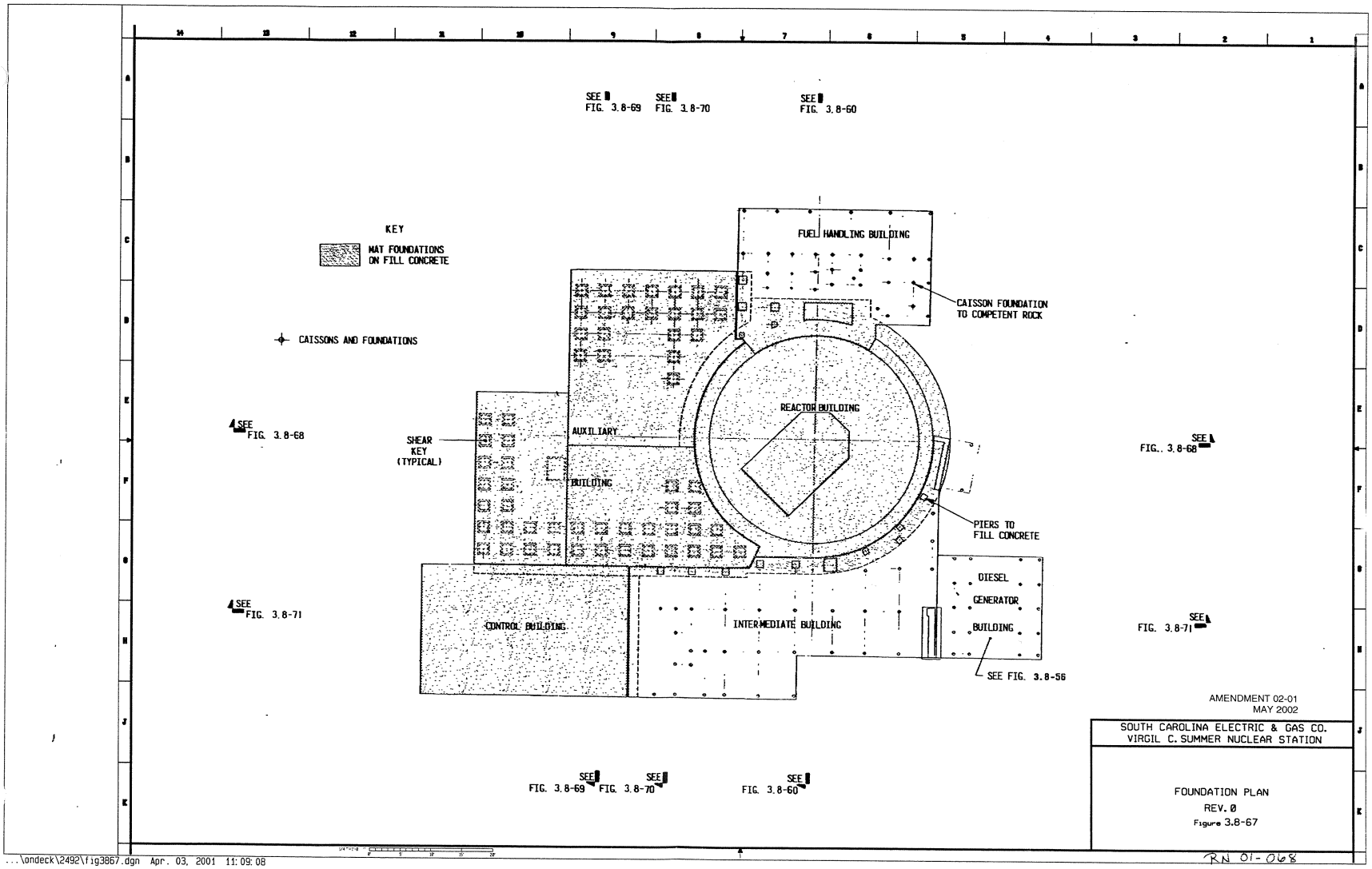
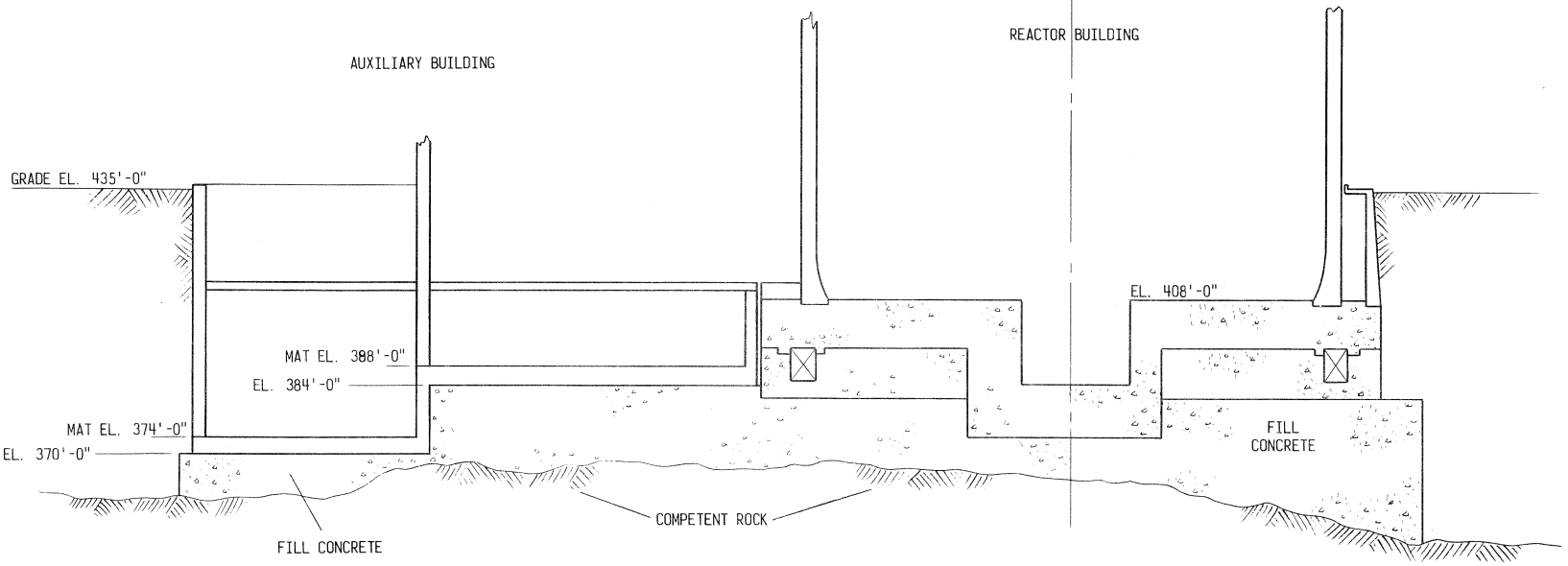


Figure 3.8-68

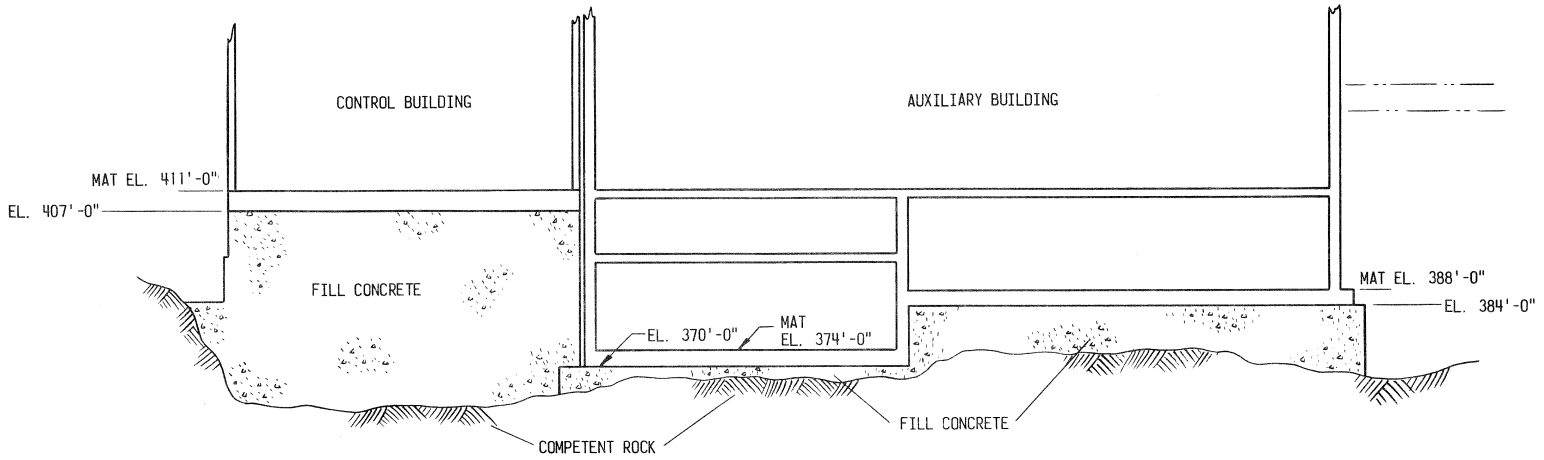
FOUNDATION SECTION THROUGH REACTOR BUILDING AND AUXILIARY BUILDING LOOKING NORTH



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Foundation Section Through Reactor Building and Auxiliary Building Looking North Figure 3.8-68

Figure 3.8-69

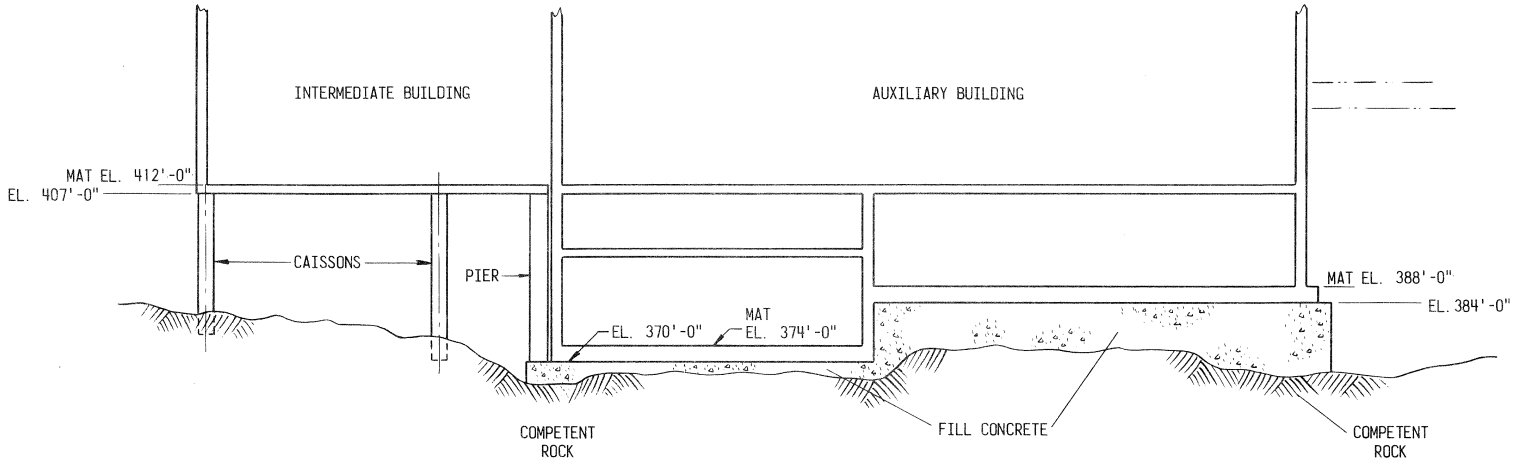
FOUNDATION SECTION THROUGH AUXILIARY BUILDING AND CONTROL BUILDING LOOKING WEST



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Foundation Section Through Auxiliary Building and Control Building Looking West Figure 3.8-69

Figure 3.8-70

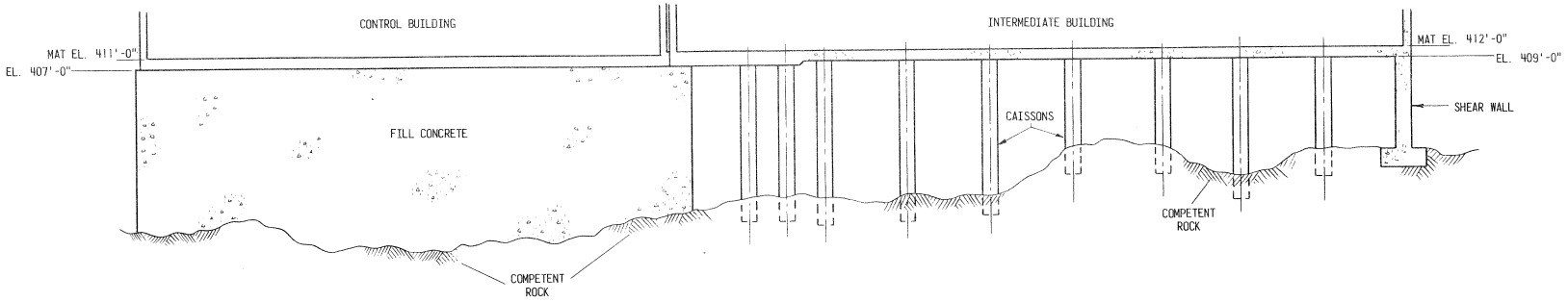
FOUNDATION SECTION THROUGH AUXILIARY BUILDING AND INTERMEDIATE BUILDING LOOKING WEST



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Foundation Section Through Auxiliary Building and Intermediate Building Looking West Figure 3.8-70

Figure 3.8-71

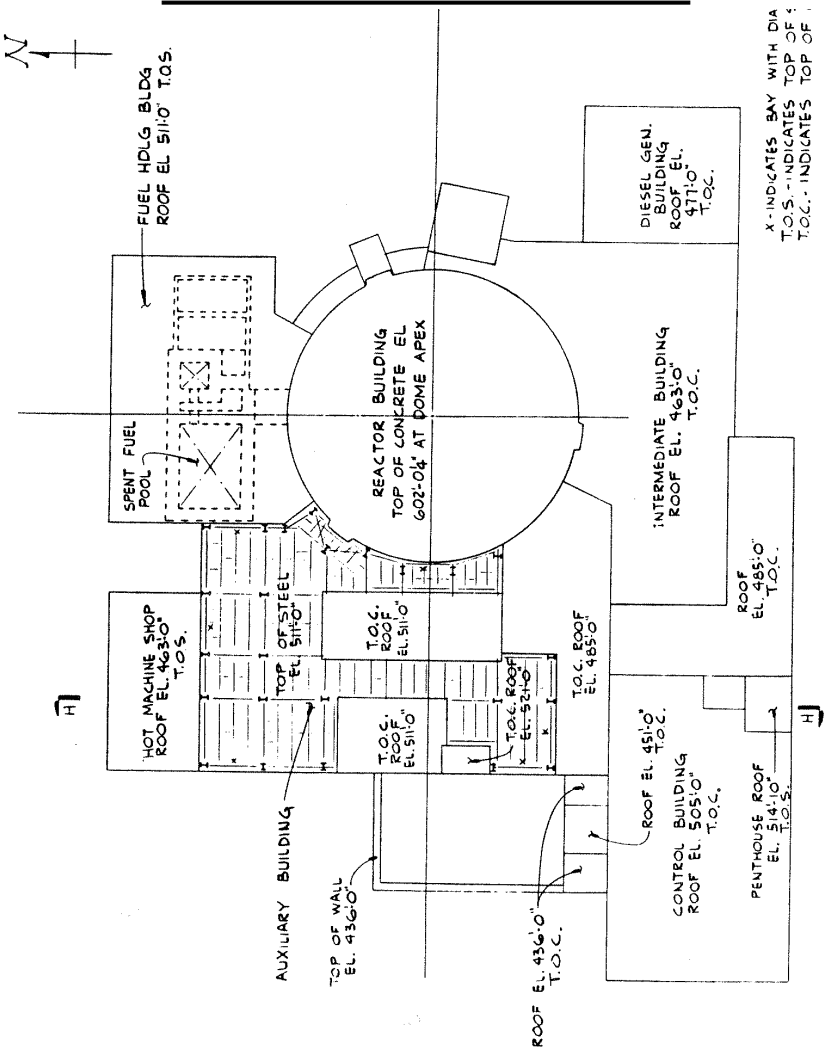
FOUNDATION SECTION THROUGH CONTROL BUILDING AND INTERMEDIATE BUILDING LOOKING NORTH



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Foundation Section Through Control Building and Intermediate Building Looking North Figure 3.8-71

Figure 3.8-72

AUXILIARY BUILDING ROOF STEEL STRUCTURE WITH SURROUNDING BUILDINGS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Auxiliary Building Roof Steel Structure With Surrounding Buildings Figure 3.8-72

Figure 3.8-73
DRAWING E-002-006
FSAR FIGURE REFERENCE

3.9 MECHANICAL SYSTEMS AND COMPONENTS

3.9.1 Dynamic System Analysis and Testing

3.9.1.1 Vibration Operational Test Program

Piping vibration tests are performed during the initial test program to comply with the recommendations of Regulatory Guide 1.68 (see Appendix 3A). Criteria for these tests satisfy the requirements of the applicable portions of the ASME Code, Section III. These tests are scheduled to commence with the heatup for hot functional testing and continue through hot functional testing and the cooldown thereafter. Further testing may be conducted during the power ascension test program. The scheduling of these tests allows system operation at normal operating temperatures and pressures.

This program encompasses all ASME Class 1, 2, and 3 piping systems, all other high energy piping systems inside Seismic Category I structures, high energy portions of systems whose failure could reduce the functioning of any Seismic Category I plant feature to an unacceptable level, and Seismic Category I portions of moderate energy piping systems located outside containment. Valves, piping, and supports associated with the components in these systems will be visually checked for abnormal vibration during the normal course of the preoperational test program. The specific conditions under which vibration will be observed are as follows where applicable.

1. Normal flow mode.
2. Minimum flow mode.
3. Maximum flow mode.
4. Startup.
5. Shutdown.
6. Other specific transient or operating conditions which might be expected to produce abnormal vibration or pressure pulsations.

Specific attention will be directed toward evaluating possible vibration problems during the performance of the following transients:

1. Start and stop reactor coolant pumps with associated operation of valves (closures/openings) in primary reactor coolant piping systems.
2. Start and stop RHR pumps with normal operation (closures/openings) of the associated valves in RHR piping systems.
3. Operation of high pressure safety injection piping system and charging system.
4. Operation of pressurizer relief valves and the associated discharge piping system.
5. Start and stop emergency feedwater pump with normal operation (closures/openings) of the associated valves in the emergency feedwater piping system.

6. Main steam turbine stop valve trip.
7. Main steam relief valve blowdown.
8. Condenser and atmospheric dump valve opening.

Acceptance criteria will include those stipulated in the ASME Code, Section III, Subparagraph NB3622.3, which states that vibration effects in piping systems shall be visually observed and, where questionable, shall be measured. If excessive vibration is measured under the above transient loadings, restraints will be installed or relocated to reduce the vibration to acceptable levels.

Determination of "questionable vibration" levels rests entirely in the judgment of a qualified observer. Typical qualification for this observer will include an engineering degree from an accredited institution, or equivalent, as well as a minimum of five years experience in the field of piping/pipe support engineering. His judgment will be based upon the operational transients which have been defined in the ASME Design Specification for the applicable piping system, presence of existing pipe support/restraint hardware provided to mitigate the consequences of these transient loads, and relative flexibility of the piping system.

If, in the opinion of the qualified observer, vibration levels are considered acceptable, no vibration measurements will be required. If vibration levels are deemed questionable, suitable instrumentation will be provided at representative locations to measure either the resulting displacement, acceleration, or pressure rise during a subsequent test of the piping system. This output will be integrated into, or compared with, existing stress calculations to evaluate the effect of this measured transient on the piping/pipe restraint system. If this transient is found to produce a negligible effect, no system revisions will be made. If the stress levels exceed the design basis, detailed computer calculations will be performed to thoroughly evaluate the system response to this transient condition. Additionally, an inspection of the support/restraint system hardware will be made to assess its adequacy.

In the event supports are added or relocated during this process, they will be considered as "design deviations" and handled in accordance with the approved quality assurance program, thereby assuring the evaluation of such deviations in the final system analysis.

3.9.1.2 Dynamic Testing Procedures

Table 3.9-0 lists mechanical equipment required for safe shutdown of the plant, as well as the method of seismic qualification. Also, this table indicates whether single or multiple axis input forcing functions were used.

A description of the analyses or tests used in the design of safety-related mechanical equipment such as pumps and heat exchangers to withstand seismic loadings is given in Sections 3.7.2 and 3.7.3.

Most of this mechanical equipment is isolated from the effects of the faulted plant condition and, therefore, will see negligible accident loadings. For equipment which is not isolated from the effects of the faulted plant condition, the dynamic accident loads are evaluated.

The analysis which demonstrates steam generator tube integrity for the combined LOCA plus SSE is included in WCAP 7832, “Evaluation of Steam Generator Tube, Tube Sheet and Divider Plate Under Combined LOCA Plus SSE Conditions”, December 1973.

The tubes in the steam generator are subject to a possible flow-induced vibration that does not exist in the primary coolant loop. This vibration could result from flow across the tubes due to vortex shedding. To ensure that no sympathetic vibration is generated by the vortex shedding, there is a wide frequency separation between the vortex frequency of the fluid and beam frequency of the tube. Parallel flow vibration is analyzed using the correlations of Burgreen, and the amplitude of vibration is shown to be low enough that neither stress, banging, nor fatigue is a problem.

3.9.1.3 Dynamic System Analysis Methods for Reactor Internals

3.9.1.3.1 Analysis Methods

The reactor internals are modeled dynamically for:

1. Loads produced by a pipe rupture of the reactor coolant loop for both cold and hot leg breaks,
2. Response due to a safe shutdown earthquake (SSE), and
3. Combination of LOCA and SSE.

The analysis methods for reactor internals are discussed in Section 3.9.3 except for seismic analysis. Seismic analysis of the reactor vessel and its internals are described in Section 3.7.

3.9.1.3.2 Preoperational Tests

The program used to establish the integrity of reactor internals has evolved from extensive design analysis, model testing, and post hot functional inspection. Additionally, full size reactors have been instrumented (Reference 1) to measure dynamic behavior including a Virgil C. Summer Nuclear Station size plant and the measurements have been compared with predicted values.

The reactor instrumentation program was instituted as part of a basic philosophy of instrumenting the internals of the “first-of-a-kind” of the current nuclear steam supply system designs for power plants. These data provide added assurance of the adequacy of the internals design and assisting in the development of increased capability for the prediction of the dynamic behavior of pressurized water reactor (PWR) internals. The “first-of-a-kind” plants that have been instrumented are R. E. Ginna (two loops), H. B. Robinson No. 2 (three loops), Indian Point Unit II (four loops), and Trojan (neutron panels and 17 x 17 style internals).

The H. B. Robinson No. 2 reactor has been established as the prototype for the Westinghouse three-loop plant internals verification program. Subsequent three-loop plants are similar in design. Experience with other reactors indicates that plants of similar designs behave in a similar manner. For these reasons an instrumentation program was conducted on the H. B. Robinson No. 2 to confirm the behavior of the reactor internal components.

The only significant differences between the Virgil C. Summer Nuclear Station internals and the H. B. Robinson No. 2 internals are the replacement of the annular thermal shield with neutron shield panels and the substitution of 17 x 17 fuel assemblies for 15 x 15 assemblies.

The replacement of the thermal shield with segmented neutron shield panels results in a reduction of the flow induced vibrations of the reactor core structures. This conclusion was confirmed in tests with a 1/22nd scale mode (References 2, 3). The flow test was first conducted on a model with a thermal shield and then on a model with neutron shield panels. The results indicated that the vibration levels of the internals were low and levels on the neutron shield panel were negligible. Appendix B on Reference 2 presents the test results. Reference 4 justifies in more detail the comparison of the relative effects of replacing the annular thermal shield with neutron shielding pads.

There is no change in the configuration of the reactor internals core support structures from the 15 x 15 fuel assembly configuration due to the incorporation of the 17 x 17 fuel assembly. The mechanical properties of the 17 x 17 fuel assembly, such as fuel assembly weight and beam stiffness, are virtually identical to the 15 x 15 fuel assembly; therefore, their input to the reactor internals core support structures is the same and the response of the total reactor internals core support structural model will not change.

The change to a 17 x 17 core configuration results in the use of newly designed guide tubes which are stronger and more rigid than the 15 x 15 guide tubes and hence are less susceptible to flow-induced vibration. The remainder of the core structure design has not been changed, and consequently remains identical to the prototype which has been tested and proven to be well within design expectations and limits.

The Portland General Electric Company Trojan plant internals have been instrumented for strain measurements on the core barrel, and on the 17 x 17 guide tube subject to highest cross flow. The Trojan plant is the lead plant featuring neutron panels and 17 x 17 style internals. The data obtained in this program provides verification of Westinghouse analysis and scale model predictions of 17 x 17 and neutron panel behavior in a full size plant and is applicable to the Virgil C. Summer Nuclear Station.

The Three Loop Internals Assurance Program conducted on H. B. Robinson No. 2, supplemented by the Trojan data on neutron panels and 17 x 17, jointly satisfy the intent of Regulatory Guide 1.20.

The core support structures receive, in addition to the testing discussed above, the normal pre and post hot functional testing examination for integrity per paragraph D, “Regulations for Reactor

Internals Similar to the Prototype Design," of Regulatory Guide 1.20 (see Appendix 3A). This examination will include the points in Figure 3.9-1, summarized as follows:

1. All major load bearing elements of the reactor internals relied upon to retain the core structure in place.
2. The lateral, vertical, and torsional restraints provided within the vessel.
3. Those locking and bolting devices whose failure could adversely affect the structural integrity of the internals.
4. Those other locations on the reactor internals components that are similar to those which were examined on the prototype H. B. Robinson No. 2 design.

The inside of the vessel is inspected before and after the hot functional test, with all the internals removed, to verify that no loose parts or foreign materials are in evidence.

1. Lower Internals

   A particularly close inspection will be made on the following items or areas, using a 5X or 10X magnifying glass where applicable. The locations of these areas are shown in Figure 3.9-1.

   a. Upper barrel to flange girth weld.
   b. Upper barrel to lower barrel girth weld.
   c. Upper core plate aligning pin. Examine bearing surfaces for any shadow marks, burnishing, buffing, or scoring. Inspect welds for integrity.
   d. Irradiation specimen guide screw locking devices and dowel pins. Check for lockweld integrity.
   e. Baffle assembly locking devices. Check for lockweld integrity.
   f. Lower barrel to core support girth weld.
   g. Neutron shield panel screw locking devices and dowel pin cover plate welds. Examine the interface surfaces for evidence of tightness and for lockweld integrity.
   h. Radial support key welds.
   i. Insert screw locking devices. Examine soundness of lockwelds.
   j. Core support columns and instrumentation guide tubes. Check all the joints for tightness and soundness of the locking devices.
   k. Secondary core support assembling welds.
   l. Lower radial support keys and inserts (Examine for any shadow marks, burnishing, buffing, or scoring. Check the integrity of the lockwelds). These members supply the radial and torsion constraint of the internals at the bottom relative to the reactor vessel while permitting axial growth between the two. One would expect to see, on the bearing

surfaces of the key and keyway, burnishing, buffing, or shadowing marks that would indicate pressure loading and relative motion between the two parts. Some scoring of engaging surfaces is also possible and acceptable.

m. Gaps at baffle joints. (Check for gaps between baffle and top former, and at baffle to baffle joints.)

2. Upper Internals

A particularly close inspection will be made on the following items or areas, using a magnifying glass of 5X or 10X magnification, where necessary. The locations of these areas are shown in Figure 3.9-1.

a. Thermocouple conduits, clamps, and couplings.

b. Guide tube, support column, and thermocouple column assembly locking devices.

c. Support column and conduit assembly clamp welds.

d. Upper core plate alignment inserts. Examine for any shadow marks, burnishing, buffing, or scoring. Check the locking devices for integrity of lockwelds.

e. Thermocouple conduit gusset and clamp welds.

f. Thermocouple end plugs. (Check for tightness.)

g. Guide tube closure welds, tube-transition plate welds, and card welds.

Acceptance standards are the same as required in the shop by the original design drawings and specifications.

During the hot functional test, the internals will be subjected to a total operating time at greater than normal full flow conditions (three pumps operating) of at least 240 hours. This provides a cyclic loading of approximately 10^7 cycles on the main structural elements of the internals. In addition, there will be some operating time with only one and two pumps operating.

When no signs of abnormal wear, no harmful vibrations are detected, or no apparent structural changes take place, the three-loop core support structures are considered to be structurally adequate and sound for operations.

3.9.1.3.3 Startup Tests

Vibration monitoring in accordance with Appendix “A” Section B.1.J of Regulatory Guide 1.20 and Section D.1.P of Regulatory Guide 1.68 is not necessary based on guidance given in Section 2.2.2.c of Regulatory Guide 1.20. This section allows the vibration testing to be conducted without real or dummy fuel assemblies if it can be shown by analytical or experimental means that such conditions will yield conservative results. An analysis of the testing described in Section 3.9.1.3.2 above, and the testing performed during hot functional testing prior to fuel loading and without any dummy fuel assemblies has been shown to yield conservative results. On this basis, no additional testing will be performed after core loading.

3.9.1.4 Correlation of Test and Analytical Results

The dynamic behavior of reactor components has been studied, using experimental data obtained from operating reactors along with results of model test and static and dynamic tests in the fabricators shops and at the plant site. Extensive instrumentation programs to measure vibration of reactor internals (including prototype units of various reactors) have been carried out during preoperational flow tests.

From scale model tests, information on stresses, displacements, flow distribution and fluctuating differential pressures is obtained. Studies have been performed (Reference 1) to verify the validity and to determine the prediction accuracy of models for determining reactor internals vibration due to flow excitation.

Vibration of structural parts during preoperational tests is measured using displacement gauges, accelerometers, and strain transducers. The signals are recorded with magnetic tape recorders. Onsite-offsite signal analysis is done using both hybrid real-time and digital techniques to determine the approximate frequency and phase content. In some structural components, the spectral content of the signals include nearly discrete-frequency or very narrow-band frequency, usually due to excitation by the main coolant pumps and other components that reflect the response of the structure at a natural frequency to broad band, mechanically or flow-induced excitation. Damping factors are also obtained from wave analyses.

In general, the determination of internals responses proceeds as follows. Frequencies and spring constants are obtained analytically and these values are confirmed with test results. Theoretical and experimental studies have provided information on the added apparent mass of the water, which has the effect of decreasing the natural frequency of the component. Damping coefficients are established experimentally and forcing functions are characterized from previous studies including those discussed above. Once these factors are established, the response can be computed analytically. In addition, the responses of important reactor structures are measured during preoperational reactor tests and frequencies and mode shapes of the structures are obtained. Once all of the dynamic parameters are obtained as explained above, the forcing functions can be estimated. When combined, these studies provide indications of the internal behavior during reactor operation.

Pre and post hot functional inspection results, in the case of plants similar to prototypes, serve to confirm preditions that the internals are well-behaved. Any gross motion or undue wear would be evident following the application of approximately 10^7 cycles of vibration expected during the test period.

3.9.1.5 Analysis Methods Under LOCA Loadings

1. Reactor Internals Analysis

Analysis of the reactor internals for blowdown loads resulting from a loss of coolant accident is based on the time history response of the internals to simultaneously applied blowdown forcing functions. The forcing functions are defined at points in the system where changes in cross section or direction of flow occur so that differential loads are generated during the blowdown transient. The dynamic analysis can employ the displacement method, lumped parameters, stiffness matrix formulations, and assumes that all components behave in a linearly elastic manner.

In addition, because of the complexity of the system and the components, it is necessary to use finite element stress analysis codes to provide more detailed information at various points. Analytical methods are discussed in more detail in Section 3.9.3.

2. Reactor Coolant Loop Analysis

   The description of the methods and procedures that will be used to compute the dynamic response of the reactor coolant loop for a loss of coolant accident is present in Section 5.2.1.

3.9.1.6 Analytical Methods for ASME Code Class 1 Components

Analytical methods for ASME Code Class 1 components are discussed in Section 5.2.1.

3.9.2 ASME Code Class 2 and 3 Components

3.9.2.1 Plant Conditions and Design Loading Combinations

For balance of plant scope, plant operating conditions are correlated with component operating conditions in Table 3.9-1. The plant operating condition categories establish related sets of design loading combinations that are applied to the design of systems and components.

For the components and equipment supplied by the NSSS vendor the design pressure, temperature, and other loading conditions that provide the bases for design of fluid systems Code Class 2 and 3 components are presented in the sections which describe the systems.

3.9.2.2 Design Loading Combinations

For balance of plant scope, design loading combinations for Code Class 2 and 3 components are based upon the categorizations of component operating condition which are derived from the plant operating conditions. Stress limits and specific loading combinations for the basic types of mechanical components, such as valves, vessels, piping, and pumps, are presented in Table 3.9-2.

The design loading combinations for ASME Code Class 2 and 3 components and supports provided by the NSSS vendor are given in Table 3.9-3. The design loading combinations are categorized with respect to Normal, Upset, and Faulted Conditions. Stress limits for each of the loading combinations are component oriented and are presented in Tables 3.9-4, 3.9-5, and 3.9-6 for tanks, pumps, and valves, respectively.

3.9.2.3 Design Stress Limits

For balance of plant scope, design stress limits which allow inelastic deformation are not permitted for Code Class 2 and 3 components, except for a limited number of situations involving piping subjected to jet impingement forces or pipe rupture loadings. Table 3.9-2 provides detailed information concerning these exceptions.

The design stress limits established for the components provided by the NSSS vendor are sufficiently low to assure that violation of the pressure retaining boundary will not occur. These limits, for each of the loading combinations, are component oriented and are presented in Tables 3.9-4 through 3.9-6.

Class 2 and 3 components within Westinghouse scope are designed and analyzed using umbrella nozzle loads. In the component analysis, the effects of these umbrella nozzle loads are combined by absolute sum with the effects of the SSE. The loads applied to the component from the piping system due to all applicable loading combinations do not exceed the loads for which the component is designed.

Combination of responses (e.g. stress, strain, moment, shear or displacement) of the SSE and the dynamic loads associated with the faulted plant condition (including LOCA) for Class 1, 2, and 3 components within the balance of plant scope is performed by the SRSS method. Engineering acceptance of this method is based upon the extremely low order of probability for the simultaneous occurrence of the SSE and a faulted plant condition. This is coupled with the fact that the SRSS combination of two time varying loads is adequately represented by this method. The SRSS methodology for treatment of multiple time varying loads is generally established in the evaluation of the three spatial earthquakes. Based upon these low probabilities, a highly satisfactory margin of safety is obtained using this method of combination.

3.9.2.4 Analytical and Empirical Methods for Design of Pumps and Valves

3.9.2.4.1 Balance of Plant Scope

A list that identifies all active Code Class 2 and 3 pumps is provided by Table 3.9-7. A similar list for active Code Class 1, 2, and 3 valves is presented by Table 3.9-8.

Stringent criteria are employed to ensure that the operability of active pumps and valves is not compromised during or following specified plant events. These criteria are specified for each active component and are included in ASME design specification or other contractual documents.

Provisions to ensure operability include specification of loading combinations and stress limits, as discussed in Section 3.9.2.3, for active pumps and valves.

In addition to compliance with the design limits specified, it is specified that assurance of operability under all design loading combinations be provided by test and/or analysis. In the performance of tests or analyses to demonstrate operability, the structural interactions of entire valve-operator and pump-motor assemblies are considered.

When superposition of test results for other than the combined loading condition is proposed, the applicability of such a procedure is demonstrated. Qualification of components by analysis only is permitted when testing is not feasible.

When proof of operability is shown by analysis, a deformation (interference) analysis is performed. The purpose of this deformation analysis is to show that all moving parts are uninhibited in movement due to deformation of components caused by any loading conditions described in Section 3.9.2.1.

3.9.2.4.2 Components and Equipment Supplied by the NSSS Vendor

The design methods and stress limits for pumps and valves are described above. These limits, selected following the Code intent, are sufficiently low to provide assurance that no gross deformation will occur in active (1) components and that the active components will operate as required following the event. The limits established for inactive (2) components are intended to assure that violation of the pressure retaining boundary will not occur. Additional requirements are provided in Section 3.9.4.

Active pumps and valves are listed in Tables 3.9-7 and 3.9-8, respectively.

3.9.2.5 Design and Installation Criteria, Pressure Relieving Devices

1. Code Class 1 Components

   Design and installation criteria for Code Class 1 pressure relieving devices are discussed in Section 5.2.2.

2. Code Class 2 Components, Main Steam Safety Valves

   Safety-relief valves are mounted on the main steam lines from each steam generator, as described in Section 10.3. These safety valves are provided in accordance with the ASME Code, Section III, and are capable of relieving at least 110 percent of rated main steam flow. The valves are mounted in a manner that minimizes the reaction moments about the mounting flanges. The valves discharge into an open vent system which is sized to permit free passage of relieved steam to the atmosphere without development of excessive backpressure.

   The most severe combinations of applicable loads relative to main steam piping are presented in Section 3.9.2.1. These loading combinations are addressed in the analysis of main steam piping and mounting nozzles. The dynamic load factor for any individual main steam safety valve opening is determined to be 1.42.

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(1) Active components are those whose operability is relied upon to perform a safety function (as well as reactor shutdown function) during the transients or events considered in the respective operating condition categories.

(2) Inactive components are those whose operability is not relied upon to perform a safety function during the transients or events considered in the respective operating condition category.

3. Code Class 2 and 3 Components, Other than Main Steam

   The safety-relief valves on the sodium hydroxide storage tank (Code Class 3) are 1-1/2 inch valves. The valve reaction forces and moments are inputs to the associated piping stress analysis.

3.9.2.6 Stress Levels for Category I Components

Methods used to analyze Seismic Category I systems are discussed in Sections 3.9.1, 3.9.2, and 5.2.

3.9.2.7 Field Run Piping System

All Seismic Category I piping is fabricated from detail dimensioned engineering drawings. Section 3.7.3.8 describes the simplified procedure for the design of this piping.

3.9.2.8 Class 2 and 3 Component Supports

3.9.2.8.1 Balance of Plant Scope

1. Piping Supports

   Piping supports for safety-related, ASME Code Class 2 and 3 piping are designed and analyzed in accordance with the requirements of the ASME Code, Section III, Subsection NF, Winter 1973 Addenda, except for supports that function as a snubber. The components within a pipe support that function as a snubber for safety related, ASME Code Class 2 and 3 piping are designed and analyzed in accordance with the requirements of the ASME Code, Section III, Subsection NF, Winter 1976 Addenda. Except for snubber components, the use of Subsection NF of the Code represents a voluntary commitment since the contract date for piping and its supports predates mandatory application of Subsection NF.

   Loading combinations and stress limits are presented in Table 3.9-2. Support deformations are limited to assure piping system function and integrity.

   A set of recommended installation instructions, as well as detailed design drawings, is provided to the pipe support installer to facilitate correct installation procedures. Control of this function is in accordance with the quality control procedures of the installer. Additionally, in accordance with the testing requirements section of Article NF-6000 of the ASME Code, Section III, Winter, 1973, Addenda the piping designer will check the hot and cold settings during the plant startup and test phase to ensure both proper installation in accordance with the design drawing and that sufficient travel is available to allow for free thermal expansion of the piping.

These components are accessible for inspection. There are a number of inspection platforms provided throughout the plant which would offer access to snubbers used on major pieces of equipment. Any snubbers found to be inoperable or maladjusted during the plant startup and operational test phase will be either readjusted, repaired, or replaced with spare components.

A tabulation listing concerning snubbers utilized for support of safety related systems and components information is maintained for all pipe supports/restraints for the plant.

All mechanical snubbers have "certified" load capacities on file in accordance with the requirements of Article NF of the ASME Code.

2. Pump and Vessel Supports

   Supports for pumps and vessels are designed and analyzed in accordance with the requirements of the ASME Code, Section III, Subsection NF, as applicable. Component supports not under the jurisdiction of Subsection NF by virtue of the contract date for the component and its supports are analyzed and designed to assure the integrity of the supports under loading combinations specified for the component.

   Loading combinations and stress limits are presented in Table 3.9-2. Support deformations are limited to assure the pressure boundary integrity and operability (for active components).

3. Valve Supports

   Except for special cases, valves are supported by the piping in which they are mounted. Details regarding load combinations and stress limits for piping are discussed in Section 3.9.2.2 and 3.9.2.3. Piping supports are discussed in Item 1 above.

   In special cases, such as large, massive valves, additional supports are provided as required. Design of these valve supports satisfies the same requirements as the piping supports.

3.9.2.8.2 Component Supports Provided by the NSSS Vendor

The stress limits used for ASME Class 2 and 3 component supports are identical to those used for the supported component. These allowed stresses are such that the design requirements for the components and the system structural integrity are maintained.

3.9.2.8.3 Support Design Criteria

Structural bolting of support components within the NF code boundary are designed in accordance with Appendix XIII of ASME Section II, Winter 1973 Addenda or later code edition, or the American Institute of Steel Construction (AISC) manual, Seventh Edition or later.

The design of pipe support components not covered by ASME Code, Section III, Subsection NF shall be in accordance with the AISC Manual of Steel Construction Seventh Edition or later.

3.9.3 Components Not Covered by ASME Code

3.9.3.1 Core and Internals Integrity Analysis (Mechanical Analysis)

The response of the reactor core and vessel internals under excitation produced by a simultaneous complete severance of a reactor coolant pipe and seismic excitation for a typical Westinghouse PWR plant internals has been determined. The following mechanical functional performance requirements apply:

1. Following the LOCA, the basic operational or functional requirement to be met for the reactor internals is that the plant shall be shut down and cooled in an orderly fashion so that fuel cladding temperature is kept within specified limits. This implies that the deformation of certain critical reactor internals must be kept sufficiently small to allow core cooling.
2. For large breaks, the reduction in water density greatly reduces the reactivity of the core, thereby shutting down the core whether the rods are tripped or not. The subsequent refilling of the core by the emergency core cooling system uses borated water to maintain the core in a subcritical state. Therefore, the main requirement is to assure effectiveness of the emergency core cooling system. Insertion of the control rods, although not needed, gives further assurance of ability to shut the plant down and keep it in a safe shutdown condition.
3. The inward upper barrel deflections are controlled to ensure no contacting of the nearest rod cluster control guide tube. The outward upper barrel deflections are controlled in order to maintain an adequate annulus for the coolant between the vessel inner diameter and core barrel outer diameter.
4. The rod cluster control guide tube deflections are limited to ensure operability of the control rods.
5. To ensure no column loading of rod cluster control guide tubes, the upper core plate deflection is limited.
6. The reactor has mechanical provisions which are sufficient to maintain the design functionality of the core and internals and to assure that the core is intact with acceptable heat transfer geometry following transients arising from the LOCA operating conditions (References 5 and 6).
7. The core internals are designed to withstand mechanical loads arising from operating basis earthquake, SSE, and pipe ruptures (References 6,7, and 8).

3.9.3.1.1 Faulted Conditions

The following events are considered in the faulted conditions category:

1. Loads produced by a rupture of the largest branch line piping, excluding the main (primary) coolant loop from consideration through crediting Leak-Before-Break (LBB) for both cases: a cold leg branch line and a hot leg branch line.

   The branch lines analyzed for V. C. Summer are the accumulator line and the pressurizer

surge line. The methods of analysis adopted are related to the type of accident assumed (cold leg break or hot leg break). Note that throughout this description, hot or cold leg break refers to where the broken branch lines were attached to the main coolant loop. The size of the postulated break and its location along the primary loop piping are determined by the size and location of the branch line piping, as a result of crediting Leak-Before-Break exclusion of the main (primary) coolant loop for consideration with respect to LOCA forces.

2. Response due to a SSE.
3. Combination of SSE and LOCA.

Maximum stress intensities are compared to allowable stresses for each of the above conditions. When fatigue is of concern, the applicable stress concentrate factors are utilized and peak stresses are used to establish the usage factor. Elastic analysis is utilized to obtain the response of the structure and the stress analysis on each component is performed on an elastic basis. For faulted conditions stresses are above yield in a few locations. For these cases only, when deformation requirements exist, a plastic analysis is independently performed to ensure that functional requirements are maintained. The reference to the use of inelastic techniques is applicable to the guide tube evaluations via test results, as well as to the core barrel inward and outward expansions. The guide tube tests and results are described in Reference 13. The evaluation of the inward deflections of the core barrel is discussed in Reference 14. The outward barrel deflection analysis is described in Reference 12. For the outward barrel deflection, inelastic behavior is confined to a small region of the girth weld where the stresses exceed yield; independent hand calculations, evaluating the elongation of this region, indicated that the residual barrel deflection does not exceed the limit given in Table 4.2-1.

The criteria for establishing the deformation limits given in Table 4.2-1 reflect the mechanical functional performance requirements, which are discussed in Section 3.9.3.1. Guide tube deflections are limited to allow control rod insertion. Inward upper barrel deflections are limited to prevent barrel contact with the nearest guide tube. Outward upper barrel deflections are limited in order to maintain an adequate annulus for ECCS flow between the vessel inner diameter and the core barrel outer diameter.

The number of full cycle variations of significant LOCA loadings is quite small; therefore, resonance and high cycle endurance limit considerations are not of concern. Dynamic amplification for LOCA impulse-like loads and, therefore, maximum system response is considered. The elastic limit allowable stresses are used to compare with the result of the analysis. No inelastic stress limits are used.

The above described analyses show that the stresses and deflections which would result following a faulted condition are less than those which would adversely affect the integrity of the structures. Also, the natural and applied frequencies are such that resonance problems should not occur.

The use of unirradiated stress and elongation limits (Paragraph 4.2.2.5) to justify these conclusions is valid because the points of interest, listed in Table 4.2-1, are in low fluence, low irradiated zones. In these areas, the total fluence level for 54 full power years is less than

1.5×10^{21} n/cm^2 (E > 1 Mev). Below this level, data indicates that the decrease in elongation of stainless steel is such that the use of unirradiated limits is valid.

3.9.3.2 Reactor Internals Response Under Blowdown and Seismic Excitation

A loss of coolant accident would result from a rupture of reactor coolant piping. During the blowdown of the coolant, critical components of the core are subjected to vertical and horizontal excitation as a result of rarefaction waves propagating inside the reactor vessel. For these large breaks, the reduction in water density greatly reduces the reactivity of the core, thereby shutting down the core whether the rods are tripped or not.

The pressure waves generated within the reactor are highly dependent on the location and nature of the postulated pipe failure. In general, the more rapid the severance of the pipe, the more severe the imposed loadings on the components. A one millisecond severance time is taken as the limiting case.

In the case of the hot leg break, the vertical hydraulic forces produce an initial upward lift of the core. A rarefaction wave propagates through the reactor hot leg nozzle into the interior of the upper core barrel. Since the wave has not reached the flow annulus on the outside of the barrel, the upper barrel is subjected to an impulsive compressive wave. Thus, dynamic instability (buckling) or large deflections of the upper core barrel or both is the possible response of the barrel during hot leg blowdown. In addition to the above effects, the hot leg break results in transverse loading on the upper core components as the fluid exits the hot leg nozzle.

In the case of the cold leg break, a rarefaction wave propagates along a reactor inlet piping arriving first at the core barrel at the inlet nozzle of the broken loop. The upper barrel is then subjected to a nonaxisymmetric expansion radial impulse which changes as the rarefaction wave propagates both around the barrel and down the outer flow annulus between vessel and barrel. After the cold leg break, the initial steady-state hydraulic lift forces (upward) decrease rapidly (within a few milliseconds) and then increase in the downward direction. These cause the reactor core and lower support structure to move initially downward.

If a simultaneous seismic event with the intensity of the SSE is postulated with the loss of coolant accident, the imposed loading on the internals component may be additive in certain cases and therefore the combined loading must be considered.

In general, however, the loading imposed by the SSE is small compared to the blowdown loading.

3.9.3.3 Acceptance Criteria

The criteria for acceptability in regard to mechanical integrity analyses is that adequate core cooling and core shutdown must be assured. This implies that the deformation of the reactor internals must be sufficiently small so that the geometry remains substantially intact. Consequently, the limitations established on the internals are concerned principally with the maximum allowable deflections and stability of the parts in addition to a stress criterion to assure integrity of the components.

1. Allowable Deflection and Stability Criteria

   For the loss of coolant plus the SSE condition, deflections of critical internal structures are limited to the values given in Section 4.2.2.

   In a hypothesized downward vertical displacement of the internals, energy absorbing devices limit the displacement after contacting the vessel bottom head, ensuring that the geometry of the core remains intact.

2. Upper Barrel

   The upper barrel deformation has the following limits:

   a. To ensure a shutdown and cooldown of the core during blowdown, the basic requirement is a limitation on the outward deflection of the barrel at the locations of the inlet nozzles connected to the unbroken lines. A large outward deflection of the barrel in front of the inlet nozzles, accompanied with permanent strains, could close the inlet area and stop the cooling water coming from the accumulators. Consequently a permanent barrel deflection in front of the unbroken inlet nozzles larger than a certain limit, called the “no loss of function” limit, could impair the efficiency of the emergency core cooling system.

   b. To assure rod insertion and to avoid disturbing the control rod cluster guide structure, the barrel should not interfere with the guide tubes. This condition also requires a stability check to assure that the barrel will not buckle under the accident loads.

3. Control Rod Cluster Guide Tubes

   The guide tubes in the upper core support package house the control rods. The deflection limits were established from tests and are provided in Section 4.2.2.

4. Fuel Assembly

   The limitations for this case are related to the stability of the thimbles in the upper end. The upper end of the thimbles must not experience stresses above the allowable dynamic compressive stresses. Any buckling of the upper end of the thimbles must not experience stresses above the allowable dynamic compressive stresses. Any buckling of the upper end of the thimbles due to axial compression could distort the guide line and thereby affect the free fall of the control rod.

5. Upper Package

   The local vertical deformation of the upper core plate, where a guide tube is located, is limited so as to prevent the guide tubes from undergoing compression.

6. Allowable Stress Criteria

   The allowable stress limits during the LOCA used for the core support structures are based on the limits specified in Section 5.2.1.3. This section defines various criteria based upon their corresponding method of analysis. To account for multi-axial stresses, the von Mises theory is also considered.

3.9.3.4 Methods of Analysis

The internal structures are analyzed for loads corresponding to normal upset, emergency, and faulted conditions. The analysis performed depends on the mode of operation under consideration.

The scope of the stress analysis problem is very large requiring many different techniques and methods, both static and dynamic. The more important and relevant methods are presented as an overview in Section 3.9.1 and summarized in the following.

3.9.3.5 Blowdown Forces Due to Cold and Hot Leg Break

The MULTIFLEX 3.0 (Reference 17) computer program, an enhancement and extension of the NRC-approved MULTIFLEX 1.0 computer program (Reference 9) was employed to generate the blowdown thermal-hydraulic transient in the primary reactor coolant system due to a postulated pipe rupture, or Loss-Of-Coolant-Accident (LOCA) in both the reactor coolant system hot and cold legs. It considers subcooled, transition and two-phase (saturated) blowdown regimes, employing the method of characteristics to solve the conservation laws, assuming one dimensional flow and a homogeneous liquid-vapor mixture. With its ability to model flow branches and a large number of nodes, MULTIFLEX 3.0 has the required flexibility to represent various flow passages within the primary reactor coolant system. The reactor coolant system is divided into subregions in which the fluid flows along longitudinal axes. While each subregion is regarded as an equivalent pipe, a complex network of these equivalent pipes is used to represent the entire primary RCS.

A coupled fluid-structure interaction is incorporated into the analysis by accounting for the deflection of the constraining boundaries, which are represented by separate springmass oscillator systems. The reactor core barrel is modeled as an equivalent beam with the structural properties of the core barrel in a plane parallel to the broken inlet nozzle. Horizontally, the barrel is divided into 10 segments, with each segment consisting of 3 walls. Mass and stiffness matrices that are obtained from an independent modal analysis of the reactor core barrel are applied in the equations of structural vibration at each of the 10 mass points locations. Horizontal forces are then calculated by applying the spatial pressure variation to the wall area at each of the elevations representative of the 10 mass points of the beam model. The resultant core barrel motion is then translated into an equivalent change in flow area in each downcomer annulus flow channel. At every time increment, MULTIFLEX iterates between the hydraulic and structural subroutines for each location confined by a flexible wall.

Predictions of this code have been compared with numerous test data (Reference 11) and the results show good agreement in both the subcooled and the saturated blowdown regimes.

1. FORCE Models for Blowdown

   The MULTIFLEX 3.0 blowdown code evaluates the pressure and velocity transients at various locations throughout the system. These pressure and velocity transients are stored as a permanent tape file and are made available to the programs LATFORC and FORCE2 (Reference 9) which utilize a detailed geometric description in evaluating the loadings on the reactor internals.

   Each reactor component for which FORCE2 calculations are required is designated as an element and assigned an element number. Forces acting upon each of the elements are calculated summing the effects of:

   a. The pressure differential across the element.
   b. Flow stagnation on, and unrecovered orifice losses across the element.
   c. Friction losses along the element.

   Input to the code, in addition to the MULTIFLEX 3.0 calculated blowdown pressure and velocity transients, includes the effective area of each element on which the force acts due to the pressure differential across the element, a coefficient to account for flow stagnation and unrecovered orifice losses, and the total area of the element along which the shear forces act.

   In addition to the vertical forces calculated by FORCE2 (Reference 9), the horizontal forces on the vessel, core barrel, and thermal shield are calculated by LATFORC (Reference 9). The horizontal forces are calculated by summing the lateral force components around the vessel, core barrel, and thermal shield, based on the pressure differential across each section, multiplied by the area of each section. This is done at 10 different elevations. The total lateral force is calculated by summing the forces over the ten elevations.

   The mechanical analysis has been performed using conservative assumptions in order to obtain results with extra margin. Some of the most significant are:

   a. When applying the hydraulic forces, no credit is taken for the stiffening effect of the fluid environment which will reduce the deflections and stresses in the structure.
   b. The multi-mass model described is considered to have a sufficient number of degrees of freedom to represent the most important modes of vibration in the horizontal and vertical direction.

The summary of the mechanical analysis follows:

2. Transverse and Vertical Excitation Model for Blowdown and Seismic Events

The mathematical model of the reactor pressure vessel (RPV) is a three dimensional nonlinear finite element model which represents the dynamic characteristics of the reactor vessel and its internals in the six geometric degrees of freedom. The model consists of three concentric structural submodels connected by nonlinear impact elements and stiffness matrices. The first submodel, represents the reactor vessel shell and associated components.

The reactor vessel is restrained by the reactor vessel supports and by the attached primary coolant piping. Each reactor vessel support is modeled by a linear horizontal stiffness and a vertical impact element. The attached piping is represented by a stiffness matrix.

The second submodel, represents the reactor core barrel (RCB), neutron panels, lower support plate, tie plates, and secondary core support components. This submodel is physically located inside the first, and is connected to it by a stiffness matrix at the internals support ledge. Core barrel to vessel shell impact is represented by nonlinear elements at the core barrel flange, core barrel nozzle, and lower radial support locations.

The third and innermost submodel, represents the upper support plate, guide tubes, support columns, upper and lower core plates, and fuel. The third submodel is connected to the first and second by stiffness matrices and nonlinear elements.

Fluid-structure or hydro-elastic interaction is included in the reactor pressure vessel model for seismic evaluation. The horizontal hydro-elastic interaction is significant in the cylindrical fluid flow region between the core barrel and reactor vessel (the downcomer). Mass matrices with off-diagonal terms (horizontal degrees-of-freedom only) attach between nodes on the core barrel and reactor vessel shell.

The diagonal terms of the mass matrix are similar to the lumping of water mass to the vessel shell and core barrel. The off-diagonal terms reflect the fact that all the water mass does not participate when there is no relative motion of the vessel and core barrel. It should be pointed out that the hydrodynamic mass matrix has no artificial virtual mass effect and is derived in a straight-forward, quantitative manner.

The matrices are a function of the properties of two cylinders with a fluid in the cylindrical annulus, specifically; inside and outside radius of the annulus, density of the fluid and length of the cylinders. Vertical segmentation of the RCB allows inclusion of radii variations along the RCB height and approximates the effects of RCB beam deformation. These mass matrices were inserted between selected nodes on the core barrel and reactor vessel shell.

This method of modeling of the reactor internals for LOCA and seismic dynamic analyses has been approved by the USNRC (Reference 18).

The appropriate forcing functions are applied simultaneously and independently. The results from the program give the forces, displacements, and deflections as functions of time for all the reactor internals components. Reactor internals response to both hot and cold leg pipe rupture was analyzed.

3. Transverse Excitation Model for Blowdown

Various reactor internal components are subjected to transverse excitation during blowdown. Specifically, the barrel, guide tubes, and upper support columns are analyzed to determine their response to this excitation.

a. Core Barrel

For the hydraulic analysis of the pressure transients during hot leg blowdown, the maximum pressure drop across the barrel is a uniform radial compressive impulse. The barrel is then analyzed for dynamic buckling using these conditions and the following conservative assumptions:

(1) The effect of the fluid environment is neglected (water stiffening is not considered);

(2) The shell is treated as simply supported.

During cold leg blowdown, the upper barrel is subjected to a nonaxisymmetric expansion radial impulse which changes as the rarefaction wave propagates both around the barrel and down the outer flow annulus between vessel and barrel.

The analysis of transverse barrel response to cold leg blowdown is performed as follows:

(1) The upper core barrel is treated as a simply supported cylindrical shell of constant thickness between the upper flange weldment and the lower core barrel weldment without taking credit for the supports at the barrel midspan offered by the outlet nozzles. This assumption leads to conservative deflection estimates of the upper core barrel.

(2) The upper core barrel is analyzed as a shell with four variable sections to model the support flange, upper barrel, reduced weld section, and a portion of the lower core barrel.

(3) The barrel with the core and thermal shielding pads, is analyzed as a beam fixed at the top, and elastically supported, at the lower radial support and the dynamic response is obtained.

b. Guide Tubes

The guide tubes in closest proximity to the outlet nozzle of the ruptured loop are the most severely loaded during a blowdown. The transverse guide tube forces decrease with increasing distance from the ruptured nozzle location.

All of the guide tubes are designed to maintain the function of the control rods for a break size of 144 in^2 and smaller. No credit for the function of the control rods is assumed for break size areas above 144 in^2. However, the design of the guide tube will permit control rod operation in all but four control rod positions which is sufficient to maintain the core in a subcritical configuration for break sizes up to a double ended hot leg break. This double ended hot leg break imposes the limiting lateral guide tube loading.

Upper support columns located close to the broken nozzle during hot leg break will be subjected to transverse loads due to cross flow. The loads applied to the columns were computed with a similar method to the one used for the guide tubes, i.e., taking into consideration the increase in flow across the column during the accident. The columns were studied as beams with variable sections and the resulting stresses were obtained using the reduced section modulus and appropriate stress risers for the various sections.

3.9.3.6 Methods and Results of Blowdown Analysis (Mechanical)

The results obtained from the nonlinear analysis indicate that during blowdown, the relative displacement between the components will close the gaps and consequently the structures will impinge on each other. The effects of the gaps that exist between vessel and barrel, between fuel assemblies, between fuel assemblies and baffle plates, and between the control rods and their guide paths are considered in the analysis. References 5, 12 and 18 provide further details of the blowdown method used in the analysis of the reactor internals.

Results of these analyses indicate that both static and dynamic stress intensities are within acceptable limits. In addition, the cumulative fatigue usage factor is also within the allowable usage factor of unity.

The stresses due to the SSE (vertical and horizontal components) are combined in the most unfavorable manner with the blowdown stresses in order to obtain the largest principal stress and deflection.

These results indicate that the maximum deflections and stress in the critical structures are below the established allowable limits. For the transverse excitation, it is shown that the upper barrel does not buckle during a hot leg break and that it has an allowable stress distribution during a cold leg break.

Even though control rod insertion is not required for plant shutdown, this analysis shows that most of the guide tubes will deform within the limits established experimentally to assure control rod insertion. For the guide tubes deflected above the no loss of function limit, it must be assumed that the rods will not drop. However, the core will still shut down due to the negative reactivity insertion in the form of core voiding. Shutdown will be aided by the great majority of rods that do drop. Seismic deflections of the guide tubes are generally negligible by comparison with the no loss of function limit.

3.9.3.7 Control Rod Drive Mechanisms

The control rod drive mechanisms are Class 1 components designed to meet the stresses of the ASME Boiler and Pressure Vessel Code and, therefore, are presented in Section 4.2.

3.9.3.8 Bolt Loads In Bolted Connections

Typical bolted connection/base plate designs, representing the majority of such designs developed for use on the Virgil C. Summer Nuclear Station, can be classified as follows:

a. Group I - Modular Embedments

   A series of four different configurations of steel base plates and Nelson studs. The plates conform to ASTM A36; the studs, to ASTM A108-58T.

b. Group II - Random Embedments

   A 12 inch square plate conforming to the same material requirements identified in Item 1 above for Group I embedments.

c. Group III - Drilled-in Expansion Bolt Anchored Plates

   Steel base plates having a variety of sizes and thicknesses anchored to the concrete with expansion bolts manufactured by Hilti, Inc. The expansion bolt material conforms to AISI-1144 and/or AISI-1038

   Maxi-Bolts, manufactured by Drillco, are another type of drilled-in anchorage system used to secure steel base plates of various size and thickness. These anchors have an undercut design and are typically utilized in applications which require a higher anchor capacity. MaxiBolt materials conform to ASTM A193, Grade B7.

These designs are illustrated by Figure 3.9-2.

Maximum allowable design loads for Group I and Group II designs are as plotted on Figures 3.9-3 and 3.9-4, respectively. These curves include consideration of the relationship between tensile loads, shears, permissible load eccentricities, and fixture types for modular and random embedments.

Group III Hilti designs were based upon a straight line interaction diagram relating tensile loads and shear loads and upon the assumption that the allowable bolt capacities in tension and shear were 25 percent of failure loads for hilti kwik bolts reported by Abbot A. Hanks, Inc., Testing Laboratories in March 1977 and published in Reference 2. The allowable loads for hilti kwik bolts are 25 percent of the ultimate tension and shear loads published by Hilti.

Group III Maxi-Bolt designs were based upon ACI 349 Appendix B criteria for ductile anchor failure and the 1986 VCS Maxi-Bolt qualification testing program. Allowable tension and shear loads specified in design documents consider minimum concrete strength (3,000 psi), minimum specified ultimate bolt strength, and bolt pre-tensioning. Load factors are in accordance with applicable FSAR loading combinations. Appropriate reduction factors take into account anchor spacing, edge distance, and / or concrete thickness where applicable.

For all three design groups, the original design considered the plates to be rigid.

The base plate and bolt designs have been reexamined to evaluate the effects of plate flexibility, bolt stiffness, and potential prying action. Procedures were developed for the analysis of plates and anchorages for moment and axial load as shown by Figures 3.9-5 through 3.9-8. The

indicated equations were derived from consideration of statics and deflection compatibility for both tension loads and moments. The equations permit calculation of the plate prying force and, subsequently, forces in the anchors and stresses in the plates. For the loading case of tension normal to the plate surface, a single equation can be solved directly for the prying force. For the loading case of moment applied to the plate surface, 6 equations were derived, the simultaneous solution of which yields the prying force. For both cases, criteria have been formulated to determine whether or not prying exists. That determination being a function primarily of the geometry of the detail, the preload and the magnitude of the applied loads.

Using the results of the analysis described by Figures 3.9-5 through 3.9-8, a variety of factors of safety and maximum axial stresses in the bolts were determined. For Group I plates the location of the applied load was chosen to produce the maximum stress in the studs. The resulting maximum stud tension was then combined with the shear on the stud, using the appropriate interaction equation, to determine the factor of safety. The interaction equation for evaluating the factor of safety for Group I and Group II embedments is, as defined in Reference 15:

$$\left(\frac{F.S. \times P}{P_{ult}}\right)^{\frac{5}{3}} + \left(\frac{F.S. \times S}{S_u}\right)^{\frac{5}{3}} \leq 1$$

For plates anchored with expansion bolts the equation is, as defined in Reference 16.

$$\frac{F.S. \times T}{T_o} + \frac{F.S. \times V}{V_o} \leq 1$$

In the above equations P and T are applied tensile loads, S and V are applied shear loads and P_{ult}, T_o, S_u and V_o are ultimate tensile and shear capacities. Because the tension in the stud controls the overall design of the anchorage, the stress in the studs is used as the basis for determining the factor of safety of Group I and Group II embedments. The results of this determination are summarized in Table 3.9-9 in which only the minimum factor of safety for the stud or bolt, determined during the investigation, is reported.

Reactions due to dynamic loads are obtained from a dynamic analysis of the piping system using a recognized and verified computer program. Pipe support reactions are generated as an output of the computer program and are used in the load summary for the design of the individual pipe supports. Since a dynamic analysis is performed, the pipe support reactions generated already include dynamic effects. Therefore, a dynamic load factor is not required.

The governing load for computing factors of safety for expansion bolts is the maximum support load including SSE.

Where appropriate, an equivalent static analysis is used in lieu of a dynamic analysis and a dynamic load factor is established. The dynamic load factor is computed by using the natural frequencies of the structures and the characteristics of the forcing function. These calculations are based upon classical techniques presented in such texts as Introduction to Structural Dynamics by Biggs.

Application of the analytical methods described in Figures 3.9-5 through 3.9-8 resulted in the conclusion that, for plates secured to a concrete surface with expansion bolts, prying forces were considerably less prevalent and, where present, less significant than for plates anchored with Nelson studs. For instance, for Group I plates approximately 35 to 70 percent of the total force on the bolt was due to prying. For Group II plates the prying force accounted for 20 to 30 percent of the total force. For Group III plates prying forces were detected in only 3 of the 94 plates analyzed and in these three cases the prying force increased the total force in the bolt by an average of 25 percent.

The difference in behavior between stud anchored plates and expansion bolt anchored plates, as affected by prying, is attributable to the greater axial stiffness of the stud with respect to the bolt anchorage. For the stud, stiffness is considered to be equal to AE/L and is, therefore, a totally elastic property of the stud. For the expansion bolt, the stiffness is determined from the expression AE/2.5L, where the factor 1/2.5 is applied to account for the reduction in axial stiffness due to tensile elongation of the concrete and the anchor. The resulting stiffness is less than that for an embedded stud but greater than that which would be determined directly from the initial slope of the force displacement curve representing a concrete pullout test of a nonpreloaded anchor. Figures 3.9-9 through 3.9-12 show typical force-displacement curves, as provided by Hilti, Inc., for several different bolt sizes. (Abbot A. Hanks Report No. 8785, January 30, 1974).

As indicated in the preceding discussion, Figures 3.9-9 through 3.9-12 provide experimentally determined force-displacement pull out curves for Hilti bolts used in the Virgil C. Summer Nuclear Station. This data is supplemented by the data presented by Table 3.9-10 which summarizes a series of additional pull out tests performed by the expansion bolt manufacturer. These latter tests consistently indicated a failure in the anchor itself rather than a concrete failure. Nelson stud anchorages were also designed to ensure a ductile failure, including the use of 7/8” by 8-3/16” studs which Nelson indicates to be the most ductile of their headed anchors.

3.9.4 Operability Assurance

Equipment for the Virgil C. Summer Nuclear Station was designed to comply with the intent of Regulatory Guide 1.48; i.e., it was designed/analyzed to ensure structural integrity and operability. However, the load combinations and stress limits that were used reflect NRC requirements that were in effect when the construction permit for this plant was issued and when the components were purchased and subsequently designed. Furthermore, the codes and procedures which were available when the components were purchased are based on conservative design requirements rather than detailed stress analysis and actual testing. These codes and procedures have been used by the nuclear industry for the design of components that are installed in plants that are presently operating.

3.9.4.1 ASME Code Class Valves

The requirements of Section III of the ASME Code were adhered to in the design of active Class 1 valves. For faulted conditions, stress intensities in the valves and extended structures were limited to 1.0 S_m for general membrane and 1.5 S_m for general membrane plus bending. These limits ensure that the valve stresses will remain within elastic limits and that no plastic deformation will occur.

The requirements of Section III of the ASME Code were adhered to in the design of Code Class 1 manually operated globe valves and check valves, 2 inches in size or less.

Class 2 and 3 active valves were also designed to the requirements of the ASME Code. In addition, an analysis of the extended structure was performed with loads of 3.0 g in the horizontal and 2.0 g in the vertical direction simultaneously. For this analysis, stresses were limited to values that restrict the maximum stress in the extended structure. Deflections of the extended structure will thus be small and operability of the valves will not be impaired.

Prior to installation, the valves are subjected to shell hydrostatic tests, seat leakage tests, and functional tests. After installation, the valves undergo cold hydrostatic tests, hot functional tests to verify operation, and periodic inservice inspection and operation to ensure the continued ability of the valves to operate.

3.9.4.2 ASME Code Class Pumps

Active pumps were designed in accordance with Section III of the ASME Code. The stress levels in the pumps did not exceed those provided in Table 3.9-5. Forces resulting from seismic accelerations in the horizontal and vertical directions are included in the analysis of the pumps and their supports. To eliminate any amplification of the seismic floor accelerations in the pump support structure, the supports were designed to have natural frequencies in excess of 33 Hz.

The pumps are subjected to a series of tests prior to installation and after installation in the plant. In-shop tests include hydrostatic tests to 150 percent of the design pressure, seal leakage tests, net positive suction head (NPSH) tests to qualify the pumps for the minimum available NPSH, and functional performance tests. For the NPSH and functional performance tests, the pumps are placed in a test loop and subjected to operating conditions. After installation, the pumps undergo cold hydrostatic tests, hot functional tests to verify operation, and periodic inservice inspection and operation. The above design procedures and qualification tests are, therefore, adequate to ensure the structural integrity and operability of the pumps and valves for this plant.

3.9.5 References

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Table 3.9-0
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
AH	XAA-1A, B; XAA-2A, B	Reactor Building Cooling Unit (4 Units)	a	1. Assembly - analysis	1. Lowest natural frequency determined to be 12.75 Hz. Dynamic seismic analysis, response spectrum input.
				2. Damper - analysis	2. Natural frequency determined to be 25.32 Hz. Static seismic analysis.
				3. Fan and Motor - analysis	3. Natural frequency determined to be 57.47 Hz. Static seismic analysis.
				4. Damper actuator	4. (2)
				5. Limit switch - test	5. Single frequency, single axis test. (1 to 35 Hz no resonance frequency determined in test range).

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
AH	XAH-12A, B	Control Room Normal Supply Cooling Unit (2 Units)	a	1. Cabinet-analysis	1. Natural frequency determined to be 31 Hz. Seismic modal analysis.
				2. Dampers-test	2. Multiple frequency, multi-axis test (1 to 40 Hz).
				3. Cooling coil - analysis	3. Natural frequency determined to be 31.5 Hz. Static seismic analysis.
				4. Fan - analysis	4. Natural frequency determined. Static seismic analysis.
				5. Motor	5. Certificate of conformance with IEEE-344 furnished by motor vendor. Qualification report on file at vendor's office for audit. Vendor considers qualification report as proprietary.

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
AH	XAH-13A, B	Relay Room Air Handling Unit (2 Units)	a	(6)	(6)
AH	XFN-30A, B	Control Room Emergency Fan (2 fans)	a	Analysis	Natural frequency determined to be 61.1 Hz. Static seismic analysis.
AH	XFN-39A, B	Battery Room Exhaust Fan (2 fans)	a	Analysis	Natural frequency determined to be 50.8 Hz. Static seismic analysis.
AH	XFN-80A, B	Service Water Pumphouse Supply Fan (2 fans)	a	Analysis	Natural frequency determined to be 56.8 Hz. Static seismic analysis.
AH	XDP-12A, B; 13A, B; 18A, B;19A, B; 21A, B; 22A, B; 23A, B; 24A, B; 35A, B; 39A, B; 45; 72A, B; 73A, B; 74A, B; 88A, B; 89A, B; 96; 99A, B; 100A, B; 103A, B; 106; 112A, B; 113A, B; 133A, B; 129	Pneumatic Actuated Dampers	a	Type test	Biaxial, multifrequency test, response spectrum input. Type tests included damper, actuator and limit switches and solenoid valves.

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
AH	XDP-152, 153, 155	Electric Motor Actuated Dampers for Battery Rooms A and B (4 Units)	a	(2)	(2)
CC	XPP-1A, B, C	Component Cooling Water Pump (3 pumps)	a	1. Pump and motor analyses	1. Natural frequency determined to be 36.5 Hz. Static analysis.
				2. Pump piping - test	2. Single sinusoidal test frequency, single axis input. Natural frequency is greater than 30 Hz.
CC	XHE-2A, B	Component Cooling Water Heat Exchanger (2 heat exchangers)	a	Analysis	Lowest natural frequency determined to be 31.5 Hz. Static seismic analysis.
CO	XTK-8	Condensate Storage Tank	b	Analysis	Hydrodynamic frequency determined to be 0.252 Hz. Seismic modal analysis (TID-25021). Response spectrum input.
CS	XPP-13A, B	Boric Acid Transfer Pump (2 pumps)	a	Analysis	Natural frequency determined greater than 30 Hz. Static seismic analysis.
CS	XPP-43A, B, C	Charging Pumps (3 pumps)	a	Analysis	Natural frequency determined greater than 30 Hz. Static seismic analysis.

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
CS	XTK-12A, B	Boric Acid Tank (2 tanks)	a	Analysis	Hydrodynamic frequency determined to be 0.464 Hz. Seismic modal analysis (TID-25021). Response spectrum input.
DG	XPP-4A, B; XPP-141A, B	Diesel Generator Fuel Oil Transfer (4 pumps)	a	Analysis	Natural Frequency determined to be 486 Hz. Static seismic analysis.
DG	XTK-9A, B, C, D	Diesel Generator Starting Air Skid (2 skids)	a	Analysis	Lowest skid natural frequency determined to be 20.7 Hz. Seismic modal analysis of starting air equipment.
DG	XTK-20A, B	Diesel Generator Fuel Oil Day Tank (2 tanks)	a	Analysis	Natural frequency determined to be 44.5 Hz. Hydrodynamic frequency determined to be 1.47 Hz. Seismic modal analysis (TID-7024). Static seismic analysis.
DG	XTK-53A, B	Diesel Generator Fuel Oil Storage Tank (2 tanks)	a	Analysis	Natural frequency determined to be 66.2 Hz. Static seismic analysis.
DG	XEG-1A, B	Diesel Generators and Associated Equipment (2 units)	a	1. Diesel engine and mechanical equipment - analysis	1. Modal analysis.
				2. Electrical and air starting controls - tests	2. Multiple frequency, multi-axis testing.

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
DG	XHD-13A, B, C, D	Diesel Generator Air Intake Filter Silencer (4 units)	a	Analysis	Natural frequency determined to be 67.1 Hz. Seismic modal analysis.
DG	XNA-7A, B	Diesel Generator Exhaust Muffler (2 mufflers)	a	Analysis	1. Lowest shell natural frequency determined to be 30 Hz. Static seismic analysis. 2. Internals lowest frequency determined to be 4.4 Hz. Seismic modal analysis.
EF	XPP-8	Turbine Driven Emergency Feedwater Pump	b	1. Pump and Turbine - analysis 2. Pump and Turbine piping appurtenances - test	1. Natural frequency determined to be 64.7 Hz. Static seismic analysis. 2. Single sinusoidal test frequency, single axis input. Natural frequency is greater than 30 Hz.
EF	XPP-21A, B	Motor Driven Emergency Feedwater Pump (2 pumps)	b	1. Pump - analysis 2. Pump piping appurtenances - test	1. Natural frequency determined to be 47.6 Hz. Static seismic analysis. 2. Single sinusoidal test frequency, single axis input. Natural frequency is greater than 30 Hz.

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
EF	IFV-3531 IFV-3536 IFV-3541 IFV-3546 IFV-3551 IFV-3556	Control Valve (6 Valves)	b	Analysis/Test	Static test of unbraced extended structure (valve bonnet, actuator, snubbers, and appurtenances) resulted in natural frequency of 20 Hz (x-axis) and 21 Hz (y-axis). Multifrequency sweep resulted in choosing 19, 24, 26, and 30 Hz (x-z axis) and 19, 22, and 30 Hz. (y-z axis) for sine beat test. Seismic test was biaxial. See also, Note 3.
FW	XVG-1611A, B, C	Main Feedwater Isolation Valves} (3 valves)	b	1. Valve and actuator - analysis	1. Natural frequency determined to be 57.48 Hz. Static seismic analysis. Natural frequencies in horizontal directions were 22 and 24 Hertz, no resonant frequencies found below 33 Hertz in vertical direction. Multifrequency and sine beat tests performed. Sine beat test performed at 22, 24, and 33 Hertz.
				2. Actuator test	2. Multiple frequency, biaxial seismic test.

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
MS	IPV-2000 IPV-2010 IPV-2020	Control Valve (3 valves)	b	Analysis/Test	Static test of unbalanced extended structure (valve bonnet, actuator, snubbers and appurtenances) resulted in natural frequency of 23 Hz. (x-axis) and 21 Hz. (y-axis) Multifrequency sweep resulted in choosing 23, 27.5 and 29 Hz. (x-z axis) and 21, 25, and 29 Hz (y-z axis) for sine beat test. Seismic test was biaxial. See also, Note 3.
MS	IFV-2030	Control Valve	b	Analysis/Test	Static test of unbalanced extended structure (valve bonnet, actuator, snubbers and appurtenances) resulted in natural frequency of 26 Hz. (x-axis) and 25 Hz. (y-axis) Multifrequency sweep resulted in choosing 23.5, 26, 29, 33.5 and 40 Hz. (x-z axis) and 25, 29, 33.5 and 40 Hz (y-z axis) for sine beat test. Seismic test was biaxial. See also, Note 3.

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
MS	XVM-2801A, B, C	Main Steam Isolation Valve (3 valves)	b	Analysis/Test	Natural frequency determined to be 58.2 Hz. Static seismic analysis. Static seismic load test.
MS	XVS-2806A - -XVS-2806N, XVS-2806P	Main Steam Safety Valves (15 valves)	b	Test	Single frequency, single axis seismic test. Natural frequency determined to 37-38 Hz.
RC	XTK-24	Pressurizer Assembly	a	Analysis	Natural frequency determined. Dynamic seismic analysis.
RC	XSG-2A, B, C	Steam Generator (3 units)	a	Analysis	Natural frequency determined. Dynamic seismic analysis.
RH	XPP-31A, B	Residual Heat Removal Pump (2 pumps)	c	Analysis	Natural frequency determined greater than 30 Hz. Static seismic analysis.
RH	XHE-5A, B	Residual Heat Removal Heat Exchanger (2 heat exchangers)	c	Analysis	Natural frequency determined. Dynamic seismic analysis.
SF	XTK-25	Refueling Water Storage Tank	a	Analysis	Hydrodynamic frequency determined to be 0.275 Hz. Seismic modal analysis (TID-25021). Response spectrum input.

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
SW	XPP-39A, B, C	Service Water Pump (3 pumps)	a	Analysis	Natural frequency determined to be 14 Hz. Seismic modal analysis. Response spectrum input.
SW	XPP-45A, B	Service Water Booster Pump (2 pumps)	a	Analysis	Natural frequency determined to be 36.6 Hz. Static seismic analysis.
VL	XAH-4A, B	RHR/Spray Pump Room Cooling Unit (2 units)	c	(6)	(6)
VL	XAH-1A, B; XAH-2	Charging Pump Room Cooling Units (3 units)	a	(6)	(6)
VL	XAH-11A, B	Emergency Feedwater Pump Area Cooling Unit (2 units)	b	(6)	(6)
VL	XAH-24A, B	Battery Room Air Handling Unit (2 units)	a	(6)	(6)
VL	XAH-9A, B	Service Water Booster Pump Area Cooling Unit (2 units)	a	(6)	(6)

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System[1]	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION [4]	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION [5]
VL	XAH-6, XAH-8	ESF Switchgear Room Cooling Unit (2 units)	a	(6)	(6)
VL	XAH-19A, B	Speed Switch Room Cooling Unit (2 units)	a	(6)	(6)
VU	XPP-48A, B, C	HVAC Chilled Water Pump (3 pumps)	a	Analysis	Natural frequency determined to be 37 Hz. Static seismic analysis.
VU	XHX-1A, B, C	HVAC Mechanical Chillers (3 chillers)	a	Test	Multiple frequency, multi-axis test (1 to 40 Hz. range).
		Power Actuated Valves (other than control valves and special valves listed above)	a	Analysis/Test	In general, valves (see Table 3.9-8) were seismically qualified by analysis. Natural frequency was determined and a static seismic analysis was performed. Selected valves and/or prototypes were tested by a static seismic load test or by a single frequency, single axis seismic test.

Table 3.9-0 (CONTINUED)
Seismic Qualification of Mechanical Equipment
Required for Safe Shutdown

System(1)	EQUIP TAG NO.	DESCRIPTION	SAFE SHUTDOWN OPERATION (4)	METHOD OF SEISMIC QUALIFICATION	DESCRIPTION OF SEISMIC QUALIFICATION (5)

(1) System:

AH - Air handling (HVAC)	MS - Main Steam
CC - Component Cooling Water	RC - Reactor Coolant
CO - Condensate	RH - Residual Heat Removal
CS - Chemical and Volume Control	SF - Spent Fuel Cooling
DG - Diesel Generator Services	SW - Service Water
EF - Emergency Feedwater	VL - Local Ventilating and Cooling
FW - Feedwater	VU - Chilled Water

(2) Vendor data not yet available - to be provided later.

(3) Seismic analysis of each type of control valve. Prototype of each control valve type was seismically tested. Multiple frequency, multi-axis seismic test.

(4) Equipment is required to maintain the plant in the following condition:
a.Hot stand-by and cold shutdown
b.Hot stand-by
c.Cold shutdown

(5) .Types of analysis:
a.Static
b.Equivalent static (also known as static coefficient analysis)
c.Dynamic (also known as seismic modal analysis), input to analysis can be either response spectrum or time-history.

(6) Qualified by similarity to XAH-12A, B-AH which was seismically analyzed/tested. XAH-12A, B-AH is the “worst case” for seismic design.

Table 3.9-1
Balance of Plant Component and Plant Operating Conditions

Operating Condition or Initiating Event	Plant Condition	System and Component Condition
Startup	Normal	Normal
Standby	Normal	Normal
Part Load	Normal	Normal
Full Load	Normal	Normal
Shutdown	Normal	Normal
Uncontrolled RCC Assembly Withdrawal at Power	Upset	Upset
Uncontrolled RCC Assembly Withdrawal from a Subcritical Condition	Upset	Upset
RCC Assembly Misalignment	Upset	Upset
Chemical and Volume Control System Malfunction	Upset	Upset
Practical Loss of Forced Reactor Coolant Flow	Upset	Upset
Startup of an Inactive Reactor Coolant Loop	Upset	Upset
Loss of External Electrical Load	Upset	Upset

Table 3.9-1 (continued)
Balance of Plant Component and Plant Operating Conditions

Operating Condition or Initiating Event	Plant Condition	System and Component Condition
Turbine Trip	Upset	Upset
Loss of Normal Feedwater	Upset	Upset
Station Blackout	Upset	Upset
Excessive Heat Removal Due to Feedwater System Malfunction	Upset	Upset
Excessive Load Increase	Upset	Upset
Slow Loss of Reactor Coolant which Actuates Emergency Core Flooding	Emergency	Upset
Minor Secondary System Pipe Break	Emergency	Upset
Loading Fuel Assembly into Improper Position	Emergency	Upset
Complete Loss of Forced Reactor Coolant Flow	Emergency	Upset
Waste Gas Decay Tank Rupture	Emergency	Upset
Loss of Coolant Accident	Faulted	Emergency or Faulted (1)
Rupture of a Steam Pipe	Faulted	Emergency or Faulted (1)

Table 3.9-1 (continued)
Balance of Plant Component and Plant Operating Conditions

Operating Condition or Initiating Event	Plant Condition	System and Component Condition
Steam Generator Tube Rupture	Faulted	Emergency
Single Reactor Coolant Pump Locked Rotor	Faulted	Emergency
Fuel Handling Accident	Faulted	Emergency
Rupture of a Control Rod Drive Mechanism Housing	Faulted	Emergency

(1) Faulted component conditions have been considered for components in a run of pipe subject to pipe rupture between pipe anchors and/or pipe rupture restraints.

Table 3.9-2
Balance of Plant Component Loading Conditions

Component	Component Condition	Design Limits and Loading Combinations	Types of Loadings
Nonactive ASME Code Class 2 and 3 Valves	Normal	Pr not exceeded, per ANSI B16.5, 1968 (see Note 1 for definition of Pr)	Internal pressure (normal) Deadweight Normal piping loads at valve ends
	Upset	Note 1.a.	Internal pressure (upset) Deadweight Upset piping loads at valve ends Operating Basis Earthquake (OBE)
	Emergency	Note 1.b.	Internal pressure (normal) Deadweight Emergency piping loads at valve ends Safe Shutdown Earthquake (SSE)
Active ASME Code Class 2 and 3 Valves	Normal	Pr not exceeded, per ANSI, B16.5, 1968	Internal pressure (normal) Deadweight Normal piping loads at valve ends
	Upset	Note 2.a.	Internal pressure (upset) Deadweight Upset I piping loads at valve ends OBE

Table 3.9-2 (continued)
Balance of Plant Component Loading Conditions

Component	Component Condition	Design Limits and Loading Combinations	Types of Loadings
Active ASME Code Class 2 and 3 Valves (Cont'd)	Upset	Note 2.b.	Internal pressure (upset) Deadweight Upset II piping loads at valve ends
	Emergency	Note 2.c.	Internal pressure (normal) Deadweight Emergency piping loads at valve ends SSE
	Faulted [(i)]	Note 2.c.	Same as emergency, above, except that faulted piping loads are applied at valve ends
ASME Code Class 2 and 3 Vessels, Designed in Accordance with Division 1 of Section VIII of the ASME Code	Normal	In accordance with the ASME Code, Section VIII, Division 1	Internal pressure (normal) Nozzle loads from attached piping (normal) Concentrated loads from supports
	Upset	Notes 3.a. and d.	Internal pressure (upset) Nozzle loads from attached piping (upset) Concentrated loads from supports OBE

Table 3.9-2 (continued)
Balance of Plant Component Loading Conditions

Component	Component Condition	Design Limits and Loading Combinations	Types of Loadings
ASME Code Class 2 and 3 Vessels, Designed in Accordance with Division 1 of Section VIII of the ASME Code (Cont'd)	Upset	Notes 3.b. and d.	Internal pressure (Upset) Nozzle loads from attached piping (upset) Concentrated loads from supports
	Emergency	Notes 3.c. and d.	Internal pressure (normal) Nozzle loads from attached piping (emergency) Concentrated loads from supports SSE
ASME Code Class 2 Vessels, Designed in accordance with Division 2 of Section VIII of the ASME Code	Normal	In accordance with the ASME Code, Section VIII, Division 2	Internal pressure (normal) Nozzle loads from attached piping (normal) Concentrated loads from supports
	Upset	Note 4..a.	Internal pressure (upset) Nozzle loads from attached piping (upset) Concentrated loads from supports OBE

Table 3.9-2 (continued)
Balance of Plant Component Loading Conditions

Component	Component Condition	Design Limits and Loading Combinations	Types of Loadings
ASME Code Class 2 Vessels, Designed in Accordance with Division 2 of Section VIII of the ASME Code (Cont'd)	Upset	Note 4.b.	Internal pressure (Upset) Nozzle loads from attached piping (upset) Concentrated loads from supports
	Emergency	Note 4.c.	Internal pressure (Normal) Nozzle loads from attached piping (emergency) Concentrated loads from supports SSE
ASME Code Class 2 and 3 Piping	Normal	In accordance with the ASME Code, Section III, for Normal design conditions	Deadweight Longitudinal pressure stress (normal) Thermal expansion stress Soil loads (buried piping only)
	Upset	Note 5.a.	Deadweight Longitudinal pressure stress (upset) Thermal expansion stress OBE (ii) Flow transients (ii) Soil loads and vehicle loads (buried piping only) Safety valve reactions, as applicable (ii)

Table 3.9-2 (continued)
Balance of Plant Component Loading Conditions

Component	Component Condition	Design Limits and Loading Combinations	Types of Loadings
ASME Code Class 2 and 3 Piping (Cont'd)	Upset	Notes 5.b. and d	Deadweight Longitudinal pressure stress (upset) Flow transients Soil loads and vehicle loads (buried piping only) Safety valve reactions, as applicable (ii) Jet loadings
	Emergency	Note 5.c.	Deadweight Longitudinal pressure stress (normal) Flow transients (ii) Soil loads (buried piping only) Jet loadings SSE (ii)
	Faulted(iii)	Note 5.c.	Deadweight Longitudinal pressure stress (normal) Flow transients (ii) Soil loads (buried piping only) Pipe rupture loads SSE (ii)

Table 3.9-2 (continued)
Balance of Plant Component Loading Conditions

Component	Component Condition	Design Limits and Loading Combinations	Types of Loadings
Nonactive ASME Code Class 2 and 3 Pumps	Normal	In accordance with the ASME Code, Section III	Internal pressure (normal) Nozzle loads from attached piping (normal) Concentrated loads from supports
	Upset	Note 6.a.	Internal pressure (upset) Nozzle loads from attached piping (upset) Concentrated loads from supports OBE
	Upset	Note 6.b.	Internal pressure (upset) Nozzle loads from attached piping (upset) Concentrated loads from supports
	Emergency	Note 6.c.	Internal pressure (normal) Nozzle loads from attached piping (emergency) Concentrated loads from supports SSE
Active ASME Code Class 2 and 3 Pumps	Normal	In accordance with the ASME Code, Section III	Internal pressure (normal) Nozzle loads from attached piping (normal) Support loads

Table 3.9-2 (continued)
Balance of Plant Component Loading Conditions

Component	Component Condition	Design Limits and Loading Combinations	Types of Loadings
Active ASME Code Class 2 and 3 Pumps (Cont'd)	Upset	Notes 7.a. and d.	Internal pressure (upset) Nozzle loads from attached piping (upset) Support loads OBE
	Upset	Notes 7.b. and d.	Internal pressure (upset) Nozzle loads from attached piping (upset) Support loads
	Emergency	Notes 7.c. and d.	Internal pressure (normal) Nozzle loads from attached piping (emergency) Support loads SSE
Code Class 2 and 3 Pipe Supports	Pipe support design conditions are consistent with the design conditions established for the piping	In accordance with the ASME Code, Section III, Subsection NF, Winter 1973 Addenda	Deadweight Superimposed loads and reactions Dynamic loads (seismic, flow transient) Thermal expansion Anchor and support movements Environmental loads

Table 3.9-2 (continued)
Balance of Plant Component Loading Conditions

Component	Component Condition	Design Limits and Loading Combinations	Types of Loadings
Code Class 2 and 3 Supports for Pumps and Vessels	Same as for supported component	In accordance with the ASME Code, Section III, Subsection NF, as applicable	Deadweight Superimposed loads and reactions Dynamic loads (seismic, flow transient) Thermal expansion Anchor and support movements Environmental loads
Code Class 2 and 3 Snubbers	Snubber design conditions are consistent with the design conditions established for the piping	In accordance with the ASME Code, Section III, Subsection NF, Winter 1976 Addenda	Dynamic loads (seismic, flow transient)

(i) Faulted component condition is specified for active valves in a run of pipe subject to a postulated pipe rupture. Operability has been demonstrated through test and analysis.
(ii) The following loads, if applicable, may be combined on a root mean square basis:
1. Flow transients.
2. OBE or SSE Peak loads.
3. Dynamic portion of safety valve reactions.
(iii) Faulted piping conditions are postulated for portions of piping systems subject to postulated pipe rupture.

TABLE 3.9-2 (Continued)

NOTES TO TABLE 3.9-2

1. Nonactive ASME Code Class 2 and 3 Valves

   The design of Code Class 2 and 3 valves encompasses the use of pressure temperature ratings. The design limits are in terms of Pr which is the primary pressure rating corresponding to the maximum transient temperature for each plant condition as specified in Articles NC-3511 and ND-3511 of the ASME Code, Section III, for Code Class 2 and 3 valves, respectively. To assure pressure retaining integrity the limits for Pr are set as follows:

   a. The primary pressure rating, Pr, is not exceeded by more than 10 percent when the component is subject to concurrent loadings associated with either:

      (1) The normal plant condition or the upset plant condition and the vibratory motion of 50 percent of the SSE.

      (2) Loading conditions associated with the emergency plant condition.

   b. Pr is not exceeded by more than 20 percent when the component is subject to concurrent loadings associated with the normal plant condition, the vibratory motion of the SSE and the dynamic system loadings associated with the faulted plant condition.

2. Active ASME Code Class 2 and 3 Valves

   To provide pressure retaining integrity and assurance of operability for active valves of Code Class 2 and 3, Pr is not exceeded for the combinations of loading delineated.

   a. The primary pressure rating, Pr, is not exceeded when the component is subjected to concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50 percent of the SSE.

   b. The primary pressure rating, Pr, is not exceeded when the component is subject to loadings associated with the emergency plant condition.

   c. The primary pressure rating, Pr, is not exceeded when the component is subject to concurrent loadings associated with the normal plant condition, the vibratory motion of the SSE and the dynamic system loadings associated with the faulted plant condition.

3. ASME Code Class 2 and 3 Vessels (designed in accordance with Division 1 of Section VIII of the ASME Code) (See Item d, below).

   To provide assurance of pressure retaining integrity for Code Class 2 and 3 vessels (designed in accordance with Division 1 of Section VIII of the ASME Code) the allowable stress value, S, (as specified in Appendix 1 of Section III of the ASME Code) is not exceeded by more than 10 percent when the component is subjected to the loading combinations identified by items a and b, below, and is not exceeded by more than 50 percent when the component is subjected to the loading combinations identified by item c, below.

TABLE 3.9-2 (Continued)

a. Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50 percent of the SSE.

b. Loadings associated with the emergency plant condition.

c. The allowable stress value, S is not exceeded by more than 50 percent when the component is subjected to concurrent loadings associated with the normal plant condition, the vibratory motion of the SSE and the dynamic system loadings associated with the faulted plant condition.

d. When a more detailed analysis is performed, Division 1 vessels satisfy, as a minimum, equations (1) and (2), below. Equation (1) is applicable to items a and b, above. Equation (2) is applicable to item c, above.

$$\sigma M < 1.1\ S > \sigma \frac{\sigma_M + \sigma_b}{1.5} \qquad (1)$$

$$\sigma M < 1.5\ S > \sigma \frac{\sigma_M + \sigma_b}{1.5} \qquad (2)$$

Where:

σ_M = Primary membrane stress.

σ_b = Primary bending stress.

S = Allowable stress value as specified in Appendix 1 of Section III of the ASME Code.

4. ASME Code Class 2 Vessels (designed in accordance with Division 2 of Section VIII of the ASME Code.)

To provide assurance of pressure retaining integrity for Code Class 2 Vessels, (designed in accordance with Division 2 of Section VIII of the ASME Code) the upset, emergency and faulted operating condition category design limits of Article NB-3200 of Section III of the ASME Code are not exceeded when the component is subjected to the following combinations:

a. The design limits specified in Article NB-3223 of the ASME Code are not exceeded when the component is subjected to concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50 percent of the SSE.

b. The design limits specified in Article NB-3224 of the ASME Code are not exceeded when the component is subjected to loadings associated with the emergency plant condition.

c. The design limits specified in Article NB-3225 of the ASME Code are not exceeded when the component is subjected to concurrent loadings associated with the normal plant condition, the vibratory motion of the SSE and the dynamic system loadings associated with the faulted plant condition.

TABLE 3.9-2 (Continued)

5. ASME Code Class 2 and 3 Piping

To provide assurance of pressure retaining integrity for Code Class 2 and 3 piping, the design limits specified in NC-3611.1(b)(4)(c)(b)(1) of the Winter 1972 Addenda to Section III of the ASME Code (i.e., 1.2Sh) are not exceeded when the piping is subjected to the loading combinations identified in items a and b, below. However, for short sections of piping exposed to jet impingement from postulated cracks or breaks in adjacent piping, a stress limit of 1.5Sh may be used.

The design limits specified in NC-3611.1(b)(4)(c)(b)(2) of the Winter 1972 Addenda to Section III of the ASME Code (i.e. 1.8Sh) are not exceeded when the piping is subjected to the loading combinations identified in item c below. However, for short sections of piping exposed to jet impingement from postulated cracks or breaks in adjacent piping, a stress limit of 2.4Sh may be used.

Whenever the 2.4Sh allowable stress limit is employed for Class 2 and 3 piping, an evaluation of the allowable collapse load will be performed in accordance with Appendix F to the ASME Code, Section III, Winter, 1972, Addenda. It is recognized that neither the "collapse load" nor the "plastic instability load," as defined by the ASME Code, refer to geometrical instability. However, test results are available which do provide a basis for evaluating geometrical stability of fittings (elbows and tees), as well as straight pipe, at stress levels associated with the ASME Code "collapse" or "plastic instability" load limit. Additionally, test results reveal that, for thickness to radius ratios (t/r) less than 0.08, the mode of collapse is not in the form of geometrical instability at the fitting or discontinuity. The piping systems evaluated generally have t/r ratios less than 0.08.

a. Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50 percent of the SSE.

b. Loadings associated with the emergency plant conditions (see Note 1).

c. Concurrent loadings associated with the normal plant condition, the vibratory motion of the SSE and the dynamic system loadings associated with the faulted plant condition.

Thermal expansion effects of piping are not evaluated for loadings associated with emergency or faulted plant conditions. Therefore, only Equation 9 of Article NC-3651 of Section III of the ASME Code is applied for the loading combinations identified in items b and c, above. Thermal expansion effects are evaluated for the loading combinations identified in item a, above.

TABLE 3.9-2 (Continued)

6. Nonactive ASME Code Class 2 and 3 pumps

   In order to assure pressure retaining integrity for nonactive Code Class 2 and 3 pumps, the primary membrane stress is not exceeded by more than 10 percent of S (as specified in Appendix 1 of Section III of the ASME Code) and the sum of the primary membrane plus primary bending stresses is not exceeded by more than 65 percent of S when the component is subjected to the following load combinations:

   a. Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50 percent of the SSE.
   b. Loadings associated with the emergency plant condition.
   c. In addition, the primary membrane stress is not exceeded by more than 20 percent of S, and the sum of the primary membrane and primary bending stresses is not exceeded by more than 80 percent of S when the component is subjected to concurrent loadings associated with the normal plant condition, the vibratory motion of the SSE and the dynamic system loadings associated with the faulted plant condition.

7. Active ASME Code Class 2 and 3 Pumps

   To provide increased assurance that unacceptable deformations affecting operability of active Code Class 2 and 3 pumps do not result, the primary membrane stress does not exceed S (as specified in Appendix 1 of Section III of the ASME Code) and the sum of the primary membrane plus primary bending stresses is not exceeded by more than 50 percent of S when the component is subjected to the following loading combinations: (See item d, below).

   a. Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50 percent of SSE.
   b. Loadings associated with the emergency plant condition.
   c. Concurrent loadings associated with the normal plant condition, the vibratory motion of the SSE and the dynamic system loadings associated with the faulted plant condition.
   d. The design limits given below are not exceeded for the applicable loading combinations. Analysis and/or testing confirms that operability is not impaired when the component is designed to these limits.

      The primary membrane stress is not exceeded by more than 10 percent of S and the sum of the primary membrane plus primary bending stresses is not exceeded by more than 65 percent of S when the component is subjected to the following combinations:

      (1) Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50 percent of the SSE.
      (2) Loadings associated with the emergency plant condition.

TABLE 3.9-2 (Continued)

The primary membrane stress is not exceeded by more than 20 percent of S and the sum of the primary membrane and primary bending stresses is not exceeded by more than 80 percent of S which the component is subjected to concurrent loadings associated with the normal plant condition, the vibratory motion of the SSE and the dynamic system loadings associated with the faulted plant condition.

Table 3.9-3
Design Loading Combinations For NSSS Supplied
ASME Code Class 2 and 3 Components and Supports

Conditions Classification	Loading Combination
Design and Normal	Design pressure Design temperature, (1) Dead weight, nozzle loads (2)
Upset	Upset condition pressure, Upset condition metal temperature, (1) deadweight, OBE, nozzle loads (2)
Faulted	Faulted condition pressure, faulted condition metal temperature, (1) deadweight, SSE, nozzle loads (2)

(1) Temperature is used to determine allowable stress only.
(2) Nozzle loads are those loads associated with the particular plant operating conditions for the component under consideration.

Table 3.9-4
Stress Criteria for NSSS Supplied Safety-Related
ASME Class 2 and Class 3 Tanks

Condition	Stress Limits
Design and Normal	The vessel shall conform to the requirements of ASME Section VIII, Division 1.
Upset	$\sigma_m \leq 1.1\ S$ (σ_m or σ_L) + $\sigma_b \leq 1.65\ S$
Faulted	$\sigma_m \leq 2.0S$ (σ_m or σ_L) + $\sigma_b \leq 2.4\ S$

Table 3.9-5
Design Criteria For NSSS Supplied Pumps

Condition	Design Criteria
Design and Normal	ASME Section III Subsection NC-3400 and ND-3400
Upset	$\sigma_m \leq 1.1\ S$ $(\sigma_m \text{ or } \sigma_L) + \sigma_b \leq 1.65\ S$
Faulted	$\sigma m \leq 2.0\ S$ $(\sigma_m \text{ or } \sigma_L) + \sigma_b \leq 2.4\ S$

Table 3.9-6
Stress Criteria For NSSS Supplied Safety-Related ASME Code
Class 2 and Class 3 Valves

Condition	Stress Limits (Notes 1-5)	P_{max} (Note 6)
Design and Normal	Valve bodies shall conform to the requirements of ASME Section III, NC-3500 (or ND-3500)	
Upset	$\sigma_m \leq 1.1\ S$ $(\sigma_m \text{ or } \sigma_L) + \sigma_b \leq 1.65\ S$	1.1
Faulted	$\sigma m \leq 2.0\ S$ $(\sigma_m \text{ or } \sigma_L) + \sigma_b \leq 2.4\ S$	1.5

(1) Stress analysis is not required when both the following conditions are satisfied: (1) section modulus and area of every plane, normal to the flow, through the region defined as the valve body crotch is at least 110% of those for the piping connected (or joined) to the valve body inlet and outlet nozzles; and, (2) code allowable stress, S, for valve body material is equal to or greater than the code allowable stress, S, of connected piping material. If the valve body material allowable stress is less than that of the connected piping, the acceptance criteria ratio shall be 110% multiplied by the ratio of S_{pipe}/S_{valve}. If unable to comply with this requirement, the design by analysis procedure of NB-3545.2 is an acceptable alternate method.

(2) Casting quality factor of 1.0 shall be used.

(3) These stress limits are applicable to the pressure retaining boundary, and include the effects of loads transmitted by the extended structures, when applicable.

(4) Design requirements listed in this table are not applicable to valve discs, stems, seat rings, or other parts of valves which are contained within the confines of the body and bonnet, or otherwise not part of the pressure boundary.

(5) These rules do not apply to Class 2 and 3 relief valves. Relief valves are designed in accordance with the ASME Code, Section III requirements.

(6) The maximum pressure resulting from upset or faulted conditions shall not exceed the tabulated factors listed under P_{max} times the design pressure or the rated pressure at the applicable operating condition temperature. If the pressure rating limits are met at the operating conditions, the stress limits in this table are considered to be satisfied.

Table 3.9-7
Active Code Class 2 and 3 Pumps

Balance of Plant Pumps

Pump Tag Number	System (1)	Location (2)	Safety Class	FSAR Figure	Method of Qualification (3)
XPP0001A	CC	IB	2b	9.2-4	A&T
XPP0001B	CC	IB	2b	9.2-4	A&T
XPP0001C	CC	IB	2b	9.2-4	A&T
XPP0004A	DG	DB	2b	9.5-2	A
XPP0004B	DG	DB	2b	9.5-2	A
XPP0141A	DG	DB	2b	9.5-2	A
XPP0141B	DG	DB	2b	9.5-2	A
XPP0008	EF	IB	2b	10.4-16	A&T
XPP0021A	EF	IB	2b	10.4-16	A&T
XPP0021B	EF	IB	2b	10.4-16	A&T
XPP0038A	SP	AB	2a	6.2-46	A
XPP0038B	SP	AB	2a	6.2-46	A
XPP0039A	SW	SW	2b	9.2-1	A
XPP0039B	SW	SW	2b	9.2-1	A
XPP0039C	SW	SW	2b	9.2-1	A
XPP0045A	SW	IB	2b	9.2-1	A
XPP0045B	SW	IB	2b	9.2-1	A
XPP0048A	VU	IB	2b	9.4-22	A
XPP0048B	VU	IB	2b	9.4-22	A
XPP0048C	VU	IB	2b	9.4-22	A
NSSS Pumps					
Charging Pumps					
XPP0043A	CS	AB	2a	6.3-1	A
XPP0043B	CS	AB	2a	6.3-1	A
XPP0043C	CS	AB	2a	6.3-1	A
RHR Pumps					
XXP0031A	RH	AB	2a	6.3-1	A
XXP0031B	RH	AB	2a	6.3-1	A

Table 3.9-7 (continued)
Active Code Class 2 and 3 Pumps

Balance of Plant Pumps

Pump Tag Number	System (1)	Location (2)	Safety Class	FSAR Figure	Method of Qualification (3)

(1) Systems are as follows:
CC - Component Cooling Water
CS - Chemical and Volume Control
DG - Diesel Generator
EF - Emergency Feedwater
RH - Residual Heat Removal
SP - Reactor Building Spray
SW - Service Water
VU - HVAC Chilled Water

(2) Locations are as follows:
IB - Intermediate Building
DB - Diesel Generating Building
AB - Auxiliary Building
SW - Service Water Pumphouse

(3) Methods of qualification are as follows:
A - Analysis
T - Test

Table 3.9-8
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVG00265-AS	AS	IB	6	3	N/A	S	A
XVG00273-AS	AS	IB	6	3	N/A	S	A
XVG0503A	BD	AB	3	2	10.4-13	AO	A
XVG0503B	BD	AB	3	2	10.4-13	AO	A
XVG0503C	BD	AB	3	2	10.4-13	AO	A
XVB9503A	CC	AB	20	3	9.2-4	MO	A
XVB9503B	CC	AB	20	3	9.2-4	MO	A
XVB9524A	CC	AB	16	3	9.2-4	MO	A
XVB9524B	CC	AB	16	3	9.2-4	MO	A
XVB9525A	CC	AB	16	3	9.2-4	MO	A
XVB9525B	CC	AB	16	3	9.2-4	MO	A
XVB9526A	CC	IB	16	3	9.2-4	MO	A
XVB9526B	CC	IB	16	3	9.2-4	MO	A
XVG9568	CC	AB	8	2	9.2-5	MO	A
XVC9570	CC	RB	8	2	9.2-5	N	A
XVG9600	CC	IB	3	2	9.2-5	MO	A
XVC9602	CC	RB	3	2	9.2-5	N	A
XVG9605	CC	RB	8	2	9.2-5	MO	A
XVG9606	CC	AB	8	2	9.2-5	MO	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVG9625	CC	AB	8	3	9.2-5	MO	A
XVG9626	CC	AB	8	3	9.2-5	MO	A
XVG9627A	CC	IB	4	3	9.2-4	AO	A
XVG9627B	CC	IB	4	3	9.2-4	AO	A
XVG9684A	CC	AB	2	3	9.2-7	AO	A
XVG9684B	CC	AB	2	3	9.2-7	AO	A
XVG9684C	CC	AB	2	3	9.2-7	AO	A
XVC9632	CC	AB	8	3	9.2-5	N	A
XVC9680A	CC	IB	4	3	9.2-4	N	A
XVC9680B	CC	IB	4	3	9.2-4	N	A
XVC9633	CC	AB	8	3	9.2-5	N	A
XVC9682A	CC	IB	24	3	9.2-4	N	A
XVC9682B	CC	IB	24	3	9.2-4	N	A
XVC9682C	CC	IB	24	3	9.2-4	N	A
XVB9687A	CC	IB	16	3	9.2-4	MO	A
XVB9687B	CC	IB	16	3	9.2-4	MO	A
XVC970A,B	DG	DB	2	3	9.5-2	N	A
XVC971A,D	DG	YD	3	3	9.5-2	N	A
XVC972A,B	DG	DB	2	3	9.5-2	N	A
XVC10977A,B	DG	DB	3/4	3	9.5-6	N	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVC10978A,B	DG	DB	3/4	3	9.5-6	N	A
XVG1001A	EF	IB	6	3	10.4-16	MO	A
XVG1001B	EF	IB	6	3	10.4-16	MO	A
XVG1002	EF	IB	8	3	10.4-16	MO	A
XVG1008	EF	IB	8	3	10.4-16	MO	A
XVC1009A	EF	PR	4	2	10.4-16	AO	A
XVC1009B	EF	PR	4	2	10.4-16	AO	A
XVC1009C	EF	PR	4	2	10.4-16	AO	A
XVC1013A	EF	IB	6	3	10.4-16	N	A
XVC1013B	EF	IB	6	3	10.4-16	N	A
XVC1014	EF	IB	8	3	10.4-16	N	A
XVC01048A	EF	IB	4	3	10.4-16	N	A
XVC01048B	EF	IB	4	3	10.4-16	N	A
XVC1016	EF	IB	4	3	10.4-16	N	A
XVK1019A	EF	IB	4	2	10.4-16	N	A
XVK1019B	EF	IB	4	2	10.4-16	N	A
XVK1019C	EF	IB	4	2	10.4-16	N	A
XVK1020A	EF	IB	4	2	10.4-16	N	A
XVK1020B	EF	IB	4	2	10.4-16	N	A
XVK1020C	EF	IB	4	2	10.4-16	N	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVC1022A	EF	IB	8	3	10.4-16	N	A
XVC1022B	EF	IB	8	3	10.4-16	N	A
XVC1023A	EF	IB	2	3	10.4-16	N	A
XVC1023B	EF	IB	2	3	10.4-16	N	A
XVC1024	EF	IB	3	3	10.4-16	N	A
XVC1034A	EF	IB	6	3	10.4-16	N	A
XVC1034B	EF	IB	6	3	10.4-16	N	A
XVG1037A	EF	IB	8	3	10.4-16	MO	A
XVG1037B	EF	IB	8	3	10.4-16	MO	A
IFV3531	EF	IB	4	2	10.4-16	AO	A & T
IFV3536	EF	IB	4	2	10.4-16	AO	A & T
IFV3541	EF	IB	4	2	10.4-16	AO	A & T
IFV3546	EF	IB	4	2	10.4-16	AO	A & T
IFV3551	EF	IB	4	2	10.4-16	AO	A & T
IFV3556	EF	IB	4	2	10.4-16	AO	A & T
XVM01072A	EF	IB	4	3	10.4-16	N	A
XVM01072B	EF	IB	4	3	10.4-16	N	A
XVG6797	FS	PR	4	2	9.5-1,Sht.3	MO	A
XVG1611A	FW	PR	18	2	10.4-12	AO	A
XVG1611B	FW	PR	18	2	10.4-12	AO	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVG1611C	FW	PR	18	2	10.4-12	AO	A
XVK1633A	FW	PR	1-1/2	2	10.4-12	MO	A
XVK1633B	FW	PR	1-1/2	2	10.4-12	MO	A
XVK1633C	FW	PR	1-1/2	2	10.4-12	MO	A
XVC1684A	FW	PR	18	2	10.4-12	N	A & T
XVC1684B	FW	PR	18	2	10.4-12	N	A & T
XVC1684C	FW	PR	18	2	10.4-12	N	A & T
XVX6050A	HR	RB	3/8	2	6.2-58	S	T
XVX6050B	HR	RB	3/8	2	6.2-58	S	T
XVX6051A	HR	RB	3/8	2	6.2-58	S	T
XVX6051B	HR	RB	3/8	2	6.2-58	S	T
XVX6051C	HR	RB	3/8	2	6.2-58	S	T
XVX6052A	HR	PR	3/8	2	6.2-58	S	T
XVX6052B	HR	FH	3/8	2	6.2-58	S	T
XVX6053A	HR	PR	3/8	2	6.2-58	S	T
XVX6053B	HR	FH	3/8	2	6.2-58	S	T
XVX6054	HR	PR	3/8	2	6.2-58	S	T
XVG6056	HR	RB	6	2	6.2-58	AO	A
XVG6057	HR	FH	6	2	6.2-58	AO	A
XVG6066	HR	RB	6	2	6.2-58	AO	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVG6067	HR	PR	6	2	6.2-58	AO	A
XVT2660	IA	AB	2	2	9.3-3	AO	T
XVT2661	IA	RB	2	2	9.3-3	N	T
XVT2662A	IA	AB	6	2	9.3-3	AO	T
XVT2662B	IA	RB	6	2	9.3-3	AO	A
IPV2000	MS	IB	8	2	10.3-1	AO	A & T
IPV2010	MS	IB	8	2	10.3-1	AO	A & T
IPV2020	MS	IB	8	2	10.3-1	AO	A & T
IFV2030	MS	IB	4	3	10.3-1	AO	A & T
XVM2801A	MS	IB	32	2	10.3-1	AO	A & T
XVM2801B	MS	IB	32	2	10.3-1	AO	A & T
XVM2801C	MS	IB	32	2	10.3-1	AO	A & T
XVG2802A	MS	IB	4	2	10.3-1	MO	A
XVG2802B	MS	IB	4	2	10.3-1	MO	A
XVS2806A	MS	IB	6x10	2	10.3-1	N	A
XVS2806B	MS	IB	6x10	2	10.3-1	N	A
XVS2806C	MS	IB	6x10	2	10.3-1	N	A
XVS2806D	MS	IB	6x10	2	10.3-1	N	A
XVS2806E	MS	IB	6x10	2	10.3-1	N	A
XVS2806F	MS	IB	6x10	2	10.3-1	N	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVS2806G	MS	IB	6x10	2	10.3-1	N	A
XVS2806H	MS	IB	6x10	2	10.3-1	N	A
XVS2806I	MS	IB	6x10	2	10.3-1	N	A
XVS2806J	MS	IB	6x10	2	10.3-1	N	A
XVS2806K	MS	IB	6x10	2	10.3-1	N	A
XVS2806L	MS	IB	6x10	2	10.3-1	N	A
XVS2806M	MS	IB	6x10	2	10.3-1	N	A
XVS2806N	MS	IB	6x10	2	10.3-1	N	A
XVS2806P	MS	IB	6x10	2	10.3-1	N	A
XVT2843A	MS	IB	1-1/2	2	10.3-1	AO	A & T
XVT2843B	MS	IB	1-1/2	2	10.3-1	AO	A & T
XVT2843C	MS	IB	1-1/2	2	10.3-1	AO	A & T
XVT2877A	MS	PR	1-1/2	2	10.3-1	AO	A & T
XVT2877B	MS	PR	1-1/2	2	10.3-1	AO	A & T
XVT2869A	MS	IB	4	2	10.3-1	AO	T
XVT2869B	MS	IB	4	2	10.3-1	AO	T
XVT2869C	MS	IB	4	2	10.3-1	AO	T
XVC2876A	MS	IB	4	3	10.3-1	N	A
XVC2876B	MS	IB	4	3	10.3-1	N	A
XVD6242A	ND	RB	3	2	9.3-12	AO	T

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVD6242B	ND	AB	3	2	9.3-12	AO	T
XVG6701	SF	YD	3	2	9.1-3	N	A
XVG3001A	SP	AB	12	2	6.2-46	MO	A
XVG3001B	SP	AB	12	2	6.2-46	MO	A
XVG3002A	SP	AB	3	3	6.2-46	MO	A
XVG3002B	SP	AB	3	3	6.2-46	MO	A
XVG3003A	SP	PR	10	2	6.2-46	MO	T
XVG3003B	SP	PR	10	2	6.2-46	MO	A
XVG3004A	SP	AB	12	2	6.2-46	MO	A
XVG3004B	SP	AB	12	2	6.2-46	MO	A
XVG3005A	SP	AB	12	2	6.2-46	MO	A
XVG3005B	SP	AB	12	2	6.2-46	MO	A
XVC3006A	SP	AB	12	2	6.2-46	N	A
XVC3006B	SP	AB	12	2	6.2-46	N	A
XVC3009A	SP	RB	10	2	6.2-46	N	A
XVC3009B	SP	RB	10	2	6.2-46	N	A
XVC3013A	SP	AB	3	2	6.2-46	N	A
XVC3013B	SP	AB	3	2	6.2-46	N	A
XVA9311A	SS	RB	1	2	9.3-4	AO	A
XVA9311B	SS	PR	1	2	9.3-4	AO	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVA9312A	SS	RB	1	2	9.3-4	AO	A
XVA9312B	SS	PR	1	2	9.3-4	AO	A
XVT9339	SS	RB	3/8	2	9.3-20	S	A
XVT9341	SS	AB	3/8	2	9.3-20	S	A
XVX9356A	SS	RB	3/8	2	9.3-4	S	A & T
XVX9356B	SS	RB	3/8	2	9.3-4	S	A & T
XVX9357	SS	AB	3/8	2	9.3-4	S	A & T
XVV3014A	SP	AB	2x2	3	6.2-46	N	T
XVV3014B	SP	AB	2x2	3	6.2-46	N	T
XVX9364B	SS	RB	3/8	2	9.3-4	S	A & T
XVX9364C	SS	RB	3/8	2	9.3-4	S	A & T
XVX9365B	SS	AB	3/8	2	9.3-4	S	A & T
XVX9365C	SS	IB	3/8	2	9.3-4	S	A & T
XVX9387	SS	AB	3/8	2	9.3-4	S	A & T
XVX9398A	SS	AB	1	2	9.3-4	S	A & T
XVX9398B	SS	IB	1	2	9.3-4	S	A & T
XVX9398C	SS	IB	1	2	9.3-4	S	A & T
XVG3103A	SW	PR	16	2	9.2-2 SH. 2	MO	A
XVG3103B	SW	IB	16	2	9.2-2 SH. 4	MO	A
XVB3106A	SW	PR	16	2	9.2-2 SH. 2	MO	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVB3106B	SW	IB	16	2	9.2-2 SH. 4	MO	A
XVB3107A	SW	PR	16	3	9.2-2 SH. 2	AO	A
XVB3107B	SW	FH	16	3	9.2-2 SH. 4	AO	A
XVG3109A	SW	RB	10	2	9.2-2 SH. 2	MO	A
XVG3109B	SW	RB	10	2	9.2-2 SH. 2	MO	A
XVG3109C	SW	RB	10	2	9.2-2 SH. 4	MO	A
XVG3109D	SW	RB	10	2	9.2-2 SH. 4	MO	A
XVB3110A	SW	PR	12	2	9.2-2 SH. 2	MO	A
XVB3110B	SW	IB	12	2	9.2-2 SH. 4	MO	A
XVG3111A	SW	PR	12	3	9.2-2 SH. 2	MO	A
XVG3111B	SW	IB	12	3	9.2-2 SH. 4	MO	A
XVG3112A	SW	PR	12	3	9.2-2 SH. 2	MO	A
XVG3112B	SW	IB	12	3	9.2-2 SH. 4	MO	A
XVC3115A	SW	SW	24	3	9.2-1	N	A
XVC3115B	SW	SW	24	3	9.2-1	N	A
XVC3115C	SW	SW	24	3	9.2-1	N	A
XVB3116A	SW	SW	24	3	9.2-1	MO	A
XVB3116B	SW	SW	24	3	9.2-1	MO	A
XVB3116C	SW	SW	24	3	9.2-1	MO	A
XVC3119A	SW	SW	8	3	9.2-2 SH. 1	N	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVC3119B	SW	SW	8	3	9.2-2 SH. 3	N	A
XVB3126A	SW	IB	6	3	9.2-2 SH. 1	MO	T
XVB3126B	SW	IB	6	3	9.2-2 SH. 3	MO	T
XVB3128A	SW	IB	6	3	9.2-2 SH. 1	MO	T
XVB3128C	SW	IB	6	3	9.2-2 SH. 1	MO	T
XVC3130A	SW	YD	30	3	9.2-2 SH. 1	N	A
XVC3130B	SW	YD	30	3	9.2-2 SH. 3	N	A
XVC3135A	SW	IB	16	3	9.2-2 SH. 2	N	A
XVC3135B	SW	IB	16	3	9.2-2 SH. 4	N	A
XVC3136A	SW	PR	12	3	9.2-2 SH. 2	N	A
XVC3136B	SW	FH	12	3	9.2-2 SH. 4	N	A
XVC3137A	SW	RB	16	2	9.2-2 SH. 2	N	A
XVC3137B	SW	RB	16	2	9.2-2 SH. 4	N	A
XVT3164	SW	RB	2	3	9.2-2 SH. 2	AO	A
XVT3165	SW	RB	2	3	9.2-2 SH. 2	AO	A
XVC3168	SW	RB	2	3	9.2-2 SH. 2	N	A
XVT3169	SW	RB	2	2	9.2-2 SH. 2	AO	A
XVV13143A	SW	PR	6	3	9.2-2 SH. 2	N	A
XVV13143B	SW	FH	6	3	9.2-2 SH. 4	N	A

Table 3.9-8 (CONTINUED)
Active Code Class 1, 2, and 3 Valves

Balance of Plant Valves

Valve Tag Number [1]	System [2]	Building [3]	Size (in)	Code Class	FSAR Figure	Operator Type [4]	Method of Qualification [5]
XVC6461A	VU	IB	6	2	9.4-22	N	A
XVC6461B	VU	IB	6	2	9.4-22	N	A
XVC6461C	VU	IB	6	2	9.4-22	N	A
XVT8095A,B	RC	RB	2	1	5.1-1	M	A
XVT8096A,B	RC	RB	2	1	5.1-1	M	A
XVB-1A	AH	FH	36	2	9.4-28	AO	T
XVB-1B	AH	RB	36	2	9.4-28	AO	T
XVB-2A	AH	FH	36	2	9.4-28	AO	T
XVB-2B	AH	RB	36	2	9.4-28	AO	T

Table 3.9-8
Active Code Class 1, 2, and 3 Valves

NSSS Valves

Valve Location Number	System	Building	Size (in) (6)	Code Class	Figure No.	Actuator	Type	Method of Qualification (5)
1-8381	CS	RB	3	2a	9.3-16	---	Check	A *
1-8152	CS	AB	3	2a	9.3-16	Air	Globe	A *
1-8112	CS	RB	2	2a	9.3-16	Motor	Globe	A *
1-8100	CS	AB	2	2a	9.3-16	Motor	Globe	A *
1-8149A,B,C	CS	RB	2	2a	9.3-16	Air	Globe	A *
1-8154	CS	RB	1	1	9.3-16	Air	Globe	A *
1-8153	CS	RB	1	1	9.3-16	Air	Globe	A *
1-LCV-460	CS	RB	3	1	9.3-16	Air	Globe	A *
1-LCV-459	CS	RB	3	1	9.3-16	Air	Globe	A *
1-8379	CS	RB	3	1	9.3-16	---	Check	A *
1-8346	CS	RB	3	1	9.3-16	---	Check	A *
1-8378	CS	RB	3	1	9.3-16	---	Check	A *
1-8347	CS	RB	3	1	9.3-16	---	Check	A *
1-8377	CS	RB	2	1	9.3-16	---	Check	A
1-8367A,B,C	CS	RB	1-1/2	1	9.3-16	---	Check	A
1-8348A,B,C	CS	RB	1-1/2	1	9.3-16	---	Check	A
1-8368A,B,C	CS	RB	1-1/2	2a	9.3-16	---	Check	T
1-8145	CS	RB	2	1	9.3-16	Air	Globe	A *
1-8102A,B,C	CS	PR	1-1/2	2a	9.3-16	Motor	Globe	A *

Table 3.9-8 (continued)
Active Code Class 1, 2, and 3 Valves

NSSS Valves

Valve Location Number	System	Building	Size (in) (6)	Code Class	Figure No.	Actuator	Type	Method of Qualification (5)
1-LCV-115C,E	CS	AB	4	2a	9.3-16	Motor	Gate	A *
1-LCV-115B,D	CS	AB	8	2a	9.3-16	Motor	Gate	A *
1-8104	CS	AB	2	2a	9.3-16	Motor	Globe	A *
1-8480A,B,C	CS	AB	2	2a	9.3-16	---	Check	A
1-8442	CS	AB	2	2a	9.3-16	---	Check	A
1-8130A,B	CS	AB	8	2a	9.3-16	Motor	Gate	A
1-8131A,B	CS	AB	8	2a	9.3-16	Motor	Gate	A
1-8109A,B,C	CS	AB	2	2a	9.3-16	Motor	Globe	A
1-8481A,B,C	CS	AB	3	2a	9.3-16	---	Check	A
1-8132A,B	CS	AB	4	2a	9.3-16	Motor	Gate	A
1-8133A,B	CS	AB	4	2a	9.3-16	Motor	Gate	A
1-8106	CS	AB	3	2a	9.3-16	Motor	Gate	A
1-8107	CS	AB	3	2a	9.3-16	Motor	Gate	A
1-8108	CS	AB	3	2a	9.3-16	Motor	Gate	A
1-8117	CS	RB	2	2a	9.3-16	---	Relief	A
1-8314A,B	CS	AB	2	2b	9.3-16	---	Check	A
XVC18529	CS	AB	1-1/2	2a	9.3-16	---	Check	A
1-8010A,B,C	RCS	RB	6	1	5.1-1	---	Relief	A
1-8047	RCS	RB	1	2a	5.1-1	Air	Diaphragm	A
1-8033	RCS	AB	1	2a	5.1-1	Air	Diaphragm	A

Table 3.9-8 (continued)
Active Code Class 1, 2, and 3 Valves

NSSS Valves

Valve Location Number	System	Building	Size (in) (6)	Code Class	Figure No.	Actuator	Type	Method of Qualification (5)
1-8046	RCS	RB	3	2a	5.1-1	---	Check	A
1-8028	RCS	AB	3	2a	5.1-1	Air	Diaphragm	A
1-8716A,B	RHR	AB	10	2a	5.5-4	---	Check	A
1-FCV-602A,B	RHR	AB	3	2a	5.5-4	Motor	Gate	A
1-8706A,B	RHR	AB	8	2a	5.5-4	Motor	Gate	A
1-8708A,B	RHR	RB	3	2a	5.5-4	---	Relief	A
1-8701A,B	RHR	RB	12	1	5.5-4	Motor	Gate	A
1-8702A,B	RHR	RB	12	1	5.5-4	Motor	Gate	A
1-8993A,B,C	SI	RB	6	1	6.3-1	---	Check	A
1-8992A,B,C	SI	RB	2	1	6.3-1	---	Check	A
1-8990A,B,C	SI	RB	2	1	6.3-1	---	Check	A
1-8988A,B	SI	RB	6	1	6.3-1	---	Check	A
1-8884	SI	PR	3	2a	6.3-1	Motor	Gate	A
1-8885	SI	PR	3	2a	6.3-1	Motor	Gate	A
1-8886	SI	PR	3	2a	6.3-1	Motor	Gate	A
1-8995A,B,C	SI	RB	2	1	6.3-1	---	Check	A
1-8997A,B,C	SI	RB	2	1	6.3-1	---	Check	A
1-8998A,B,C	SI	RB	6	1	6.3-1	---	Check	A
1-8801A,B	SI	FH	3	2a	6.3-1	Motor	Gate	A

Table 3.9-8 (continued)
Active Code Class 1, 2, and 3 Valves

NSSS Valves

Valve Location Number	System	Building	Size (in) (6)	Code Class	Figure No.	Actuator	Type	Method of Qualification (5)
1-8947	SI	RB	1	2a	6.3-1	---	Check	T
1-8880	SI	PR	1	2a	6.3-1	Air	Globe	A
1-8956A,B,C	SI	RB	12	1	6.3-1	---	Check	A
1-8948A,B,C	SI	RB	12	1	6.3-1	---	Check	A
1-8961	SI	PR	3/4	2a	6.3-1	Air	Globe	A
1-8871	SI	RB	3/4	2a	6.3-1	Air	Globe	A
1-8926	SI	AB	8	2a	6.3-1	---	Check	A
1-8958A,B	SI	AB	14	2a	6.3-1	---	Check	A
1-8809A,B	SI	AB	14	2a	6.3-1	Motor	Gate	A
1-8811A,B	SI	AB	14	2a	6.3-1	Motor	Gate	A
1-8812A,B	SI	AB	14	2a	6.3-1	Motor	Gate	A
1-8887A,B	SI	PR	10	2a	6.3-1	Motor	Gate	A
1-8861	SI	RB	1	2a	6.3-1	---	Check	A
1-8860	SI	PR	1	2a	6.3-1	Air	Globe	A
1-8889	SI	PR	10	2a	6.3-1	Motor	Gate	A
1-8888A,B	SI	PR	10	2a	6.3-1	Motor	Gate	A
1-8974A,B	SI	RB	10	2a	6.3-1	---	Check	A
1-8973A,B,C	SI	RB	6	1	6.3-1	---	Check	A
1-7136	WL	AB	3	2a	11.2-2	Air	Diaphragm	A
1-7170	WL	RB	3	2a	11.2-2	Air	Diaphragm	A

Table 3.9-8 (continued)
Active Code Class 1, 2, and 3 Valves

NSSS Valves

Valve Location Number	System	Building	Size (in) (6)	Code Class	Figure No.	Actuator	Type	Method of Qualification (5)
1-7150	WL	AB	3/4	2a	11.2-2	Air	Diaphragm	A
1-7126	WL	RB	3/4	2a	11.2-2	Air	Diaphragm	A

(1) Valve types are as follows:

a. Control Valves

IFV - Flow Control
ILV - Level Control
IPV - Pressure Control
ITV - Temperature Control
IVV - Vapor Vent Control

b. Noncontrol Valves

XVA - Ball
XVB - Butterfly
XVC - Check
XVD - Diaphragm
XVG - Gate
XVK - Stop/Check
XVM - Special
XVN - Needle
XVP - Plug
XVR - Relief
XVS - Safety
XVT - Globe
XVV - Vacuum Breaker
XVX - Solenoid Valve

(2) Systems are as follows:

AS - Auxiliary Steam
BD - Steam Generator Blowdown
CC - Component Cooling Water
CS - Chemical and Volume Control System
DG - Diesel Generator
EF- Emergency Feedwater
FS - Fire Service
FW - Feedwater
HR - Post Accident Hydrogen Removal
IA - Instrument Air
MS - Main Steam
ND - Nuclear Drain
NG - Nitrogen Blanket
RCS - Reactor Coolant
RHR - Residual Heat Removal
SA - Station Service and Instrument Air
SF - Spent Fuel Cooling
SI - Safety Injection
SP - Reactor Building Spray
SS - Nuclear Sampling
SW - Service Water
VU - HVAC Chilled Water
WL - Liquid Waste
AH - Air Handling

Table 3.9-8 (continued)
Active Code Class 1, 2, and 3 Valves

NSSS Valves

Valve Location Number	System	Building	Size (in) [6]	Code Class	Figure No.	Actuator	Type	Method of Qualification [5]

(3) Buildings are as follows:

AB - Auxiliary Building
IB - Intermediate Building
RB - Reactor Building
PR - Penetration Access Area
CB - Control Building
DB - Diesel Generator Building
FH - Fuel Handling Building
YD - Yard Area

(4) Operator types are as follows:

AO - Air Operated
MO - Motor Operated
PH - Pneumatic Hydraulic
S - Solenoid
N - No External Operator

(5) Methods of qualification are as follows:

A - Analysis
T - Test

(6) The 2 inch and under check valves shown in the CS and SI systems were bought to meet NSSS design criteria but were not bought as part of the NSSS package.

Table 3.9-9
Factors of Safety and Bolt Stresses for
Linear Component Supports

Connection Plate	Bolt Size & Type	Minimum Factor of Safety vs. Failure	Max. Axial Stress in Bolt	Bolt Capacity Criteria
Group I Modular Embedment	7/8" ϕ x 8-3/16 Nelson Headed Stud	4.2	7.4 ksi	Nelson Catalog
Group II Random Embedment	7/8" ϕ x 8-3/16 Nelson Headed Stud	2.5	11 ksi	Nelson Catalog
Group III Typical Expansion Bolt Anchored Plates	5/8" ϕ x 6 Hilti 3/4" ϕ x 7 Hilti 1" ϕ x 9 Hilti 1-1/4" ϕ x 12 Hilti	2.98 (1)	Not determined	Hilti Catalog

(1) Of the 94 expansion bolt anchorages investigated, 84 had factors of safety in excess of 4, and none had a factor of safety less than 2.98. Calculations indicate that a factor of safety of 4 is not demonstrated for all cases. This is generally attributed to the difference in methodology of the analysis described in Figures 3.9-5 through 3.9-8, with respect to the original analysis. The existence of prying force did contribute to the reduction in factor of safety in two cases. In either case the factors of safety less than 4 were determined to exist only under upset or faulted load combinations.

Table 3.9-10
KWIK Bolt Tests

Kwik-Bolt Size								Load at Initial Displacement				Ultimate Load		
Dia.	Length	Kwik-Bolt Embedment	Initial Torque	Turns of Anchor Nut	Time of Day at Installation Day 2	Time of Day at Testing Day 2	Torque Reading at Testing	Torque Loss	Gage Read.	Force	Subsequent Torques Applied	Gage Read.	Force	Mode of Failure
In.	In.	In.	Ft-Lbs				Ft-Lbs	Ft-Lbs	psi	lbs	Ft-Lbs	psi	lbs	
5/8	8 1/2	7 1/2	70	1/2	8:30am	2:00pm	70	0	400	2668		1400	9415	Wedges pulled over end of anchor
									500	3335	100			(Anchor failure)
									850	5670	140			
5/8	8 1/2	7 1/2	70	1	8:30am	3:00pm	65	5	600	3335		1800	12000	Wedges pulled over end of anchor
									1000	6670	120			(Anchor failure)
5/8	8 1/2	7 1/2	70	1/2	8:30am	3:20pm	60	10	300	2001		1500	10125	Wedges pulled over end of anchor
									700	4669	100			(Anchor failure)
									800	5336	110			
												Avg.	10513	
3/4	10	9	120	2	8:40am	11:30am	110	10	400	2668		2500	17100	Wedges pulled over end of anchor
									500	3335	170			(Anchor failure)
									1500	10125	240			

Table 3.9-10 (continued)
KWIK Bolt Tests

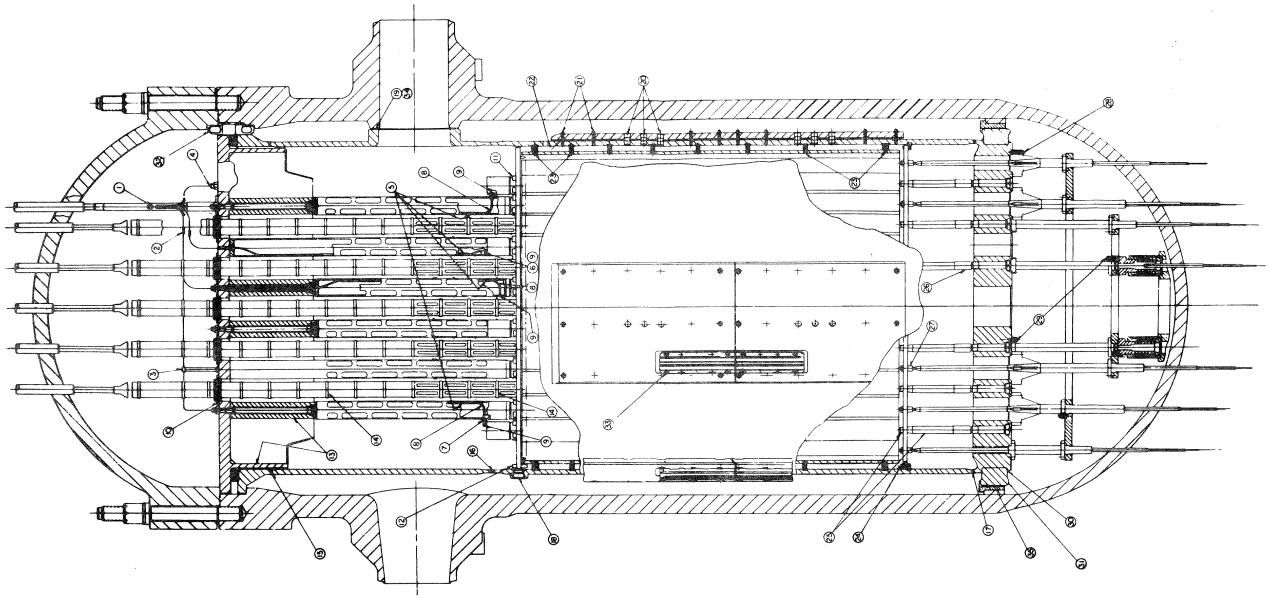
Kwik-Bolt Size								Load at Initial Displacement				Ultimate Load		
Dia.	Length	Kwik-Bolt Embedment	Initial Torque	Turns of Anchor Nut	Time of Day at Installation Day 2	Time of Day at Testing Day 2	Torque Reading at Testing	Torque Loss	Gage Read.	Force	Subsequent Torques Applied	Gage Read.	Force	Mode of Failure
In.	In.	In.	Ft-Lbs				Ft-Lbs	Ft-Lbs	psi	lbs	Ft-Lbs	psi	lbs	
3/4	10	9	120	1/2	8:40am	1:00pm	80	40	500	3335		2600	17750	Wedges pulled over end of anchor
									900	6003	180			(Anchor failure)
									1300	8710	220			
3/4	10	9	120	3/4	2:00pm	10:10am	120	0	700	4669		2900	20000	Wedges pulled over end of anchor
									1400	9415	180			(Anchor failure)
												Avg.		
													18283	
1	12	10	240	2 1/2	9:30am	1:00pm	200	40	800	5336		2800	19250	Wedges pulled over end of anchor
									1400	9415	290			(Anchor failure)
1	12	10	240	2	9:30am	1:00pm	190	50	1000	6670		3500	24125	Wedges pulled over end of anchor
									1400	9415	290			(Anchor failure)
1	12	10	240	2	11:00am	1:00pm	240	0	850	5670		2800	19250	Wedges pulled over end of anchor

Table 3.9-10 (continued)
KWIK Bolt Tests

Kwik-Bolt Size								Load at Initial Displacement				Ultimate Load		
Dia.	Length	Kwik-Bolt Embedment	Initial Torque	Turns of Anchor Nut	Time of Day at Installation Day 2	Time of Day at Testing Day 2	Torque Reading at Testing	Torque Loss	Gage Read.	Force	Subsequent Torques Applied	Gage Read.	Force	Mode of Failure
In.	In.	In.	Ft-Lbs				Ft-Lbs	Ft-Lbs	psi	lbs	Ft-Lbs	psi	lbs	
									1450	9751	290			(Anchor failure)
												Avg.	20875	
1 1/4	12	10 1/2	400	5	10:45am	2:00pm	320	80	1300	8710		2400	16375	Wedges pulled over end of anchor
									1600	10750	480			(Anchor failure)
									2600	17750	530			
1 1/4	12	10 1/2	400	5 1/2	10:45am	2:00pm	270	130	1150	7694		3000	20650	Wedges pulled over end of anchor
									1900	13250	480			(Anchor failure)
1 1/4	12	10 1/2	400	6	10:45am	2:00pm	320	80	1200	8028		4200	29000	Wedges pulled over end of anchor
									2300	15625	480			(Anchor failure)
												Avg.	22008	

Figure 3.9-1

VIBRATION CHECKOUT FUNCTIONAL TEST INSPECTION POINTS

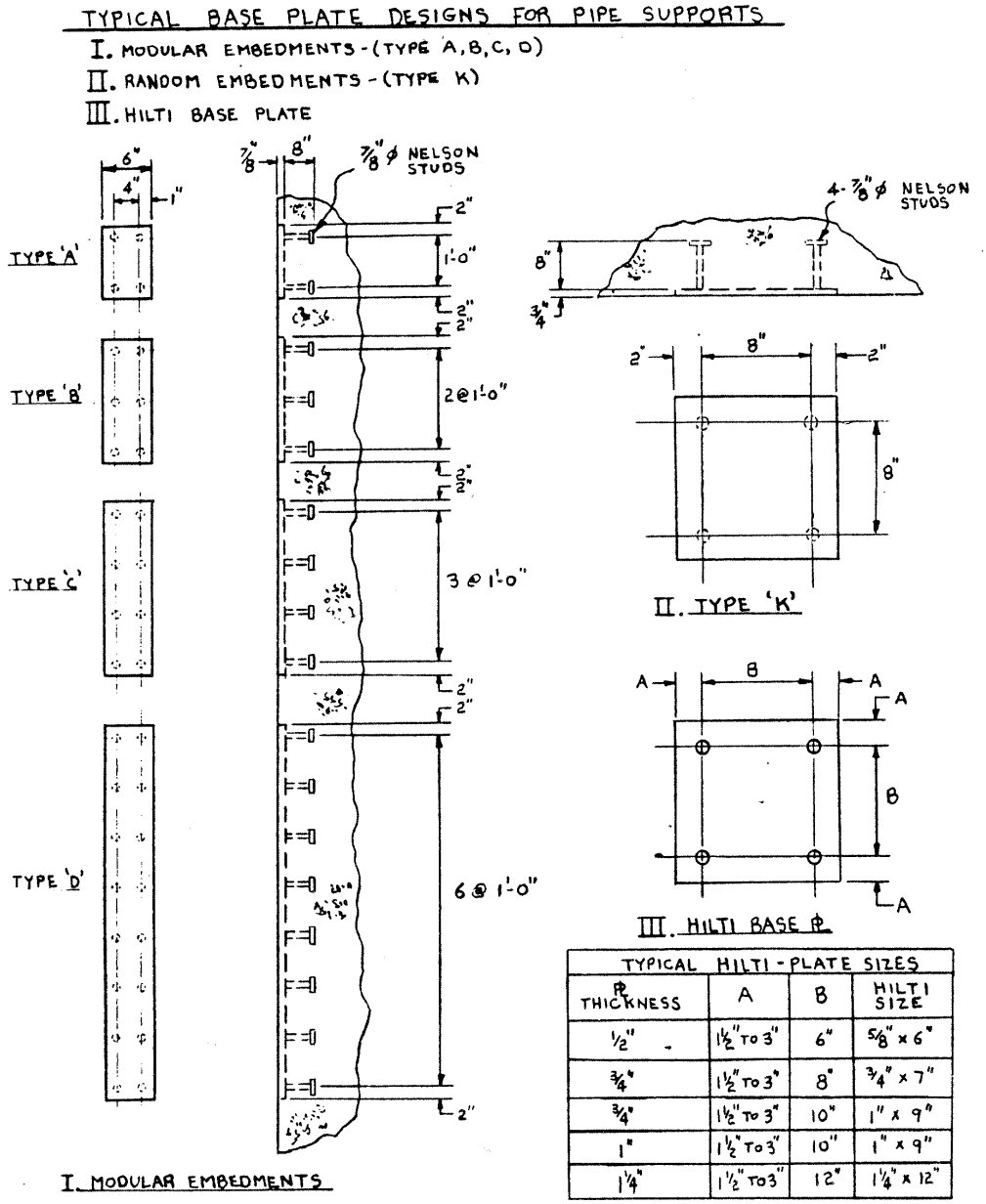


	FEATURES TO BE EXAMINED
1	THERMOCOUPLE CONDUIT CLAMPS INSIDE THE THERMOCOUPLE COLUMN
2	CONDUIT SWAGELOK FITTINGS, THEIR BANDINGS, AND THE TAB TYPE LOCKS.
3	CLAMP ARRANGEMENTS AT THE MOUNTING BRACKET LOCATIONS.
4	PLUG TO CONDUIT WELD AT THE FOUR SUPPORT COLUMNS ADJACENT TO THE THERMOCOUPLE COLUMNS.
5	ACCESSIBLE ANGLE CONDUIT CLAMPS INSIDE THE UPPER SUPPORT COLUMNS.
6	ACCESSIBLE WELD JOINTS AT THE THERMOCOUPLE STOP FOR THE SELF INSTRUMENTED COLUMNS.
7	WELD JOINTS ON ACCESSIBLE SUPPORT COLUMN AND MIXING DEVICE GUSSETS (THERMOCOUPLE SUPPORT HARDWARE.)
8	RIGIDITY OF EXPOSED PORTION OF THERMOCOUPLE CONDUIT RUNS, AT ACCESSIBLE LOCATIONS. (INSIDE SUPPORT COLUMNS LOWER END.)
9	RIGIDNESS OF THE ACCESSIBLE PROTRUDING THERMOCOUPLE TIPS.
10	THERMOCOUPLE COLUMN AND GUIDE TUBE SCREW LOCKING DEVICES.
11	ACCESSIBLE SUPPORT COLUMN, MIXING DEVICE, ORIFICE PLATE, AND CORE PLATE INSERT SCREW LOCKING DEVICES.
12	UPPER CORE PLATE INSERTS.
13	DEEP BEAM WELDS AT THE SKIRT AND AT THE OUTER HOLLOW ROUNDS.
14	ACCESSIBLE GUIDE TUBE WELDS.
15	UPPER BARREL TO FLANGE GIRTH WELD.
16	UPPER BARREL TO LOWER BARREL GIRTH WELD.
17	LOWER BARREL TO CORE SUPPORT GIRTH WELD.
18	UPPER CORE PLATE ALIGNING PIN WELDS AND BEARING SURFACES.
19	OUTLET NOZZLE INTERFACE SURFACE CONDITION.
20	NEUTRON SHIELD PANEL DOWEL PIN COVER PLATE WELDS.
21	NEUTRON SHIELD PANEL SCREW LOCKING DEVICES.
22	INTERFACE SURFACES AT THE SPACER PADS ALONG THE TOP AND BOTTOM ENDS OF THE NEUTRON PANELS
23	BAFFLE ASSEMBLY SCREW LOCKING ARRANGEMENTS AT THE TWO TOP AND THE TWO BOTTOM FORMER ELEVATIONS.
24	LOWER CORE PLATE TO CORE BARREL FLANGE SCREW LOCKING DEVICES ACCESSIBLE AT THE 0°, 90°, 180°, AND 270° AXES.
25	CORE SUPPORT COLUMNS AND THEIR SCREW LOCKING DEVICES.
26	CORE SUPPORT COLUMN ADJUSTING SLEEVES.
27	ACCESSIBLE (2) INSTRUMENTATION GUIDE COLUMN LOCKING COLLARS NEAREST THE MANWAY.
28	LOCKING DEVICES AND CONTACT OF THE CRUCIFORM SHAPED BOTTOM INSTRUMENTATION GUIDE COLUMNS WHERE ATTACHES TO THE CORE SUPPORT AND TIE PLATES.
29	LOCKING DEVICES OF THE SECONDARY CORE SUPPORT BUTT COLUMNS AT THE CORE SUPPORT AND AT THE TIE PLATE.
30	BARREL SUPPORT KEY WELDS.
31	BARREL SUPPORT KEY LOCKING ARRANGEMENTS AND BEARING SURFACES.
32	HEAD AND VESSEL ALIGNING PIN SCREW LOCKING DEVICES AND BEARING SURFACES.
33	IRRADIATION SPECIMEN GUIDE SCREW LOCKING DEVICES AND DOWEL PINS.
34	VESSEL NOZZLE INTERFACE SURFACE CONDITION.
35	VESSEL CLEVIS LOCKING ARRANGEMENTS AND BEARING SURFACES.

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Vibration Checkout Functional Test Inspection Points Figure 3.9-1

Figure 3.9-2

TYPICAL BASE PLATE DESIGNS FOR PIPE SUPPORTS



TYPICAL HILTI-PLATE SIZES			
PL THICKNESS	A	B	HILTI SIZE
1/2"	1 1/2" TO 3"	6"	5/8" x 6"
3/4"	1 1/2" TO 3"	8"	3/4" x 7"
3/4"	1 1/2" TO 3"	10"	1" x 9"
1"	1 1/2" TO 3"	10"	1" x 9"
1 1/4"	1 1/2" TO 3"	12"	1 1/4" x 12"

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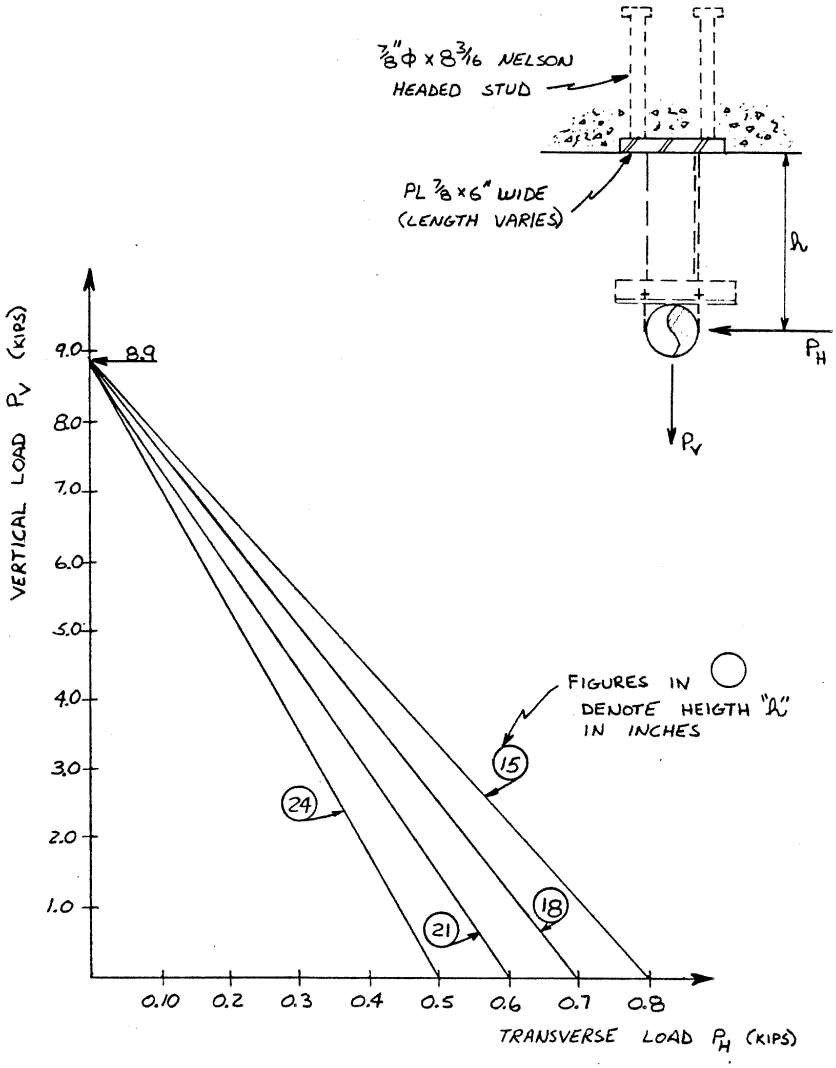
Typical Base Plate Designs for Pipe Supports

Figure 3.9-2

Figure 3.9-3

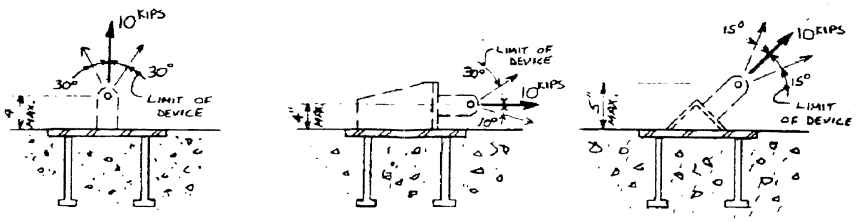
ALLOWABLE TRANSVERSE LOAD VS. ALLOWABLE VERTICAL LOAD FOR MODULAR EMBEDMENT PLATES



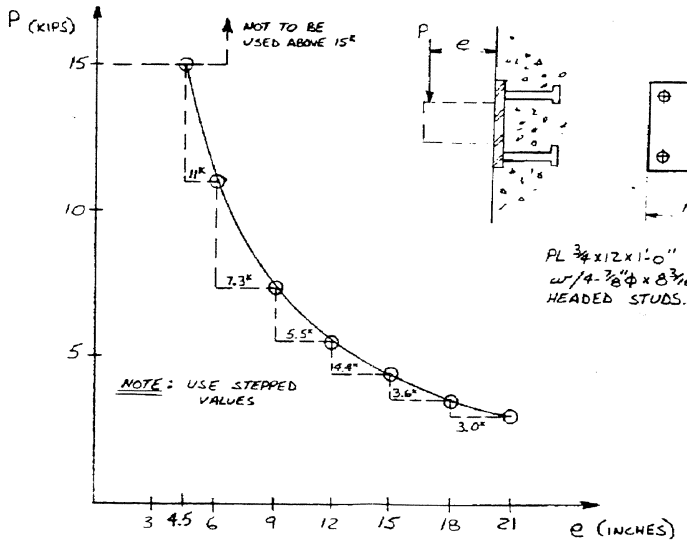
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Allowable Transverse Load Vs. Allowable Vertical Load for Modular Embedment Plates Figure 3.9-3

Figure 3.9-4

ALLOWABLE LOADS ON RANDOM EMBEDMENT PLATES



ALLOWABLE LOAD FOR CLEVIS TYPE FIXTURE ON RANDOM EMBEDMENT PLATE



ALLOWABLE LOADS ON RANDOM EMBEDMENT PLATES FOR VARIED FIXTURE TYPES

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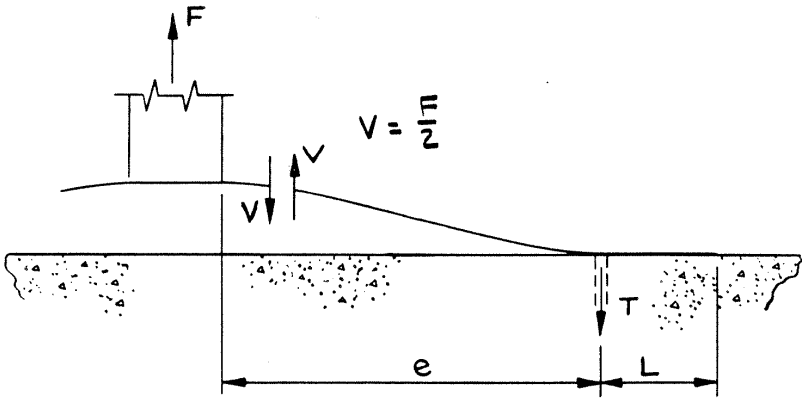
ALLOWABLE LOADS ON RANDOM EMBEDMENT PLATES

REV. 0
Figure 3.9-4

Figure 3.9-5

ANALYSIS FOR PRYING ACTION UNDER TENSILE LOAD - NO PRYING FORCE

CONDITION 1



WHEN $(T_i - V)L \geq V\frac{e}{2}$, ANCHOR LOAD $T = T_i$ = PRELOAD IN THE ANCHO

PRYING FORCE = 0

T = TOTAL LOAD IN ANCHOR

T_i = PRELOAD IN ANCHOR

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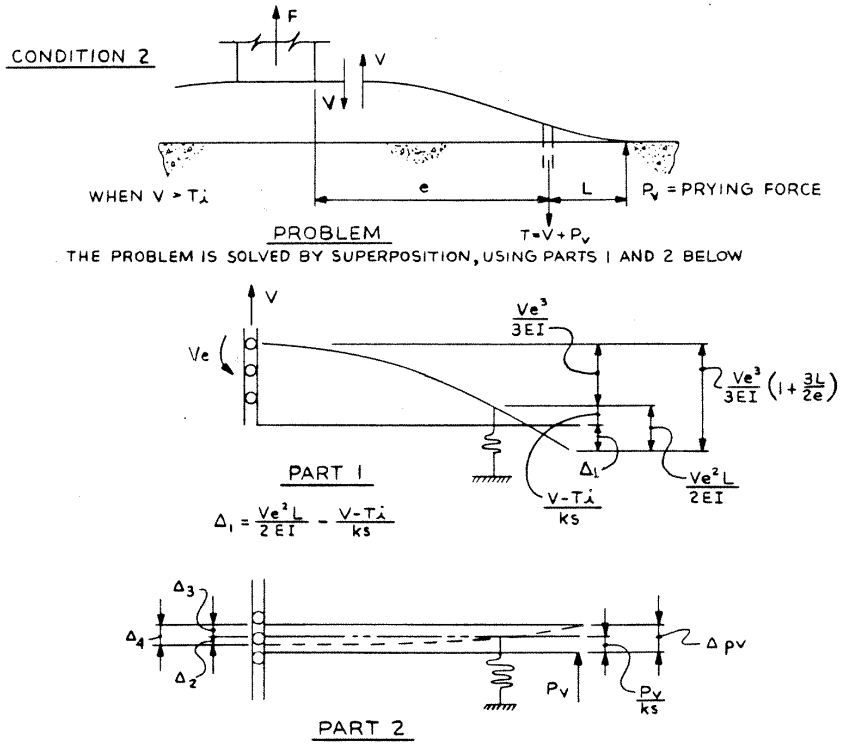
Analysis for Prying Action Under Tensile Load - No Prying Force Figure 3.9-5

Figure 3.9-6

ANALYSIS FOR PRYING ACTION UNDER TENSILE LOAD - PRYING FORCES POSSIBLE



$$\Delta_3 = \Delta_4 - \Delta_2 = \frac{P_v L^2 e}{EI} + \frac{P_v L^3}{3EI} + \frac{6}{5}\frac{P_v L}{AG}$$

$$\Delta pv = \Delta_3 + \frac{P_v}{ks} = \frac{P_v L^2 e}{EI} + \frac{P_v L^3}{3EI} + \frac{6}{5}\frac{P_v L}{AG} + \frac{P_v}{ks}$$

(EQ.1) EQUATING $\Delta_1 = \Delta pv$; $P_v = \left[\frac{Ve^2L}{2EI} - (V-T_i)\frac{1}{ks}\right] \div \left[\frac{1}{ks} + \frac{L^2 e}{EI} + \frac{L^3}{3EI} + \frac{6}{5}\frac{L}{AG}\right]$

IF $\frac{Ve^2L}{2EI} < \frac{V-T_i}{ks}$ NO PRYING EXISTS AND T = V

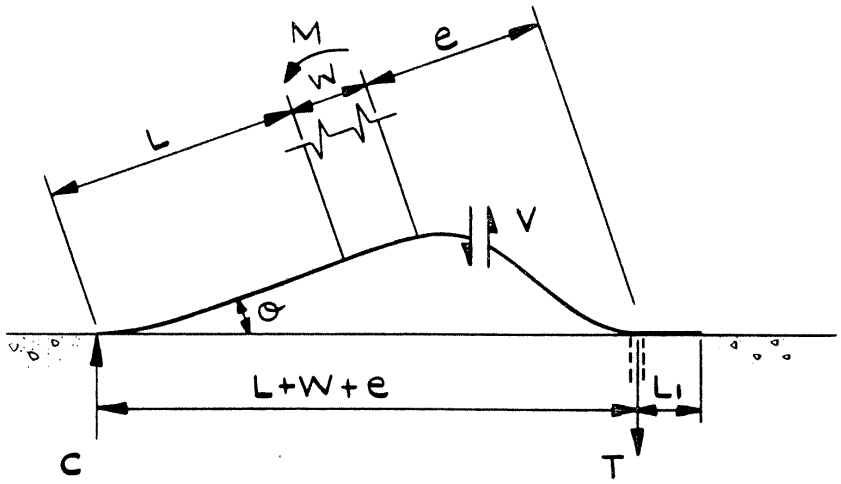
IF $\frac{Ve^2L}{2EI} > \frac{V-T_i}{ks}$ SOLUTION OF EQ-1 YEILDS THE PRYING FORCE P_v.

TOTAL BOLT FORCE IS $V + P_v$

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Analysis for Prying Action Under Tensile Load - Prying Forces Possible Figure 3.9-6

Figure 3.9-7
ANALYSIS FOR PRYING ACTION UNDER APPLIED MOMENT- NO PRYING FORCES

CONDITION I: NO TENSION ANCHOR ROTATION OR DISPLACEMENT



T = TOTAL LOAD IN ANCHOR
T_i = PRELOAD IN ANCHOR

FOR $M \leq \left(\frac{T_i L_1}{e/2 + L_1}\right)(L+W+e)$, $T = T_i$

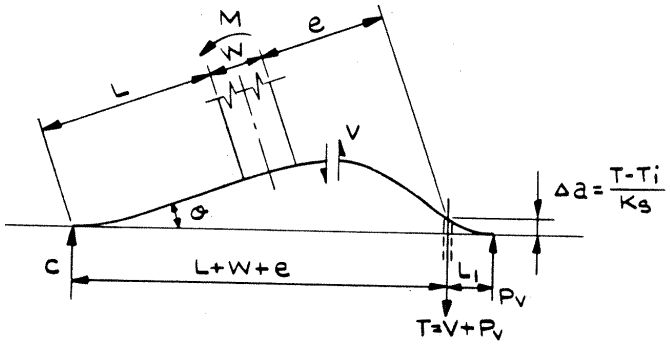
PRYING FORCE = 0

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Analysis for Prying Action Under Applied Moment - No Prying Forces Figure 3.9-7

Figure 3.9-8

ANALYSIS FOR PRYING ACTION UNDER APPLIED MOMENT- PRYING FORCES POSSIBLE

CONDITION 2 : TENSION ANCHOR ROTATION AND DISPLACEMENT



T=TOTAL LOAD IN ANCHOR
T_i=PRELOAD IN ANCHOR

$$T = V + P_V$$

$$\Delta a = \frac{T-T_i}{K_s}$$

$$\theta = \frac{VL^2}{2EI_p}$$

$$L = \frac{3}{\theta}\left\{\left[\Delta a - \frac{P_V L_1 e^2}{2EI} + \frac{Ve^3}{3EI}\right] - \theta W - \theta e\right\}$$

$$V = \frac{M + P_V L_1}{e+W+L}$$

$$P_V = \frac{\frac{Ve^2 L_1}{2EI} - \frac{V-T_i}{K_s} - \theta L_1}{\frac{1}{K_s} + \frac{L_1^2 e}{EI} + \frac{L_1^3}{3EI} + \frac{6}{5}\frac{L_1}{AG}}$$

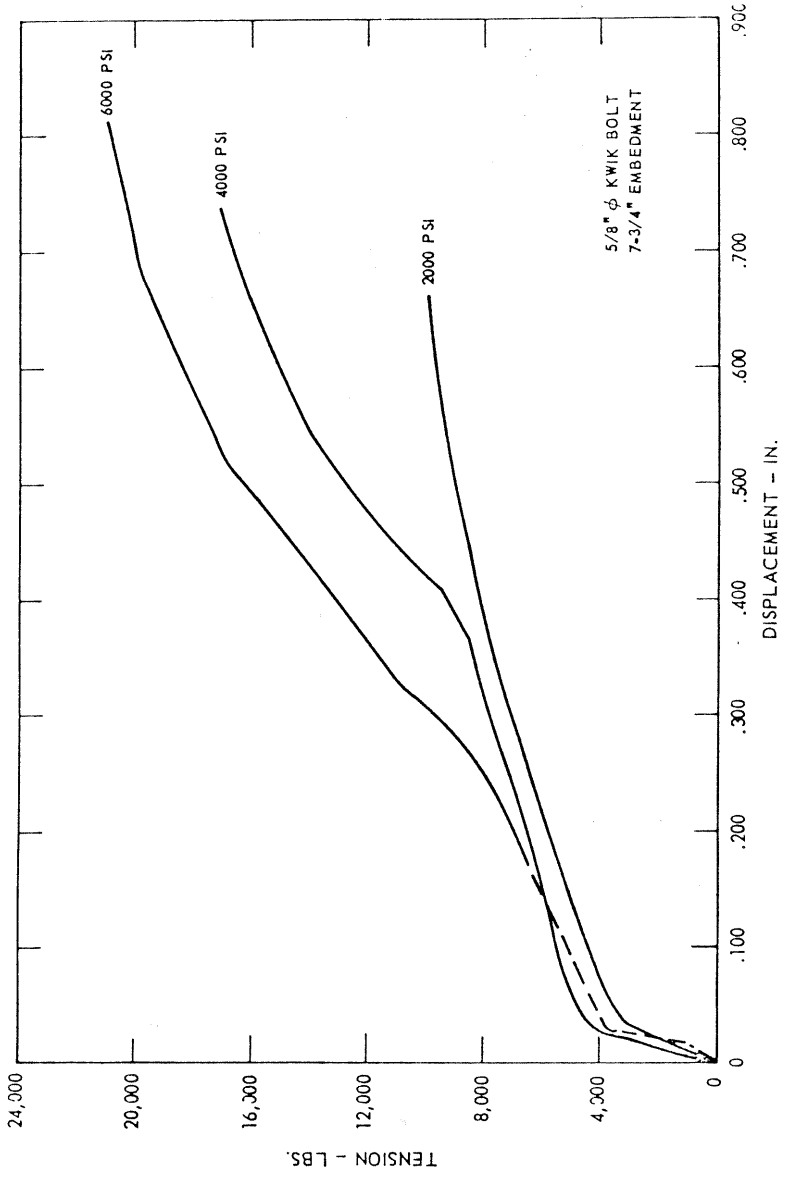
IF $\frac{V-T_i}{K_s} \geq \frac{Ve^2 L_1}{2EI} - \theta L_1$, NO PRYING EXISTS AND T=V=C

IF $\frac{V-T_i}{K_s} < \frac{Ve^2 L_1}{2EI} - \theta L_1$, SIMULTANEOUS SOLUTION OF THE SIX EQUATIONS GIVEN ABOVE WILL YIELD THE LOCATION OF THE COMPRESSIVE FORCE C AND THE MAGNITUDE OF THE PRYING FORCE P_V

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Analysis for Prying Action Under Applied Moment - Prying Forces Possible Figure 3.9-8

Figure 3.9-9

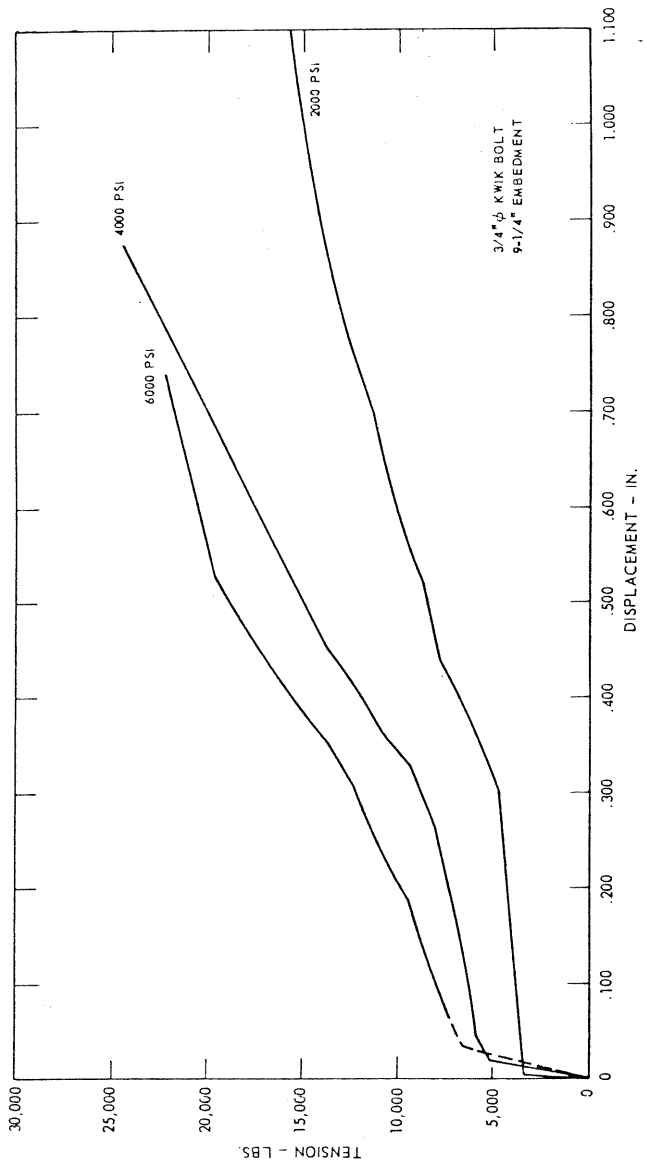
FORCE - DISPLACEMENT PULL OUT CURVE FOR 5/8" HILTI KWIK BOLT AND 7-3/4" EMBEDMENT



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Force - Displacement Pull Out Curve for 5/8" Hilti Kwik Bolt and 7 - 3/4" Embedment Figure 3.9-9

Figure 3.9-10

FORCE - DISPLACEMENT PULL OUT CURVE FOR 3/4" HILTI KWIK BOLT AND 9- 1/4" EMBEDMENT



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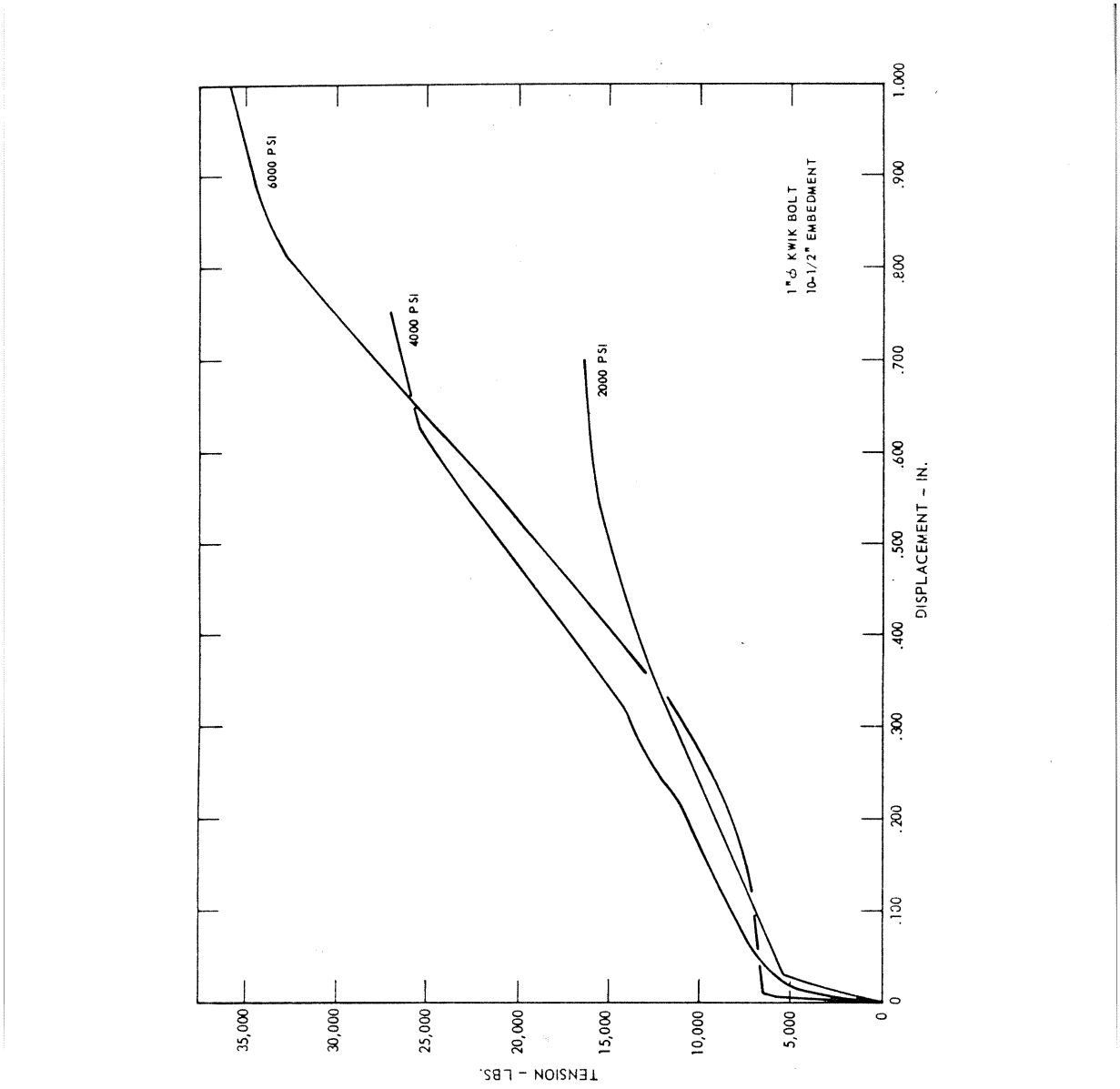
Force - Displacement Pull Out Curve
for 3/4" Hilti Kwik Bolt and
9 - 1/4" Embedment

Figure 3.9-10

Figure 3.9-11

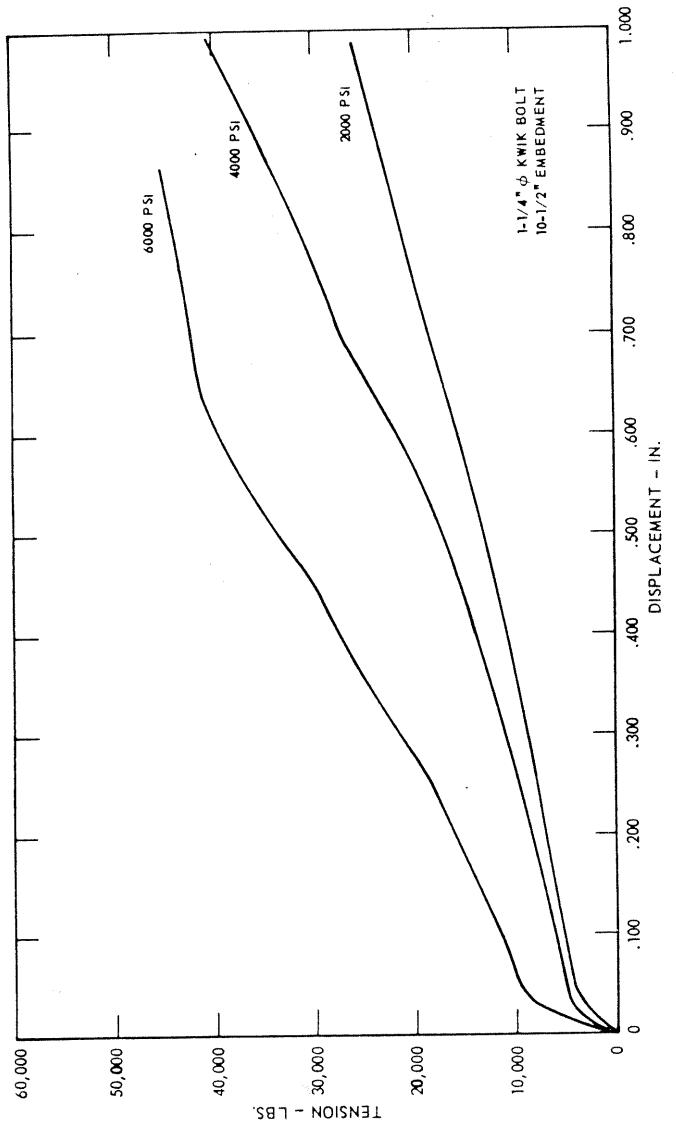
FORCE - DISPLACEMENT PULL OUT CURVE FOR 1" HILTI KWIK BOLT AND 10- 1/2" EMBEDMENT



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Force - Displacement Pull Out Curve for 1" Hilti Kwik Bolt and 10 - 1/2" Embedment Figure 3.9-11

Figure 3.9-12

FORCE - DISPLACEMENT PULL OUT CURVE FOR 1-1/4" HILTI KWIK BOLT AND 10-1/2" EMBEDMENT



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Force - Displacement Pull - Out Curve for 1-1/4" Hilti Kwik Bolt and 10-1/2" Embedment Figure 3.9-12

3.10 SEISMIC QUALIFICATION OF SEISMIC CATEGORY 1 INSTRUMENTATION AND ELECTRICAL EQUIPMENT

3.10.1 Seismic Qualification Criteria

The safety-related instrumentation and electrical equipment that is seismically qualified is identified in Table 3.10-1. The safety-related instrumentation and electrical equipment within the scope of the Nuclear Steam Supply System (NSSS) and which requires seismic qualification is identified in Table 3.10-2. This equipment is designed to withstand the combined effect of normal operating loads acting simultaneously with horizontal and vertical components of the safe shutdown earthquake (SSE) (described in Section 3.7.1) without loss of function or structural integrity.

Suppliers of safety-related equipment are provided with the response spectrum curves for the SSE loading applicable for the equipment location. The response spectrum curves for the various locations within the plant are developed from the input ground motion, as described in Section 3.7.1.

Equipment suppliers are required to submit test data and/or calculations to demonstrate that their equipment does not suffer loss of function during or after seismic loading due to an SSE, as described in Section 3.7.5.

The seismic qualification of safety-related equipment, systems, and components may be accomplished in various ways. Three of the methods used are as follows:

1. Determine equipment performance through analysis (see Section 3.10.2.1.1).
2. Test the equipment under simulated seismic conditions (see Section 3.10.2.1.2).
3. Qualification by combined test and analysis.

The choice is based upon the practicality of the method for the type, size, shape, and complexity of the equipment under consideration, as well as the reliability of the conclusions resulting from the analysis, test, or combination.

Data submitted by the equipment suppliers is required to include justification for the use of the method chosen.

The NSSS supplier has previously type tested and qualified items 1 through 8, of the equipment listed in Section 3.10-2 in accordance with IEEE-344 (Reference 1). Item 9 is discussed in Section 3.10.2. Reference 2 presents the testing procedures used to qualify NSSS equipment by type testing. Seismic qualification testing of this equipment in accordance with IEEE-344 (Reference 1) is documented in References 3 through 9. Reference 10 presents the theory and practice, as well as justification for the use of single axis sine beat test inputs used in the seismic qualification of electrical equipment. In addition, it is noted that the NSSS supplier has conducted the seismic qualification demonstration test program outlined in Reference 11 (also see References 9, 12, 13, 14, and 15).

For the seismic qualification of NSSS electrical equipment outside of the Reactor Building, this demonstration test program, in conjunction with the justification for the use of single axis sine beat tests presented in Reference 10 indicates that the original tests, documented in References 3 through 9, satisfy the requirements of IEEE-344-1975, "IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations." The general method showing the multi-frequency, multi-directional test inputs used in the demonstration test program is presented in Reference 12.

The peak accelerations used in the type testing are conservative values that are checked against those derived by structural analyses of SSE loadings. For the SSE, there may be permanent deformation of the equipment provided the capability to perform its function is maintained.

Seismic qualification of Category 1 instrumentation and electrical equipment meets the requirements of Criterion 2 of the 1971 GDC.

3.10.2 Methods and Procedures for Qualifying Electrical Equipment and Instrumentation

3.10.2.1 Balance of Plant Equipment

3.10.2.1.1 Seismic Analysis

1. Equipment is individually modeled as a multi-degree-of-freedom, lumped-mass system with mass-free interconnections. Three different models are used to determine the seismic response for the vertical and two horizontal directions of excitation.

   The number of mass points chosen in the analysis is selected to yield an accurate prediction of the response of the equipment to a seismic disturbance.

   The natural frequencies and mode shapes are determined for the equipment in the mounted, ready for service condition. Consideration is given to the relationship of the fundamental natural frequency of the equipment to the rigid frequency (i.e., greater, equal to, or less). The equipment supplier then performs a structural analysis of the equipment to ensure that material stress limits are not exceeded.

2. Equipment is analyzed statically when the fundamental frequency of the equipment is greater than the rigid frequency. In the static analysis, seismic forces on each component of the equipment is obtained by multiplying the lumped mass of each mass point by the appropriate maximum floor acceleration. The maximum floor acceleration is obtained from the high frequency end of the response spectra envelope. Response spectra curves are discussed in Section 3.7.2.

3. For cable trays, tray supports, and similar structures, the structures are analyzed statically using peak response accelerations. A conservatively low damping value is used when determining the peak response acceleration. Structural properties for the cable trays are determined by load tests and the properties of the members for supporting structures are obtained from Reference 16 and other similar documents. The load on a structure is

determined by multiplying the peak acceleration by the mass of the structure. The resulting force is distributed in proportion to the mass of the structure and is combined with dead loads. A stress analysis is then performed on the structure to ensure its structural adequacy.

4. The majority of the instrument sensors are qualified to a conservatively high acceleration level which envelopes both frequency and acceleration for all plant locations. The remainder of the instrument sensors are qualified by one of the above methods. The values selected are 1.5 g for wall mounted instruments and 3 g for pipe mounted instruments. Except for pipe mounted instruments, instruments are mounted either on wall racks or floor stands. Table 3.10-3 identifies pipe mounted instruments and their locations. Instrument racks and stands are stiffened to preclude excessive amplification. For pipe mounted instruments, the attachment between the instrument and associated piping is designed to be rigid. The instrument and seismic qualification level will be included in the piping system design specification.
5. If by analysis, it is determined that the fundamental frequency of a valve assembly is greater than 30 Hz, a static seismic structural and deflection/clearance analysis is performed to show the structural and functional adequacy of the valve assembly.

3.10.2.1.2 Testing Under Simulated Seismic Conditions

Test methods used include the following:

1. Random vibration test.
2. Sinusoidal sweep test.
3. Continuous sine test.
4. Sine beat test.
5. Decaying sinusoidal test.
6. Short time sinusoidal test.
7. Multi-frequency biaxial test.

Testing is performed by subjecting devices and assemblies to vibratory motion which simulates seismic conditions predicted for the equipment mounting location during an SSE. Assemblies are tested with devices in operating condition except in the case of complex assemblies, such as control panels, switchgear, etc., where testing requirements dictate that devices be inoperative. Such testing demonstrates the ability of equipment to perform its intended function under seismic conditions or, in the case of complex assemblies, qualifies the assemblies and provides data for device mountings to be used as input information when testing individual component devices. Such data is in the form of a response spectrum or other equivalent forms.

Assemblies or component devices being tested are mounted for testing in a manner simulating the intended service mounting. Due to different characteristics of various driving mechanisms and the interaction between heavy equipment and the shake table, the input to the shake table may be

different from the motions at the equipment mounting. Hence, the input to the equipment is based upon the motions at the equipment mounting instead of the input to the shake table.

Vertical and horizontal inputs are applied simultaneously unless it can be demonstrated that horizontal and vertical responses are uncoupled. Maximum vibratory accelerations at the equipment mounting are equal to or greater than the maximum floor acceleration.

3.10.2.2 Nuclear Steam Supply System Equipment

NSSS Seismic Category-1 instrumentation and electrical equipment was seismically qualified by type testing using sine beat inputs to each of three perpendicular axes independently applied according to the procedures of IEEE-344 (Reference 1), Section 3.2. At the time of this testing, which is reported in References 3 through 9, implementation of the IEEE-344 (Reference 1) testing method fulfilled all seismic qualification requirements. The results show that there are no electrical irregularities that would leave the plant in an unsafe condition. In addition, as noted in Section 3.10.1, a demonstration test program was conducted which, when considered in conjunction with those tests presented in References 3 through 8 and 17, results in satisfying the requirements of IEEE-344 1975.

In the reported tests, the equipment operated properly during and after testing with equivalent ground accelerations at zero period ranging up to 0.4 g and higher. The sine beat inputs were applied not only at the equipment natural frequencies but also at many frequencies (spaced at about 1/2 octave) below 33 Hz to ensure that the equipment would function normally regardless of uncertainties of building or equipment natural frequencies. The sine beat test is severe because it excites the resonant response of the equipment, thereby producing the most damaging effect to the components. This test not only excites the component to motion greater than the input but also produces fatigue damage well above that produced by seismic disturbances. This method assumes that building natural frequency coincides with that of the equipment and is as conservative as the one proposed by the NRC Staff. Any possible coupling effect loses importance when compared to the excitation of components at sensitive frequencies as is done by the sine beat test. This test, therefore, provides more positive proof of equipment capability than the simultaneous random input test which, because of phase relationships, could result in less severe application of the seismic input.

The nuclear instrumentation system power range neutron detector is qualified for seismic environments by testing at acceleration levels greater than those expected at their location during a seismic disturbance as defined in Sections 2.5 and 3.7.

The power range detector has been vibration tested in both the transverse (horizontal) direction and the longitudinal (vertical) direction. The pressure and differential pressure transmitters are qualified by multi- axial, multifrequency testing. Seismic inputs for this testing were developed using the methods described in WCAP 8687.

The Westinghouse ISD 7300 series process control cabinets were originally qualified using single-axis sine beat test methods and results reported in Reference 7. To resolve NRC concerns regarding the ability of the process bistables to change state during a postulated seismic event and

to address NRC questions relative to multi-axis, multifrequency effects, a typical 7300 channel was tested using bi-axial, multifrequency inputs. These inputs were developed in accordance with Reference 12. Results of the testing were submitted to the NRC as Reference 15. Seismic qualification of the solid state protection system was performed using single-axis sine beat test methods and results provided in References 5 and 6.

Initial testing on the Nuclear Instrumentation System (NIS) was performed using single-axis sine beat methods and reported in References 3 and 5. The NIS was also tested to verify the ability of the bi-stables to change state during a seismic event. This testing was performed using multifrequency bi-axial inputs; however, unlike the process control equipment bi-stable testing, a single (out of four) NIS cabinet was tested. Electrical operability of the bi-stables was confirmed. Results of this testing were submitted to the NRC as Reference 14. The safeguards test cabinets were qualified by single-axis sine beat testing and results are Reported inReference 18. The narrow range resistance temperature detectors were tested using single-axis sinusoidal techniques. Results of this testing are documented in Reference 9 (approved by NRC). Seismic qualification of the type DS reactor trip switchgear is scheduled to begin in late 1978. Unless limited by facility configuration, the intent is to utilize bi-axial, multifrequency test methods.

Original testing of the instrument supply inverters (static inverters) was performed using single-axis sine beat methods and results reported in References 3 and 5. To satisfy NRC concerns regarding the original test at less than full load, the static inverter was seismically retested at the approximate normal operation and accident power loading condition using bi-axial sine beat inputs. Results of this testing were submitted to the NRC as Reference 13. Westinghouse supplied indicators and recorders used for post accident monitoring are qualified using multi-axial multifrequency test methods per WCAP 8687.

Equipment for the Virgil C. Summer Nuclear Station is procured on a similar basis to that which is qualified. Any design change in the equipment is evaluated to determine if the changes were of a nature that could affect the results of the seismic tests or would require the equipment to be requalified for seismic integrity.

The criteria and verification procedure employed to account for the possible amplified design loads (frequency and amplitude) for NSSS safety-related instrumentation and electrical equipment is presented in Reference 2, Appendix B of Reference 3 and Section 4 of Reference 10.

3.10.3 Methods and Procedures of Analysis or Testing of Supports of Electrical Equipment and Instrumentation

Testing of electrical equipment and instrumentation supports is performed in the manner described in Section 3.10.2.

3.10.4 Operating License Review

The documentation for the equipment demonstrates that the equipment satisfies performance requirements before, during and after subjection to the seismic accelerations for which the equipment is qualified in accordance with the seismic criteria specified.

3.10.4.1 Analytical Data

In those cases where proof of performance was obtained by analytical means, a report is prepared. This report is presented in a step-by-step form which is readily auditable by persons skilled in such analyses. The report includes the following information:

1. The equipment identification and description.
2. Summary of analytical results.
3. Load criteria and assumptions.
4. Methods of analysis.
5. Calculations.
6. Certification of the report by an independent reviewer.

3.10.4.2 Test Data

When proof of performance is obtained through testing, a report similar to that described in Section 3.10.4.1 is prepared. This report includes the following information:

1. Equipment identification.
2. Test facility.
    a. Location.
    b. Test equipment.
    c. Test method.
    d. Test data (as a minimum: date, frequency, amplitudes, and duration of test).
    e. Results and conclusions.
    f. Certification of the report by an independent reviewer.

3.10.5 References

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3. Vogeding, E. L., *Seismic Testing of Electrical and Control Equipment,* WCAP-7397-L (Proprietary), February, 1970 and WCAP-7817 (Non-Proprietary), December, 1971.

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5. Potochnik, L. M., *Seismic Testing of Electrical and Control Equipment (Low Seismic Plants)*, WCAP-7817, Supplement 2, December, 1971.

6. Vogeding, E. L., *Seismic Testing of Electric and Control Equipment (Westinghouse Solid State Protection System), (Low Seismic Plants)*, WCAP-7817, Supplement 3, December, 1971.

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8. Vogeding, E. L., *Seismic Testing of Electrical and Control Equipment (Instrument Bus Distribution Panel), (Low Seismic Plants)*, WCAP-7817, Supplement 5, March, 1974.

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10. Fischer, E. G. and Jarecki, S. J., *Qualification of Westinghouse Seismic Testing Procedure for Electrical Equipment Tested Prior to May 1974*, WCAP-8373, August, 1974.

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12. Jarecki, S. J., *General Method of Developing Multi-Frequency Bi-axial Test Inputs for Bistables*, WCAP-8624 (Proprietary) and WCAP-L8695 (Non-Proprietary), September 1975.

13. Figenbaum, E. K., *Seismic Testing of Electrical and Control Equipment, Static Inverter and Instrument Bus Distribution Panel*, WCAP-7821, Supplement 2, Addendum 1, October, 1975.

14. Jarecki, S. J., et al., *Seismic Operability Demonstration Testing of the Nuclear Instrumentation System Bistables*, WCAP-8830 (Proprietary) and WCAP-8831 (Non-Proprietary), October, 1976.

15. Jarecki, S. J., et al., *Seismic Operability Demonstration Testing of the WISD 7300 Series Process Instrumentation system Bistables,* WCAP-8828 (Proprietary) and WCAP-8829 (Non-Proprietary), October, 1976.

16. American Institute of Steel Construction, *Manual of Steel Construction*, 7th Edition.

17. *Electric Hydrogen Recombiner for PWR Containments*, WCAP-7709-L, Supplement 7 (Proprietary) and WCAP-7820, Supplement 7 (Non-Proprietary), August, 1977.

18. Vogeding, E. L., *Seismic Testing of Electrical and Control Equipment for Low Seismic Plants,* WCAP-7817, Supplement 7, September, 1976.

Table 3.10-1
Methods and Procedures for Seismic Qualification of BOP
Seismic Category 1 Equipment and Associated Supports

Equipment	Method
Valve Operators (actuator) (1)	See the applicable EQDP, EQF and/or SQF.
7200 Volt Switchgear (1)	See the applicable EQDP, EQF and/or SQF.
480 Volt Unit Substations (1)	See the applicable EQDP, EQF and/or SQF.
480 Volt Vital System Transformers	See the applicable EQDP, EQF and/or SQF.
Motor Control Centers (1)	See the applicable EQDP, EQF and/or SQF.
Motors for Safety Class Pumps and Fans (1)	See the applicable EQDP, EQF and/or SQF.
Battery Chargers(1)	See the applicable EQDP, EQF and/or SQF.
Diesel Generators (1)	See the applicable EQDP, EQF and/or SQF.
Cable Tray and Cable Tray Hangers (1)	Analysis. Peak response acceleration of structures vector sum combination of stress
Electrical Containment Penetrations (1)	See the applicable EQDP, EQF and/or SQF.
Distribution Panels(1)	See the applicable EQDP, EQF and/or SQF.
Batteries and Battery Racks (1)	See the applicable EQDP, EQF and/or SQF.
Speed Switches (7200 volt) (1)	See the applicable EQDP, EQF and/or SQF.
Transfer Switches (7200 volt) (3)	See the applicable EQDP, EQF and/or SQF.
Transfer Switches (480 volt) (3)	See the applicable EQDP, EQF and/or SQF.
Pressure Transmitters (1)	See the applicable EQDP, EQF and/or SQF.
Level Transmitters (1)	See the applicable EQDP, EQF and/or SQF.
Flow Transmitters (1)	See the applicable EQDP, EQF and/or SQF.
Temperature Sensors (1)	Type test. Single frequency; single axis test.
Control Board Switch Modules(1)	See the applicable EQDP, EQF and/or SQF.
ESF Loading Sequence (1) Control Panels	See the applicable EQDP, EQF and/or SQF.
Reactor Protection Under-frequency and Voltage Relay Panels	Type test and analysis. Random frequency with super-imposed sine beats; multi-axis test.
Main Control Board (1) (5)	See the applicable EQDP, EQF and/or SQF.
Heating, Ventilation and Air Conditioning Control Panel (1) (5)	See the applicable EQDP, EQF and/or SQF.

Table 3.10-1 (continued)
Methods and Procedures for Seismic Qualification of BOP
Seismic Category 1 Equipment and Associated Supports

Equipment	Method
Balance of Plant Instrument Panels	See the applicable EQDP, EQF and/or SQF.
Control Room Evacuation Panel	See the applicable EQDP, EQF and/or SQF.
HVAC Mechanical Water Chiller Control Panels and Motors (1)	See the applicable EQDP, EQF and/or SQF.
Radiation Monitoring Control Panel	See the applicable EQDP, EQF and/or SQF.
Termination Panels (1)	See the applicable EQDP, EQF and/or SQF.
Earthquake Instrumentation	See the applicable EQDP, EQF and/or SQF.
Hydrogen Analyzer Panels	See the applicable EQDP, EQF and/or SQF.
Radiation Monitors; RM-L1, RM-A2, RM-G7 (6)	See the applicable EQDP, EQF and/or SQF.
Radiation Monitors; RM-G18, RM-G17A&B (6)	See the applicable EQDP, EQF and/or SQF.
Level Switches, leak detection	Type test. Random frequency, multi-axis.
Flow Meter, leak detection	Type test. Random frequency, multi-axis.
TSC Isolation Cabinets	See the applicable EQDP, EQF and/or SQF.
RTD/I Converters	See the applicable EQDP, EQF and/or SQF.
Isolation Fuses and Fuse Blocks, within Heat Trace Panels	See the applicable EQDP, EQF and/or SQF.

(1) Equipment required for safe shutdown.
(2) Deleted
(3) Electrical continuity required for safe shutdown but transfer capability not required.
(4) Deleted
(5) The control boards are seismically qualified. Non-nuclear safety class components mounted on the boards are not required to be seismically qualified but the control boards are so designed that failure of non-nuclear safety class components does not degrade any seismically qualified components.
(6) Pertinent requirements of Regulatory Guide 4.15 Revision 1 apply to the quality assurance program.

Table 3.10-2
Identification of Nuclear Steam Supply System
Seismic Category I Instrumentation, Electrical
Equipment, and Supports

	Item	Method
1.	Pressure Transmitters ** and Differential Pressure Transmitters **	Multi-axial, multi-frequency
2.	Process Control Equipment Cabinets **	Single axis sine beat, biaxial multi-frequency
3.	NSSS Solid State Protection System Cabinets	Single axis sine beat
4.	Nuclear Instrumentation System Cabinets	Single axis sine beat, biaxial multi-frequency
5.	Safeguards Test Racks	Single axis sine beat
6.	Resistance Temperature Detectors **	Single, sinusoidial
7.	Instrument Supply Inverters **	Single axis sine beat, biaxial sine beat***
8.	Reactor Trip Switchgear	Multiaxis, multi-frequency
9.	Power Range Neutron Detectors	Single axis sinusoidal
10.	Post Accident Monitoring Equipment (Indicators ** and Recorders)	Multi-axis, multi frequency
11.	Post Accident Electric Hydrogen Recombiners	Single axis sine beat for recombiners, bi-axial sine beat for control panel
12.	Core Subcooling Monitor	Exempt from qualification per NRC acceptance of the SCE&G response to Generic Letter 82-28
13.	Critical System Leak Monitoring System	Removed per MRF-20206
14.	Reactor Vessel Level Instruments	Single axis sine beat, bi-axial multi-frequency
15.	Pressurizer Safety Valve Flow Monitor	Sine sweep test; bi-axial multi-frequency test.

** Required for safe shutdown (assuming normal operation and not post accident conditions).
*** Replacement Inverters qualified via multi-axis multi-frequency testing.

Table 3.10-3
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITE4480	SW	Cooling water to reactor building air handling heat exchange loop A, temperature element, computer input T4480A, post accident monitor, 100 ohm RTD	SW; -; 425’-0"	D-302-222; E-303-010; E-811-037
ITW4481	SW	Service water supply header A, thermowell, local test	SW; -; 425’-0"	D-302-221; E-303-010; E-811-037
ITE4510	SW	Cooling water to reactor building air handling heat exchange loop B, temperature element, computer input T4510A, post accident monitor, 100 ohm RTD	SW; -; 425’-0"	D-302-222; E-303-010; E-811-037
ITW4511	SW	Service water supply header B, thermowell, local test	SW; -; 425’-0"	D-302-221; E-303-010; E-811-037
ITW4477	SW	Service water to diesel generator cooler A, thermowell, local test	DG; H.4-1; 436’-0"	D-302-222; E-303-022; E-811-047
ITE4478	SW	Service water from diesel generator cooler A, temperature element, type E thermocouple	DG; H.4-1; 436’-0"	D-302-222; E-303-022; E-811-047
ITW4507	SW	Service water to diesel generator cooler B, thermowell, local test	DG; J.1-1; 436’-0"	D-302-222; E-303-022; E-811-047
ITE4508	SW	Service water from diesel generator cooler B, temperature element, type E thermocouple	DG; J.1-1; 436’-0"	D-302-222; E-303-022; E-811-047

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITE2094	MS	Main steam, temperature element, computer input T2094A, 100 ohm RTD	IB; H4-4.4; 436’-0"	D-302-012; E-304-013; E-811-019
ITE3307A	FW	30" main feedwater header, temperature element, computer input, 100 ohm RTD	IB; G4-5.9; 436’-0"	D-302-083; E-304-084; -
ITE3307B	FW	30" main feedwater header, temperature element, computer input, 100 ohm RTD	IB; G4-5.9; 436’-0"	D-302-083; E-304-084; -
ITE3318	FW	Feedwater to steam generator A, temperature element, computer input T0418A, 100 ohm RTD	RB; RC-13; 436’-0"	D-302-083; E-304-085; E-811-004
ITE3320	FW	Feedwater to steam generator A, temperature element, type E thermocouple	AB; L-7.6; 436’-0"	D-302-083; E-304-085; E-811-013
ITE3322	FW	Feedwater to steam generator A, temperature element, computer input, 100 ohm RTD	RB; Q-4; 456’-0"	D-302-083; E-304-085; E-811-004
ITE3328	FW	Feedwater to steam generator B, temperature element, computer input T0438A, 100 ohm RTD	RB; RC-8; 436’-0"	D-302-083; E-304-085; E-811-004
ITE3330	FW	Feedwater to steam generator B, temperature element, computer input, type E thermocouple	IB; J1-4.4; 436’-0"	D-302-083; E-304-085; E-811-019

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITE3332	FW	Feedwater to steam generator B, temperature element, computer input, 100 ohm RTD	RB; RC-8; 453’-0"	D-302-083; E-304-085; E-811-004
ITE3338	FW	Feedwater to steam generator C, temperature element, computer input T0458A, 100 ohm RTD	RB; RC-7; 436’-0"	D-302-083; E-304-085; E-811-004
ITE3340	FW	Feedwater to steam generator C, temperature element, computer input, type E thermocouple	IB; J6-2.8; 436’-0"	D-302-083; E-304-085; E-811-019
ITE3342	FW	Feedwater to steam generator C, temperature element, computer input, 100 ohm RTD	RB; Q-1; 436’-0"	D-302-083; E-304-085; E-811-004
ITW4470	SW	Service water to component cooling heat exchanger A, thermowell, local test	IB; H4-3.6 -	D-302-222; E-304-253; E-811-017

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITE4471	SW	Service water from component cooling heat exchanger A, temperature element, type E thermocouple	IB; H4-4.4; 412’-0"	D-302-222; E-304-253; E-811-017
ITW4500	SW	Service water to component cooling heat exchanger B, thermowell, local test	IB; J1-3.6; 412’-0"	D-302-222; E-304-253; E-811-017
ITE4501	SW	Service water from component cooling heat exchanger B, temperature element, type E thermocouple	IB; J1-3.6; 412’-0"	D-302-222; E-304-253; E-811-017
ITE4467	SW	Cooling water from reactor building air handling heat exchange loop A, temperature element, computer input T4467A, post accident monitor, 100 ohm RTD	AB; M-7.7; 463’-0"	D-302-222; E-304-255; E-811-015
ITW4469	SW	Cooling water from reactor building air handling heat exchange loop A, temperature thermowell, local test	AB; M-7.7; 463’-0"	D-302-222; E-304-255; E-811-015
ITW4473	SW	Service water to HVAC mechanical water chiller A, thermowell, local test	IB; F1-5.2; 412’-0"	D-302-222; E-304-256; E-811-018
ITE4474	SW	Service water from HVAC mechanical water chiller A, temperature element, type E thermocouple	IB; F1-5.2; 412’-0"	D-302-222; E-304-256; E-811-018
ITW4482	SW	Service water to HVAC mechanical water chiller C, thermowell, local test	IB; F1-5.9; 412’-0"	D-302-222; E-304-256; E-811-018

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITE4484	SW	Service water from HVAC mechanical water chiller C, temperature element, type E thermocouple	IB; F1-5.9; 412’-0"	D-302-222; E-304-256; E-811-018
ITE4497	SW	Cooling water from reactor building air handling heat exchange loop B, temperature element, computer input T4497A, post accident monitor, 100 ohm RTD	FB; Q-5.4; 463’-0"	D-302-222; E-304-256; E-811-034
ITW4499	SW	Cooling water from reactor building air handling heat exchange loop B, thermowell, local test	FB; Q5-4.1; 463’-0"	D-302-222; E-304-256; E-811-034
ITW4503	SW	Service water to HVAC mechanical water chiller B, thermowell, load test	IB; F1-6.8; 412’-0"	D-302-222; E-304-256; E-811-018
ITE4504	SW	Service water from HVAC mechanical water chiller B, temperature element, type E thermocouple	IB; F1-6.8; 412’-0"	D-302-222; E-304-256; E-811-018
ITE4514	SW	Service water from HVAC mechanical water chiller C, temperature element, type E thermocouple	IB; F1-5.9; 412’-0"	D-302-222; E-304-256; E-811-018
ITW0410	RC	Loop 1 cold leg thermal well, TW-410	RB; RC-13; 412’-0"	E-302-601; E-304-601; -
ITW0412	RC	Loop 1 cold leg well, TW-412	RB; RC-13; 412’-0"	E-302-601; E-304-601; E-811-003

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITW0412-1	RC	Loop 1 hot leg well, TW-412-1	RB; RC-15; 412’-0"	E-302-603; E-304-601; E-811-003
ITW0412-2	RC	Loop 1 hot leg well, TW-412-2	RB; RC-15; 412’-0"	E-302-603; E-304-601; E-811-003
ITW0412-3	RC	Loop 1 hot leg well, TW-412-3	RB; RC-15; 412’-0"	E-302-603; E-304-601; E-811-003
ITW0413	RC	Loop 1 hot leg well, TW-413	RB; RC-15; 412’-0"	E-302-601; E-304-601; -
ITW0420	RC	Loop 2 cold leg well, TW-420	RB; RC-8; 412’-0"	E-302-601; E-304-601; -
ITW0422	RC	Loop 2 cold leg well, TW-422	RB; RC-8; 412’-0"	E-302-601; E-304-601; E-811-003
ITW0422-1	RC	Loop 2 hot leg well, TW-422-1	RB; RC-9; 412’-0"	E-302-604; E-304-601; E-811-003
ITW0422-2	RC	Loop 2 hot leg well, TW-422-2	RB; RC-9; 412’-0"	E-302-604; E-304-601; E-811-003

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITW0422-3	RC	Loop 2 hot leg well, TW-422-3	RB; RC-9; 412’-0"	E-302-604; E-304-601; E-811-003
ITW0423	RC	Loop 2 hot leg well, TW-423	RB; RC-9; 412’-0"	E-302-601; E-304-601; -
ITW0430	RC	Loop 3 cold leg well, TW-430	RB; RC-1; 412’-0"	E-302-601; E-304-601; -
ITW0432	RC	Loop 3 cold leg well, TW-432	RB; RC-1; 412’-0”	E-302-601; E-304-601; E-811-003
ITW0432-1	RC	Loop 3 hot leg well, TW-432-1	RB; RC-2; 412’-0"	E-302-605; E-304-601; E-811-003
ITW0432-2	RC	Loop 3 hot leg well, TW-432-2	RB; RC-2; 412’-0"	E-302-605; E-304-601; E-811-003
ITW0432-3	RC	Loop 3 hot leg well, TW-432-3	RB; RC-2; 412’-0	E-302-605; E-304-601; E-811-003
ITW0433	RC	Loop 3 hot leg well, TW-433	RB; RC-2; 412’-0"	E-302-601; E-304-601; -

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITW0450	RC	Pressurizer surge line well, TW-450	RB; RC-15; 412’-0"	E-302-602; E-304-601; -
ITW0451	RC	Pressurizer spray line well, TW-451	RB; RC-15; 436’-0"	E-302-602; E-304-601; -
ITW0452	RC	Pressurizer spray line well, TW-452	RB; RC-15; 436’-0"	E-302-602; E-304-601; -
IPI7000	CC	Component cooling pump A, suction pressure indicator, local indication	IB; H4-3.6; 412’-0"	D-302-611; E-304-611; E-811-017
IPI7002	CC	Component cooling pump A, discharge pressure indicator, local indication	IB; H7-3.6; 412’-0"	D-302-611; E-304-611; E-811-017
IPI7010	CC	Component cooling pump B, suction pressure indicator, local indication	IB; H4-6.8; 412’-0"	D-302-611; E-304-611; E-811-018
IPI7012	CC	Component cooling pump B, discharge pressure indicator, local indication	IB; H4-5.9; 412’-0"	D-302-611; E-304-611; E-811-018
IPI7020	CC	Component cooling pump C, suction pressure indicator, local indication	IB; H4-5.9; 412’-0"	D-302-611; E-304-611; E-811-018

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
IPI7022	CC	Component cooling pump C, discharge pressure indicator, local indication	IB; H4-5.2; 412'-0"	D-302-611; E-304-611; E-811-018
IPI7101	CC	Component cooling booster pump, suction header pressure indicator, local indication	IB; J-8.3; 412'-0"	D-302-612; E-304-611; E-811-012
ITE7047	CC	Component cooling water from residual heat removal heat exchanger B	AB; L-11-5; 412'-0"	D-302-611; E-304-612; E-811-011
ITW7183	CC	Component cooling water to radioactive sample coolers, thermowell, local test	AB; L-9.5; 412'-0"	D-302-613; E-304-612; E-811-011
ITW7203	CC	Component cooling water to spent fuel heat exchanger, thermowell, local test	AB; R-8-8; 388'-0"	D-302-613; E-304-613; E-811-007
ITW7204	CC	Component cooling water to waste gas compressor, thermowell, local test	AB; N-8.8; 388'-0"	D-302-613; E-304-613; E-811-007
ITE7037	CC	Component cooling water from residual heat removal heat exchanger A	AB; K-11.5; 436'-0"	D-302-611; E-304-614; E-811-013
ITW7052	CC	Component cooling water from component cooling heat exchanger A, thermowell	IB; G4-4.4; 412'-0"	D-302-611; E-304-614; E-811-017

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITW7062	CC	Component cooling water from component cooling heat exchanger B, thermowell	IB; J1-5.2; 412’-0"	D-302-611; E-304-614; E-811-017
IPI7103A	CC	Component cooling booster pump A, discharge pressure indicator, local indication	IB; J-8.3; 412’-0"	D-302-612; E-304-614; E-811-018
IPI7103B	CC	Component cooling booster pump B, discharge pressure indicator, local indication	IB; J-8.3; 412’-0"	D-302-612; E-304-614; E-811-018
IPI7103C	CC	Component cooling booster pump C, discharge pressure indicator, local indication	IB; J-8.3; 412’-0"	D-302-612; E-304-614; E-811-018
ITW7234	CC	Component cooling water to recycle evaporator package, thermowell, local test	AB: N-9.5; 412’-0"	D-302-613; E-304-614: E-811-010
ITE7188	CC	Component cooling water from seal water heat exchanger, temperature element, type E thermocouple	AB: N-9.5; 412’-0"	D-302-613; E-304-615; E-811-010
ITW7193	CC	Component cooling water to letdown and seal water heat exchangers, thermowell, local test	AB; M-9.5; 412’-0"	D-302-613; E-304-615; E-811-010
ITE7196	CC	Component cooling water from letdown heat exchanger, temperature element, type E thermocouple	AB; N-9.5; 412’-0"	D-302-613; E-304-615; E-811-010

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITE7201	CC	Component cooling water from waste gas compressor A, temperature element, type E thermocouple	AB; N-9.5; 388'-0"	D-302-613; E-304-615; E-811-007
ITE7206	CC	Component cooling water from spent fuel pool heat exchanger A, temperature element, type E thermocouple	AB; Q-7.7; 388'-0"	D-302-613; E-304-615; E-811-007
ITE7211	CC	Component cooling water from waste gas compressor B, temperature element, type E thermocouple	AB; N-11.5; 388'-0"	D-302-613; E-304-615; E-811-007
ITE7216	CC	Component cooling water from spent fuel pool heat exchanger B, temperature element, type E thermocouple	AB; R-6.6; 388'-0"	D-302-613; E-304-615; E-811-007
ITE7221	CC	Component cooling water from waste processing system recombiner A, temperature element, type E thermocouple	AB; N-9.5; 388'-0"	D-302-613; E-304-615; E-811-007
ITE7226	CC	Component cooling water from recycle evaporator package, temperature element, type E thermocouple	AB; P-9.5; 412'-0"	D-302-613; E-304-615; E-811-010
ITI7227	CC	Component cooling water from recycle evaporator package, temperature indicator, local indication, well furnished by Pyco	AB; P-9.5; 412'-0"	D-302-613; E-304-615; E-811-010
ITE7231	CC	Component Cooling water from waste processing system recombiner B, temperature element, type E thermocouple	AB; N-11.5; 388'-0"	D-302-613; E-304-615; E-811-007

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITE7236	CC	Component cooling water from waste evaporator package, temperature element, type E thermocouple	AB; M-8.8; 412’-0"	D-302-613; E-304-615; E-811-010
ITW7244	CC	Component cooling water to waste evaporator package, thermowell, local test	AB; N-8.8: 412’-0"	D-302-613; D-304-615; E-811-010
ITE7246	CC	Component cooling water from residual heat removal pump A seal cooling, temperature element, type E thermocouple	AB; J-8.8; 374’-0"	D-302-614; E-304-615; E-811-006
ITE7256	CC	Component cooling water from residual heat removal pump B seal cooling, temperature element, type E thermocouple	AB; L-8.8; 374’-0"	D-302-614; E-304-615; E-811-006
ITW7107	CC	Component cooling water to reactor coolant pump thermal barrier cooler, thermowell, local test	IB; J6-3.6; 436’-0"	D-302-612; E-304-616; E-811-019
ITE7108	CC	Component cooling water from excess letdown heat exchanger, temperature element, 100 ohm RTD	RB; RC-15; 436’-0"	D-302-612; E-304-617; E-811-004
ITW7112	CC	Component cooling water to excess letdown heat exchanger and reactor coolant drain tank heat exchanger, thermowell, local test	RB; RC-13; 436’-0"	D-302-612; E-304-617; E-811-004
ITE7118	CC	Component cooling water from reactor coolant drain tank heat exchanger, temperature element, 100 ohm platinum RTD	RB; RC-17; 412’-0"	D-302-612; E-304-618; E-811-003

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITE7128	CC	Component cooling water from reactor coolant pump A upper bearing, temperature element, 100 ohm platinum RTD	RB; RC-12; 436’-0"	D-302-612; E-304-618; E-811-004
ITE7134	CC	Component cooling water from reactor coolant pump A lower bearing, temperature element, 100 ohm platinum RTD	RB; RC-12; 436’-0"	D-302-612; E-304-618; E-811-004
ITE7140	CC	Component cooling water from reactor coolant pump A thermal barrier, temperature element, 100 ohm platinum RTD	RB; RC-12; 436’-0"	D-302-612; E-304-618; E-811-004
ITE7148	CC	Component cooling water from reactor coolant pump B upper bearing, temperature element, 100 ohm platinum RTD	RB; RC-8; 436’-0"	D-302-612; E-304-618; E-811-004
ITE7154	CC	Component cooling water from reactor coolant pump B lower bearing, temperature element, 100 ohm platinum RTD	RB; RC-8; 436’-0"	D-302-612; E-304-618; E-811-004
ITE7160	CC	Component cooling water from reactor coolant pump B thermal barrier, temperature element, 100 ohm platinum RTD	RB; RC-8; 436’-0"	D-302-612; E-304-618; E-811-004
ITE7168	CC	Component cooling water from reactor coolant pump C upper bearing, temperature element, 100 ohm platinum RTD	RB; RC-3; 436’-0"	D-302-612; E-304-618; E-811-004
ITE7174	CC	Component cooling water from reactor coolant pump C lower bearing, temperature element, 100 ohm platinum RTD	RB; RC-3; 436’-0"	D-302-612; E-304-618; E-811-004

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITE7180	CC	Component cooling water from reactor coolant pump C thermal barrier, temperature element, 100 ohm platinum RTD	RB; RC-3; 436’-0"	D-302-612; E-304-618; E-811-004
ITW0604A	RH	Residual heat removal pump, thermowell, TW-604A	AB; J-8.8; 374’-0"	E-302-641; E-304-644; -
ITW0604B	RH	Residual heat removal pump, thermowell, TW-604B	AB; L-7.7; 374’-0"	E-302-641; E-304-644; -
ITW0606A	RH	Residual heat exchanger outlet, thermowell, TW-606A	AB; K-9.5; 412’-0"	E-302-641; E-304-645; -
ITW0606B	RH	Residual heat exchanger outlet, thermowell, TW-606B	AB; K-11.5; 412’-0"	E-302-641; E-304-645; -
IPI7441	SF	Spent fuel cooling pump A, suction strainer pressure indicator, local indication	AB; R-6.6; 412’-0"	D-302-651; E-304-656; E-811-010
IPI7442	SF	Spent fuel cooling pump A, suction pressure indicator, local indication	AB; R-6.6; 412’-0"	D-302-651; E-304-656; E-811-010
IPI7444	SF	Spent fuel cooling pump A, discharge pressure indicator, local indication	AB; R-6.6; 412’-0"	D-302-651; E-304-656; E-811-010

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
IPI7451	SF	Spent fuel cooling pump B, suction strainer pressure indicator, local indication	AB; R-7.7; 412’-0"	D-302-651; E-304-656; E-811-010
IPI7452	SF	Spent fuel cooling pump B, suction pressure indicator, local indication	AB; R-7.7; 412’-0"	D-302-651; E-304-656; E-811-010
IPI7454	SF	Spent fuel cooling pump B, discharge pressure indicator, local indication	AB; R-7.2; 412’-0"	D-302-651; E-304-656; E-811-010
IPI7362	SP	Reactor building spray pump A, suction pressure indicator, local indication	AB; J-8.8; 374’-0"	D-302-661; E-304-667; E-811-006
IPI7366	SP	Reactor building spray pump A, discharge pressure indicator, local indication	AB; J-8.8; 374’-0"	D-302-661; E-304-667; E-811-006
IPI7372	SP	Reactor building spray pump B, suction pressure indicator, local indication	AB; L-8.8; 374’-0"	D-302-661; E-304-667; E-811-006
IPI7376	SP	Reactor building spray pump B, discharge pressure indicator, local indication	AB; L-8.8; 374’-0"	D-302-661; E-304-667; E-811-006
ITW0139	CS	Excess letdown heat exchanger, thermowell, TW-139	RB; RC-17; 412’-0"	E-302-673; E-304-671; -

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITW0140	CS	Regenerative heat exchanger letdown, thermowell, TW-140	RB; RC-1; 412’-0"	E-302-673; E-304-671; -
ITW0144	CS	Letdown heat exchanger outlet, thermowell, TW-144	AB; M-9.5; 426’-6"	E-302-674; E-304-674; E-811-010
ITW0381	TR	Letdown reheat heat exchanger outlet, thermowell, TW-381	AB; M-8.8; 426’-6"	E-302-676; E-304-674; -
ITW0386	TR	Chemical and volume control system return header, test well, TW-386	AB; K-8.8; 426’-6"	E-302-676; E-304-675; -
ITW0389	TR	Ion exchange outlet, thermowell, TW-389	AB; J-8.8; 426’-6"	E-302-676; E-304-675; -
ITW0133	CS	Seal water return, thermowell, TW-133	AB; N-7.7; 412’-0"	E-302-673; E-304-676; -
ITW0136	CS	Seal water heat exchanger, thermowell, TW-136	AB; N-9.5; 426’-6"	E-302-675 E-304-681; -
IPI7351	SP	Sodium hydroxide storage tank, pressure indicator, local indication	YD; K-11.5; 436’-0"	D-302-661; E-304-728; E-811-011

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
ITW9011A	VU	Chilled water chiller A exit, thermowell, local test	IB; F1-5.2; 412'-0"	D-302-841; E-304-841; E-811-018
ITW9011B	VU	Chilled water chiller B exit, thermowell, local test	IB; F1-6.8; 412'-0"	D-302-841; E-304-841; E-811-018
ITE9013	VU	Chilled water chiller A exit, temperature element, 100 ohm RTD	IB; F1-5.2; 412'-0"	D-302-841; E-304-841; E-811-018
ITE9023	VU	Chilled water chiller B exit, temperature element, 100 ohm RTD	IB; F1-7.5; 412'-0"	D-302-841; E-304-841; E-811-018
ITE9033A	VU	Chilled water chiller C exit, temperature element, 100 ohm RTD	IB; F1-6.8; 412'-0"	D-302-841; E-304-841; E-811-018
ITE9033B	VU	Chilled water chiller C exit, temperature element, 100 ohm RTD	IB; F1-6.8; 412'-0"	D-302-841; E-304-841; E-811-018
IPI9007A	VU	Chilled water pump A suction, pressure indicator, local indication	IB; F1-5.9; 412'-0"	D-302-841; E-304-845; E-811-018
IPI9007B	VU	Chilled water pump B suction, pressure indicator, local indication	IB; G4-5.9; 412'-0"	D-302-841; E-304-845; E-811-018

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.
IPI9009A	VU	Chilled water pump A discharge, pressure indicator, local indication	IB; F1-5.9; 412'-0"	D-302-841; E-304-845; E-811-018
IPI9009B	VU	Chilled water pump B discharge, pressure indicator, local indication	IB; G4-5.9; 412'-0"	D-302-841; E-304-845; E-811-018
ITE9017	VU	Chilled water supply header A, temperature element, computer input T9017S, 100 ohm RTD	IB; G4-5.9; 412'-0"	D-302-841; E-304-845; E-811-018
ITW9018A	VU	Chilled water supply header A, thermowell, local test	IB; G4-5.2; -	D-302-841; E-304-845; E-811-018
ITW9018B	VU	Chilled water supply header B, thermowell, local test	IB; G4-7.5; 412'-0"	D-302-841; E-304-845; E-811-018
ITE9027	VU	Chilled water supply header B, temperature element, computer input T9027A, 100 ohm RTD	IB; G4-7.5; 412'-0"	D-302-841; E-304-845; E-811-018
IPI9028	VU	Chilled water pump C suction, pressure indicator, local indication	IB; G4-5.9; 412'-0"	D-302-841; E-304-845; E-811-018
IPI9029	VU	Chilled water pump C discharge, pressure indicator, local indication	IB; G4-5.9; 412'-0"	D-302-841; E-304-845; E-811-018

Table 3.10-3 (continued)
Seismically Qualified Pipe Mounted Instruments

Instr. No.	System [1]	Description	Bldg;[2] Column No.; Elev.	Flow Diagram Piping Dwg; Location Dwg.

(1) System:
CC - Component cooling water
CS - Chemical and volume control
EF - Emergency feedwater
FW - Main feedwater
MS - Main steam
RC - Reactor coolant
RH - Residual heat removal
SP - Reactor building spray
SW - Service water
TR - Thermal regeneration
VU - Chilled water

(2) Building:

AB - Auxiliary building
DG - Diesel generator building
FB - Fuel handling building
IB - Intermediate building
RB - Reactor building
SW - Service water pumphouse
YD - Yard

3.11 ENVIRONMENTAL QUALIFICATION OF MECHANICAL AND ELECTRICAL EQUIPMENT

This section describes the program for environmental qualification of electrical equipment. The Virgil C. Summer Nuclear Station does not have a licensing commitment to environmentally qualify safety-related mechanical equipment to the level of detail required to qualify electrical equipment. However, mechanical equipment has been specified and procured to satisfy requirements which assure that it can withstand the normal, abnormal, accident, and post-accident conditions to which it may be subjected. The environmental qualification program for the V. C. Summer Nuclear Station identifies the electrical equipment to be qualified, defines the environmental conditions under normal, abnormal, accident, and post-accident operating conditions. The program also documents the qualification tests and analyses employed to demonstrate the equipment's capability to perform design safety functions including post-accident monitoring when exposed to normal, abnormal, accident, and post-accident environments as applicable. Seismic qualification is addressed in Section 3.10 for mechanical and electrical equipment.

3.11.1 Environmental Conditions and Equipment Identification

This section identifies: 1) the environmental design basis for electrical equipment, including the definition of the normal, abnormal, accident, and post-accident environments, and 2) the systems and electrical equipment that are required to perform a design safety function, including Regulatory Guide 1.97 (Reference 24) monitoring.

3.11.1.1 Environmental Conditions

Electrical equipment location for environmental qualification purposes is defined by environmental zones. Various environmental zones are encountered within the plant's building(s) (i.e. Auxiliary Bldg., Containment Bldg., Intermediate Bldg., etc.). The environmental zone boundaries are shown on plant layout drawings, called "Environmental Zone Maps", as documented by drawings SS-021-001 through SS-021-017 (Reference 3). The zone boundaries shown on drawings SS-021-001 through SS-021-017 were determined based on contiguous areas with similar environmental conditions.

An equipment qualification database with environmental zone information as zones documented by drawing S-021-018 (Reference 4) provides a list of the environmental zones and conditions, including the normal, abnormal, and accident (including post-accident) environmental conditions. Environmental data is provided for the temperature, pressure, relative humidity, and radiation parameters for each environmental condition postulated to occur within each zone. Definitions used in determining the environmental conditions are as follows:

a. Normal Conditions - planned, purposeful, unrestricted reactor operating modes that include startup, power range and hot standby (condenser available), shutdown, and refueling modes.

b. Abnormal Conditions - any deviation from normal conditions anticipated to occur often enough that design should include a capability to withstand the conditions without operation impairment; planned testing including preoperational tests are also considered abnormal conditions (loss of non-safety related HVAC is an example of an abnormal condition).

c. Accident Conditions - a single event not reasonably expected during the course of plant operations that has been hypothesized for analysis purposes or postulated from unlikely but possible situations or that has the potential to cause a release of radioactive material (a reactor coolant pressure boundary rupture may qualify as an accident; a fuel cladding defect does not). Postulated accident conditions include those resulting from: a Main Steam Line Break (MSLB) inside or outside of containment; a Loss of Coolant Accident (LOCA); a High Energy Line Break/Superheated Blowdown Outside Containment (HELB/SBOC); or other Line Break Accidents. Accident conditions are calculated for a post-accident period sufficient to ensure that steady state conditions have been reached.

The environmental parameters listed in drawing S-021-018 are based on verified design calculations and do not include margins required in qualification testing or analyses as described in Section 3.11.2. The design basis used for preventing the loss of ventilation for some zones is discussed in Section 3.11.4. The basis for the estimated chemical and radiation environmental conditions is discussed in Section 3.11.5. Environmental conditions listed in drawing S-021-018, and environmental zone boundaries shown on Environmental Zone Maps, drawings SS-021-001 through SS-021-017, will be revised when a modification in equipment or components or the results of temperature monitoring affect environmental qualification conditions.

Technical Requirements for Quality Related (QR) steam propagation barriers /components which are required to maintain area environmental conditions for equipment qualification (EQ) purposes are provided in plant procedures which specify the technical criteria for design, procurement, installation/maintenance and inspection of these QR components. These barriers/components segregate EQ zones to ensure that the conditions for which the equipment qualification were based on are not exceeded.

To aid in the application of the qualification program acceptance criteria that is discussed in Section 3.11.2, the environmental zones listed in S-021-018 drawings have been classified as either a harsh or mild environment based on the following definitions:

Harsh Environments - Those zones or areas where the environmental conditions significantly exceed the normal or abnormal range as a result of a DBE. A harsh environment area is an area or zone of the plant where one or more of the following environmental service conditions exist:

- Radiation

  TID (normal plus accident) > 1.0 E05 Rads (1.0 E04 for electronics) and the accident dose is greater than or equal to normal.

- Humidity:

  Relative Humidity = 100%

- Pressure:

  ≥ 0.1 psig above atmospheric

- Temperature

  The accident temperature is ≥ a 20% change from the normal maximum temperature.

Mild Environments - Those zones or areas where the environmental conditions do not significantly exceed the normal or abnormal range as a result of a DBE. A mild environment area is an area or zone of the plant where the following environmental service conditions exist:

- Radiation:

  TID (normal plus accident) ≤ 1.0 E05 Rads; or, if greater than 1.0 E05, the accident dose is less than TID normal. The 1.0 E05 limit is reduced to 1.0 E04 for electronics.

- Humidity:

  Relative Humidity < 100%

- Pressure:

  < 0.1 psig above atmospheric

- Temperature:

  The accident temperature is < a 20% change from the normal maximum temperature.

3.11.1.2 Equipment Identification

1. General

   Electrical equipment to be qualified includes equipment associated with systems that are essential to:

   a. Emergency reactor shutdown.
   b. Containment isolation.
   c. Reactor core cooling.
   d. Containment heat removal.

e. Reactor heat removal.

f. Preventing significant release of radioactive material to the environment, or

g. Provide Regulatory Guide 1.97 Category 1 and 2 indicating and post-accident monitoring. Non 1E, Regulatory Guide 1.97 Category 2 equipment installed in a geographic mild environment is excluded from the mild EQ Program

This is equipment that:

a. Performs the previous functions automatically,

b. Is used by the operator to perform these functions manually, or

c. The failure of which can prevent the satisfactory accomplishment of one or more of the previous safety functions.

"Safety-related" equipment is categorized in three groups by design safety function:

a. Safety-related electrical equipment - designated as "Class 1E" per IEEE Standard 308. (Reference 1)

b. Safety-related "Active" Mechanical Equipment - that equipment which must move or change position to perform its design safety function (examples are pumps, motor operated valves, and safety relief valves).

c. Safety-related "Passive" Mechanical Equipment - that equipment which must only maintain its pressure integrity to perform its design safety function (examples are tanks, heat exchangers, and manual valves).

The design safety functions for specific equipment items are discussed on a system basis in Chapters 3 (Sections 3.4, 3.5, and 3.6), 5, 6, 7, 8, 9, 12, and 15.

2. List of Equipment

The Equipment Qualification Database (EQDB) (Reference 2) identifies electrical equipment which requires environmental qualification. The Database provides specific informative data such as: Tag number, manufacturer, model number, equipment qualification documentation package number, etc. It is a computerized Database accessed on the site intranet system. Refer to Section 3.11.3.1 for discussion.

An overview of major safety-related equipment and components other than Class 1E equipment that are required to function during and/or subsequent to the design basis accidents are listed in Tables 3.11-1 for equipment and components located inside the Reactor Building, and 3.11-2 for equipment and components located outside the Reactor Building. The remainder of the information required to comply with General Design Criterion (GDC) 4 is discussed in Sections 3.11.1.1 through 3.11.3.3.

3. Equipment Categorization

   a. For environmental qualification, “Environmentally Qualified” electrical equipment is grouped into one or more categories or designations based on the equipment’s functional design requirements. A breakdown of environmental categories and designations including their respective definitions are as follows:

      1. Category A1:

         Equipment that could experience the environmental conditions of design basis (LOCA) accidents for which it must function to mitigate said accident. It must be qualified to demonstrate operability in the accident environment for the time required for accident mitigation with safety margin to failure.

      2. Category A2:

         Equipment that could experience the environmental conditions of design basis line break accidents, including Main Steam Line Break (MSLB), High Energy Line Break/Superheated Blowdown Outside Containment (HELB/SBOC), and/or other line breaks for which it must function to mitigate said accidents. It must be qualified to demonstrate operability in its specifically applicable accident environment for the time required for accident mitigation with safety margin to failure.

      3. Category A1 *:

         Equipment that could experience increased radiation exposure due to Post-LOCA recirculation for which it must function to mitigate said accident. It must be qualified to demonstrate operability in the radiation environment for the time required for accident mitigation with safety margin to failure.

      4. Category B1:

         Equipment that could experience environmental conditions of design basis (LOCA) accidents through which it need not function for mitigation of said accident, but through which it must not fail in a manner detrimental to plant safety or accident mitigation. It must be qualified to demonstrate the capability to withstand any LOCA accident environment for the time during which it must not fail with safety margin to failure.

5. Category B2:

   Equipment that could experience the environmental conditions of design basis line break accidents, including Main Steam Line Break (MSLB), High Energy Line Break/Superheated Blowdown Outside Containment (HELB/SBOC), and/or other line breaks for which it need not function for mitigation of said accidents, but through which it must not fail in a manner detrimental to plant safety or accident mitigation. It must be qualified to demonstrate the capability to withstand any such specifically applicable accident environment for the time which it must not fail with safety margin to failure.

6. Category B1 *:

   Equipment that could experience increased radiation exposure due to Post-LOCA recirculation through which it need not function for mitigation of said accident, but through which it must not fail in a manner detrimental to plant safety or accident mitigation. It must be qualified to demonstrate the capability to withstand any radiation environment for the time during which it must not fail with safety margin to failure.

7. Category C1:

   Equipment that could experience environmental conditions of design basis (LOCA) accidents through which it need not function for mitigation of said accident, and whose failure is deemed not detrimental to plant safety or accident mitigation. It deemed not detrimental to plant safety or accident mitigation. It need not be qualified for any LOCA accident environment, but must be qualified for the non-accident environment.

8. Category C2:

   Equipment that could experience the environmental conditions of design basis line break accidents, including Main Steam Line Break (MSLB), High Energy Line Break/Superheated Blowdown Outside Containment (HELB/SBOC), and/other line breaks through which it need not function for mitigation of said accidents and whose failure is deemed not detrimental to plant safety or accident mitigation. It need not be qualified for these accident environments, but must be qualified for the non-accident environment.

9. Category C1 *:

   Equipment that could experience increased radiation exposure due to Post-LOCA recirculation through which it need not function for mitigation of said accident and whose failure is deemed not detrimental to plant safety or accident mitigation. It need not be qualified for any Post-LOCA harsh accident environment, but must be qualified for the non-accident environment. Also equipment that could experience increased radiation exposure due to Post-LOCA recirculation but has completed its functional requirement prior to the environment becoming harsh and whose failure (after completing any required function) is deemed not detrimental to plant safety or accident mitigation need not be qualified for any Post-LOCA harsh accident environment, but must be qualified for the non-accident and Post-LOCA mild accident environments.

10. Category D:

    Equipment that would not experience environmental conditions of design basis accidents and that must be qualified to demonstrate operability in the normal and abnormal service environment. This equipment is located outside containment.

11. Designation QR-H:

    Equipment that is quality related and requires harsh environment qualification per design documents.

12. Designation QR-M:

    Equipment that is quality related and requires mild environment qualification per design documents.

b. Environmental categories for Regulatory Guide 1.97 equipment are similar to those previously identified for other safety-related electrical equipment except that a prefix letter E is used.

   A breakdown of Regulatory Guide 1.97 environmental categories and respective definitions are as follows:

1. Category EA1:

   Equipment that could experience the environmental conditions of design basis (LOCA) accidents for which it must function to provide Regulatory Guide 1.97 monitoring information to the operator. It must be qualified to demonstrate operability in the accident environment for the time required with safety margin to failure.

2. Category EA2:

   Equipment that could experience the environmental conditions of design basis line break accidents, including Main Steam Line Break (MSLB), High Energy Line Break/Superheated Blowdown Outside Containment (HELB/SBOC), and/or other line breaks for which it must function to provide Regulatory Guide 1.97 monitoring information to the operator. It must be qualified to demonstrate operability in its specific applicable accident environment for the time required with safety margin to failure.

3. Category EA1:*

   Equipment that could experience increased radiation exposure due to Post-LOCA recirculation for which it must function to provide RG 1.97 monitoring information to the operator. It must be qualified to demonstrate operability in the radiation environment for the time required with safety margin to failure.

4. Category EB1:

   Equipment that could experience environmental conditions of Design Basis (LOCA) accidents through which it need not function to provide RG 1.97 monitoring information to the operator, but through which it must not fail in a manner detrimental to any related RG 1.97 monitoring function. It must be qualified to demonstrate the capability to withstand any such accident environment for the time during which it must not fail with safety margin to failure.

5. Category EB2:

   Equipment that could experience the environmental conditions of design basis line break accidents, including Main Steam Line Break (MSLB), High Energy Line Break/Superheated Blowdown Outside Containment (HELB/SBOC), and/or other line breaks for which it need not function to provide RG 1.97 monitoring information to the operator, but through which it must not fail in a manner detrimental to any related RG 1.97 monitoring function. It must be qualified to demonstrate the capability to withstand any such specifically applicable accident environment for the time during which it must not fail with safety margin to failure

6. Category EB1:*

   Equipment that could experience increased radiation exposure due to Post-LOCA recirculation through which it need not function to provide RG 1.97 monitoring information to the operator, but through which it must not fail in a manner detrimental to any related RG 1.97 monitoring function. It must be qualified to demonstrate the capability to withstand any such accident environment for the time during which it must not fail with safety margin to failure.

7. Category EC1:

   Equipment that could experience the environmental conditions of design basis (LOCA) accidents through which it need not function for Regulatory Guide 1.97 monitoring purposes and whose failure is not deemed detrimental to the Regulatory Guide 1.97 monitoring function. It need not be qualified for a LOCA accident environment, but must be qualified for the non-accident environment.

8. Category EC2:

   Equipment that could experience the environmental conditions of design basis line break accidents, including Main Steam Line Break (MSLB), High Energy Line Break/Superheated Blowdown Outside Containment (HELB/SBOC), and other line breaks through which it need not function for Regulatory Guide 1.97 monitoring purposes and whose failure is deemed not detrimental to the Regulatory Guide 1.97 monitoring function. It need not be qualified for these accident environments, but must be qualified for the non-accident environment.

9. Category EC1:*

   Equipment that could experience increased radiation exposure due to Post-LOCA recirculation through which it need not function to provide RG 1.97 monitoring information to the operator and whose failure is deemed not detrimental to the RG 1.97 monitoring function. It need not be qualified for any Post-LOCA harsh accident environment, but must be qualified for the non-accident environment.

   Also equipment that could experience increased radiation exposure due to Post-LOCA recirculation but has completed its RG 1.97 monitoring requirement prior to the environment becoming harsh, and whose failure (after completing any required function) is deemed not detrimental to the RG 1.97 monitoring function. It need not be qualified for any Post-LOCA harsh accident environment, but must be qualified for the non-accident and the Post-LOCA mild accident environment.

10. Category ED:

    Equipment that would not experience environmental conditions of design basis accidents and that must be qualified to demonstrate operability for its Regulatory Guide 1.97 monitoring function in its normal and abnormal service environment. This equipment is located outside containment.

3.11.2 Environmental Qualification Program Acceptance Criteria

This section describes the environmental qualification program acceptance criteria that were employed to meet the following general requirements:

a. The equipment was designed to have the capability of performing its design safety functions under postulated normal, abnormal, accident, and post-accident environments for the length of time for which its function is required plus margin.

b. The equipment environmental capability was demonstrated by appropriate testing, analyses, and/or operating experience.

c. A quality assurance program meeting the requirements of 10CFR50, Appendix B, was established and implemented to provide assurance that all requirements have been satisfactorily accomplished.

The Virgil C. Summer Nuclear Station is committed to qualification of electrical equipment requiring harsh qualification in accordance with NUREG-0588 (Reference 5), Cat. II, which relates to IEEE 323-1971 (Reference 6) for the original plant design. However, some equipment was qualified to IEEE 323-1974 (Reference 7) (NUREG 0588, Cat. 1) requirements. New and replacement electrical equipment requiring harsh qualification is governed by the current regulations of 10CFR50.49. The status of electrical equipment qualification in accordance with the applicable IEEE Standards and Regulatory requirements is documented in Virgil C. Summer Nuclear Station Equipment Qualification Documentation Packages (EQDP's) for equipment which requires hard qualification and Equipment Qualification Files (EQF's) for equipment which requires mild qualification. Refer to Section 3.11.3 for further discussion.

3.11.2.1 Conformance with Regulatory Requirements

Conformance with General Design Criteria 1, 4, 23, and 50 is discussed in Section 3.1.

3.11.2.1.1 10CFR50 Appendix A Criterion 4 (Reference 8) - Environmental and Missile Design Bases

The scope of electrical equipment and the environmental requirements for GDC 4 are addressed in Section 3.11.1. Refer to Sections 3.5 and 3.6 for discussions related to missile protection.

Electrical equipment that is required to perform a design safety function is designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents in accordance with GDC 4.

3.11.2.1.2 10CFR50 Appendix B (Reference 9)

The Electrical Equipment Environmental Qualification Program is in compliance with the Virgil C. Summer Nuclear Station Quality Assurance Program. The Quality Assurance Program meets the requirements of 10CFR50, Appendix B.

3.11.2.1.3 Regulatory Guide 1.89 (Reference 10)

Compliance with Regulatory Guide 1.89, which pertains to the qualification of Class 1E electrical equipment, is also discussed in Appendix 3A.

Class 1E electrical equipment is qualified in accordance with IEEE 323-1974, as endorsed by Regulatory Guide 1.89 with the following exceptions:

a. In cases where the qualification has been demonstrated in accordance with IEEE 323-1971, documentation of that qualification is maintained in the form of auditable file packages. Refer to Section 3.11.3.2 for discussion.

b. Specific criteria for assessing the acceptability of the original scope of the environmental qualification program for safety related electrical equipment requiring harsh qualification is provided by NUREG-0588 Category II, as related to IEEE 323-1971, or Category I as related to IEEE 323-1974. Specific criteria for assessing the acceptability of the environmental qualification program for electrical equipment added or replaced in harsh environments are provided by 10CFR50.49 (Reference 11), dated January 17, 1983.

c. Mild environment equipment qualification by test and/or analysis is not a requirement of 10CFR50.49. Mild environment equipment qualification files are established to provide design, procurement, and maintenance information in a readily accessible form.

3.11.2.1.4 Regulatory Guides 1.30 (Reference 12), 1.40 (Reference 13), 1.63 (Reference 14), and 1.73 (Reference 15)

The detailed criteria contained in these documents as they relate to environmental qualification should be used in conjunction with the more comprehensive criteria of NUREG-0588 for evaluating the respective equipment environmental qualification.

Compliance with these Regulatory Guides is discussed in Appendix 3A.

3.11.2.1.5 Regulatory Guide 1.97 (Reference 24)

Regulatory Guide 1.97 imposes environmental qualification requirements on electrical components used for monitoring certain plant parameters after an accident. Design and qualification criteria for Regulatory Guide 1.97 instrumentation, as described in Table 1 of the Regulatory Guide, states that the instrumentation should be environmentally qualified in accordance with Regulatory Guide 1.89 and the methodology as described in NUREG-0588.

Regulatory Guide 1.97 describes three equipment categories for design and equipment qualification requirements. V. C. Summer Nuclear Station Regulatory Guide 1.97 category 1 and 2 equipment conforms to Regulatory Guide 1.89 environmental qualification requirements. Regulatory Guide 1.97 Category 3 equipment has no special regulatory requirements but the regulatory position is that the equipment should be of high quality commercial grade and should be selected to withstand the specified service environment.

3.11.2.2 Qualification Methodologies for Safety-Related Electrical Equipment

Safety-related electrical equipment including Reg. Guide 1.97 monitoring equipment requiring harsh environmental qualification supplied by Westinghouse under the NSSS contract is qualified as outlined in Section 3.11.2.2.1.

All other safety-related electrical equipment including Reg. Guide 1.97 monitoring equipment requiring harsh environmental qualification is qualified using the methodologies of Section 3.11.2.2.2. Safety-related electrical equipment requiring mild environmental qualification is qualified as discussed in Exception c to Regulatory Guide 1.89 (refer to Section 3.11.2.1.3).

The documentation of the application of the methodologies for the specific equipment identified in Section 3.11.1.2, to demonstrate qualification to the environmental conditions defined in Section 3.11.1.1, is presented in Section 3.11.3.

3.11.2.2.1 Qualification Tests and Analyses Applicable to the NSSS Electrical Equipment

Westinghouse has qualified its NSSS safety-related electrical equipment in accordance with IEEE-323-1971. The Westinghouse supplemental qualification program (Reference 16) is an NRC approved seismic and environmental qualification program, as stated in the Staff letter, D. B. Vassallo to C. Eicheldinger dated November 19, 1975. Mechanical equipment design basis considerations are described in Chapters 5, 6, 9, and 10. Mechanical and electrical components have been identified and classified relative to their safety classification in Section 3.2.

Comprehensive testing and/or analysis is conducted for those electrical equipment and components which are required to function during and subsequent to any of the design basis accidents and that experience hostile environments. The program consists of performance tests of individual pieces of equipment in the manufacturer's shop, integrated tests of the system as a whole in the field, and periodic inspection and tests of the activation circuitry and mechanical components to assure reliable performance, upon demand, throughout the plant lifetime.

The initial qualification tests of individual components and the integrated tests of the systems as a whole complement each other to assure performance of the system as designed and to prove proper operation of the actuation circuitry. For engineered safeguard features (ESF) equipment located inside the Reactor Building, qualification testing and/or analysis is performed under the effects of the conservative post accident temperature, pressure, humidity, radiation, and chemical environment, when applicable. Routine periodic inspection and testing of ESF equipment is performed as outlined in Technical Specifications.

Chapter 6.0 describes the containment temperature and pressure response to various sizes of in-containment main steam line ruptures. Qualified equipment located inside the Reactor Building is required to provide protection in the unlikely event of one of these breaks.

For the larger steam line breaks evaluated, the steam line pressure instrumentation, which is located outside containment, will initiate safety injection on low steam line pressure.

3.11.2.2.2 Qualification Tests and Analyses Applicable to the BOP Electrical Equipment

Balance of plant electrical equipment, including cabling, is designed to accommodate the effects of, and to be compatible with, the environmental conditions associated with the location of the equipment. The environmental conditions considered include those expected during normal operation, maintenance, testing, and, if applicable, post accident periods.

The ESF mechanical and electrical equipment and instrumentation associated with balance of plant systems inside the Reactor Building are designed to perform required functions under the conservative accident and post-accident temperature, pressure, humidity, radiation, and chemical conditions.

Where design of balance of plant equipment to withstand dynamic effects of missiles, pipe whip, and jet forces was impractical, barriers were designed to protect such equipment (refer to Sections 3.5 and 3.6).

Safety-related equipment located outdoors is either qualified for expected environmental conditions or is protected from such conditions.

Qualification of BOP electrical equipment is accomplished by type testing, analysis, and/or documented operating experience. Electrical equipment requiring harsh environmental qualification is qualified in accordance with IEEE 323 and ancillary daughter standards (e.g., IEEE Std. 317 (Reference 17), 334 (Reference 18), 382 (Reference 19), 383 (Reference 20). Although type testing is the preferred method of qualification, equipment qualification usually involves some combination of the three methods. The qualification methods used depend on a number of factors, including:

1. Material used in construction of the equipment.
2. Applicable normal, abnormal, accident, and post-accident environmental conditions.
3. Operational requirements (during and after accidents).
4. Nature of safety function(s).
5. Size of equipment.
6. Dynamic characteristics of expected failure modes (structural or functional).

In general, analysis is used to supplement test data, although equipment requiring mild environmental qualification and simple components may lend themselves to analysis in lieu of full scale testing. The role of operating experience is generally limited to aiding in determining realistic performance goals.

Equipment samples selected for qualification are of the same basic design and materials as the equipment to be installed at the Virgil C. Summer Nuclear Station. The sample is manufactured using similar techniques and processes as those used for the installed equipment. Any significant variations or deviations are noted in the qualification results with justification provided as necessary.

The list of electrical equipment subject to environmental qualification is documented by the Equipment Qualification Database (EQDB). The EQDB lists the electrical equipment as identified in Section 3.11.1.2. NUREG-0588 sets forth NRC positions in implementation of IEEE 323-1971 and 1974 versions of the “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations” and was used as the basis for assessing the acceptability of the original scope of the environmental qualification program. Electrical equipment for replacements or modifications to the plant is procured under the guidance of 10CFR50.49 and is qualified under the requirements of IEEE 323-1974 and Regulatory Guide 1.89, if the equipment requires harsh environmental qualification.

3.11.2.2.2.1 Main Steam Line Break Inside Containment Equipment Qualification

Main steam line breaks (MSLB) inside containment have previously been discussed in Section 6.2.

The composite temperature profiles for environmental zones subject to MSLB conditions are presented in drawing S-021-018. Electrical equipment located in these environmental zones and required to mitigate the MSLB accident has been qualified to these temperature profiles as documented in the applicable EQDP's.

3.11.2.2.2.2 Main Steam Line Break Outside Containment Equipment Qualification

Main steam line breaks (MSLB) outside containment have previously been discussed in Section 3.6. However, as a result of Information Notice No. 84-90 (Reference 21), South Carolina Electric and Gas Company has elected to address the HELB/SBOC (High Energy Line Break/Superheated Blowdown Outside Containment) accident scenario as a Virgil C. Summer Plant requirement and as a modification to the previously postulated MSLB accident scenario. A complete analysis of the HELB/SBOC environmental conditions and equipment qualification is presented in Reference 22. An increase in temperature in certain areas of the East and West Penetration Access areas and the Intermediate Building is the only significant environmental change resulting from postulated HELB/SBOC ruptures relative to that of the MSLB accident environment previously evaluated and identified in Section 3.6. All other environmental conditions remain unchanged.

Steamline breaks resulting in HELB/SBOC can only occur in the 436 ft. floor elevation of the East and West Penetration Access areas, 436 ft. floor elevation of the Intermediate Building, and in the Turbine Building. Breaks postulated in the 4-inch steamlines supplying the turbine driven EFW Pump result in a break area too small to lead to a superheated steam discharge per Westinghouse WCAP-10961 (Reference 23); therefore, the licensing analysis for the 4-inch line remains unchanged. HELB/SBOC resulting from postulated breaks in large steam lines need not be addressed for the Turbine Building since equipment in this area is not required in order to mitigate the consequences of an HELB/SBOC.

For each environmental zone in which the ambient temperature profile for the HELB/SBOC exceeds that previously established for a MSLB, a composite temperature profile was generated. The composite temperature profiles for these environmental zones are presented in drawing S-021-018. Electrical equipment located in these environmental zones and required to mitigate the HELB/SBOC accident has been qualified to these temperature profiles.

Qualification of the required equipment in superheat high energy line break environmental zones was accomplished by a series of detailed engineering analyses. In some cases, these analyses are based on specific as-built hardware and location specific transient heat transfer analyses. Qualification for each component is based on qualification test data, but in some cases this data has been extrapolated using acceptable analytical techniques. The evaluations specifically address the higher temperature effect of the HELB/SBOC accident and the capability of the equipment to withstand the accident conditions for the operating time required to perform its safety function.

These evaluations have demonstrated that the required equipment as installed, is environmentally qualified for the postulated environmental conditions.

3.11.2.2.3 Qualification Maintenance

Qualification is not a guarantee of performance for each component of a system. It is rather, assurance that the system can perform its safety function under all specified service conditions. Maintenance of the qualified status of harsh environment electrical equipment requires scheduled maintenance to prevent components from exceeding their qualified life, and periodic testing to locate components that may have failed, or be near failure.

Scheduled maintenance is also performed on mild environment electrical equipment to ensure proper operation of the equipment throughout the established service life.

Scheduled maintenance activities required to maintain harsh and mild environment equipment qualification is specified for all safety-related electrical equipment. These activities are documented in the Equipment Qualification Database.

3.11.3 Qualification Test Results

This section addresses the qualification test results applicable to Nuclear Steam Supply System and Balance of Plant Electrical equipment. This equipment is required to function under anticipated normal operating conditions, and/or is required to function to mitigate the consequences of design basis accidents, including LOCA and MSLB inside containment and MSLB outside containment. In addition to the qualification results provided in this section, a complete analysis of the High Energy Line Break/Superheated Blowdown Outside Containment accident environmental conditions, as discussed in Section 3.11.2.2.2.2, is presented in Reference 22.

The results of the qualification program for each type of electrical equipment are recorded in the applicable Equipment Qualification Documentation Packages (EQDP's) and/or Equipment Qualification Files (EQF's). The collection of various computer data files containing information relative to equipment qualification and qualified equipment are included in an Equipment Qualification Database (EQDB). Electrical equipment and data relative to environmental qualification are listed in the EQDB.

Westinghouse NSSS supplied safety-related equipment, which is required to function to mitigate the consequences of a postulated accident and which may be exposed to the elevated environmental conditions that may result from the accident, is qualified by Westinghouse under the 1971 version of IEEE-323. The Westinghouse supplemental qualification program (Reference 16) has been accepted by the NRC staff as meeting the requirements of IEEE 323-1971 in NRC letter D. B. Vassallo to C. Eicheldinger dated November 19, 1975.

A portion of the Westinghouse supplied electrical equipment has subsequently been upgraded to the qualification requirements of IEEE 323-1974, by WCAP 8587 and WCAP 8687. This equipment upgrade has been documented in their respective EQDP's and EQF's.

3.11.3.1 Qualified Equipment List

The “Qualified Equipment/Components and Materials” list provides a listing of equipment, components, and materials for which environmental qualification is maintained. The list includes items subject to both mild and harsh environments and comprises two sections of the EQDB. One section is arranged alphanumerically by equipment number while the other section is arranged alphanumerically by system.

3.11.3.2 Auditable File

The auditable files are arranged in equipment qualification documentation packages or equipment qualification files by Qualification File Number. The “Equipment Qualification File Index” (part of EQDB) provides a listing of the EQDP’s and EQF’s and specifies the components to which each qualification file applies.

3.11.3.3 Master Equipment List

The “Master Equipment List” is contained within the EQDB and provides a listing of equipment and materials to which the requirements of 10CFR50.49 for environmental qualification of electrical equipment subject to harsh environment applies.

3.11.4 Loss of Ventilation

Safety-related electrical equipment and components, as identified in Section 3.11.1.2, are located in areas which are mechanically cooled or ventilated by safety-related or quality related HVAC systems.

Safety-related HVAC systems providing cooling or ventilation are designed to satisfy the following considerations:

1. Seismic Category I requirements.
2. Redundant active system components are provided, as required.
3. Independent and redundant Class 1E power sources are provided.
4. Arrangement is such that single failure of an active or passive component does not result in loss of required cooling function.

In certain cases, such as rooms housing only one train of safety-related electrical equipment, each room is serviced by a single air handling unit. In these cases the safety-related HVAC systems, such as those servicing the Residual Heat Removal/Reactor Building Spray Pump Rooms, the Charging/SI Pump Rooms, the ESF Switchgear and Speed Switch Rooms, and the Auxiliary Building Motor Control Center Rooms, are designed such that no single failure can cause loss of cooling to more than one room, and subsequently to more than one train of redundant safety-related electrical equipment.

Quality Related (QR) HVAC equipment provides cooling or ventilation for some areas of the plant, outside the Reactor Building, which contain Class 1E electrical equipment. Class 1E equipment in these areas was evaluated on a case by case basis and is designed to function in the unlikely event of abnormal environmental conditions caused by loss of non-safety related HVAC. Loss of QR HVAC does not have an immediate effect on, or correlation to, the performance of the Class 1E equipment safety function. However, since credit is taken for normal conditions of HVAC operation in determining qualified life of Class 1E equipment located in harsh environmental areas and in determining service life of Class 1E equipment located in mild environmental areas, loss of QR HVAC systems could have a long term effect on equipment life expectancy. Therefore, QR HVAC is procedurally controlled and operability of QR HVAC systems is monitored to ensure that air flow to these areas, and subsequently the environmental conditions upon which the Class 1E equipment qualification was based, is maintained.

Controls and electrical equipment necessary for operation of safety-related HVAC systems outside the Reactor Building, following a LOCA or high energy line break condition, are located such that they are not exposed to post-accident environmental conditions, or are designed to withstand these severe conditions. Controls and electrical equipment required by safety-related HVAC systems within the Reactor Building are capable of withstanding the worst case environmental conditions resulting from a DBA.

Environmental test reports describing qualification of ventilation and cooling equipment located inside and outside the Reactor Building are referenced in the applicable equipment qualification data packages, and equipment qualification files.

The preceding discussions result in the determination that loss of ventilation, although highly unlikely, will not prevent performance of the Class 1E equipment safety function or affect the environmental qualification status of the safety-related electrical equipment.

3.11.5 Estimated Chemical and Radiation Environment

This section presents the justification for the estimated chemical and radiation environments of Section 3.11.1.

3.11.5.1 Chemical Environment

3.11.5.1.1 Normal Operation

Adverse chemical environmental conditions do not exist during normal plant operation.

3.11.5.1.2 Design Basis Accident

The chemical spray environment for which electrical equipment inside containment must be qualified is based upon a maximum operating time for the spray system of 24 hours based on IEEE 323 testing standards. During a design basis LOCA, the containment spray system will be operated for a minimum period of four hours and up to a maximum of 40 days as required to return containment pressure and temperature conditions to normal levels. Therefore, a period of

up to 40 days has been used as a basis for judging the adequacy of electrical equipment qualification.

The chemical spray environment for which electrical equipment inside containment must be qualified is based upon the following post-accident operating envelopes and spray pH conditions:

Operating Period	Spray pH Range
0-2 hours (minimum)	8.7-10.5
2 hours – 40 days (maximum)	8.0-8.5

These chemical spray environmental (pH) conditions are based upon analyzing the drawdown of the Refueling Water Storage Tank (RWST) and Sodium Hydroxide Storage Tank (SHST) to develop a buffered borated water solution in the spray header. The analysis is performed for the range of boron sources (RWST, RGS, SIS), and sodium hydroxide concentrations (20-22 wt/%) required by the Technical Specifications in conjunction with the design, normal, and degraded operating modes discussed in Section 6.2.2.2.1.2.

Depending upon the spray system operating mode, the results of the analysis yield a spray pH range of 8.8 to 10.1 during the drawdown of the RWST (~ 23 to 65 minutes post LOCA). At the completion of the RWST drawdown, the spray system operation is maintained by recirculation of the Reactor Building Sump Water (pH: 7.5 - 8.5) and the injection of any remaining NaOH from the SHST. Upon recirculation from the sump the spray system pH is maintained in the range of 8.7 to 10.5 until the SHST is emptied (approximately 10 to 40 minutes). Thereafter, the spray pH is equal to the sump water pH of 8.1 to 8.5. Refer to Section 6.2.2.3.1.4 for a detailed discussion of drawdown analysis.

3.11.5.2 Radiation Environment

3.11.5.2.1 Normal Operation

The design basis radiation sources and dose rates for various plant systems and equipment during normal plant operation are discussed in Chapters 11 and 12. The neutron and gamma radiation source terms and energy spectra data for major equipment is summarized in Tables 12.1-3 through 12.1-17. Based upon these source terms and plant shielding, the plant radiation exposure zones for normal operation, shutdown, and refueling are presented in Figures 12.1-1 through 12.1-20. The total integrated (over 40 years) radiation doses resulting for normal plant operation are given in EQDB drawing S-021-018.

3.11.5.2.2 Design Basis Accident

The design basis post accident radiation sources and doses for vital plant systems and equipment are discussed in Chapter 12A. The radiation sources are based upon NUREG 0737, Section II.B.2. The post-accident total integrated (over 1 year) gamma and beta doses addressing the requirements of NUREG-0588 are given in EQDB drawing S-021-018.

3.11.6 References

1. Institute of Electrical and Electronics Engineers (IEEE), *Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations*, Standard 308, dated 1971.
2. Virgil C. Summer Nuclear Station Equipment Qualification Database.
3. Virgil C. Summer Nuclear Station Environmental Zone Maps SS-021-001 through SS-021-017.
4. Virgil C. Summer Nuclear Station Equipment Qualification Database Environmental Zone Information drawing S-021-018.
5. NUREG-0588, *Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment*.
6. Institute of Electrical and Electronics Engineers (IEEE), *General Guide for Qualifying Class 1E Electrical Equipment for Nuclear Power Generating Stations*, Standard 323, dated 1971.
7. Institute of Electrical and Electronics Engineers (IEEE), *Standard for Qualifying Class 1E Equipment Nuclear Power Generating Stations*, Standard 323, dated 1974.
8. 10 CFR Part 50, Appendix A - General Design Criterion 4, *Environmental and Missile Design Bases*.
9. 10 CFR Part 50, Appendix B - Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.
10. U.S. Nuclear Regulatory Commission Regulatory Guide 1.89, *Qualification of Class 1E Equipment for Nuclear Power Plant*s.
11. 10 CFR Part 50, Section 50.49, *Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants*.
12. U.S. Nuclear Regulatory Commission Regulatory Guide 1.30, *Q/A Requirements for the Installation, Inspection and Testing of Instrument and Electric Equipment*.
13. U.S. Nuclear Regulatory Commission Regulatory Guide 1.40, *Qualification Tests of Continuous Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants*.
14. U.S. Nuclear Regulatory Commission Regulatory Guide 1.63, *Electric Penetration Assemblies in Containment Structures for Light Water-Cooled Nuclear Power Plants*.
15. U.S. Nuclear Regulatory Commission Regulatory Guide 1.73, *Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants*.
16. Letter NS-CE-692, dated July 10, 1975, from C. Eicheldinger (Westinghouse) to D. B. Vassallo (NRC).
17. Institute of Electrical and Electronics Engineers (IEEE), *Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations*, Standard 317, dated 1972.
18. Institute of Electrical and Electronics Engineers (IEEE), *Standard for Type Tests of Continuous Duty Class 1E Motors for Nuclear Power Generating Stations*, Standard 334, dated 1971.

19. Institute of Electrical and Electronics Engineers (IEEE), *Standard for Qualification of Safety-Related Valve Actuators*, Standard 382, dated 1972.

20. Institute of Electrical and Electronics Engineers (IEEE), *Standard for Type Tests of Class 1E Electric Cables, Field Splices and Connections for Nuclear Power Generating Stations*, Standard 383, dated 1974.

21. *Main Steam Line Break Effect on Environmental Qualification of Equipment*, Nuclear Regulatory Commission Information Notice No. 84-90, December 7, 1984.

22. *Evaluation to Address Environmental Qualification of Qualified Equipment Subjected to a High Energy (Steam) Line Break of Superheated Blowdown Outside Containment and a Main Steam Line Break (MSLB) Inside Containment*, Gilbert Associates, Inc. Report No. 2616.

23. *Steamline Break Mass/Energy Releases for Equipment Environmental Qualification Outside Containment*, Westinghouse Topical Report, WCAP-10961, October 1985.

24. U.S. Nuclear Regulatory Commission Regulatory Guide 1.97, *Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident*.

Table 3.11-0
Nuclear Steam Supply System Class 1E Equipment
in Containment

Table 3.11-0A
Balance of Plant Class 1E Equipment

The EQ Master List is available as “Report 984” from EQDB which is accessed through the site intranet system.

Table 3.11-1
Equipment and Components, Other Than Class 1E,
Inside the Reactor Building Required to Function
During and/or After an Accident

1. Containment Spray System

   Piping
   Spray Header and Nozzles

2. Reactor Building Cooling Units

3. Containment Isolation System

   Isolation Valves
   Mechanical Penetrations
   Air Locks and Hatches

4. Emergency Core Cooling System

   Accumulators
   Valves and Piping

NOTES: 1. Unless otherwise indicated, equipment is located outside the secondary shield wall

2. Refer to drawing S-200-971, “Essential Equipment List”, which includes a listing of equipment and components, other than Class 1E, required for safe shutdown and/or design basis accident, condition IV, mitigation.

Table 3.11-2
Equipment and Components, Other Than Class 1E,
Outside the Reactor Building Required to Function
During and/or After an Accident

1. Service Water System

   Pumps
   Valves and Piping
   Heat Exchangers

2. Component Cooling Water System

   Pumps
   Valves
   Heat Exchangers
   Surge Tank

3. Containment Isolation System

   Isolation Valves
   Mechanical Penetrations
   Air Locks and Hatches

4. Main Steam System

   Valves and Piping to Turbine Driven Emergency Feedwater Pump

5. HVAC Chilled Water System

   Pumps
   Valves and Piping
   Chillers

6. Building Ventilation and Cooling Systems for the Control Room, Relay Room; RHR/RB Spray Pump Rooms; Charging/SI Pump Rooms, Auxiliary Building Motor Control Center and Switchgear Areas; ESF Switchgear and Speed Switch Rooms, Battery Rooms, Service Water Booster Pump Areas, Emergency Feedwater Pump Rooms; Diesel Generator Building; and Service Water Pumphouse.

   Air Handling Units
   Filters
   Fans
   Ducts, Dampers, Valves and Piping

Table 3.11-2 (continued)
Equipment and Components, Other Than Class 1E,
Outside the Reactor Building Required to Function
During and/or After an Accident

7. Emergency Core Cooling System

   Refueling Water Storage Tank
   Charging Pumps
   RHR Pumps
   RHR Heat Exchanger
   Valves and Piping (see Section 6.3)

8. Reactor Building Spray System

   Reactor Building Spray Pump
   Valves and Piping
   Refueling Water Storage Tank
   Sodium Hydroxide Storage Tank

9. Spent Fuel Cooling System

   Pumps
   Heat Exchangers
   Valves and Piping

10. Emergency Feedwater System

    Condensate Storage Tank
    Motor Driven Emergency Feedwater Pumps
    Turbine Driven Emergency Feedwater Pump
    Valves and Piping

NOTE: Refer to drawing S-200-971, “Essential Equipment List”, which includes a listing of equipment and components, other than Class 1E, required for safe shutdown and/or design basis accident, condition IV, mitigation.

Table 3.11-3
Postulated Environmental Conditions

Table 3.11-3 environmental data have been combined in a series of controlled drawings.

An equipment qualification database with environmental zone information, as documented by EQDB drawing S-021-018, provides a list of the environmental zones and conditions, including the normal, abnormal, and accident (including post-accident) environmental conditions for each environmental zone.

3.12 CONTROL OF HEAVY LOADS

3.12.1 Introduction / Licensing Background

In 1978, Nuclear Regulatory Commission (NRC) staff initiated Generic Technical Activity Task A-36 to systematically examine licensing criteria and the adequacy of measures in effect at operating nuclear power plants to ensure the safe handling of heavy loads and to recommend necessary changes to those measures.

Following licensee input, the results of this evaluation were reported in NUREG-0612. The NRC staff concluded that existing measures to control the handling of heavy loads, although providing protection from certain potential problems did not adequately cover the major causes of load-handling accidents and that these measures should be revised.

In NUREG-0612, the NRC provided a series of guidelines designed to achieve a two-phase objective using an accepted approach or protection philosophy. The first portion of the objective, achieved through a set of general guidelines identified in Article 5.1.1, ensures that all load-handling systems at nuclear power plants are designed and operated such that their probability of failure is uniformly small and appropriate for the critical tasks in which they are employed.

The approach used to develop these guidelines for minimizing the potential for a load drop was based on defense in depth and is summarized as follows:

- Provide sufficient operator training, handling system design, load-handling instructions, and equipment inspection to assure reliable operation of load handling systems.
- Define safe load travel paths through procedures and operator training so that, to the extent practical, heavy loads are not carried over, or near, irradiated fuel or safe shutdown equipment.
- Provide mechanical stops or electrical interlocks to prevent movement of heavy loads over irradiated fuel or in proximity to equipment associated with redundant shutdown paths.

The second portion of the objective, achieved through guidelines identified in NUREG-0612 Articles 5.1.2 through 5.1.5, would ensure that, for load-handling systems in areas where their failure might result in significant consequences, either (1) features are provided to ensure that the potential for a load drop is extremely small (e.g., a single-failure-proof crane); or (2) conservative evaluations of load-handling accidents indicate that the potential consequences of any load drop are acceptably small.

On 12/22/1980, the NRC issued a Generic Letter (GL 80-113) from D. G. Eisenhut requesting that the station review provisions for handling and control of heavy loads, evaluate these provisions with respect to the guidelines of NUREG-0612, and provide certain additional information to be used for an independent determination of conformance with these guidelines. Generic Letter 81-07 provided supplemental information regarding the GL 80-113 response.

VCSNS responded in submittals which included GAI Report 2364, Control of Heavy Loads at Nuclear Power Plants – Virgil C. Summer Nuclear Station, Unit 1 (currently VCSNS Technical

Report TR03920-002), and WCAP-10233, Evaluation of the Acceptability of the Reactor Vessel Head Lift Rig, Reactor Vessel Internals Lift Rig, Load Cell, and Load Cell Linkage to the Requirements of NUREG-0612.

In 1983, NRC consultant Idaho National Engineering Laboratory (EG&G Idaho, Inc.) performed a review of the station compliance with NUREG-0612, resulting in the issuance of two Technical Evaluation Reports (TER). The Phase I TER assessed conformance with NUREG-0612 Article 5.1.1. The Phase II TER reviewed compliance with Articles 5.1.2 through 5.1.5. Subsequent revisions to the GAI Report addressed the concerns identified in this evaluation.

On 5/23/1985, the NRC issued a Safety Evaluation Report, concluding that VCSNS had satisfied the Phase I guidelines of NUREG-0612. This correspondence and Revision 3 of GAI Report 2364 document the commitments made to the Nuclear Regulatory Commission.

The NRC issued Generic Letter 85-11, in June 1985, which stated in part ". . . . Based on the improvements in heavy loads handling obtained from implementation of NUREG-0612 (Phase I), further action is not required . . . . .and Phase II of NUREG-0612 is considered completed."

In April 1996, the NRC issued IE Bulletin 96-02, to alert licensees to the importance of complying with existing regulatory guidelines associated with the control and handling of heavy loads. Addressees were asked to review plans and capabilities for handling heavy loads while the reactor is at power and to determine whether those activities are within the licensing basis. SCE&G responded (RC-96-0176) that all station activities were within the current licensing basis. The NRC subsequently closed this issue in 1998.

The NRC established generic safety issue, GI-186, in 1999 to investigate the need for additional regulation or guidance to address risk associated with increased frequency of moving spent fuel storage casks during power operation. NUREG-1774 documented a survey of operating experience prepared as part of the GI-186 investigation. In evaluating this data, the NRC staff determined that the frequency of load drops was indeed low and unlikely to justify additional regulations or guidance. Problems identified in the survey would be addressed by clarification and reemphasis of existing guidance on control of heavy loads.

As a result of the GI-186 investigations, the NRC issued Regulatory Issue Summary (RIS) 2005-25 in October 2005. This document reemphasized the NUREG-0612 guidelines on control of heavy loads and provided additional recommendations based upon operating experience and inspection information. These suggestions included:

- Evaluate the capability of rigging components and materials to withstand rigging errors.
- Evaluate the need to establish standardized calculation methodologies for heavy load drops.
- Endorsement of ASME NOG-1-2004.

In May 2007, Supplement 1 to RIS 2005-25 was issued to discuss remaining recommendations associated with GI-186 and to communicate regulatory expectations related to the safe handling of heavy loads. Topics presented include:

- Selection of lifting devices for use with single-failure-proof cranes.
- Application of ASME NOG-1 design criteria in satisfying NUREG-0554 guidelines.
- Industry consensus documents providing guidance for heavy load drop evaluations.
- FSAR inclusion of station reliance on single-failure-proof crane and/or load drop analysis.
- Application of 10CFR50.59 to procedure changes governing the handling and control of heavy loads (such as changes to motion restrictions, maximum height or weight, and medium present under the load).

NEI 08-05 was developed in response to RIS 2005-25 and RIS 2005-25 Supplement 1, discussing interpretation and implementation of the provided regulatory guidance. This effort was undertaken to ensure that heavy load lifts continue to be conducted safely and that actual station practices are accurately reflected in licensing bases. Topics include configuration risk management for heavy loads, Reactor Pressure Vessel Head (RPVH) load drop analysis, single-failure-proof crane equivalence for reactor pressure vessel head lifts, and updates to the FSAR regarding control of heavy loads.

3.12.2 Safety Bases

The safety bases employed to prevent or mitigate the consequences of an accidental heavy load drop are discussed within Technical Report TR03920-002 and includes (1) compliance with the Phase I guidelines of NUREG-0612, (2) reliance on a load drop analysis to demonstrate that consequences from a postulated RPVH load drop are within acceptable limits (i.e., core remains covered and cooling is available), and (3) use of a single-failure-proof fuel handling building crane.

3.12.3 Scope of Heavy Load-Handling Systems

NUREG-0612 describes a “heavy load” as any load that weighs more than the combined weight of a single spent fuel assembly and its associated handling tool. At VCSNS, a heavy load is any load greater than 2,500 pounds.

The station’s load-handling systems are identified within Technical Report TR03920-002. Initially, all permanently installed overhead handling systems were initially reviewed. Systems were then excluded from further consideration based upon capacity and physical separation from either spent fuel or equipment required for safe shutdown / decay heat removal.

The remaining overhead handling systems manipulate “NUREG-0612 heavy loads”; i.e., loads where a postulated drop could impact spent nuclear fuel, spent fuel in the reactor vessel, or equipment required for safe shutdown / decay heat removal. Specific load drops were then analyzed to evaluate consequences of a load drop accident. In some instances, facility modifications were performed to minimize or eliminate risk.

The load-handling systems used at VCSNS to lift NUREG-0612 heavy loads, as well as the description of the safe load paths, and postulated load drop analysis (where applicable), are included in Technical Report TR03920-002.

3.12.4 Control of Heavy Loads Program

The stations' program governing the control of NUREG-0612 heavy loads is delineated within Technical Report TR03920-002. Originally identified as GAI Report 2364, this document was submitted to the Nuclear Regulatory Commission as part of the station's NUREG-0612 response. On 5/23/1985, the NRC issued a Safety Evaluation Report concluding that VCSNS satisfied the Phase I guidelines of NUREG-0612.

The VCSNS program for the control of heavy loads consists of the following:

1. License commitments made in response to NUREG-0612, Phase I.
2. Safety bases for the handling of the Reactor Pressure Vessel Head (RPVH). Reliance on a load drop analysis, which includes the basis lift height, load weight, medium present under load, necessary for concluding satisfaction to acceptance criteria.
3. Safety bases for the handling of spent fuel casks within the Fuel Handling Building.

3.12.4.1 Commitments in Response to NUREG-0612, Phase I

VCSNS license commitments made in response to NUREG-0612, Phase I are described within Technical Report TR03920-002, and are summarized below:

1. Safe Load Paths

   Safe load paths have been identified for each NUREG-0612 heavy load-handling crane or hoist to minimize the possibility of a heavy load drop onto spent nuclear fuel, spent fuel in the reactor vessel, or equipment required for safe shutdown or decay heat removal. In those cases where a safe load path could not be defined, station procedures have been generated and / or design modifications made to minimize the consequences of an inadvertent load drop. Safe load paths are permanently marked, where practical.

2. Load-handling procedures

   Special operating procedures have been prepared for NUREG-0612 heavy load handling devices, and where possible, incorporated into standard component maintenance procedures to define the handling of heavy loads.

3. Qualifications, training, and specified conduct of crane operators

   Crane operators and riggers undertake an extensive training program, which meets or exceeds the requirements of ANSI B30.2-1976, Chapter 2-3. This training program incorporates the safe load path concept and station procedures covering the handling of NUREG-0612 heavy loads.

4. Special lifting devices

   Special lifting devices used for the handling of NUREG-0612 heavy loads associated with servicing reactor vessel components (i.e., RPVH lift rig, RV internals lift rig, load cell, and load cell linkage) do not strictly comply with ANSI N14.6-1978. The equipment vendor has performed an evaluation (WCAP-10233) of these discrepancies and has recommended alternate methods for demonstrating equivalency with the ANSI requirements. These recommendations include a detailed inspection and testing program, which has been incorporated into station procedures.

   Note that the original RPVH Lift Rig has been subsequently replaced with a special lifting device integrated into the Reactor Head Service Structure (A.K.A. Integrated Head Assembly (IHA)). This device complies with ANSI 14.6-1978 design requirements as documented in the IHA Design Report (Reference 21).

5. Lifting devices that are not specially designed

   Non-specifically designed lifting devices (i.e., slings) used for the handling of NUREG-0612 heavy loads do not strictly comply with NUREG-0612, Guideline 5; which states that these lifting devices should (1) be installed and used in accordance with the guidelines of ANSI B30.9-1971, and (2) be selected based upon the sum of static and dynamic loads (excluding SSE loads).

   In the Phase I response to NUREG-0612, VCSNS stated that non-specifically designed lifting devices (i.e., slings) would be installed and used consistent with the guidelines of 29CFR1910.184. Additionally, the station evaluated the loading for each NUREG-0612 heavy load-handling crane or hoist, and determined dynamic loads to be a relatively small fraction (15% or less) of the static loads. VCSNS concluded that modifying the selection criteria for these lifting devices to accommodate such minor additional loads, would not have a substantial effect on overall load-handling reliability. Therefore, lifting device selection would be based upon static load.

   The NRC found both these approaches to be consistent with the intent of the NUREG-0612, and acceptable.

6. Periodic inspection, and maintenance

   Cranes and rigging equipment used for the handling of NUREG-0612 heavy loads are maintained, tested, and inspected to the requirements of ANSI B30.2-1976, Chapter 2-2.

7. Crane Design

   Cranes used for the handling of NUREG-0612 heavy loads were procured and designed in accordance with CMAA Specification 70 and ANSI B30.2-1976. Chapter 2-1.

3.12.4.2 Reactor Pressure Vessel Head Lifting Procedures

To control the handling of the Reactor Pressure Vessel Head (RPVH), station procedures are used to direct the lift, movement, and replacement of the RPVH. These procedures establish limitations on load weight, lift height, safe load path, and medium present under the load. Limits are based on the current RPVH load drop analysis, which provides assurance that the core will remain covered and cooled in the event of a postulated reactor pressure vessel head drop.

The original load drop analysis for VC Summer, which was based upon a generic Westinghouse plant design, has been superseded with a plant specific evaluation, which also addresses concerns identified by the NRC in RIS 2005-25 and RIS 2005-25, Supplement 1. The current assessment considers the concentric drop of a 320,000 lbs. Reactor Pressure Vessel Head from a height of 35 feet above the Reactor Vessel Flange, through air (i.e. no water below). The evaluation utilizes Finite Element Analysis (FEA) methodology to determine postulated loads and displacements associated with the Head drop. Structural integrity of the Reactor Vessel, Vessel Support Assemblies, Main Loop RCS Piping and Concrete supporting structure are then assessed following application of these loads/displacements. Guidance and acceptance criteria for this type of evaluation are provided in NEI 08-05.

This plant specific analysis demonstrates that after the postulated Reactor Vessel Head Drop Accident:

1. The Reactor Core will remain covered with coolant, and
2. Coolant retaining components (such as the Reactor Vessel, Vessel Nozzles, Main Loop RCS piping and elbows) will remain sufficiently intact to provide cooling capability.

Consistent with the described RPVH Drop Analysis, the following limitations have been incorporated into appropriate station procedures.

- Maximum Lift Weight of 315,000 lbs. or 157.5 tons (conservative).
- Maximum Lift Height of 35 feet above the reactor vessel flange.

3.12.4.3 Single Failure Proof Crane for Spent Fuel Casks

The safe handling of spent fuel casks is addressed within Technical Report TR03920-002. The fuel handling building crane is a single-failure-proof crane having a single-failure-proof 125 ton main hoist. The fuel handling building crane meets the modified crane single-failure-proof criteria and guidelines of NUREG-0554, “Single-Failure-Proof Cranes for Nuclear Power Plants”, Appendix C of NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants”, and meets the NRC-accepted single-failure-proof crane requirements of Ederer Generic Licensing Topical Report EDR-1 (P)-A, (Reference 23). Use of a single-failure-proof fuel handling building crane facilitates spent fuel cask handling without the need to postulate or analyze dropped cask accidents.

3.12.5 Safety Evaluation

VCSNS Technical Report TR03920-002 establishes policy for the safe handling and control of NUREG-0612 heavy loads. Based on the stations' response to Phase I of NUREG-0612, this program establishes measures which assure an adequate level of defense-in-depth for heavy loads handled in the vicinity of spent nuclear fuel, spent fuel in the reactor vessel, or equipment required for safe shutdown / decay heat removal.

Measures taken to minimize the potential for occurrence of a NUREG-0612 heavy load-handling accident include:

- Controls implemented by station commitments to NUREG-0612, Phase I guidelines make the risk of a load drop very unlikely.
- In the event of a postulated load drop, the consequences are acceptable, as demonstrated by load drop analysis. Station procedures reflect restrictions on load weight, lift height, and medium present under the load.
- Where applicable, risk associated with the movement of NUREG-0612 heavy loads conducted during power operation or shutdown conditions is a configuration management activity with administrative controls established in accordance with 10 CFR 50.65(a)(4). This applies to RPVH lifts, spent fuel cask lifts, and other NUREG-0612 heavy load lifts defined in the station procedures.
- Changes to the program controlling heavy loads, such as station maintenance activities which handle NUREG-0612 loads outside the bounds of previous analysis, modifications which add or impact overhead handling systems, or implementation of dry cask storage of spent nuclear fuel, will be evaluated in accordance with 10CFR50.59 to determine the existence of an unreviewed safety question and the need for license amendment.

3.12.6 Reference Documents

1. 10CFR50.59; Changes, Tests, and Experiments.
2. 29CFR1910.184; Slings
3. ANSI B30.2-1976; Overhead and Gantry Cranes
4. ANSI B30.9-1971; Slings
5. ANSI N14.6-1978; Standard for Special Lifting Devices for Shipping Containers weighing 10,000 pounds or more for Nuclear Material
6. ASME NOG-1-2004; Rules for Construction of Overhead and Gantry Cranes (Top Running Bridge, Multiple Girder)
7. CMAA Specification 70-1975; Specifications for Electric Overhead Traveling Cranes
8. EGM 2007-006; Enforcement Discretion for Heavy Load Handling Activities, 28/2007
9. Generic Letter 80-113; Control of Heavy Loads
10. Generic Letter 81-07; Control of Heavy Loads

11. Generic Letter 85-11; Completion of Phase II of Control of Heavy Loads at Nuclear Power Plants, NUREG-0612
12. GI-186; Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants
13. IE Bulletin 96-02; Movement of Heavy Loads over Spent Fuel, Over Fuel in the Reactor Core, or Over Safety Related Equipment
14. NEI 08-05; Industry Initiative on Control of Heavy Loads, 7/2008
15. NUREG-0554; Single-Failure-Proof Cranes for Nuclear Power Plants
16. NUREG-0612; Control of Heavy Loads
17. NUREG-1774; A Survey of Crane Operating Experience at U. S. Nuclear Power Plants from 1968 through 2002
18. RIS 2005-25; Clarification of NRC Guidelines for the Control of Heavy Loads
19. RIS 2005-25 Supplement 1; Clarification of NRC Guidelines for the Control of Heavy Loads
20. TR03920-002, Control of Heavy Loads at Virgil C. Summer Nuclear Station, Unit 1 (former GAI Report No. 2364)
21. DC05900-004, Integrated Head Assembly Design Report
22. WCAP-10233, Revision 0; Evaluation of the Acceptability of the Reactor Vessel Head Lift Rig, Reactor Vessel Internals Lift Rig, Load Cell, and Load Cell Linkage to the Requirements of NUREG-0612
23. TR03920-007, EDR-1 (P)-A, Generic Licensing Topical Report for Ederer's Nuclear Safety Related e<u>X</u>tra – Safety And Monitoring (X-SAM) Cranes, 10/8/82.
24. DC03920-026, Reactor Head Load Drop Analysis

Appendix 3A
Conformance With Regulatory Guides

This appendix discusses conformance with Division 1 NRC Regulatory Guides applicable to the Virgil C. Summer Nuclear Station. Specific revision numbers and dates of issue are identified in the title of each guide.

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3A.1 NET POSITIVE SUCTION HEAD FOR ECCS AND CONTAINMENT HEAT REMOVAL SYSTEM PUMPS (REVISION 0; 11/70)

Regulatory Guide 1.1 recommends that the emergency core cooling and containment heat removal systems be designed so that adequate net positive suction head (NPSH) is provided to system pumps assuming maximum expected temperatures of pumped fluids and no increase in containment pressure from that present prior to postulated loss of coolant accidents.

As discussed in Sections 6.3.2 and 6.2.2, the emergency core cooling and containment heat removal systems are designed to provide an available NPSH which is greater than pump vendor specified minimum NPSH requirements. In addition to considering the static head and suction line pressure drop, the calculation of available NPSH in the recirculation mode does not take credit for subcooling, i.e., the vapor pressure of the liquid in the sump is assumed to be equal to the saturation pressure corresponding to the temperature of the sump fluid.

3A.2 THERMAL SHOCK TO REACTOR PRESSURE VESSELS (REVISION 0; 12/70)

The NRC has withdrawn this Regulatory Guide which is superseded by Section 50.61 of 10 CFR 50 and Regulatory Guide 1.154.

3A.3 ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A LOSS OF COOLANT ACCIDENT FOR BOILING WATER REACTORS (REVISION 2; 6/74)

Regulatory Guide 1.3 is not applicable to the Virgil C. Summer Nuclear Station since it uses a PWR.

3A.4 ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A LOSS OF COOLANT ACCIDENT FOR PRESSURIZED WATER REACTORS (REVISION 2; 6/74)

The guidance of Regulatory Guide 1.4 including the use of the TID-14844 accident source term remains the licensing basis for the following:

1. Equipment qualification
2. NUREG-0737 evaluations other than Control Room Habitability Envelope (CRHE) and Technical Support Center (TSC) doses
3. Final Safety Analysis Report (FSAR) accidents not analyzed in accordance with Regulatory Guide 1.183 including the loss of offsite power and the waste gas tank rupture

The Virgil C. Summer Nuclear Station licensing basis incorporates a full implementation application of the Alternative Source Term (AST) methodology compliant with Regulatory Guide 1.183, which is used for the design basis case loss-of-coolant accident (LOCA), main steam line break (MSLB) accident, fuel handling accident (FHA), steam generator tube rupture (SGTR), reactor coolant pump (RCP) locked rotor accident (LRA) and the control rod ejection accident (CREA).

3A.5 ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A STEAM LINE BREAK ACCIDENT FOR BOILING WATER REACTORS (REVISION 0; 3/71)

Regulatory Guide 1.5 is not applicable to the Virgil C. Summer Nuclear Station since it uses a PWR.

3A.6 INDEPENDENCE BETWEEN REDUNDANT STANDBY (ONSITE) POWER SOURCES AND BETWEEN THEIR DISTRIBUTION SYSTEMS (REVISION 0; 3/71)

The Virgil C. Summer Nuclear Station design complies with the recommendations of Regulatory Guide 1.6.

See Sections 8.1, 8.3.1.2, and 8.3.2.2 for details.

3A.7 CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT FOLLOWING A LOSS OF COOLANT ACCIDENT (REVISION 0; 3/71; SUPPLEMENT 10/71)

The design guidance and assumptions of Regulatory Guide 1.7 are used for control of combustible gas concentrations in containment following a loss of coolant accident, as described in Sections 6.2.5 and 15.4.

3A.8 PERSONNEL SELECTION AND TRAINING

Conformance with Regulatory Guide 1.8 is described in Appendix C of the Dominion Energy QA Topical Report DOM-QA-1, “Nuclear Facility Quality Assurance Program Description”, which is incorporated by reference. This description includes the specific revision of Regulatory Guide 1.8, along with any exceptions, alternatives, or clarifications.

3A.9 SELECTION OF DIESEL GENERATOR SET CAPACITY FOR STANDBY POWER SUPPLIES (REVISION 0; 3/71)

The Virgil C. Summer Nuclear Station standby power system is discussed in Sections 8.3.1.1 and 8.3.1.2 and complies with the recommendations of Regulatory Guide 1.9.

3A.10 MECHANICAL (CADWELD) SPLICES IN REINFORCING BARS OF CATEGORY 1 CONCRETE STRUCTURES (REVISION 1; 1/73)

Regulatory Guide 1.10 has been withdrawn per NRC letter of July 8, 1981. However, the Virgil C. Summer Nuclear Station still complies with the recommendations of Regulatory Guide 1.10 with the following clarifications:

1. Regulatory Position C.1 [paragraph 2, subitem (2)] is interpreted as follows - Each member or crew is subject to requalification if more than 7% of the completed splices fail to pass the visual inspection test or fail to pass the tensile tests.
2. Regulatory Position C.4 - Separate test cycles are established for mechanical splices in horizontal, vertical, and diagonal bars.
3. Regulatory Position C.4.b - Concerning test frequency for combinations of production and sister splices. One splice, either production or sister splice out of every 33 is sampled in lieu of 3 out of every 100.
4. Regulatory Position C.5.a - If any production splice fails to meet the tensile requirement of Regulatory Position C.3.a (tensile strength greater than 125% of yield strength of the reinforcement) and failure did not occur in the bar, the adjacent production splices on each side of the failed splice shall be tested. If any sister splice used for testing fails to meet the tensile requirement of Regulatory Position C.3.a and failure did not occur in the bar, two additional sister splices shall be tested. If either of these retests fails to meet the requirements, splicing by the crew performing the work represented by the failed splices shall be halted. Splicing shall not be resumed until the cause and extent of the failures have been determined, corrected, and resolved.
5. Regulatory Position C.5.b - If the average tensile strength of 15 consecutive samples fails to meet the requirement of Regulatory Position C.3.b, the average equaling or exceeding the ultimate tensile strength of the substandard splices shall be investigated, and the necessary corrective action taken.

   Mechanical (cadweld) splice testing and acceptance criteria are in accordance with the requirements of the ASME Code, Section III Division 2. Refer to Section 3.8.1.6.

3A.11 INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT (REVISION 0; 3/71)

Instrument sensing lines that penetrate containment are provided with isolation valves in accordance with Regulatory Guide 1.11 except for four lines necessary for sensing Reactor Building wide range pressure. Redundant containment boundaries are provided on these Reactor Building pressure sensing lines by use of filled bellows as described in Section 6.2.4.

3A.12 INSTRUMENT FOR EARTHQUAKES (REVISION 1; 4/74)

Seismic monitoring instrumentation provided in the Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.12 with the following clarifications and exceptions:

1. The frequency range of the response spectrum recorders is 2 to 25.4 Hertz;
2. Triaxial peak accelerographs have been removed from the plant and not replaced due to their inability to monitor seismic motions over background ambient vibration noise.
3. The recorder specified in Section 5.3 of ANSI N18.5-1974 has been upgraded with a solid-state recording/analysis system.
4. The seismic trigger specified in Section 5.4 of ANSI N18.5-1974 has been removed from service and replaced with solid-state actuation using the Reactor Building foundation mat accelerometer as the trigger sensor.

The maximum SSE foundation acceleration for the Virgil C. Summer Nuclear Station is 0.25g; therefore, seismic monitoring instrumentation is provided in accordance with position C.1 of the guide.

A description of the seismic instrumentation is presented in Section 3.7.4.

3A.13 SPENT FUEL STORAGE FACILITY DESIGN-BASIS (REVISION 1;12/75)

Comparison of the Virgil C. Summer Nuclear Station with Regulatory Guide 1.13 Recommendations.

Regulatory Position	Virgil C. Summer Nuclear Station Design Features
1.	The safety class 2b spent fuel pool and the Seismic Category I Fuel Handling Building are designed to withstand the SSE without loss of function.

Regulatory Position	Virgil C. Summer Nuclear Station Design Features
2.	The reinforced concrete walls and the spent fuel pool liner of the Fuel Handling Building were designed to prevent loss of watertight integrity due to tornadic winds or missiles generated by these winds, as specified in Table 3.5-5 (Requirement C2.(a) of Regulatory Guide 1.13.) These missiles are, however, capable of penetrating the exterior metal walls and roof panels of the Fuel Handling Building. The steel frame superstructure has been designed so that the loss of any one structural member will not adversely affect the building superstructure integrity. This redundancy in structural support was achieved by the use of moment connections. Studies have shown an extremely low probability that spent fuel will be contacted by the postulated tornado missiles. Consider the wood plank and wood pole as potential missiles. Based upon the annual probability of a tornado strike, the difference in density between wood and water, and the probability of attaining critical missile flight trajectory and orientation, the total probability of either of these two missiles entering the spent fuel pool and subsequently coming into contact with the fuel storage racks is substantially less than 10^{-7}. The height of the missile resistant concrete wall (approximately 28 feet above ground), as stated previously, prevents the utility pole, compact and passenger automobiles from being thrown into the spent fuel pool by a tornadic wind. The only other missile listed in Table 3.5-5, that was considered to be a potential missile capable of causing fuel damage, is the 3 inch schedule 40 pipe. A conservative probability estimate indicates that, in the event of the 3 inch pipe entering the spent fuel pool and contacting the fuel racks, the resulting offsite doses can be maintained within the 10 CFR 100 limits. It also indicates that the requirement of position C.2(b) of Regulatory Guide 1.13 can be satisfied. The basis for such a conclusion can be described by the following procedure:
a.	Determine the probability, P1, of the 3 inch pipe, as a potential missile, entering the spent fuel pool.

Regulatory Position	Virgil C. Summer Nuclear Station Design Features

b. Calculate the allowable missile velocity, v, at impact, beyond which fuel assemblies and/or fuel racks could experience damage and consequently cause significant release of radioactivity.

It is noted that the fuel assemblies are completely submerged in the stainless steel fuel racks of square cross section. The three inch pipe missile with the above impact velocity was found not capable of penetrating through the fuel rack and coming into contact with the enclosed fuel assemblies. Hence, the requirement of position C.2(b) of Regulatory Guide 1.13 is satisfied.

c. Determine the number of fuel assemblies which are allowed to be damaged by the missile for the resulting offsite doses to be within 10 CFR 100 limits. For conservatism, a total of four fuel assemblies are considered permissible.

d. Determine the required missile flight trajectory (in both horizontal and vertical planes) relative to the spent fuel pool and the missile alignment with respect to its flight path, in entering the spent fuel pool to make potential contact with more than four fuel cells and to result in a reduced impact velocity higher than the allowable velocity, v, previously established. Then determine the probability, P2, of such events occurring.

e. Combine the probabilities, P1 and P2, to obtain the total probability, P, of the postulated 3 inch pipe missile being thrown into the spent fuel pool and subsequently damaging more than four fuel assemblies due to the impact effects transmitted through the fuel racks. This probability, P, was found to be less than 10^{-7}, the recognized acceptable probability limit.

3. See response to Item 5

4. The building enclosing the spent fuel pool is a low leakage building. The Fuel Handling Building Ventilation System exhausts to the plant vent through charcoal and HEPA filters. However, the Fuel Handling Building charcoal exhaust system is not required during the movement of fuel in the spent fuel pool or during crane operation with loads over the pool. The fuel handling accident is analyzed in Chapter 15. Due to the use of Alternate Source Term methods, no credit for ventilation system operation is needed for dose calculations.

5. In addition to electrical interlocks, the Fuel Handling Building crane is prevented from moving over the spent fuel pool by stops welded to the rails. Only the spent fuel bridge crane is used to lift items from the fuel pool. The pool is designed to withstand, without leakage which could uncover the fuel, the impact of the heaviest load carried by this crane.

Regulatory Position	Virgil C. Summer Nuclear Station Design Features
6.	The spent fuel pool cooling and purification lines are located such that they cannot drain the pool. The only drain line that conceivably drains the pool is the refueling cavity drain which is a small line with two isolation valves. The refueling cavity is isolated from the spent fuel pool by the fuel transfer tube valve and the fuel transfer canal gate, which are Seismic Category I equipment.
7.	Spent fuel pool level and radiation levels are monitored and activate alarms in the control room if abnormal conditions are detected. Radiation Monitors are described in Sections 12.1.4 and 12.2.4. The radiation monitors do not actuate the filtration system, because the filtration system is not credited in the Chapter 15 accident analysis.
8.	Normal makeup water is from the station demineralized water supply which is not designed to withstand the SSE. However, two safety class backup supplies are provided. These are the refueling water storage tank and the reactor makeup water storage tank which are Safety Class 2a and 2b respectively.

3A.14 REACTOR COOLANT PUMP FLYWHEEL INTEGRITY (REVISION 1; 8/75)

The Virgil C. Summer Nuclear Station addresses the recommendations of Regulatory Guide 1.14 as described in Section 5.2.6 and below:

1. Post-Spin Inspection

   Westinghouse has shown in WCAP-8163, “Topical Report on Reactor Coolant Pump Integrity in LOCA,” that the flywheel would not fail at 290% of normal speed for a flywheel flaw of 1.15 inches or less in length. Results for a double ended guillotine break at the pump discharge with full separation of pipe ends assumed, show the maximum overspeed to be less than 110% of normal speed. The maximum overspeed was calculated in WCAP-8163 to be about 280% of normal speed for the same postulated break, and an assumed instantaneous loss of power to the reactor coolant pump. In comparison with the overspeed presented above, the flywheel is tested at 125% of normal speed. Thus, the flywheel could withstand a speed up to 2.3 times greater than the flywheel spin test speed of 125% provided that no flaws greater than 1.15 inches are present. If the maximum speed were 125% of normal

speed or less, the critical flaw size for failure would exceed 6 inches in length. Non-Destructive tests and critical dimension examinations are all performed before the spin tests. The inspection methods employed (described in WCAP-8163) provide assurance that flaws significantly smaller than the critical flaw size of 1.15 inches for 290% of normal speed would be detected. Flaws in the flywheel will be recorded in the pre-spin inspection program (see WCAP-8163). Flaw growth attributable to the spin test (i.e., from a single reversal of stress, up to speed and back), under the most adverse conditions is about three orders of magnitude smaller than what nondestructive inspection techniques are capable of detecting. For these reasons, Westinghouse performs no post-spin inspections and believes that pre-spin test inspections are adequate.

2. Interference Fit Stresses and Excessive Deformation

   Much of Revision 1 deals with stresses in the flywheel resulting from the interference fit between the flywheel and the shaft. Because Westinghouse's design specifies a light interference fit between the flywheel and the shaft; at zero speed, the hoop stresses and radial stresses at the flywheel bore are negligible. Centering of the flywheel relative to the shaft is accomplished by means of keys and/or centering devices attached to the shaft, and at normal speed, the flywheel is not in contact with the shaft in the sense intended by Revision 1. Hence, the definition of "Excessive Deformation," as defined in Revision 1 of Regulatory Guide 1.14, is not applicable to the Westinghouse design since the enlargement of the bore and subsequent partial separation of the flywheel from the shaft does not cause unbalance of the flywheel. Extensive Westinghouse experience with reactor coolant pump flywheels installed in this fashion has verified the adequacy of the design. Westinghouse's position is that combined primary stress levels, as defined in Revision 0 of Safety Guide 14 [C.2. (a) and (c)] are both conservative and proven and that no changes to these stress levels are necessary. Westinghouse designs to these stress limits and thus does not have permanent distortion of the flywheel bore at normal or spin test conditions.

3. Section B, Discussion of Cross Rolling Ratio of 1 to 3

   Cross Rolling Ratio - Westinghouse's position is that specification of a cross rolling ratio is unnecessary since past evaluations have shown that ASME SA-533-B Class 1 materials produced without this requirement have suitable toughness for typical flywheel applications. Proper material selection and specification of minimum material selection and specification of minimum material properties in the transverse direction adequately ensure flywheel integrity. An attempt to gain isotropy in the flywheel material by means of cross rolling is unnecessary since adequate margins of safety are provided by both flywheel material selection (ASME SA-533-B Class 1) and by specifying minimum yield and tensile levels and toughness test values taken in the direction perpendicular to the maximum working direction of the material.

4. Section C, Item 1.a Relative to Vacuum-Melting and Degassing Process or the Electroslag Process

   Vacuum Treatment - The requirements for vacuum melting and degassing process or the electroslag process are not essential in meeting the balance of the Regulatory Position nor do they, in themselves, ensure compliance with the overall Regulatory Position. The initial Safety Guide 14 stated that the "flywheel material should be produced by a process that minimized flaws in the material and improves its fracture toughness properties." This is accomplished by using SA-533 material including vacuum treatment.

5. Section C, Item 2b; Westinghouse interprets this paragraph to mean:

   Design Speed Definition

   Design speed should be 125% of normal speed or the speed to which the pump motor might be electrically driven by station turbine generator during anticipated transients, whichever is greater. Normal speed is defined as the synchronous speed of the a-c drive motor at 60 Hz.

3A.15 TESTING OF REINFORCING BARS FOR CONCRETE STRUCTURES (REVISION 1; 12/72)

Regulatory Guide 1.15 has been withdrawn per NRC letter of July 8, 1981. However, the testing of reinforcing bars for concrete structures is still in compliance with the recommendations of Regulatory Guide 1.15. The testing requirements are discussed in Section 3.8.1.6.

3A.16 REPORTING OF OPERATING INFORMATION (REVISION 4; 8/75)

Regulatory Guide 1.16 has been withdrawn per NRC Federal Register Notice 74 FR 40244 dated 11 August 2009. However, operating information will be reported in accordance with the recommendations of this guide. A discussion of this subject is given in Section 6.9 of the Technical Specifications.

3A.17 PROTECTION OF NUCLEAR POWER PLANTS AGAINST INDUSTRIAL SABOTAGE (REVISION 1; 6/73)

The Virgil C. Summer Nuclear Station's Physical Security Plan generally complies with the recommendations of Regulatory Guide 1.17 with the following exceptions as clarified below:

1. Alarms are automatically reset after obtaining operator acknowledgment. No alarm point status changes or actuation of locks are made without CAS/SAS knowledge.
2. Intrusion alarms, emergency exit alarms, alarm systems, and line supervisory systems meet the level of performance and reliability indicated by GSA Federal Specification WA00450B (GSA-FSS) Section 3.

3. X-ray systems are tested every 7 days for operability and quarterly for performance.
4. Tamper switches on alarm sensors, premise control units, junction boxes, and line supervisory units are checked every 3 months to ensure proper operation and that tampering has not occurred.
5. a) On-site communications are tested for performance at the beginning of each work shift.

   b) Off-site communications are tested for performance once per day.

3A.18 STRUCTURAL ACCEPTANCE TEST FOR CONCRETE PRIMARY REACTOR CONTAINMENTS (REVISION 1; 12/72)

Regulatory Guide 1.18 has been withdrawn per NRC Letter of July 8, 1981. However, the Virgil C. Summer Nuclear Station still complies with the recommendations of this guide as described in Section 3.8.1.

3A.19 NON-DESTRUCTIVE EXAMINATION OF PRIMARY CONTAINMENT LINER WELDS (REVISION 1; 8/72)

Regulatory Guide 1.19 has been withdrawn per NRC letter of July 8, 1981. However, the Virgil C. Summer Nuclear Station still complies with the recommendations of Regulatory Guide 1.19 as described in Section 3.8.1.

3A.20 COMPREHENSIVE VIBRATION ASSESSMENT PROGRAM FOR REACTOR INTERNALS DURING PREOPERATIONAL AND INITIAL STARTUP TESTING (REVISION 2; 5/76)

In accordance with Regulatory Guide 1.20 recommendations, the results of tests and inspections during hot functional testing are to be compared with design data and previous test data for verification that detrimental reactor internals vibrations do not exist. A description of these tests, inspections, and analysis is found in Section 3.9.1.

3A.21 MEASURING, EVALUATING, AND REPORTING RADIOACTIVITY IN SOLID WASTES AND RELEASES OF RADIOACTIVE MATERIALS IN LIQUID AND GASEOUS EFFLUENTS FROM LIGHT-WATER-COOLED NUCLEAR POWER PLANTS (REVISION 1; 6/74)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.21 with the following clarification. Turbine Building vents and sumps and Intermediate Building vents are not considered “principal effluent discharge paths” and are not continuously monitored. Assessment of radiation doses to the public from radioactive effluents will be implemented in accordance with the Offsite Dose Calculation Manual as required by Technical Specification, Section 6.9.1.8.

Meteorological conditions will be reported as required by the Offsite Dose Calculation Manual.

3A.22 PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS (REVISION 0; 2/72)

Protection system actuation functions include the capability for periodic testing which meets the recommendations of Regulatory Guide 1.22. The periodic testing is described in Sections 7.1.2.5, 7.2.2, and 7.3.2.

3A.23 PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS (REVISION 0; 2/72)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.23 with the following clarification. Every reasonable effort will be made to assure 90% annual data recovery for those meteorological measurements used in the final documentation of station operational environmental impact. These measurements are to be made to obtain one full year of data following station commercial operation. Efforts for 90% annual data recovery shall be continued after this period only for wind speed 10M, wind direction 10M, and differential temperature (10-61M) as other measurements cannot reasonably be required for the assessment of diffusion characteristics. Readouts for these parameters (wind speed 10M, wind direction 10M, and differential temperature 10-61M) will be made available in the control room.

3A.24 ASSUMPTION USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A PRESSURIZED WATER REACTOR GAS STORAGE TANK FAILURE (REVISION 0; 3/72)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.24 with the following clarifications. The waste gas decay tank contents as described in Section 15.3.5 are based on the planned operation of the Virgil C. Summer Nuclear Station Gaseous Waste Processing System rather than the method of operation assumed by the Regulatory Guide. Actual site related diffusion characteristics are utilized rather than those specified in the Guide.

3A.25 ASSUMPTION USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A PRESSURIZED WATER REACTOR GAS STORAGE TANK FAILURE (REVISION 0; 3/72)

Regulatory Guide 1.25 is not applicable to the Virgil C. Summer Nuclear Station since it uses Regulatory Guide 1.183 for evaluating fuel handling accidents.

3A.26 QUALITY GROUP CLASSIFICATION AND STANDARDS FOR WATER, STEAM, AND RADIOACTIVE-WASTE-CONTAINING COMPONENTS OF NUCLEAR POWER PLANTS (REVISION 3; 2/76)

Quality groups classification of fluid system equipment for the Virgil C. Summer Nuclear Station is described in Section 3.2.2.

Nuclear Steam Supply System fluid system components important to safety are classified in accordance with the August 1970 Draft of ANSI N18.2, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants" except that components of the accumulator subsystem are classified in accordance with the 1973 version of N18.2, as finally accepted by ANSI, and components of the Liquid and Gaseous Waste Processing Systems and the Boron Recycle System are classified in accordance with Regulatory Guide 1.143.

Classification by this means is an alternative acceptable method of meeting the intent of Regulatory Guide 1.26.

3A.27 ULTIMATE HEAT SINK FOR NUCLEAR POWER PLANTS (REVISION 2; 1/76)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.27. The transient and thermal-hydraulic model analyses of the service water pond satisfy the changes noted in this guide.

The details of our analyses and design bases can be found in Sections 2.4.8 and 9.2.5 and V. C. Summer Technical Report, TR 02230-014, "Service Water Pond Thermal Study," dated June, 2000.

3A.28 QUALITY ASSURANCE PROGRAM REQUIREMENTS (DESIGN AND CONSTRUCTION) (REVISION 3; 8/85)/(REVISION 4-2010-REACTOR HEAD REPLACEMENT)

The Virgil C. Summer Nuclear Station complies with the recommendations of this guide as described in Section 17.1 and as discussed below.

The Virgil C. Summer Nuclear Station commits to Regulatory Position C.2 and Table 1 only, along with NQA-1-1994 Basic Requirement 17 and Supplementary Requirement 17S-1 for quality assurance record types and retention requirements.

V. C. Summer commits to Revision 4-2010 of this Regulatory Guide for the design and fabrication of the Replacement Reactor Vessel Closure Head. The Replacement Reactor Vessel Closure Head design and fabrication is performed in accordance with Design Specifications prepared and maintained by Westinghouse.

3A.29 SEISMIC DESIGN CLASSIFICATION (REVISION 2; FOR COMMENT 2/76)/(REVISION 4-2013-REACTOR HEAD REPLACEMENT)

Seismic classification of structures, systems, and components for the Virgil C. Summer Nuclear Station is as described in Sections 3.2.1 and 3.8.

The classification of components by safety class provides the means of establishing applicable a seismic design requirements of both components and systems. At the time the Virgil C. Summer Nuclear Station was designed, duplication by special seismic classification was unnecessary since American National Standard (ANSI) N18.2 was considered to establish seismic design requirements of systems having components classified as Safety Class 1, Safety Class 2, or Safety Class 3. The structures described in Section 3.8 are classified as Seismic Category I.

Classification by this means is an alternate acceptable method of meeting the intent of Regulatory Guide 1.29, since the design construction and quality assurance provided fulfill the recommendations of Regulatory Guide 1.29.

V. C. Summer Commits to Revision 4-2013 of this Regulatory Guide for the design and fabrication of the Replacement Reactor Vessel Closure Head. This Replacement Reactor Vessel Closure Head design and fabrication is performed by Westinghouse with Seismic Classification consistent with the original replaced components.

3A.30 QUALITY ASSURANCE REQUIREMENTS FOR THE INSTALLATION, INSPECTION, AND TESTING OF INSTRUMENTS AND ELECTRICAL EQUIPMENT (REVISION 0; 8/72)

Delete commitment. The Virgil C. Summer Nuclear Station commitment to Regulatory Guide 1.30 is no longer needed with the adoption of NQA-1-1994 Subpart 2.4. NQA-1-1994 Subpart 2.4 is equivalent to the requirements of ANSI N45.2.4-1972.

3A.31 CONTROL OF STAINLESS STEEL WELDING (REVISION 1; 6/73)/(REVISION 4-2013-REACTOR HEAD REPLACEMENT)

1. Welding Under Daniel's Scope

Regulatory Position	Compliance
1.a	Procedures are qualified with filler metal containing 5-12% delta ferrite. Procedure qualification tests are examined by magnetic instruments to ensure a minimum delta ferrite of 3% at the surface. The above procedures ensure that weld deposits contain between 5 and 12% delta ferrite for wrought structures and between 5 and 15% for duplex cast structures.

Regulatory Position	Compliance
1.b	Chemical analysis is performed by the filler metal manufacturer. For procedure qualification chemical analyses are performed on undiluted weld deposits and delta ferrite content is predicted by using an applicable constitution diagram to demonstrate compliance with Regulatory Position 1.a above.
1.c	For procedure qualification delta ferrite content in weld metal is determined using magnetic measurement devices.
1.d	Heat input is controlled during production welding by specifying amperage voltage, and maximum interpass limits. Stringers are preferred welding method. However, to meet the intent of the regulatory position for speed of travel, monitoring, the following is implemented: 1. Weaving does not exceed 3 electrode diameters (uncoated) or the gas cup orifice inside diameter whichever is greater. 2. Daniel welder qualification procedures are reviewed to preclude excessive weaving. 3. QC spot checks production welds to ensure compliance with the procedure.
1.e	Bend tests are conducted and evaluated in accordance with ASME Section IX.
2.	The results of the destructive and nondestructive test required in Regulatory Position 1 above are included in the certified qualification test report. Results are reported on the Record of Welding Procedure Qualification Tests.
3.	The welding materials used for production welds meet the requirements of Section III of the ASME B&PV Code. In addition, each Lot or Heat of Welding material meets the requirements of Regulatory Positions 1.a and 1.b above. Additionally, delta ferrite content is determined by the filler metal manufacturer with a magnetic measuring instrument.
4.	Daniel considers use of only single lots and heats of filler material to be impracticable. Filler material meets the requirements of Position 3 above. Traceability of filler metal to joint is maintained.
5.	Measurements are taken at the surface using a magnetic instrument and indicate a minimum of 3%. Surface measurements of delta ferrite are performed on all welds with a thickness greater than 1 inch. For welding stainless steel piping with a weld thickness of 1 inch or less, a sampling program has been initiated to sample 20% of the first 500 welds completed. At the end of this sampling program an engineering evaluation shall be made to determine whether sampling continuance is warranted.

Regulatory Position	Compliance
6.	In the event that requirements of the commitment to meet Position 5 above are not met, an engineering evaluation shall be performed which may include metallographic examinations performed on weld metal samples cut in a plane transverse to the weld location and correlated with magnetic measurement transverse. Weld acceptance will be based on the absence of unacceptable fissures or cracks.
7.	Production welding is monitored for essential variables in accordance with ASME Section IX, and as described in 1.d above.

2. Welding Under Westinghouse Scope

   The control of stainless steel welding for material procured by Westinghouse is discussed in Section 5.2.5.7. The Westinghouse production weld verification program, as described in WCAP-8324-A, June 1975, is a satisfactory substitute for conformance with the NRC Interim Position on this regulatory guide. The results of the verification program are summarized and documented in WCAP-8693, January 1976.

   Revision 4 is utilized by Westinghouse for the Replacement Reactor Vessel Closure Head Design Specifications.

3. Welding Under Piping Fabrication Scope

   Welding materials are tested by the fabricator using the specific process(es) and the maximum welding energy inputs to be employed in production welding. The tests are in accordance with the requirements of ASME Section III, NB-2430.

   The following additional requirements apply to stainless steel welding:

   a. Tests on stainless steel weld metal include delta ferrite determinations indicating between 5 and 12% for materials to weld wrought base metals and between 5 and 15% for materials to weld cast metals.

   b. These ferrite determinations are made on undiluted weld metal from each heat or lot of welding material and are made by performing chemical analyses on the weld deposits and predicting the delta ferrite content using the “Schaeffler Constitution Diagram for Stainless Steel Weld Metal,” verified by one of the magnetic measurement methods in sub-item c.

   c. Ferrite measurements are made on production welds with a thickness greater than 1 inch. For production welds 1 inch or less in thickness a sampling program has been initiated to randomly sample 20% of the first 500 welds completed. The results of this sampling are reviewed by the OWNER/ENGINEER to determine whether the sampling plan is continued as is, or altered.

Regulatory
Position Compliance

Production weld determinations are made using a Magna gage, Ferrite Scope, Elecometer, or Equal, calibrated to known test welds whose ferrite contents have been determined by the Magna gage-Schaeffler method. Acceptable production welds have a minimum ferrite content of 3% measured at the surface along the centerline of the completed weld.

d. In the event that the requirement of subitem c for at least 3% of ferrite is not met, an engineering evaluation is performed which may include metallographic examinations of samples of weld metal cut in a plane transverse to the weld. Acceptance of the joints is based on the absence of unacceptable fissures or cracks.

4. Welding Under Other Scopes

For safety-related ASME Section III stainless steel components purchased by SCE&G or GAI, welding requirements meeting the intent of Regulatory Guide 1.31 recommendations have been imposed upon manufacturers. Welding materials and welding procedures meet the requirements of ASME Code, Section III and IX.

5. The reactor coolant pump lower bearing oil cooler flexible hoses have been manufactured in accordance with Revision 3 of Regulatory Guide 1.31.

3A.32 ELECTRIC SAFETY-RELATED POWER SYSTEMS FOR NUCLEAR POWER RB PLANTS (REVISION 2, 2/77)

The Virgil C. Summer Nuclear Station design complies with the recommendations of Regulatory Guide 1.32 as discussed below:

1(a). Availability of Offsite Power - Comply. Refer to Sections 8.2.1.1 and 8.3.1.2.1.

1(b). Battery Charger Supply - Comply. Refer to Section 8.3.2.1.5.2.

1(c). Battery Performance Discharge Tests - Comply, with the exception of battery service test “intervals not to exceed 18 months.” Our service tests are performed during refueling outages with a nominal interval of 18 months. However, due to scheduling requirements within outage windows, the interval between tests can slightly exceed 18 months. In addition, per Tech Specs, service tests are not performed during refueling outages that require “performance discharge tests.” Refer to Section 8.3.2.2.2.

1(d). Independence of Redundant Standby Sources - Refer to positions on Regulatory Guides 1.6 and 1.75 in Appendix 3A.

1(e). Connection of Non-Class 1E Equipment to Class 1E Systems - Refer to position on Regulatory Guide 1.75 in Appendix 3A.

1(f). election of Diesel Generator Set Capacity for Standby Power Supplies - Refer to position on Regulatory Guide 1.9 in Appendix 3A.

2(a). Shared Electric Systems for Multi-Unit Nuclear Power Plants - Refer to position on Regulatory Guide 1.81 in Appendix 3A.

2(b). 2(b). Availability of Electric Power Sources - Refer to position on Regulatory Guide 1.93 in Appendix 3A.

3A.33 QUALITY ASSURANCE PROGRAM REQUIREMENTS (OPERATION) (REVISION 2; 2/78)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.33 with the following exceptions and clarifications:

1. The plant has programmatic control requirements in place that make the biennial review process redundant. These programmatic controls were affected in an effort to ensure that plant instructions and procedures are reviewed for possible revision when pertinent source material is revised, therefore maintaining the procedures current. In addition to these controls, the Quality Systems group will perform a biennial Quality Assurance Audit of the procedural development program utilizing a representative sampling process, thereby providing verification that the controls are effective in maintaining procedures current. SCE&G believes that this approach better addresses the intent of the biennial review process and is more acceptable from both a technical and a practical perspective than a static two-year review process.
2. The plant takes exception to paragraph C.4 regarding the increased frequencies required for the performance of the Nonconformance, Surveillance Testing, and Unit Staff audits. The specified frequencies in C.4 are six months, twelve months, and twelve months respectively. The plant will audit these areas at a minimum frequency of " . . . within a period of (2) two years.” using the guidance of the Standard Review Plan 17.2. This change allows more flexibility in the scheduling of audits and allocation resources. Also, since previous audits have not identified any significant deficiencies in the stated programs, the frequency change will not decrease the effectiveness of the audits. The plant will audit these areas every two years. Audits shall be performed at the intervals designated for each audit area. Schedules shall be based on the month in which the audit starts. Two year audits may be extended not to exceed 25 percent of its interval. The maximum time between audits will not exceed 30 months. When an audit interval extension greater than one month is used, the next audit for that particular audit area will be scheduled from the original anniversary month rather from the month of the extended audit.

3A.34 CONTROL OF ELECTROSLAG WELD PROPERTIES (REVISION 0; 12/72)

Electroslag welding is not used for safety-related components at Virgil C. Summer Nuclear Station.

3A.35 INSERVICE INSPECTION OF UNGROUTED TENDONS IN PRE-STRESSED CONCRETE CONTAINMENT STRUCTURES (REVISION 3; 7/90)

Regulatory Guide 1.35 was withdrawn by the NRC on 27 August 2015 (80 FR52067). Inservice inspection of ungrouted tendons must now comply with the more stringent requirements of 10CFR50.55a and, as incorporated by reference therein, the requirements of ASME Boiler and Pressure Vessel Section XI, Subsection IWL. The VCSNS Containment ISI (CISI) Program has been revised to meet the requirements of both 10CFR50.55a and Subsection IWL.

In the calculation of the Base Value, zero tolerance has been applied to the losses. The losses are combined by considering the interaction of the tendon stress relaxation and concrete creep using the procedure described in “A Method for Predicting Prestress Losses in a Prestressed Concrete Structure” which appeared in the Prestressed Concrete Institute Journal, March/April 1972. The Surveillance program is discussed in Section 3.8.1 and the Virgil C. Summer Nuclear Station Technical Specifications.

Following the third (5th year) tendon surveillance, the total losses predicted for the 4th and subsequent surveillances are based upon non-interaction of loss sources which is conservative compared to the interaction method previously used. For the non-interaction method each contributor to loss in tendon prestress force is evaluated individually and combined by direct summation.

3A.35.1 DETERMINING PRESTRESSING FORCES FOR INSPECTION OF PRESTRESSED CONCRETE CONTAINMENTS (REVISION 3; 7/90)

Regulatory Guide 1.35.1 governs the prediction of tendon forces and is based on accounting for material and structural loss factors; such as elastic shortening, shrinkage, creep, and relaxation. This Guide utilizes the 95% Base Value and 90% Base Value. The Base Value is the force predicted for a tendon at the time of the surveillance. The Base Value is equal to the original tendon stressing force minus the prestressing losses having occurred since that time.

3A.36 NON-METALLIC THERMAL INSULATION FOR AUSTENITIC STAINLESS STEEL (REVISION 0; 2/73)

Regulatory Guide 1.36 is not applicable for components within the Reactor Building since only stainless steel mirror insulation or a mass type encapsulated in stainless steel is used on austenitic stainless steel piping and equipment.

For austenitic stainless steel piping and components outside the Reactor Building, Regulatory Guide 1.36 is followed.

3A.37 QUALITY ASSURANCE REQUIREMENTS FOR CLEANING OF FLUID SYSTEMS AND ASSOCIATED COMPONENTS OF WATER-COOLED NUCLEAR POWER PLANTS (REVISION 1; 3/07)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.37. Procurement orders apply cleaning requirements during fabrication and packaging of safety-related components so that equipment is delivered to the site in a properly cleaned condition. Site procedures for the operational phase meet the requirements of ASME NQA-1-1994, Part II, Subpart 2.1 and this guide.

3A.38 QUALITY ASSURANCE REQUIREMENTS FOR PACKAGING, SHIPPING, RECEIVING, STORAGE, AND HANDLING OF ITEMS FOR WATER-COOLED NUCLEAR POWER PLANTS (REVISION 0; 3/73)

Delete commitment. The Virgil C. Summer Nuclear Station commitment to Regulatory Guide 1.38 is no longer needed with the adoption of NQA-1-1994 Subpart 2.2. NQA-1-1994 Subpart 2.2 is equivalent to the requirements of ANSI N45.2.2-1973.

3A.39 HOUSEKEEPING REQUIREMENTS FOR WATER-COOLED NUCLEAR POWER PLANTS (REVISION 2, 9/77)

Delete commitment. The Virgil C. Summer Nuclear Station commitment to Regulatory Guide 1.39 is no longer required with the adoption of NQA-1-1994 Subpart 2.3. NQA-1-1994 Subpart 2.3 is equivalent to the requirements of ANSI N45.2.3-1973.

3A.40 QUALIFICATION TESTS OF CONTINUOUS-DUTY MOTORS INSTALLED INSIDE THE CONTAINMENT OF WATER-COOLED NUCLEAR POWER PLANTS (REVISION 0; 3/73)

The specifications for continuous-duty Class I motors installed within the containment stipulate the recommendations of IEEE-334-71. The vendor’s qualification tests are in compliance with the recommendations of Regulatory Guide 1.40.

3A.41 PREOPERATIONAL TESTING OF REDUNDANT ON-SITE ELECTRIC POWER SYSTEMS TO VERIFY PROPER LOAD GROUP ASSIGNMENTS (REVISION 0; 3/73)

The Virgil C. Summer Nuclear Station preoperational testing program complies with the recommendations of Regulatory Guide 1.41.

3A.42 INTERIM LICENSING POLICY ON AS LOW AS PRACTICABLE FOR GASEOUS RADIOIODINE RELEASES FROM LIGHT-WATER-COOLED NUCLEAR POWER REACTORS (REVISION 1; 3/74)

The NRC staff has withdrawn this Regulatory Guide.

3A.43 CONTROL OF STAINLESS STEEL WELD CLADDING OF LOW-ALLOY STEEL COMPONENTS (REVISION 0; 5/73)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.43 as discussed herein. To ensure guide compliance, welding processes that induce underclad cracking by generating excessive heating and promoting grain coarsening in the base metal are not used. Known affected components are restricted to the reactor vessel, the steam generator, and the pressurizer.

Virgil C. Summer endorses Revision 1-2011 of this Regulatory Guide for the design and fabrication of the Replacement Reactor Vessel Closure Head.

The reactor vessel heads and shell courses were constructed of SA-533 Grade B Class 1 plate material made to a fine grain practice. The closure head and vessel flanges and the primary nozzles were constructed of SA-508 Class 2 forging material.

This plate and forging material was clad utilizing the shielded metal arc and the two-wire submerged arc processes which are considered low heat input processes. Since the plate material and the low heat input clad processes used on forging material are not subject to restrictions by the guide, the vessel is in compliance with Regulatory Position C.1. Regulatory Position C.2 is not applicable in this case. The reactor vessel fabricator monitored and recorded the weld parameters to verify compliance with the parameters established by the procedure qualifications of Regulatory Position C.3.

The steam generator and the pressurizer parts which are clad are constructed of SA-533 Grade A Class 2 and SA-508 Class 2a steels. These materials are made to fine grain practice and welding is done with low heat input techniques.

3A.44 CONTROL OF THE USE OF SENSITIZED STAINLESS STEEL (REVISION 0; 5/73)

The Virgil C. Summer Nuclear Station complies with the recommendations of this guide as discussed herein. Specific items pertaining to this guide are discussed in Section 5.2.5. For those exceptions where sensitized material is used, justification is provided in WCAP-7735, “Topical Report-Compiled by W. S. Hazelton, August 1974, Sensitized Stainless Steel in Westinghouse PWR Steam Supply System (WNES Class 3).”

Compliance with separate guide positions is as follows:

1. The use of processing, packaging, and shipping controls and preoperational cleaning to preclude adverse effects of exposure to contaminants on stainless steel materials are in accordance with the guide. Additional information is given in discussions of Regulatory Guides 1.37 and 1.38.
2. Where practical, austenitic stainless steel starting materials are utilized in the final heat treated condition required by the respective ASME Code Section II material specification for the particular type or grade of alloy in accordance with the guide.
3. Compliance with this guide position is discussed in Section 5.2.5.3.
4. This subject is discussed in Section 5.2.5.5. To provide a more rapid reduction of the oxygen concentration by reaction with hydrazine an upper limit of 250° F is used. Startup operations provide for hydrazine additions after the temperature is about 225° F. Oxygen scavenging at 225° F is rapid and complete.

Components with stainless steel sensitized in the manner expected during component fabrication and installation will operate satisfactorily under normal plant chemistry conditions in pressurized water reactor systems, because chlorides, fluorides, and particularly oxygen, are controlled to very low levels (0.15 ppm each).

Delta ferrite control is discussed in the Regulatory Guide 1.31 position and Section 5.2.5.7.

5. The compliance with this regulatory position is discussed in Section 5.2.5.6. Also, delta ferrite control is discussed in the Regulatory Guide 1.31 position and Section 5.2.5.7.
6. Compliance with this guide position in application to Westinghouse scope items is discussed in Section 5.2.5.5. For welding under Daniel's scope, E-308L-16 and ER-108L filler material is used in stainless steel production welding. In addition, an intergranular corrosion test is performed for each stainless welding procedure qualification. The use of E-308-16 and E-308 filler material when specified by Westinghouse is acceptable in accordance with criteria specified in Section 5.2.5.5.

Virgil C. Summer endorses Revision 1-2011 of this Regulatory Guide for the design and fabrication of the Replacement Reactor Vessel Closure Head.

3A.45 REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS (REVISION 0; 5/73)

The Virgil C. Summer Nuclear Station meets the technical recommendation of Regulatory Guide 1.45. Diverse methods for determination of reactor coolant leakage are employed in the design of Virgil C. Summer Nuclear Station which follows the recommendations of Regulatory Guide 1.45. Specific methods for reactor coolant leakage detection are described in Section 5.2.7.

3A.46 PROTECTION AGAINST PIPE WHIP INSIDE CONTAINMENT (REVISION 0; 5/73)

The following information and exceptions are provided to clearly define the means of implementing the recommendations of Regulatory Guide 1.46. The modifications specified below reflect the recommendations of relevant standards as referenced. An exception to Regulatory Guide 1.46 Regulatory Position C.4.d is taken to specify the measures for restraint against pipe whipping as a result of the design basis breaks postulated to occur at the locations specified in accordance with the guide need not be provided for piping where both the following pipe normal operating conditions are met:

1. The maximum normal operating temperature is less than or equal to 200° F and;
2. The maximum normal operating pressure is less than or equal to 275 psig.

Normal operating conditions are defined as those during reactor startup, operation at power, hot standby, or reactor cooldown to cold shutdown condition.

Through-wall leakage cracks instead of breaks may be postulated in the piping of those fluid systems that qualify as high-energy fluid systems for only short operational periods, but qualify as moderate-energy fluid systems for the major operational period. The above change is in agreement with the NRC's latest position as stated in "Branch Technical Position - MEB No. 1" dated September 23, 1974, on pipe Rupture Outside Containment, and definitions included in Regulatory Guide 1.XX Appendix D2 dated March 15, 1974. SCE&G concurs that such an exception constitutes a reasonable approach.

A second exception is taken to the criteria of Regulatory Guide 1.46 with respect to break area for a longitudinal pipe rupture. A postulated longitudinal rupture will be assumed to have an area of opening equal to the cross-sectional flow area of the affected pipe in lieu of two cross-sectional flow areas as suggested in Regulatory Guide 1.46. This assumption has been shown to be conservative. This change of criteria is in agreement with both Regulatory Guide 1.XX and ANSI N176.

Regulatory Guide 1.46 and the NRC's Mechanical Engineering Branch's Technical Position MEB 3-1, "Postulated Break and Leakage Locations in Fluid System Piping Outside Containment," June 1987 differ significantly on the postulated orientation and location of longitudinal breaks. Regulatory Guide 1.46 requires longitudinal breaks to be postulated at all break locations in piping 4 inches nominal pipe size and larger and oriented at any point around the pipe circumference. MEB 3-1 does not recommend a longitudinal break to be postulated at terminal ends, unless longitudinal welds are used, and most importantly for longitudinal breaks states "Splits should be oriented (but not concurrently) at two diametrically-opposed points on the piping circumference such that the jet causes out-of-plane bending of the piping configuration."

Guidelines of MEB 3-1 are utilized to determine the location and orientation of longitudinal breaks inside the Reactor Building in preference to those of Regulatory Guide 1.46. Such use of MEB 3-1 is endorsed by NRC's Standard Review Plan, section 3.6.2, paragraph II.1.

Dynamic forces resulting from circumferential pipe breaks are assumed to cause whipping in any direction of either end of the ruptured pipe normal to the pipe axis unless the direction of whipping can be defined giving due consideration to the geometry of the ruptured pipe and the effects of a less than instantaneous pipe rupture. Regulatory Guide 1.46 makes no provisions for the defining of pipe whip direction.

Regulatory Guide 1.XX and ANSI N176 limit the direction of pipe whip to the plane defined by the piping geometry. The stated assumption while more liberal than that of Regulatory Guide 1.46, is more conservative than the position set forth in Regulatory Guide 1.XX and ANSI N176 and can be substantiated using simple mechanics of propulsion.

For NSSS scope of supply, the Virgil C. Summer Nuclear Station utilizes the Westinghouse generic break criteria as specified in WCAP-8083-P-A. An AEC letter dated May 22, 1974 from D. B. Vassallo to R. Salvatori concerning WCAP-8083-P-A accepts the WCAP criteria and presents a discussion of the six items identified in the acceptance letter. These provide a level of protection equivalent to that provided by the application of Regulatory Guide 1.46 criteria. The protection against dynamic effects associated with the postulated rupture of piping are discussed in Section 3.6.

3A.47 BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS (REVISION 0; 5/73)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.47 for deliberate operator action as discussed in Section 7.1.2.6.

3A.48 DESIGN LIMITS AND LOADING COMBINATIONS FOR SEISMIC CATEGORY I FLUID SYSTEM COMPONENTS (REVISION 0; 5/73)

The Virgil C. Summer Nuclear Station components are in compliance with the recommendations of Regulatory Guide 1.48. Additional design details are given in Section 3.9.

Equipment Under Gilbert Scope

The seismic specification requires qualification of safety-related equipment by test and/or analyses. The parent procurement specification specifies that qualification of equipment be demonstrated under loading combinations, and design limits delineated in Regulatory Guide 1.48. The loading combinations stress limits and assurance of operability requirements, as applicable, are indicated in each specification. A sample of the requirements for each category is shown below.

Specification Paragraphs to be Used When Addressing Regulatory Guide 1.48 Requirements

Bidder shall offer equipment for which "Loading Combination" are in compliance with the Gilbert specification. The bidder shall use the following design limits and load combinations when complying with the specification (1)

1. Nonactive ASME Code Class 2 and 3 Valves

   The design of Code Class 2 and 3 valves encompasses the use of pressure temperature ratings. The design limits given herein are in terms of Pr which is the primary pressure rating corresponding to the maximum transient temperature for each plant condition as specified in paragraphs NC-3511 and ND-3511 of the ASME Code Section III for Code Class 2 and 3 valves respectively. To assure pressure retaining integrity the limits for Pr are set as follows:

   a. The primary pressure rating Pr should not be exceeded more than 10% when the component is subject to concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50% of the safe shutdown earthquake or loadings conditions associated with the emergency plant condition.

   b. Pr should not be exceeded by more than 20% when the component is subject to concurrent loadings associated with the normal plant condition, the vibratory motion of the safe shut-down earthquake, and the dynamic system loadings associated with the faulted plant condition.

2. Active ASME Code Class 2 and 3 Valves

   To provide pressure retaining integrity and assurance of operability for active valves of Code Class 2 and 3, Pr should not be exceeded for the combinations of loadings delineated herein. (See Note 2.1 and 2.2.)

   a. The primary pressure rating Pr should not be exceeded when the component is subjected to concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50% of the safe shutdown earthquake.

   b. The primary pressure rating Pr should not be exceeded when the component is subject to loadings associated with the emergency plant condition.

   c. The primary pressure rating Pr should not be exceeded when the component is subject to concurrent loadings associated with the normal plant condition, the vibratory motion of the safe shutdown earthquake, and the dynamic system loadings associated with the faulted plant condition.

(1) Included as preface for each category.

Note 2.1: It is strongly preferred that valves having electric, pneumatic, or hydraulic operators; or having position limit switches or other miscellaneous electrical or pneumatic control devices, be qualified by test rather than by analysis. Should testing of the complete assembly be unavailable, it is then preferred that the operators and control devices be qualified by test. Qualification of these components by analysis only is judged least desirable. There will be major evaluation considerations given this.

Note 2.2: If proof of operability is to be shown by analysis, it is suggested that a deformation (interference) analysis is performed. The purpose of this analysis would be to show that all moving parts are uninhibited in movement due to deformation of components caused by any loading conditions as described above.

3. Non-Active ASME Code Class 1 Pumps and Valves (Designed by Analysis)

   In order to assure pressure-retaining integrity for nonactive Code Class 1 pumps and valves, the upset, emergency, and faulted operating condition category design limits of NB-3200 of Section III of the ASME Code should not be exceeded when the component is subjected to the following loading combinations:

   a. The design limits specified in NB-3223 of the ASME Code should not be exceeded when the component is subjected to concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50% of the safe shutdown earthquake.
   b. The design limits specified in NB-3224 of the ASME Code should not be exceeded when the component is subjected to concurrent loadings associated with the normal plant condition, the vibratory motion of the safe shutdown earthquake, and the dynamic system loadings associated with the faulted plant condition.

4. Non-Active ASME Code Class 1 Valves (Designed by Standard or Alternative Design Rules)

   Standard or alternative design rules, which encompass the use of pressure-temperature ratings, for Code Class 1 valves are specified by NB-3512 and NB-3513 of Section III of the ASME Code. The design limits given herein are in terms of Pr which is the primary pressure rating corresponding to the maximum transient temperature for each plant condition as specified in Tables NB-3531-1 to NB-3531-7 of Section III of the ASME Code. To assure pressure-retaining integrity, Pr should not be exceeded by more than 10, 20, and 50% when the component is subjected to the following combinations:

   a. Pr should not be exceeded by more than 10% when the component is subjected to concurrent loadings associated with either the normal plant conditions or the upset plant condition and the vibratory motion of 50% of the safe shutdown earthquake.
   b. Pr should not be exceeded by more than 20% when the component is subjected to the loadings associated with the emergency plant condition.

c. Pr should not be exceeded by more than 50% when the component is subjected to concurrent loadings associated with the normal plant conditions, the vibratory motion of the safe shutdown earthquake, and the dynamic system loadings associated with the faulted plant condition.

5. ASME Code Class 2 and 3 Vessels (Designed to Division 1 of Section VIII of the ASME Code) (See Note 5.1)

   To provide assurance of pressure-retaining integrity for Code Class 2 and 3 vessels (Designed to Division 1 of Section VIII of the ASME Code) the allowable stress value S (as specified in Appendix 1 of Section III of the ASME Code) should not be exceeded by more than 10% when the component is subjected to the loading combinations identified by items a and b below, and should not be exceeded by more than 50% when the component is subjected to the loading combinations identified by item c below.

   a. Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50% of the safe shutdown earthquake.

   b. Loadings associated with the emergency plant condition.

   c. The allowable stress value S should not be exceeded by more than 50% when the component is subjected to concurrent loadings associated with the normal plant condition, the vibratory motion of the safe shutdown earthquake, and the dynamic system loadings associated with the faulted plant condition.

Note: 5.1 If a more detailed analysis is performed, Division 1 vessels should meet, as a minimum equations (1) and (2) below. Equation (1) is applicable to items a and b above. Equation (2) is applicable to item c, above.

(1) $\sigma_M < 1.1S > \frac{\sigma_M + \sigma_b}{1.5}$

(2) $\sigma_M < 1.5S > \frac{\sigma_M + \sigma_b}{1.5}$

Where:

σ_m	=	Primary Membrane Stress
σ_b	=	Primary Bending Stress
S	=	Allowable stress value as specified in Appendix 1 of Section III of the ASME Boiler and Pressure Vessel Code.

6. ASME Code Class 2 Vessels (Designed to Division 2 of Section VIII of the ASME Code)

   To provide assurance of pressure-retaining integrity for Code Class 2 Vessels, (Designed to Division 2 of Section VIII of the ASME Code) the upset, emergency, and faulted operating condition category design limits of NB-3200 of Section III of the ASME Code should not be exceeded when the component is subjected to the following loading combinations:

   a. The design limits specified in NB-3223 of the ASME Code should not be exceeded when the component is subjected to concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50% of the safe shutdown earthquake.

   b. The design limits specified in NB-3224 of the ASME Code should not be exceeded when the component is subjected to loadings associated with the emergency plant condition.

   c. The design limits specified in NB-3225 of the ASME Code should not be exceeded when the component is subjected to concurrent loadings associated with the normal plant condition, the vibratory motion of the safe shutdown earthquake, and the dynamic system loadings associated with the faulted plant condition.

7. ASME Code Class 2 and 3 Piping

   To provide assurance of pressure retaining integrity for Code Class 2 and 3 piping, the design limits specified in NC3611.1(b)(4)(c)(b)(1) of the Winter 1972 Addenda to Section III of the ASME Code (i.e., 1.2 Sh) are not exceeded when the piping is subjected to the loading combinations identified in items a and b, below. However, for short sections of piping exposed to jet impingement from postulated cracks or breaks in adjacent piping, a stress limit of 1.5 Sh may be used.

   The design limits specified in NC3611.1(b)(4)(c)(b)(2) of the Winter 1972 Addenda to Section III of the ASME Code (i.e., 1.8 Sh) are not exceeded when the piping is subjected to the loading combinations identified in item c, below. However, for short sections of piping exposed to jet impingement from postulated cracks or breaks in adjacent piping, a stress limit of 2.4 Sh may be used.

   a. Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50% of the safe shutdown earthquake.

   b. Loadings associated with the emergency plant conditions.

   c. Concurrent loadings associated with the normal plant condition, the vibratory motion of the safe shutdown earthquake, and the dynamic system loadings associated with the faulted plant condition.

8. Non-Active ASME Code Class 2 and 3 Pumps

   In order to assure pressure-retaining integrity for nonactive Code Class 2 and 3 pumps, the primary membrane stress should not be exceeded by more than 10% of S (as specified in Appendix 1 of Section III of the ASME Code) and the sum of the primary membrane plus primary bending stresses should not be exceeded by more than 65% of S when the components is subjected to the following load combinations:

   a. Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50% of the safe shutdown earthquake.
   b. Loadings associated with the emergency plant condition.

      In addition, the primary membrane stress should not be exceeded by more than 20% of S, and the sum of the primary membrane and primary bending stresses should not be exceeded by more than 80% of S when the component is subjected to concurrent loadings associated with the normal plant condition, the vibratory motion of the safe shutdown earthquake, and the dynamic system loadings associated with the faulted plant condition.

9. Active ASME Code Class 2 and 3 Pumps

   To provide increased assurance that unacceptable deformation affecting operability of active Code Class 2 and 3 pumps will not result, the primary membrane stress should not exceed S (as specified in Appendix 1 of Section III of the ASME Code) and the sum of the primary membrane plus primary bending stresses should not be exceeded by more than 50% of S when the component is subjected to the following loading combinations: (See notes 9.1 and 9.2.)

   a. Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50% of safe shutdown earthquake.
   b. Loadings associated with the emergency plant condition.
   c. Concurrent loadings associated with the normal plant condition, the vibratory motion of the safe shutdown earthquake, and the dynamic system loadings associated with the faulted plant condition.

   Note 9.1: The design limits given below may be used for the applicable loading combinations if stringent analysis and/or testing confirms that operability will not be impaired when the component is designed to these limits.

   The primary membrane stress should not be exceeded by more than 10% of S and the sum of the primary membrane plus primary bending stresses should not be exceeded by more than 65% of S when the component is subjected to the following load combinations:

   a. Concurrent loadings associated with either the normal plant condition or the upset plant condition and the vibratory motion of 50% of the safe shutdown earthquake.

b. Loadings associated with the emergency plant condition.

The primary membrane stress should not be exceeded by more than 20% of S, and the sum of the primary membrane and primary bending stresses should not be exceeded by more than 80% of S when the component is subjected to concurrent loadings associated with the normal plant condition, the vibratory motion of the safe shutdown earthquake, and the dynamic system loadings associated with the faulted plant condition.

Note 9.2: In addition to compliance with the design limits specified, it is strongly preferred that the assurance of operability under all design loading combinations be provided by test. In the performance of test or analysis to demonstrate operability, the structural interaction of the entire pump-motor assembly should be considered. Should this be unavailable, it is then preferred that the components, with any appurtenances attached thereto, be qualified by test. If superposition of test results for other than the combined loading condition is proposed, the applicability of such a procedure should be demonstrated. Qualification of these components by analysis only is judged least desirable. There will be major evaluation consideration given this.

Westinghouse Supplied Equipment

Westinghouse equipment was designed to ensure structural integrity and operability. However, it must be realized that the load combinations and stress limits that were used reflect AEC (NRC) recommendations that were in effect when the construction permit for this plant was issued and when the components were purchased and designed. Furthermore, the codes and procedures which were available when the components were purchased are based on conservative design requirements rather than detailed stress analyses. These codes and procedures have been widely used by the nuclear industry for the design of components which are installed in plants that are presently operating. A discussion of the stress limits and loading combinations is presented in Section 5.2.1 for Code Class 1 components and in Section 3.9.2 for Code Class 2 and 3 components. The operability of active components are discussed in Sections 5.2.1, 3.9.2, and 3.9.4.

Prior to installation, the valves are subjected to shell hydrostatic tests, seat leakage tests, and functional tests to show that the valves will open and close within the specified time limits when subjected to the design differential pressure. After installation the valves undergo cold hydrostatic tests, hot functional tests to verify operation, and periodic inservice inspection and operation to assure the continued ability of the valves to operate. Class 1 active valves are designed in accordance with the ASME Code, Section III. In addition to Class 2 and 3 active valves designed in accordance with the ASME Code Section III, there are some Class 2 and 3 valves within the pump and valve code. These are designed to the requirements of the ANSI B16.5 Code.

Active pumps are designed in accordance with the ASME Code Section III. The stress levels in the pump’s pressure retaining parts do not exceed those allowed by the Code. Forces resulting from seismic accelerations in the horizontal and vertical directions are included in the analyses of the pumps and their supports. To eliminate any amplification of the seismic floor acceleration in

the pump support structure, the supports are designed to have natural frequencies in excess of 30 Hertz.

The above design procedures and qualification tests are, therefore, adequate to ensure the structural integrity and operability of the pumps and valves for this plant.

3A.49 POWER LEVELS OF NUCLEAR PLANTS (REVISION 1; 12/73)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.49 since the power level is less than 3800 MWt.

3A.50 CONTROL OF PREHEAT TEMPERATURES FOR WELDING OF LOW-ALLOY STEEL (REVISION 0; 5/73)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.50 with the following clarifications and exceptions:

1. Welding Under General Contractor's Scope

Regulatory Position	Methods Of Compliance
1	Low alloy steels do not include those designated as P-1 by the ASME Code, Section IX.
1.(a)	A minimum preheat and maximum preheat and maximum interpass temperature is specified by the appropriate welding procedure.
1.(b)	Procedures are qualified in accordance with the ASME Code, Section IX. In general, preheat conditions are not maintained until initiation of post weld heat treatment.
2	For production welds, the preheat temperature is not maintained until a post-weld heat treatment has been performed. The alternate position as stated in Regulatory Guide Position 4 is utilized. Welding Under Westinghouse's Scope
3	Preheat and interpass temperatures are monitored by construction and QC personnel.
4	Acceptance of welds is determined by NDE after postweld heat treatment is complete.

2. Welding Under Westinghouse's Scope

   Westinghouse considers that this guide applies to ASME Section III Class 1 components.

   The Westinghouse practice for Class 1 components is in agreement with the positions of Regulatory Guide 1.50 except for Regulatory Position 1.b and 2. For Class 2 and 3 components, Westinghouse does not apply any of the Regulatory Guide 1.50 recommendations.

In the case of Regulatory Position C.1.b, the welding procedures are qualified within the preheat temperature ranges required by Section IX of the ASME Code. Westinghouse experience has shown excellent quality of welds using the ASME qualification procedures.

In the case of Regulatory Position C.2, the Westinghouse position is that this guide recommendation is both unnecessary and impractical. Code accepted low alloy steel welds have been and are being made under present Westinghouse specified procedures. It is not necessary to maintain the preheat temperature until a post weld heat treatment has been performed, as recommended by the guide, in the case of large components.

In the case of reactor vessel main structural welds, the practice of maintaining preheat until the intermediate, or final post weld heat treatment, has been followed by Westinghouse. In either case, the welds have shown high integrity.

Westinghouse practices are documented in WCAP-8577 which has been accepted by the NRC.

For the reactor vessel the soundness of the welds has been verified by extensive ultrasonic testing as permitted by Regulatory Position C.4.

Revision 1-2011 is used for the design and fabrication of the Replacement Reactor Vessel Closure Head by Westinghouse in the Design Specifications.

Regulatory Position	Methods Of Compliance

3. Welding Under Other's Scope

   Low alloy steel items falling within the category of items of this guide are limited to the exhaust piping for the diesel engine for which piping is fabricated in accordance with guide welding recommendations.

3A.51 INSERVICE INSPECTION OF ASME CODE CLASS 2 AND 3 NUCLEAR POWER PLANT COMPONENTS (REVISION 0; 5/75)

The NRC staff has withdrawn this regulatory guide.

3A.52 DESIGN, TESTING, AND MAINTENANCE CRITERIA FOR ENGINEERED SAFETY FEATURE ATMOSPHERIC CLEANUP SYSTEM AIR FILTRATION AND ADSORPTION UNITS OF LIGHT-WATERCOOLED NUCLEAR POWER PLANTS (REVISION 1; 7/76)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.52 with the following exceptions and clarifications. A comparison of the Guide's

recommendations and our compliance for the Reactor Building HEPA filter system, Control Room emergency filter system, and Fuel Handling Building charcoal exhaust system is given in Section 6.5.1. Table 6.5.1 indicates portions of SCE&G position of Regulatory Guide 1.52 which comply with the recommendations of Revision 2.

3A.53 APPLICATION OF THE SINGLE-FAILURE CRITERION TO NUCLEAR POWER PLANT PROTECTION SYSTEMS (REVISION 0: 6/73)

As described in Section 7.1.2.7 and 7.3.2.2, protection systems included in the design of the Virgil C. Summer Nuclear Station can tolerate single failure without degrading the system functional capabilities to unacceptable levels and are in compliance with the recommendation of Regulatory Guide 1.53.

3A.54 QUALITY ASSURANCE REQUIREMENTS FOR PROTECTIVE COATINGS APPLIED TO WATER COOLED NUCLEAR POWER PLANTS (REVISION 0; 6/73)

The Virgil C. Summer Nuclear Station is in compliance with the recommendations of Regulatory Guide 1.54 with the following clarifications and exceptions.

For the Westinghouse scope of supply, Westinghouse employs process specifications and the Westinghouse Quality Assurance Program, including quality assurance surveillance and auditing, to provide adequate confidence that coating work within Westinghouse scope will perform satisfactorily in service.

An alternate method of compliance with this regulatory guide has been submitted to the NRC (via letter NS-CE-1352, dated February 1, 1977, to Mr. C. J. Heltemes, Jr., Quality Assurance Branch, NRC, from Mr. C. Eicheldinger, Westinghouse PWRSD, Nuclear Safety Department) and accepted (via letter, dated April 27, 1977, to Mr. C. Eicheldinger from Mr. C. J. Heltemes, Jr.).

3A.55 CONCRETE PLACEMENT IN CATEGORY I STRUCTURES (REVISION 0; 6/73)

Regulatory Guide 1.55 has been withdrawn per NRC letter of July 8, 1981. However, concrete placement for the Virgil C. Summer Nuclear Station is still in compliance with the recommendation of Regulatory Guide 1.55 with the following exceptions.

Creep tests for concrete are performed for the Reactor Building only. Loss of prestress through creep is not applicable to nonprestressed structures.

Concrete placement and testing are discussed in Section 3.8.1.

3A.56 MAINTENANCE OF WATER PURITY IN BOILING WATER REACTORS

(REVISION 0; 6/73)

Regulatory Guide 1.56 is not applicable to the Virgil C. Summer Nuclear Station since it uses a PWR.

3A.57 DESIGN LIMITS AND LOADING COMBINATIONS FOR METAL PRIMARY REACTOR CONTAINMENT SYSTEM COMPONENTS (REVISION 0; 6/73)

Regulatory Guide 1.57 is not applicable to the Virgil C. Summer Nuclear Station since a concrete-metal containment structure that relies on concrete for its structural integrity is used.

3A.58 QUALIFICATION OF NUCLEAR POWER PLANT INSPECTION, EXAMINATION, AND TESTING PERSONNEL (REVISION 1; 9/80)

Delete commitment. Regulatory Guide 1.58 has been withdrawn. The requirements of NQA-1-1994 Basic Requirement 2, Supplementary Requirement 2S-1, Supplementary Requirement 2S-2, and Appendix 2A-1, are equivalent to the requirements of ANSI N45.2.6-1978.

3A.59 DESIGN BASIS FLOODS FOR NUCLEAR POWER PLANTS (REVISION 1; FOR COMMENT; 4/76)

Regulatory Guide 1.59 applies to plants by riverside, streamside, on estuaries, on coastal plain, or at the Great Lakes. It does not presently apply to plants with man-made reservoirs for cooling systems. SCE&G, however, performed the analyses consistent with the guidelines presented in Appendix A of the Regulatory Guide. Flood design considerations are discussed in Sections 2.4.2, 2.4.3, and 2.4.4.

3A.60 DESIGN RESPONSE SPECTRA FOR SEISMIC DESIGN OF NUCLEAR POWER PLANTS (REVISION 1; 12/73)

The construction permit for the Virgil C. Summer Nuclear Station was issued based on

the seismic data given in the PSAR. Considerable investigation was performed by the AEC/DOL and the ACRS prior to issuance. Designs have been accomplished based on data which was submitted and approved at that time. The same data is presently utilized for equipment procurement and testing. Refer to Sections 2.5.2 and 3.7. Since the data given in the PSAR had AEC/DOL and ACRS approval, this constitutes an acceptable alternate to this regulatory guide.

3A.61 DAMPING VALUES FOR SEISMIC DESIGN OF NUCLEAR POWER PLANTS

(REVISION 0; 10/73)

The construction permit for the Virgil C. Summer Nuclear Station was issued based on the seismic data given in the PSAR. Considerable investigation was performed by the AEC/DOL and the ACRS prior to issuance. Designs have been accomplished based on data which was submitted and approved at that time. The same data is presently utilized for equipment procurement and testing. Refer to Sections 2.5.2 and 3.7. Since the data given in the PSAR had AEC/DOL and ACRS approval, this constitutes an acceptable alternate to this regulatory guide.

3A.62 MANUAL INITIATION OF PROTECTION ACTIONS (REVISION 0; 10/73)

Manual initiation of protective actions at the systems level may be accomplished from the control room of the Virgil C. Summer Nuclear Station in compliance with the recommendations of Regulatory Guide 1.62. Drawings and descriptions of the manual initiation circuits are found in Chapters 7 and 8.

3A.63 ELECTRICAL PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURE FOR WATER-COOLED NUCLEAR POWER PLANTS (REVISION 1; 5/77)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.63 with the following clarifications.

This guide states the regulatory position with respect to IEEE 317-1976. The GAI procurement specification (No. 559) references, and requires compliance with IEEE 317-1972, as applicable to the Virgil C. Summer Nuclear Station. In Section C.1 of the guide IEEE 279-1971 is referenced as a guide for circuit overload protection, but IEEE-279 does not specifically apply to either power circuits or overload protection. Penetration assemblies are qualified to maintain containment integrity with a single failure of any overcurrent protective device.

In order to meet the recommendations of Regulatory Guide 1.63, primary and backup overcurrent protective devices are used on Class 1E and non-Class 1E power and control circuits feeding through penetrations, or justification/analysis is performed demonstrating that primary and backup overcurrent protection is not required. A listing of these protective devices is found in Appendix 8G.

The penetration conductors have short-time overload and short circuit ratings consistent with the characteristics of the backup protective-device, assuming the failure of the primary protective device. For the reactor coolant pump circuits fed from 7.2 kV switchgear, the motor feeder protective relays are coordinated with, and backed up by, the bus protective relays. The control power for the trip coils of the reactor coolant pump breakers are supplied by the plant Class 1E battery which is independent of the station battery which provides control power for the 7200 volt bus supply breakers. This precludes loss of protection from a single loss of control power.

For circuits fed from 480 volt switchgear, the time delay and instantaneous overcurrent trips or the motor feeder air circuit breaker are coordinated with, and backed up by, either the overcurrent relays of the bus protective breaker or fuses in the motor feeder circuit. The 480 volt breakers are provided with solid state tripping devices which are powered by the fault current through individual power supply sensors and signal sensors. Therefore, independent DC control power is not required.

For circuits fed from motor control centers, the normal overcurrent protective devices are backed up by a thermal-magnetic current limiting circuit breaker added to each circuit.

For motor operated valves that have their overload protection device bypassed during safety injection (see discussion of Regulatory Guide 1.106), a thermal-magnetic breaker is substituted for the normal magnetic only circuit breaker. The thermal-magnetic breaker is backed up by a thermal-magnetic current limiting circuit breaker.

Control rod drive power circuits are protected by two sets of fuses which are integral with the rod drive control system. These fuses are sized to protect solid state components within the control system from overcurrent levels which are conservative compared to penetration conductor capabilities.

Power circuits feeding the pressurizer heaters are protected by the heater bank power distribution circuit fuses and are backed up by the power distribution panel main fuses.

Power circuits supplied from a-c and d-c power panels are protected with thermal-magnetic circuit breakers which are backed up by fuses in series with the breakers.

AC and DC control circuits and protection associated with electrical penetrations are divided into four basic categories:

Category 1 — AC control circuits supplied by 480-120V control power transformers located in motor control centers are each protected with a fuse on the secondary side of the transformer. An analysis of data obtained from tests demonstrated that the available short circuit current on the secondary of these 480-120V MCC control transformers is limited by the transformers impedance and eventual destruction, which occurs before reaching the I^2t capabilities of the penetration conductors. Therefore, the transformer will provide back-up protection in the event that the fuse on the secondary side of the control transformer fails to clear a fault.

Category 2 — Certain AC and DC control circuits which are justified by examination of a potential fault and the type of circuit shorted do not require primary and backup overcurrent protection because the potential effect of their associated faults is negligible. This category applies to low level analog circuits, circuits supplied by equipment whose internal power supplies and wiring are current limiting by design, and circuits whose postulated fault will affect circuit operation but will not create a short circuit condition because the circuit load is located outside the Reactor Building.

Category 3 The majority of DC control circuits (those circuits which are not identified as Category 2) are supplied from ungrounded DC power systems. Each circuit is protected with two fuses, one in each positive and negative leg of the circuit. One fuse provides backup protection for the other. Both fuses are sized to clear a fault before the I^2t capability of the penetration conductors is reached.

Category 4 The majority of AC control circuits (i.e., those circuits which are not identified as Category 1 and 2) are protected with primary and backup overcurrent protective devices in series. Both devices are sized to clear a fault before the I^2t capability of their associated penetration conductors is reached.

3A.64 QUALITY ASSURANCE REQUIREMENTS FOR THE DESIGN OF NUCLEAR POWER PLANTS (REVISION 2; 6/76)

Delete commitment. Regulatory Guide 1.64 has been withdrawn. The requirements of NQA-1-1994 Basic Requirement 3 and Supplementary Requirement 3S-1 are equivalent to the requirements of ANSI N45.2.11-1974 and Regulatory Guide 1.64.

3A.65 MATERIALS AND INSPECTIONS FOR REACTOR VESSEL CLOSURE STUDS (REVISION 0; 10/73)

The reactor vessel closure nuts and washers were procured after the issuance of Regulatory Guide 1.65 and as result are in compliance with the recommendations of this guide.

Regulatory Guide 1.65 was issued after the Virgil C. Summer Nuclear Station reactor vessel stud bolting material was procured. However, this material directly meets the major portions of the guide. The only exceptions are that a maximum tensile strength of 170,000 psi was not actually specified although achieved, and the calibration for the radial ultrasonic testing was established on each stud. Each point of compliance and the exceptions are discussed in detail as follows:

1. Bolting Materials

   The Virgil C. Summer Nuclear Station reactor vessel closure head studs were manufactured from SA-540 Grade B24 material. This material directly complies with Regulatory Position C.1.a of the guide.

   The tensile and Charpy-V-notch impact data for the stud bolt bar stock is as follows:

	Room Temperature Ultimate Tensile Strength (range)	Charpy V-notch Impact Test (range) Energy at 10 °F	Lateral Expansion
Stud bolt bar stock	156,000-163,150 psi	48-57 ft-lbs	27-35 mils

Although, as noted, a maximum tensile strength was not specified, the maximum measured ultimate tensile strength data do not exceed 170,000 psi and therefore meet the Guide Position C.1.b(1) tensile strength criterion. The Charpy V-Notch impact testing was performed according to the ASME SA-370 standard, and the actual results are in excess of 45 ft-lbs and 25 mils lateral expansion. The tests were performed at 10 °F rather than the higher temperatures allowed by Par. IV.A.4 of Appendix G to 10 CFR 50, since the tests were conducted to the ASME Code Section III addenda in effect at the time of procurement and prior to issuance of Appendix G of the Regulation. If tested at the allowed higher temperature, the impact energy requirements of 45 ft-lbs and 25 mils lateral expansion would have been met. The guide position C.1.b.(3) has also been met since the bolt materials are not plated and are lubricated according to the guide position.

2. Inspection

Review of the mill test data, ultrasonic testing specifications, and ultrasonic test procedures applicable to the Virgil C. Summer Nuclear Station reactor vessel stud bolting material indicates that the intent of the portion of the NRC Regulatory Guide 1.65, Section C.2, concerning ultrasonic testing has been met as described in the following:

The bolting materials were ultrasonically examined according to Westinghouse approved procedures which require that:

a. The 100% examination is conducted after heat treatment and prior to machining.
b. The material is scanned in both the radial and axial directions, per the ASME Code, Section III, Paragraphs NB-2584 and 2585, and ASME SA-388.
c. The calibration for the radial examination is based on a standard back reflection established in an indication-free area of each stud.
d. The calibration for the axial scan is based on a distance corrected reference level established on the responses from 3/8 in. diameter flat bottomed holes in a representative calibration block, per the ASME Code, Section III, Paragraph NB-2583.
e. The acceptance criteria for radial testing state that material containing discontinuities that produce an indication exceeding 20% of the calibration back reflection are unacceptable. For axial testing, material containing a discontinuity or discontinuities producing an indication or indications, equal to or greater than the primary distance amplitude curve reference line are unacceptable.

The above procedures comply with the guide recommendations except for procedure (c). In this case, the guide states that the calibration standard used to establish the first back reflection for the ultrasonic test should be based on sound representative material. The section of the standard should be based on a preliminary scan. Westinghouse believes that procedure (c) above is a more directly applicable procedure, and while not directly following the guide position, meets the intent of the guide.

Magnetic particle examination was performed on the studs and nuts after final heat treatment and threading per the ASME Code, Section III, Paragraph NB-2583.

3. Protection Against Corrosion

   During venting and filling of the pressure vessel and while the head is removed, Westinghouse procedures require that the stud bolts, nuts, and washers and stud bolt holes in the vessel flange are protected from corrosion and contamination. Section 5.4.2.2, and Section 5.4.4.4 thus meeting Position C.3 of the guide. Design of the reactor vessel studs, nuts, and washers, providing protection against corrosion by allowing them to be completely removed during each refueling and placed in storage racks on the containment operating deck, as required by Westinghouse refueling procedures. The stud holes in the flange are sealed with special plugs before removing the reactor closure. Thus, the bolting materials and stud holes are never exposed to the borated refueling cavity water.

4. Inservice Inspection

   The reactor vessel design permits inservice inspection per the Guide Position C.4 and as discussed further in Sections 5.4.4.4, and 5.7.1.

3A.66 NON-DESTRUCTIVE EXAMINATION OF TUBULAR PRODUCTS (REVISION 0; 10/73)

The NRC Staff has withdrawn this Regulatory Guide.

3A.67 INSTALLATION OF OVERPRESSURE PROTECTIVE DEVICES (REVISION 0; 10/73)

Safety and relief valves and associated piping and valve headers, within the scope of Regulatory Guide 1.67, installed at the Virgil C. Summer Nuclear Station have been designed, analyzed, and qualified in accordance with the recommendations of this guide.

3A.68 PREOPERATIONAL AND INITIAL STARTUP TEST PROGRAMS FOR WATER-COOLED POWER REACTORS (REVISION 0; 11/73)

The Virgil C. Summer Nuclear Station test programs comply with the recommendations of Regulatory Guide 1.68. A detailed discussion of the preoperational and initial startup test program is given in Chapter 14.

It should be noted that the Virgil C. Summer Nuclear Station plant computer does not perform any safety-related control or essential monitoring function nor is it required for the operation of the plant; therefore Item D.1.r of Appendix 3A is not applicable.

For Appendix item B.1.C. refer to Table 14.1-55 and Section 4.2.3.4.1. For Appendix C, item C, Fourth paragraph, use the following: Nuclear instruments should be calibrated. A neutron count rate (on the order of at least 1/2 counts per second) should register on startup channels before the startup begins, and the signal-to-noise ratio should be at least two. A conservative startup rate limit (no smaller than 30-seconds period) should be employed in obtaining low power. Power should be leveled after attaining criticality and before attaining sensible nuclear heat. Low-power testing should be performed at this level.

3A.68.2 INITIAL STARTUP TEST PROGRAM TO DEMONSTRATE REMOTE SHUTDOWN CAPABILITY FOR WATER-COOLED NUCLEAR POWER PLANTS (REVISION 1; 7/78)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.68.2. (See Table 14.1-79.)

3A.69 CONCRETE RADIATION SHIELDS FOR NUCLEAR POWER PLANTS (REVISION 0; 12/73)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.69 as follows:

The recommended practices contained in ANSI N101.6-1972, have been incorporated into Regulatory Guide 1.69. The ANSI standard directs itself first to the nuclear shielding aspects and secondly to structural design and construction of these shields. This standard puts special emphasis on the use of high density concrete. However, for the Virgil C. Summer Nuclear Station, normal density concrete has been used in shielding calculations. The structural design and construction of the concrete shield walls follows the standards and recommended practices in the ANSI standard.

3A.70 STANDARD FORMAT AND CONTENT OF SAFETY ANALYSIS REPORTS FOR NUCLEAR POWER PLANTS (REVISION 1; 10/72)

Per discussions held among the NRC Staff, Westinghouse, Gilbert, and SCE&G on March 12, 1976 this FSAR was prepared in accordance with an updated Revision 1 (October 1972) Format.

Requirements for additional information which have been issued either as Regulatory Guides, Series 1.70.x, or as Revision 2 (September, 1975) format, have been met subject to informational availability.

3A.71 WELDER QUALIFICATION FOR AREAS OF LIMITED ACCESSIBILITY (REVISION 0; 12/73)

The recommendations of Regulatory Guide 1.71 for limited accessibility qualification or requalification, in addition to ASME Code Sections III and IX requirements, is an unduly

restrictive requirement for shop fabrication, where the welder's physical position relative to the welds is controlled and does not present any significant problems. In addition, shop welds of limited accessibility are repetitive due to multiple production of similar components, and such welding is closely supervised.

Welding performed by Daniel (DDC) at the site is in accordance with the following:

Regulatory Position	Compliance
1	Determination of restricted access definitions done on case by case basis. Initial determination of obstructions within 12 to 14 inches for the purpose of potential access restriction identification is made and documented by a responsible QC inspector. The actual weld accessibility determination is made and documented by the Daniel welding engineer for each joint identified above. Such documentation includes the engineer's basis for each decision. When the weld is determined to actually qualify as a restricted access weld, then a qualified restricted access welder is used.
2.a	See above.
2.b	Procedures require Section IX compliance.
3	Production welding is monitored as necessary to assure requirements are satisfied.

3A.72 SPRAY POND PLASTIC PIPING (REVISION 0; 12/73)

Regulatory Guide 1.72 does not apply to the Virgil C. Summer Nuclear Station since the design does not incorporate plastic piping.

3A.73 QUALIFICATION TESTS OF ELECTRIC VALVE OPERATORS INSTALLED INSIDE THE CONTAINMENT OF NUCLEAR POWER PLANTS (REVISION 0; 1/74)

The Virgil C. Summer Nuclear Station complies with the recommendations Regulatory Guide 1.73 with the following clarifications:

For safety-related motor operated valves located inside containment, the recommendations of Regulatory Guide 1.73 with the exception that stem mounted limit switches are tested separately to the provisions of IEEE STD. 382-1972 are followed.

3A.74 QUALITY ASSURANCE TERMS AND DEFINITIONS (REVISION 0; 2/74)

Delete commitment. Regulatory Guide 1.74 has been withdrawn. With the adoption of NQA-1-1994 Part I "Introduction" defining terms and definitions, ANSI N45.2.10-1973 is no longer needed.

3A.75 PHYSICAL INDEPENDENCE OF ELECTRICAL SYSTEMS (REVISION 1; 1/75)

The Virgil C. Summer Nuclear Station design complies with the recommendations of Regulatory Guide 1.75 with the following clarifications:

1. The basis for physical separation is described in Section 8.3.1.4. Since issuance of the guide followed significant design completion of affected areas, Virgil C. Summer Nuclear Station will comply with Section 4.6.2 of IEEE 384-1974 by analysis as in alternative (1).

   a. A case-by-case analysis is described in Appendix 8C to demonstrate that circuits in a non-safety related tray that runs adjacent to a safety related tray will not degrade the separation levels between the circuits in the safety related tray and any redundant safety related circuits. Cases in which the adequacy of separation between a non-safety related tray and safety related tray(s) of a single channel cannot be demonstrated, will be separated by barriers as described in Appendix 8B.

   b. A separate analysis has been performed to identify cases of multiple violations where non-safety related cable trays do not meet the separation distance requirements between safety related cable trays of redundant channels in the same fire area. These cases were resolved by providing tray covers on some cable trays or assigning the circuit breaker protective devices of some cables to a controlled breaker surveillance program. Refer to FSAR Section 8.3.1.4.1, item 4 for details.

2. Regulatory Guide Position C.1, "Interruption devices actuated by fault current are not considered to be isolation devices." This policy is contrary to basic functional design bases.

   When non-safety related loads are fed from safety related buses, the following criteria apply to the Virgil C. Summer Nuclear Station design:

   a. 7200 volt and 480 volt switchgear - Non-Safety loads are automatically tripped upon receipt of an SI or undervoltage signal. The only exception to this is the supplies to the Technical Support Center which are provided with Class 1E circuit breakers and current limiting fuses for isolation through redundant diverse devices.

   b. Motor Control Centers - Isolation for Non-Safety loads is accomplished with the use of two diverse, Class 1E overcurrent protective devices in series or by load shedding where the contactor is controlled by an SI or undervoltage signal. Class 1E overcurrent devices include I-limiter thermal magnetic breakers, current limiting fuses, and magnetic breakers combined with starter thermal overloads.

c. Vital Distribution Panels and Class 1E DC System Distribution Panels - Isolation is accomplished with the use of a thermal magnetic breaker in series with a current limiting fuse. Both of these devices have been qualified for Class 1E application. This also provides diverse redundant isolation capability.

The diesel generator, batteries, and inverters have been sized to include these loads so there would be no concern for diesel generator, batteries, or inverter degradation. This design was incorporated to prevent the automatic loss of non-safety systems such as: Radiation Monitoring, Security, Heat Tracing, Annunciator Panels, Leak Detection Annunciation, Rod Position Indication, Control Room Lighting, and the power for the Technical Support Center.

Current limiting devices were included in the design to accommodate the Regulatory Guide's concern with the use of fault current actuated isolation devices.

Details of the electrical system physical independence and identification are discussed in Sections 8.3.1.4, 8.3.1.5 and in GAI - "Construction Guideline for Electrical Circuit Physical Separation" (Drawing S-200-926).

3A.76 DESIGN BASIS TORNADO FOR NUCLEAR POWER PLANTS (REVISION 0; 4/74)

The Virgil C. Summer Nuclear Station meets the recommendations of Regulatory Guide 1.76 as discussed in Section 3.3.2.

3A.77 ASSUMPTION USED FOR EVALUATING A CONTROL ROD EJECTION ACCIDENT FOR PRESSURIZED WATER REACTORS (REVISION 0; 5/74)

Virgil C. Summer Nuclear Station meets the recommendations of this guide as discussed in WCAP-7588, Revision 1, "An Evaluation of the Rod Ejection Accident in Westinghouse PWRs Using Spatial Kinetics Methods," which received Regulatory Staff approval in August 1973 and Section 15.4. Doses for the Control Rod Ejection Accident are evaluated in accordance with Regulatory Guide 1.183.

3A.78 ASSUMPTIONS FOR EVALUATING THE HABITABILITY OF A NUCLEAR POWER PLANT CONTROL ROOM DURING A POSTULATED HAZARDOUS CHEMICAL RELEASE (REVISION 0; 6/74)

Consideration has been given to possible accidents involving hazardous chemicals in the vicinity of Virgil C. Summer Nuclear Station control room. These accidents are discussed in Sections 2.2 and 6.4. The threat to control room operators from hazardous chemicals is minimal; however, Virgil C. Summer Nuclear Station provides self-contained breathing apparatus of at least one-half hour capacity for each control room operator.

3A.79 PREOPERATIONAL TESTING OF EMERGENCY CORE COOLING SYSTEMS FOR PRESSURIZED WATER REACTORS (REVISION 1; 9/75)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.79 with the following exceptions and clarifications.

Integrated system verification tests are accomplished by simulating a safety injection signal concurrent with a loss of offsite power in one safety train. However, valves which if operated would have a detrimental effect on the subsequent commissioning of the plant are blocked from operation. Similarly, where full flow conditions cannot be achieved, pumps may be operated on minimum flow or bypass conditions.

3A.80 PRE-OPERATIONAL TESTING OF INSTRUMENT AIR SYSTEMS (REVISION 0; 6/74)

Based on the fact that the failure mode of pneumatic devices from loss of air has been systematically designed to be in the preferred (safe) position, the instrument air system is not classified as being safety-related, therefore, Regulatory Guide 1.80 does not apply. Testing is performed to verify that operation of the instrument air system is consistent with instrument air system requirements described in Section 9.3.1.

3A.81 SHARED EMERGENCY AND SHUTDOWN ELECTRIC SYSTEMS FOR MULTI-UNIT NUCLEAR POWER PLANTS (REVISION 1; 1/75)

This Regulatory Guide is not applicable to the Virgil C. Summer Nuclear Station since the Virgil C. Summer Nuclear Station is not a multi-unit facility.

3A.82 SUMPS FOR EMERGENCY CORE COOLING AND CONTAINMENT SPRAY SYSTEMS (REVISION 0; 6/74)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.82 with the following clarifications.

The design of redundant Reactor Building recirculation sumps is discussed in Section 6.2.2.

As shown by Figure 3.8-17, the design of the recirculation sumps includes specific features for minimizing the potential for clogging of the screens. These design features include the following:

1. An outer trash rack to protect the fine screens from large pieces of debris.
2. The vertical orientation of the fine screens.
3. The establishment of low velocity settling areas for each of the four individual deep sumps.

The first low velocity settling area is established at the entrance to the 1/2 inch mesh screens by directing the downward flow path around each 6 foot by 6 foot standpipe to horizontal flow through the 1/2 inch screens. Based upon the available flow area around each 6 foot by 6 foot standpipe and the RHR pump design flow rate of 3750 gpm, the calculated fluid velocity at the entrance to the 1/2 inch mesh screens is 0.156 ft/sec.

The second low velocity settling area is provided between the 1/2 inch mesh screens and the 1/4 inch mesh screens. The location of the vertically mounted 1/4 inch mesh screens results in an upward flow path between the 1/2 inch and 1/4 inch mesh screens with the two required changes in flow direction to obtain horizontal flow through both sets of screens. Based upon the flow area between the screens and the RHR pump design flow rate (3750 gpm), the calculated fluid velocity in this second low velocity settling area is 0.42 ft/sec.

The total amount of fine screen in each recirculation sump standpipe provides enough total free area to ensure that the resultant pressure drop has no appreciable effect on the net positive suction head available to each RHR pump. For the postulated condition of partially clogged screens, the total pressure drop was conservatively calculated using only half of the free area of the screens. This calculated pressure drop for flow through both sets of screens is 0.2 feet for the RHR pump design flow rate of 3750 gpm. This pressure drop represents a reduction of only 0.77% in the net positive suction head available to the RHR pumps.

Additional features incorporated into the plant design to minimize clogging of the sumps are as follows:

1. Use of insulation described under Regulatory Guide 1.36 for equipment and piping inside the Reactor Building.
2. Use of coating systems as described under Regulatory Guide 1.54 for carbon steel and concrete surfaces.

3A.83 INSERVICE INSPECTION OF PRESSURIZED WATER REACTOR STEAM GENERATOR TUBES (REVISION 1; 7/75)

Originally, Virgil C. Summer Nuclear Station complied with the recommendations of Regulatory Guide 1.83 with exceptions for its in-service inspections of the steam generators. However, the NRC now endorses a more risk informed and performance-based approach to regulatory compliance and has withdrawn Regulatory Guide 1.83. VCSNS has adopted this approach by implementing the requirements of Technical Specifications 3/4.4.5, “Steam Generator Tube Integrity,” and 6.8.4.k, “Steam Generator Program.” These technical specifications are based on Nuclear Energy Institute (NEI) 97-06, “Steam Generator Program Guidelines,” and TSTF-449.

3A.84 DESIGN, FABRICATION, AND MATERIALS, CODE CASE ACCEPTABILITY, ASME SECTION III (LATEST REVISON PER 10 CFR 50.55A)

Regulatory Guides 1.84 and 1.85 (first effective date: July 1, 1974) were issued long after the issuance of the Construction Permit for the Virgil C. Summer Nuclear Station. Only ASME approved Code Cases are used for Code Class 1, 2, and 3 components. For Class 1 components, a discussion of Code Cases is contained in Section 5.2.1.4. AEC (NRC) approval of Code Cases for Class 2 and 3 components was not required and not obtained. After the regulatory guides' first effective date, Code Cases were reviewed against those specified in these regulatory guides.

The NRC staff reviews ASME BPV Section Ill Code Cases, rules upon the acceptability of each Code Case and publishes its findings in regulatory guides. The regulatory guides are revised periodically as new Code Cases are published by the ASME. The NRC incorporates by reference the regulatory guides listing acceptable and conditionally acceptable ASME Code Cases in 10 CFR 50.55a. The latest edition of 10 CFR 50.55a is available on the NRC's Public Web site. Licensees may use these Code Cases without requesting authorization from the NRC, provided that they are used with any identified limitation or condition.

3A.85 CODE CASE ACCEPTABILITY ASME SECTION III MATERIALS

(Withdrawn 06/2004) Materials Code Case Acceptability - ASME Section III, Division 1 (Guidance incorporated into Revision 32 of Regulatory Guide 1.84, published 06/03).

3A.86 TERMINATION OF OPERATING LICENSES FOR NUCLEAR REACTORS (REVISION 0; 6/74)

The termination of the operating license and subsequent decommissioning of the Virgil C. Summer Nuclear Station will be in accordance with regulations in effect at that time.

3A.87 CONSTRUCTION OF CLASS 1 COMPONENTS IN ELEVATED TEMPERATURE REACTORS (SUPPLEMENT TO ASME SECTION III CODE CASES 1592, 1593, 1594, 1595, 1596) (REVISION 1; 6/75)

Regulatory Guide 1.87 does not apply to the Virgil C. Summer Nuclear Station.

3A.88 COLLECTION, STORAGE, AND MAINTENANCE OF NUCLEAR POWER PLANT QUALITY ASSURANCE RECORDS (REVISION 2; 10/76)

Delete commitment. Regulatory Guide 1.88 has been withdrawn. The adoption of NQA-1-1994 Basic Requirement 17, Supplementary Requirement 17S-1, and commitment to Regulatory Guide 1.28, Revision 3, Regulatory Position C.2, contain the requirements for quality assurance records and replaces ANSI N45.2.9-1974 and Regulatory Guide 1.88.

3A.89 QUALIFICATION OF CLASS 1E EQUIPMENT FOR NUCLEAR POWER PLANTS (REVISION 0; 11/74)

Engineering design of the Virgil C. Summer Nuclear Station (VCSNS) was commenced and construction permit was granted prior to the issuance of Regulatory Guide 1.89. Therefore, the guidance of IEEE-323-1971 was used as the principal document in formulating the original environmental qualification programs for Class 1E equipment used in the Virgil C. Summer Nuclear Station.

NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment” was issued in November of 1979 to provide the NRC staff positions regarding selected areas of environmental qualification of safety-related electrical equipment for plants committed to satisfy the requirements set forth in either the 1971 or 1974 version of the IEEE 323 standard.

Environmental qualification of safety-related electrical equipment purchased under the NSSS scope was based on the requirements of IEEE 323-1971 and the supplemental qualification program described in NS-CE-692 (7/10/75) from C. Eicheldinger to D. B. Vassallo of the Nuclear Regulatory Commission.

Environmental qualification of safety-related electrical equipment purchased under the BOP scope was based on the requirements of IEEE 323-1971 or IEEE 323-1974 and ancillary daughter standards (e.g., IEEE Stds. 317, 334, 382, 383) in accordance with the guidance provided by NUREG-0588. Environmental qualification of BOP electrical equipment was performed in accordance with NUREG-0588, Cat. II, which relates to IEEE 323-1971 for the original plant design. However, some equipment was qualified to IEEE 323-1974 (NUREG 0588, Cat. I) requirements. New and replacement electrical equipment is governed by the current regulations of 10 CFR 50.49 and the methodology described in Regulatory Guide 1.89 (Revision 1; 6/84).

In cases where qualification has been done to later revisions of the IEEE Standards, documentation of that qualification is maintained. The status of electrical qualification in accordance with the applicable IEEE Standards and Regulatory requirements is documented in VCSNS Equipment Qualification Documentation Packages (EQDP’s) for equipment requiring harsh qualification and Equipment Qualifications Files (EQF’s) for equipment requiring mild qualification. Refer to Section 3.11 for further discussion. However, 10 CFR 50.49 does not require safety-related electrical equipment located in mild environments to be qualified by test and/or analysis. Thus, electrical equipment requiring mild environmental qualification is considered qualified if it meets the requirements of Generic Letter 82-09, Item 4, and any applicable IEEE Standards.

3A.90 INSERVICE INSPECTION OF PRE-STRESSED CONCRETE CONTAINMENT STRUCTURES WITH GROUTED TENDONS (REVISION 0; 11/74)

Regulatory Guide 1.90 is not applicable to the Virgil C. Summer Nuclear Station since the tendons are greased not grouted.

3A.91 EVALUATION OF EXPLOSIONS POSTULATED TO OCCUR ON TRANSPORTATION ROUTES NEAR NUCLEAR POWER PLANT SITES (REVISION 0; 1/75)

While not applicable to the Virgil C. Summer Nuclear Station due to implementation date requirements, the recommendations of Regulatory Guide 1.91 are met due to distance factors and relative explosive proximity.

3A.92 COMBINING MODAL RESPONSES AND SPATIAL COMPONENTS IN SEISMIC RESPONSE ANALYSIS (REVISION 1; 2/76)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.92 and is discussed in Section 3.7.2.

3A.93 AVAILABILITY OF ELECTRIC POWER SOURCES (REVISION 0; 12/74)

This guide is not directly applicable to the Virgil C. Summer Nuclear Station since the regulatory guide implementation date postdates Construction Permit SER issuance date, August 1972 for the Virgil C. Summer Nuclear Station.

The available sources of power are discussed in Chapter 8 and the affect on plant operation is discussed in the Technical Specifications and the station operating procedures.

3A.94 QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION, AND TESTING OF STRUCTURAL CONCRETE AND STRUCTURAL STEEL DURING THE CONSTRUCTION PHASE OF NUCLEAR POWER PLANTS (REVISION 1; 4/76)

Delete commitment. The Virgil C. Summer Nuclear Station commitment to Regulatory Guide 1.94 is no longer required with the adoption of NQA-1-1994 Subpart 2.5. NQA-1-1994 Subpart 2.5 is equivalent to the requirements of ANSI N45.2.5-1974.

3A.95 PROTECTION OF NUCLEAR POWER PLANT CONTROL ROOM OPERATORS AGAINST AN ACCIDENTAL CHLORINE RELEASE (REVISION 0; 2/75)

The Virgil C. Summer Nuclear Station complies with Regulatory Guide 1.95. Compliance with Section C.2 is currently ensured through the onsite storage of chlorine in amounts less than 150 lbs. per tank. Should per tank storage in amounts in excess of 150 lbs. become necessary, the pertinent regulatory guide recommendations will be re-evaluated. Accidental chlorine release is discussed further in Sections 2.2 and 6.4.

3A.96 DESIGN OF MAIN STEAM ISOLATION VALVE LEAKAGE CONTROL SYSTEMS FOR BOILING WATER REACTORS NUCLEAR POWER PLANTS (REVISION 1; 6/76)

Regulatory Guide 1.96 is not applicable to the Virgil C. Summer Nuclear Station since it uses a PWR.

3A.97 INSTRUMENTATION FOR LIGHT-WATER COOLED NUCLEAR POWER PLANTS TO ASSESS PLANT CONDITIONS DURING AND FOLLOWING AN ACCIDENT (REVISION 3; 12/83)

The Virgil C. Summer Nuclear Station meets the intent of Regulatory Guide 1.97, Revision 3. Specific details concerning Regulatory Guide 1.97 related instrumentation are provided in Section 7.5.

3A.98 ASSUMPTIONS USED FOR EVALUATING THE POTENTIAL RADIOLOGICAL CONSEQUENCES OF A RADIOACTIVE OFFGAS SYSTEM FAILURE IN A BOILING WATER REACTOR (REVISION 0; FOR COMMENT; 3/76)

Regulatory Guide 1.98 is not applicable to the Virgil C. Summer Nuclear Station since it uses a PWR.

3A.99 RADIATION EMBRITTLEMENT OF REACTOR VESSEL MATERIALS (REVISION 2; 5/88)

Regulatory Guide 1.99 is used to predict the effect of neutron radiation on reactor vessel materials to support implementation of Appendix G of 10 CFR Part 50.

3A.100 SEISMIC QUALIFICATION OF ELECTRIC EQUIPMENT FOR NUCLEAR POWER PLANTS (REVISION 0; FOR COMMENT; 3/76)

Regulatory Guide 1.100 is not applicable to Virgil C. Summer Nuclear Station due to the regulatory guide implementation date.

Although Virgil C. Summer Nuclear Station is not committed to the requirements of IEEE 344-1975 for seismic equipment qualification (SEQ), it was recognized by the Nuclear Regulatory Commission (Reference SER Supplement 4, paragraph 3.10; August 1982) that the SEQ program met the requirements and recommendations of IEEE 344-1975 and the regulatory positions of Regulatory Guide 1.100. As such, Virgil C. Summer Nuclear Station has maintained a SEQ program which is in general conformance with IEEE 344-1975 and Regulatory Guide 1.100.

Seismic design of Category I instrumentation and electrical equipment is discussed in Section 3.10.

Revision 3-2009 of this Regulatory Guide is utilized by Westinghouse in the design and fabrication of the Replacement Reactor Vessel Closure Head as noted in the Design Specification.

3A.101 EMERGENCY PLANNING FOR NUCLEAR POWER PLANTS (REVISION 0; FOR COMMENT; 11/75)

Regulatory Guide 1.101 was used as a guide in developing the contents of the Virgil C. Summer Nuclear Station Emergency Plan. For further information, see Section 13.3 and the "Virgil C. Summer Nuclear Station Emergency Plan."

By NRC letter from Mr. R. B Minogue, Director, Office of Standards Development, on September 24, 1980 this regulatory guide was withdrawn.

3A.102 FLOOD PROTECTION FOR NUCLEAR POWER PLANTS (REVISION 0; FOR COMMENT; 10/75)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.102 as described in Sections 2.4, 3.4, and Technical Specifications.

3A.103 POST-TENSIONED PRE-STRESSING SYSTEMS FOR CONCRETE REACTOR VESSELS AND CONTAINMENTS (REVISION 0; FOR COMMENT; 11/75)

Regulatory Guide 1.103 has been withdrawn per NRC letter of July 8, 1981. However, the Virgil C. Summer Nuclear Station still complies with the recommendations of Regulatory Guide 1.103 as issued for comments and is discussed in Section 3.8.1.

3A.104 OVERHEAD CRANE HANDLING SYSTEMS FOR NUCLEAR POWER PLANTS (REVISION 0; FOR COMMENT; 2/76)

Regulatory Guide 1.104 was issued by the NRC For Comment in February 1976, and was Withdrawn by the NRC on July 27, 1981 and replaced by NUREG-0554, "Single-Failure-Proof Cranes for Nuclear Power Plants".

3A.105 INSTRUMENT SPANS AND SETPOINTS (REVISION 0; FOR COMMENT; 11/75)

The Virgil C. Summer Nuclear Station received its construction permit before the July 1, 1976 implementation date for Regulatory Guide 1.105. For this reason, the guide is not applicable to the Virgil C. Summer Nuclear Station.

South Carolina Electric and Gas Company concurs with the following comments made by Westinghouse on the "For Comment" issue of Regulatory Guide 1.105.

Detailed information on instrument spans and setpoints are included in the Technical Specifications.

Regulatory Guide 1.105, being circulated by the NRC for comments, is unduly restrictive for the allowable range of setpoint settings of the instrument span. Westinghouse will take exception to this guide in several areas as discussed below.

1. Item B, fourth paragraph: Westinghouse proposes to change "expected vibration and minor calibration variations" to "and environmental conditions."
2. Item C.1 is not consistent with current Westinghouse practice in determining setpoints. Currently, the inaccuracy of the instrument and the calibration uncertainty in measuring a parameter exclusive of allowances for instrument and setpoint drift are accounted for by the difference between the Technical Specification setpoint limit and the value of a parameter at which protective action is assumed to be initiated in the accident analyses. The difference between the setpoint and the Technical Specification setpoint limit is used to account for instrument and setpoint drift. Refer to Comment 8.
3. Item C.2 is unduly restrictive for the allowable range of setpoint settings which could only result in an unnecessary increase of the instrument range and corresponding decrease of the measurement accuracy, without benefit to safety. Item C.2 should be reworded as below.

   "The designer shall verify that the accuracy attainable at the chosen setpoint settings is adequate to meet the requirements of the safety analysis. In general, the setpoints should fall between 5% and 95% of the calibrated span of the instrument except for flow measurements based on differential pressure which should be between 25% and 95% of the calibrated span."
4. Item C.3: The range of the instrument should be based on the span required for safety, i.e., Item C.3 should not be interpreted to rule out narrow range transmitter. Nor should Item C.3 be interpreted as implying the instrument must work after the accident if it is not needed for a safety-related function.
5. Item C.4: Westinghouse recommends to delete the sentence beginning, "The instruments should not anneal...." Anything of this nature should be covered by the next sentence which references qualification programs.
6. Item C.5: Administrative procedures coupled with the present cabinet alarms and/or locks provide sufficient control over the setpoint adjustment mechanism such that no integral setpoint locking device should be required.
7. Item C.6: Westinghouse recommends to make changes as below.

   The assumptions used in selecting the setpoint values in Regulatory Position C.1, and the minimum margin with respect to the limiting safety system settings, calibration uncertainty, and instrument channel drift should be documented.

8. In the present NRC Standard Technical Specifications, the nominal instrument trip setpoints and allowable trip settings are listed in the tables. The allowable trip settings are provided for instrument and setpoint drift. The NRC should revise Section B, the fourth paragraph.

An additional comment on Item C.2 is: For setpoints that function only to alarm instrumentation or instrument power failure, the minimum setpoint of 5% or 25% or the maximum setpoint of 95% should not apply.

3A.106 THERMAL OVERLOAD PROTECTION FOR ELECTRIC MOTORS ON MOTOR OPERATED VALVES (REVISION 0; FOR COMMENT; 11/75)

The Virgil C. Summer Nuclear Station design complies with the recommendations of Regulatory Guide 1.106 in that motor operated valves operated by a safety injection signal in the event of a LOCA have their respective thermal overload protection devices bypassed by the same safety injection signal contact that initiates the valve operation. Valves that are not operated by a safety injection signal do not have this feature.

3A.107 QUALIFICATION FOR CEMENT GROUTING FOR PRE-STRESSING TENDONS IN CONTAINMENT STRUCTURES (REVISION 0; FOR COMMENT; 11/75)

This regulatory guide does not apply to the Virgil C. Summer Nuclear Station since the tendon system is not cement grouted.

3A.108 PERIODIC TESTING OF DIESEL GENERATOR UNITS USED AS ONSITE ELECTRIC POWER SYSTEMS AT NUCLEAR POWER PLANTS (REVISION 1; 8/77, INCLUDING ERRATA SHEET DATED 9/77)

In response to question 423.36 the Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.108 positions C.2.a and C.2.b with the following clarification:

Item C.2(a)7 - The design of the Virgil C. Summer Nuclear Station Diesel Generator Fuel Oil System is such that each diesel generator has its own fuel oil system, each of which must meet the seven day storage requirement. Therefore, this item is not applicable.

Additionally, as of the effective date of Technical Specification Amendment 139 (March 30, 1998), the Virgil C. Summer Station takes exception the following provisions of Regulatory Guide 1.108:

- Reliability demonstration per Regulatory Position C.2.a.(9) - Reliability of the V. C. Summer Emergency Diesel Generators is monitored and ensured by the provisions of 10 CFR 50.65

(Maintenance Rule) and Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

- Accelerated testing provisions of Regulatory Position C.2.d. - Accelerated testing, as a means of demonstrating reliability was removed from the Technical Specifications in accordance with Generic Letter 94-01. Monitoring the effectiveness of Emergency Diesel Generator maintenance and demonstrating reliability is governed by the provisions of 10 CFR 50.65 and Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

- Reporting requirements of Regulatory Position C.3.b - The 30 day Special Report requirement was removed from the Technical Specifications in accordance with Generic Letter 94-01. Reporting EDG performance problems is governed by the provisions of 10 CFR 50.72, "Immediate Reporting Requirements of Operating Nuclear Power Reactors" and 10 CFR 50.73, "Licensee Event Report System."

3A.109 CALCULATION OF ANNUAL DOSES TO MAN FROM ROUTINE RELEASES OF REACTOR EFFLUENTS FOR THE PURPOSE OF EVALUATING COMPLIANCE WITH 10 CFR, PART 50, APPENDIX I (REVISION 0; FOR COMMENT; 3/76)

The Virgil C. Summer Nuclear Station complies with the methodology and calculational procedures set forth in Regulatory Guide 1.109 as discussed in Chapter 11.

Pursuant to the September 4, 1975 annex to Appendix I of 10 CFR 50, no cost benefit analysis is required or warranted.

3A.110 COSTS-BENEFIT ANALYSIS FOR RADWASTE SYSTEMS FOR LIGHT-WATER-COOLED NUCLEAR POWER REACTORS (REVISION 0; FOR COMMENT; 3/76)

Section D of the "For Comment" version of Regulatory Guide 1.110 provides for implementation of the guide in the evaluation of construction permit applications docketed after June 4, 1976, and thus this guidance is not applicable to the Virgil C. Summer Nuclear Station Operating License Application.

At the time of issuance of the Virgil C. Summer Nuclear Station Construction Permit, NRC evaluations of "as low as practicable" used the then proposed "staff" Appendix I and as indicated in the NRC's FES; therefore, requirements of the present Appendix I as amended are met.

Further detailed descriptions of equipment for the control of gaseous and liquid effluent are included in Chapter 11. Procedures for control of gaseous and liquid effluents and for the maintenance and use of equipment installed in radioactive waste systems are included in the Virgil C. Summer Nuclear Station Operating Procedures.

3A.111 METHODS FOR ESTIMATING ATMOSPHERIC TRANSPORT AND DISPERSION OF GASEOUS EFFLUENTS IN ROUTINE RELEASES FROM LIGHT WATER COOLED REACTORS (REVISION 0; FOR COMMENT; 3/76)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.111 as indicated in Section 2.3.

3A.112 CALCULATION OF RELEASES OF RADIOACTIVE MATERIALS IN GASEOUS AND LIQUID EFFLUENTS FROM LIGHT WATER COOLED POWER REACTORS (REVISION 0; FOR COMMENT; 4/76)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.112 as discussed in Chapter 11.

3A.113 ESTIMATING AQUATIC DISPERSION OF EFFLUENTS FROM ACCIDENTAL AND ROUTINE REACTOR RELEASES FOR THE PURPOSE OF IMPLEMENTING APPENDIX I (REVISION 0; FOR COMMENT; 5/76)

The implementation date for Regulatory Guide 1.113; “For Comment” version, is after the issuance date of the Virgil C. Summer Nuclear Station Construction Permit and is not applicable for this reason. However, aquatic dispersion of effluents is addressed in Section 11.2.

3A.114 GUIDANCE ON BEING OPERATOR AT THE CONTROLS OF A NUCLEAR POWER PLANT (REVISION 0; 2/76)

The Virgil C. Summer Nuclear Station operators will follow the guidance presented in Regulatory Guide 1.114.

3A.115 PROTECTION AGAINST LOW TRAJECTORY TURBINE MISSILES (REVISION 0; FOR COMMENT; 3/76)

Current and historical turbine missile analyses are documented within VCSNS Technical Report TR03880-002. This report demonstrates that the hazard presented to an essential system or target from low trajectory turbine missiles is less than 10-8/year, and that based on the single piece monoblock rotor there is no longer any wheel disc integrity concern.

3A.116 QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION, AND TESTING OF MECHANICAL EQUIPMENT

ANDSYSTEMS (REVISION 0-R; 6/76)

Delete commitment. The Virgil C. Summer Nuclear Station commitment to Regulatory Guide 1.116 is no longer required with the adoption of NQA-1-1994 Subpart 2.8. NQA-1-1994 Subpart 2.8 is equivalent to the requirements of ANSI N45.2.8-1975.

3A.117 TORNADO DESIGN CLASSIFICATION (REVISION 0; FOR COMMENT; 6/76)

This guide is not applicable due to its implementation date. However, structures, systems, and components are constructed and/or protected against the design basis tornado (Regulatory Guide 1.76) and the resulting postulated missiles to ensure that (1) the plant can be safely shutdown and maintained in a safe condition (2) doses from the postulated related failures will be within acceptable limits. Tornado missile protection is presently being included for ESF equipment. For other equipment, where it is impractical due to present building design and layout, probability analysis is utilized to indicate conservatism. The Reactor Building has been designed to withstand the design basis tornado and the control room vents are provided with a tornado missile shield.

Design features utilized include redundancy, separation, barriers, or probability considerations (see Regulatory Guides 1.76 and 1.12).

3A.118 PERIODIC TESTING OF ELECTRIC POWER AND PROTECTION SYSTEMS (REVISION 0; 6/76)

Section 7.1.2.11 outlines the provisions for dealing with periodic testing of electric power and protection systems in conformance with IEEE 338-1971. Chapter 14.0 outlines preoperational testing. Regulatory Guide 1.118 supplements IEEE 338-1975. Therefore, Regulatory Guide 1.118 is considered not applicable to the Virgil C. Summer Nuclear Station.

3A.121 BASES FOR PLUGGING DEGRADED PWR STEAM GENERATOR TUBES (REVISION 0; 8/76)

Section XI, Subsection IWB-3521.1 of the ASME Code requires steam generator tube plugging or repair when a defect has penetrated 40% through the tube wall for tubes with a r/t ratio of > 8.70, and does not address specific degradation modes. RG 1.121(draft) has been used as the basis for establishing tubing operability limits for specific degradation modes. While the Alloy 690 tubing in the Delta-75 steam generators are not expected to experience service related degradation, RG 1.121 can be used to assess the operability of specific non-destructive examination indications. The U. S. NRC has claimed that RG 1.121 forms the basis for the current Standard Technical Specifications steam generator tube plugging limit, however, detailed analyses performed by Westinghouse have routinely established acceptable defect depths in excess of 40% throughwall (with eddy current uncertainty applied). The U. S. NRC has never accepted these alternate depth based analyses, with the exception of a few case by case submittals (such as pitting degradation at Indian Point Unit 2) applied to a limited number of tubes.

3A.123 QUALITY ASSURANCE REQUIREMENTS FOR CONTROL OF PROCUREMENT OF ITEMS AND SERVICES FOR NUCLEAR POWER PLANTS (REVISION 1; 7/77)

Delete commitment. Regulatory Guide 1.123 has been withdrawn. NQA-1-1994 Basic Requirement 7 and Supplementary Requirement 7S-1 replaces the commitment to Regulatory Guide 1.123 and ANSI N45.2.13-1976.

3A.137 FUEL OIL SYSTEMS FOR STANDBY DIESEL GENERATORS (REVISION 1; 10/79)

The Virgil C. Summer Nuclear Station complies with the recommendations of Regulatory Guide 1.137 as discussed below:

Regulatory Position	Compliance
C.1.a	Responses to separate regulatory guides are found in Appendix 3A. Commission regulations are addressed individually, as required by the regulation.
C.1.b	The Diesel Generator Fuel Oil System quality assurance meets the recommendations of Regulatory Guide 1.28, as discussed in Appendix 3A.
C.1.c	The fuel oil storage capacity requirements were calculated in accordance with the ANSI N195-1976 time dependent load method except the margin for Mode 1-4 for fuel inventory is 2% vs. the 10% margin indicated in ANSI N195-1976. The time dependent loads are bounded by those identified in Table 8.3-3.
C.1.d	The diesel manufacturer’s criteria for locating the day tanks is to permit gravity drainage of excess fuel oil from the injectors. The engine driven and backup motor driven fuel oil pumps are gear type positive displacement pumps with suction lift capability. The day tank location provides adequate net positive suction head to the pumps.
C.1.e	Preservice and inservice inspection of the Diesel Generator Fuel Oil System will be performed in accordance with ASME Code Section XI.
C.1.f	Since no provisions have been made for heating of the fuel oil system, assurance that fuel oil will be supplied and ignited under the most severe environmental conditions expected at the site will be accomplished by conformance to the “Cloud Point” specifications.

Regulatory Position	Compliance
C.1.g	The buried fuel oil piping is coal tar enameled and felt wrapped in accordance with AWWA C-203. Insulating flanges are provided between buried piping and indoor piping. The buried fuel oil storage tanks are external coated with coal tar epoxy. The buried piping and tanks are provided with cathodic protection and the necessary corrosion test facilities.
C.1.h	The fire protection for the diesel generator is discussed in Section 9.2-3 and in the Fire Protection (FP) DBD.
C.2.a	Diesel generator fuel oil is procured to an appropriate version of ASTM D975 to ensure the operability of the diesel generator and at a minimum meets the requirements of ASTM D975-81, “Standard Specification For Diesel Fuel Oils.”
C.2.b	Prior to adding oil to the supply tank, a sample is taken and analyzed for 1) specific or API gravity, 2) clear and bright appearance (water and sediment), 3) kinematic viscosity at 40°C, and 4) flash point. Samples are also taken and analyzed for the remaining properties in ASTM D975-81, with results available within 30 days.
C.2.c	Sampling is performed manually in accordance with ASTM-D4057-81.
C.2.d, .e	Provisions have been incorporated into system design to provide for water removal and pipe flushing. Operational procedures will comply with the recommendations of the regulatory guide.
C.2.f	Provisions have been incorporated into system design to provide for removal of fuel oil from the storage tanks. Operational procedures will comply with the recommendations of the regulatory guide.
C.2.g	No special design provisions have been provided to minimize turbulence of accumulated sediment in the bottom of the storage tank during filling. However, the fuel oil storage tank filling system features a filter/water separator which will help minimize the quantity of sediment in the bottom of the tank.
C.2.h	Refer to C.1.g. Appropriate surveillance procedures will be established, if required.

3A.143 DESIGN GUIDANCE FOR RADIOACTIVE WASTE MANAGEMENT SYSTEMS, STRUCTURES, AND COMPONENTS INSTALLED IN LIGHT-WATER COOLED NUCLEAR POWER PLANTS

The radioactive waste treatment and disposal systems at Virgil C. Summer were constructed to comply with the August 1970 Draft of ANSI N18.2 which in most cases is more restrictive than the guidelines of Regulatory Guide 1.143.

The intent of Regulatory Guide 1.143 is met by our systems. Future equipment procurement and modifications will meet or exceed the quality and code requirements of the Regulatory Guide. Specific exceptions to the provisions of 1.143 are as follows:

1. Discussion Section B

   The Boron Recycle System is reclassified to Non-Nuclear Safety grade and future equipment procurement and modifications will meet or exceed the code and quality requirements of Regulatory Guide 1.143. The basis for this reclassification is that this system is similar in function and design to the Liquid Waste Processing System. Accordingly, it can be considered in the same manner as the Liquid Waste Processing System in determining the appropriate safety classification. Support for this viewpoint is provided by the NRC's approval of a non-nuclear safety grade Boron Recycle System as documented in their safety evaluation report (NUREG-0491) on RESAR-414.

2. Position C 1.1.3

   Foundations and walls of structures that house the Liquid Radwaste System are designed to the seismic criteria as described in FSAR Section 3.7.

3. Position C 1.2

   The design features to prevent uncontrolled releases of radioactive materials due to spillage in buildings or from outdoor tanks are in accordance with ANSI N18.2-1973 (Section 5.6.4). In most cases curbs or elevated thresholds with floor drains routed to the liquid radwaste treatment system have been utilized.

4. Position C 2.1.3

   Portions of the Gaseous Radwaste System that are intended to store or delay the release of gaseous radioactive waste, including portions of structures housing these systems are designed to the seismic criteria as described in FSAR Section 3.7.

5. Position C 3.1.3

Vendor supplied portable solid radwaste treatment systems will be located inside the Auxiliary Building which is designed to the seismic criteria as described in FSAR Section 3.7. Vendor supplied mobile solid radwaste treatment systems will be located in an area designed to prevent uncontrolled releases due to accidental spillage during processing in accordance with ANSI N18.2-1973 (Section 5.6.4).

6. Position C 5

   The applicable seismic design is described in FSAR Section 3.7.

7. Position C 6, "4.2.3.1(1)"

   Procurement documents shall be independently verified for conformance to the requirements of Regulatory Guide 1.143 by the individual(s) within the quality assurance organization.

8. As an alternate to ANSI B31.1 which covers piping and valves, ASME Section VIII may be substituted for the design of pressure relief valve arrangements. This option is based on the interpretation that ASME Section VIII code boundary may be extended up to and including the stop valve and relief valve as a part of the pressure vessel design. The stop valve itself, is covered by ANSI B31.1 since ASME Section VIII does not cover its design.
9. Regulatory Guide 1.143 specifies 30 minute hold time for leak testing of piping systems in addition to the required codes and standards. An exception to the Regulatory Guide 1.143 30 minute hold time is the 10 minute specified in ASME and ANSI codes without an additional 30 minutes. The basis for this exception is, all systems installed, maintained, and modified are tested in accordance with ASME Section III, Section XI and ANSI B-31-1 Codes. This exception will eliminate any confusion regarding test time and ANSI code requirements.

3A.144 AUDITING OF QUALITY ASSURANCE PROGRAMS FOR NUCLEAR POWER PLANTS (REVISION 0; 1/79)

Delete commitment. Regulatory Guide 1.144 has been withdrawn. The requirements of NQA-1-1994 Basic Requirements 7 and 18 and Supplementary Requirements 7S-1 and 18S-1 are adequate alternatives to the requirements of ANSI N45.2.12-1979 and Regulatory Guide 1.144.

3A.146 QUALIFICATION OF QUALITY ASSURANCE PROGRAM AUDIT PERSONNEL FOR NUCLEAR POWER PLANTS (REVISION 0; 8/80)

Delete commitment. Regulatory Guide 1.146 has been withdrawn. The requirements of NQA-1-1994 Basic Requirement 2 and Supplementary Requirement 2S-3 are adequate alternatives to the requirements of ANSI N45.2.23-1978 and Regulatory Guide 1.146.

3A.147 INSERVICE INSPECTION CODE CASE ACCEPTABILITY ASME SECTION XI DIVISION 1, (LATEST REVISION PER 10 CFR 50.55A)

Regulatory Guide 1.147 identifies the Code Cases that the NRC has determined to be acceptable alternatives to the applicable parts of Section XI. Licenses may use these Code Cases without requesting authorization from the NRC, provided that they are used with any identified limitation or modifications.

3A.154 FORMAT AND CONTENT OF PLANT-SPECIFIC PRESSURIZED THERMAL SHOCK SAFETY ANALYSIS REPORTS FOR PRESSURIZED WATER REACTORS (REVISION 0; 1/87)

The NRC established screening criteria after extensive industry analysis identified the likelihood of a reactor vessel failure due to Pressurized Thermal Shock (PTS) events. The rule required that any plant that wishes to operate at values above the RTPTS screening criterion must provide an extensive safety analysis. Westinghouse performed a study and supplied a report to SCE&G. The report, WCAP-15103, Revision 0 (September 1998), “Evaluation of Pressurized Thermal Shock for V. C. Summer,” satisfies the requirement that current and projected values of RTPTS for reactor vessel beltline region materials be evaluated and reported to the NRC. RTPTS values contained in the report are based on actual plate and weld material chemistry data and are well below the NRC screening criteria values for pressurized thermal shock. The actual fluence levels (determined from surveillance capsule data) and projected levels for plant operation at 2900 MWt were used to calculate the RTPTS values at 32 and 48 EFPY. The most limiting plate, A9154-1 was calculated to exhibition an RTPTS value of 157 °F at 48 EFPY. Using surveillance capsule data, the RTPTS value for this plate was found to be 98 °F.

3A.155 STATION BLACKOUT (REVISION 0; 6/88)

The Virgil C. Summer Nuclear Station's Station Blackout Program meets the guidance provided by Regulatory Guide 1.155.

3A.160 MONITORING THE EFFECTIVENESS OF MAINTENANCE AT NUCLEAR POWER PLANTS (REVISION 4; 8/18)

The Virgil C. Summer Nuclear Station Maintenance Rule Program meets the guidance provided by Regulatory Guide 1.160.

3A.183 ALTERNATIVE RADIOLOGICAL SOURCE TERMS FOR EVALUATING DESIGN BASIS ACCIDENTS AT NUCLEAR POWER REACTORS (REVISION 0; 7/00)

The Virgil C. Summer Nuclear Station meets the guidance provided in Regulatory Guide 1.183.

3A.189 FIRE PROTECTION FOR OPERATING NUCLEAR POWER PLANTS (REVISION 2; 10/09)

SCE&G implements quality requirements for the Fire Protection System in accordance with Regulatory Position 1.7, “Quality Assurance” with the exception of section 1.7.8, “Corrective Action.” Corrective actions associated with Fire Protection will follow the guidance in QAPD Section 16, Corrective Action.

3A.192 OPERATION AND MAINTENANCE CODE CASE ACCEPTABILITY, ASME OM CODE (LATEST REVISION PER 10 CFR 50.55A)

The NRC staff reviews ASME OM Code Cases, rules upon the acceptability of each Code Case and publishes its findings in regulatory guides. The regulatory guides are revised periodically as new Code Cases are published by the ASME. The NRC incorporates by reference the regulatory guides listing acceptable and conditionally acceptable ASME Code Cases in 10 CFR 50.55a. The latest edition of 10 CFR 50.55a is available on the NRC's Public Web site. Licensees may use these Code Cases without requesting authorization from the NRC, provided that they are used with any identified limitation or condition.

3A.194 ATMOSPHERIC RELATIVE CONCENTRATIONS FOR CONTROL ROOM RADIOLOGICAL HABITABILITY ASSESSMENTS AT NUCLEAR PLANTS (REVISION 0; 6/03)

The Virgil C. Summer Nuclear Station meets the guidance provided in Regulatory Guide 1.194.

3A.196 CONTROL ROOM HABITABILITY AT LIGHT-WATER NUCLEAR POWER REACTORS (REVISION 0;5/03)

The Virgil C. Summer Nuclear Station complies with the compensatory measures guidance discussed in Regulatory Guide 1.196, Revision 0, Section C.2.7.3.

3A.197 DEMONSTRATING CONTROL ROOM ENVELOPE INTEGRITY AT NUCLEAR POWER REACTORS (REVISION 0; 5/03)

The Virgil C. Summer Nuclear Station complies with the testing methods and testing frequencies specified in Regulatory Guide 1.197, Revision 0, Section C.1 and C.2.

V.C. Summer Nuclear Station
Safety Analysis Report

Reactor

Chapter 4

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 4 - REACTOR

4.0 REACTOR

4.1 SUMMARY DESCRIPTION

This chapter describes the mechanical components of the reactor and reactor core including the fuel rods and fuel assemblies, reactor internals, and the control rod drive mechanisms (CRDM's); the nuclear design; and the thermal - hydraulic design.

The reactor core is comprised of Westinghouse 17 x 17 OFA/VANTAGE + fuel assemblies arranged in a checkered, low-leakage core loading pattern.

The VANTAGE + fuel system design is based upon the Westinghouse VANTAGE 5 fuel designs as described in WCAP-10444-P-A, "Reference Core Report, VANTAGE 5 Fuel Assembly," (Reference 1). V.C. Summer Regions 7-8 and 9D utilized VANTAGE 5 fuel assemblies.

VANTAGE + is a modification of the NRC-approved VANTAGE 5 fuel assembly design; it includes the following VANTAGE 5 product features:

Reconstitutable Top Nozzle (RTN)
Intermediate Flow Mixing (IFM) Grids
Axial Blankets
Integral Fuel Burnable Absorbers (IFBA)

A detailed description and evaluation of these features is provided in Reference 1 NRC approval for the above VANTAGE 5 features and assembly fuel system design was received in a July 1985 SER.

VANTAGE + also includes the following:

ZIRLO®/Optimized ZIRLO™ Fuel Rod Clad
ZIRLO® Guide Thimbles
Plenum Fuel Stack Variable Pitch Coil Spring
Annular Axial Blanket Pellets
Modified Assembly Skeleton Dimensions

A detailed description and evaluation of the above features is provided in Reference 4. V.C. Summer Regions 9A-9C and 10 utilized VANTAGE+ fuel assemblies

The VANTAGE + fuel assemblies utilized in Regions 11 through 31 contained Performance + features. The additional features include:

Additional reduced fuel rod to bottom nozzle gap
Extended burnup bottom grid design

ZIRLO® mid-grids and Intermediate Flow Mixer grids
Mid enriched annular pellets in axial blankets

Starting with Region 30 (Cycle 28) the Westinghouse Integral Nozzle (WIN) top nozzle replaces the Reconstitutable Top Nozzle (RTN) on the V. C. Summer VANTAGE+ fuel assembly. The WIN design is a proactive change made to reduce the potential for holddown spring screw failures in the top nozzle by eliminating the holddown spring screw. The springs are held in the nozzle by a machined pocket and a tack welded pin pushed through the pocket and springs. The WIN maintains the same reconstitutable upper connection to the guide thimbles as the RTN.

Fuel assemblies from Regions 7 through 31 utilized the Debris Filter Bottom Nozzle (DFBN).

Starting with Region 32 (Cycle 30), V. C. Summer has implemented the Westinghouse 17x17 OFA design with PRIME^{TM} fuel features. The PRIME^{TM} fuel assembly design incorporates advanced features to improve fuel reliability and corrosion resistance. The PRIME^{TM} fuel features include Low Tin ZIRLO^{TM} grid strap material to improve the corrosion resistance and the PRIME^{TM} bottom nozzle which incorporates a low pressure drop filter plate design along with lowered side skirts to help improve debris resistance. The PRIME^{TM} advanced fuel design has been extensively evaluated, tested, and analyzed, and it was demonstrated that it meets all the applicable mechanical design and safety criteria.

The core is cooled and moderated by light water at a normal operating pressure of 2250 psia in the reactor coolant system. The moderator coolant contains boron as a neutron absorber. The concentration of boron in the coolant is varied as required to control relatively slow reactivity changes including the effects of fuel burnup. Additional boron, in the form of IFBA or burnable absorber rods, may be employed in the core to establish the desired initial reactivity.

Two hundred and sixty-four fuel rods are mechanically joined in a square array to form a fuel assembly. The fuel rods are supported in intervals along their length by grid assemblies which maintain the lateral spacing between the rods throughout the design life of the assembly. The grid assembly consists of an “egg-crate” arrangement of interlocked straps. The straps contain spring fingers and dimples for fuel rod support as well as coolant mixing vanes. The fuel rods consist of uranium dioxide ceramic cylindrical pellets contained in slightly cold worked zirconium alloy tubing which is plugged and seal welded at the ends to encapsulate the fuel. All fuel rods are pressurized with helium during fabrication to reduce stresses and strains in order to increase fatigue life.

The center position in the assembly is reserved for the incore instrumentation, while the remaining 24 positions in the array are equipped with guide thimbles joined to the grids and the top and bottom nozzles. Depending upon the position of the assembly in the core, the guide thimbles are used as core locations for rod cluster control assemblies (RCCA’s), neutron source assemblies, and burnable absorber rods (if used). Otherwise, the guide thimbles may be fitted with plugging devices to further limit bypass flow. Starting with the Cycle 5 core, the use of plugging devices is optional.

The bottom nozzle is a box-like structure which serves as a bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly.

The top nozzle assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the RCCA or other components.

The RCCA's each consist of a group of individual absorber rods fastened at the top end to a common hub or spider assembly. These assemblies contain absorber material to control the reactivity of the core under operating conditions.

The CRDM's are of the magnetic jack type. Control rods are positioned by electro-mechanical (solenoid) action utilizing gripper latches, which engage grooved drive rods which in turn are coupled to the RCCA's. The CRDM's are so designed that upon a loss of electrical power to the coils, the RCCA is released and falls by gravity to shutdown the reactor.

The components of the reactor internals are divided into three parts consisting of the lower core support structure (including the entire core barrel and neutron shield pad assembly), the upper core support structure and the incore instrumentation support structure. The reactor internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and CRDM's, direct coolant flow past the fuel elements and to the pressure vessel head, provide gamma and neutron shielding, and provide guides for the incore instrumentation.

The nuclear design analyses and evaluation establish physical locations for control rods, burnable absorber assemblies and physical parameters such as fuel enrichments and boron concentration in the coolant. The nuclear design evaluation established that the reactor core has inherent characteristics which together with corrective actions of the reactor control and protective systems provide adequate reactivity control even if the highest reactivity worth RCCA is stuck in the fully withdrawn position.

The design also provides for inherent stability against diametral and azimuthal power oscillations and for control of induced axial power oscillations.

The thermal-hydraulic design analyses and evaluation establish coolant flow parameters which assure that adequate heat transfer is provided between the fuel clad and the reactor coolant. The thermal design takes into account local variations in dimensions, power generation, flow distribution and mixing. The mixing vanes incorporated in the fuel assembly spacer grid design, and the IFM grids induce additional flow mixing between the various flow channels within a fuel assembly as well as between adjacent assemblies.

Instrumentation is provided in and out of the core to monitor the nuclear, thermal-hydraulic and mechanical performance of the reactor, and to provide inputs to automatic control functions.

Table 4.1-1 presents the principal nuclear, thermal-hydraulic, and mechanical reactor design parameters. The effects of fuel densification were evaluated with the methods described in Reference 2. The analysis techniques employed in the core design are tabulated in Table 4.1-2.

The loading conditions considered in general for the core internals and components are tabulated in Table 4.1-3. Specific or limiting loads considered for design purposes of the various components are listed as follows: fuel assemblies in Section 4.2.1.1.2; reactor internals in Section 4.2.2.3 and Table 5.2-2; neutron absorber rods, burnable absorber rods, neutron source rods, and thimble plug assemblies in Section 4.2.3.1.3; and CRDM's in Section 4.2.3.1.4. The dynamic analyses, input forcing functions, and response loadings are presented in Section 3.9

4.1.1 REFERENCES

1. Davidson, S. L. (Ed.), *Reference Core Report - VANTAGE 5 Fuel Assembly,* WCAP-10444-P-A, September, 1985.
2. Hellman, J. M. (Ed.), *Fuel Densification Experimental Results and Model for Reactor Application*, WCAP-8218-P-A (Proprietary) and WCAP-8219-A (Non-Proprietary), March, 1975.
3. Davidson, S.L. and Nuhfer, D.L., *VANTAGE + Fuel Assembly Reference Core Report*, WCAP-12610, June 1990.
4. Letter from R. W. Kerr (Westinghouse) to W. Herwig (SCE&G), South Carolina Electric & Gas Company, V. C. Summer Nuclear Station, Transmittal of *SER Compliance of WCAP-12610-P-A & CENPD-404-P-A Addendum 1-A, Optimized ZIRLOTM* (Proprietary)," NF-CG-10-58, July 29, 2010.

Table 4.1-1
Reactor Design Parameters

Thermal and Hydraulic Design Parameters	Current RTP and Engineered Safeguards Design Rating
1. Reactor Core Heat Output, MWt	2900
2. Reactor Core Heat Output, 10^6 Btu/h	9898
3. Heat Generated in Fuel,%	97.4
4. System Pressure, Nominal, psia	2250
5. System Pressure, Minimum Steady-State, psia	2200
6. Minimum Departure from Nucleate Boiling Ratio for Design Transients (Design Limit)	(Typical Flow Channel) 1.23 (Thimble Flow Channel)
6a. DNB Correlation Used	WRB-2
COOLANT FLOW	
7. Total Thermal Design Flow Rate (TDF), 10^6 lbm/hr	104.0
7a. Minimum Measured Flow Rate, 10^6 lbm/hr	106.1
8. Effective Flow Rate for Heat Transfer, 10^6 lb/hr	94.74
9. Effective Flow Area for Heat Transfer, ft^2	44.0
10. Average Velocity Along Fuel Rods, ft/sec	13.7
11. Average Mass Velocity, 10^6 lbm/hr-ft^2	2.15

Table 4.1-1 (CONTINUED)
Reactor Design Parameters

Thermal and Hydraulic Design Parameters	Current RTP and Engineered Safeguards Design Rating
COOLANT TEMPERATURE, °F (BASED ON TDF)	
12. Nominal Inlet	552.9
13. Average Rise in Vessel	69.0
14. Average Rise in core	74.8
15. Average in core	592.8
16. Average in Vessel	587.4
HEAT TRANSFER	
17. Active Heat Transfer, Surface Area, ft^2	46.780
18. Average Heat Flux, BTU/hr-ft^2	206,100
19. Maximum Heat Flux for Normal Operation, Btu/hr-ft^2	504,900
20. Average Thermal Output, kW/ft	5.69
21. Maximum Thermal Output for Normal Operation, kW/ft	13.9(2)
22. (Deleted)	
23. Heat Flux Hot Channel Factor, F_Q	2.45(1)
24. (Deleted)	

Table 4.1-1 (CONTINUED)
Reactor Design Parameters

Core Mechanical Design Parameters	Fuel Assembly
FUEL ASSEMBLIES	
25. Design	RCC Canless
26. Number of Fuel Assemblies	157
27. UO_2 Rods per Assembly	264
28. Rod Pitch, in.	0.496
29. Overall Dimensions, in.	8.426 x 8.426
30. Fuel Weight (as UO_2), lb	174,894
31. Clad Weight, lb	35,244
32. Number of Grids per Assembly	2 - Type R (Inconel End) 6 - ZIRLO$^{(R)}$/Low Tin ZIRLO^{TM} 1 - Protective
33. Number of IFMs per Assembly	3
34. Loading Technique	multi-region nonuniform-checkered
FUEL RODS	
35. Number	41,448
36. Outside Diameter, in.	0.360
37. Diametral Gap, in.	0.0062
38. Clad Thickness, in.	0.0225

Table 4.1-1 (CONTINUED)
Reactor Design Parameters

Core Mechanical Design Parameters	Fuel Assembly
39. Clad Material	ZIRLO®/Optimized ZIRLO™
FUEL PELLETS	
40. Material	UO_2 Sintered
41. Density (% of Theoretical)	95
42. Diameters, in. OD/ID	0.3088/-(Enriched) 0.155 (Midenriched)
43. Length, in.	0.370 (Enriched) 0.500 (Midenriched)
ROD CLUSTER CONTROL ASSEMBLIES	
44. Neutron Absorber	Ag-In-Cd
45. Cladding Material	Type 304 SS-Cold Worked
46. Clad Thickness, in.	0.0185
47. Number of Clusters	48
48. Number of Absorber Rods per Cluster	24

Table 4.1-1 (CONTINUED)
Reactor Design Parameters

Core Mechanical Design Parameters	Fuel Assembly
CORE STRUCTURE	Fuel Assembly
49. Core Barrel, I.D./O.D., in.	133.85/137.875
50. Thermal Shield, I.D./O.D., in.	Neutron Pad Design
STRUCTURE CHARACTERISTICS	
51. Core Diameter, in. (Equivalent)	119.7
52. Core Height, in. (Active Fuel)	144
REFLECTOR THICKNESS AND COMPOSITION	
53. Top - Water plus Steel, in.	~ 10
54. Bottom - Water plus Steel, in.	~ 10
55. Side - Water plus Steel, in.	~ 15
56. H_2O/U Molecular Ratio core, Lattice (Cold)	2.73

(1) This is the value of FQ for normal operation
(2) This limit associated with an FQ = 2.45

Table 4.1-2
Analytic Techniques in Core Design

Analysis	Technique	Computer Code	Section Referenced
Mechanical Design of Core Internals			
Loads, Deflections, and Stress Analysis	Static and dynamic modeling	Blowdown code, FORCE, finite element structural analysis code, and others	3.7.2.1 3.9.1 3.9.3
Fuel Rod Design			
Fuel Performance Characteristics (temperature, internal pressure, clad stress, etc.)	Semi-empirical thermal model of fuel rod with consideration of fuel density changes, heat transfer, fission gas release, etc.	Westinghouse Performance Analysis and Design Model (PAD5)	4.2.1.3.1 4.3.3.1 4.4.2.2 4.4.3.4.2
Nuclear Design			
1. Cross Sections and Group Constants	Microscopic data; Macroscopic constants for homogenized core regions	PHOENIX, NEXUS, PARAGON	4.3.2.2 4.3.3.2
	Group constants for control rods with self-shielding	PHOENIX, NEXUS, PARAGON	4.3.3.2
2. X-Y-Z Power Distributions, Fuel Depletion, Critical Boron Concentrations, x-y Xenon Distributions, Reactivity Coefficients	3-D, Advanced Nodal Theory	ANC	4.3.3.3

Table 4.1-2 (continued)
Analytic Techniques in Core Design

Analysis	Technique	Computer Code	Section Referenced
3. Axial Power Distributions, Control Rod Worths, and Axial Xenon Distribution	1-D, 2-Group Diffusion Theory	APOLLO	4.3.3.3
	3D, Diffusion Theory	NEXUS, PARAGON, ANC	4.3.3.3
4. Fuel Rod Power	Integral Transport Theory	LASER	4.3.3.1
Effective Resonance Temperature	Monte Carlo Weighting Function	REPAD	
Thermal-Hydraulic Design			
1. Steady-State	Subchannel analysis of local fluid conditions in rod bundles, including inertial and crossflow resistance terms, solution progresses from core-wide to hot assembly to hot channel	THINC-IV	4.4.3.4.1
2. Transient Departure from Nucleate Boiling Analysis	Subchannel analysis of local fluid conditions in rod bundles during transients by including accumulation terms in conservation equations	THINC-I (THINC-III)	4.4.3.4.1

Table 4.1-3
Design Loading Conditions For Reactor Core Components

1. Fuel Assembly Weight
2. Fuel Assembly Spring Forces
3. Internals Weight
4. Control Rod Trip (equivalent static load)
5. Differential Pressure
6. Spring Preloads
7. Coolant Flow Forces (static)
8. Temperature Gradients
9. Differences in Thermal Expansion
    a. Due to temperature differences
    b. Due to expansion of different materials
10. Interference Between Components
11. Vibration (mechanically or hydraulically induced)
12. One or More Loops Out of Service
13. All Operational Transients Listed in Table 5.2-2
14. Pump Overspeed
15. Seismic Loads (operating basis earthquake and safe shutdown earthquake)
16. Blowdown Forces (due to cold and hot leg break)

4.2 MECHANICAL DESIGN

The plant conditions for design are divided into 4 categories in accordance with their anticipated frequency of occurrence and risk to the public: Condition I - Normal Operation; Condition II - Incidents of Moderate Frequency; Condition III - Infrequent Incidents; Condition IV - Limiting Faults.

The reactor is designed so that its components meet the following performance and safety criteria:

1. The mechanical design of the reactor core components and their physical arrangement, together with corrective actions of the reactor control, protection and emergency cooling systems (when applicable) assure that:
   a. Fuel damage (1) is not expected during Condition I and Condition II events. It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the plant cleanup system and are consistent with plant design bases.
   b. The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged (1) although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.
   c. The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.
2. The fuel assemblies are designed to accommodate expected conditions for handling during assembly inspection, refueling operations and shipping loads.
3. The fuel assemblies are designed to accept control rod insertions in order to provide the required reactivity control for power operations and reactivity shutdown conditions.
4. All fuel assemblies have provisions for the insertion of incore instrumentation necessary for plant operation.
5. The reactor internals, in conjunction with the fuel assemblies, direct reactor coolant through the core to achieve acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements can be met for all modes of operation. In addition, the internals provide core support and distribute coolant flow to the pressure vessel head so that the temperature differences between the vessel flange and head do not result in leakage from the flange during the Condition I and II modes of operation. Required inservice inspection can be carried out as the internals are removable and provide access to the inside of the pressure vessel.

(1) Fuel damage as used here is defined as penetration of the fission product barrier (i.e., the fuel rod clad)

4.2.1 Fuel

4.2.1.1 Design Basis

The fuel rod and fuel assembly design bases are established to satisfy the general performance and safety criteria presented in Section 4.2 and specific criteria noted below.

4.2.1.1.1 Fuel Rods

The integrity of the fuel rods is ensured by proper fuel rod design. This is achieved by designing the fuel rods so that specific design criteria are satisfied. The design process must consider the effects of variations and fluctuations in core and local power, and in reactor coolant temperature, pressure and flow which occur during normal operation and Anticipated Operational Occurrences (AOOs).

To ensure reliable operation, established fuel rod design criteria must be satisfied for all operating conditions consistent with normal operation and AOOs. The fuel rod design is judged to have met these criteria when it is demonstrated that the performance of a fuel region is within the limits specified by the criteria for these events. This is generally accomplished by demonstrating that the limiting fuel rod performance with appropriate allowance for uncertainties is within the limits specified by each criterion. These evaluations are performed using the Performance Analysis and Design (PAD5) code and models (Reference 17) which is licensed up to a fuel rod average burnup of 62,000 MWD/MTU.

- Clad Stress
  - Design Basis - The fuel system will not be damaged due to excessive fuel clad stress.
  - Acceptance Limit - Maximum cladding stress intensities excluding Pellet-Cladding Interaction (PCI) induced stress shall be evaluated based on American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code guidelines. Stresses in the cladding are combined to calculate a maximum stress intensity which is then compared to the criteria described in Reference 17.
- Clad Strain
  - Design Basis - The fuel rod will not fail due to excessive fuel clad strain.
  - Acceptance Limit - The design limit for the fuel rod clad strain is that the total tensile strain, elastic plus plastic, due to uniform cylindrical fuel pellet deformation during any single Condition I or II transient shall be less than 1% from the pre-transient value. The hydrogen-based transient clad strain limit (Reference 35) can be used for Condition II overpower transients in lieu of the 1% clad strain limit.
- Rod Internal Pressure
  - Design Basis - The fuel system will not be damaged due to excessive fuel rod internal pressure.
  - Acceptance Limit - The internal pressure of the lead fuel rod in the reactor will (1) be limited to a value below that which could cause the diameter gap to increase (cladding liftoff) due to outward cladding creep during normal operation; (2) be limited to a value below that which could result in cladding hydride reorientation in the radial

direction; and (3) be limited to preclude extensive Departure from Nucleate Boiling (DNB) propagation.

- Clad Fatigue
  - •• Design Basis - The fuel system will not be damaged due to fatigue.
  - •• Acceptance Limit - The fatigue life usage factor is limited to prevent reaching the material fatigue limit.
- Clad Oxidation
  - •• Design Basis - The fuel system will not be damaged due to excessive fuel clad oxidation.
  - •• Acceptance Limit - The predicted oxide thickness shall be no greater than 100 microns.
- Clad Hydrogen Pickup
  - •• Design Basis - The fuel system will be operated to prevent significant degradation of mechanical properties of the clad at low temperatures as a result of hydrogen embrittlement caused by the formation of zirconium hydride platelets.
  - •• Acceptance Limit - The best estimate hydrogen pickup in the cladding shall not exceed 600 ppm on a volume-average basis at end of life through the entire clad wall.
- Fuel Rod Axial Growth
  - •• Design Basis - The fuel system will not be damaged due to excessive axial interference between the fuel rods and the fuel assembly structure.
  - •• Acceptance Limit - The fuel rods shall be designed with adequate clearance between the fuel rod and the top and bottom nozzles to accommodate the differences in the growth of fuel rods and the growth of the assembly without interference.
- Clad Flattening
  - •• Design Basis - Fuel rod failures will not occur due to clad flattening.
  - •• Acceptance Limit - The fuel rod design shall preclude clad flattening during projected exposure.
- Clad Free Standing
  - •• Design Basis - The fuel system will not be damaged due to excessive fuel clad stress.
  - •• Acceptance Limit - The cladding shall be short-term free standing at beginning of life, at power, and during hot hydrostatic testing.
- Fuel Pellet Overheating (Power-to-Melt)
  - •• Design Basis - The fuel rods will not fail due to fuel centerline melting for normal operation or AOOs.
  - •• Acceptance Limit - The fuel rod centerline temperature shall not exceed the fuel melt temperature during Condition I and II operation, accounting for degradation of the melt temperature due to burnup and the addition of integral burnable absorbers.
  - •• The PAD5 melting temperature model uses the following equation based on an unirradiated UO_2 fuel melting point of 5080°F and burnup.

$$T_{melt} = 5080°F - \frac{9}{10{,}000}(BU)$$

Where,

T_{melt} = UO_2 melting temperature, °F
BU = UO_2 burnup, MWD/MTU

- Pellet/Clad interaction (PCI)

- Design Basis - The fuel rod will not fail due to pellet clad interaction.
- Acceptance Limit –Two related criteria, the one percent clad strain criterion and the fuel overheating criterion, must be met. The hydrogen-based transient clad strain limit (Reference 35) can be used for Condition II overpower transients in lieu of the 1% clad strain limit.

Reference 17 is the basis for these fuel performance criteria, which are evaluated on a cycle-specific basis as part of each fuel reload.

An extensive irradiation testing and fuel surveillance operational experience program has been, and continues to be, conducted to verify the adequacy of the fuel performance and design bases. This program is discussed in Section 4.2.1.3.3. Fuel surveillance and testing results, as they become available, are used to improve fuel rod design and manufacturing processes and assure that the design bases and safety criteria are satisfied.

4.2.1.1.2 Fuel Assembly Structure

Structural integrity of the fuel assemblies is assured by setting limits on stresses and deformations due to various loads and by determining that the assemblies do not interfere with the functioning of other components. Three (3) types of loads are considered.

1. Nonoperational loads such as those due to shipping and handling.
2. Normal and abnormal loads which are defined for Conditions I and II.
3. Abnormal loads which are defined for Conditions III and IV.

These criteria are applied to the design and evaluation of the top and bottom nozzles, the guide thimbles, grids and thimble joints. The design bases for evaluating the structural integrity of the fuel assemblies are:

1. Nonoperational (e.g., shipping) - 4 g axial loading and 6 g lateral loading with dimensional stability.
2. For the normal operating and upset conditions, the fuel assembly component structural design criteria are classified into 2 material categories, namely austenitic steels and zirconium alloys. The stress categories and strength theory presented in the ASME Boiler and Pressure Vessel Code, Section III, are used as a general guide. The maximum shear-theory (Tresca criterion) for combined stresses is used to determine the stress intensities for the austenitic steel components. The stress intensity is defined as the numerically largest difference between the various principal stresses in a 3 dimensional field. The allowable stress intensity value for austenitic steels, such as nickel-chromium-iron alloys, is given by the lowest of the following:
   a. 1/3 of the specified minimum tensile strength or 2/3 of the specified minimum yield strength at room temperature;
   b. 1/3 of the tensile strength or 90% of the yield strength at temperature but not to exceed 2/3 of the specified minimum yield strength at room temperature.

The stress limits for the austenitic steel components are given below. All stress nomenclature is per the ASME Boiler and Pressure Vessel Code, Section III.

Stress Intensity Limits

Categories	Limit
General Primary Membrane Stress Intensity	Sm
Local Primary Membrane Stress Intensity	1.5 Sm
Primary Membrane plus Bending Stress Intensity	1.5 Sm
Total Primary plus Secondary Stress Intensity	3.0 Sm

The zirconium alloy structural components which consist of guide thimble and fuel tubes are in turn subdivided into 2 categories because of material differences and functional requirements. The fuel tube design criteria are covered separately in Section 4.2.1.1.1. The maximum shear theory is used to evaluate the guide thimble design. For conservative purposes, the zirconium alloy unirradiated properties are used to define the stress limits.

Reference 19 describes the structural stress criteria for fuel assembly structural components composed of Zircaloy-4 and ZIRLO material. NRC-approved Topical Report WCAP-16500-P-A justifies the applicability of Reference 19 to Low Tin ZIRLO^{TM} grids.

3. Abnormal loads during Conditions III or IV - worst cases represented by combined seismic and blowdown loads.
   a. Deflections or failures of components cannot interfere with the reactor shutdown or emergency cooling of the fuel rods.
   b. The fuel assembly structural component stresses under faulted conditions are evaluated using primarily the methods outlined in Appendix F of the ASME Boiler and Pressure Vessel Code, Section III. Since the current analytical methods utilize elastic analysis, the stress allowables are defined as the smaller value of 2.4 Sm or 0.70 Su for primary membrane and 3.6 Sm or 1.05 Su for primary membrane plus primary bending. For the austenitic steel fuel assembly components, the stress intensity is defined in accordance with the rules described in the previous section for normal operating conditions. For the zirconium alloy components, the stress intensity limits are set at 2/3 of the material yield strength, Sy, at reactor operating temperature. This results in stress limits being the smaller of 1.6 Sy or 0.70 Su for primary membrane and 2.4 Sy or 1.05 Su for primary membrane plus bending. For conservative purposes, the zirconium alloy unirradiated properties are used to define the stress limits.

The grid component strength criteria are based on experimental tests. For grids, the limit is established based on the 95% confidence level on the true mean of the test data (experimental collapse load) at operating temperature.

4.2.1.2 Design Description

Fuel assembly and fuel rod design data are given in Table 4.1-1. NRC approval of the VANTAGE+ design was given in Reference 29. The 17x17 OFA PRIME fuel features were communicated to the NRC as provided in Reference 28.

Two hundred sixty four (264) fuel rods, or variations of fuel rods and filler rods (with respect to fuel assembly reconstitution, Reference 30, 24 guide thimble tubes and 1 instrumentation thimble tube are arranged within a supporting structure to form a fuel assembly. The instrumentation thimble is located in the center position and provides a channel for insertion of an incore neutron detector, if the fuel assembly is located in an instrumented core position. The guide thimbles provide channels for insertion of either a rod cluster control assembly, a neutron source assembly, a burnable absorber assembly or a plugging device (if used), depending on the position of the particular fuel assembly in the core. Figure 4.2-1 shows a cross-section of the fuel assembly array, and Figure 4.2-2 shows fuel assembly full length view. The fuel rods are loaded into the fuel assembly structure so that there is clearance between the fuel rod ends and the top and bottom nozzles.

The 17x17 OFA exterior assembly envelope is equivalent to those of previous Westinghouse designs, and is designed to be mechanically and hydraulically compatible with previous Westinghouse designs (LOPAR, Optimized, VANTAGE5, VANTAGE+). The same functional requirements and design criteria as previously established for the VANTAGE+ fuel assembly design remain valid for the 17x17 OFA PRIME fuel design.

Each fuel assembly is installed vertically in the reactor vessel and stands upright on the lower core plate, which is fitted with alignment pins to locate and orient the assembly. After all fuel assemblies are set in place, the upper support structure is installed. Alignment pins, built into the upper core plate, engage and locate the upper ends of the fuel assemblies. The upper core plate then bears downward against the fuel assembly top nozzle via the holddown springs to hold the fuel assemblies in place.

4.2.1.2.1 Fuel Rods

The fuel rods consist of uranium dioxide ceramic pellets contained in slightly cold worked zirconium alloy tubing which is plugged and seal welded at the ends to encapsulate the fuel. A schematic of the fuel rods is shown in Figure 4.2-3. The fuel pellets are right circular cylinders consisting of uranium dioxide powder which has been compacted by cold pressing and then sintered to the required density. The fuel rods also contain, annular Axial Blanket pellets, and an Integral Fuel Burnable Absorber (IFBA) coating on some of the enriched fuel pellets.

The bottom end plug has an internal grip feature to facilitate rod loading and provides appropriate lead-in for the removable top nozzle reconstitution feature.

A chamfered pellet design is used with the objective of improving manufacturability while maintaining or improving performance (e.g., improved pellet chip resistance during manufacturing/handling).

The V. C. Summer fuel design uses mid-enriched annular axial blanket pellets. The axial blankets are a nominal 6 inches of fuel pellets at each end of the fuel rod pellet stack. Axial blankets reduce neutron leakage and improve fuel utilization. The axial blankets utilize chamfered pellets physically different than the pellets, which help to prevent accidental mixing during manufacturing. The physical difference includes a longer pellet length than the pellet (see Table 4.1-1).

The IFBA coated fuel pellets are identical to the enriched uranium dioxide pellets except for the addition of a thin boride coating on the pellet cylindrical surface. Coated pellets occupy the central portion of the fuel column. The number and pattern of IFBA rods within an assembly may vary depending on specific application. The ends of the enriched coated pellets and enriched uncoated pellets are dished to allow for greater axial expansion at the pellet centerline and void volume for fission gas release. An evaluation and test program for the IFBA design features are given in Section 2.5 in Reference 24.

To avoid overstressing of the clad or seal welds, void volume and clearances are provided within the rods to accommodate fission gases released from the fuel, differential thermal expansion between the clad and the fuel, and fuel density changes during burnup. Shifting of the fuel within the clad during handling or shipping prior to core loading is prevented by a stainless steel helical spring which bears on top of the fuel. At assembly the pellets are stacked in the clad to the required fuel height, the spring is then inserted into the top end of the fuel tube and the end plugs pressed into the ends of the tube and welded. All fuel rods are internally pressurized with helium during the welding process in order to minimize compressive clad stresses and creep due to coolant operating pressures.

The fuel rods are presently being pre-pressurized and designed so that the internal gas pressure design basis (Section 4.2.1.1.1) is satisfied and clad flattening will not occur during the fuel core life as determined by the methods in Reference 3.

4.2.1.2.2 Fuel Assembly Structure

The fuel assembly structure consists of a bottom nozzle, top nozzle, guide thimbles, and grids, as shown in Figure 4.2-2.

4.2.1.2.2.1 Bottom Nozzle

The bottom nozzle is a box-like structure which serves as a bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The VANTAGE+ with Performance + features includes a 2 piece composite bottom nozzle design incorporating a highly machined stainless steel adaptor plate welded to a low cobalt investment casting as shown in Figure 4.2-2. The plate itself acts to prevent a downward ejection of the fuel rods from their fuel

assembly. The bottom nozzle is fastened to the fuel assembly guide tubes by weld-locked screws which penetrate through the nozzle and mate with an inside fitting in each guide tube.

The debris filter bottom nozzle (DFBN) utilized in Regions 7-31 was introduced to reduce the possibility of fuel rod damage due to debris-induced fretting. The relatively large flow holes in a conventional bottom nozzle are replaced with a new pattern of smaller flow holes for the DFBN. The holes are sized to minimize passage of debris particles large enough to cause damage while providing sufficient flow area, comparable pressure drop, and continued structural integrity of the nozzle. Tests to measure pressure drop and demonstrate structural integrity have been performed to verify that the DFBN is totally compatible with the fuel assembly design.

Starting with Region 32 (Cycle 30), V. C. Summer will use the Westinghouse PRIME^{TM} bottom nozzle. The PRIME^{TM} bottom nozzle includes the Lowered Side Skirt from the Advanced DFBN and the Low Pressure Drop Feature of the 17x17 NGF design. The PRIME bottom nozzle improves fuel performance with respect to leaking fuel rods due to debris-induced fretting by improving debris capture. This advanced bottom nozzle design has been extensively evaluated, tested, and analyzed, and it was demonstrated that it meets all of the applicable mechanical design and safety criteria.

Coolant flow through the fuel assembly is directed from the plenum in the bottom nozzle upward through the penetrations in the plate to the channels between the fuel rods. The penetrations in the plate are positioned between the rows of the fuel rods. Axial loads (holddown) imposed on the fuel assembly and the weight of the fuel assembly are transmitted through the bottom nozzle to the lower core plate. Indexing and positioning of the fuel assembly is controlled by alignment holes in 2 diagonally opposite bearing plates which mate with locating pins in the lower core plate. Any lateral loads on the fuel assembly are transmitted to the lower core plate through the locating pins.

4.2.1.2.2.2 Top Nozzle

The top nozzle assembly functions as the upper structural element of the fuel assembly in addition to providing a partial protective housing for the rod cluster control assembly or other components. It consists of an adapter plate, enclosure, top plate, and pads. The integral welded assembly has holddown springs mounted on the assembly as shown in Figure 4.2-2.

The square adapter plate is provided with round penetrations and semicircular ended slots to permit the flow of coolant upward through the top nozzle. Other round holes are provided to accept sleeves which are welded to the adapter plate and mechanically attached to the thimble tubes. The ligaments in the plate cover the tops of the fuel rods and prevent their upward ejection from the fuel assembly. The enclosure is a box-like structure which sets the distance between the adapter plate and the top plate. The top plate has a large square hole in the center to permit access for the control rods and the control rod spiders. Holddown springs are mounted on the top plate and are retained by clamps and either spring screws or retaining pins located at two diagonally opposite corners. On the other 2 corners integral pads are positioned which contain alignment holes for locating the upper end of the fuel assembly.

To remove the top nozzle, a tool is first inserted through a lock tube and expanded radially to engage the bottom edge of the tube. An axial force is then exerted on the tool which overrides local lock tube deformations and withdraws the lock tube from the insert. After the lock tubes have been withdrawn, the nozzle is removed by raising it off the upper slotted ends of the nozzle inserts which deflect inwardly under the axial lift load. With the top nozzle removed, direct access is provided for fuel rod examinations or replacement. Reconstitution is completed by the remounting of the nozzle and the insertion of lock tubes. Additional details of this design feature, the design bases and evaluation of the reconstitutable top nozzle are given in Section 2.3.2 in Reference 24.

4.2.1.2.2.3 Guide and Instrument Thimbles

The guide thimbles are structural members which also provide channels for the neutron absorber rods, burnable absorber rods, thimble plugs, or neutron source assemblies. Each one is fabricated from zirconium alloy tubing having 2 different diameters. The larger diameter at the top provides a relatively large annular area to permit rapid insertion of the control rods during a reactor trip as well as to accommodate the flow of coolant during normal operation. Four (4) holes are provided on the thimble tube above the dashpot to reduce the rod drop time. The lower portion of each guide thimble has a reduced diameter to produce a dashpot action near the end of the control rod travel during normal operation and to accommodate the outflow of water from the dashpot during a reactor trip. The dashpot is closed at the bottom by means of an end plug which is provided with a small flow port to avoid fluid stagnation in the dashpot volume during normal operation. The top end of the guide thimble is fastened to a tabular insert by 3 expansion swages. The insert engages into the top nozzle and is secured into position by a lock tube. The lower end of the guide thimble is fitted with an end plug which is then fastened into the bottom nozzle by a weld locked screw.

Each grid is fastened to the guide thimble assemblies to create an integrated structure. Westinghouse has chosen one 4 lobe bulge at each thimble and instrumentation tube location for the fastening technique as depicted in Figures 4.2-4 and 4.2-5 for all but the top and bottom grids.

An expanding tool is inserted into the inner diameter of the thimble tube to the elevation of the sleeves that have been welded to the middle grid assemblies. The 4 lobed tool forces the thimble and sleeve outward to a predetermined diameter, thus joining the 2 components.

For the 17x17 OFA fuel assembly, the top grid to nozzle attachment is shown in Figure 4.2-6. The thimbles are fastened to the top nozzle inserts by expanding the members as shown in Figures 4.2-4 and 4.2-5. The inserts then engage the top nozzle and are secured into position by the insertion of lock tubes.

The bottom grid assembly is not mechanically fastened as described above, but rather is joined to the assembly as shown in Figure 4.2-7. The stainless steel insert is spotwelded to the bottom grid and later captured between the guide thimble end plug and the bottom nozzle by means of a stainless steel thimble screw.

Starting with Region 32 (Cycle 30), V. C. Summer will use the Westinghouse PRIME^{TM} fuel features, including structurally stiffening the dashpot region of the guide thimble tube to minimize the potential for incomplete rod insertion. The joints and connections of the bottom grid, protective grid, and bottom nozzle remain identical to the swaged guide thimble design associated with the VANTAGE+ fuel design. All applicable mechanical design and safety criteria remain satisfied.

The central instrumentation thimble of each fuel assembly is not attached to either the top or bottom nozzles, but the thimble is constrained by its seating in counterbores of each nozzle. This thimble's internal diameter does not vary, and incore neutron detectors pass through the bottom nozzle's large counterbore into the center thimble. This thimble is expanded at the top and mid grids in the same manner as the previously discussed expansion of the guide thimbles to the grids.

The guide thimble tube ID provides an adequate nominal diametral clearance for the control rods. The thimble tube ID also provides sufficient diametral clearance for burnable absorber rods, source rods, and dually compatible thimble plugs (see Figures 4.2-2 and 4.2-20).

The instrumentation tube also has a sufficient diametral clearance for the flux thimble to traverse the tube without binding.

The IFM grids employ a single bulge connection to the sleeve and thimble just as is used in the intermediate grids.

4.2.1.2.2.4 Grid Assemblies

The fuel rods, as shown in Figure 4.2-2, are supported laterally at intervals along their length by grid assemblies which maintain the lateral spacing between the rods throughout the design life of the assembly. Each fuel rod is afforded lateral support within each grid by the combination of support dimples and springs. The grid assembly consists of individual slotted straps interlocked and welded in an "egg-crate" arrangement to join the straps permanently at their points of intersection. The straps contain spring fingers, support dimples and mixing vanes.

The grid material is zirconium alloy (mid-grids) and Inconel 718 (end grids) for 17x17 OFA fuel assemblies. Inconel 718 was chosen for its corrosion resistance assembly and high strength properties. Zirconium Alloy was chosen for the 17x17 OFA fuel assembly mid-grids due to its corrosion resistance, low neutron cross-section, and adequate strength properties. The magnitude of the grid restraining force on the fuel rod is set high enough to minimize possible fretting, without overstressing the cladding at the points of contact between the grids and fuel rods. The grid assemblies also allow axial thermal expansion of the fuel rods without imposing restraint sufficient to develop buckling or distortion of the fuel rods.

Four types of grid assemblies are used in the 17x17 OFA fuel design. The top and bottom Inconel (non-mixing vane) grids are used. Six (6) intermediate (mixing vane) structural grids are used. They are made of Zirconium Alloy material. The third grid type is an Intermediate Flow Mixer, also made of Zirconium Alloy. These Intermediate Flow Mixer (IFM) grids shown in Figure 4.2-2 are located in the 3 uppermost spans between the Zirconium Alloy mixing vane structural grids

and incorporate a similar mixing vane array. Their prime function is mid-span flow mixing in the hottest fuel assembly spans. Each IFM grid cell contains 4 dimples which are designed to prevent mid-span channel closure in the spans containing IFMs and fuel rod contact with the mixing vanes. This simplified cell arrangement allows short grid cells so that the IFM grid can accomplish its flow mixing objective with minimal pressure drop.

The 17x17 OFA fuel design IFM grids are not intended to be structural members. The outer strap configuration is designed to preclude grid hang-up and damage during fuel handling. Additionally, the grid envelope is smaller which further minimizes the potential for damage and reduces calculated forces during seismic/LOCA events.

A fourth type of grid used in the 17x17 OFA fuel design is a Robust Protective Grid (RPG). The grid is an Inconel 718 grid that is mounted below the bottom grid (on top of the bottom nozzle) and acts to strain out foreign materials before they can flow up the fuel assembly, be trapped by the other grids and cause damage to the fuel rods.

4.2.1.3 Design Evaluation

4.2.1.3.1 Fuel Rods

The fuel rods are designed to assure the design bases are satisfied for Condition I and II events. This assures that the fuel performance and safety criteria (Section 4.2) are satisfied.

4.2.1.3.1.1 Materials - Fuel Cladding

The desired fuel rod clad is a material which has a superior combination of neutron economy (low absorption cross section), high strength (to resist deformation due to differential pressures and mechanical interaction between fuel and clad), high corrosion resistance (to coolant, fuel and fission products), and high reliability. ZIRLO®/Optimized ZIRLO™ has this desired combination of clad properties. As shown in Reference 4, there is considerable PWR operating experience on the capability of Zircaloy and ZIRLO® as a clad material. Optimized ZIRLO™ has the same chemical composition as ZIRLO® with the exception of a lower tin content for improved corrosion resistance, Reference 16. Clad hydriding has not been a significant cause of clad perforation since current controls on levels of fuel contained moisture were instituted, Reference 4.

Metallographic examinations of irradiated commercial fuel rods have shown occurrences of fuel/clad chemical interaction. Reaction layers of < 1 mil in thickness have been observed between fuel and clad at limited points around the circumference. Westinghouse metallographic data indicates that this interface layer remains very thin even at high burnup. Thus, there is no indication of propagation of the layer and eventual clad penetration.

Stress corrosion cracking is another postulated phenomenon related to fuel/clad chemical interaction. Reaction tests have shown that in the presence of high clad tensile stresses, large concentrations of iodine can chemically attack the Zirconium-based alloy tubing and can lead to

eventual clad cracking. Westinghouse has no in reactor evidence that this mechanism is operative in commercial fuel.

4.2.1.3.1.2 Materials - Fuel Pellets

Sintered, high density uranium dioxide fuel reacts only slightly with the clad, at core operating temperatures and pressures. In the event of clad defects, the high resistance of uranium dioxide to attack by water protects against fuel deterioration although limited fuel erosion can occur. As has been shown by operating experience and extensive experimental work, the thermal design parameters conservatively account for changes in the thermal performance of the fuel elements due to pellet fracture which may occur during power operation. The consequences of defects in the clad are greatly reduced by the ability of uranium dioxide to retain fission products including those which are gaseous or highly volatile. Observations from several operating Westinghouse PWRs (References 2 and 4) have shown that fuel pellets can densify under irradiation to a density higher than the manufactured values. Fuel densification and subsequent incomplete settling of the fuel pellets results in local and distributed gaps in the fuel rods.

Fuel densification has been minimized by improvements in the fuel manufacturing process and by specifying a nominal initial fuel density of 95%.

The effects of fuel densification have been taken into account in the nuclear and thermal hydraulic design of the reactor described in Sections 4.3 and 4.4, respectively.

4.2.1.3.1.3 Materials - Strength Considerations

One of the most important limiting factors in fuel element duty is the mechanical interaction of fuel and clad. This fuel/clad interaction produces cyclic stresses and strains in the clad, and these in turn consume clad fatigue life. The reduction of fuel/clad interaction is therefore a principal goal of design. In order to achieve this goal and to enhance the cyclic operational capability of the fuel rod, the technology for using pre-pressurized fuel rods in Westinghouse PWR’s has been developed.

Initially the gap between the fuel and clad is sufficient to prevent hard contact between the two. However, during power operation a gradual compressive creep of the clad onto the fuel pellet occurs due to the external pressure exerted on the rod by the coolant. Clad compressive creep eventually results in the hard fuel/clad contact. During this period of fuel/clad contact, changes in power level could result in significant changes in clad stresses and strains. By using pre-pressurized fuel rods to partially offset the effect of the coolant external pressure, the rate of clad creep toward the surface of the fuel is reduced. Fuel rod pre-pressurization delays the time at which substantial fuel/clad interaction and hard contact occur and hence significantly reduces the number and extent of cyclic stresses and strains experienced by the clad both before and after fuel/clad contact. These factors result in an increase in the fatigue life margin of the clad and lead to greater clad reliability. If gaps should form in the fuel stacks, clad flattening will be prevented by the rod pre-pressurization so that the flattening time will be greater than the fuel core life.

4.2.1.3.1.4 Steady-State Performance Evaluation

In the calculation of the steady-state performance of a nuclear fuel rod, the following interacting factors must be considered:

1. Clad creep and elastic deflection,
2. Pellet density changes, thermal expansion, gas release, and thermal properties as a function of temperature and fuel burnup,
3. Internal pressure as a function of fission gas release, rod geometry, and temperature distribution.

These effects are evaluated using an overall fuel rod design model, per References 7 and 17 which include appropriate models for time dependent fuel densification. With these interacting factors considered, the model determines the fuel rod performance characteristics for a given rod geometry, power history, and axial power shape. In particular, internal gas pressure, fuel and clad temperatures, and clad deflections are calculated. The fuel rod is divided lengthwise into several sections and radially into a number of annular zones. Fuel density changes, clad stresses, strains and deformations, and fission gas releases are calculated separately for each segment. The effects are integrated to obtain the internal rod pressure.

The initial rod internal pressure is selected to delay fuel/clad mechanical interaction and to avoid the potential for flattened rod formation. It is limited, however, by the rod internal pressure design basis given in Section 4.2.1.1.1.

The gap conductance between the pellet surface and the clad inner diameter is calculated as a function of the composition, temperature, and pressure of the gas mixture, and the gap size or contact pressure between clad and pellet. After computing the fuel temperature for each pellet annular zone, the fractional fission gas release is assessed using an empirical model derived from experimental data in Reference 17. The total amount of gas released is based on the average fractional release within each axial and radial zone and the gas generation rate which in turn is a function of burnup. Finally, the gas released is summed over all zones and the pressure is calculated.

The model shows good agreement in fit for a variety of published and proprietary data on fission gas release, fuel temperatures and clad deflections, Reference 17. Included in this spectrum are variations in power, time, fuel density, and geometry. The in-pile fuel temperature measurement comparisons used are shown in Reference 17.

Typical fuel clad inner diameter and the fuel pellet outer diameter as a function of exposure are presented in Figure 4.2-8. The cycle to cycle changes in the pellet outer diameter represent the effects of power changes as the fuel is moved into different positions as a result of refueling. The gap size at any time is merely the difference between clad inner diameter and pellet outer diameter. Total clad-pellet surface contact occurs near the end of Cycle 2. The figure represents hot fuel dimensions for a fuel rod operating at the power level shown in Figure 4.2-9.
Figure 4.2-9 illustrates representative fuel rod internal gas pressure and linear power for the lead

burnup rod versus irradiation time. In addition, it outlines the typical operating range of internal gas pressures which is applicable to the total fuel rod population within a region. The “best estimate” fission gas release model was used in determining the internal gas pressures as a function of irradiation time. The plenum height of the fuel rod has been designed to ensure that the maximum internal pressure of the fuel rod will not exceed the design pressure of the reactor coolant.

The clad stresses at a constant local fuel rod power are low. Compressive stresses are created by the pressure differential between the coolant pressure and the rod internal gas pressure. Because of the pre-pressurization with helium, the volume average effective stresses are less than 13,500 psi at the pressurization level used in this fuel rod design. Stresses due to the temperature gradient are not included in this average effective stress because thermal stresses are, in general, negative at the clad inside diameter and positive at the clad outside diameter and their contribution to the clad volume average stress is small. Furthermore, the thermal stress decreases with time during steady-state operation due to stress relaxation. The stress due to pressure differential is highest in the minimum power rod at the beginning of life (due to low internal gas pressure). The thermal stress is highest in the maximum power rod (due to steep temperature gradient).

Tensile stresses could be created once the clad has come in contact with the pellet. These stresses would be induced by the fuel pellet swelling during irradiation. As shown in Figure 4.2-8, there is very limited clad pushout after pellet-clad contact. Fuel swelling can result in small clad strains (< 1%) for expected discharge burnups but the associated clad stresses are very low because of clad creep (thermal and irradiation-induced creep). Furthermore, the 1% strain criterion is extremely conservative for fuel-swelling driven clad strain because the strain rate associated with solid fission products swelling is very slow (-5×10^{-7} hr-1). In-pile experiments in Reference 8 have shown that Zircaloy tubing exhibits “super-plasticity” at slow strain rates during neutron irradiation. Uniform clad strains of greater than 10% have been achieved under these conditions with no sign of plastic instability.

4.2.1.3.1.5 Transient Evaluation Method

Pellet thermal expansion due to power increases is considered the only mechanism by which significant stresses and strains can be imposed on the clad. Power increases in commercial reactors can result from fuel shuffling (e.g., Region 3 positioned near the center of the core for Cycle 2 operation after operating near the periphery during Cycle 1), reactor power escalation following extended reduced power operation, and control rod movement. In the mechanical design model, lead rods are depleted using best estimate power histories as determined by core physics calculations. During the depletion, the amount of diametral gap closure is evaluated based upon the pellet expansion-cracking model, clad creep model, and fuel swelling model. At various times during depletion the rod power is assumed to increase locally up to the burnup dependent attainable power density as determined by core physics calculations. Historically, the radial, tangential, and axial clad stresses resulting from the power increase are combined into a volume average effective clad stress.

According to Reference 17, the fuel rod will not fail due to pellet clad interaction (PCI). The NRC Standard Review Plan (SRP) does not require a specific design criterion for PCI; however, there

are two criteria imposed to protect the cladding from PCI during Condition I and II operation: the 1% clad transient strain criterion and the fuel overheating (no melt) criterion. The hydrogen-based transient clad strain limit (Reference 35) can be used for Condition II overpower transients in lieu of the 1% clad strain limit. No further analysis of PCI is required in the fuel rod design except that these two design limits must be satisfied.

Slow transient power increases can result in large clad strains because of clad creep and stress. Based upon high strain rate burst and tensile test data on irradiated tubing, 1% transient strain was determined to be the lower limit on irradiated clad ductility and thus adopted as a design criterion. The hydrogen-based transient clad strain limit (Reference 35) can be used for Condition II overpower transients in lieu of the 1% clad strain limit.

In addition to the mechanical design models and design criteria, Westinghouse relies on performance data accumulated through transient power test programs in experimental and commercial reactors, and through normal operation in commercial reactors.

It is recognized that a possible limitation to the satisfactory behavior of the fuel rods in a reactor which is subjected to daily load follow is the failure of the clad by low cycle strain fatigue. During their normal residence time in reactor, the fuel rods may be subjected to 1,000 or more cycles with typical changes in power level from 50 to 100% of their steady-state values.

The assessment of the fatigue life of the fuel rod clad is subjected to a considerable uncertainty due to the difficulty of evaluating the strain range which results from the cyclic interaction of the fuel pellets and clad. This difficulty arises from such highly unpredictable phenomena as pellet cracking, fragmentation, and relocation. Nevertheless, since early 1968, Westinghouse has been investigating this particular phenomenon both analytically and experimentally. Strain fatigue tests on irradiated and nonirradiated hydrided Zircaloy-4 claddings were performed which permitted a definition of a conservative fatigue life limit and recommendation of a methodology to treat the strain fatigue evaluation of the Westinghouse reference fuel rod designs.

However, Westinghouse is convinced that the final proof of the adequacy of a given fuel rod design to meet the load follow requirements can only come from incore experiments performed on actual reactors. The Westinghouse experience in load follow operation dates back to early 1970 with the load follow operation of the Saxton reactor.

Successful load follow operation has been performed on reactor A (300 load follow cycles) and reactor B (150 load follow cycles). In both cases, there was no significant coolant activity increase that could be associated with the load follow mode of operation.

The following paragraphs present briefly the Westinghouse analytical approach to strain fatigue.

A comprehensive review of the available strain-fatigue models was conducted by Westinghouse as early as 1968. This included the Langer-O'Donnel model Reference 9, the Yao-Munse model, and the Manson-Halford model. Upon completion of this review and using the results of the Westinghouse experimental programs discussed below, it was concluded that the approach

defined by Langer-O'Donnel would be retained and the empirical factors of their correlation modified in order to conservatively bound the results of the Westinghouse testing program.The Langer-O'Donnel empirical correlation has the following form:

$$S_a = \frac{E}{4(N_f)^{0.5}} \ln\left(\frac{100}{100 - RA}\right) + S_e$$

Where:

S_a = 1/2 E $\Delta\varepsilon t$ = pseudo-stress amplitude which causes failure in N_f cycles (lb/in^2)

$\Delta\varepsilon t$ = total strain range (in/in)

E = Young's Modulus (lb/in^2)

N_f = number of cycles to failure

RA = reduction in area at fracture in a uniaxial tensile test (%)

S_e = endurance limit (lb/in^2)

Both RA and S_e are empirical constants which depend on the type of material, the temperature and irradiation. The Westinghouse testing program was subdivided in the following subprograms:

1. A rotating bend fatigue experiment on unirradiated Zircaloy-4 specimens at room temperature and at 725 °F. Both hydrided and nonhydrided Zircaloy-4 cladding were tested.
2. A biaxial fatigue experiment in gas autoclave on unirradiated Zircaloy-4 cladding both hydrided and nonhydrided.
3. A fatigue test program on irradiated cladding from the CVTR and Yankee Core V conducted at Battelle Memorial Institute.

The results of these test programs provided information on different cladding conditions including the effect of irradiation, hydrogen level, and temperature.

The Westinghouse design equations followed the concept for the fatigue design criterion according to the ASME Boiler and Pressure Vessel Code, Section III, namely:

1. The calculated pseudo-stress amplitude (S_a) has to be multiplied by a factor of 2 in order to obtain the allowable number of cycles (N_f).

2. The allowable cycles for a given S_a is 5% of N_f, or a safety factor of 20 on cycles.

The lesser of the 2 allowable number of cycles is selected. The cumulative fatigue life fraction is then computed as:

$$\sum_{1}^{k} \frac{n_k}{N_{fk}} \leq 1$$

Where:

n_k = number of diurnal cycles of mode k.

The potential effects of operation with waterlogged fuel are discussed in Section 4.4.3.6. Waterlogging is not considered to be a concern during operational transients.

4.2.1.3.1.6 Rod Bowing

Reference 10 presents the model used for evaluation of fuel rod bowing.

4.2.1.3.2 Fuel Assembly Structure

4.2.1.3.2.1 Stresses and Deflections

The fuel assembly component stress levels are limited by the design. For example, stresses in the fuel rod due to thermal expansion and cladding irradiation growth are limited by the relative motion of the rod as it slips over the grid spring and dimple surfaces. Clearances between the fuel rod ends and nozzles are provided so that cladding irradiation growth will not result in rod end interferences. Stresses in the fuel assembly caused by tripping of the rod cluster control assembly have little influence on fatigue because of the small number of events during the life of an assembly. Assembly components and prototype fuel assemblies made from production parts have been subjected to structural tests to verify that the design bases requirements are met.

The fuel assembly response resulting from the most limiting pipe break was analyzed using time-history numerical techniques. Since the resulting vessel motion induces primarily lateral loads on the reactor core, a finite element model similar to the seismic model described in Reference 31 was used to assess the fuel assembly deflections and impact forces.

The reactor core finite element model which simulates the fuel assembly interaction during lateral excitation consists of fuel assemblies arranged in a planer array with inter assembly gaps. For the Virgil C. Summer Nuclear Station the fuel assembly rows 15, 13, 11, 9, 7, and 3 were analyzed. The fuel assemblies and the reactor baffle supports are represented by single beam elements. Figure 4.2-28 shows this single beam schematic for row 15, the maximum number of assemblies across the core diameter. The time-history motion for the upper and lower core plates and the barrel at the upper core plate elevation are simultaneously applied to the simulated reactor core

model as illustrated in Figure 4.2-28. The 3 time-history motions were obtained from the time-history analysis of the reactor vessel and internals finite element model.

An evaluation of fuel assembly structural integrity considered the lateral effects of a LOCA accident with an upflow conversion determined that the seismic analysis of record remains applicable to the VC Summer Upflow conversion. The grid impact loads resulting from seismic and LOCA accidents were combined by SRSS (Square root sum of square) method. The safe shutdown earthquake and LOCA analyses indicated that the flow mixers will share some grid load among the structural grids. The analysis results confirmed that the calculated grid loads are less than the allowable limit except 3 fuel assembly (FA) row. According to Reference 32, the core coolable geometry is maintained when the crushed grids occur at 3 FA row.

Because the Virgil C. Summer Nuclear Station is not bounded by the LOCA/Seismic loads considered in Reference 25 and Reference 24, additional analyses have been performed to demonstrate fuel assembly structural integrity. The evaluation of the VANTAGE 5 fuel assembly, in accordance with NRC requirements as given in SRP 4.2, Appendix A, shows that the VANTAGE 5 fuel is structurally acceptable for an all VANTAGE 5 core; the grids will not buckle due to combined impact forces of a seismic/LOCA event except in the 3 fuel assembly row. Since the 3 fuel assembly row is located at a low powered region, the core coolable geometry is maintained based on Reference 32. The stresses in the fuel assembly components resulting from seismic and LOCA loads are well within acceptable limits ensuring that the reactor can be safely shutdown under the combined faulted condition loads.

Since the 17x17 OFA fuel assembly is structurally identical to that of VANTAGE 5, the evaluations discussed above are also applicable to 17x17 OFA fuel.

The fuel assembly design loads for shipping have been established at 6 g lateral and 4 g axial. Accelerometers are permanently placed into the shipping cask to monitor and detect fuel assembly accelerations that would exceed the criteria. Past history and experience has indicated that loads which exceed the allowable limits rarely occur. Exceeding the limits requires reinspection of the fuel assembly for damage. Tests on various fuel assembly components such as the grid assembly, sleeves, inserts and structure joints have been performed to assure that the shipping design limits do not result in impairment of fuel assembly function.

4.2.1.3.2.2 Dimensional Stability

The VANTAGE 5 Mechanical Test Program description and results are given in Appendix A of Reference 24 and are considered to be applicable to 17x17 OFA as the 2 assemblies are essentially identical from a structural standpoint.

The coolant flow channels are established and maintained by the structure composed of grids and guide thimbles. The lateral spacing between fuel rods is provided and controlled by the support dimples of adjacent grid cells. Contact of the fuel rods on the dimples is maintained through the clamping force of the grid springs. Lateral motion of the fuel rods is opposed by the spring force and the internal moments generated between the spring and the support dimples.

No interference with control rod insertion into thimble tubes will occur during a postulated loss of coolant accident transient due to fuel rod swelling, thermal expansion, or bowing. In the early phase of the transient following the coolant break, the high axial loads, which potentially could be generated by the difference in thermal expansion between fuel clad and thimbles, are relieved by slippage of the fuel rods through the grids. The relatively low drag force restraint on the fuel rods will induce only minor thermal bowing, which is insufficient to close the fuel rod-to-thimble tube gap. This rod-to-grid slip mechanism occurs simultaneously with control rod drop. Subsequent to the control rod insertion the transient temperature increase of the fuel rod clad can result in swelling sufficient to contact the thimbles.

4.2.1.3.2.3 Vibration and Wear

Fuel rod vibrations are flow induced. The effect of the vibration on the fuel assembly and individual fuel rods is minimal. The cyclic stress range associated with deflections of such small magnitude is insignificant and has no effect on the structural integrity of the fuel rod.

The reaction force on the grid supports due to rod vibration is small and is much less than the spring preload. Firm contact is maintained. No significant wear of the clad or grid supports is expected during the life of the fuel assembly.

Clad fretting and fuel rod vibration has been experimentally investigated as discussed in Reference 24 for VANTAGE 5 fuel and is applicable directly to the 17x17 OFA fuel design.

4.2.1.3.3 Operational Experience

A discussion of fuel operating experience is given in Reference 4.

4.2.1.4 Tests and Inspections

4.2.1.4.1 Quality Assurance Program

The Quality Assurance Program Plan of the Westinghouse Commercial Nuclear Fuel Division is summarized in Reference 13.

The program provides for control over all activities affecting product quality, commencing with design and development, and continuing through procurement, materials handling, fabrication, testing and inspection, storage, and transportation. The program also provides for the indoctrination and training of personnel and for the auditing of activities affecting product quality through a formal auditing program.

Westinghouse drawings and product, process, and material specifications identify the inspection to be performed.

4.2.1.4.2 Quality Control

Quality control philosophy is generally based on the following inspections being performed to a 95% confidence that at least 95% of the product meets specification, unless otherwise noted.

1. Fuel System Components and Parts

   The characteristics inspected depends upon the component parts and includes dimensional, visual, check audits of test reports, material certification and nondestructive examination such as X-Ray and ultrasonic.

   All material used in this core is verified and released by Quality control.

2. Pellets

   Inspection is performed for dimensional characteristics such as diameter, density, length and squareness of ends. Additional visual inspections are performed for cracks, chips and surface conditions according to approved standards.

   Density is determined in terms of weight per unit length and is plotted on zone charts used in controlling the process. Chemical analyses are taken on a specified sample basis through pellet production.

3. Rod Inspection

   Fuel rod, control rodlet, burnable poison and source rod inspection consists of the following nondestructive examination techniques and methods, as applicable.

   a. Leak Testing

      Each rod is tested using a calibrated mass spectrometer with helium being the detectable gas.

   b. Enclosure Welds

      Rod welds are inspected by ultrasonic test or X-ray in accordance with a qualified technique and Westinghouse specifications.

   c. Dimensional

      All rods are dimensionally inspected prior to final release. The requirements include such items as length, camber, and visual appearance.

   d. Plenum Dimensions

      100% of the fuel rods are inspected by gamma scanning or other approved methods to ensure proper plenum dimensions.

   e. Pellet-to-Pellet Gaps

100% of the fuel rods are inspected by gamma scanning or other methods to ensure that no significant gaps exist between pellets.

f. Pellet Enrichment

100% of the fuel rods are active gamma scanned to verify enrichment control prior to acceptance for assembly loading.

g. Traceability

Traceability of rods and associated rod components is established by Quality Control.

4. Assemblies

Each fuel, control rod, burnable absorber and source rod assembly is inspected for drawing and/or specification requirements. Other incore control component inspection and specification requirements are given in Section 4.2.3.4.

5. Other Inspections

The following inspections are performed as part of the routine inspection operation:

a. Tool and gage inspection and control including standardization to primary and/or secondary working standards. Tool inspection is performed at prescribed intervals on all serialized tools. Complete records are kept of calibration and conditions of tools.

b. Audits are performed of inspection activities and records to assure that prescribed methods are followed and that records are correct and properly maintained.

c. Surveillance inspection where appropriate, and audits of outside contractors are performed to ensure conformance with specified requirements.

6. Process Control

To prevent the possibility of mixing enrichments during fuel manufacture and assembly, strict enrichment segregation and other process controls are exercised.

The UO_2 powder is kept in sealed containers or is processed in a closed system. The containers are either fully identified both by descriptive tagging and preselected color coding or, for the closed system, the material is monitored by a computer data management information system. For the sealed container system, a Westinghouse identification tag completely describing the contents is affixed to the containers before transfer to powder storage. Isotopic content is confirmed by analysis.

Powder withdrawal from storage can be made by only one authorized group, which directs the powder to the correct pellet production line. All pellet production lines are physically separated from each other and pellets of only a single nominal enrichment and density are produced in a given production line.

Finished pellets are placed on trays and transferred to segregated storage racks within the confines of the pelleting area. Samples from each pellet lot are tested for physical and chemical properties including isotopic content and impurity levels prior to acceptance by Quality Control. Physical barriers prevent mixing of pellets of different nominal designs and enrichment in this storage area. Unused powder and substandard pellets are returned to storage for disposition.

Loading of pellets into the clad is performed in isolated production lines and again only one density and enrichment is loaded on a line at a time.

A serialized traceability code is placed on each fuel tube which identifies the enrichment. The end plugs are inserted and then inert welded to seal the tube. The fuel tube remains coded and traceability identified until just prior to installation in the fuel assembly.

At the time of installation into an assembly, the traceability codes are removed and a matrix is generated to identify each rod in its position within a given assembly. After the fuel rods are installed, an inspector verifies that all fuel rods in an assembly carry the correct identification character describing the fuel enrichment and density for the core region being fabricated. The top nozzle is inscribed with a permanent identification number providing traceability to the fuel contained in the assembly.

Similar traceability is provided for burnable absorber, source rods and control rodlets as required.

4.2.1.4.3 Onsite Inspection

Onsite inspection programs for fuel, control rods, and internals are based on the NSSS supplier's detailed procedures. In the event reloads or other components are supplied by other suppliers, additional programs will be developed based on that supplier's procedures.

Loaded fuel containers, when received onsite, are externally inspected to ensure that labels and markings are intact and seals are unbroken. After the containers are opened, the shock indicators attached to the suspended internals are inspected to determine if movement during transit exceeded design limitations.

Following removal of the fuel assembly from the container in accordance with detailed procedures from the fuel fabricator the polyethylene wrapper is then removed and a visual inspection of the entire bundle is performed.

Control rod assemblies are normally shipped in fuel assemblies and are drag tested in the fuel assembly by the fuel vendor prior to shipment. Upon receipt at the site, the exposed section of the control rod assembly is visibly inspected for mechanical integrity and the control rod assembly is then stored with the fuel assembly.

Reactor internals are visually inspected and manually checked for tightness upon receipt at the site. Clearance measurements performed during assembly and installation in accordance with the manufacturer's detailed procedures, also serve to verify the mechanical integrity of the internals.

Surveillance of fuel and reactor performance is routinely conducted by operating personnel. Coolant activity and chemistry are followed to permit early detection of any fuel clad defects.

Visual fuel inspection in accordance with the EPRI-Fuel Reliability Guidelines Reference 18 is conducted during refueling. This type of inspection is capable of identifying gross anomalies such as broken fuel rods or torn grid straps. Additional fuel inspections are dependent on the results of the operational monitoring and visual inspection.

4.2.2 Reactor Vessel Internals

4.2.2.1 Design Bases

The design bases for the mechanical design of the reactor vessel internals components are as follows:

1. The reactor internals in conjunction with the fuel assemblies shall direct reactor coolant through the core to achieve acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements are met for all modes of operation. In addition, required cooling for the pressure vessel head shall be provided so that the temperature differences between the vessel flange and head do not result in leakage from the flange during reactor operation.
2. In addition to neutron shielding provided by the reactor coolant, the reactor internals are designed to limit the exposure of the pressure vessel in order to maintain the required ductility of the material for all modes of operation.
3. Provisions shall be made for installing incore instrumentation useful for the plant operation and vessel material test specimens required for a pressure vessel irradiation surveillance program.
4. The core internals are designed to withstand mechanical loads arising from operating basis earthquake, safe shutdown earthquake and pipe ruptures and meet the requirement of item 5 below.
5. The reactor shall have mechanical provisions which are sufficient to adequately support the core and internals and to assure that the core is intact with acceptable heat transfer geometry following transients arising from abnormal operating conditions.
6. Following the design basis accident, the plant shall be capable of being shutdown and cooled in an orderly fashion so that fuel cladding temperature is kept within specified limits. This implies that the deformation of certain critical reactor internals must be kept sufficiently small to allow core cooling.

The functional limitations for the core structures during the design basis accident are shown in Table 4.2-1. To ensure no column loading of rod cluster control guide tubes, the upper core plate deflection is limited to not exceed the value shown in Table 4.2-1. Details of the dynamic analyses, input forcing functions, and response loadings are presented in Section 3.9.

4.2.2.2 Description and Drawings

The reactor vessel internals are described as follows:

The components of the reactor internals are divided into 3 parts consisting of the lower core support structure (including the entire core barrel and neutron shield pad assembly), the upper core support structure and the incore instrumentation support structure. The reactor internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and control rod drive mechanisms, direct coolant flow past the fuel elements, direct coolant flow to the pressure vessel head, provide gamma and neutron shielding, and guides for the incore instrumentation. The coolant flows from the vessel inlet nozzles down the annulus between the core barrel and the vessel wall and then into a plenum at the bottom of the vessel. It then reverses and flows up through the core support and through the lower core plate. The lower core plate is sized to provide the desired inlet flow distribution to the core. After passing through the core, the coolant enters the region of the upper support structure and then flows radially to the core barrel outlet nozzles and directly through the vessel outlet nozzles. A small portion of the coolant flows between the baffle plates and the core barrel to provide additional cooling of the barrel. Beginning with Cycle 19, the direction of coolant flow between the baffle plates and core barrel was changed from a downflow configuration to an upflow configuration to reduce baffle jetting - related fuel failures. Similarly, a small amount of the entering flow is directed into the vessel head plenum and exits through the vessel outlet nozzles.

All the major material for the reactor internals is Type 304 stainless steel. Parts not fabricated from Type 304 stainless steel include bolts and dowel pins which are fabricated from Type 316 stainless steel and radial support key bolts which are fabricated of Inconel-750. These materials are listed in Table 5.2-12. There are no other materials used in the reactor internals or core support structures which are not otherwise included in ASME Code, Section III, Appendix I.

The discussions provided in Sections 5.2.3 and 5.2.5 are applicable to the welding of reactor internals and core support components.

The discussions provided in Sections 5.2.5.1, 5.2.5.2, 5.2.5.3, 5.2.5.4, 5.2.5.5, and 5.2.5.6 are applicable to the degree of conformance of reactor internals and core support structures with Regulatory Guide 1.44.

The discussion provided in Section 5.2.5.7 addresses Regulatory Guide 1.31 with respect to reactor internals and core support structures.

Appendix 3A addresses Regulatory Guides 1.66 and 1.71 with respect to reactor internals and core support structures.

Austenitic stainless steel is used for the majority of reactor internals structures, and this material is not subject to brittle fracture. The core hold down spring, however, is made of Type 403 stainless steel. Significant crack growth has been found to be impossible for this component considering the stress state and possible flaw size. The core hold down spring is the only stainless steel

material in the reactor core support structure with a yield strength greater than 90,000 psi and is acceptable based upon Code Case 1337.

All reactor internals are removable from the vessel for the purpose of their inspection as well as the inspection of the vessel internal surface.

4.2.2.2.1 Lower Core Support Structure

The major containment and support member of the reactor internals is the lower core support structure, shown in Figure 4.2-10. This support structure assembly consists of the core barrel, the core baffle, the lower core plate and support columns, the neutron shield pads, and the core support which is welded to the core barrel. All the major material for this structure is Type 304 stainless steel. The lower core support structure is supported at its upper flange from a ledge in the reactor vessel head flange and its lower end is restrained in its transverse movement by a radial support system attached to the vessel wall. Within the core barrel are in axial baffle and a lower core plate, both of which are attached to the core barrel wall and form the enclosure periphery of the assembled core. The lower core support structure and principally the core barrel serve to provide passageways and control for the coolant flow. The lower core plate is positioned at the bottom level of the core below the baffle plates and provides support and orientation for the fuel assemblies.

The lower core plate is a member through which the necessary flow distribution holes for each fuel assembly are machined. Fuel assembly locating pins (2 for each assembly) are also inserted into this plate. Columns are placed between this plate and the core support of the core barrel in order to provide stiffness and to transmit the core load to the core support. Adequate coolant distribution is obtained through the use of the lower core plate and core support.

The neutron shield pad assembly consists of 4 pads that are bolted and pinned to the outside of the core barrel. These pads are constructed of Type 304 stainless steel and are approximately 48 inches wide by 148 inches long by 2.8 inches thick. The pads are located azimuthally to provide the required degree of vessel protection. Specimen guides in which material surveillance samples can be inserted and irradiated during reactor operation are attached to the pads. The samples are held in the guides by a preloaded spring device at the top and bottom to prevent sample movement. Additional details of the neutron shield pads and irradiation specimen holders are given in Reference 14.

Vertically downward loads from weight, fuel assembly preload, control rod dynamic loading, hydraulic loads and earthquake acceleration are carried by the lower core plate partially into the lower core plate support flange on the core barrel shell and partially through the lower support columns to the core support and thence through the core barrel shell to the core barrel flange supported by the vessel head flange. Transverse loads from earthquake acceleration, coolant cross flow, and vibration are carried by the core barrel shell and distributed between the lower radial support to the vessel wall, and to the vessel flange. Transverse loads of the fuel assemblies are transmitted to the core barrel shell by direct connection of the lower core plate to the barrel wall and by upper core plate alignment pins which are welded onto the core barrel.

The main radial support system of the lower end of the core barrel is accomplished by “key” and “key-way” joints to the reactor vessel wall. At equally spaced points around the circumference, an Inconel clevis block is welded to the vessel inner diameter. Another Inconel insert block is bolted to each of these blocks and has a “key-way” geometry. Opposite each of these is a “key” which is attached to the internals. At assembly, as the internals are lowered into the vessel, the keys engage the keyways in the axial direction. With this design, the internals are provided with a support at the furthest extremity, and may be viewed as a beam fixed at the top and simply supported at the bottom.

Radial and axial expansions of the core barrel are accommodated but transverse movement of the core barrel is restricted by this design. With this system, cyclic stresses in the internal structures are within the ASME Section III limits. In the event of an abnormal downward vertical displacement of the internals following a hypothetical failure, energy absorbing devices limit the displacement after contacting the vessel bottom head. The load is then transferred through the energy absorbing devices of the internals to the vessel.

The energy absorbers, cylindrical in shape, are contoured on their bottom surface to the reactor vessel bottom head geometry. Assuming a downward vertical displacement the potential energy of the system is absorbed mostly by the strain energy of the energy absorbing devices.

4.2.2.2.2 Upper Core Support Assembly

The upper core support assembly, shown in Figures 4.2-11 and 4.2-12 consists of the upper support plate assembly and the upper core plate between which are contained support columns and guide tube assemblies. The support columns establish the spacing between the upper support plate assembly and the upper core plate and are fastened at top and bottom to these plates. The support columns transmit the mechanical loadings between the 2 plates and serve the supplementary function of supporting thermocouple guide tubes. The guide tube assemblies, sheath and guide the control rod drive shafts and control rods. They are fastened to the top support plate and are restrained by pins in the upper core plate for proper orientation and support. Additional guidance for the control rod drive shafts is provided by the upper guide tube which is attached to the upper support plate and guide tube.

The upper core support assembly is positioned in its proper orientation with respect to the lower support structure by flat-sided pins pressed into the core barrel which in turn engage in slots in the upper core plate. At an elevation in the core barrel where the upper core plate is positioned, the flat-sided pins are located at angular positions of 90° from each other. Four (4) slots are milled into the core plate at the same positions. As the upper support structure is lowered into the main internals, the slots in the plate engage the flat-sided pins in the axial direction. Lateral displacement of the plate and of the upper support assembly is restricted by this design. Fuel assembly locating pins protrude from the bottom of the upper core plate and engage the fuel assemblies as the upper assembly is lowered into place. Proper alignment of the lower core support structure, the upper core support assembly, the fuel assemblies and control rods are thereby assured by this system of locating pins and guidance arrangement. The upper core support assembly is restrained from any axial movements by a large circumferential spring which rests

between the upper barrel flange and the upper core support assembly and is compressed by the reactor vessel head flange.

Vertical loads from weight, earthquake acceleration, hydraulic loads and fuel assembly preload are transmitted through the upper core plate via the support columns to the top support plate assembly and then the reactor vessel head. Transverse loads from coolant cross flow, earthquake acceleration, and possible vibrations are distributed by the support columns to the top support plate and upper core plate. The top support plate is particularly stiff to minimize deflection.

The following information describes repairs which were made to the original Reactor Vessel Head. Although these components are no longer installed at VCS, this information is being retained for historical purposes. During RF-20 and RF-21, repairs were performed to mitigate Primary Water Stress Corrosion Cracking (PWSCC) in the CRDM nozzle J-groove welds in the Reactor Vessel Upper Head enclosure (per ECR-50846). The J-groove weld repairs follow WCAP-15987-P, Rev. 2-P-A, Rev. 2-P-A, “Technical Basis for the Embedded Flaw Process for Repair of Reactor Vessel Head Penetrations,” which has been approved by the NRC on April 30, 2014, under Relief Request RR-4-05 Alternative Weld Repair for Reactor Vessel Upper Head Penetrations.” This repair required the permanent removal of the Part-Length (P/L) Mechanism drive rod located in penetration #19 during RF-20. Additional P/L CRDM drive rods were cut in penetrations #1 and 18 in RF-21 to facilitate the thermal sleeve degradation inspections. To retain the flow characteristics through the upper internals, flow restrictors were mechanically clamped into the Upper Internals assembly guide tubes which sit under RV Head penetration #1, 18 and 19.

4.2.2.2.3 Incore Instrumentation Support Structures

The incore instrumentation support structures consist of an upper system to convey and support thermocouples penetrating the vessel through the head and a lower system to convey and support flux thimbles penetrating the vessel through the bottom (Figure 7.7-9 shows the basic flux-mapping system).

The upper system utilizes the reactor vessel head penetrations. Instrumentation port columns are slip-connected to inline columns that are in turn fastened to the upper support plate. These port columns protrude through the head penetrations. The thermocouples are carried through these port columns and the upper support plate at positions above their readout locations. The thermocouple conduits are supported from the columns of the upper core support system. The thermocouple conduits are sealed stainless steel tubes.

In addition to the upper incore instrumentation, there are reactor vessel bottom port columns which carry the retractable, cold worked stainless steel flux thimbles that are pushed upward into the reactor core. Conduits extend from the bottom of the reactor vessel down through the concrete shield area and up to a thimble seal line. The minimum bend radii are about 144 inches and the trailing ends of the thimbles (at the seal line) are extracted approximately 15 feet during refueling of the reactor in order to avoid interference within the core. The thimbles are closed at the leading ends and serve as the pressure barrier between the reactor pressurized water and the containment atmosphere.

Mechanical seals between the retractable thimbles and conduits are provided at the seal line. During normal operation, the retractable thimbles are stationary and move only during refueling or for maintenance, at which time a space of approximately 15 feet above the seal line is cleared for the retraction operation.

The incore instrumentation support structure is designed for adequate support of instrumentation during reactor operation and is designed to resist damage or distortion under the conditions imposed by handling during the refueling sequence. These are the only conditions which affect the incore instrumentation support structure. Reactor vessel surveillance specimen capsules are covered in Section 5.4.3.6.

4.2.2.3 Design Loading Conditions

The design loading conditions that provide the basis for the design of the reactor internals are:

1. Fuel Assembly Weight
2. Fuel Assembly Spring Forces
3. Internals Weight
4. Control Rod Trip (equivalent static load)
5. Differential Pressure
6. Spring Preloads
7. Coolant Flow Forces (static)
8. Temperature Gradients
9. Differences in thermal expansion
    a. Due to temperature differences
    b. Due to expansion of different materials.
10. Interference between components
11. Vibration (mechanically or hydraulically induced)
12. One (1) or more loops out of service
13. All operational transients listed in Table 5.2-2
14. Pump overspeed
15. Seismic loads (operating basis earthquake and safe shutdown earthquake)
16. Blowdown forces (due to cold and hot leg break)

The main objective of the design analysis is to satisfy allowable stress limits, to assure an adequate design margin, and to establish deformation limits which are concerned primarily with the functioning of the components. The stress limits are established not only to assure that peak stresses will not reach unacceptable values, but also limit the amplitude of the oscillatory stress

component in consideration of fatigue characteristics of the materials. Both low and high cycle fatigue stresses are considered when the allowable amplitude of oscillation is established. Dynamic analysis on the reactor internals are provided in Section 3.9.

As part of the evaluation of design loading conditions, extensive testing and inspections are performed from the initial selection of raw materials up to and including component installation and plant operation. Among these tests and inspections are those performed during component fabrication, plant construction, startup and checkout, and during plant operation.

4.2.2.4 Design Loading Categories

The combination of design loadings fit into either the normal, upset, emergency or faulted conditions as defined in the ASME Code, Section III.

Loads and deflections imposed on components due to shock and vibration are determined analytically and experimentally in both scaled models and operating reactors. The cyclic stresses due to these dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces and thermal gradients for the determination of the total stresses of the internals.

The reactor internals are designed to withstand stresses originating from various operating conditions as summarized in Table 5.2-2.

The scope of the stress analysis problem is very large requiring many different techniques and methods, both static and dynamic. The analysis performed depends on the mode of operation under consideration.

For normal operating conditions, downward vertical deflection of the lower core support plate is negligible.

For the loss of coolant accident plus the safe shutdown earthquake condition, the deflection criteria of critical internal structures are the limiting values given in Table 4.2-1. The corresponding no loss of function limits are included in Table 4.2-1 for comparison purposes with the allowed criteria.

The criteria for the core drop accident is based upon analyses which have to determine the total downward displacement of the internal structures following a hypothesized core drop resulting from loss of the normal core barrel supports. The initial clearance between the secondary core support structures and the reactor vessel lower head in the hot condition is approximately 1/2 inch. An additional displacement of approximately 3/4 inch would occur due to strain of the energy absorbing devices of the secondary core support; thus the total drop distance is about 1-1/4 inches which is insufficient to permit the tips of the rod cluster control assembly to come out of the guide thimble in the fuel assemblies.

Specifically, the secondary core support is a device which is never expected to be used, except during a hypothetical accident of the core support (core barrel, barrel flange, etc.). There are 4 supports in each reactor. This device limits the fall of the core and absorbs the energy of the fall which otherwise would be imparted to the vessel. The energy of the fall is calculated assuming a complete and instantaneous failure of the primary core support and is absorbed during the plastic deformation of the controlled volume of stainless steel, loaded in tension. The maximum deformation of this austenitic stainless piece is limited to approximately 15%, after which a positive stop is provided to ensure support.

For additional information on design loading categories see Section 3.9.

4.2.2.5 Design Criteria Basis

For normal operating conditions Section III of the ASME Nuclear Power Plant Components Code is used as a basis for evaluating acceptability of calculated stresses. Both static and alternating stress intensities are considered. It should be noted that the allowable stresses in Section III of the ASME Code are based on unirradiated material properties. In view of the fact that irradiation increases the strength of the Type 304 stainless steel used for the internals, although decreasing its elongation, it is considered that use of the allowable stresses in Section III is appropriate and conservative for irradiated internal structures.

The allowable stress limits during the design basis accident used for the core support structures are based on the January 1971 draft of the ASME Code for Core Support Structures, Subsection NG, and the Criteria for Faulted Conditions.

4.2.3 Reactivity Control System

4.2.3.1 Design Bases

Bases for temperature, stress on structural members, and material compatibility are imposed on the design of the reactivity control components.

4.2.3.1.1 Design Stresses

The reactivity control system is designed to withstand stresses originating from various operating conditions as summarized in Table 5.2-2.

1. Allowable Stresses

   For normal operating conditions Section III of the ASME Boiler and Pressure Vessel Code is used. All pressure boundary components are analyzed as Class 1 components under Article NB-3000.

2. Dynamic Analysis

The cyclic stresses due to dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces and thermal gradients for the determination of the total stresses of the reactivity control system.

4.2.3.1.2 Material Compatibility

Materials are selected for compatibility in a PWR environment, for adequate mechanical properties at room and operating temperature, for resistance to adverse property changes in a radioactive environment, and for compatibility with interfacing components.

4.2.3.1.3 Reactivity Control Components

The reactivity control components are subdivided into 2 categories:

1. Permanent devices used to control or monitor the core and,
2. Optional devices used to control or monitor the core.

The permanent type components are the rod cluster control assemblies (contain absorber rods), control rod drive mechanisms and neutron source assemblies. The optional type components are the IFBA, burnable absorber assembly, and thimble plug assembly. Although the thimble plug assembly does not directly contribute to the reactivity control of the reactor, it is presented as a reactivity control system component in this document because it may be used to restrict bypass flow through those thimbles not occupied by absorber, source or burnable absorber rods. The design bases for each of the mentioned components, except the IFBA rods, are in the following paragraphs. The IFBA rods are discussed in the Fuel Section 4.2.1.

4.2.3.1.3.1 Absorber Rods

The following are considered design conditions under Article NB-3000 of the ASME Boiler and Pressure Vessel Code, Section III.

1. The external pressure equal to the reactor coolant system operating pressure.
2. The wear allowance equivalent to 1,000 reactor trips.
3. Bending of the rod due to a misalignment in the guide tube.
4. Forces imposed on the rods during rod drop.
5. Loads caused by accelerations imposed by the control rod drive mechanism.
6. Radiation exposure for maximum core life.

The control rod which is cold rolled Type 304 stainless steel is the only noncode material used in the control rod assembly. The stress intensity limit Sm for this material is defined at 2/3 of the 0.2% offset yield stress.

The absorber material temperature shall not exceed its melting temperature of 1470 °F for silver-indium-cadmium alloy absorber material (Reference 15).

4.2.3.1.3.2 Burnable Absorber Rods

The burnable absorber rods may be of the design containing borosilicate glass or the Wet Annular Burnable Absorber (WABA) design containing Al_2O_3-B_4C absorber material. The burnable absorber rod clad (304 SS for the borosilicate design and Zircaloy 4 for the WABA design) is designed using the requirements of a Class 1 component under Article NB-3000 of the ASME Boiler and Pressure Vessel Code, Section III, 1973 for Conditions I and II as a guide. For abnormal loads during Conditions III and IV, code stresses are not considered limiting. Failures of the burnable absorber rods during these conditions must not interfere with reactor shutdown or cooling of the fuel rods.

The burnable poison absorber material is nonstructural. The structural elements of the burnable absorber rod are designed to maintain the absorber geometry even if the absorber material is fractured. The rods are designed so that the borosilicate absorber material is below its softening temperature (1492 °F (1) for reference 12.5 w/o boron rods), and the Al_2O_3-B_4C material is below 1200 °F during normal operation or overpower transients.

(1) Borosilicate glass is accepted for use in burnable absorber rods if the softening temperature is 1510 ± 18 °F. The softening temperature is defined in ASTM C 338.

4.2.3.1.3.3 Neutron Source Rods

The neutron source rods are designed to withstand the following:

1. The external pressure equal to the reactor coolant system operating pressure and
2. An internal pressure equal to the pressure generated by released gases over the source rod life.

4.2.3.1.3.4 Thimble Plug Assembly (if used)

The thimble plug assemblies satisfy the following:

1. Accommodate the differential thermal expansion between the fuel assembly and the core internals.
2. Maintain positive contact with the fuel assembly and the core internals.
3. Be inserted into the fuel assembly by a force not exceeding 40 pounds.

4.2.3.1.4 Control Rod Drive Mechanisms

The control rod drive mechanisms (CRDMs) pressure housings are Class 1 components designed to meet the stress requirements for normal operating conditions of Section III of the ASME Boiler

and Pressure Vessel Code. Both static and alternating stress intensities are considered. The stresses originating from the required design transients are included in the analysis.

A dynamic seismic analysis is required on the CRDMs when a seismic disturbance has been postulated to confirm the ability of the pressure housing to meet ASME Code, Section III allowable stresses and to confirm its ability to trip when subjected to the seismic disturbance.

4.2.3.1.4.1 Control Rod Drive Mechanism Operation Requirements

The basic operational requirements for the CRDMs are:

1. 5/8 inch step,
2. 144 inch travel,
3. 360 pound maximum load (includes drive rod weight),
4. Step in or out at 5 to 45 inches/minute (8 to 72 steps/minute),
5. Electrical power interruption shall initiate release of drive rod assembly,
6. Trip delay time of less than 150 milliseconds - Free fall of drive rod assembly shall begin less than 150 milliseconds after power interruption no matter what holding or stepping action is being executed with any load and coolant temperature of 100 °F to 550 °F.
7. 40 year design life with normal refurbishment.

4.2.3.2 Design Description

Reactivity control is provided by IFBA pins, burnable absorber rods, and a soluble chemical neutron absorber (boric acid). The boric acid concentration is varied to control long term reactivity changes such as:

1. Fuel depletion and fission product buildup.
2. Cold to hot, zero power reactivity change.
3. Reactivity change produced by intermediate term fission products such as xenon and samarium.
4. Burnable absorber depletion.

Chemical and volume control is covered in Section 9.3.4.

The rod cluster control assemblies provide reactivity control for:

1. Shutdown.
2. Reactivity changes due to coolant temperature changes in the power range.
3. Reactivity changes associated with the power coefficient or reactivity.
4. Reactivity changes due to void formation.

The neutron source assemblies provide a means of monitoring the core during periods of low neutron activity.

The most effective reactivity control components are the rod cluster control assemblies and their CRDMs which are the only kinetic parts in the reactor. Figure 4.2-13 identifies the full length rod cluster control and CRDM assembly, in addition to the arrangement of these components in the reactor relative to the interfacing fuel assembly and guide tubes. In the following paragraphs, each reactivity control component is described in detail.

The guidance system for the control rod cluster is provided by the guide tube as shown in Figure 4.2-13. The guide tube provides 2 sections of guidance: 1) In the lower section a continuous guidance system provides support immediately above the core. The system protects the rod against excessive deformation and wear due to hydraulic loading. 2) The region above the continuous section provides support and guidance at uniformly spaced intervals.

The envelope of support is determined by the pattern of the control rod cluster as shown in Figure 4.2-14. The guide tube assures alignment and support of the control rods, spider body, and drive rod while maintaining trip times at or below required limits.

4.2.3.2.1 Reactivity Control Components

4.2.3.2.1.1 Rod Cluster Control Assembly

The rod cluster control assemblies are divided into 2 categories: control and shutdown. The control groups compensate for reactivity changes due to variations in operating conditions of the reactor; i.e., power and temperature variations. Two (2) criteria have been employed for selection of the control group. First the total reactivity worth must be adequate to meet the nuclear requirements of the reactor. Second, in view of the fact that these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that the power capability is met. The control and shutdown group provides adequate shutdown margin which is defined as the amount by which the core would be subcritical at hot shutdown if all rod cluster control assemblies are tripped assuming that the highest worth assembly remains fully withdrawn and assuming no changes in xenon or boron concentration.

A rod cluster control assembly comprises a group of individual neutron absorber rods fastened at the top end to a common spider assembly, as illustrated in Figure 4.2-14.

The absorber material used in the control rods is silver-indium-cadmium alloy which is essentially “black” to thermal neutrons and has sufficient additional resonance absorption to significantly increase its worth. The alloy is in the form of extruded rods which are sealed in stainless steel tubes to prevent the rods from coming in direct contact with the coolant. In construction, the silver-indium-cadmium rods are inserted into cold-worked stainless steel tubing which is then sealed at the bottom and the top by welded end plugs as shown in Figure 4.2-15. Sufficient diametral and end clearance is provided to accommodate relative thermal expansions. A thin layer of chrome electroplate is applied to the stainless steel cladding.

The bottom plugs are made bullet-nosed to reduce the hydraulic drag during reactor trip and to aid smooth entry into the dashpot section of the fuel assembly guide thimbles. The upper plug is threaded for assembly to the spider and has a reduced end section to make the joint more flexible.

The material used in the absorber rod end plugs is Type 308 stainless steel. The design stresses used for the Type 308 material are the same as those defined in the ASME Code, Section III, for Type 304 stainless steel. At room temperature the yield and ultimate stresses per ASTM-580 are exactly the same for the 2 alloys. In view of the similarity of the alloy composition, the temperature dependence of strength for the 2 materials is also assumed to be the same.

The allowable stresses used as a function of temperature are listed in Table 1-1.2 of Section III of the ASME Boiler and Pressure Vessel Code. The fatigue strength for the Type 308 material is based on the S-N curve for austenitic stainless steels in Figure 1-9.2 of Section III. There are no other applications of stressed wrought Type 308 stainless steel in the control rod assembly.

The spider assembly is in the form of a central hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Handling detents and detents for connection to the drive rod assembly are machined into the upper end of the hub. A coil spring inside the spider body absorbs the impact energy at the end of a trip insertion. The radial vanes are joined to the hub by tack welds and brazing while the fingers are joined to the vanes by brazing alone. A centerpost which holds the spring and its retainer is threaded into the hub within the skirt and welded to prevent loosening in service. All components of the spider assembly are made from Types 304 and 308 stainless steel except for the retainer which is of 17-4 PH material and the springs which are Inconel-718 alloy or oil tempered carbon steel where the springs do not contact the coolant.

The absorber rods are fastened securely to the spider to assure trouble free service. The rods are first threaded into the spider fingers and then pinned to maintain joint tightness, after which the pins are welded in place. The end plug below the pin position is designed with a reduced section to permit flexing of the rods to correct for small operating or assembly misalignments.

The overall length is such that when the assembly is withdrawn through its full travel the tips of the absorber rods remain engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Since the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble.

4.2.3.2.1.2 Burnable Absorber Assembly

Each burnable absorber assembly consists of borosilicate or wet annular burnable absorber rods attached to a hold down assembly. Conceptual burnable absorber assemblies (containing borosilicate) are shown in Figure 4.2-17. WABA rods may be used in place of the borosilicate rods.

The borosilicate absorber rods consist of borosilicate glass tubes contained within Type 304 stainless steel tubular cladding which is plugged and seal welded at the ends to encapsulate the glass. The glass is also supported along the length of its inside diameter by a thin wall tubular

inner liner. The top end of the liner is open to permit the diffused helium to pass into the void volume and the liner overhangs the glass. The liner has an outward flange at the bottom end to maintain the position of the liner with the glass. A typical borosilicate burnable absorber rod is shown in longitudinal and transverse cross-sections in Figure 4.2-18.

A WABA rod (Figure 4.2-18a) consists of annular pellets of alumina-boron carbide (Al_2O_3-B_4C) burnable absorber material contained within 2 concentric Zircaloy tubes. These Zircaloy tubes, which form the inner and outer clad for the WABA rod, are plugged and welded at each end to encapsulate the annular stack of absorber material. The assembled rod is then internally pre-pressurized to 650 psig and seal welded. The absorber stack lengths are positioned axially within the WABA rods by the use of Zircaloy bottom-end spacers. An annular plenum is provided within the rod to accommodate the helium gas released from absorber material depletion during irradiation. The reactor coolant flows inside the inner tube and outside the outer tube of the annular rod. Further design details are given in Section 3.0 of Reference 26.

The burnable absorber rods are statically suspended and positioned in selected guide thimbles within the fuel assemblies. The absorber rods in each assembly are attached together at the top end of the rods to a hold down assembly by a flat, perforated retaining plate which fits within the fuel assembly top nozzle and rests on the adaptor plate. The absorber rod assembly is held down and restrained against vertical motion through a spring pack which is attached to the plate and is compressed by the upper core plate when the reactor upper internals assembly is lowered into the reactor. This arrangement ensures that the absorber rods cannot be ejected from the core by flow forces. Each rod is permanently attached to the base plate by a nut which is locked into place.

The borosilicate rod clad is slightly cold worked Type 304 stainless steel, and the WABA rod clad is Zircaloy 4. All other structural materials are Types 304 or 308 stainless steel except for the springs which are Inconel-718. The absorber rods and IFBAs provide sufficient boron content to meet the criteria discussed in Section 4.3.1.

4.2.3.2.1.3 Neutron Source Assembly

The purpose of the neutron source assembly is to provide a base neutron level to ensure that the detectors are operational and responding to core multiplication neutrons. Since there is very little neutron activity during loading, refueling, shutdown, and approach to criticality, a neutron source may be placed in the reactor to provide a positive neutron count of at least 2 counts per second on the source range detectors attributable to core neutrons. The detectors, called source range detectors, are used primarily when the core is subcritical and during special subcritical modes of operations.

The source assembly also permits detection of changes in the core multiplication factor during core loading refueling, and approach to criticality. This can be done since the multiplication factor is related to an inverse function of the detector count rate. Therefore a change in the multiplication factor can be detected during addition of fuel assemblies while loading the core, a change in control rod positions, and changes in boron concentration.

Both primary and secondary neutron source rods are used. The primary source rod, containing a radioactive material, spontaneously emits neutrons during initial core loading and reactor startup. After the primary source rod decays beyond the desired neutron flux level, neutrons are then supplied by the secondary source rod. The secondary source rod contains a stable material, which must be activated by neutron bombardment during reactor operation. The activation results in the subsequent release of neutrons. This becomes a source of neutrons during periods of low neutron flux, such as during refueling and the subsequent startups.

The reactor core may employ 2 secondary source assemblies. Each secondary source assembly contains a symmetrical grouping of 4 secondary source rods. Locations not filled with a source or burnable absorber rod contain a thimble plug. Conceptual source assemblies are shown in Figures 4.2-19 and 4.2-20.

Neutron source assemblies are employed at opposite sides of the core. The assemblies are inserted into the rod cluster control guide thimbles in fuel assemblies at selected unrodded locations.

The source assemblies contain a hold down assembly identical to that of the burnable absorber assembly.

The primary and secondary source rods both utilize slightly coldworked 304 SS cladding material. The secondary source rods contain 500 grams of stacked antimony-beryllium pellets and the rod is internally pre-pressurized to 650 psig. The primary source rods contain capsules of Californium source material and alumina spacer rods to position the source material within the cladding. The rods in each assembly are permanently fastened at the top end to a hold down assembly, which is identical to that of the burnable absorber assemblies.

The other structural members are fabricated from Type 304 and 308 stainless steel except for the springs exposed to the reactor coolant. They are wound from an age hardened nickel base alloy for corrosion resistance and high strength.

4.2.3.2.1.4 Thimble Plug Assembly

If it is desired to further limit bypass flow through the rod cluster control guide thimbles in fuel assemblies which do not contain either control rods, source rods, or burnable absorber rods, the fuel assemblies at those locations may be fitted with thimble plug assemblies.

The thimble plug assemblies as shown in Figure 4.2-21 consist of a flat base plate with short rods suspended from the bottom surface and a spring pack assembly. The 24 short rods, called thimble plugs, project into the upper ends of the guide thimbles to reduce the bypass flow. Similar short rods are also used on the source assemblies and burnable absorber assemblies to plug the ends of all vacant fuel assembly guide thimbles. At installation in the core, the thimble plug assemblies interface with both the upper core plate and with the fuel assembly top nozzles by resting on the adaptor plate. The spring pack is compressed by the upper core plate when the upper internals assembly is lowered into place. Each thimble plug is permanently attached to the base plate by a nut which is locked to the threaded end of the plug.

All components in the thimble plug assembly, except for the springs, are fabricated from Type 304 and 308 stainless steel. The springs are wound from an age hardened nickel base alloy for corrosion resistance and high strength.

4.2.3.2.2 Control Rod Drive Mechanism

All parts exposed to reactor coolant are fabricated of metals which resist the corrosive action of the primary coolant. Three (3) types of metals are used exclusively: stainless steels, nickel-chrome-iron alloys and cobalt based alloys. In the case of stainless steels, only austenitic and martensitic stainless steels are used.

The discussions (Sections 5.2.5, 5.2.5.1, 5.2.5.2, 5.2.5.3, 5.2.5.4, 5.2.5.5, and 5.2.5.6) concerning the processes, inspections and tests on austenitic stainless steel components to assure freedom from increased susceptibility to intergranular corrosion caused by sensitization, and the discussions (Sections 5.2.5.5 and 5.2.5.7) on the control of welding of austenitic stainless steels, especially control of delta ferrite, are applicable to the austenitic stainless steel pressure retaining components of the control rod drive mechanisms.

Wherever magnetic flux is induced on parts exposed to the main coolant, 400 series stainless steel is used. Cobalt based alloys are used for the pins and latch tips.

Nickel-chrome-iron alloy is used for the springs of both latch assemblies and Type 304 stainless steel is used for all pressure containing parts as listed in Table 5.2-8.

Hard chrome plating provides wear surfaces on the sliding parts and prevents galling between mating parts.

Position indicator assemblies slide over the control rod drive mechanism rod travel housings. Each assembly detects the drive rod position by means of 42 discrete coils that magnetically sense the entry and presence of the rod drive line through its center line over the normal length of the drive rod travel.

Control rod drive mechanisms are located on the dome of the reactor vessel. They are coupled to rod control clusters which have absorber material over the entire length of the control rods. The full length control rod drive mechanism is shown in Figure 4.2-22 and schematically in Figure 4.2-23.

The primary function of the control rod drive mechanism is to insert or withdraw a rod cluster control assembly within the core to control average core temperature and to shutdown the reactor.

The control rod drive mechanism is a magnetically operated jack. A magnetic jack is an arrangement of 3 electromagnets which are energized in a controlled sequence by a power cycler to insert or withdraw a rod cluster control assembly in the reactor core in discrete steps. Rapid insertion of the rod cluster control assembly occurs where electrical power is interrupted.

The control rod drive mechanism consists of 4 separate subassemblies. They are the pressure vessel, coil stack assembly, latch assembly, and the drive rod assembly.

1. The pressure vessel includes a latch housing and a rod travel housing which are connected by a threaded, seal welded, maintenance joint which facilitates replacement of the latch assembly. The closure at the top of the rod travel housing is an integral forged end for pressure integrity.

   The latch housing is the lower portion of the vessel and contains the latch assembly. The rod travel housing is the upper portion of the vessel and provides space for the drive rod during its upward movement as the control rods are withdrawn from the core.

2. The coil stack assembly includes the coil housings, an electrical conduit and connector, and 3 operating coils; 1) the stationary gripper coil, 2) the moveable gripper coil, and 3) the lift coil.

   The coil stack assembly is a separate unit which is installed on the drive mechanism by sliding it over the outside of the latch housing. It rests on the base of the latch housing without mechanical attachment.

   Energizing the operating coils causes movement of the pole pieces and latches in the latch assembly.

3. The latch assembly includes the guide tube, stationary pole pieces, moveable pole pieces, and the 2 sets of latches; 1) the moveable gripper latches and 2) the stationary gripper latches.

   The latches engage grooves in the drive rod assembly. The moveable gripper latches are moved up or down in 5/8 inch steps by the lift pole to raise or lower the drive rod. The stationary gripper latches hold the drive rod assembly while the moveable gripper latches are repositioned for the next 5/8 inch step.

4. The drive rod assembly includes a flexible coupling, a drive rod, a disconnect button, a disconnect rod, and a locking button.

   The drive rod has 5/8 inch grooves which receive the latches during holding or moving of the drive rod. The flexible coupling is attached to the drive rod and provides the means for coupling to the rod cluster control assembly.

   The disconnect button, disconnect rod, and locking button provide positive locking of the coupling to the rod cluster control assembly and permits remote disconnection of the drive rod.

The control rod drive mechanism is a trip design. Tripping can occur during any part of the power cycler sequencing if electrical power to the coils is interrupted.

The control rod drive latch mechanism housing is full penetration welded on an adaptor on top of the reactor vessel and is coupled to the rod cluster control assembly directly below.

The mechanism is capable of raising or lowering a 360 pound load, (which includes the drive rod weight) at a rate of 45 inches/minute. Withdrawal of the rod cluster control assembly is accomplished by magnetic forces while insertion is by gravity.

The mechanism internals are designed to operate in 650 °F reactor coolant. The pressure vessel is designed to contain reactor coolant at 650 °F and 2500 psia. The 3 operating coils are designed to operate at 392 °F with forced air cooling required to maintain that temperature.

The full length control rod drive mechanism, shown schematically in Figure 4.2-23, withdraws and inserts a rod cluster control assembly, as shaped electrical pulses are received by the operating coils. An ON or OFF sequence, repeated by silicon controlled rectifiers in the power programmer, causes either withdrawal or insertion of the control rod. Position of the control rod is measured by 42 discrete coils mounted on the position indicator assembly surrounding the rod travel housing. Each coil magnetically senses the entry and presence of the top of the ferromagnetic drive rod assembly as it moves through the coil center line.

During plant operation the stationary gripper coil of the drive mechanism holds the rod cluster control assembly in a static position until a stepping sequence is initiated at which time the moveable gripper coil and lift coil is energized sequentially.

1. Rod Cluster Control Assembly Withdrawal

   The rod cluster control assembly is withdrawn by repetition of the following sequence of events (refer to Figure 4.2-23):

   a. Movable Gripper Coil (B) – ON

      The latch locking plunger raises and swings the movable gripper latches into the drive rod assembly groove. A 0.055 inch axial clearance exists between the latch teeth and the drive rod.

      Note: The 0.055 inch referred to is a nominal value for a new CRDM at room temperature. This will change with wear and temperature.

   b. Stationary Gripper Coil (A) – OFF

      The force of gravity, acting upon the drive rod assembly and attached control rod, causes the stationary gripper latches and plunger to move downward 0.055 inch until the load of the drive rod assembly and attached control rod is transferred to the movable gripper latches. The plunger continues to move downward and swings the stationary gripper latches out of the drive rod assembly groove.

   c. Lift Coil (C) – ON

      The 5/8 inch gap between the movable gripper pole and the lift pole closes, and the drive rod assembly raises 1 step length (5/8 inch).

d. Stationary Gripper Coil (A) – ON

The plunger raises and closes the gap below the stationary gripper pole. The 3 links, pinned to the plunger, swing the stationary gripper latches into a drive rod assembly groove. The latches contact the drive rod assembly and lift it (and the attached control rod) 0.055 inch. The 0.055 inch vertical drive rod assembly movement transfers the drive rod assembly load from the movable gripper latches to the stationary gripper latches.

e. Movable Gripper Coil (B) – OFF

The latch locking plunger separates from the movable gripper pole under the force of a spring and gravity. Three (3) links, pinned to the plunger, swing the 3 movable gripper latches out of the drive rod assembly groove.

f. Lift Coil (C) – OFF

The gap between the movable gripper pole and lift pole opens. The movable gripper latches drop 0.625 inch to a position adjacent to a drive rod assembly groove.

g. Repeat Step a

The sequence described above (Items a through f) is termed as 1 step or 1 cycle. The rod cluster control assembly moves 5/8 inch for each step or cycle. The sequence is repeated at a rate of up to 72 steps per minute and the drive rod assembly (which has a 5/8 inch groove pitch) is raised 72 grooves per minute. The rod cluster control assembly is thus withdrawn at a rate up to 45 inches per minute.

2. Rod Cluster Control Assembly Insertion

The sequence for rod cluster control assembly insertion is similar to that for control rod withdrawal, except the timing of lift coil (C) ON and OFF is changed to permit lowering the control assembly.

a. Lift Coil (C) – ON

The 0.625 inch gap between the movable gripper and lift pole closes. The movable gripper latches are raised to a position adjacent to a drive rod assembly groove.

b. Movable Gripper Coil (B) – ON

The latch locking plunger raises and swings the movable gripper latches into a drive rod assembly groove. A 0.055 inch axial clearance exists between the latch teeth and the drive rod assembly.

c. Stationary Gripper Coil (A) – OFF

The force of gravity, acting upon the drive rod assembly and attached rod cluster control assembly, causes the stationary gripper latches and plunger to move downward 0.055 inch

until the load of the drive rod assembly and attached rod cluster control assembly is transferred to the movable gripper latches. The plunger continues to move downward and swings the stationary gripper latches out of the drive rod assembly groove.

d. Lift Coil (C) – OFF

The force of gravity and spring force separate the movable gripper pole from the lift pole and the drive rod assembly and attached rod cluster control drop down 5/8 inch.

e. Stationary Gripper (A) – ON

The plunger raises and closes the gap below the stationary gripper pole. The 3 links, pinned to the plunger, swing the 3 stationary gripper latches into a drive rod assembly groove. The latches contact the drive rod assembly and lift it (and the attached control rod) 1/16 inch. The 1/16 inch vertical drive rod assembly movement transfers the drive rod assembly load from the movable gripper latches to the stationary gripper latches.

f. Movable Gripper Coil (B) – OFF

The latch locking plunger separates from the movable gripper pole under the force of a spring and gravity. Three (3) links, pinned to the plunger, swing the 3 movable gripper latches out of the drive rod assembly groove.

g. Repeat Step a

The sequence is repeated, as for rod cluster control assembly withdrawal, up to 72 times per minute which gives an insertion rate of 45 inches per minute.

3. Holding and Tripping of the Control Rods

During most of the plant operating time, the control rod drive mechanisms hold the rod cluster control assemblies withdrawn from the core in a static position. In the holding mode, only 1 coil, the stationary gripper coil (A), is energized on each mechanism. The drive rod assembly and attached rod cluster control assemblies hang suspended from the 3 latches.

If power to the stationary gripper coil is cut off, the combined weight of the drive rod assembly and the rod cluster control assembly plus the stationary gripper return spring is sufficient to move latches out of the drive rod assembly groove. The control rod falls by gravity into the core. The trip occurs as the magnetic field, holding the stationary gripper plunger half against the stationary gripper pole, collapses and the stationary gripper plunger half is forced down by the stationary gripper return spring and the weight acting upon the latches. After the rod cluster control assembly is released by the mechanism, it falls freely until the control rods enter the dashpot section of the thimble tubes in the fuel assembly.

4.2.3.3 Design Evaluation

4.2.3.3.1 Reactivity Control Components

The components are analyzed for loads corresponding to normal, upset, emergency and faulted conditions. The analysis performed depends on the mode of operation under consideration.

The scope of the analysis requires many different techniques and methods, both static and dynamic.

Some of the loads that are considered on each component where applicable are as follows:

1. Control Rod Trip (equivalent static load)
2. Differential Pressure
3. Spring Preloads
4. Coolant Flow Forces (static)
5. Temperature Gradients
6. Differences in thermal expansion
   a. Due to temperature differences
   b. Due to expansion of different materials
7. Interference between components
8. Vibration (mechanically or hydraulically induced)
9. All operational transients listed in Table 5.2-2
10. Pump Overspeed
11. Seismic Loads (operating basis earthquake and safe shutdown earthquake)
12. Blowdown Forces (due to cold and hot leg break)

The main objectives of the analysis are to satisfy allowable stress limits, assure an adequate design margin, and establish deformation limits which are concerned primarily with the functioning of the components. The stress limits are established not only to assure that peak stresses will not reach unacceptable values, but also to limit the amplitude of the oscillatory stress component in consideration of fatigue characteristics of the materials. Standard methods of strength of materials are used to establish the stresses and deflections of these components. The dynamic behavior of the reactivity control components has been studied using experimental test data and experience from operating reactors.

The design of reactivity component rods provides a sufficient cold void volume within the burnable absorber and source rods to limit the internal pressures to a value which satisfies the criteria in Section 4.2.3.1. The void volume for the helium in the borosilicate glass burnable absorber rods is obtained through the use of glass in tubular form which provides a central void

along the length of the rods. For the WABA rods, an annular void volume is provided between the 2 tubes at the top, and along the length of each WABA rod (Figure 4.2-18a). Helium gas is not released by the neutron absorber rod material, thus the absorber rod only sustains an external pressure during operating conditions. The internal pressure of source rods continues to increase from ambient until end of life at which time the internal pressure never exceeds that allowed by the criteria in Section 4.2.3.1. Except for WABA rods, the stress analysis of reactivity component rods assumes 100% gas release to the rod void volume, considers the initial pressure within the rod, and assumes the pressure external to the component rod is zero. Stress analysis for the WABA rods assumed a maximum 30% gas released, consistent with Reference 26.

Based on available data for properties of the borosilicate glass and on nuclear and thermal calculations for these burnable absorber rods, gross swelling or cracking of the glass tubing is not expected during operation. Some minor creep of the glass at the hot spot on the inner surface of the tube could occur but would continue only until the glass came in contact with the inner liner. The wall thickness of the inner liner is sized to provide adequate support in the event of slumping and to collapse locally before rupture of the exterior cladding if unexpected large volume changes due to swelling or cracking should occur. The top of the inner liner is open to allow communication to the central void by the helium which diffuses out of the glass.

An evaluation of the WABA rod design is given in Reference 26.

Sufficient diametral and end clearances have been provided in the neutron absorber, burnable absorber and source rods to accommodate the relative thermal expansions between the enclosed material and the surrounding clad and end plugs. There is no bending or warping induced in the rods although the clearance offered by the guide thimble would permit a postulated warpage to occur without restraint on the rods. Bending, therefore, is not considered in the analysis of the rods. The radial and axial temperature profiles have been determined by considering gap conductance, thermal expansion, and neutron and/or gamma heating of the contained material as well as gamma heating of the clad. The maximum neutron absorber material temperature was found to be less than 850 °F which occurs axially at only the highest flux region. The maximum borosilicate glass temperature was calculated to be about 1200 °F and takes place following the initial rise to power. The glass temperature then decreases rapidly for the following reasons: 1) reduction in power generation due to B10 depletion; 2) better gap conductance as the helium produced diffuses to the gap; and 3) external gap reduction due to borosilicate glass creep. Rod, guide thimble, and dashpot flow analysis performed indicates that the flow is sufficient to prevent coolant boiling and maintain clad temperatures at which the clad material has adequate strength to resist coolant operating pressures and rod internal pressures.

Temperatures for thimbles at the bottom of the fuel assemblies range from approximately 530 °F to 553 °F. Mid-assembly temperatures reach a high of about 593 °F while the maximum temperatures at the top of the assemblies are about 641 °F.

Analysis on the rod cluster control spider indicates the spider is structurally adequate to withstand the various operating loads including the higher loads which occur during the drive mechanism stepping action and rod drop. Experimental verification of the spider structural capability has been completed (see Section 1.5).

The materials selected are considered to be the best available from the standpoint of resistance to irradiation damage and compatibility to the reactor environment. The materials selected partially dictate the reactor environment (e.g., Cl^- control in the coolant). The current design type reactivity controls have been in service for many years with no unanticipated degradation of construction materials.

With regard to the materials of construction exhibiting satisfactory resistance to adverse property changes in a radioactive environment, it should be noted that work on breeder reactors in current design, similar materials are being applied. At high fluences the austenitic materials increase in strength with a corresponding decreased ductility (as measured by tensile tests) but energy absorption (as measured by impact tests) remain quite high. Corrosion of the materials exposed to the coolant is quite low and proper control of Cl^- and O_2 in the coolant will prevent the occurrence of stress corrosion. All of the austenitic stainless steel base materials used are processed and fabricated to preclude sensitization. Although the control rod spiders are fabricated by furnace brazing, the procedure used requires that the pieces be rapidly cooled so that the time-at-temperature is minimized. The time that is spent by the control rod spiders in the sensitization range, 800 - 1500 °F, is not more than 0.2 hour, as a maximum, during fabrication to preclude sensitization. The 17-4 PH parts are all aged at the highest standard aging temperature of 1100 °F to avoid stress corrosion problems exhibited by aging at lower temperatures.

Analysis of the rod cluster control assemblies show that if the drive mechanism housing ruptures, the rod cluster control assembly will be ejected from the core by the pressure differential of the operating pressure and ambient pressure across the drive rod assembly. The ejection is also predicated on the failure of the drive mechanism to retain the drive rod/rod cluster control assembly position. It should be pointed out that a drive mechanism housing rupture will cause the ejection of only 1 rod cluster control assembly with the other assemblies remaining in the core. Analysis also showed that pressure drop in excess of 4000 psi must occur across a two-fingered vane to break the vane/spider body joint causing ejection of 2 neutron absorber rods from the core. Since the greatest pressure drop in the system is only 2250 psi, a pressure drop in excess of 4000 psi is incredible. Thus, the ejection of the neutron absorber rods is not possible.

Ejection of a burnable absorber or thimble plug assembly is conceivable based on the postulation that the holddown bar fails and that the base plate and burnable absorber rods are severely deformed. In the unlikely event that failure of the holddown bar occurs, the upward displacement of the burnable absorber assembly only permits the base plate to contact the upper core plate. Since this displacement is small, the major portion of the borosilicate glass tubing remains positioned within the core. In the case of the thimble plug assembly, the thimble plugs will partially remain in the fuel assembly guide thimbles thus maintaining a majority of the desired flow impedance. Further displacement or complete ejection would necessitate the square base and burnable absorber rods be forced, thus plastically deformed, to fit up through a smaller diameter hole. It is expected that this condition requires a substantially higher force or pressure drop than that of the holddown bar failure.

Experience with control rods, burnable absorber rods, and source rods are discussed in Reference 4.

The mechanical design of the reactivity control components provides for the protection of the active elements to prevent the loss of control capability and functional failure of critical components. The components have been reviewed for potential failure and consequences of a functional failure of critical parts. The results of the review are summarized below.

4.2.3.3.1.1 Rod Cluster Control Assembly

1. The basic absorbing material is sealed from contact with the primary coolant, the fuel assembly and guidance surfaces by a high quality stainless steel clad. Potential loss of absorber mass or reduction in reactivity control material due to mechanical or chemical erosion or wear is therefore reliably prevented.
2. A breach of the cladding for any postulated reason does not result in serious consequences. The silver-indium-cadmium absorber material is relatively inert and would still remain remote from high coolant velocity regions. Rapid loss of material resulting in significant loss of reactivity control material would not occur.
3. The individually clad absorber rods are doubly secured to the retaining spider vane by a threaded joint and a welded lock pin. This joint has been qualified by functional testing and actual service in operating plants.

   It should also be noted that in several instances of control rod jamming caused by foreign particles, the individual rods at the site of the jam have borne the full capacity of the control rod drive mechanism and higher impact loads to dislodge the jam without failure. The conclusion to be drawn from this experience is that this joint is extremely insensitive to potential mechanical damage. A failure of the joint would result in the insertion of the individual rod into the core resulting in reduced reactivity.
4. The spider finger braze joint by which the individual rods are fastened to the vanes has also experienced the service described above and been subjected to the same jam freeing procedures also without failure. A failure of this joint would also result in insertion of the individual rod into the core.
5. The radial vanes are attached to the spider body, again by a brazed joint. The joints are designed to a theoretical strength in excess of that of the components joined.

   It is a feature of the design that the guidance of the rod cluster control is accomplished by the inner fingers of these vanes. They are therefore the most susceptible to mechanical damage. Since these vanes carry 2 rods, failure of the vane-to-hub joint such as the isolated incidents at Connecticut-Yankee does not prevent the free insertion of the rod pair. Neither does such a failure interfere with the continuous free operation of the drive line, also as experienced at Connecticut-Yankee.

Failure of the vane-to-hub joint of a single rod vane could potentially result in failure of the separated vane and rod to insert. This could occur only at withdrawal elevations where the spider is above the continuous guidance section of the guide tube (in the upper internals). A rotation of the disconnected vane could cause it to hang on one of the guide cards in the intermediate guide tube. Such an occurrence would be evident from the failure of the rod cluster control to insert below a certain elevation but with free motion above this point.

This possibility is considered extremely remote because the single rod vanes are subjected to only vertical loads and very light lateral reactions from the rods. The consequences of such a failure are not considered critical since only 1 drive line of the reactivity control system would be involved. This condition is readily observed and can be corrected at shutdown.

6. The spider hub being of single unit cylindrical construction is very rugged and of extremely low potential for damage. It is difficult to postulate any condition to cause failure. Should some unforeseen event cause fracture of the hub above the vanes, the lower portion with the vanes and rods attached would insert by gravity into the core causing a reactivity decrease. The rod could then not be removed by the drive line. Fracture below the vanes cannot be postulated since all loads, including scram impact, are taken above the vane elevation.
7. The rod cluster control rods are provided a clear channel for insertion by the guide thimbles of the fuel assemblies. All fuel rod failures are protected against by providing this physical barrier between the fuel rod and the intended insertion channel. Distortion of the fuel rods by bending cannot apply sufficient force to damage or significantly distort the guide thimble. Fuel rod distortion by swelling, though precluded by design, would be terminated by fracture before contact with the guide thimble occurs. If such were not the case, it would be expected that a force reaction at the point of contact would cause a slight deflection of the guide thimble. The radius of curvature of the deflected shape of the guide thimbles would be sufficiently large to have a negligible influence on rod cluster control insertion.

4.2.3.3.1.2 Burnable Absorber Assemblies

The burnable absorber assemblies are static temporary reactivity control elements. The axial position is assured by the holddown assembly which bears against the upper core plate. Their lateral position is maintained by the guide thimbles of the fuel assemblies.

The individual rods are shouldered against the underside of the retainer plate and securely fastened at the top by a threaded nut which is then locked in place. The square dimension of the retainer plate is larger than the diameter of the flow holes through the core plate. Failure of the holddown bar or spring pack therefore does not result in ejection of the burnable absorber rods from the core.

The only incident that could potentially result in ejection of the burnable absorber rods is a multiple fracture of the retainer plate. This is not considered credible because of the light loads borne by this component. During normal operation the loads borne by the plate are approximately 5 pounds/rod or a total of 100 pounds distributed at the points of attachment. Even a multiple fracture of the retainer plate would result in jamming of the plate segments against the upper core

plate, again preventing ejection. Excessive reactivity increase due to burnable absorber rod ejection is therefore prevented.

Burnable absorber rods are clad with either stainless steel or Zircaloy 4. The burnable absorber is either a borosilicate glass tube which is maintained in position by a central hollow stainless steel tube or Al_2O_3-B_4C annular pellets contained within 2 concentric Zircaloy tubes. Burnable absorber rods are placed in static assemblies and are not subjected to motion which might damage the rods. Further, the guide thimble tubes of the fuel assembly afford additional protection from damage.

During the accumulated thousands of years of burnable absorber rodlet operating experience, only 1 instance of penetration of the stainless steel burnable absorber cladding has been observed. The consequences of clad breach are also small. It is anticipated that upon clad breach, the B_4C or borosilicate glass would be leached by the coolant water and that localized power peaking of a few percent would occur; no design criteria would be violated. Additional information on the consequences of postulated WABA rod failures is presented in Reference 26.

4.2.3.3.1.3 Drive Rod Assemblies

All postulated failures of the drive rod assemblies either by fracture or uncoupling lead to a decrease in reactivity. If the drive rod assembly fractures at any elevation, that portion remaining coupled falls with, and is guided by the rod cluster control assembly. This always results in reactivity decrease for control rods.

4.2.3.3.2 Control Rod Drive Mechanism

4.2.3.3.2.1 Material Selection

All pressure containing materials comply with Section III of the ASME Boiler and Pressure Vessel Code, and are fabricated from austenitic (Type 304) stainless steel.

Magnetic pole pieces are fabricated from Type 410 stainless steel. All nonmagnetic parts, except pins and springs, are fabricated from Type 304 stainless steel. Haynes 25 is used to fabricate link pins. Springs are made from nickel-chrome-iron alloy. Latch arm tips are clad with Cobalt-6 to provide improved wearability. Hard chrome plate and Cobalt-6 are used selectively for bearing and wear surfaces.

At the start of the development program, a survey was made to determine whether a material better than Type 410 stainless steel was available for the magnetic pole pieces. Ideal material requirements are as follows:

1. High magnetic saturation value.
2. High permeability.
3. Low coercive force.

4. High resistivity.
5. High curie temperature.
6. Corrosion resistance.
7. High impact strength.
8. Nonoriented.
9. High machinability.
10. Low susceptibility to radiation damage.

After a comprehensive material study was made it was decided that the Type 410 stainless steel was satisfactory for this application.

The cast coil housings require a magnetic material. Both low carbon cast steel and ductile iron have been successfully tested for this application. The choice, made on the basis of cost, indicates that ductile iron will be specified on the control rod drive mechanism. The finished housings are zinc plated or flame sprayed to provide corrosion resistance.

Coils are wound on bobbins of molded Dow Corning 302 material, with double glass insulated copper wire. Coils are then vacuum impregnated with silicon varnish. A wrapping of mica sheet is secured to the coil outside diameter. The result is a well insulated coil capable of sustained operation at 200° centigrade.

The drive rod assembly utilizes a Type 410 stainless steel drive rod. The coupling is machined from Type 403 stainless steel. Other parts are Type 304 stainless steel with the exception of the springs which are nickel-chrome-iron alloy and the locking button which is Haynes 25.

4.2.3.3.2.2 Radiation Damage

As required by the equipment specification, the control rod drive mechanisms are designed to meet a radiation requirement of 10 rads/hour. Materials have been selected to meet this requirement. The above radiation level which amounts to 1.753×10^6 rads in 20 years will not limit control rod drive mechanism life. Control rod drive mechanisms at Yankee Rowe which have been in operation since 1960 have not experienced problems due to radiation.

4.2.3.3.2.3 Positioning Requirements

The control rod drive mechanism has a step length of 5/8 inch which determines its positioning capabilities. Positioning requirements are determined by reactor physics.

4.2.3.3.2.4 Evaluation of Material's Adequacy

The ability of the pressure housing components to perform throughout the design lifetime as defined in the equipment specification is confirmed by the stress analysis report required by the ASME Boiler and Pressure Vessel Code, Section III. Internal components subjected to wear will

withstand a minimum of 3,000,000 steps without refurbishment as confirmed by life tests. Latch assembly inspection is recommended after 2.5 x 10^6 steps have been accumulated on a single control rod drive mechanism.

4.2.3.3.2.5 Results of Dimensional and Tolerance Analysis

With respect to the control rod drive mechanism system as a whole, critical clearances are present in the following areas:

1. Latch assembly (Diametral clearances).
2. Latch arm-drive rod clearances.
3. Coil stack assembly-thermal clearances.
4. Coil fit in coil housing.

The following write-up defines clearances that are designed to provide reliable operation in the control rod drive mechanism in these 4 critical areas. These clearances have been proven by life tests and actual field performance at operating plants.

4.2.3.3.2.6 Latch Assembly - Thermal Clearances

The magnetic jack has several clearances where parts made of Type 410 stainless steel fit over parts made from Type 304 stainless steel. Differential thermal expansion is therefore important. Minimum clearances of these parts at 68 °F is 0.011 inch. At the maximum design temperature of 650 °F minimum clearance is 0.0045 inch and at the maximum expected operating temperatures of 550 °F is 0.0057 inch.

4.2.3.3.2.7 Latch Arm - Drive Rod Clearances

The control rod drive mechanism incorporates a load transfer action. The movable or stationary gripper latch are not under load during engagement, as previously explained, due to load transfer action.

Figure 4.2-26 shows latch clearance variation with the drive rod as a result of minimum and maximum temperatures. Figure 4.2-27 shows clearance variations over the design temperature range.

4.2.3.3.2.8 Coil Stack Assembly - Thermal Clearances

The assembly clearance of the coil stack assembly over the latch housing was selected so that the assembly could be removed under all anticipated conditions of thermal expansion.

At 70 °F the inside diameter of the coil stack is 7.308/7.298 inches. The outside diameter of the latch housing is 7.260/7.270 inches. Thermal expansion of the mechanism due to operating temperature of the control rod drive mechanism results in the minimum inside diameter of the coil

stack being 7.310 inches at 222 °F and the maximum latch housing diameter being 7.302 inches at 532 °F.

Under the extreme tolerance conditions listed above, it is necessary to allow time for a 70 °F coil housing to heat during a replacement operation.

Four (4) coil stack assemblies were removed from 4 hot control rod drive mechanisms mounted on 11.035 inch centers on a 550 °F test loop, allowed to cool, and then replaced without incident as a test to prove the preceding.

4.2.3.3.2.9 Coil Fit in Coil Housing

Control rod drive mechanism and coil housing clearances are selected so that coil heat up results in a close to tight fit. This is done to facilitate thermal transfer and coil cooling in a hot control rod drive mechanism.

4.2.3.3.2.10 Protection from Pipe Rupture and Missiles

The control rod drive mechanisms are protected from postulated pipe ruptures and missiles as discussed in Sections 3.6 and 3.5, respectively.

4.2.3.4 Tests, Verification and Inspections

4.2.3.4.1 Reactivity Control Components

Tests and inspections are performed on each reactivity control component to verify the mechanical characteristics. In the case of the rod cluster control assembly, prototype testing has been conducted and both manufacturing test/inspections and functional testing at the plant site are performed.

During the component manufacturing phase, the following requirements apply to the reactivity control components to assure the proper functioning during reactor operation:

1. All materials are procured to specifications to attain the desired standard of quality.
2. A spider from each braze lot is proof tested by applying a 5000 pound load to the spider body, so that approximately 310 pounds is applied to each vane. This proof load provides a bending moment at the spider body approximately equivalent to 1.4 times the load caused by the acceleration imposed by the control rod drive mechanism.
3. All clad/end plug welds are checked for integrity by visual inspection, X-ray, and are helium leak checked. All the seal welds in the neutron absorber rods, burnable absorber rods and source rods are checked in this manner.
4. To assure proper fit with the fuel assembly, the rod cluster control, burnable absorber and source assemblies are installed in the fuel assembly without restriction or binding in the dry condition. Also a straightness of 0.01 in/ft is required on the entire inserted length of each rod assembly.

The rod cluster control assemblies are functionally tested, following core loading but prior to criticality to demonstrate reliable operation of the assemblies.

In order to demonstrate continuous free movement of the rod cluster control assemblies, and to ensure acceptable core power distributions during operations, partial movement checks are performed on the rod cluster control assemblies as required by the Technical Specifications. In addition, periodic drop tests of the rod cluster control assemblies are performed at each refueling shutdown to demonstrate continued ability to meet trip time requirements. During these tests the acceptable drop time of each assembly is not greater than 2.7 seconds, at full flow and operating temperatures, from the beginning of motion to dashpot entry.

If a rod cluster control assembly cannot be moved by its mechanism, adjustments in the boron concentration ensure that adequate shutdown margin would be achieved following a trip. Thus, inability to move 1 rod cluster control assembly can be tolerated. More than 1 inoperable rod cluster control assembly could be tolerated, but would impose additional demands on the plant operator. Therefore, the number of inoperable rod cluster control assemblies has been limited to 1.

4.2.3.4.2 Control Rod Drive Mechanisms

Quality assurance procedures during production of control rod drive mechanisms include material selection, process control, mechanism component tests and inspections during production and hydrotests.

After all manufacturing procedures had been developed, several prototype control rod drive mechanisms and drive rod assemblies were life tested with the entire drive line under environmental conditions of temperature, pressure and flow. All acceptance tests confirm the 3×10^6 step unrefurbished life capability of the control rod drive mechanism and drive rod assembly.

These tests include verification that the trip time achieved by the control rod drive mechanisms meet the original design requirement of 2.7 seconds from start of rod cluster control assembly motion to dashpot entry. This trip time requirement will be confirmed for each control rod drive mechanism prior to initial reactor operation and at periodic intervals after initial reactor operation. In addition, a Technical Specification has been set to ensure that the trip time requirement is met.

It is expected that all control rod drive mechanisms will meet specified operating requirements for the duration of plant life with normal refurbishment. However, a Technical Specification pertaining to an inoperable rod cluster control assembly has been set.

To confirm the mechanical adequacy of the fuel assembly, the control rod drive mechanism, and rod cluster control assembly, functional test programs have been conducted on a full scale 12 foot control rod. The 12 foot prototype assembly was tested under simulated conditions of reactor temperature, pressure, and flow for approximately 1000 hours. The prototype mechanism accumulated about 3,000,000 steps and 600 trips. At the end of the test the control rod drive mechanism was still operating satisfactorily. A correlation was developed to predict the amplitude of flow excited vibration of individual fuel rods and fuel assemblies. Inspection of the drive line components did not reveal significant fretting.

There are no significant differences between the prototype control rod drive mechanisms and the replaced production units. Design materials, tolerances and fabrication techniques (Section 4.2.3.3.2) are the same, or as noted.

Actual experience in many operating Westinghouse plants, indicates excellent performance of these control rod drive mechanisms.

All units are production tested prior to shipment to confirm ability of the control rod drive mechanism to meet design specification operational requirements.

Each control rod drive mechanism undergoes a production test as listed below:

Test	Acceptance Criteria
Cold (ambient) hydrostatic	ASME Section III
Confirm step length and load transfer (stationary gripper to movable gripper or movable gripper to stationary gripper)	Step Length 5/8 ±0.015 inch axial movement Load Transfer 0.055 ±0.007 inch nominal axial movement
Cold (ambient) performance Test at design load - 5 full travel excursions	Operating Speed 45 inches/minute Trip Delay Free fall of drive rod to begin within 150 MS

4.2.3.5 Instrumentation Applications

Instrumentation for determining reactor coolant average temperature (T_{avg}) is provided to create demand signals for moving groups of rod cluster control assemblies to provide load follow (determined as a function of first stage turbine pressure) during normal operation and to counteract operational transients. The hot and cold leg resistance temperature detectors (RTDs) are described in Section 7.2 in the reactor coolant bypass loops. The location of the RTDs in each loop is shown on the flow diagrams in Chapter 5.0. The reactor control system which controls the reactor coolant average temperature by regulation of control rod bank position is described in Section 7.3.

Rod position indication instrumentation is provided to sense the actual position of each control rod so that the actual position of the individual rod may be displayed to the operator. Signals are also supplied by this system as input to the rod deviation comparator. The rod position indication system is described in Chapter 7.0.

The reactor makeup control system whose functions are to permit adjustment of the reactor coolant boron concentration for reactivity control (as well as to maintain the desired operating fluid inventory in the volume control tank), consists of a group of instruments arranged to provide a manually preselected makeup composition that is borated or diluted as required to the charging

pump suction header or the volume control tank. This system, as well as other systems including boron sampling provisions that are part of the chemical and volume control system, are described in Section 9.3.

Monitoring of the neutron flux for various phases of reactor power operation as well as of core loading, shutdown, startup, and refueling is by means of the nuclear instrumentation system. The monitoring functions, readout and indication characteristics for the following means of monitoring reactivity during these phases are included in the discussion on safety-related display instrumentation in Section 7.5:

1. Nuclear Instrumentation System
2. Temperature Indicators
   a. T average (Measured)
   b. ΔT (Measured)
   c. Auctioneered T average
   d. T reference
3. Demand Position of Rod Cluster Control Assembly Group
4. Actual Rod Position Indicator

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Table 4.2-1
Maximum Deflections Allowed For Reactor Internal Support Structures

Component	Allowable Deflections (in.)	No-Los-of Function Deflections (in.)
Upper Barrel		
radial inward	4.1	8.2
radial outward	1.0	1.0
Upper Package (1)	0.10	0.15
Rod Cluster Guide Tubes	1.00	1.75

(1) The vertical motion of the upper core plate relative to the upper support plate shall not cause buckling of the guide tubes.

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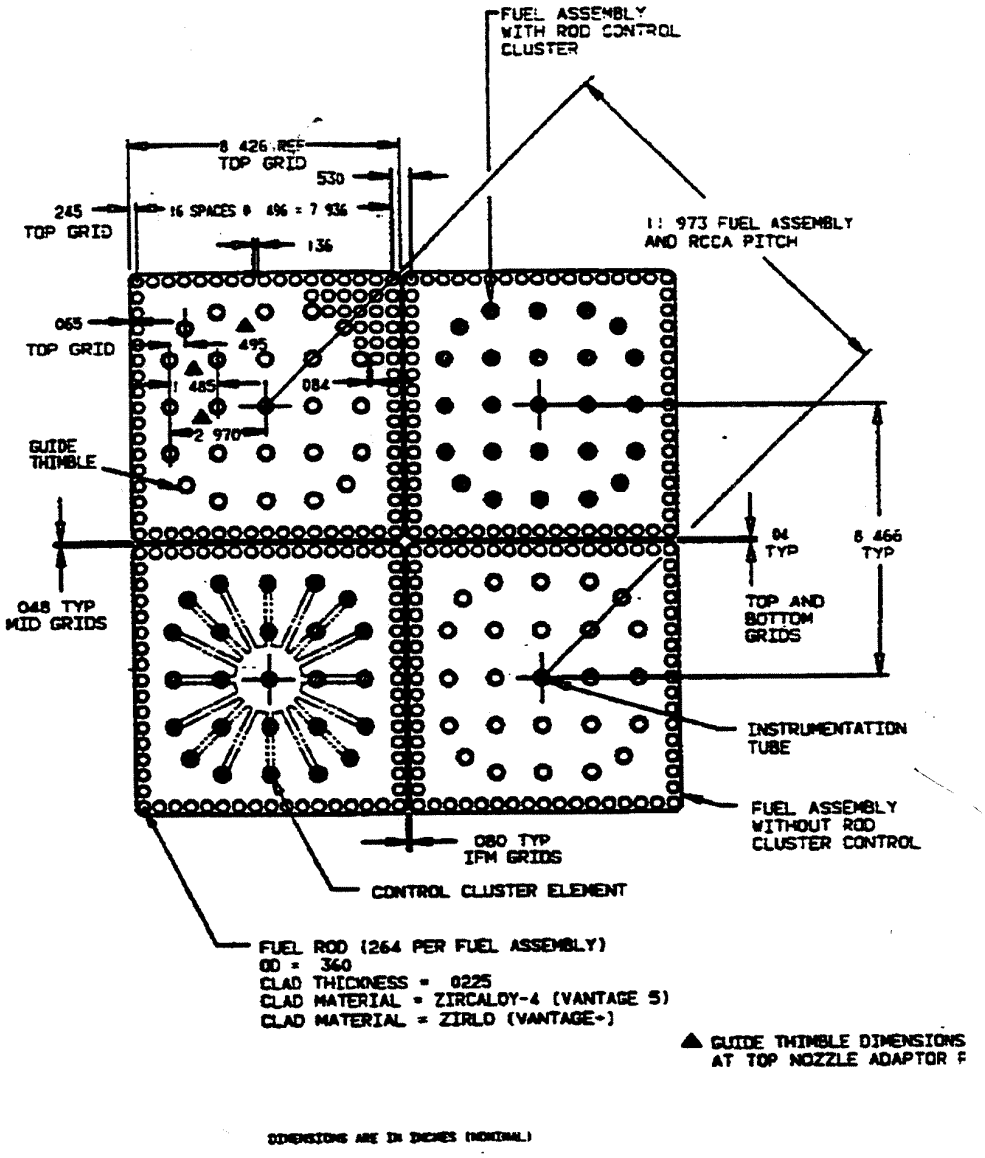
Figure 4.2-1
FUEL ASSEMBLY CROSS SECTION 17X17



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Fuel Assembly Cross Section 17x17 Figure 4.2-1

Figure 4.2-2
17 X 17 OFA PRIME
FUEL ASSEMBLY

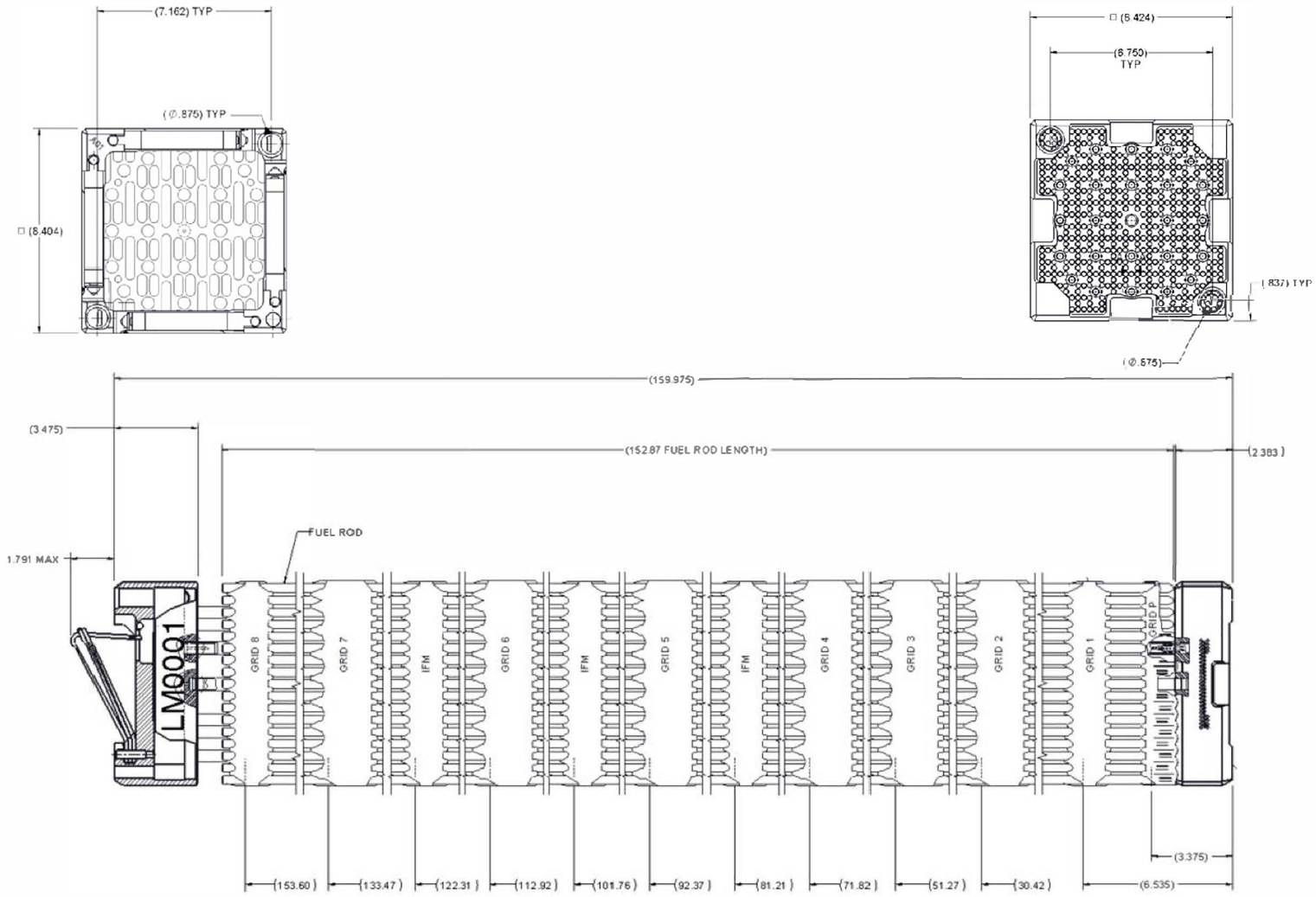
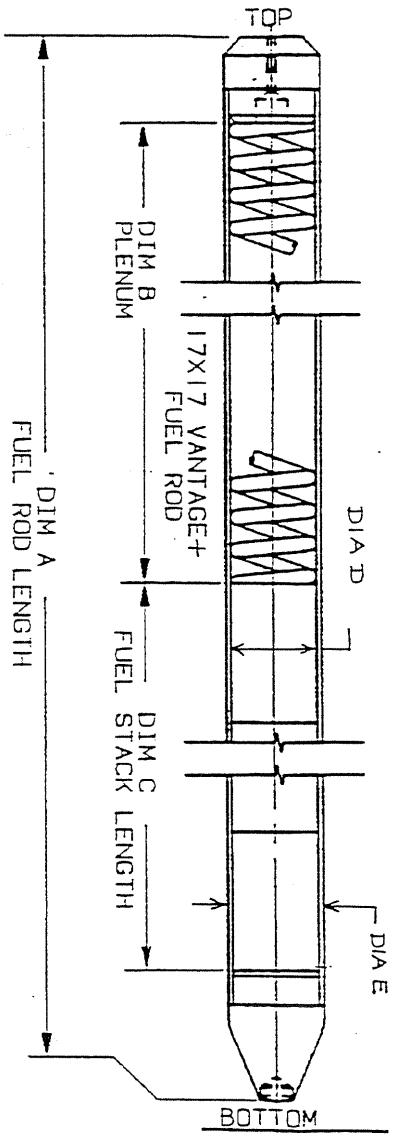


Figure 4.2-3
REPRESENTATIVE 17X17 OFA FUEL ROD



DIM	V+ with P+ Features
A	152.670 in
B	7.410 in
C	144.00 in
DIA D	0.315 in
DIA E	0.360 in

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17 x 17 Vantage + with Performance +

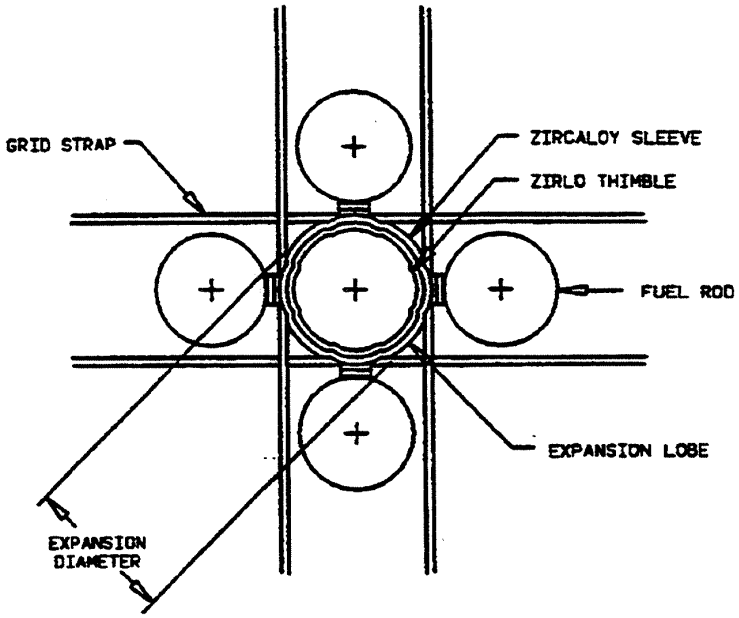
Fuel Rod

Figure 4.2-3

Amendment 98-01
August 1998

NOTE:
Region 14 increased the following dimensions:
DIM A to 152.870 in and DIM B to 7.730 in

Figure 4.2-4
REPRESENTATIVE FUEL PLAN VIEW



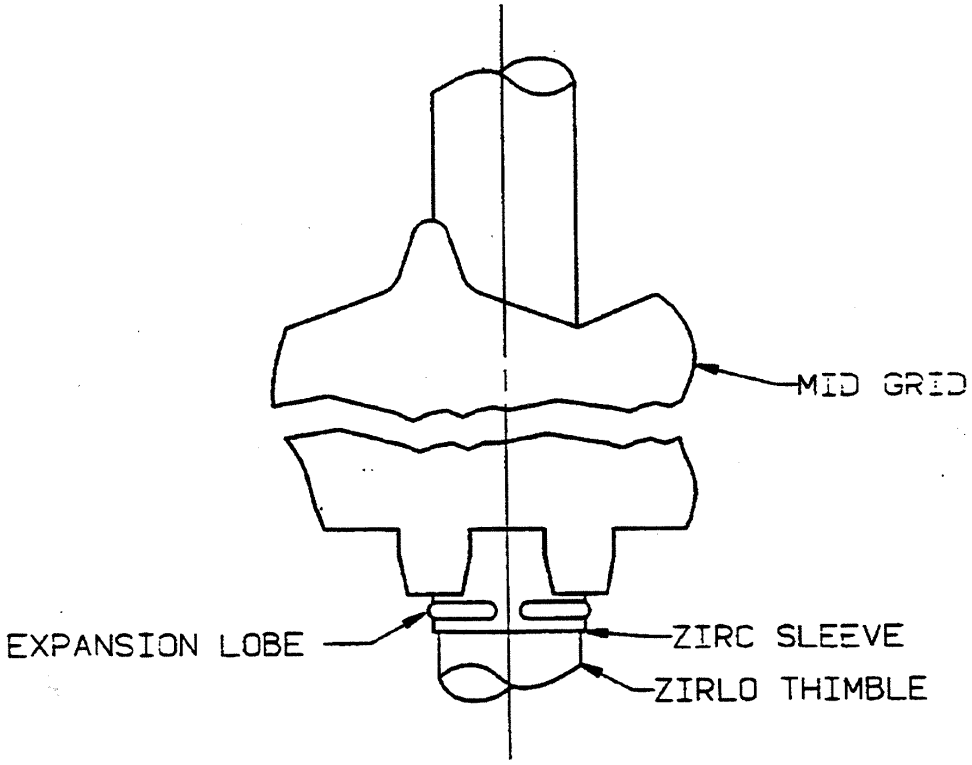
MID GRID EXPANSION JOINT DESIGN

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Vantage+ Fuel Plan View Figure 4.2-4

AMENDMENT 96-02
JULY 1996

fsar424.m(343,jr14325) JR14325@jr14325. Fri Jun 28 13:05:06 EDT 1996

Figure 4.2-5
REPRESENTATIVE FUEL ELEVATION VIEW

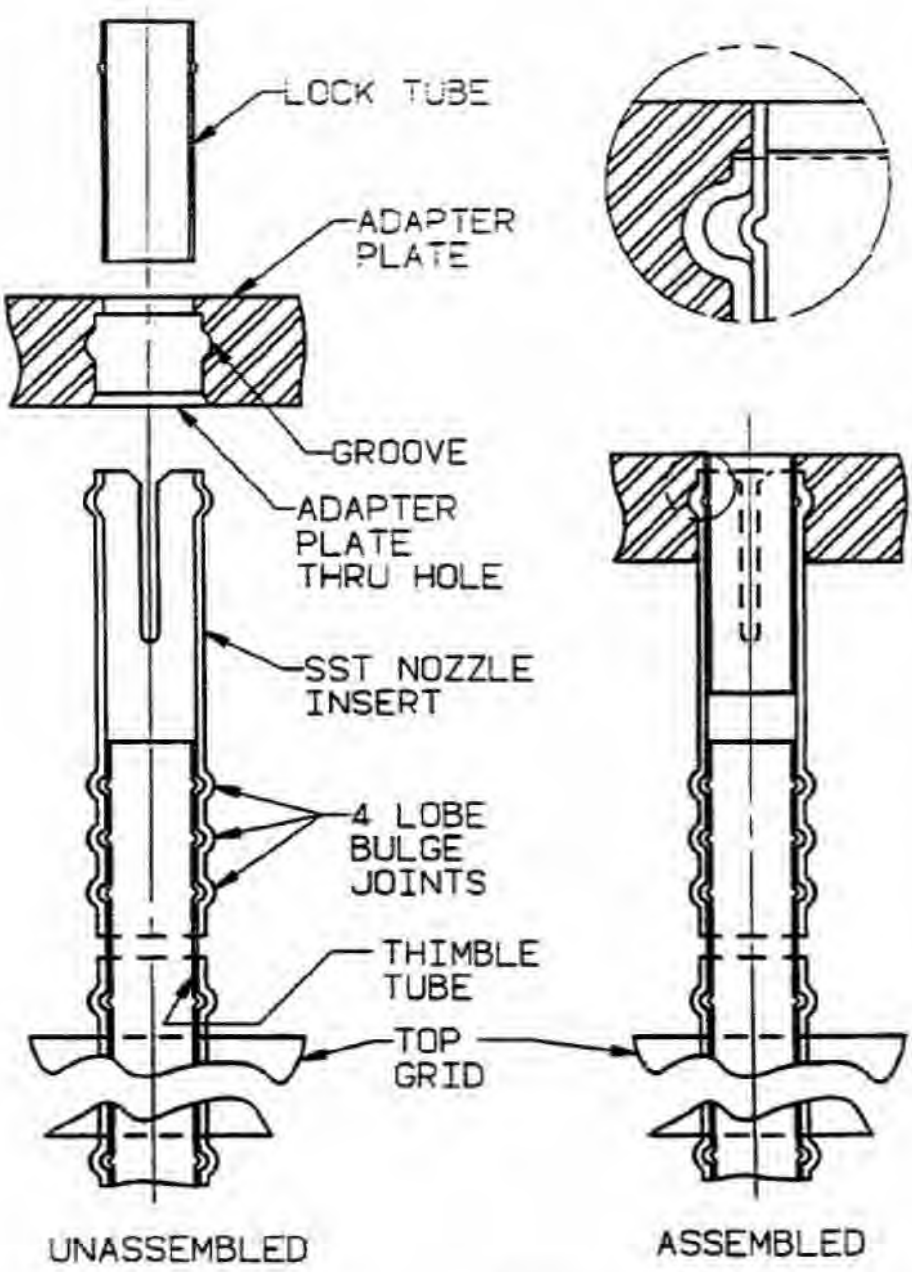


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Elevation View - Vantage+ Fuel
Figure 4.2-5

AMENDMENT 96-02
JULY 1996

fsar425.m(339,jr14325) JR14325@jr14325. Fri Jun 28 12:13:03 EDT 1996

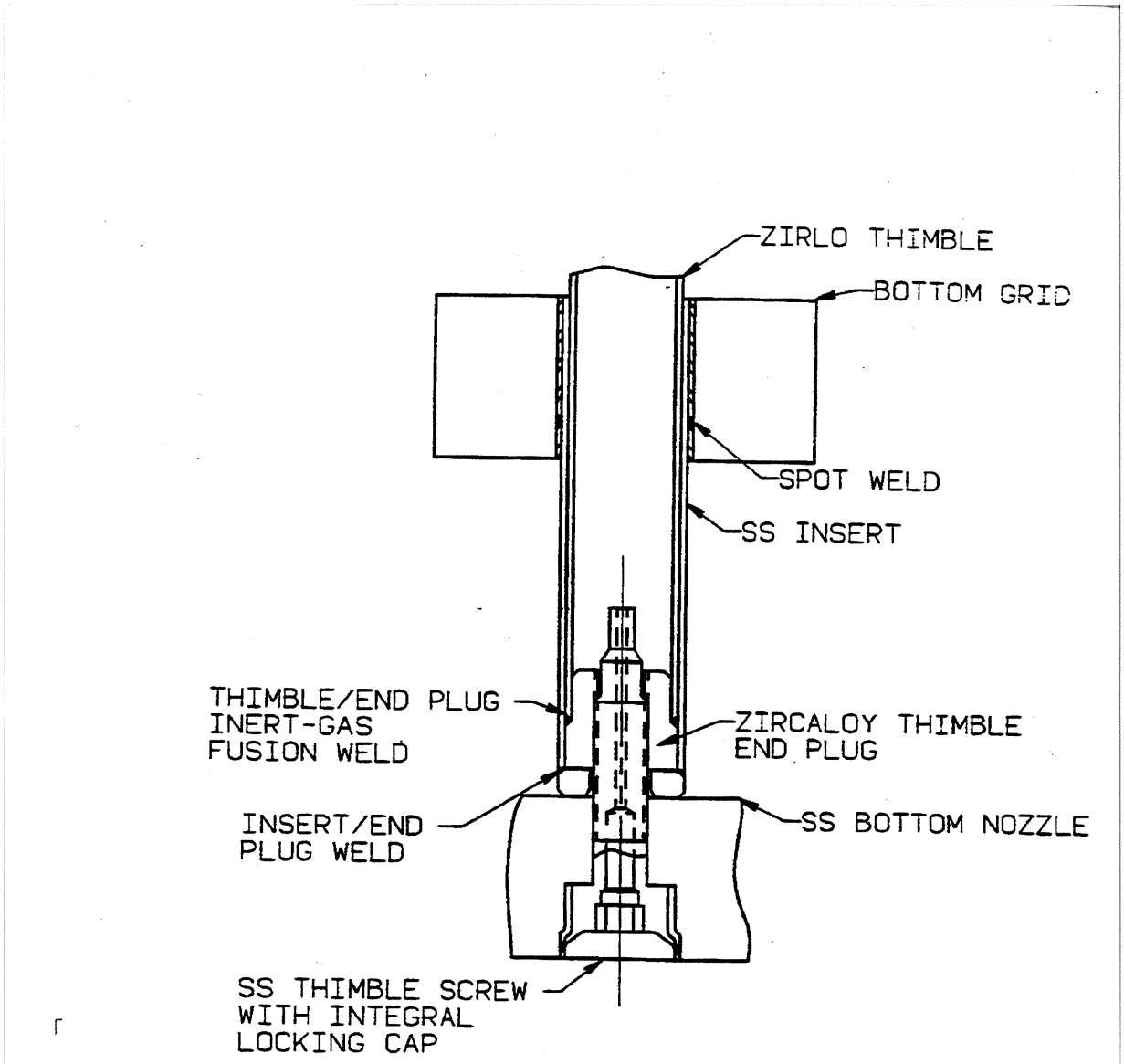
Figure 4.2-6
REPRESENTATIVE FUEL TOP GRID TO NOZZLE ATTACHMENT



RN 18-018

South Carolina Electric & Gas Company
Virgil C. Summer Nuclear Station
VANTAGE+ Fuel Top Grid to Nozzle Attachment
Figure 4.2-6
October 2018

Figure 4.2-7
REPRESENTATIVE FUEL GUIDE THIMBLE TO BOTTOM NOZZLE JOINT



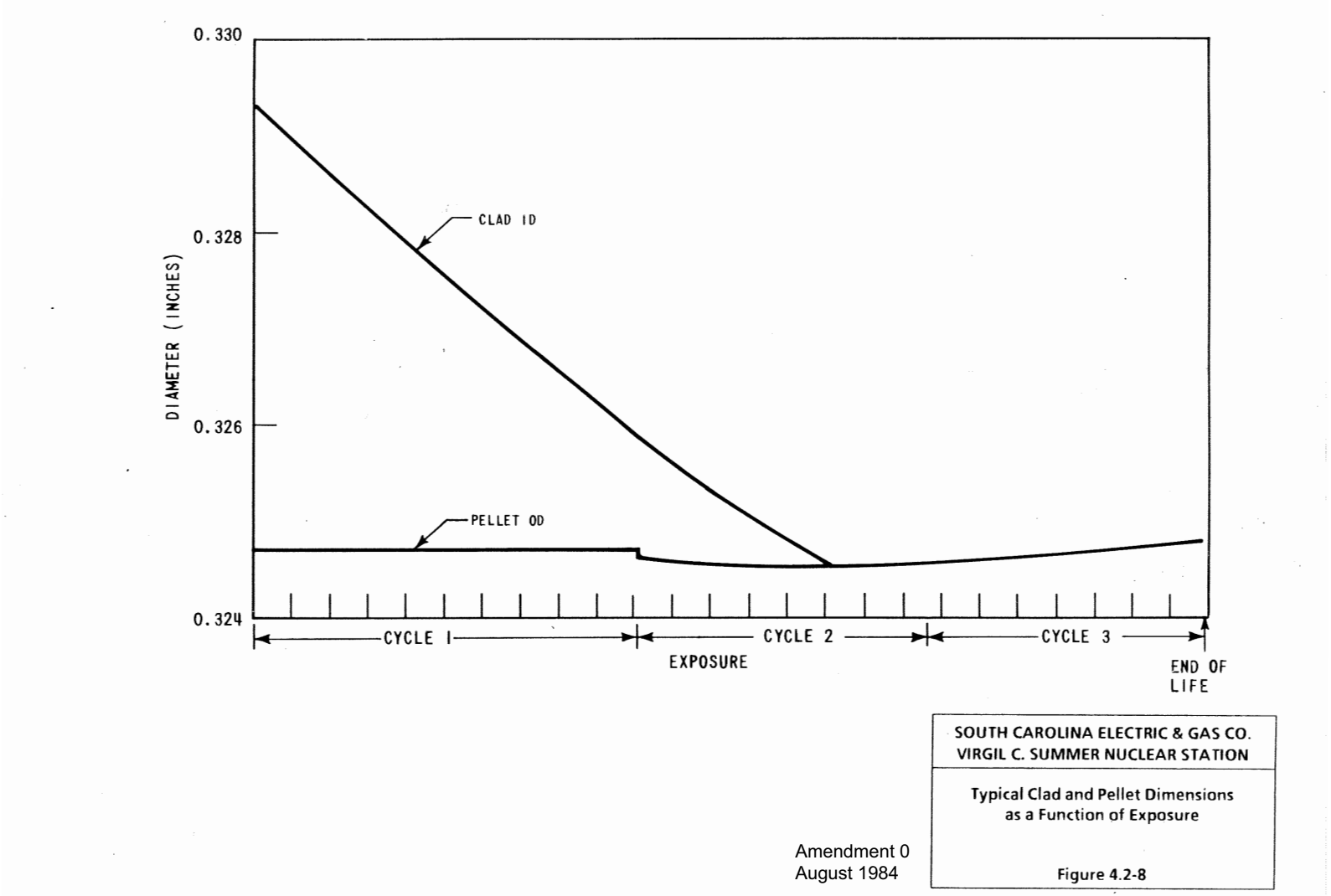
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Vantage+ Fuel Guide Thimble To Bottom Nozzle Joint Figure 4.2-7

AMENDMENT 96-02
JULY 1996

fsar427.sx(342,jr14325) JR14325@jr14325. Fri Jun 28 13:02:22 EDT 1996

Figure 4.2-8

TYPICAL CLAD AND PELLET DIMENSIONS AS A FUNCTION OF EXPOSURE



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

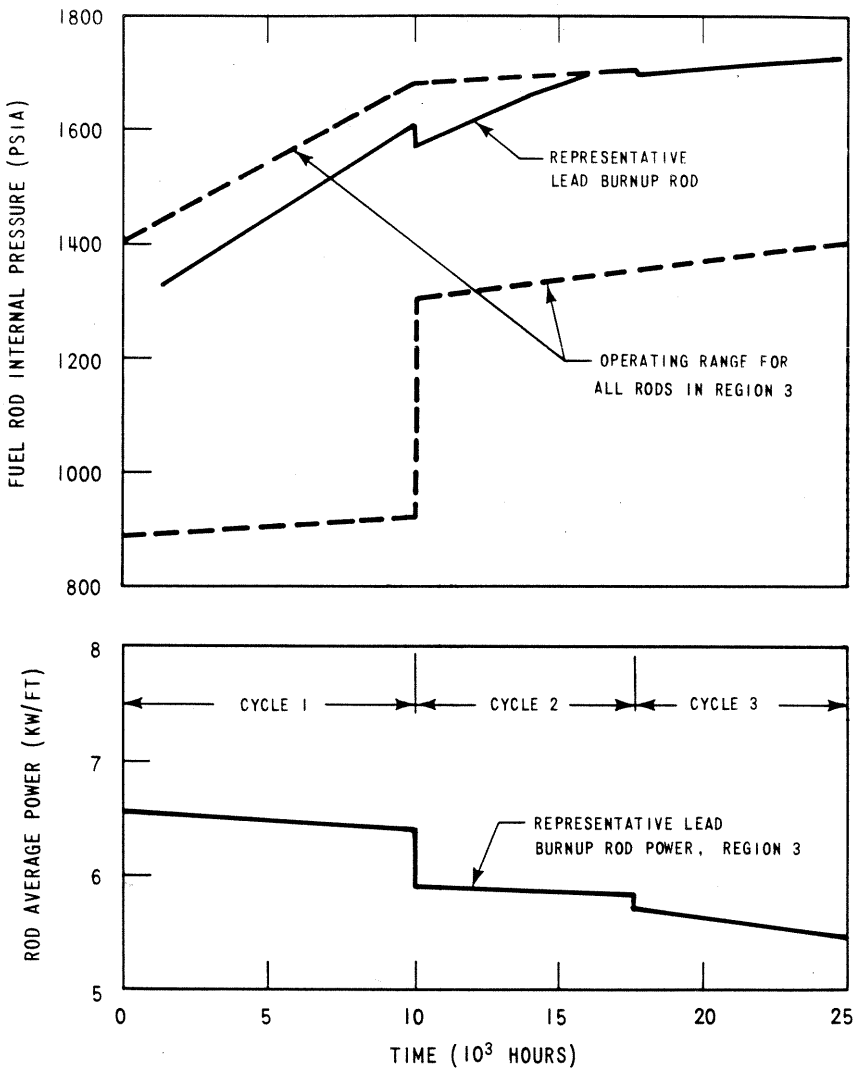
Typical Clad and Pellet Dimensions as a Function of Exposure

Figure 4.2-8

Amendment 0
August 1984

Figure 4.2-9

REPRESENTATIVE FUEL ROD INTERNAL PRESSURE AND LINEAR POWER DENSITY FOR THE LEAD BURNUP RAD AS A FUNCTION OF TIME



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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Representive Fuel Rod Internal Pressure and Linear Power Density for the Lead Burnup Rod as a Function of Time Figure 4.2-9

Figure 4.2-10
LOWER CORE SUPPORT ASSEMBLY
(CORE BARREL ASSEMBLY)

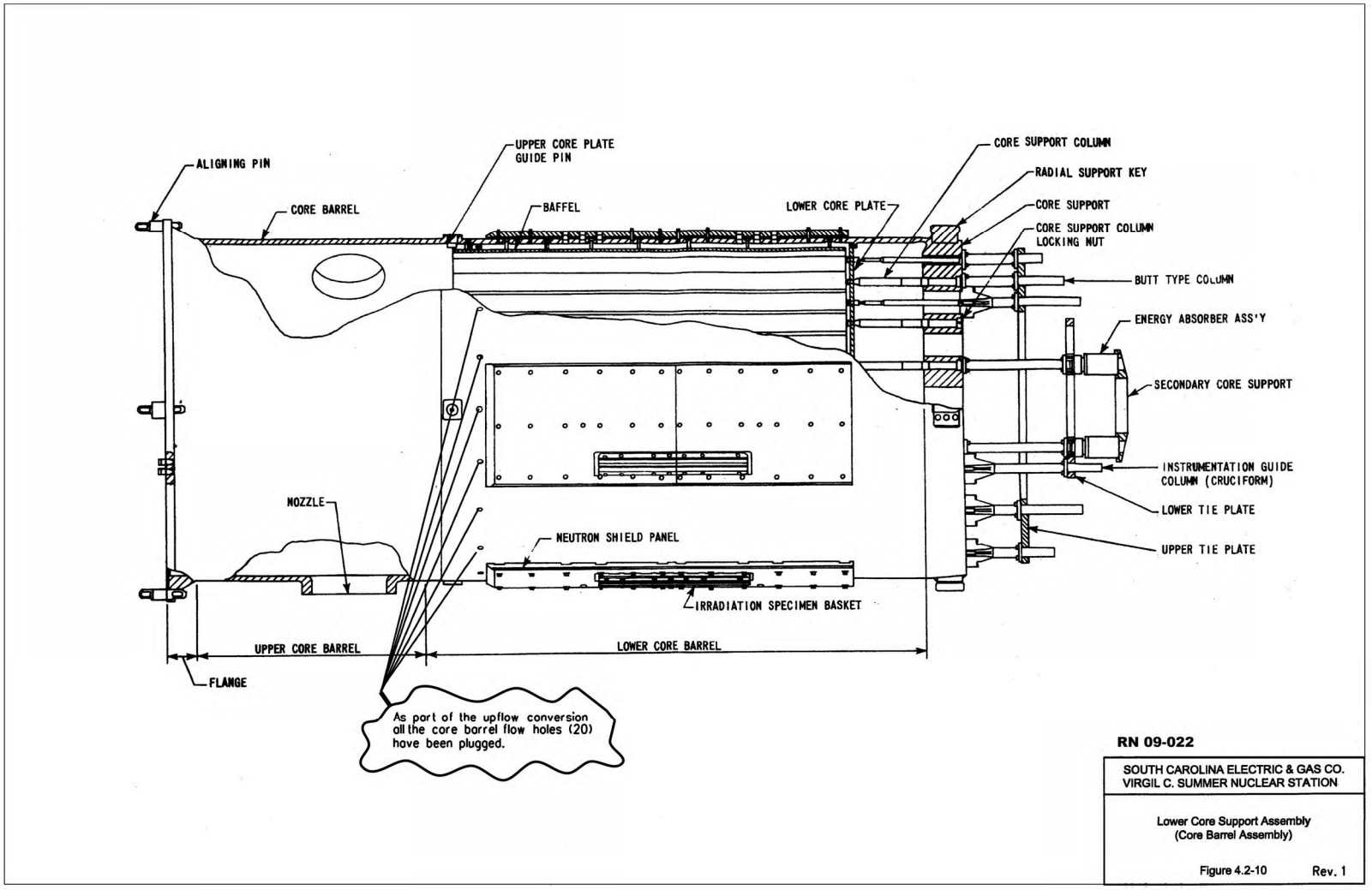
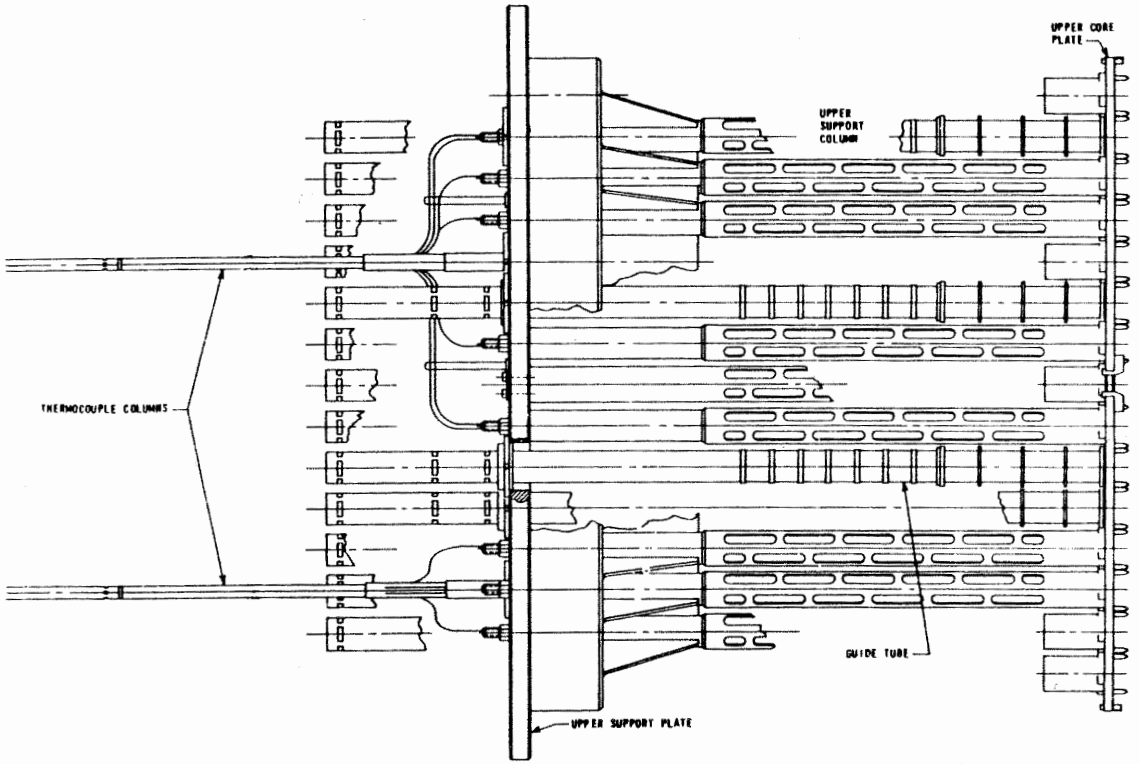


Figure 4.2-11
UPPER CORE SUPPORT ASSEMBLY



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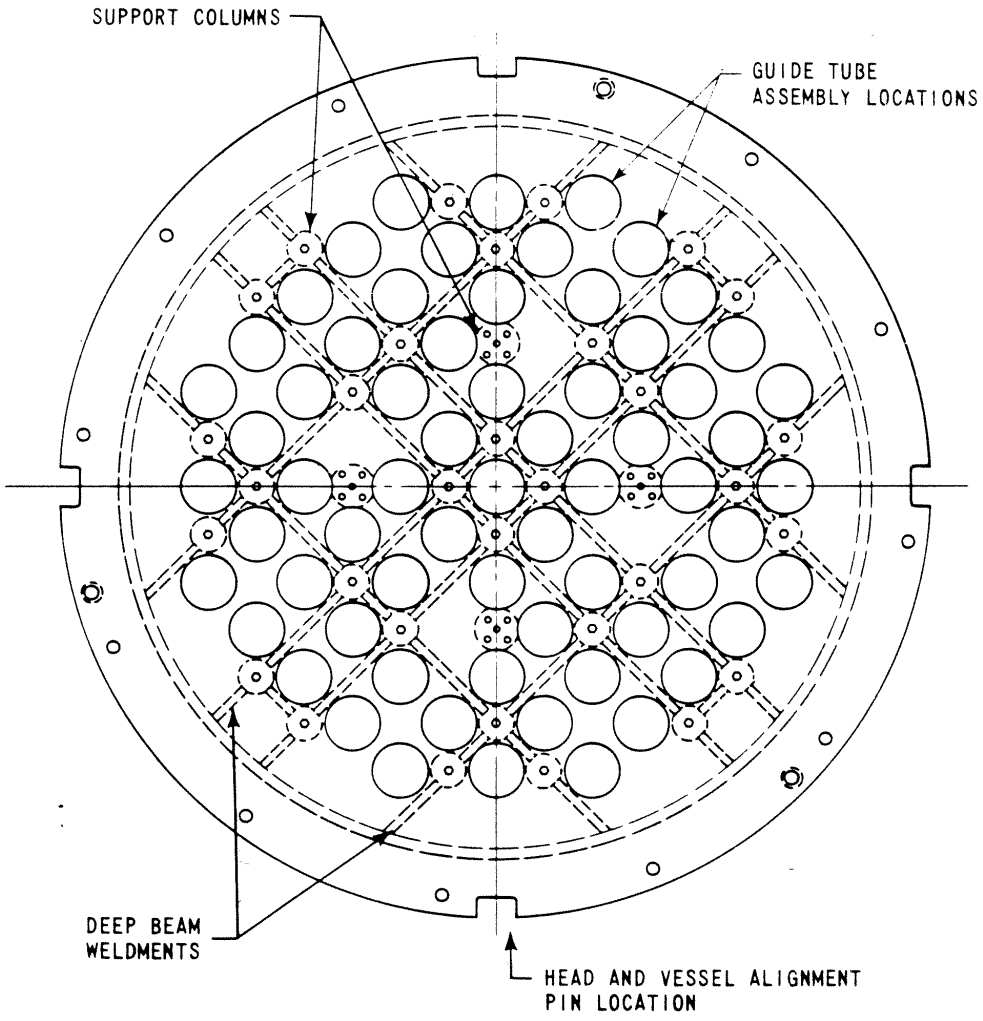
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Upper Core Support Assembly

Figure 4.2-11

Figure 4.2-12
PLAN VIEW OF UPPER CORE SUPPORT STRUCTURE



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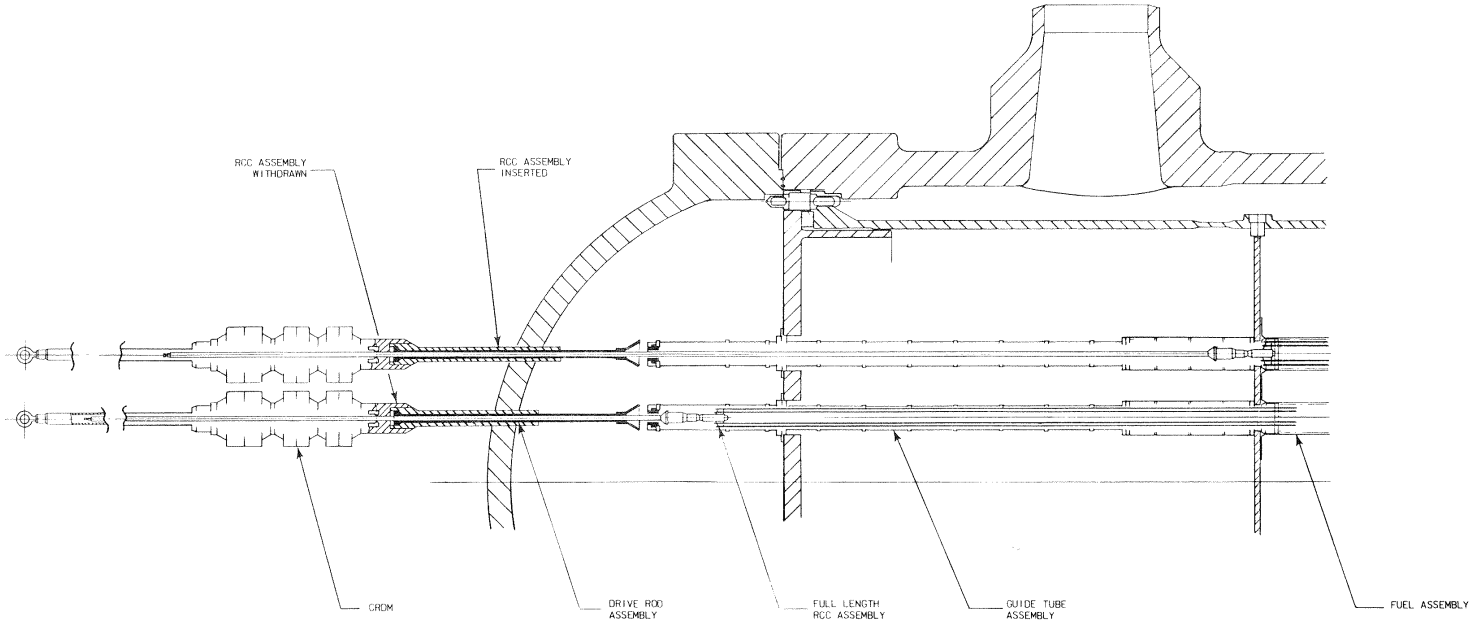
Plan View of Upper Core Support Structure Figure 4.2-12

Figure 4.2-13

FULL LENGTH ROD CLUSTER CONTROL AND DRIVE ROD ASSEMBLY WITH INTERFACING COMPONENTS



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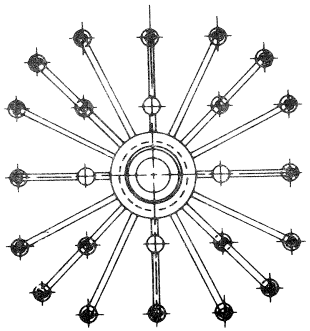
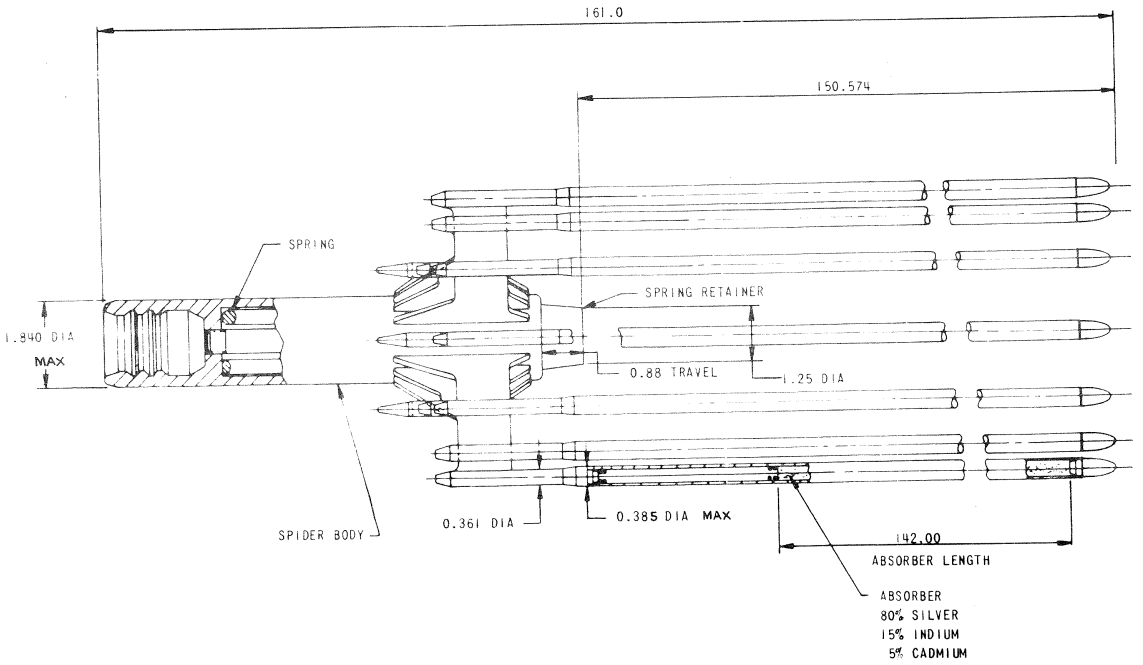
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Full Length Rod Cluster Control and Drive Rod Assembly with Interfacing Components Figure 4.2-13

Figure 4.2-14
FULL LENGTH ROD CLUSTER CONTROL ASSEMBLY OUTLINE





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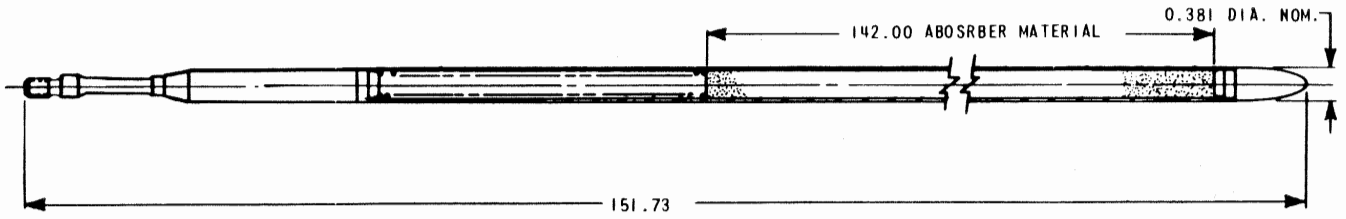
Full Length Rod Cluster Control Assembly Outline Figure 4.2-14

Figure 4.2-15
FULL LENGTH ABSORBER ROD



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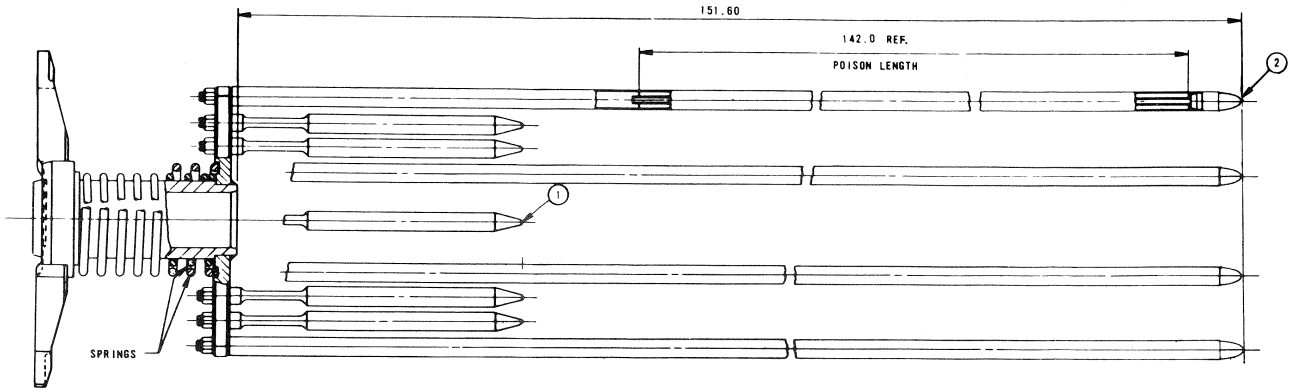
VIRGIL C. SUMMER NUCLEAR STATION

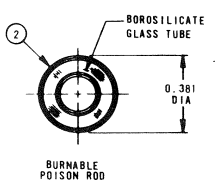
Full Length Absorber
Rod

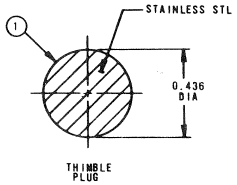
Figure 4.2-15

Figure 4.2-17

BOROSILICATE ABSORBER ASSEMBLY





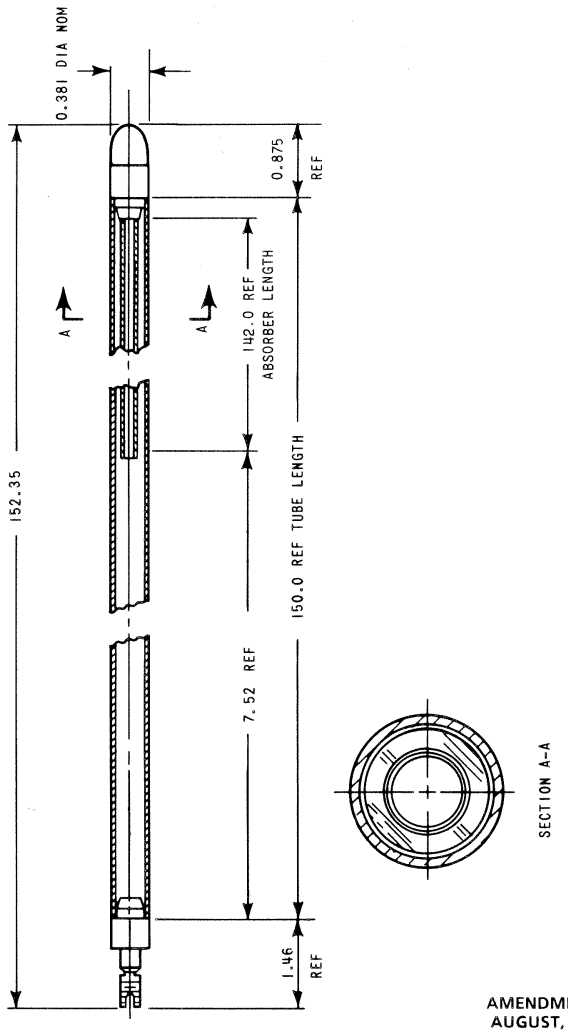


AMENDMENT 6
AUGUST, 1990

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Borosilicate Absorber Assembly Figure 4.2-17

Figure 4.2-18

BOROSILICATE ABSORBER ROD CROSS SECTION



AMENDMENT 6
AUGUST, 1990

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Borosilicate Absorber Rod Cross Section Figure 4.2-18

Figure 4.2-18a

WET ANNULAR BURNABLE ABSORBER ROD

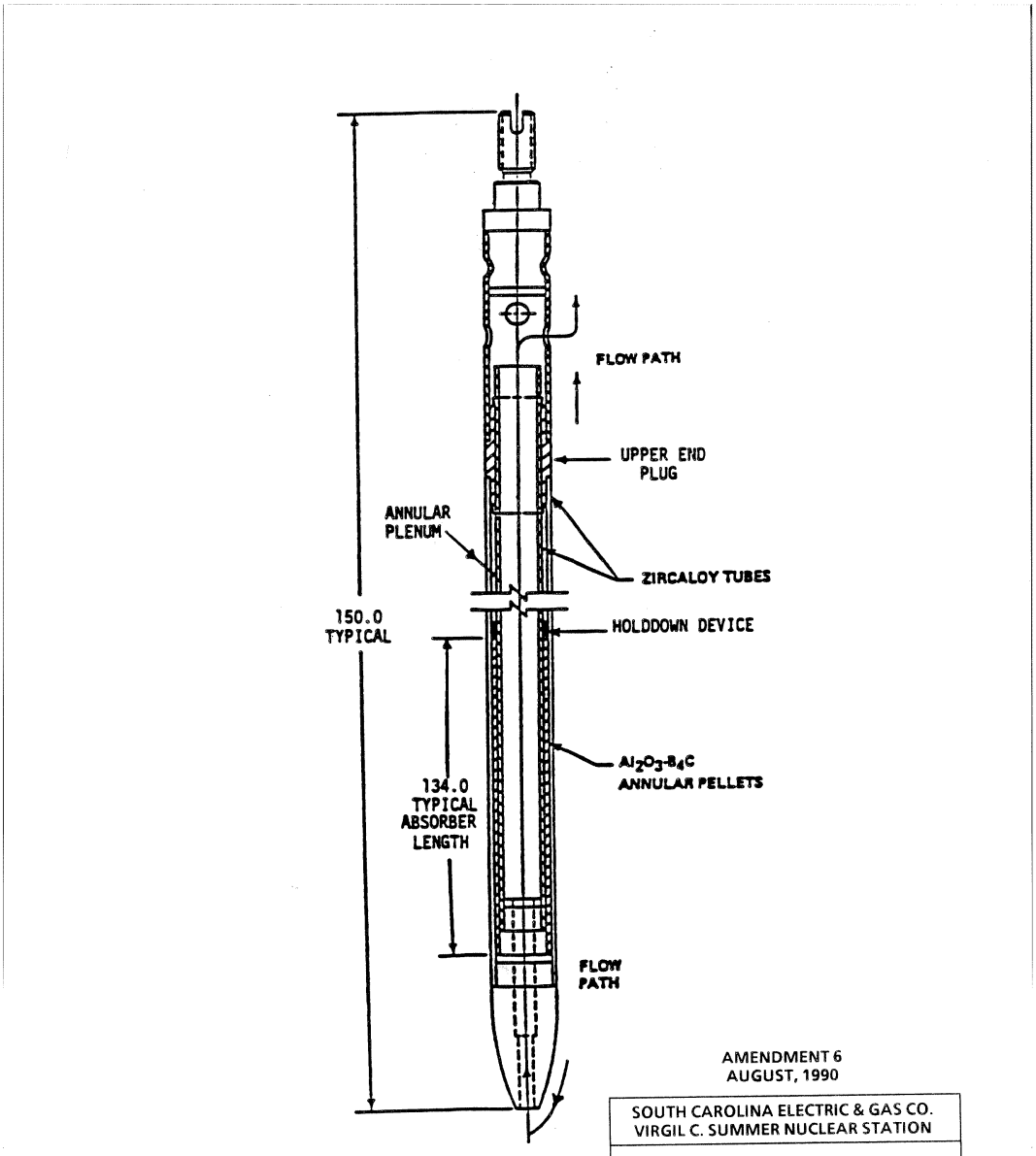
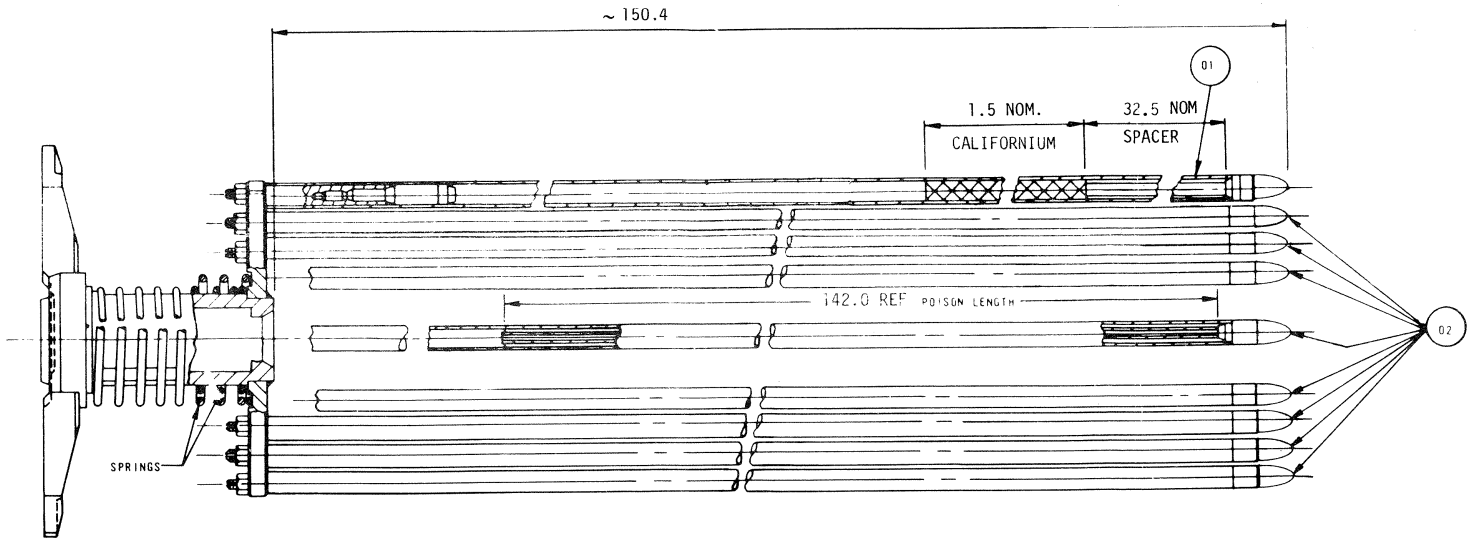
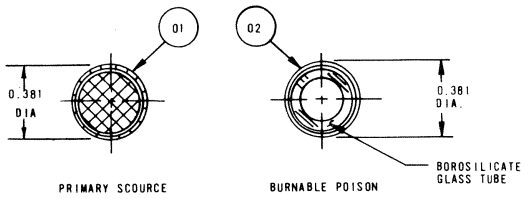


Figure 4.2-19

PRIMARY SOURCE ASSEMBLY



NOTE: ALL DIMENSIONS ARE IN INCHES



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August 1984

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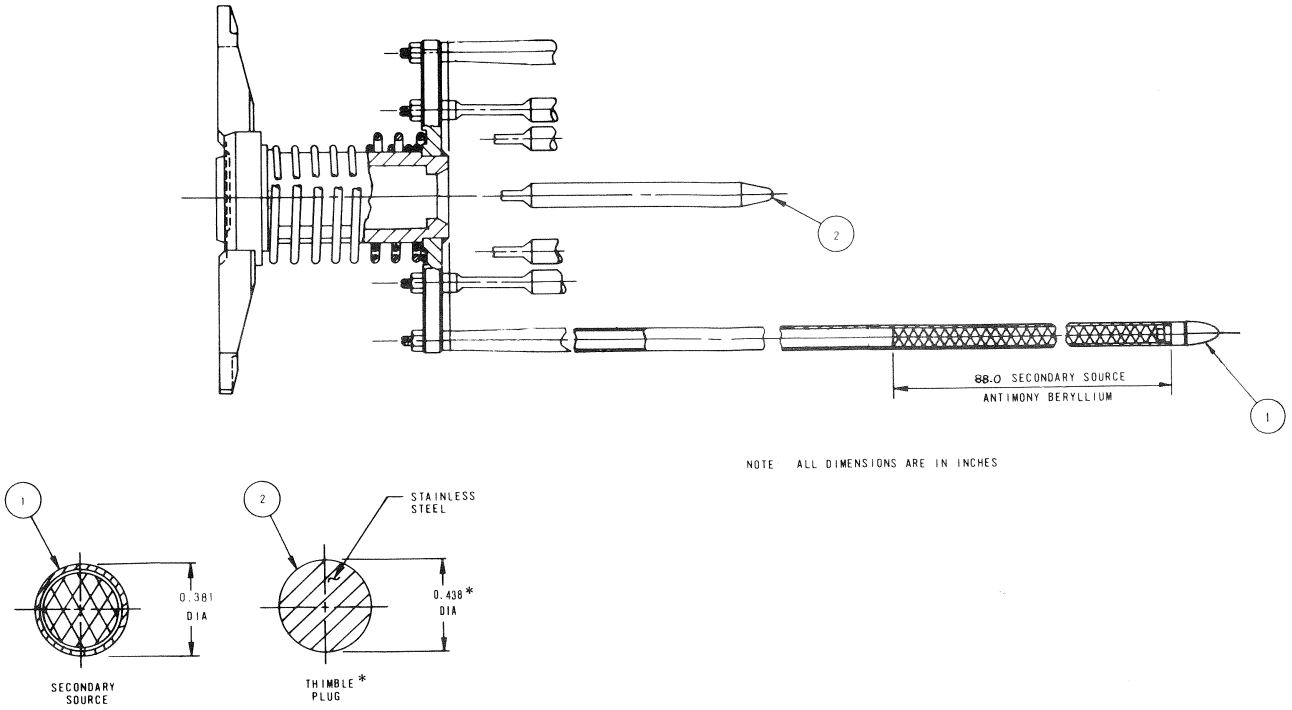
Primary Source Assembly Figure 4.2-19

Figure 4.2-20

SECONDARY SOURCE ASSEMBLY



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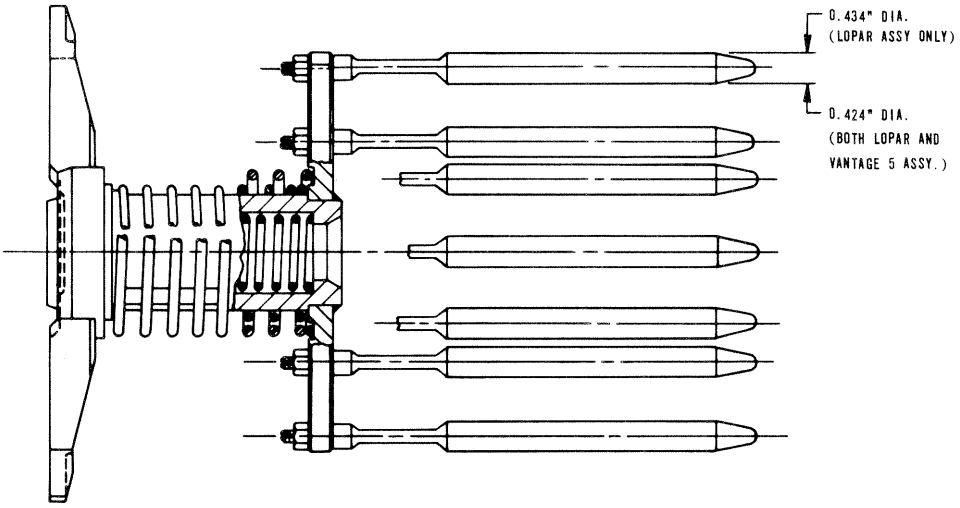
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Secondary Source Assembly Figure 4.2-20

Figure 4.2-21
THIMBLE PLUG ASSEMBLY



AMENDMENT 6
AUGUST, 1990

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VIRGIL C. SUMMER NUCLEAR STATION

Thimble Plug Assembly
Figure 4.2-21

Figure 4.2-22
FULL LENGTH CONTROL ROD DRIVE MECHANISM

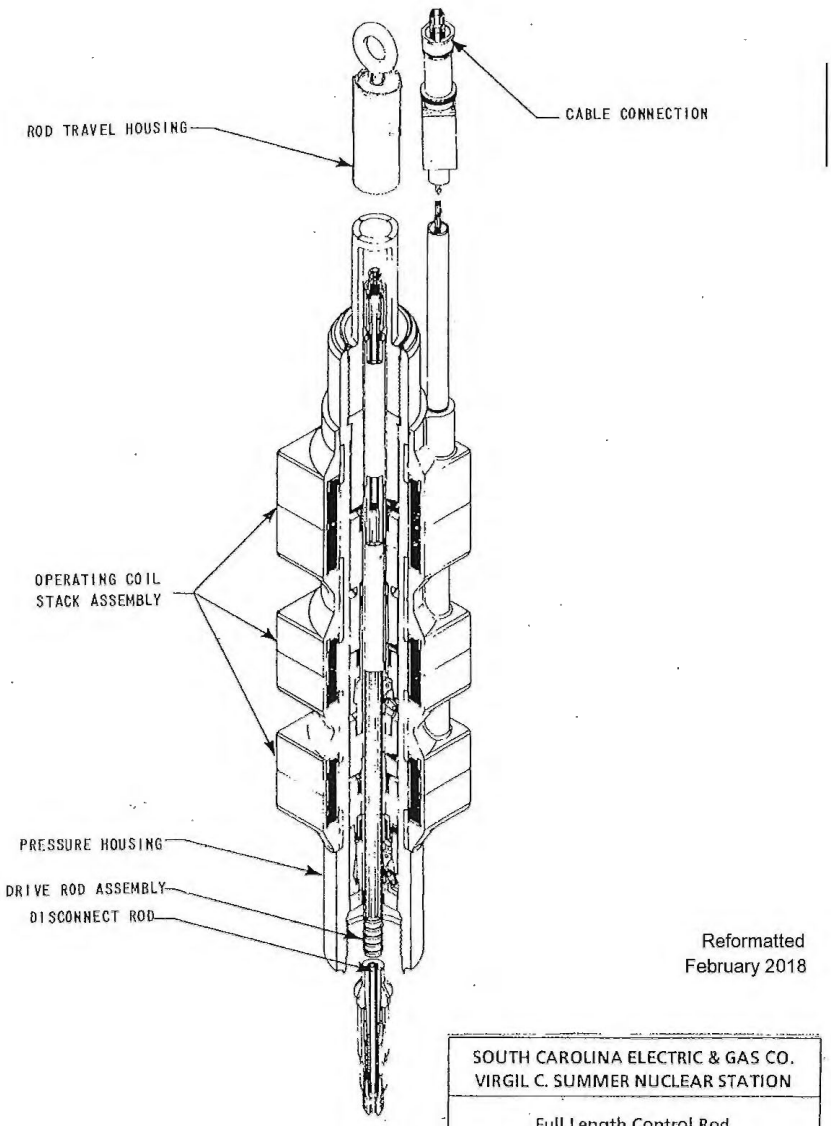
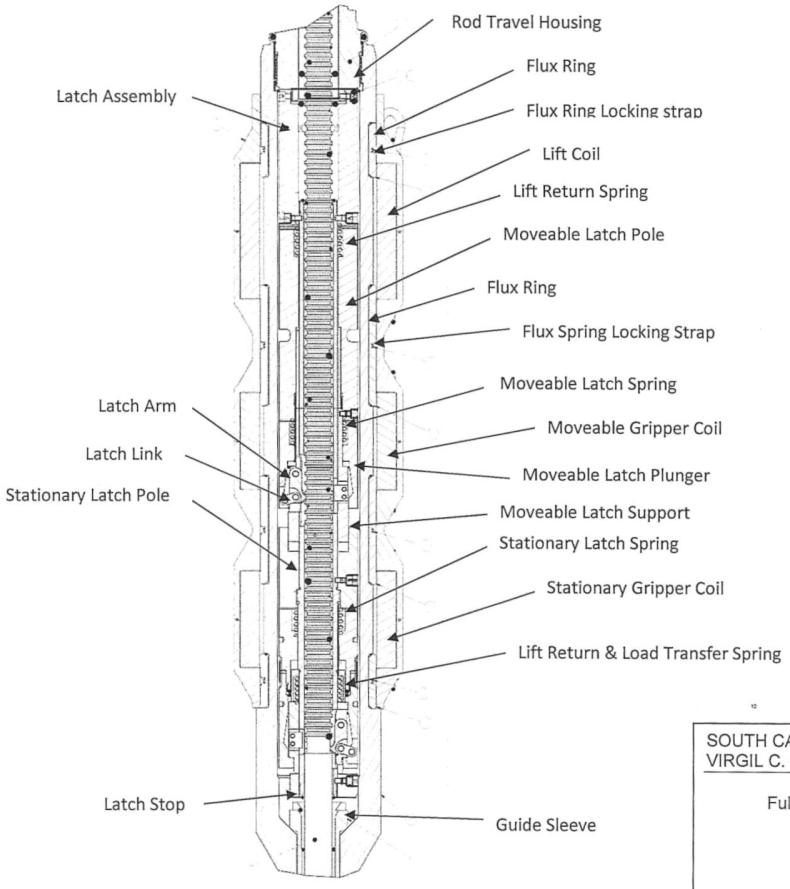


Figure 4.2-23
FULL LENGTH CONTROL ROD DRIVE MECHANISM



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February 2018

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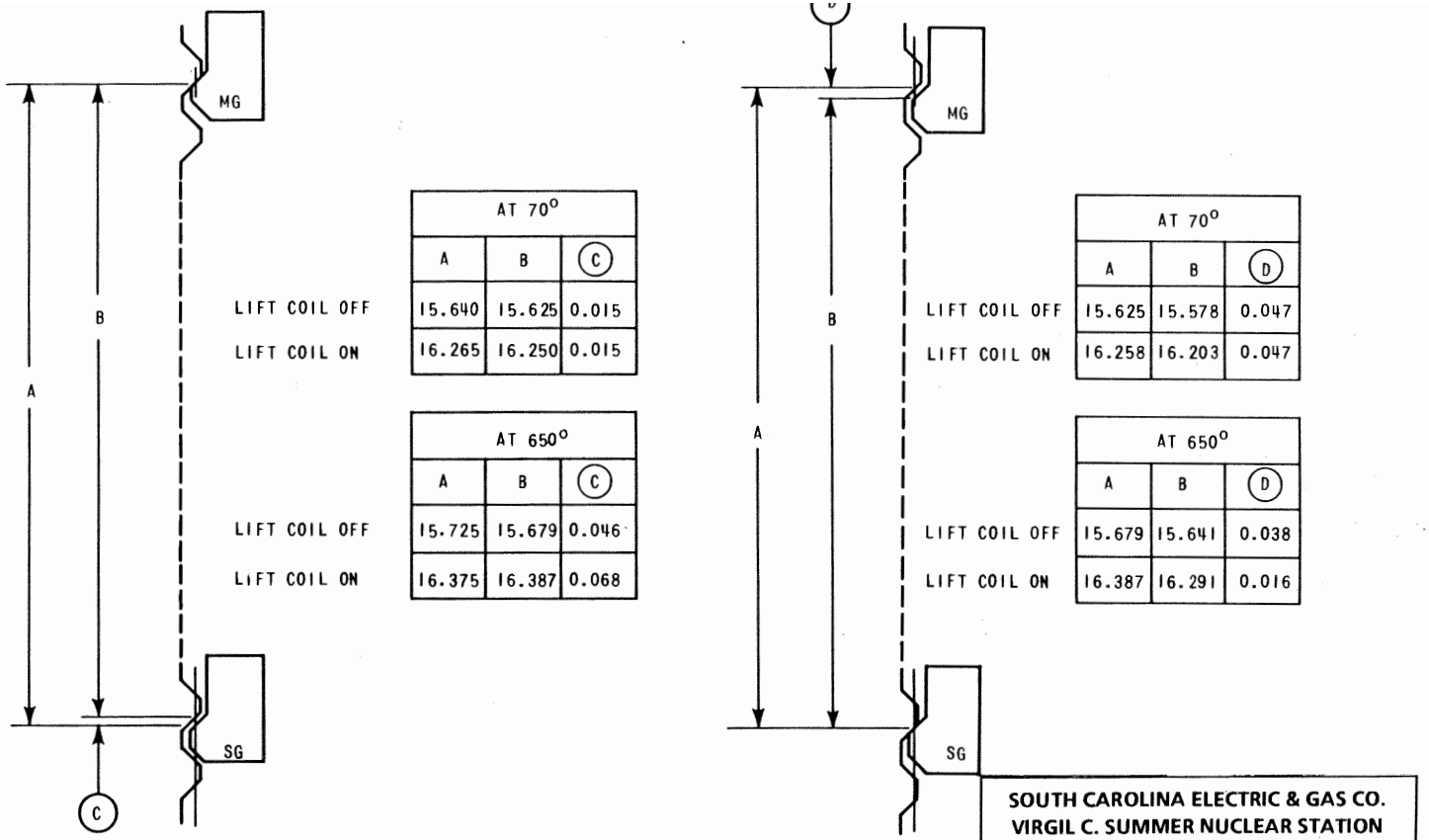
Full Length Control Rod Drive Mechanism

Figure 4.2-23

Figure 4.2-26

NOMINAL LATCH CLEARANCE AT MINIMUM AND MAXIMUM TEMPERATURE



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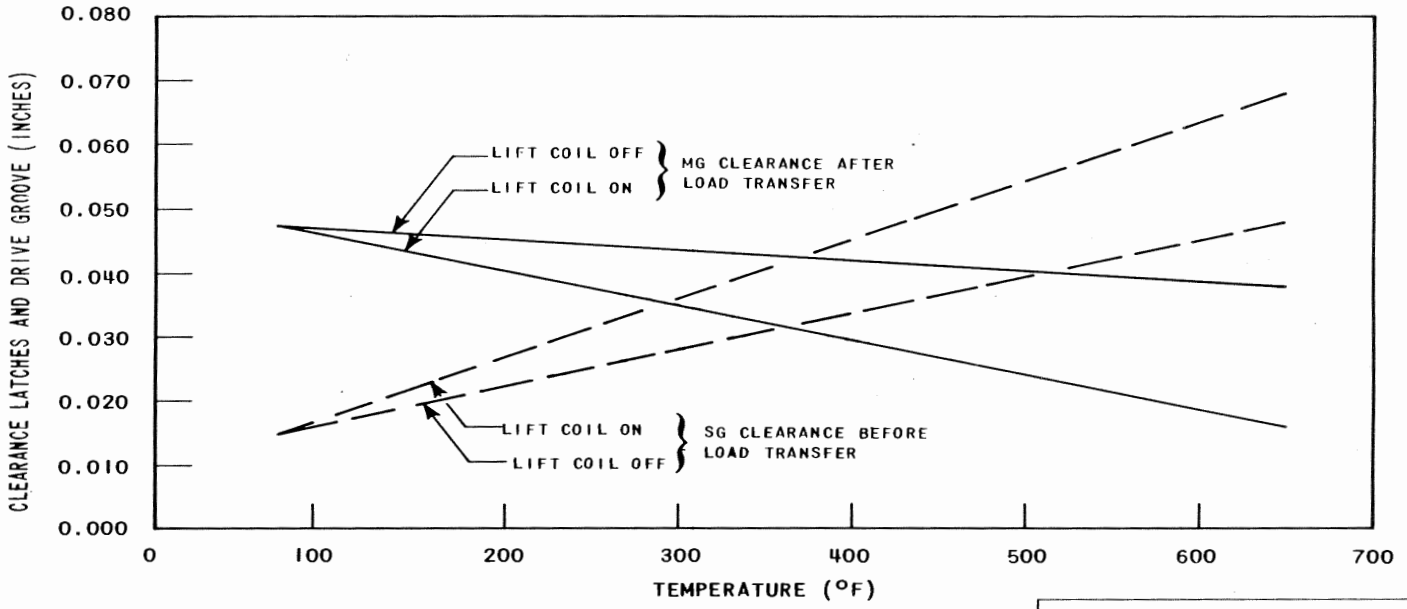
Nominal Latch Clearance at Minimum and Maximum Temperature

Figure 4.2-26

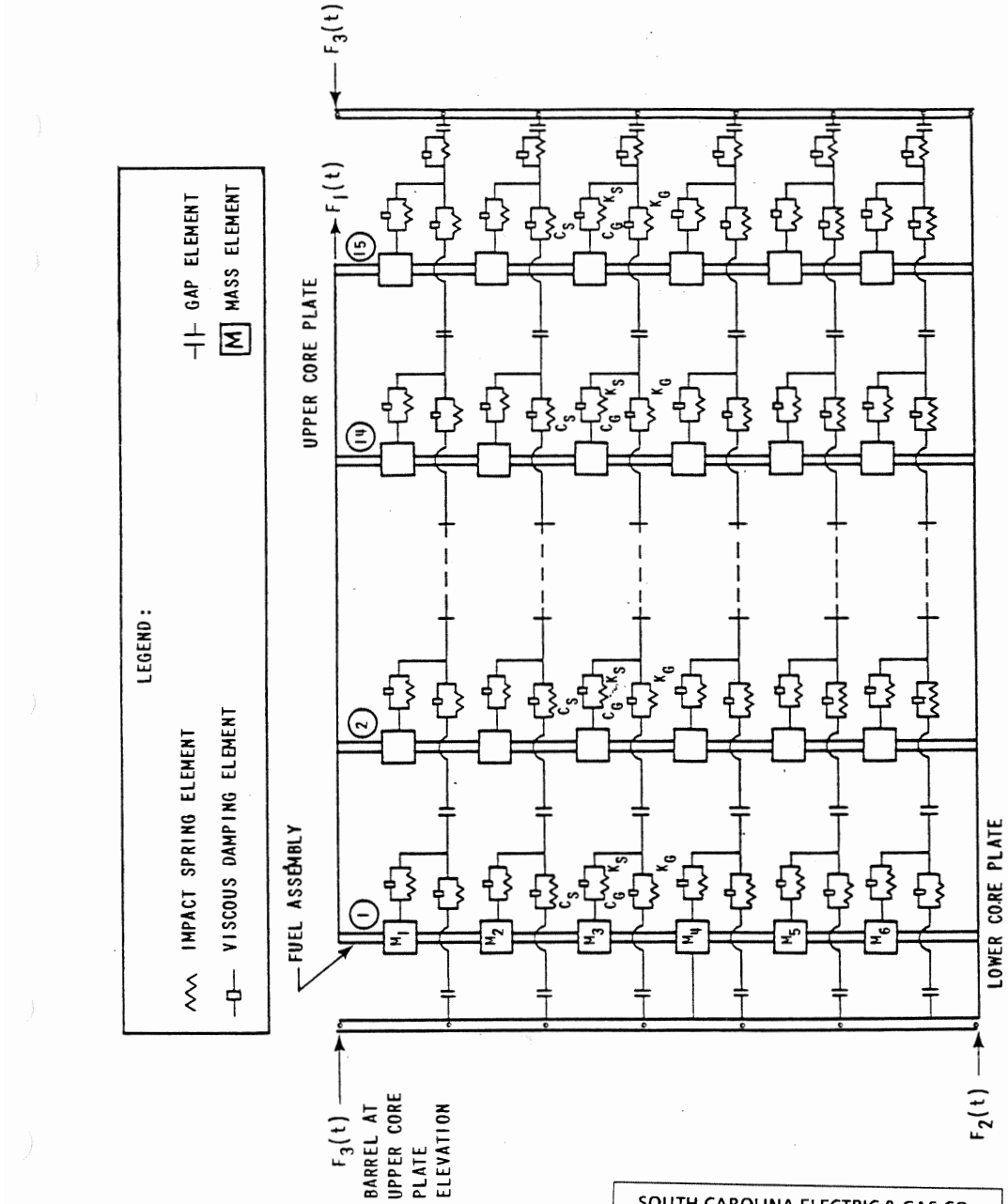
Figure 4.2-27

CONTROL ROD DRIVE MECHANISM
LATCH CLEARANCE THERMAL EFFECT



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Control Rod Drive Mechanism Latch Clearance Thermal Effect Figure 4.2-27

Figure 4.2-28
SCHEMATIC REPRESENTATION OF REACTOR CORE MODEL



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VIRGIL C. SUMMER NUCLEAR STATION

Schematic Representation of Reactor Core Model

Figure 4.2-28

Amendment 0
August 1984

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4.3 NUCLEAR DESIGN

4.3.1 Design Bases

This section describes the design bases and functional requirements used in the nuclear design of the fuel and reactivity control system and relates these design bases to the General Design Criteria (GDC) of July 1971. Where appropriate, supplemental criteria such as the Final Acceptance Criteria for Emergency Core Cooling Systems are addressed. Before discussing the nuclear design bases, it is appropriate to briefly review the 4 major categories ascribed to the conditions of plant operation.

The full spectrum of plant conditions is divided into 4 categories, in accordance with the anticipated frequency of occurrence and risk to the public:

1. Condition I - Normal Operation
2. Condition II - Incidents of Moderate Frequency
3. Condition III - Infrequent Faults
4. Condition IV - Limiting Faults

In general, the Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Condition II incidents are accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action. Fuel damage (as used here is defined as penetration of the fission product barrier, i.e., the fuel rod clad) is not expected during Condition I and Condition II events. It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the plant cleanup system and are consistent with the plant design basis.

Condition III incidents shall not cause more than a small fraction of the fuel elements in the reactor to be damaged, although sufficient fuel element damage might occur to preclude immediate resumption of operation. The release of radioactive material due to Condition III incidents should not be sufficient to interrupt or restrict public use of these areas beyond the exclusion radius. Furthermore, a Condition III incident shall not, by itself generate a Condition IV fault or result in a consequential loss of function of the reactor coolant or reactor containment barriers.

Condition IV occurrences are faults that are not expected to occur but are defined as limiting faults which must be designed against. Condition IV faults shall not cause a release of radioactive material that results in an undue risk to public health and safety.

Condition II, III, and IV events or accidents requiring the minimum shutdown margin are assumed to start from normal operating conditions. Normal operation does not require maintaining the minimum shutdown margin; but some accidents which start from normal operation require that the minimum shutdown margin be available, i.e., at anytime during Condition I operation, the plant must be able to go to zero power and be subcritical by at least the

minimum shutdown margin. If this condition is met, then the consequences of accidents assumed to start from normal operation will be within acceptable limits.

The core design power distribution limits related to fuel integrity are met for Condition I occurrences through conservative design and maintained by the action of the control system. The requirements for Condition II occurrences are met by providing an adequate protection system which monitors reactor parameters. The control and protection systems are described in Chapter 7.0 and the consequences of Condition II, III, and IV occurrences are given in Chapter 15.0.

4.3.1.1 Fuel Burnup

4.3.1.1.1 Basis

The fuel rod design basis is described in Section 4.2. The nuclear design basis is to install sufficient reactivity in the fuel to attain the desired core lifetime and energy requirements while meeting all safety related criteria. The above along with the design basis in Section 4.3.1.3, satisfies GDC-10.

4.3.1.1.2 Discussion

Fuel burnup is a measure of fuel depletion which represents the integrated energy output of the fuel (MWD/MTU) and is a convenient means for quantifying fuel exposure criteria.

The core design lifetime or design discharge burnup is achieved by installing sufficient initial excess reactivity in each fuel region and by following a fuel replacement program (such as that described in Section 4.3.2) that meets all safety-related criteria in each cycle of operation.

Initial excess reactivity installed in the fuel, although not a design basis, must be sufficient to maintain core criticality at full power operating conditions throughout cycle life with equilibrium xenon, samarium, and other fission products present. The end of design cycle life is defined to occur when the chemical shim concentration is essentially zero with control rods present to the degree necessary for operational requirements. In terms of chemical shim boron concentration this represents approximately 10 ppm with no control rod insertion.

A limitation on initial installed excess reactivity is not required, other than as is quantified in terms of other design bases, such as core negative reactivity feedback and shutdown margin discussed below.

4.3.1.2 Negative Reactivity Feedbacks (Reactivity Coefficient)

4.3.1.2.1 Basis

The fuel temperature coefficient will be negative and the moderator temperature coefficient of reactivity will be nonpositive for full power operating conditions, thus providing negative reactivity feedback characteristics. Below 70% power, an MTC of up to +7 pcm (percent

mille)/°F is allowed. From 70% to 100%, the MTC limit decreases linearly from +7 to 0 pcm/°F. The design basis meets GDC-11.

4.3.1.2.2 Discussion

When compensation for a rapid increase in reactivity is considered, there are 2 major effects. These are the resonance absorption effects (Doppler) associated with changing fuel temperature and the spectrum effect resulting from changing moderator density. These basic physics characteristics are often identified by reactivity coefficients. The use of slightly enriched uranium ensures that the Doppler coefficient of reactivity is negative. This coefficient provides the most rapid reactivity compensation. The core is also designed to have an overall negative moderator temperature coefficient of reactivity at full power operating conditions so that average coolant temperature or void content provides another, slower compensatory effect. Nominal full power operation is permitted only in a range of overall negative moderator temperature coefficient. The negative moderator temperature coefficient at full power can be achieved through the use of fixed burnable absorbers and/or boride absorber coated fuel pellets and/or control rods by limiting the reactivity controlled by soluble boron.

Burnable absorber content (quantity and distribution) is not stated as a design basis other than as it relates to accomplishment of a nonpositive moderator temperature coefficient at power operating conditions discussed above.

4.3.1.3 Control of Power Distribution

4.3.1.3.1 Basis

The nuclear design basis is that, with at least a 95% confidence level:

1. The fuel will not be operated at greater than 13.9 (1.02) = 14.02 kW/ft under normal operating conditions including an allowance of 2% for calorimetric error and not including power spike factor due to densification.
2. Under abnormal conditions including the maximum overpower condition, the fuel peak power will not cause melting as defined in Section 4.4.1.2.
3. The fuel will not operate with a power distribution that violates the departure from nucleate boiling (DNB) design basis (i.e., the DNBR shall not be less than the design limit DNBR as discussed in Section 4.4.1) under Condition I and II events including the maximum overpower condition.
4. Fuel management will be such as to produce rod powers and burnups consistent with the assumptions in the fuel rod mechanical integrity analysis of Section 4.2.

The above basis meets GDC-10.

4.3.1.3.2 Discussion

Calculation of extreme power shapes which affect fuel design limits is performed with proven methods and verified frequently with measurements from operating reactors. The conditions under which limiting power shapes are assumed to occur are chosen conservatively with regard to any permissible operating state.

Even though there is good agreement between measured peak power calculations and measurements, a nuclear uncertainty margin is applied to calculated peak local power. Such a margin is provided both for the analysis during normal operating states and anticipated transients.

4.3.1.4 Maximum Controlled Reactivity Insertion Rate

4.3.1.4.1 Basis

The maximum reactivity insertion rate due to withdrawal of rod cluster control assemblies or by boron dilution is limited. During normal at power operation, the maximum controlled reactivity rate change is less than 105 pcm/sec. A maximum reactivity change rate (90 pcm/sec)(1) for accidental withdrawal of control banks is set such that peak heat generation rate and DNBR do not exceed the maximum allowable at overpower conditions. This satisfies GDC-25.

The maximum reactivity worth of control rods and the maximum rates of reactivity insertion employing control rods are limited so as to preclude rupture of the coolant pressure boundary or disruption of the core internals to a degree which would impair core cooling capacity due to a rod withdrawal or ejection accident (see Chapter 15.0).

Following any Condition IV event (rod ejection, steamline break, etc.), the reactor can be brought to the shutdown condition and the core will maintain acceptable heat transfer geometry. This satisfies GDC-28.

(1) pcm = 10^{-5} $\Delta\rho$ (See footnote on Table 4.3-2)

4.3.1.4.2 Discussion

Reactivity addition, associated with an accidental withdrawal of a control bank(s) is limited by the maximum rod speed (or travel rate) and by the worth of the bank(s). For this reactor, the maximum normal operation control rod speed is 45 inches per minute and the maximum rate of reactivity change considering 2 control banks moving is less than 90 pcm/sec. During normal at power operation and with normal control rod overlap, the maximum reactivity change rate is less than 105 pcm/sec. The reactivity change rates are conservatively calculated assuming unfavorable axial power and xenon distributions. The peak xenon burnout rate is 25 pcm/min, significantly lower than the maximum reactivity addition rate of 105 pcm/sec for normal operation and 90 pcm/sec for accidental withdrawal of 2 banks.

4.3.1.5 Shutdown Margins

4.3.1.5.1 Basis

Minimum shutdown margin, as specified in the Technical Specifications, is required at any power operating condition in both the hot standby and the cold shutdown condition.

In all analyses involving reactor trip, the single, highest worth rod cluster control assembly is postulated to remain untripped in its fullout position (stuck rod criterion). This satisfies GDC-26.

4.3.1.5.2 Discussion

Two (2) independent reactivity control systems are provided, namely control rods and soluble boron in the coolant. The control rod system can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full-load to no-load. In addition, the control rod system provides the minimum shutdown margin under Condition I events and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits assuming that the highest worth control rod is stuck at its furthest withdrawn position during a reactor trip.

The boron system can compensate for all xenon burnout reactivity changes and will maintain the reactor in the cold shutdown condition. Thus, backup and emergency shutdown provisions are provided by a mechanical and a chemical shim control system which satisfies GDC-26

4.3.1.5.3 Basis

When fuel assemblies are in the pressure vessel and the vessel head is not in place, K_{eff} will be maintained at or below 0.95 with control rods and soluble boron. Further, the fuel will be maintained sufficiently subcritical that removal of all rod cluster control assemblies will not result in criticality.

4.3.1.5.4 Discussion

ANS Standard N18.2 (Reference 1) specifies a K_{eff} not to exceed 0.95 in spent fuel storage racks and transfer equipment flooded with pure water and a K_{eff} not to exceed 0.98 in normally dry new fuel storage racks assuming optimum moderation. No criterion is given for the refueling operation, however a 5% margin, which is consistent with spent fuel storage and transfer and the new fuel storage, is adequate for the controlled and continuously monitored operations involved.

The boron concentration required to meet the refueling shutdown criteria is specified in the Technical Specifications. Verification that this shutdown criteria is met, including uncertainties, is achieved using standard Westinghouse design methods such as the PHOENIX (Reference 35), PARAGON (Reference 40), and ANC (Reference 34) codes. The subcriticality of the core is continuously monitored as described in the Technical Specifications.

4.3.1.6 Stability

4.3.1.6.1 Basis

The core will be inherently stable to power oscillations at the fundamental mode. This satisfies GDC-12.

4.3.1.6.2 Discussion

Oscillations of the total power output of the core, from whatever cause, are readily detected by the loop temperature sensors and by the nuclear instrumentation. The core is protected by these systems and a reactor trip would occur if power increased unacceptably, preserving the design margins to fuel design limits. The stability of the turbine/steam generator/core systems and the reactor control system is such that total core power oscillations are not normally possible. The redundancy of the protection circuits ensures an extremely low probability of exceeding design power levels.

4.3.1.6.3 Basis

Spatial power oscillations, within the core with a constant core power output, can be reliably and readily detected and suppressed if they should occur.

4.3.1.6.4 Discussion

The core is designed so that diametral and azimuthal oscillations due to spatial xenon effects are self-damping and no operator action or control action is required to suppress them. The stability to diametral oscillations is so great that this excitation is highly improbable. Convergent azimuthal oscillations can be excited by prohibited motion of individual control rods. Such oscillations are readily observable and alarmed, using the excore long ion chambers. Indications are also continuously available from incore thermocouples and loop temperature measurements. Moveable incore detectors can be activated to provide more detailed information. Additionally, the BEACON Power Distribution Monitoring System (PDMS), Reference 38, is available on-line

above 25% rated thermal power to provide a continuous real time picture of the core. In all presently proposed cores these horizontal plane oscillations are self-damping by virtue of reactivity feedback effects designed into the core.

However, axial xenon spatial power oscillations may occur late in core life. The control bank and excore detectors are provided for control and monitoring of axial power distributions. Assurance that fuel design limits are not exceeded is provided by reactor overpower ΔT and overtemperature ΔT trip functions which use the measured axial power imbalance as an input.

4.3.1.7 Anticipated Transients Without Trip

The effects of anticipated transients with failure to trip are not considered in the design bases of the plant. Analysis has shown that the likelihood of such a hypothetical event is negligibly small. Furthermore, analysis of the consequences of a hypothetical failure to trip following anticipated transients has shown that no significant core damage would result, system peak pressures would be limited to acceptable values, and no failure of the reactor coolant system would result. These analyses were documented (Reference 4) in August 1974 in accordance with the policy outlined in WASH-1270, “Technical Report on Anticipated Transients Without Scram for Water-Cooled Power Reactors,” September, 1973.

4.3.2 Description

4.3.2.1 Nuclear Design Description

The reactor core consists of a specified number of fuel rods which are held in bundles by spacer grids and top and bottom fittings. The fuel rods are constructed of Zirconium alloy cylindrical tubes containing UO_2 fuel pellets. The bundles, known as fuel assemblies, are arranged in a pattern which approximates a right circular cylinder.

Each fuel assembly contains a 17 x 17 rod array composed of 264 fuel rods, 24 rod cluster control thimbles and an incore instrumentation thimble. Figure 4.2-1 shows a cross sectional view of a 17 x 17 fuel assembly and the related rod cluster control locations. Further details of the fuel assembly are given in Section 4.2.1. Limited substitutions of Zircaloy 4, ZIRLO®, and/or stainless steel filler rods for fuel rods, if justified by a cycle specific reload analysis using NRC approved methodology, may be used.

The V. C. Summer fuel design uses mid-enriched annular axial blanket pellets. The diameter of this annulus is 1/2 the outer diameter of the fuel pellet. Fuel assemblies are placed in the core to establish favorable axial and radial power distributions.

Figure 4.3-1 shows a typical fuel loading pattern. The feed fuel is loaded in a checkerboard pattern among the burned fuel to provide a flat radial power distribution. Burned fuel is placed on the core periphery to reduce neutron leakage. The cores will operate for approximately 18 months between refueling, accumulating approximately 18,000 MWD/MTU burnup. The exact reloading pattern, initial and final positions of assemblies, number of fresh assemblies and their placement

are dependent on the energy requirement for the next cycle and burnup and power histories of the previous cycles.

The core average enrichment is determined by the amount of fissionable material required to provide the desired core lifetime and energy requirements. The physics of the burnout process is such that operation of the reactor depletes the amount of fuel available due to the absorption of neutrons by the U-235 atoms and their subsequent fission. The rate of U-235 depletion is directly proportional to the power level at which the reactor is operated. In addition, the fission process results in the formation of fission products, some of which readily absorb neutrons. These effects, depletion and buildup of fission products, are partially offset by the buildup of plutonium shown in Figure 4.3-2 for a typical 17 x 17 fuel assembly, which occurs due to the non-fission absorption of neutrons in U-238. Therefore, at the beginning of any cycle a reactivity reserve equal to the depletion of the fissionable fuel and the buildup of fission product poisons over the specified cycle life must be incorporated in the reactor design. This excess reactivity is controlled by removable neutron absorbing material in the form of boron dissolved in the primary coolant and boride absorber coated fuel pellets and/or burnable absorber rods.

The concentration of boric acid in the primary coolant is varied to provide control and to compensate for long term reactivity requirements. The concentration of the soluble neutron absorber is varied to compensate for reactivity changes due to fuel burnup, fission product poisoning including xenon and samarium, burnable absorber depletion, and the cold-to-operating moderator temperature change. Using its normal makeup path, the chemical and volume control system (CVCS) is capable of inserting negative reactivity at a rate of approximately 30 pcm/min when the reactor coolant boron concentration is 1000 ppm and approximately 35 pcm/min when the reactor coolant boron concentration is 100 ppm. If the emergency boration path is used, the CVCS is capable of inserting negative reactivity at a rate of approximately 65 pcm/min when the reactor coolant concentration is 1000 ppm and approximately 75 pcm/min when the reactor coolant boron concentration is 100 ppm. The peak burnout rate for xenon is 25 pcm/min (Section 9.3.4.3.1 discusses the capability of the CVCS to counteract xenon decay). Rapid transient reactivity requirements and safety shutdown requirements are met with control rods.

As the boron concentration is increased, the moderator temperature coefficient becomes less negative. The use of a soluble absorber alone would result in a positive moderator coefficient at beginning of life for the first cycle. Therefore, burnable absorber rods are used to reduce the soluble boron concentration sufficiently to ensure that the moderator temperature coefficient is negative for power operating conditions. During operation the absorber content in these rods is depleted thus adding positive reactivity to offset some of the negative reactivity from fuel depletion and fission product buildup. The depletion rate of the burnable absorber rods is not critical since chemical shim is always available and flexible enough to cover any possible deviations in the expected burnable absorber depletion rate. Figure 4.3-3 is a graph of critical boron concentration versus cycle burnup for a typical transition core and an equilibrium core.

In addition to reactivity control, the burnable absorbers are strategically located to provide a favorable radial power distribution. Figure 4.3-4 shows the burnable absorber distributions within a fuel assembly for some of the several integral fuel burnable absorber pin patterns used in a 17 x

17 array. A typical burnable absorber loading pattern to be used in the core is shown in Figure 4.3-5.

Tables 4.3-1 through 4.3-3 contain a summary of the reactor core design parameters for typical reload cycles including reactivity coefficients, delayed neutron fractions and neutron lifetimes. Sufficient information is included to permit an independent calculation of the nuclear performance characteristics of typical reload cores.

4.3.2.2 Power Distributions

The accuracy of power distribution calculations has been confirmed through approximately 1000 flux maps during some 20 years of operation under conditions very similar to those expected for the Virgil C. Summer Nuclear Station. Details of this confirmation are given in Reference 5 and in Section 4.3.2.2.6.

4.3.2.2.1 Definitions

Power distributions are quantified in terms of hot channel factors. These factors are a measure of the peak pellet power within the reactor core and the total energy produced in a coolant channel and are expressed in terms of quantities related to the nuclear or thermal design namely:

Power density is the thermal power produced per unit volume of the core (kW/liter).

Linear power density is the thermal power produced per unit length of active fuel (kW/ft). Since fuel assembly geometry is standardized this is the unit of power density most commonly used. For all practical purposes it differs from kW/liter by a constant factor which includes geometry and the fraction of the total thermal power which is generated in the fuel rod.

Average linear power density is the total thermal power produced in the fuel rods divided by the total active fuel length of all rods in the core.

Local heat flux is the heat flux at the surface of the cladding ($Btu\text{-}ft^2\text{-}hr^1$). For nominal rod parameters this differs from linear power density by a constant factor.

Rod power or rod integral power is the length integrated linear power density in 1 rod (kW).

Average rod power is the total thermal power produced in the fuel rods divided by the number of fuel rods (assuming all rods have equal length).

The hot channel factors used in the discussion of power distributions in this section are defined as follows:

F_Q, Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods.

F_Q^N, Nuclear Heat Flux Hot Channel Factor, is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and rod parameters.

F_Q^E, Engineering Heat Flux Hot Channel Factor, is the allowance on heat flux required for manufacturing tolerances. The engineering factor allows for local variations in enrichment, pellet density and diameter, surface area of the fuel rod and eccentricity of the gap between pellet and clad.

Combined statistically the net effect is a factor of 1.03 to be applied to fuel rod surface heat flux.

$F_{\Delta H}^N$, Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

Manufacturing tolerances, hot channel power distribution and surrounding channel power distributions are treated explicitly in the calculation of the DNBR described in Section 4.4.

It is convenient for the purposes of discussion to define subfactors of F_Q, however, design limits are set in terms of the total peaking factor.

$$F_Q = \text{Total peaking factor or heat flux hot channel factor}$$

$$= \frac{\text{Maximum kW/ft}}{\text{AveragekW/ft}}$$

without densification effects:

$$F_Q = F_Q^N \times F_Q^E$$

$$= F_{XY}^N \times F_Z^N \times F_U^N \times F_Q^E$$

Where:

F_Q^N and F_Q^E are defined above.

F_U^N = factor for conservatism, assumed to be 1.05.

F_{XY}^N = ratio of peak power density to average power density in the horizontal plane of peak local power.

F_Z^N = ratio of the power per unit core height in the horizontal plane of peak local power to the average value of power per unit core height. If the plane of peak local power coincides with the plane of maximum power per unit core height then F_Z^N is the core average axial peaking factor.

To include the allowances made for densification effects, which are height dependent, the following quantities are defined.

S(Z) = the allowance made for densification effects at height Z in the core (see Section 4.3.2.2.5).

P(Z) = ratio of the power per unit core height in the horizontal plane at height Z to the average value of power per unit core height.

Then:

F_Q = Total peaking factor

$$F_Q = \frac{\text{Maximum kW/ft}}{\text{Average kW/ft}}$$

Including densification allowance:

$$F_Q = \max \left(F_{XY}^N(Z) \times P(Z) \times S(Z) \times F_U^N \times F_Q^E\right)$$

4.3.2.2.2 Radial Power Distributions

The power shape in horizontal sections of the core at full power is a function of the fuel and burnable absorber loading patterns, and the presence or absence of a single bank of control rods. Thus, at any time in the cycle any horizontal section of the core can be characterized as unrodded or with group D control rods. These two situations combined with burnup effects determine the radial power shapes which can exist in the core at full power. The effect on radial power shapes of power level, xenon, samarium and moderator density effects are also considered but these are quite small. The effect of nonuniform flow distribution is negligible. While radial power distributions in various planes of the core are often illustrated, the core radial enthalpy rise distribution, as determined by the integral of power up each channel, is of greater interest. For representative operating conditions, Figures 4.3-6 through 4.3-10 show representative radial power distributions for 1/4 of the core for a transition cycle. These conditions are; 1) Hot Full Power (HFP) at Beginning of Life (BOL) - unrodded - no xenon, 2) HFP at BOL - unrodded - equilibrium xenon, 3) HFP at BOL - Bank D at the HFP insertion limit in - equilibrium xenon, 4) HFP at Middle of Life (MOL) - unrodded - equilibrium xenon, and 5) HFP at End of Life (EOL) - unrodded - equilibrium xenon. Figures 4.3-11 through 4.3-15 show the same information for a typical equilibrium reload.

Since the position of the hot channel varies from time to time, a single reference radial design power distribution is selected for DNB calculations. This reference power distribution is chosen conservatively to concentrate power in one area of the core, minimizing the benefits of flow redistribution. Assembly powers are normalized to core average power.

4.3.2.2.3 Assembly Power Distributions

For the purpose of illustration, rodwise power distributions for a typical assembly for BOL and EOL conditions are shown in Figures 4.3-16 and 4.3-17, respectively.

Since the detailed power distribution surrounding the hot channel varies from time to time, a conservatively flat assembly power distribution is assumed in the DNB analysis, described in Section 4.4, with the rod of maximum integrated power artificially raised to the design value of $F\frac{N}{\Delta H}$.

Care is taken in the nuclear design of all fuel cycles and all operating conditions to ensure that a flatter assembly distribution does not occur with limiting values of $F\frac{N}{\Delta H}$.

4.3.2.2.4 Axial Power Distributions

The shape of the power profile in the axial or vertical direction is largely under the control of the operator either through the manual operation of the control rods or automatic motion of the rods responding to manual operation of the CVCS. Nuclear effects which cause variations in the axial power shape include moderator density, Doppler effect on resonance absorption, spatial xenon, burnup and distribution of fuel and burnable absorber material. Automatically controlled

variations in total power output and full length rod motion are also important in determining the axial power shape at any time. Signals are available to the operator from the excore ion chambers which are long ion chambers outside the reactor vessel running parallel to the axis of the core. Separate signals are taken from the top and bottom halves of the chambers. The difference between top and bottom signals from each of 4 pairs of detectors is displayed on the control panel and called the flux difference, ΔI. Calculations of core average peaking factor for many plants and measurements from operating plants under many operating situations are associated with either ΔI or axial offset in such a way that an upper bound can be placed on the peaking factor. For these correlations axial offset is defined as:

$$\text{axial offset} = \frac{\Phi_t - \Phi_b}{\Phi_t + \Phi_b}$$

and Φ_t and Φ_b are the top and bottom detector readings.

Representative axial power shapes for a typical transition and a fully transitioned core for BOL, MOL, and EOL conditions are displayed in Figures 4.3-18 through 4.3-20.

4.3.2.2.5 Local Power Peaking

Fuel densification, which has been observed to occur under irradiation in several operating reactors, causes the fuel pellets to shrink both axially and radially. The pellet shrinkage combined with random hang-up of fuel pellets results in gaps in the fuel column when the pellets below the hung-up pellet settle in the fuel rod. The gaps vary in length and location in the fuel rod. Because of decreased neutron absorption in the vicinity of the gap, power peaking occurs in the adjacent fuel rods resulting in an increased power peaking factor. A quantitative measure of this local peaking is given by the power spike factor S(Z) where Z is the axial location in the core.

The method used to compute the power spike factor is described in Reference 7 and is summarized in Figure 4.3-22. The information flow outlined in Figure 4.3-22 is as follows:

1. The probability that an axial gap of a certain size will occur at a given location in the core is determined from fuel performance data.
2. The magnitude of the power spike caused by a single axial gap of a certain size is determined from nuclear calculations as shown in Figure 4.3-23. This curve is valid for uranium fuel enrichments up to 4.5 w/o. 3.
3. For each axial interval to be analyzed, axial gap occurrence probabilities and the single event power spikes are entered into the DRAW (Reference 7) computer code. The code produces a curve of power spike versus probability of exceeding power spike for each elevation in the core. The power census for a core is then statistically combined with the power spike probability curve to obtain a power spike penalty for the core such that less than 1 rod will exceed $F\frac{N}{Q}$ at 95% confidence level.

The power spike factor due to densification is assumed to be a local perturbation applicable to overpower transients. Thus, densification affects F_Q but not $F_{\Delta H}$. The magnitude of the increased power peaking increases from no effect at the bottom of the core to a few percent at the top of the core as shown in Figure 4.3-24, which is applicable to the nominal 95% (geometric) dense pellets.

For fuel produced by processes other than those for which Reference 7 is applicable, specifications will be followed to ensure that the effects of densification will be no greater than has been allowed for in the design. The specifications for quantifying the extent of densification will be based on the NRC report on fuel densification (Reference 33).

Results reported in a Westinghouse Topical Report concerning the spike penalty in LOCA analysis (Reference 8) show that the power spike penalty should not be included in the LOCA envelope.

4.3.2.2.6 Limiting Power Distributions

According to the ANS classification of plant conditions (see Chapter 15.0), Condition I occurrences are those which are expected frequently or regularly in the course of power operation, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Inasmuch as Condition I occurrences occur frequently or regularly, they must be considered from the point of view of affecting the consequences of fault conditions (Conditions II, III, and IV). In this regard, analysis of each fault condition described is generally based on a conservative set of initial conditions corresponding to the most adverse set of conditions which can occur during Condition I operation.

The list of steady-state and shutdown conditions, permissible deviations (such as 1 coolant loop out of service), and operational transients is given in Section 15.1. Implicit in the definition of normal operation is proper and timely action by the reactor operator. That is, the operator follows recommended operating procedures for maintaining appropriate power distributions and takes any necessary remedial actions when alerted to do so by the plant instrumentation. Thus, as stated above, the worst or limiting power distribution which can occur during normal operation is to be considered as the starting point for analysis of ANS Conditions II, III, and IV events.

Improper procedural actions or errors by the operator are assumed in the design as occurrences of moderate frequency (ANS Condition II). Some of the consequences which might result are listed in Section 15.2. Therefore, the limiting power shapes which result from such Condition II events, are those power shapes which deviate from the normal operating condition at the recommended axial offset band, e.g., due to lack of proper action by the operator during a xenon transient following a change in power level brought about by control rod motion. Power shapes which fall in this category are used for determination of the reactor protection system setpoints so as to maintain margin to overpower or DNB limits.

The means for maintaining power distributions within the required hot channel factor limits are described in the Technical Specifications. A complete discussion of power distribution control in Westinghouse PWRs is included in Reference 9. Detailed background information on the design

constraints on local power density in a Westinghouse PWR, on the defined operating procedures and on the measures taken to preclude exceeding design limits is presented in the Westinghouse Topical Reports and power distribution control and load following procedures (Reference 10). The following paragraphs summarize these reports and describe the calculations used to establish the upper bound on peaking factors.

The calculations used to establish the upper bound on peaking factors, F_Q and $F_{\Delta H}$, include all of the nuclear effects which influence the radial and/or axial power distributions throughout core life for various modes of operation including load follow, reduced power operation, and axial xenon transients.

Radial power distributions are calculated for the full power condition and fuel and moderator temperature feedback effects are included for the average enthalpy plane of the reactor. The steady-state nuclear design calculations are done for normal flow with the same mass flow in each channel and flow redistribution effects neglected. The effect of flow redistribution is calculated explicitly where it is important in the DNB analysis of accidents. The effect of xenon on radial power distribution is small (compare Figures 4.3-6 and 4.3-7) but is included as part of the normal design process. Radial power distributions are relatively fixed and easily bounded with upper limits.

The core average axial profile, however, can experience significant changes which can occur rapidly as a result of rod motion and load changes and more slowly due to xenon distribution. For the study of points of closest approach to axial power distribution limits, several thousand cases are examined. Since the properties of the nuclear design dictate what axial shapes can occur, boundaries on the limits of interest can be set in terms of the parameters which are readily observed on the plane. Specifically, the nuclear design parameters which are significant to the axial power distribution analysis are:

1. Core power level
2. Core height
3. Coolant temperature and flow
4. Coolant temperature program as a function of reactor power
5. Fuel cycle lifetimes
6. Rod bank worths
7. Rod bank overlaps

Normal operation of the plant assumes compliance with the following conditions:

1. Control rods in a single bank move together with no individual rod insertion differing by more than 13 steps (indicated) from the bank demand position;
2. Control banks are sequenced with overlapping banks;
3. The control bank insertion limits are not violated;

4. Axial power distribution procedures, which are given in terms of flux difference control and control bank position, are observed.

The axial power distribution procedures referred to above are part of the required operating procedures which are followed in normal operation. Briefly, they require control of the axial offset (flux difference divided by fractional power) at all power levels within a permissible operating band.

Calculations are performed for normal operation of the reactor beginning, middle, and end of cycle conditions. Different histories of operation are implicitly included in the methodology. These different histories assume base loaded operation and extensive load following.

These cases represent many possible reactor states in the life of 1 fuel cycle. The cases are described in detail in Reference 10 and they are considered to be necessary and sufficient to generate a local power density limit which, when increased by 5% for conservatism, will not be exceeded with a 95% confidence level. Many of the points do not approach the limiting envelope, however they are generated as part of the process which lead to the shapes which do define the envelope.

It is not possible to single out any transient or steady-state condition which defines the most limiting case. It is not even possible to separate out a small number which form an adequate analysis. The process of generating a myriad of shapes is essential to the philosophy that leads to the required level of confidence. A set of parameters that produce a limiting case for 1 reactor fuel cycle, (defined as approaching the line of Figure 4.3-25) is not necessarily a limiting case for another reactor or fuel cycle with different control bank worths, enrichments, burnup, reactivity coefficients, etc. Each shape depends on the detailed history of operation up to that time and on the manner in which xenon was conditional in the days immediately prior to the time at which the power distribution is calculated.

The calculated points are synthesized from axial calculations combined with radial factors appropriate for rodded and unrodded planes. In these calculations the effects on the radial peak of xenon redistribution that occurs following the withdrawal of a control bank (or banks) from a rodded region is obtained from three-dimensional calculations. The factor applied on the unrodded radial peak is obtained from calculations in which the xenon distribution is preconditioned by the presence of control rods and then allowed to redistribute for several hours. A detailed discussion of this effect may be found in References 10 and 11. The calculated values are increased by a factor of 1.05 for conservatism and a factor of 1.03 for the engineering factor F_Q^E.

The envelope drawn over the calculated ([F_Q • Power] max) points in Figure 4.3-25 represents an upper bound envelope on local power density versus elevation in the core. It should be emphasized that this envelope is a conservative representation of the bounding values of local power density. Expected values are considerably smaller and, in fact, less conservative bounding values may be justified with additional analysis or surveillance requirements. For example,

Figure 4.3-25 bounds BOL, MOL, and EOL conditions. Figure 4.3-25 is based on a radial power distribution invariant with core elevation.

Finally, as previously discussed, this upper bound envelope is based on operation within an allowed range of axial flux difference limits. These limits are detailed in the Technical Specifications and are predicted only upon excore surveillance supplemented by the periodic full core map requirement and by computer based alarms on deviation and time of deviation from the allowed flux difference band. An alternative to performing the periodic full core flux map while above 25% RTP is to use the BEACON Power Distribution Monitoring System, Reference 38.

Allowing for fuel densification effects, the average kW/ft at 2900 MWt is 5.69 kW/ft. From Figure 4.3-25, the conservative upper bound value of normalized local power density, including uncertainty allowances, is 2.45 corresponding to a peak local power density of 14.2 kW/ft at 102% of 2900 MWt.

To determine reactor protection system setpoints, with respect to power distributions, 3 categories of events are considered, namely rod control equipment malfunctions, operator errors of commission and operator errors of omission. In evaluating these 3 categories of events, the core is assumed to be operating within the 4 constraints described above.

The first category comprises uncontrolled rod withdrawal (with rods moving in the normal bank sequence). Also included are motions of the control banks below their insertion limits, which could be caused, for example, by uncontrolled dilution or primary coolant cooldown. Power distributions were calculated throughout these occurrences assuming short term corrective action, that is, no transient xenon effects were considered to result from the malfunction. The event was assumed to occur from typical normal operating situations which did not include normal xenon transients. It was further assumed in determining the power distributions that total power level would be limited by reactor trip to below 118%. Typical results are given in Figure 4.3-26 in units of kW/ft. The peak power density which can occur in such events, assuming reactor trip at or below 118%, is less than that required for center-line melt including uncertainties and densification effects.

For the uncontrolled RCCA bank withdrawal from subcritical accident, which starts from zero power, the reactor reaches prompt critical causing the nuclear flux to briefly rise to several times full power. Therefore, the linear heat generation rate instantaneously rises to a high value and then decreases.

For rapid transients such as the RCCA withdrawal from subcritical accident, in order to determine that the fuel temperature criterion is not exceeded (Reference 42), a transient heat transfer calculation must be performed. The peak fuel centerline temperature during the transient conservatively evaluated at the hot spot did not exceed 4000 °F. This is below the limiting value defined in Reference 42.

The second category, also illustrated in Figure 4.3-26, assumes that the operator mispositions the control rod bank in violation of the insertion limits and creates short term conditions not included in normal operating conditions.

The third category assumes that the operator fails to take action to correct a flux difference violation. Typical results shown on Figure 4.3-27 are F_Q multiplied by 102% power including an allowance for calorimetric error. The figure shows that provided the assumed error in operation does not continue for a period which is long compared to the xenon time constant, the maximum local power does not exceed 22.8 kW/ft including the above factors.

Analyses of possible operating power shapes for the reactor described herein show that the appropriate hot channel factors F_Q and $F^N_{\Delta H}$ for peak local power density and for DNB analysis at full power are the values given in Table 4.3-2 and addressed in the Technical Specifications.

F_Q can be increased with decreasing power as shown in the Technical Specifications. Increasing $F^N_{\Delta H}$ with decreasing power is permitted by the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits as described in Section 4.4.3.2. The allowance for increased $F^N_{\Delta H}$ permitted is $F^N_{\Delta H} = (1.62)\,[1+ 0.3\,(1-P)]$[(1)] where P is the fraction of allowed power level. This becomes a design basis criterion which is used for establishing acceptable control rod patterns and control bank sequencing. Likewise fuel loading patterns for each cycle are selected with consideration of this design criterion. The worst values of $F^N_{\Delta H}$ for possible rod configurations occurring in normal operation are used in verifying that this criterion is met.

(1) See Table 4.3-2

Typical radial factors are given in Table 4.3-2 and the radial power distributions are shown in Figures 4.3-6 through 4.3-15. The worst values generally occur when the rods are assumed to be at their insertion limits. As discussed in Section 3.2 of Reference 12, it has been determined that provided the above Conditions 1 through 4 are observed, the Technical Specification limits, are met. These limits are taken as input to the thermal-hydraulic design basis as described in Section 4.4.3.2.1. When a situation is possible in normal operation which could result in local power densities in excess of those assumed as the pre-condition for a subsequent hypothetical accident, but which would not itself cause fuel failure, administrative controls and alarms are provided for returning the core to a safe condition. These alarms are described in detail in Chapters 7.0 and Technical Specifications.

4.3.2.2.7 Experimental Verification of Power Distribution Analysis

This subject is discussed in depth in Reference 5. A summary of this report is given here.

In a measurement of peak local power density, F_Q, with the movable detector system described in Sections 7.7.1 and 4.4.5, the following uncertainties have to be considered:

1. Reproducibility of the measured signal,
2. Errors in the calculated relationship between detector current and local flux,
3. Errors in the calculated relationship between detector flux and peak rod power some distance from the measurement thimble.

The appropriate allowance for category 1 above has been quantified by repetitive measurements made with several inter-calibrated detectors by using the common thimble features of the incore detector system. This system allows more than one detector to access any thimble. Errors in category 2, above, are quantified to the extent possible, by using the fluxes measured at 1 thimble location to predict fluxes at another location which is also measured. Local power distribution predictions are verified in critical experiments on arrays of rods with simulated guide thimbles, control rods, burnable absorber, etc. These critical experiments provide quantification of errors of types 2 and 3, above.

Reference 5 describes critical experiments performed at the Westinghouse Reactor Evaluation Center and measurements taken on 2 Westinghouse plants with incore systems of the same type as used in the Virgil C. Summer Nuclear Station. The report concludes that the uncertainty associated with the peak nuclear heat flux factor, F_Q is 4.58% at the 95% confidence level with only 5% of the measurements greater than the inferred value. This is the equivalent of a 2σ limit on a normal distribution, and is the uncertainty to be associated with a full core flux map with movable detectors reduced with a reasonable set of input data incorporating the influence of burnup on the radial power distribution. The uncertainty is usually rounded up to 5%.

In comparing measured power distributions (or detector currents) against the calculations for the same situation, it is not possible to subtract out the detector reproducibility. Thus a comparison between measured and predicted power distributions has to include some measurement error. Such a comparison is given in Figure 4.3-28 for 1 of the maps used in Reference 5. Since the first

publication of the report, hundreds of maps have been taken on these and other reactors. The results confirm the adequacy of the 5% uncertainty allowance on F_Q.

A similar analysis for the uncertainty in $F_{\Delta H}$ (rod integral power) measurements results in an allowance of 3.65% at the equivalent of a 2σ confidence level. For historical reasons an 8% uncertainty factor is allowed in the nuclear design basis; that is, the predicted rod integrals at full power must not exceed the design $F_{\Delta H}$ less 8%. This 8% may be reduced in final design to 4% to allow a wider range of acceptable axial power distributions in the DNB analysis and still meet the design bases of Section 4.3.1.3.

As an example, a recent measurement in the second cycle of a 121 assembly, 12 foot, core is compared with a simplified one dimensional core average axial calculation in Figure 4.3-29. This calculation does not give explicit representation to the fuel grids.

The accumulated data on power distributions in actual operation is basically of 3 types:

1. Much of the data is obtained in steady-state operation at constant power in the normal operating configuration;
2. Data with unusual values of axial offset are obtained as part of the excore detector calibration exercise which is performed monthly;
3. Special tests have been performed in load follow and other transient xenon conditions which have yielded useful information on power distributions.

These data are presented in detail in Reference 10. Figure 4.3-30 contains a summary of measured values of F_Q as a function of axial offset for 5 plants from that report.

4.3.2.2.8 Testing

A very extensive series of physics tests is performed on first cores. These tests and the criteria for satisfactory results are described in detail in Chapter 14.0. Since not all limiting situations can be created at BOL, the main purpose of the tests is to provide a check on the calculational methods used in the predictions for the conditions of the test.

4.3.2.2.9 Monitoring Instrumentation

The adequacy of instrument numbers, spatial deployment, required correlations between readings and peaking factors, calibration, and errors are described in References 5, 9, and 12. The relevant conclusions are summarized here in Sections 4.3.2.2.7 and 4.4.5.

Provided the limitations given in Section 4.3.2.2.6 on rod insertion and flux difference are observed, the excore detector system provides adequate monitoring of power distributions.

Further details of specific limits on the observed rod positions and flux difference are given in the Technical Specifications together with a discussion of their bases.

Limits for alarms, reactor trip, etc. are given in the Technical Specifications. Descriptions of the systems provided are given in Section 7.7.

4.3.2.3 Reactivity Coefficients

The kinetic characteristics of the reactor core determine the response of the core to changing plant conditions or to operator adjustments made during normal operation, as well as the core response during abnormal or accidental transients. These kinetic characteristics are quantified in reactivity coefficients. The reactivity coefficients reflect the changes in the neutron multiplication due to varying plant conditions such as power, moderator or fuel temperatures, or less significantly due to a change in pressure or void conditions. Since reactivity coefficients change during the life of the core, ranges of coefficients are employed in transient analysis to determine the response of the plant throughout life. The results of such simulations and the reactivity coefficients used are presented in Chapter 15.0.

The reactivity coefficients are calculated on a corewise basis by radial and axial diffusion theory methods. The effect of radial and axial power distribution on core average reactivity coefficients is implicit in those calculations and is not significant under normal operating conditions. For example, a skewed xenon distribution which results in changing axial offset by 5% changes the moderator and Doppler temperature coefficients by less than 0.01 pcm/°F and 0.03 pcm/°F, respectively. An artificially skewed xenon distribution which results in changing the radial $F_{\Delta H}$ by 3% changes the moderator and Doppler temperature coefficients by less than 0.03 pcm/°F and 0.001 pcm/°F, respectively. The spatial effects are accentuated in some transient conditions; for example, in postulated rupture of the main steamline break and rupture of rod cluster control assembly mechanism housing described in Sections 15.4.2 and 15.4.6, and are included in these analyses.

The analytical methods and calculational models used in calculating the reactivity coefficients are given in Section 4.3.3. These models have been confirmed through extensive testing of more than 30 cores similar to the plant described herein; results of these tests are discussed in Section 4.3.3.

Quantitative information for calculated reactivity coefficients, (density, temperature, pressure, void) and power coefficient is given in the following sections.

4.3.2.3.1 Fuel Temperature (Doppler Coefficient)

The fuel temperature (Doppler) coefficient is defined as the change in reactivity per degree change in effective fuel temperature and is primarily a measure of the Doppler broadening of U-238 and Pu-240 resonance absorption peaks. Doppler broading of other isotopes such as U-236, Np-237, etc. are also considered, but their contributions to the Doppler effect is small. An increase in fuel temperature increases the effective resonance absorption cross sections of the fuel and produces a corresponding reduction in reactivity.

The fuel temperature coefficient is calculated by performing 2-group two or three dimensional calculations. Moderator temperature is held constant and the power level is varied. Spatial

variation of fuel temperature is taken into account by calculating the effective fuel temperature as a function of power density as discussed in Section 4.3.3.1.

Typical Doppler temperature coefficients are shown in Figure 4.3-31 as a function of the effective fuel temperature (at BOL and EOL conditions). The effective fuel temperature is lower than the volume averaged fuel temperature since the neutron flux distribution is non-uniform through the pellet and gives preferential weight to the surface temperature. An example of Doppler-only contribution to the power coefficient, defined later, is shown in Figure 4.3-32 as a function of relative core power. The integral of the differential curve on Figure 4.3-32 is an example of the Doppler contribution to the power defect and is shown in Figure 4.3-33 as a function of relative power. The Doppler coefficient becomes more negative as a function of life as the Pu-240 content increases, thus increasing the Pu-240 resonance absorption but less negative as the fuel temperature changes with burnup as described inSection 4.3.3.1. The upper and lower limits of Doppler coefficient used in accident analyses are given in Chapter 15.0.

4.3.2.3.2 Moderator Coefficients

The moderator coefficient is a measure of the change in reactivity due to a change in specific coolant parameters such as density, temperature, pressure or void. The coefficients obtained are moderator density, temperature, pressure, and void coefficients.

4.3.2.3.2.1 Moderator Density and Temperature Coefficients

The moderator temperature (density) coefficient is defined as the change in reactivity per degree change in the moderator temperature. Generally, the effect of the changes in moderator density as well as the temperature are considered together. A decrease in moderator density means less moderation which results in a negative moderator coefficient. An increase in coolant temperature, keeping the density constant, leads to a hardened neutron spectrum and results in an increase in resonance absorption in U-238, Pu-240 and other isotopes. The hardened spectrum also causes a decrease in the fission-to-capture ratio in U-235 and Pu-239. Both of these effects make the moderator coefficient more negative. Since water density changes more rapidly with temperature as temperature increases, the moderator temperature (density) coefficient becomes more negative with increasing temperature.

The soluble boron used in the reactor as a means of reactivity control also has an effect on moderator density coefficient since the soluble boron absorber density, as well as, the water density is decreased when the coolant temperature rises. A decrease in the soluble absorber concentration introduces a positive component in the moderator coefficient.

Thus, if the concentration of soluble absorber is large enough, the net value of the coefficient may be positive. With the burnable absorber rods present, however, the initial hot boron concentration is sufficiently low that the moderator temperature coefficient is negative at full power operating conditions. The effect of control rods is to make the moderator coefficient more negative by reducing the required soluble boron concentration and by increasing the “leakage” of the core.

With burnup, the moderator coefficient becomes more negative primarily as a result of boric acid dilution but also to a significant extent from the effects of the buildup of plutonium and fission products.

The moderator coefficient is calculated for the various plant conditions discussed above by performing 2-group two or three dimensional calculations, varying the moderator temperature (and density) by about ± 5 °F about each of the mean temperatures. The moderator coefficient is shown as a function of core temperature and boron concentration for the unrodded and rodded core in Figures 4.3-34 through 4.3-36. The temperature range covered is from cold (68 °F) to about 600 °F. The contribution due to Doppler coefficient (because of change in moderator temperature) has been subtracted from these results. Figure 4.3-37 shows the hot, full power moderator temperature coefficient plotted as a function of cycle lifetime at the critical boron concentration for a transition cycle and a typical equilibrium reload cycle.

The moderator coefficients presented here are calculated on a corewise basis, since they are used to describe the core behavior in normal and accident situations when the moderator temperature changes can be considered to affect the whole core.

4.3.2.3.2.2 Moderator Pressure Coefficient

The moderator pressure coefficient relates the change in moderator density, resulting from a reactor coolant pressure change, to the corresponding effect on neutron production. This coefficient is much less significant in comparison with the moderator temperature coefficient. A change of 50 psi in pressure has approximately the same effect on reactivity as a half-degree change in moderator temperature. This coefficient can be determined from the moderator temperature coefficient by relating change in pressure to the corresponding change in density. The moderator pressure coefficient is negative over a portion of the moderator temperature range at BOL (-0.004 pcm/psi, BOL) but is always positive at operating conditions and becomes more positive during life (+0.5 pcm/psi, EOL).

4.3.2.3.2.3 Moderator Void Coefficient

The moderator void coefficient relates the change in neutron multiplication to the presence of voids in the moderator. In a PWR this coefficient is not very significant because of the low void content in the coolant. The core void content is less than 1/2 of 1% and is due to local or statistical boiling. The void coefficient varies from 50 pcm/percent void at BOL, and at low temperatures to -250 pcm/percent void at EOL and at operating temperatures. The negative void coefficient at operating temperature becomes more negative with fuel burnup.

4.3.2.3.3 Power Coefficient

The combined effect of moderator temperature and fuel temperature change as the core power level changes is called the total power coefficient and is expressed in terms of reactivity change per percent power change. The power coefficient at BOL and EOL conditions for a typical reload cycle is given in Figure 4.3-38.

It becomes more negative with burnup reflecting the combined effect of moderator and fuel temperature coefficients with burnup. The power defect (integral reactivity effect) at BOL and EOL for a typical reload cycle is given in Figure 4.3-39.

4.3.2.3.4 Comparison of Calculated and Experimental Reactivity Coefficients

Section 4.3.3 describes the comparison of calculated and experimental reactivity coefficients in detail. Based on the data presented there, the accuracy of the current analytical model is:

± 0.2% $\Delta\rho$ for Doppler and power defect
± 2 pcm/°F for the moderator coefficient

Experimental evaluation of the calculated coefficients is done during the physics startup testing described in Chapter 14.0.

4.3.2.3.5 Reactivity Coefficients Used in Transient Analysis

Table 4.3-2 gives the representative ranges for the reactivity coefficients used in transient analysis. The exact values of the coefficient used in the analysis depend on whether the transient of interest is examined at the BOL or EOL, whether most negative or the most positive (least negative) coefficients are appropriate, and whether spatial nonuniformity must be considered in the analysis. Conservative values of coefficients, considering various aspects of analysis are used in the transient analysis. This is completely described in Chapter 15.0.

The values listed in Table 4.3-2 and illustrated in Figures 4.3-31 through 4.3-39 apply to the core described in Table 4.3-1. The coefficients appropriate for use in subsequent cycles depends on the core's operating history, the number and enrichment of fresh fuel assemblies, the loading pattern of burned and fresh fuel, the type, number and location of any absorbers rods, etc. The need for a re-evaluation of any accident in a subsequent cycle is contingent upon whether or not the coefficients for that cycle fall within the identified range used in the analysis presented in Chapter 15.0 with due allowance for the calculational uncertainties given in Section 4.3.3.3. Control rod requirements are given in Table 4.3-3 for a typical reload cycle.

4.3.2.4 Control Requirements

To ensure the shutdown margin stated in the Technical Specifications under conditions where a cooldown to ambient temperature is required, concentrated soluble boron is added to the coolant. Boron concentrations for several core conditions are listed in Table 4.3-2. For all core conditions including refueling, the boron concentration is well below the solubility limit. The rod cluster control assemblies are employed to bring the reactor to the hot shutdown condition. The minimum required shutdown margin is given in the Technical Specifications.

The ability to accomplish the shutdown for hot conditions is demonstrated in Table 4.3-3 by comparing the difference between the rod cluster control assembly reactivity available with an allowance for the worst stuck rod with that required for control and protection purposes. The shutdown margin includes an allowance of 10% for analytic uncertainties (see Section 4.3.2.4.9).

The largest reactivity control requirement appears at the EOL when the moderator temperature coefficient reaches its peak negative value as reflected in the larger power defect.

The control rods are required to provide sufficient reactivity to account for the power defect from full power to zero power and to provide the required shutdown margin. The reactivity addition resulting from power reduction consists of contributions from Doppler, variable average moderator temperature, flux redistribution, and reduction in void content as discussed below.

4.3.2.4.1 Doppler

The Doppler effect arises from the broadening of U-238 and Pu-240 resonance peaks with an increase in effective pellet temperature. This effect is most noticeable over the range of zero power to full power due to the large pellet temperature increase with power generation.

4.3.2.4.2 Variable Average Moderator Temperature

When the core is shutdown to the hot, zero power condition, the average moderator temperature changes from the equilibrium full load value determined by the steam generator and turbine characteristics (steam pressure, heat transfer, tube fouling, etc.) to the equilibrium no load value, which is based on the steam generator shell side design pressure. The design change in temperature is conservatively increased by 4 °F to account for the control dead band and measurement errors.

The moderator coefficient becomes more negative as the fuel depletes because the boron concentration is reduced. This effect is the major contributor to the increased requirement at EOL.

4.3.2.4.3 Redistribution

During full power operation the coolant density decreases with core height, and this, together with any partial insertion of control rods, results in less fuel depletion near the top of the core. Under steady-state conditions, the relative power distribution will be slightly asymmetric towards the bottom of the core. On the other hand, at hot zero power conditions, the coolant density is uniform up the core, and there is no flattening due to Doppler. The result will be a flux distribution which at zero power can be skewed toward the top of the core. The reactivity insertion due to the skewed distribution is calculated with an allowance for effects of xenon distribution.

4.3.2.4.4 Void Content

A small void content in the core is due to nucleate boiling at full power. The void collapse coincident with power reduction makes a small reactivity contribution.

4.3.2.4.5 Rod Insertion Allowance

At full power, the control bank is operated within a prescribed band of travel to compensate for small periodic changes in boron concentration, changes in temperature and very small changes in the xenon concentration not compensated for by a change in boron concentration. When the

control bank reaches either limit of this band, a change in boron concentration is required to compensate for additional reactivity changes. Since the insertion limit is set by a rod travel limit, a conservatively high calculation of the inserted worth is made which exceeds the normally inserted reactivity.

The rod insertion limits are a function of several design criteria. The usual procedure is to base the insertion limits on the limiting design criteria, which experience has shown to be the required shutdown margin. The remaining criteria, e.g., the $F_{\Delta H}$ design basis and the statically misaligned rod safety criteria, are checked to insure that they are met. For the Virgil C. Summer Nuclear Station, the Technical Specification limit is based on the shutdown criteria and is slightly conservative with respect to the misaligned rod criteria. Therefore, with bank D inserted to its full power insertion limit and 1 RCCA fully withdrawn, the DNB design criteria is met, i.e., minimum DNBR is greater than the design limit.

4.3.2.4.6 Burnup

Excess reactivity is installed at the beginning of each cycle to provide sufficient reactivity to compensate for fuel depletion and fission products throughout the cycle. This reactivity is controlled by the addition of soluble boron to the coolant and by boride absorber coated fuel pellets and/or burnable absorber rods. Typical soluble boron concentration for several core configurations and unit boron worths for reload cycles are given in Table 4.3-2. Since the excess reactivity for burnup is controlled by soluble boron and/or burnable absorbers, it is not included in control rod requirements.

4.3.2.4.7 Xenon and Samarium Poisoning

Changes in xenon and samarium concentrations in the core occur at a sufficiently slow rate, even following rapid power level changes, that the resulting reactivity change is controlled by changing the soluble boron concentration.

4.3.2.4.8 pH Effects

Changes in reactivity due to a change in coolant pH, if any, are sufficiently small in magnitude and occur slowly enough to be controlled by the boron system. Further details are available in Reference 14.

4.3.2.4.9 Experimental Confirmation

Following a normal shutdown, the total core reactivity change during cooldown with a stuck rod has been measured on a 121 assembly 10 foot high core and a 121 assembly 12 foot high core. In each case, the core was allowed to cooldown until it reached criticality simulating the steamline break accident. For the 10 foot core, the total reactivity change associated with the cooldown is overpredicted by about 0.3% $\Delta\rho$ with respect to the measured result. This represents an error of about 5% in the total reactivity change and is about half the uncertainty allowance for this quantity. For the 12 foot core, the difference between the measured and predicted reactivity change was an even smaller 0.2% $\Delta\rho$. These measurements and others demonstrate the ability of

the methods described in Section 4.3.3 to accurately predict the total shutdown reactivity of the core.

4.3.2.5 Control

Core reactivity is controlled by means of a chemical absorber dissolved in the coolant, rod cluster control assemblies, and boride absorber coated fuel pellets and/or burnable absorber rods, as described below.

4.3.2.5.1 Chemical Absorber

Boron in solution as boric acid is used to control relatively slow reactivity changes associated with:

1. The moderator temperature defect in going from cold shutdown at ambient temperature to the hot operating temperature at zero power,
2. The transient xenon and samarium poisoning, such as that following power changes or changes in rod cluster control position,
3. The excess reactivity required to compensate for the effects of fissile inventory depletion and buildup of long-life fission products, The burnable absorber depletion.

The boron concentrations for various core conditions are presented in Table 4.3-2.

4.3.2.5.2 Rod Cluster Control Assemblies

The rod cluster control assemblies are used for shutdown and control purposes to offset fast reactivity changes associated with:

1. The required shutdown margin in the hot zero power, stuck rods condition,
2. The reactivity compensation as a result of an increase in power above hot zero power (power defect including Doppler, and moderator reactivity changes),
3. Unprogrammed fluctuations in boron concentration, coolant temperature, or xenon concentration (with rods not exceeding the allowable rod insertion limits),
4. Reactivity ramp rates resulting from load changes.

The allowed control rod bank reactivity insertion is limited at full power to maintain shutdown capability. As the power level is reduced, control rod reactivity requirements are also reduced and more rod insertion is allowed. The control bank position is monitored and the operator is notified by an alarm if the limit is approached. The determination of the insertion limit uses conservative xenon distributions. In addition, the rod cluster control assembly withdrawal pattern determined from these analyses is used in determining power distribution factors and in determining the maximum worth of an inserted rod cluster control assembly ejection accident. For further discussion, refer to the Technical Specifications on rod insertion limits.

Power distribution, rod ejection and rod misalignment analyses are based on the arrangement of the shutdown and control groups of the rod cluster control assemblies shown in Figure 4.3-40. All shutdown rod cluster control assemblies are withdrawn before withdrawal of the control banks is initiated. In going from zero to 100% power, control banks A, B, C, and D are withdrawn sequentially. The limits of rod positions and further discussion on the basis for rod insertion limits are provided in the Technical Specifications.

4.3.2.5.3 Burnable Absorbers

The burnable absorbers (either discrete or integral type) provide partial control of the excess reactivity available during the fuel cycle. In doing so, these rods prevent the moderator temperature coefficient from being positive at normal operating conditions. They perform this function by reducing the requirement for soluble absorber in the moderator at the beginning of the cycle, as described previously. A typical burnable absorber pattern in the core together with the number of rods per assembly is shown in Figure 4.3-5, while typical, arrangements within an assembly are displayed in Figure 4.3-4. The burnable absorber is depleted with burnup but at a sufficiently slow rate so that the resulting critical concentration of soluble boron is such that the moderator temperature coefficient remains negative at all times for full power operating conditions.

4.3.2.5.4 Peak Xenon Startup

Compensation for the peak xenon buildup is accomplished using the boron control system. Startup from the peak xenon condition is accomplished with a combination of rod motion and boron dilution. The boron dilution may be made at any time, including during the shutdown period, provided the shutdown margin is maintained.

4.3.2.5.5 Load Follow Control and Xenon Control

During load follow maneuvers, power changes are accomplished using control rod motion and dilution or boration by the boron system as required. Control rod motion is limited by the control rod insertion limits as provided in the Technical Specifications and discussed in Sections 4.3.2.5.2 and 4.3.2.5.3. The power distribution is maintained within acceptable limits. Reactivity changes due to the changing xenon concentration can be controlled by rod motion and/or changes in the soluble boron concentration.

4.3.2.5.6 Burnup

Control of the excess reactivity for burnup is accomplished using soluble boron and/or burnable absorber. The boron concentration must be limited during full power operating conditions to ensure the moderator temperature coefficient is negative. Sufficient burnable absorber is installed at the beginning of a cycle to give the desired cycle lifetime without exceeding the boron concentration limit. The practical minimum boron concentration is 10 ppm.

4.3.2.6 Control Rod Patterns and Reactivity Worth

The rod cluster control assemblies are designated by function as the control groups and the shutdown groups. The terms “group” and “bank” are used synonymously throughout this report to describe a particular grouping of control assemblies. The rod cluster assembly pattern is displayed in Figure 4.3-40 which is not expected to change during the life of the plant. The control banks are labeled A, B, C, and D and the shutdown banks are labeled SA, SB, etc., as applicable. Each bank, although operated and controlled as a unit, is comprised of 2 subgroups. The axial position of the rod cluster control assemblies may be controlled manually or automatically. The rod cluster control assemblies are all dropped into the core following actuation of reactor trip signals.

Two (2) criteria have been employed for selection of the control groups. First the total reactivity worth must be adequate to meet the requirements specified in Table 4.3-3. Second, in view of the fact that these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that the power capability requirements are met. Analyses indicate that the first requirement can be met either by a single group or by 2 or more banks whose total worth equals at least the required amount. The axial power shape would be more peaked following movement of a single group of rods worth 3 to 4% $\Delta\rho$; therefore, 4 banks (described as A, B, C, and D in Figure 4.3-40) each worth approximately 1% $\Delta\rho$ have been selected.

The positions of control banks for criticality under any reactor condition is determined by the concentration of boron in the coolant. On an approach to criticality, boron is adjusted to ensure that criticality will be achieved with control rods above the insertion limit set by shutdown and other considerations (see the Technical Specifications). Early in the cycle there may also be a withdrawal limit at low power to maintain a negative moderator temperature coefficient more negative than the Technical Specification limit.

Ejected rod worths are given in Section 15.4.6 for several different conditions. Experimental confirmation of these worths can be found by reference to startup test reports such as Reference 15.

Allowable deviations due to misaligned control rods are discussed in the Technical Specifications.

A representative calculation for 2 banks of control rods withdrawn simultaneously (rod withdrawal accident) is given in Figure 4.3-41.

Calculation of control rod reactivity worth versus time following reactor trip involves both control rod velocity and differential reactivity worth. The rod position versus time of travel after rod release assumed is given in Figure 4.3-42. For nuclear design purposes, the reactivity worth versus rod position is calculated by a series of steady-state calculations at various control rod positions assuming all rods out of the core as the initial position in order to minimize the initial reactivity insertion rate. Also to be conservative, the rod of highest worth is assumed to be stuck out of the core and the flux distribution (and thus reactivity importance) is assumed to be skewed to the bottom of the core. A sample result of these calculations is shown on Figure 4.3-43.

The shutdown groups provide additional negative reactivity to assure an adequate shutdown margin. Shutdown margin is defined as the amount by which the core would be subcritical at hot shutdown if all rod cluster control assemblies are tripped, but assuming that the highest worth assembly remains fully withdrawn and no changes in xenon or boron take place. The loss of control rod worth due to the material irradiation is negligible since only bank D may be in the core under normal operating conditions.

The values given in Table 4.3-3 show that the available reactivity in withdrawn rod cluster control assemblies provides the design bases minimum shutdown margin allowing for the highest worth cluster to be at its fully withdrawn position. Allowance for uncertainty in the calculated worth of N-1 rods is made before determination of the shutdown margin.

4.3.2.7 Criticality of Fuel Assemblies

Criticality of fuel assemblies outside the reactor is precluded by adequate design of fuel transfer and fuel storage facilities and by administrative control procedures. This section identifies those criteria important to criticality safety analyses. Westinghouse 17 x 17 fuel assemblies (STANDARD, VANTAGE 5, and VANTAGE+) were included in the analyses with the most limiting being assumed in all cases.

4.3.2.7.1 New Fuel Storage

New fuel is normally stored in 21 inch center to center racks in the new fuel storage facility with no water present but which are designed so as to prevent accidental criticality even if unborated water is present. For the flooded condition, assuming new fuel of the highest anticipated enrichment (5.0 w/o U-235) in place, the effective multiplication factor does not exceed 0.95. For the normally dry condition the effective multiplication factor does not exceed 0.98 with new fuel of the highest anticipated enrichment in place, assuming optimum moderation. Credit is taken for the inherent neutron absorbing effect of materials of construction of the racks.

In the analysis for the new fuel storage facilities, the fuel assemblies are assumed to be in their most reactive condition, namely fresh or undepleted and with no control rods or removable neutron absorbers present. Assemblies can not be closer together than the design separation provided by the storage facility except in special cases such as in fuel shipping containers where analyses are carried out to establish the acceptability of the design. The mechanical integrity of the fuel assembly is assumed.

New fuel may also be stored in Region 1 of the spent fuel storage facility, as discussed in Section 4.3.2.7.2.

4.3.2.7.2 Spent Fuel Storage

The high density spent fuel storage racks are designed to assure that a K_{eff} equal to or less than 0.95 is maintained with the racks fully loaded with fuel of the highest anticipated reactivity in each of 2 regions and flooded with unborated water at a temperature corresponding to the highest reactivity. The maximum calculated reactivity is obtained by adding calculational and

methodology biases and the statistically combined material and construction tolerances and uncertainties to the nominal reference reactivity. Table 4.3-4 summarizes the biases and statistical uncertainties determined for each spent fuel rack region. The maximum reactivity for each region is less than 0.95 with a 95% probability at a 95% confidence level.

To assure that the true reactivity will always be less than the calculated reactivity, the following conservative assumptions were used to develop the nominal reference reactivity:

1. The effective multiplication factor of an infinite array of fuel assemblies is assumed, except for the assessment of peripheral effects and certain abnormal/accident conditions where neutron leakage is inherent.
2. No credit is taken for spacer grids, spacer grid sleeves, fuel dishing or fuel chamfering.
3. The racks were assumed to be fully loaded with the most reactive fuel authorized to be stored.
4. Depletion calculations assume conservative operating conditions; highest fuel and moderator temperature and an allowance for the soluble boron concentration during in-core operations.
5. All fuel assembly parameters relevant to the criticality analysis are based on the Westinghouse 17 x 17 fuel assembly design (STANDARD, VANTAGE 5, or VANTAGE+) which yields the highest reactivity in each region.
6. For assemblies that use WABAs during in-core depletion, it is assumed that the maximum burnup of the assembly when the WABA is removed is 30 GWD/MTU.

The moderator is assumed to be pure water (no boron) at a temperature of 68 °F and a density of 1.0 gm/cm^3. A reactivity bias is applied to account for the normal range of spent fuel pool water temperatures (39 °F to 248 °F). A nominal Boral poison material loadings 0.0324 (minimum of 0.0300) grams B-10 per square centimeter are used throughout the lattice for Regions 1 and 2.

The design methods which ensure the criticality safety of the fuel assemblies in the spent fuel storage racks are discussed in Reference 37. The criticality analysis performed for each of the 2 storage regions produced separate criteria defining the storage limits applicable to each region as follows:

1. Region 1 is designed to accommodate the storage of new and freshly discharged fuel assemblies with a maximum nominal enrichment of 4.95 weight percent U-235.
2. Region 2 is designed to accommodate the storage of fuel assemblies with a maximum nominal initial enrichment of 4.95 weight percent U-235 with a minimum burnup of 41,611 MWD/MTU or fuel of initial enrichment and burnup combinations within the acceptable domain depicted in Figure 4.3-44.

Figure 4.3-44 illustrates, as a function of the initial fuel enrichment, the minimum acceptable burnup which yields the maximum allowable reactivity for Region 2, respectively. This curve is incorporated in the Technical Specifications.

Most accident conditions will not result in an increase in K_{eff} of the spent fuel storage rack. Examples are:

1. Fuel Assembly Drop on Top of Rack - The rack structure pertinent for criticality is not excessively deformed and the dropped assembly which comes to rest horizontally on top of the rack has sufficient water separating it from the active fuel height of stored assemblies to preclude neutronic interaction.
2. Fuel Assembly Drop Between Rack Modules - the design of the spent fuel racks are such that they preclude the insertion of a fuel assembly in other than prescribed locations.
3. Fuel Assembly Drop Between Rack and Wall - the design of the spent fuel racks are such that they preclude the insertion of fuel assembly in other than prescribed locations.
4. Rack Lateral Movement - The racks are constructed with the baseplates extending beyond the edge of the outer cells which assures that the minimum spacing between racks is maintained under all conditions.
5. Bulk Coolant Cooldown - For both regions the moderator temperature coefficient of reactivity is negative. Therefore it is assumed that the moderator is at the temperature (39 °F) which results in the highest reactivity, assuring that the true reactivity will always be lower over the expected range of water temperatures.
6. Fuel Assembly Drop into Loaded Cell - For both regions, a vertical impact would at most cause a small compression of the stored assembly, i-educing the water-to-fuel ratio and thereby reducing reactivity. In addition, the distance between the active regions of both assemblies will be more than sufficient to ensure no neutron interaction.
7. Fuel Assembly Drop into Empty Cell - For both regions this postulated accident could result in a localized deformation of the rack baseplate, and therefore result in the active fuel height of that assembly no longer being completely covered by the Boral. Such a misalignment of the active fuel height and Boral of up to three inches would cause a negligible increase in reactivity.

One (1) accident can be postulated which could cause reactivity to increase beyond the analyzed condition. It is:

1. Fuel Assembly Misload - For Region 2, this postulated accident would result in an increase in reactivity. The effect of misplacing a single fresh 4.95 weight percent U-235 fuel assembly that has no integral fuel burnable absorbers into the center of a fully loaded rack would have greatest effect. This event could increase reactivity by as much as 0.42 ΔK. To offset this increase, 500 ppm of soluble boron is required to maintain the maximum reactivity less than 0.95.

For occurrences of any of the above postulated accidents, the double contingency principle of ANSI/ANS 8.1-1983 can be applied. This states that one is not required to assume two unlikely, independent, concurrent events to ensure protection against criticality accidents. Thus, for these

conditions, the presence of soluble boron in the storage pool water can be assumed as a realistic initial condition since not assuming its presence would be a second unlikely event.

Since the V. C. Summer spent fuel pool boron concentration is maintained at a minimum of 2000 ppm whenever fuel handling operation are active, and since it is expected this level of boron would remain in the pool between outages, should a postulated accident occur which causes reactivity to increase, K_{eff} will be maintained less than or equal to 0.95 due to the negative reactivity effect of the dissolved boron.

4.3.2.8 Stability

4.3.2.8.1 Introduction

The stability of the PWR cores against xenon-induced spatial oscillations and the control of such transients are discussed extensively in References 9, 17, 18, and 19. A summary of these reports is given in the following discussion and the design bases are given in Section 4.3.1.6.

In a large reactor core, xenon-induced oscillations can take place with no corresponding change in the total power of the core. The oscillation may be caused by a power shift in the core which occurs rapidly in comparison with the xenon-iodine time constants. Such a power shift occurs in the axial direction when a plant load change is made by control rod motion and results in a change in the moderator density and fuel temperature distributions. Such a power shift could occur in the diametral plane of the core as a result of abnormal control action.

Protection against total power instabilities is provided by the control and protection system as described in Section 7.7. Hence, the discussion on the core stability will be limited here to xenon-induced spatial oscillations.

4.3.2.8.2 Stability Index

Power distributions, either in the axial direction or in the X-Y plane, can undergo oscillations due to perturbations introduced in the equilibrium distributions without changing the total core power. The xenon-induced oscillations are essentially limited to the first flux overtones in the current PWRs, and the stability of the core against xenon-induced oscillations can be determined in terms of the eigenvalues of the first flux overtones. Writing, either in the axial direction or in the X-Y plane, the eigenvalue ξ of the first flux harmonic as:

$$\xi = b + ic, \quad (4.3\text{-}1)$$

then b is defined as the stability index and $T = 2n/c$ as the oscillation period of the first harmonic. The time-dependence of the first harmonic $\delta\phi$in the power distribution can now be represented as:

$$\delta\phi(t) = Ae^{\xi t} = ae^{bt} \cos ct, \quad (4.3\text{-}2)$$

where A and a are constants. The stability index can also be obtained approximately by:

$$b = \frac{1}{T} \ln \frac{A_n + 1}{A_n} \qquad (4.3\text{-}3)$$

where A_n A_n + 1 are the successive peak amplitudes of the oscillation and T is the time period between the successive peaks.

4.3.2.8.3 Prediction of the Core Stability

The stability of the core described herein (i.e., with 17 x 17 fuel assemblies) against xenon-induced spatial oscillations is expected to be equal to or better than that of earlier designs. The prediction is based on a comparison of the parameters which are significant in determining the stability of the core against the xenon-induced oscillations, namely; 1) the overall core size is unchanged and spatial power distributions will be similar, 2) the moderator temperature coefficient is expected to be similar at full power, and 3) the Doppler coefficient of reactivity is expected to be similar at full power.

Analysis of both the axial and X-Y xenon transient tests, discussed in Section 4.3.2.8.5, shows that the calculational model is adequate for the prediction of core stability.

4.3.2.8.4 Stability Measurements

1. Axial Measurements

   Two (2) axial xenon transient tests conducted in a PWR with a core height of 12 feet and 121 fuel assemblies is reported in Reference 20, and will be briefly discussed here. The tests were performed at approximately 10% and 50% of cycle life.

   Both a free-running oscillation test and a controlled test were performed during the first test. The second test at mid-cycle consisted of a free-running oscillation test only. In each of the free-running oscillation tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of the control Bank D and the subsequent oscillation was monitored to measure the stability index and the oscillation period. In the controlled test conducted early in the cycle, the part length rods were used to follow the oscillations to maintain an axial offset within the prescribed limits. The axial offset of power was obtained from the excore ion chamber readings (which had been calibrated against the incore flux maps) as a function of time for both free-running tests as shown in Figure 4.3-46.

The total core power was maintained constant during these spatial xenon tests. The stability index and the oscillation period were obtained from a least-square fit of the axial offset data in the form of Equation (4.3-2). The axial offset of power is the quantity that properly represents the axial stability in the sense that it essentially eliminates any contribution from even order harmonics including the fundamental mode. The conclusions of the tests are:

a. The core was stable against induced axial xenon transients both at the core average burnups of 1550 MWD/MTU and 7700 MWD/MTU. The measured stability indices are -0.041 hr^{-1} for the first test (Curve 1 of Figure 4.3-46) and-0.014 hr^{-1} for the second test (Curve 2 of Figure 4.3-46). The corresponding oscillation periods are 32.4 and 27.2 hours, respectively.

b. The reactor core becomes less stable as fuel burnup progresses and the axial stability index was essentially zero at 12,000 MWD/MTU.

2. Measurements in the X-Y Plane

Two (2) X-Y xenon oscillation tests were performed at a PWR plant with a core height of 12 feet and 157 fuel assemblies. The first test was conducted at a core average burnup of 1540 MWD/MTU and the second at a core average burnup of 12,900 MWD/MTU. The X-Y xenon tests show that the core was stable in the X-Y plane at both burnups. The second test shows that the core became more stable as the fuel burnup increased and all Westinghouse PWRs with 121 and 157 assemblies are expected to be stable throughout their burnup cycles.

In each of the 2 X-Y tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of 1 rod cluster control unit located along the diagonal axis. Following the perturbation, the uncontrolled oscillation was monitored using the movable detector and thermocouple system and the excore power range detectors. The quadrant tilt difference (QTD) is the quantity that properly represents the diametral oscillation in the X-Y plane of the reactor core in that the differences of the quadrant average powers over 2 symmetrically opposite quadrants essentially eliminates the contribution to the oscillation from the azimuthal mode. The QTD data were fitted in the form of Equation (4.3-2) through a least-square method. A stability index of -0.076 hr-1 with a period of 29.6 hours was obtained from the thermocouple data shown in Figure 4.3-47.

It was observed in the second X-Y xenon test that the PWR core with 157 fuel assemblies had become more stable due to an increased fuel depletion although the stability index was not determined.

4.3.2.8.5 Comparison of Calculations with Measurements

The analysis of the axial xenon transient tests was performed in an axial slab geometry using a flux synthesis technique. The direct simulation of the axial offset data was carried out using an updated version of the PANDA Code (Reference 21). The analysis of the X-Y xenon transient tests was performed in an X-Y geometry using a modified TURTLE (Reference 13) Code. Both the PANDA and TURTLE codes solve the 2-group time-dependent neutron diffusion equation with time-dependent xenon and iodine concentrations. The fuel temperature and moderator

density feedback is limited to a steady-state model. The X-Y calculations were performed in an average enthalpy plane.

The basic nuclear cross sections used in this study were generated from a unit cell depletion program which has evolved from the codes LEOPARD (Reference 2) and CINDER (Reference 22). The detailed experimental data during the tests including the reactor power level, enthalpy rise and the impulse motion of the control rod assembly, as well as the plant follow burnup data were closely simulated in the study.

The results of the stability calculation for the axial tests are compared with the experimental data in Table 4.3-5. The calculations show conservative results for both of the axial tests with a margin of approximately -0.01 hr^{-1} in the stability index.

An analytical simulation of the first X-Y xenon oscillation test shows a calculated stability index of -0.081 hr^{-1}, in good agreement with the measured value of -0.075 hr^{-1}. As indicated earlier, the second X-Y xenon test showed that the core had become more stable compared to the first test and no evaluation of the stability index was attempted. This increase in the core stability in the X-Y plane due to increased fuel burnup is due mainly to the increased magnitude of the negative moderator temperature coefficient.

Previous studies of the physics of xenon oscillations, including three-dimensional analysis, are reported in the series of topical reports, References 17, 18, and 19. A more detailed description of the experimental results and analysis of the axial and X-Y xenon transient tests is presented in Reference 20 and Section 1 of Reference 23.

4.3.2.8.6 Stability Control and Protection

The excore detector system is utilized to provide indications of xenon-induced spatial oscillations. The readings from the excore detectors are available to the operator and also form part of the protection system.

1. Axial Power Distribution

   For maintenance of proper axial power distributions, the operator is instructed to maintain an axial offset within prescribed limits, based on the excore detector readings. Should the axial offset be permitted to move far enough outside these limits, the protection limit will be reached and the power will be reduced.

   Twelve (12) foot PWR cores become less stable to axial xenon oscillations as fuel burnup progresses. However, free xenon oscillations are not allowed to occur except for special tests. The control rod banks present in all modern Westinghouse PWRs are sufficient to dampen and control any axial xenon oscillations present. Should the axial offset be inadvertently permitted to move far enough outside the limits due to an axial xenon oscillation, or any other reason, the protection limit on axial offset will be reached and the power will be automatically cut back.

2. Radial Power Distribution

   The core described herein is calculated to be stable against X-Y xenon induced oscillations at all times in life.

   The X-Y stability of large PWRs has been further verified as part of the startup physics test program at a PWR core with 193 fuel assemblies. The measured X-Y stability of the PWR core with 157 assemblies and the good agreement between the calculated and measured stability index for this core, as discussed in Sections 4.3.2.8.4 and 4.3.2.8.5, make it very unlikely that a sustained X-Y oscillation can occur in a core with 193 assemblies. However, in the unlikely event that X-Y oscillations occur, backup actions are possible and would be implemented, if necessary, to increase the natural stability of the core. This is based on the fact that several actions could be taken to make the moderator temperature coefficient more negative, which will increase the stability of the core in the X-Y plane.

   Provisions for protection against non-symmetric perturbations in the X-Y power distribution that could result from equipment malfunctions are made in the protection system design. This includes control rod drop, rod misalignment and asymmetric loss of coolant flow.

   A more detailed discussion of the power distribution control in PWR cores is presented in Reference 9.

4.3.2.9 Vessel Irradiation

It is beyond the scope of this section to present methods and analyses used in determination of neutron and gamma flux attenuation between the core and the pressure vessel other than a brief review given below. A more complete discussion on the pressure vessel irradiation and surveillance program is given in Section 5.4.3.6.

The primary shielding material that serves to attenuate high energy neutron and gamma flux originating in the core consists primarily of the core baffle, core barrel, the neutron pads, and associated water annuli, all of which are within the region between the core and the pressure vessel.

In general, few group neutron diffusion theory codes are used to determine flux and fission power density distributions within the active core and the accuracy of these analyses is verified by incore measurements on operating reactors. Outside the active core, methods such as those which use multigroup space dependent slowing down codes described in Section 5.4.3.6.2 are used. Region wise power sharing information from the core calculations is often used as reference source data for the multigroup codes.

The neutron flux distribution and spectrum in the various structural components varies significantly from the core to the pressure vessel. Representative values of the neutron flux distribution and spectrum are presented in Table 4.3-6. The values listed are based on equilibrium cycle reactor core parameters and power distributions, and thus, are suitable for long term net projections and for correlation with radiation damage estimates.

As discussed in Section 5.4.3.6, the irradiation surveillance program utilizes actual test samples to verify the accuracy of the calculated fluxes at the vessel.

4.3.3 Analytical Methods

Calculations required in nuclear design consist of 3 distinct types, which are performed in sequence:

1. Determination of effective fuel temperatures,
2. Generation of macroscopic few-group parameters,
3. Space-dependent, few-group diffusion calculations.

These calculations are carried out by computer codes which can be executed individually, however, at Westinghouse most of the codes required have been linked to form an automated design sequence which minimizes design time, avoids errors in transcription of data, and standardizes the design methods.

4.3.3.1 Fuel Temperature (Doppler) Calculations

Temperatures vary radially within the fuel rod, depending on the heat generation rate in the pellet, the conductivity of the materials in the pellet, gap, and clad; and the temperature of the coolant.

The fuel temperatures for use in most nuclear design Doppler calculations are obtained from a simplified version of the Westinghouse fuel rod design model described in Section 4.2.1.3.1 which considers the effect of radial variation of pellet conductivity, expansion-coefficient and heat generation rate, elastic deflection of the clad, and a gap conductance which depends on the initial fill gap, the hot open gap dimension, and the fraction of the pellet over which the gap is closed. The fraction of the gap assumed closed represents an empirical adjustment used to produce good agreement with observed reactivity data at beginning-of-life. Further gap closure occurs with burnup and accounts for the decrease in Doppler defect with burnup which has been observed in operating plants.

Radial power distributions in the pellet as a function of burnup are obtained from LASER (Reference 24) calculations.

The effective U-238 temperature for resonance absorption is obtained from the radial temperature distribution by applying a radially dependent weighting function. The weighting function was determined from REPAD (Reference 25) Monte Carlo calculations of resonance escape probabilities in several steady-state and transient temperature distributions. In each case a flat pellet temperature was determined which produced the same resonance escape probability as the actual distribution. The weighting function was empirically determined from these results.

The effective Pu-240 temperature for resonance absorption is determined by a convolution of the radial distribution of Pu-240 densities from LASER burnup calculations and the radial weighting

function. The resulting temperature is burnup dependent, but the difference between U-238 and Pu-240 temperatures, in terms of reactivity effects, is small.

The effective pellet temperature for pellet dimensional change is that value which produces the same outer pellet radius in a virgin pellet as that obtained from the temperature model. The effective clad temperature for dimensional change is its average value.

The temperature calculational model has been validated by plant Doppler defect data as shown in Table 4.3-7 and Doppler coefficient data as shown in Figure 4.3-48. Stability index measurements also provide a sensitive measure of the Doppler coefficient near full power (see Section 4.3.2.8). It can be seen that Doppler defect data is typically within 0.2% $\Delta\rho$ of prediction.

4.3.3.2 Macroscopic Group Constants

Early benchmarking and calculation of macroscopic group constants were performed using a linked version of LEOPARD (Reference 2) and CINDER (Reference 22). Group constants for reloads were previously generated using the PHOENIX-P code (Reference 35). More recently, group constant calculations were performed using the PARAGON/NEXUS (References 40 and 41) code package.

Macroscopic few-group constants and analogous microscopic cross sections (needed for feedback and microscopic depletion calculations) can be generated for fuel cells by a recent version of the LEOPARD and CINDER codes, which are linked internally and provide burnup dependent cross sections. Normally a simplified approximation of the main fuel chains is used; however, where needed, a complete solution for all the significant isotopes in the fuel chains from Th-232 to Cm-244 is available (Reference 26). Fast and thermal cross-section library tapes contain microscopic cross-sections taken for the most part from the ENDF/B (Reference 27) library, with a few exceptions where other data provided better agreement with critical experiments, isotopic measurements, and plant critical boron values. The effect on the unit fuel cell of non-lattice components in the fuel assembly is obtained by supplying an appropriate volume fraction of these materials in an extra region which is homogenized with the unit cell in the fast (MUFT) and thermal (SOFOCATE) flux calculations. In the thermal calculation, the fuel rod, clad, and moderator are homogenized by energy-dependent disadvantage factors derived from an analytical fit to integral transport theory results.

Group constants for burnable absorber cells, guide thimbles, instrument thimbles and interassembly gaps are generated in a manner analogous to the fuel cell calculation. Reflector group constants are taken from infinite medium LEOPARD calculations. Baffle group constants are calculated from an average of core and radial reflector microscopic group constants for stainless steel.

The group constants for core materials, calculated above, are placed in a pin-by-pin discrete 2-group diffusion theory code, an updated version of the TURTLE code, to solve for 2-group nodal macroscopic and microscopic cross sections, through flux-volume weighting homogenization.

Group constants for control rods are calculated in a linked version of the HAMMER (Reference 28) and AIM (Reference 29) codes to provide an improved treatment of self shielding in the broad resonance structure of these isotopes at epithermal energies than is available in LEOPARD. The Doppler broadened cross-sections of the control rod materials are represented as smooth cross-sections in the 54 group LEOPARD fast group structure and in 30 thermal groups. The 4 group constants in the rod cell and appropriate extra region are generated in the coupled space-energy transport HAMMER calculation. A corresponding AIM calculation of the homogenized rod cell with extra region is used to adjust the absorption cross-sections of the rod cell to match the reaction rates in HAMMER. These transport-equivalent group constants are reduced to 2-group constants for use in space-dependent diffusion calculations. In discrete X-Y calculations, only 1 mesh interval per cell is used, and the rod group constants are further adjusted for use in this standard mesh by reaction rate matching the standard mesh unit assembly to a fine-mesh unit assembly calculation.

Validation of the cross-section method is based on analysis of critical experiments as shown in Table 4.3-4, isotopic data as shown in Table 4.3-8, plant critical boron (CB) values at HZP, BOL, as shown in Table 4.3-9 and at HFP as a function of burnup as shown in Figures 4.3-49 through 4.3-51. Control rod worth measurements are shown in Table 4.3-10.

Confirmatory critical experiments on burnable absorbers are described in Reference 30.

The PHOENIX-P computer code is a two-dimensional, multigroup, transport based lattice code and capable of providing all necessary data for PWR analysis. Being a dimensional lattice code, PHOENIX-P does not rely on pre-determined spatial/spectral interaction assumptions for a heterogeneous fuel lattice, hence, will provide a more accurate multi-group flux solution than versions of LEOPARD/CINDER. The PHOENIX-P computer code is approved by the USNRC as the lattice code for generating macroscopic and microscopic few group cross sections for PWR analysis (Reference 35).

The solution for the detailed spatial flux and energy distribution is divided into 2 major steps in PHOENIX-P (Reference 35). In the first step, a two-dimensional fine energy group nodal solution is obtained which couples individual subcell regions (pellet, clad, and moderator) as well as surrounding pins. PHOENIX-P uses a method based on the Carlvik’s collision probability approach and heterogeneous response fluxes which preserves the heterogeneity of the pin cells and their surroundings. The nodal solution provides accurate and detailed local flux distribution which is then used to spatially homogenize the pin cells to fewer groups.

The second step in the solution process solves for the angular flux distribution using a standard S^4 discrete ordinates calculation. This step is based on the group-collapsed and homogenized cross sections obtained from the first step of the solution. The S^4 fluxes are then used to normalize the detailed spatial and energy nodal fluxes. The normalized nodal fluxes are used to compute reaction rates, power distribution and to deplete the fuel and burnable absorbers. A standard B1 calculation is employed to evaluate the fundamental mode critical spectrum and to provide an improved fast diffusion coefficient for the core spatial codes.

The PHOENIX-P cross sections library was designed to properly capture integral properties of the multi-group data during group collapse, and enabling proper modeling of important resonance parameters. The library contains all neutronic data necessary for modeling fuel, fission products, cladding and structural, coolant, and control/burnable absorber materials present in Light Water Reactor cores.

Group constants for burnable absorber cells, guide thimbles, instruments thimbles, control rod cells, and other non-fuel cells can be obtained directly from PHOENIX-P without any adjustments such as those required in the cell or ID lattice codes.

PARAGON (Reference 40) has been approved by the NRC as the Westinghouse lattice code. PARAGON is a replacement for PHOENIX-P and its primary use will be to provide the same types of input data that PHOENIX-P generates for use in three dimensional core simulator codes. This includes macroscopic cross sections, microscopic cross sections for feedback adjustments to the macroscopic cross sections, pin factors for pin power reconstruction calculations, discontinuity factors for a nodal method solution, and other data needed for safety analysis or other downstream applications.

PARAGON is based on collision probability – interface current cell coupling methods. PARAGON provides flexibility in modeling that was not available in PHOENIX-P including exact cell geometry representation instead of cylinderization, multiple rings and regions within the fuel pin and the moderator cell geometry, and variable cell pitch. The solution method permits flexibility in choosing the quality of the calculation through both increasing the number of regions modeled within the cell and the number of angular current directions tracked at the cell interfaces.

The calculation scheme in PARAGON is based on the conventional lattice modules: resonance calculation, flux solution, leakage correction, and depletion. The cross section resonance calculation module is based on the space dependent Dancoff method; it is a generalization of the PHOENIX-P methodology that permits the user to subdivide the fuel pin into many rings and therefore generates space dependent selfshielded isotopic cross-sections. The flux solution module uses the interface current collision probability method and permits a detailed representation of the fuel cells. The other two modules (leakage and depletion) are similar to the ones used in PHOENIX-P.

The current PHOENIX-P and PARAGON cross section libraries use 70 energy groups, based on the ENDF/B basic nuclear data. The PARAGON qualification library has been improved through the addition of more explicit fission products and fission product chains. PARAGON is however designed to employ any number of energy groups.

The NEXUS (Reference 41) cross-section generation system uses PARAGON as the lattice code.

4.3.3.3 Spatial Few-Group Diffusion Calculations

Spatial few-group diffusion calculations for early reload cores consisted of 2-group X-Y calculations using an updated version of the TURTLE code, and 2-group axial calculations using

an updated version of the PANDA code. Modern reload calculations are performed directly in 3D using the ANC (Advanced Nodal Code) (Reference 34).

Nodal three-dimensional calculations are carried out to determine the critical boron concentrations and power distributions. The moderator coefficient is evaluated by varying the inlet temperature in the same calculations used for power distribution and reactivity predictions.

Validation of TURTLE reactivity calculations is associated with the validation of the group constants themselves, as discussed in Section 4.3.3.2. Validation of the Doppler calculations is associated with the fuel temperature validation discussed in Section 4.3.3.1. Validation of the moderator coefficient calculations is obtained by comparison with plant measurements at hot zero power conditions as shown in Table 4.3-11.

ANC is used in two-dimensional and three-dimensional calculations. ANC can be used for safety analyses and to calculate critical boron concentrations, control rod worths, reactivity coefficients, etc.

Axial calculations are used to determine differential control rod worth curves (reactivity versus rod insertion) and axial power shapes during steady-state and transient xenon conditions (flyspeck curve). Group constants are obtained from ANC three-dimensional calculations homogenized by flux-volume weighting.

Validation of the spatial codes for calculating power distributions involves the use of incore and excore detectors and is discussed in Section 4.3.2.2.7.

Based on comparison with measured data it is estimated that the accuracy of current analytical methods is:

± 0.2% $\Delta\rho$ for Doppler defect

± 2 x 10^{-5}/°F for moderator coefficient

± 50 ppm for critical boron concentration with depletion

± 3% for power distributions

± 0.2% $\Delta\rho$ for rod bank worth

± 4 pcm/step for differential rod worth

± 0.5 pcm/ppm for boron worth

± 0.1% $\Delta\rho$ for moderator defect

4.3.4 References

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Table 4.3-1
Reactor Core Description

Active Core	17 x 17 OFA
Equivalent Diameter, in.	119.7
Active Fuel Height, First Core, in.	144.0
Height-to-Diameter Ratio	1.20
Total Cross Section Area, ft^2	78.14
H2O/U Molecular Ratio, lattice (Colt)	2.73
Number of Fuel Assemblies	157
Fuel Weight (as UO_2), lb	162,652
Zircaloy Weight, lb	37,350
Weight of Grids, lb	597 INC.
	3297 ZIRC
Fuel Assemblies	
Rod Array	17 x 17
Rods per Assembly	264
Rod Pitch, in.	0.496
Overall Transverse Dimensions, in.	8.426 x 8.426
Number of Grids per Assembly	2 INC, 6 Zirc, 1 RPG
Number of IFMs per Assembly	3
Composition of Grids	Inconel
	ZIRLO(R) / Low Tin ZIRLO™
Number of Guide Thimbles per Assembly	24
Composition of Guide Thimbles	ZIRLO
Diameter of Guide Thimbles (upper part), in.	0.442 1.D.x
	0.474 O.D.

Table 4.3-1 (continued)
Reactor Core Description

Fuel Assemblies (continued)	
Diameter of Guide Thimbles (lower part), in.	0.397 I.D.x
	0.430 O.D.
Diameter of Instrument Guide Thimbles, in.	0.442 I.D.x
	0.474 O.D.
Fuel Rods	
Number	41,448
Outside Diameter, in.	0.360
Diameter Gap, in.	0.0062
Clad Thickness, in.	0.0225
Clad Material	ZIRLO®/Optimized ZIRLO (TM)
Fuel Pellets	
Material	UO_2 Sintered
Density (percent of Theoretical)	95
Diameter, in.	0.3088*
Length, in.	0.370 Enriched
	0.500 Midenriched
Mass of UO_2 per foot of Fuel Rod, lb/ft	0.334
Rod Cluster Control Assemblies	
Neutron Absorber	Ag-IN-CD
Composition,%	80, 15, 5
Diameter, in.	0.341
Density, lb/in^3	0.367

* IFBA coated fuel pellets have a thin (less than 1 mil) boride coating on the pellet cylindrical surface.

Table 4.3-1 (continued)
Reactor Core Description

Rod Cluster Control Assemblies (continued)	
Cladding Material	Type 304, Cold worked, Stainless Steel
Clad Thickness, in.	0.0185
Number of Clusters	
Full Length	48
Part Length	0
Number of Absorber Rods per Cluster	24
Full Length Assembly Weight (dry), lb	157
Burnable Absorber Rods (Borosilicate)	
Number	1072
Material	Borosilicate Glass
Outside Diameter, in.	0.381
Inner Tube, O.D., in.	0.1815
Clad Material	Stainless Steel
Inner Tube Material	Stainless Steel
Boron Loading (w/o B203 in glass rod)	12.5
Weight of Boron - 10 per foot of rod, lb/ft	0.000419
Initial Reactivity Worth,%Δρ	7.0 (hot), ~ 5.5
Wet Annular Burnable Absorber (WABA) Rods	
Material	Aluminum Oxide Boron Carbide
Outside Diameter, in.	0.381
Inner Tube, O.D., in.	00267
Clad Material	Zircaloy-4
Inner Tube Material	Zircaloy-4
Weight of Boron 10, gms/cm	0.00603

* IFBA coated fuel pellets have a thin (less than 1 mil) boride coating on the pellet cylindrical surface.

Table 4.3-2
Nuclear Design Parameters
(Typical Reload Cycle)

Core Average Linear Power, kW/ft, Including Densification Effects	5.69
Total Heat Flux Hot Channel Factor, F_Q	2,45
Nuclear Enthalpy Rise Hot Channel Factor, $F^N_{\Delta H}$	1.62
Reactivity Coefficients	
Doppler Coefficient	See Figures 4.3-31 and 4.3-32
Moderator Temperature Coefficient at Operating Conditions, pcm/°F(1)	0 to -50
Boron Coefficient in Primary Coolant, pcm/ppm (1)	-16 to -8
Rodded Moderator Density Coefficient at Operating Conditions, pcm/gm/cc	$\leq + 0.50 \times 10^5$
Delayed Neutron Fraction and Lifetime	
β_{eff} BOL, (EOL)	0.0075 (0.0044)
ℓ *, BOL, (EOL) μsec	14.0 (17.0)
Control Rod Worths	
Rod Requirements	See Table 4.3-3
Maximum Bank Worth, pcm	<2300
Maximum Ejected Rod Worth	See Chapter 15.0
Boron Concentrations	
Refueling	2000
Zero Power, K_{eff} = 0.99, Hot Rod Cluster Control Assemblies Out	2133
Full Power, No Xenon, K_{eff} = 1.0, Hot Rod Cluster Control Assemblies Out	1857
Reduction with Fuel Burnup	See Figure 4.3-3*

Table 4.3-2 (continued)
Nuclear Design Parameters
(Typical Reload Cycle)

(1) 1 pcm = (percent mille) 10^{-4} $\Delta\rho$ where $\Delta\rho$ is calculated from two state point values of K_{eff} by In (K_2/K_1).

* Figure 4.3-3 is a graph of critical boron concentration versus cycle burnup for a typical transition core and a full core.

Table 4.3-3
Reactivity Requirements for Rod Cluster Control Assemblies
(Typical Reload Cycle)

Reactivity Effects, Percent	Beginning of Life	End of Life
1. Control Requirements		
Fuel temperature (Doppler),%Δρ	1.11	1.06
Moderator temperature(1),%Δρ	0.06	1.06
Redistribution,%Δρ	0.85	1.00
Rod Insertion Allowance,%Δρ	0.50	0.50
2. Total Control,%Δρ	2.52	3.62
3. Estimated Rod Cluster Control Assembly Worth (52 Rods)		
a. All assemblies inserted,%Δρ	10.18	8.40
b. All but one (highest worth) assemblies inserted,%Δρ	6.43	7.61
4. Estimated Rod Cluster Control Assembly credit with 10% adjustment to accommodate uncertainties (3b - 10 percent),%Δρ	5.79	6.85
5. Shutdown Margin Available (4-2),%Δρ	3.27	3.23(2)

(1) Includes void effects.
(2) The design basis minimum shutdown is 1.77%.

Table 4.3-4
Summary of Spent Fuel Rack Criticality Biases
and Statistical Uncertainties

	Region 1	Region 2
CALCULATIONAL & METHODOLOGY BIASES		
Methodology (Benchmark) Bias	+0.0009	+0.0009
Pool Water Temperature Variation	+0.0016	+0.0021
Axial Burnup Distribution	N/A	+0.0062
TOTAL Bias	+0.0025	+0.0092
TOLERANCES & UNCERTAINTIES		
UO_2 Enrichment Tolerance	+0.0016	+0.0032
UO_2 Density Tolerance	+0.0022	+0.0030
Storage Cell ID Tolerance	N/A	+0.0011(1)
Boral Width Tolerance	+0.0006	+0.0008
Boral Minimum B10 Content	+0.0019	+0.0028
Depletion Uncertainty	N/A	+0.0146
Calculational Uncertainty (95/95)	+0.0016	+0.0012
Methodology Bias Uncertainty	+0.0011	+0.0011
TOTAL Uncertainty (statistical)	+0.0086	+0.0157
TOTAL OF BIASES & UNCERTAINTIES	+0.0111	+0.0249

(1) As the box I.D. and cell pitch are interrelated a change in one of these parameters will necessarily the other parameter. It is assumed that both the cell pitch and box I.D. are manufactured at their minimum.
(2) This assumes the maximum possible change in the water gap, predicated on the box I.D. and cell pitch being manufactured at their greatest tolerance in opposition to each other (i.e. maximum box I.D. and minimum cell pitch).

Table 4.3-5
Axial Stability Index Pressurizer Water
Reactor Core With a 12 Foot Height

Burnup (MWD/T)	F_z	C_B (ppm)	Stability Index (hr^{-1})	
			Exp	Calc
1550	1.34	1065	-0.041	-0.032
7700	1.27	700	-0.014	-0.006
		Difference	+0.027	+0.026

Table 4.3-6
Typical Neutron Flux Levels (n/cm^2 - sec) at Full Power

	E > s1.0 Mev	5.53 Kev < E < 1.0 Mev	0.625 ev ≤ E < 5.53 Kev	E < 0.625 ev $(nv)_o$
Core Center	6.73×10^{13}	1.18×10^{14}	8.92×10^{13}	3.14×10^{13}
Core Outer Radius at Midheight	3.39×10^{13}	6.03×10^{13}	4.85×10^{13}	9.03×10^{12}
Core Top, on Axis	1.60×10^{13}	2.54×10^{13}	2.20×10^{13}	1.71×10^{13}
Core Bottom, on Axis	2.48×10^{13}	4.13×10^{13}	3.67×10^{13}	1.53×10^{13}
Pressure Vessel Inner Wall, Azimuthal Peak, Core Midheight	2.90×10^{10}	6.03×10^{10}	6.32×10^{10}	8.78×10^{10}

Table 4.3-7
Comparison of Measured and Calculated Doppler Defects

Plant	Fuel Type	Core Burnup (MWD/MTU)	Measured (pcm)(1)	Calculated (pcm)
1	Air - Filled	1800	1700	1710
2	Air - Filled	7700	1300	1440
3	Air and Helium - Filled	8460	1200	1210

(1) pcm = 10^5 x In k_1/k_2

Table 4.3-8
Saxton Core II Isotopics Rod MY, Axial Zone 6

Atom Ratio	Measure[1]	2σ Precision (%)	LEOPARD Calculation
U-234/U	4.65×10^{-5}	± 29	4.60×10^{-5}
U-235/U	5.74×10^{-3}	± 0.9	5.73×10^{-3}
U-236/U	3.55×10^{-4}	± 5.6	3.74×10^{-4}
U-238/U	0.993816	± 0.01	0.99385
Pu-238/Pu	1.32×10^{-3}	± 2.3	1.222×10^{-3}
Pu-239/Pu	0.73971	± 0.03	0.74497
Pu-240/Pu	0.19302	± 0.2	0.19102
Pu-241/Pu	6.014×10^{-2}	± 0.3	5.74×10^{-2}
Pu-242/Pu	5.81×10^{-3}	± 0.9	5.38×10^{-3}
Pu/U [2]	5.938×10^{-2}	± 0.7	5.970×10^{-2}
Np-237/U-238	1.14×10^{-4}	± 15	0.86×10^{-4}
Am-241/Pu-239	1.23×10^{-2}	± 15	1.08×10^{-2}
Cm-242/Pu-239	1.05×10^{-4}	± 10	1.11×10^{-4}
Cm-244/Pu-239	1.09×10^{-4}	± 20	0.98×10^{-4}

(1) Reported in Reference 31
(2) Weight ratio

Table 4.3-9
Critical Boron Concentrations, HZP, BOL

Plant Type	Measured	Calculated
2-Loop, 121 Assemblies 10-foot Core	1583	1589
2-Loop, 121 Assemblies 12-foot Core	1625	1624
2-Loop, 121 Assemblies 12-foot Core	1517	1517
2-Loop, 157 Assemblies 12-foot Core	1169	1161

Table 4.3-10
Comparison of Measured and Calculated Rod Worth

2-Loop Plant, 121 Assemblies, 10-foot Core	Measured (pcm)	Calculated (pcm)
Group B	1885	1893
Group A	1530	1649
Shutdown Group	3050	2917
ESADA Critical [1], 0.69" Pitch, 2 w/o $Pu0_2$ 8% Pu-240 9 Control Rods		
6.21" Rod Separation	2250	2250
2.07" Rod Separation	4220	4160
1.38" Rod Separation	4100	4019

(1) Reported in Reference 32

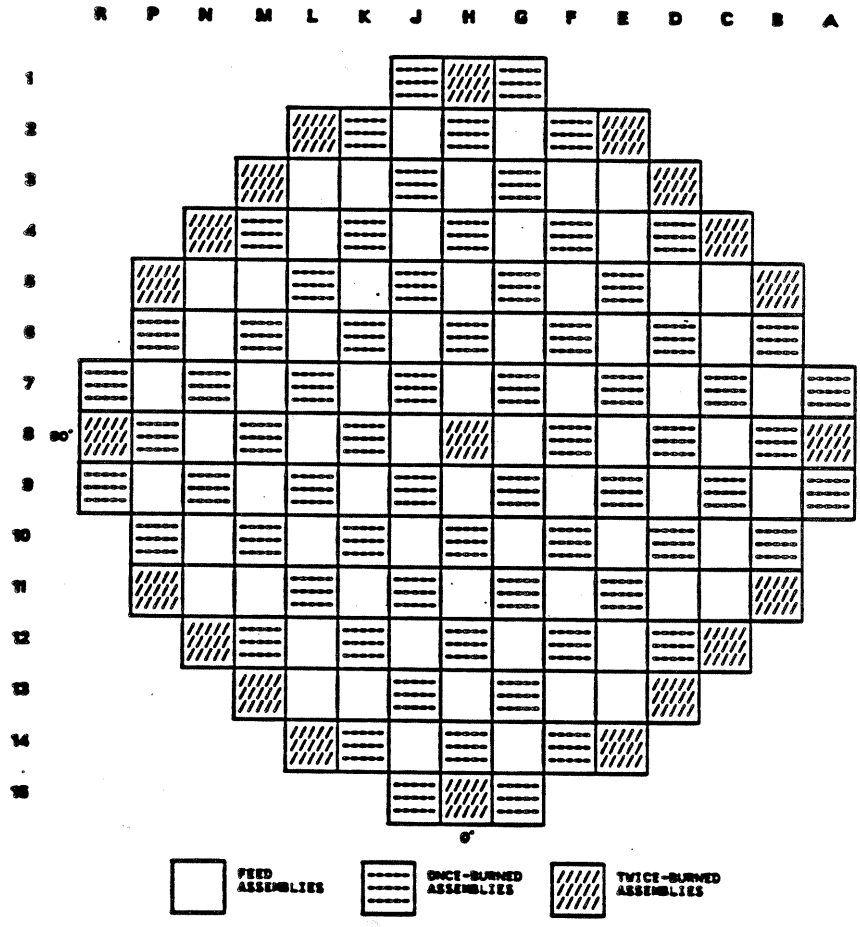
Table 4.3-11
Comparison of Measured and Calculated Moderator
Coefficients at HZP, BOL

Plant Type/ Control Bank Configuration	Measured α_{iso} (1) (pcm/°F)	Calculated α_{iso} (pcm/°F)
3-Loop, 157 Assemblies, 12-foot Core		
D at 160 steps	-0.50	-0.50
D in, C at 190 steps	-3.01	-2.75
D in, C at 28 steps	-7.67	-7.02
B, C, and D in	-5.16	-4.45
2-Loop, 121 Assemblies, 12-foot Core		
D at 180 steps	+0.85	+1.02
D in, C at 180 steps	-2.40	-1.90
C and D in, B at 165 steps	-4.40	-5.58
B, C, and D in, A at 174 steps	-8.70	-8.12

(1) Isothermal coefficients, which include the Doppler effect in the fuel.

$$\alpha_{in} = 10^5 \ln \frac{k_2}{k_1} / \Delta T°F$$

Figure 4.3-1
TYPICAL RELOAD CORE FUEL LOADING ARRANGEMENT



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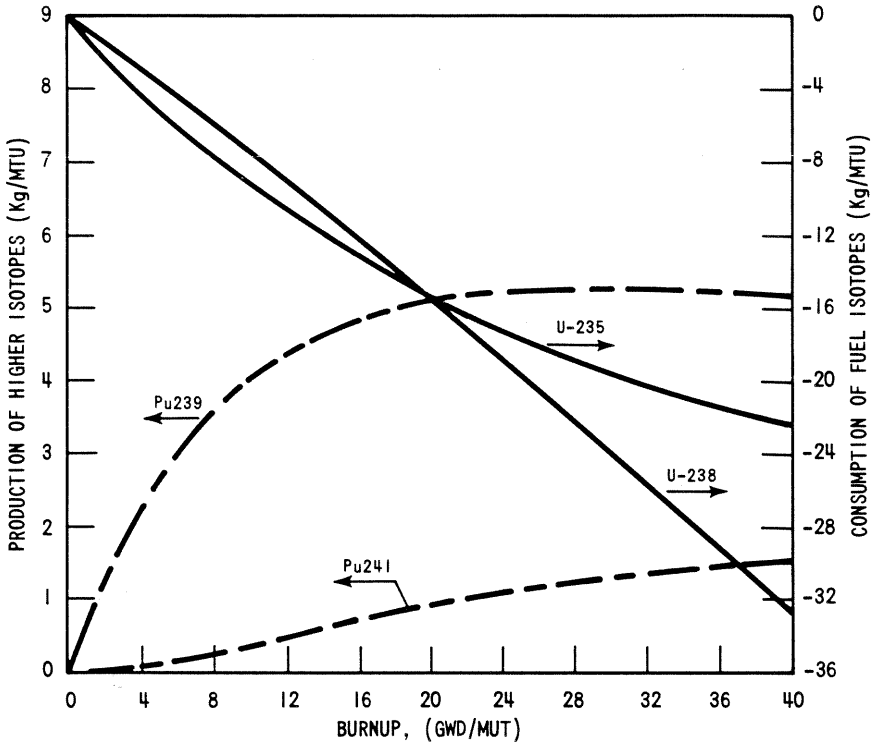
VIRGIL C. SUMMER NUCLEAR STATION

Typical Reload Core Fuel
Loading Arrangement

Figure 4.3-1

Figure 4.3-2
PRODUCTION AND CONSUMPTION OF HIGHER ISOTOPES

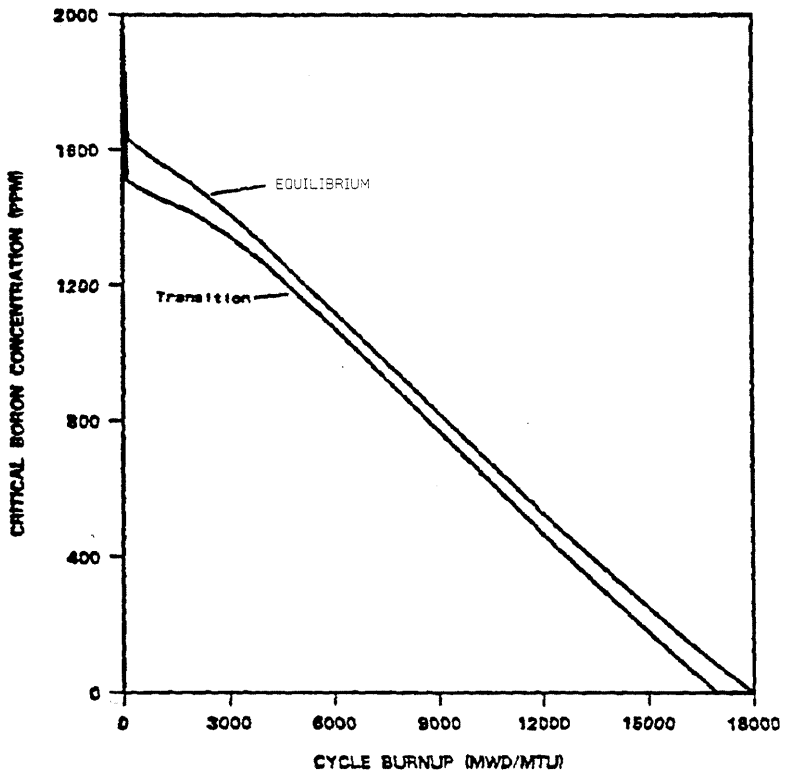


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Production and Consumption
of Higher Isotopes

Figure 4.3-2

Figure 4.3-3
BORON CONCENTRATION VERSUS BURNUP FOR TRANSITION AND EQUILIBRIUM CORES



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Boron Concentration Versus Burnup For Transition and Equilibrium Cores Figure 4.3-3

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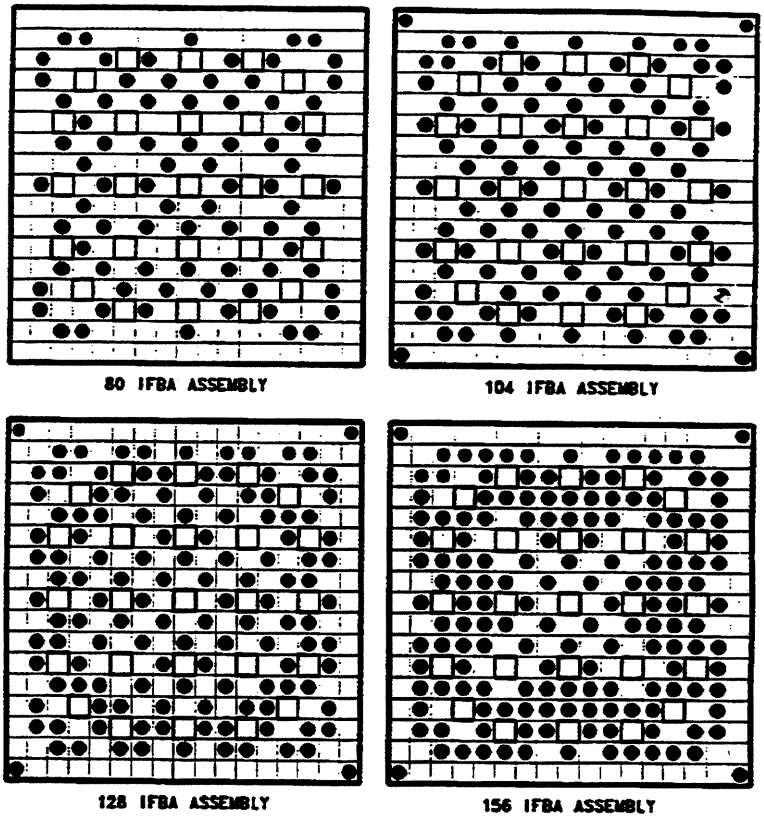
JULY 1996

fsar433.m(359,jr14325) JR14325@jr14325. Wed Jul 3 10:58:54 EDT 1996

Figure 4.3-4

INTEGRAL FUEL BURNABLE ABSORBER ROD ARRANGEMENT WITH AN ASSEMBLY (SHEET 1 OF 2)



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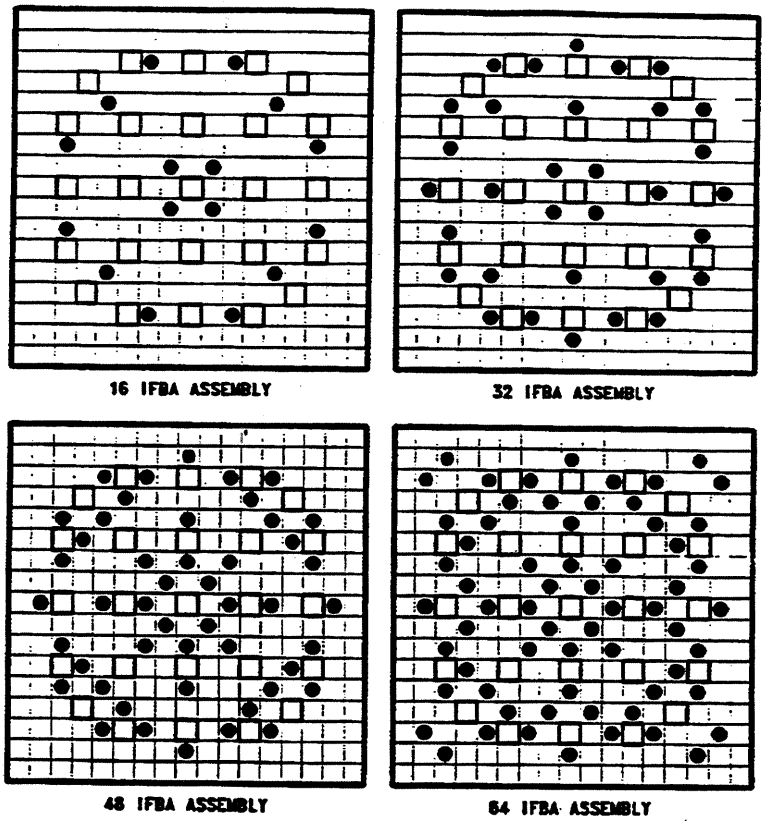
fsr434_1.m(335,jr14325) JR14325@jr14325. Fri Jun 28 11:39:34 EDT 1996

Figure 4.3-4

INTEGRAL FUEL BURNABLE ABSORBER ROD ARRANGEMENT WITHIN AN ASSEMBLY (SHEET 2 OF 2)



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VIRGIL C. SUMMER NUCLEAR STATION

Integral Fuel Burnable Absorber Rod
Arrangement Within an Assembly
(Sheet 2 of 2)

Figure 4.3-4

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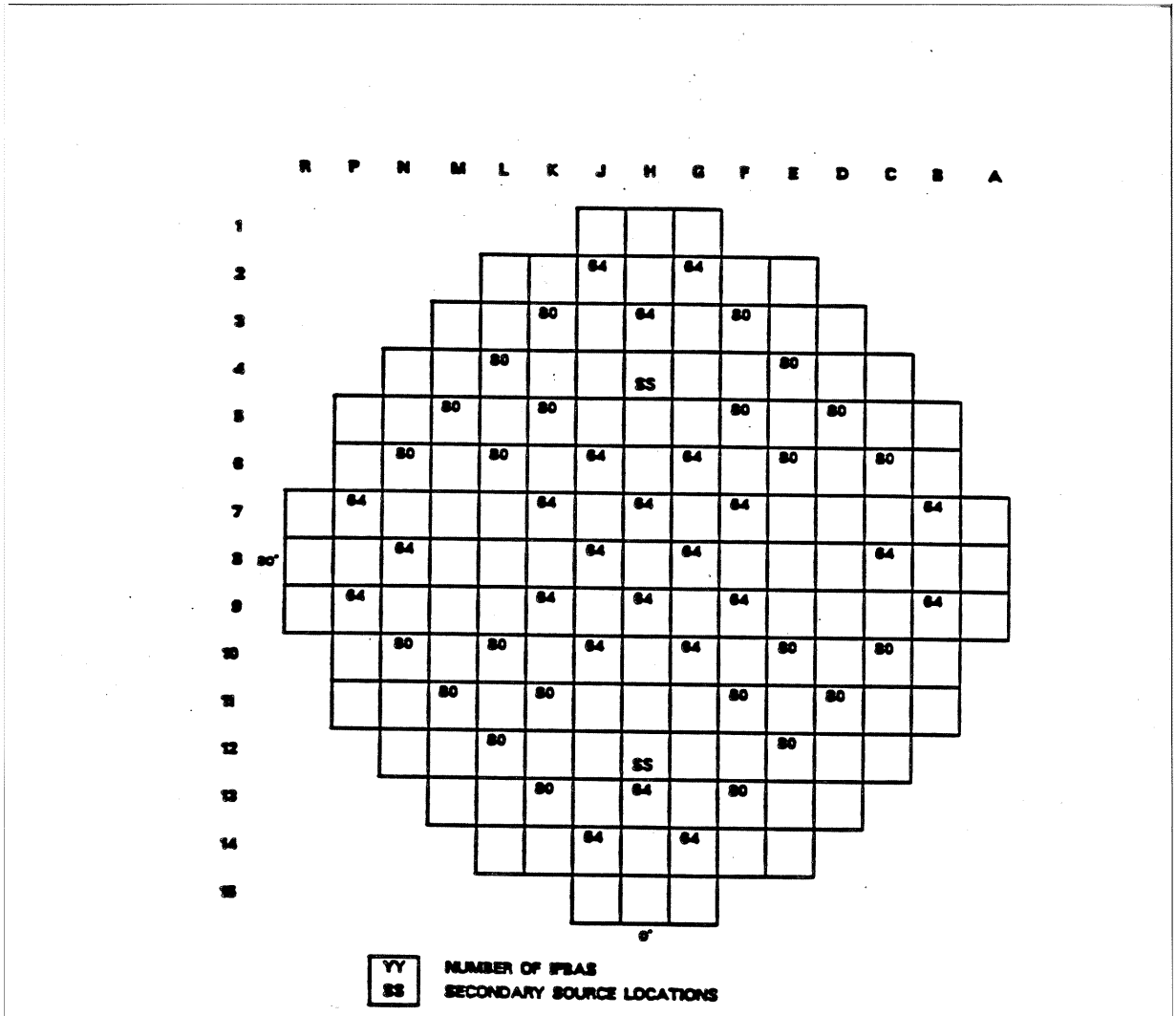
Figure 4.3-5
TYPICAL BURNABLE ABSORBER LOADING PATTERN



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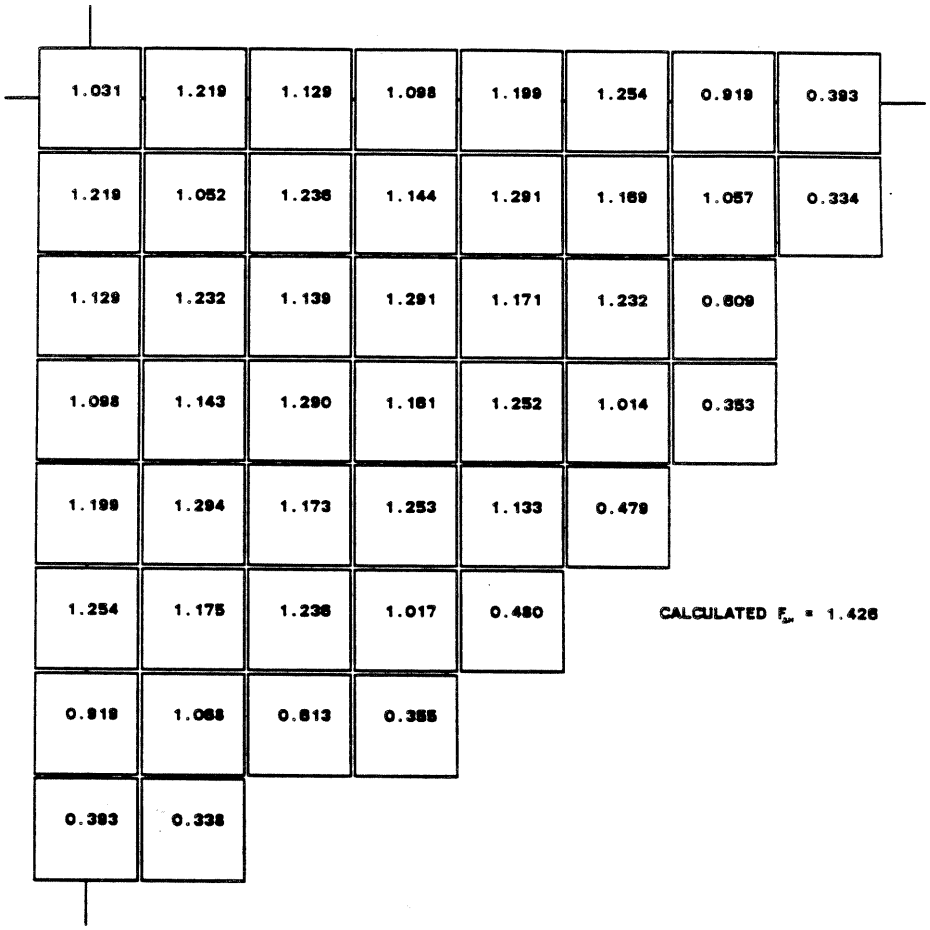
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Typical Burnable Absorber
Loading Pattern

Figure 4.3-5

Figure 4.3-6

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BEGINNING OF LIFE, UNRODDED CORE, HOT FULL POWER, NO XENON (TRANSITION CORE)



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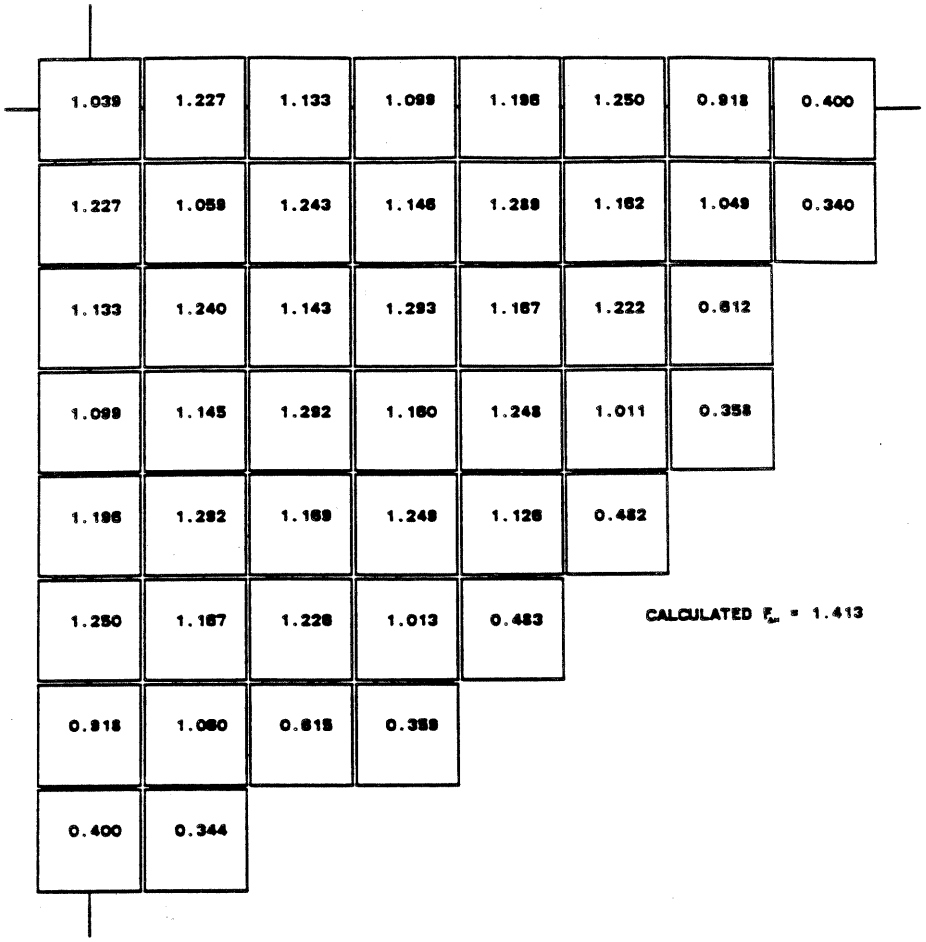
VIRGIL C. SUMMER NUCLEAR STATION

Normalized Power Density Distribution
Near Beginning of Life, Unrodded Core,
Hot Full Power, No Xenon
(Transition Core)

Figure 4.3-6

Figure 4.3-7

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BEGINNING OF LIFE, UNRODDED CORE, HOT FULL POWER, EQUILIBRIUM XENON (TRANSITION CORE)



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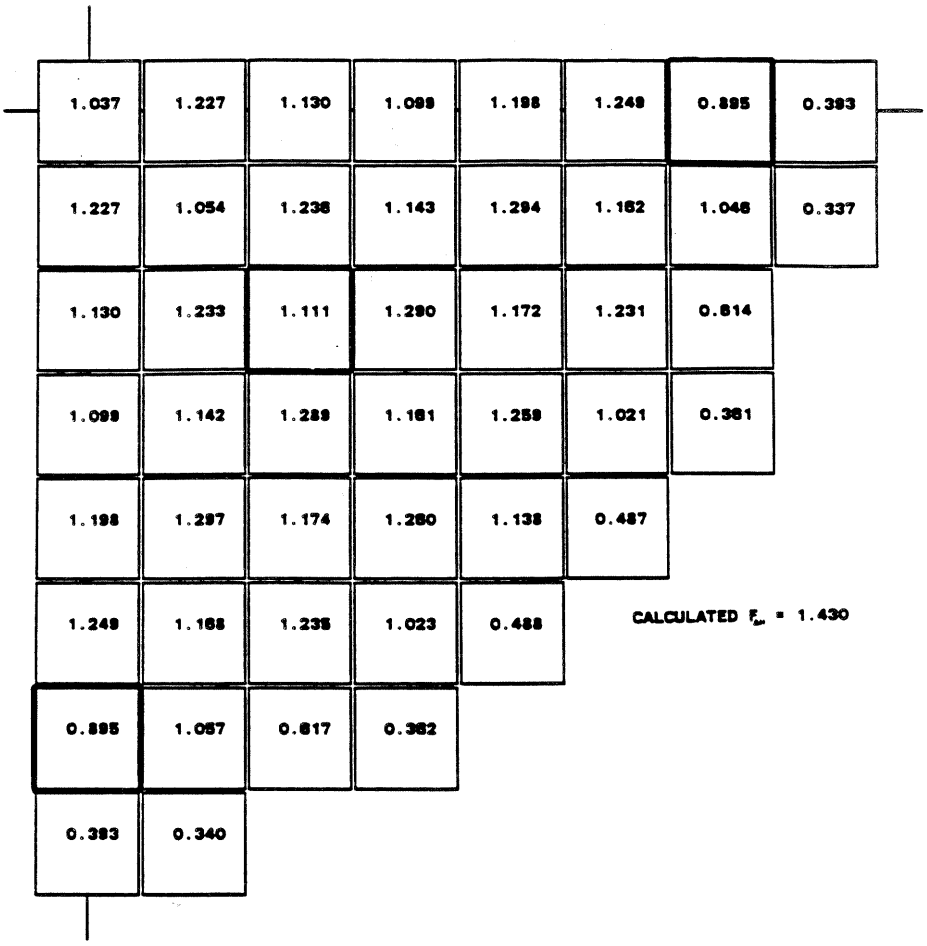
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Normalized Power Density Distribution Near Beginning of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon (Transition Core) Figure 4.3-7

Figure 4.3-8

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BEGINNING OF LIFE, GROUP D AT HFP INSERTION LIMIT, HOT FULL POWER, EQUILIBRIUM XENON (TRANSITION CORE)



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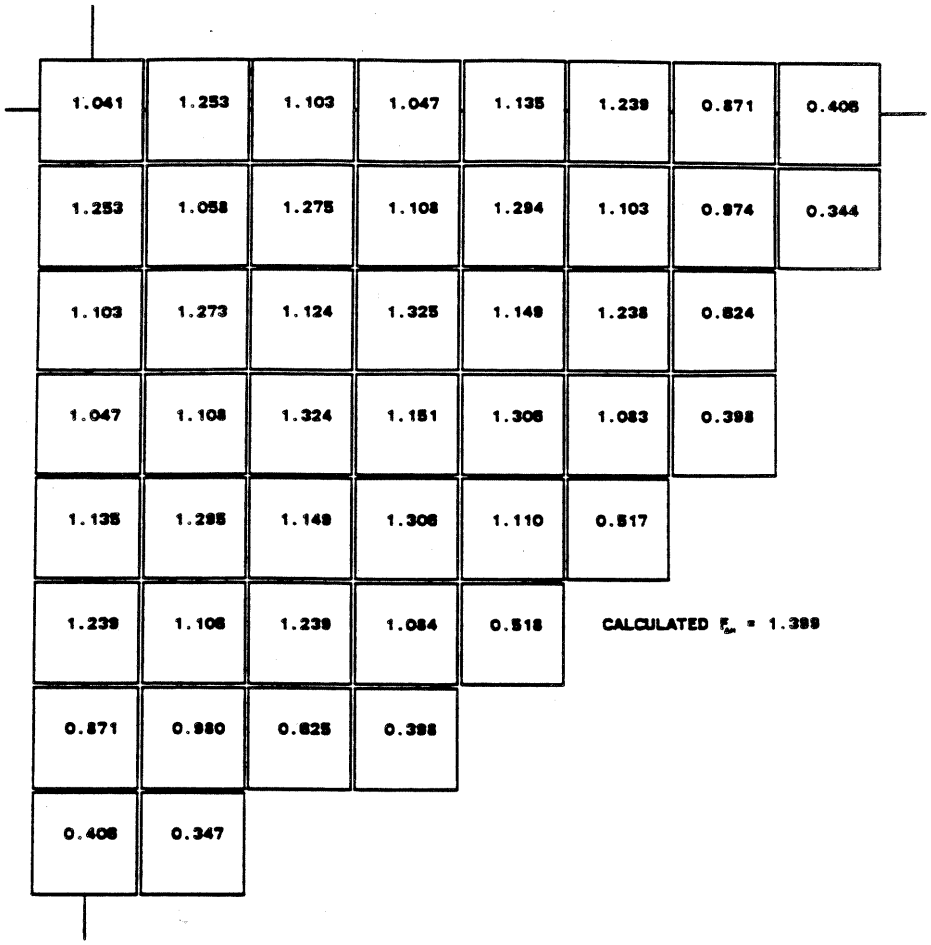
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Normalized Power Density Distribution Near Beginning of Life, Group D at HFP Insertion Limit, Hot Full Power, Equilibrium Xenon (Transition Core) Figure 4.3-8

Figure 4.3-9

NORMALIZED POWER DENSITY DISTRIBUTION
NEAR MIDDLE OF LIFE, UNRODDED CORE,
HOT FULL POWER, EQUILIBRIUM XENON (TRANSITION CORE)



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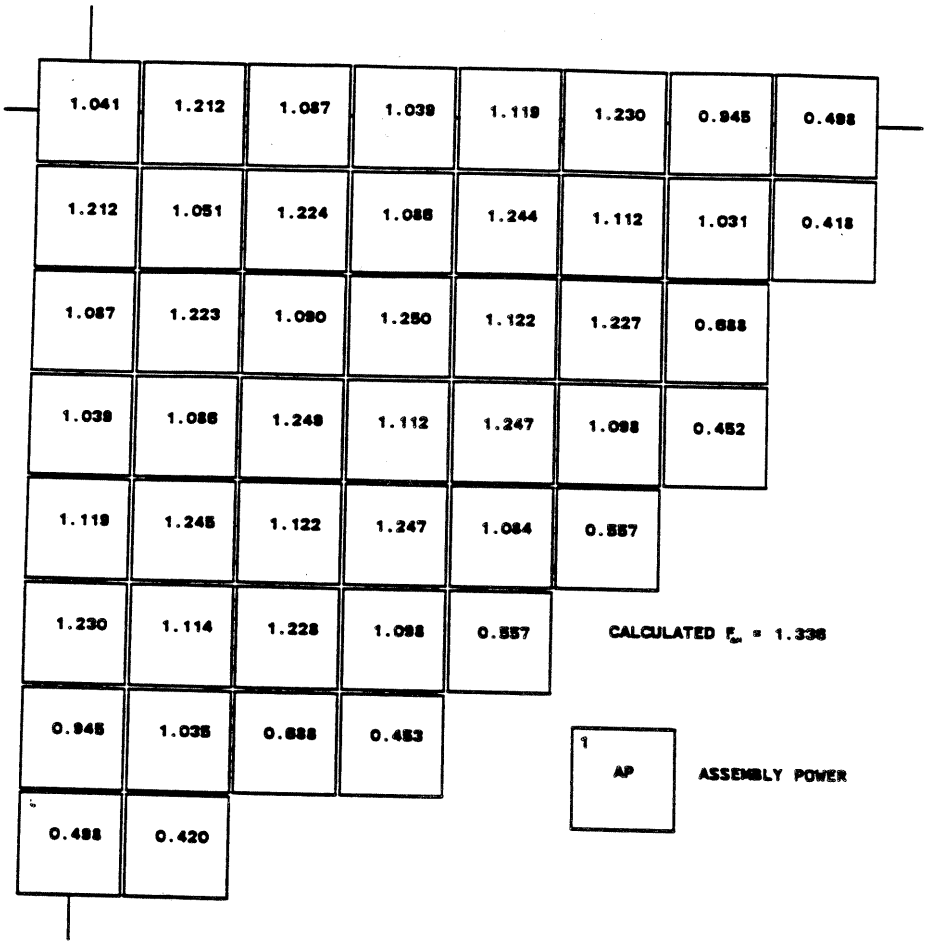
VIRGIL C. SUMMER NUCLEAR STATION

Normalized Power Density Distribution
Near Middle of Life, Unrodded Core,
Hot Full Power, Equilibrium Xenon
(Transition Core)

Figure 4.3-9

Figure 4.3-10

NORMALIZED POWER DENSITY DISTRIBUTION
NEAR END OF LIFE, UNRODDED CORE,
HOT FULL POWER, EQUILIBRIUM XENON (TRANSITION CORE)



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SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Normalized Power Density Distribution Near End of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon (Transition Core) Figure 4.3-10

Figure 4.3-11

NORMALIZED POWER DENSITY DISTRIBUTION NEAR BEGINNING OF LIFE, UNRODDED CORE, HOT FULL POWER, NO XENON (EQUILIBRIUM CORE)

0.811	1.131	1.019	1.293	1.196	1.384	0.855	0.304
1.131	0.978	1.220	1.174	1.361	1.205	1.030	0.285
1.019	1.221	1.074	1.350	1.234	1.295	0.564	
1.293	1.173	1.349	1.283	1.373	1.118	0.318	
1.196	1.359	1.231	1.371	0.755	0.378		
1.384	1.200	1.291	1.115	0.378			
0.855	1.021	0.561	0.317				
0.304	0.282						

CALCULATED $F_{\Delta H} = 1.556$

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Normalized Power Density Distribution
Near Beginning of Life, Unrodded Core,
Hot Full Power, No Xenon
(Equilibrium Core)

Figure 4.3-11

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Figure 4.3-12

NORMALIZED POWER DENSITY DISTRIBUTION
NEAR BEGINNING OF LIFE, UNRODDED CORE,
HOT FULL POWER, EQUILIBRIUM XENON (EQUILIBRIUM CORE)

0.837	1.155	1.034	1.296	1.191	1.372	0.859	0.315
1.155	0.999	1.232	1.174	1.352	1.196	1.030	0.293
1.034	1.233	1.081	1.344	1.223	1.282	0.570	
1.296	1.174	1.343	1.271	1.357	1.110	0.324	
1.191	1.351	1.221	1.356	0.758	0.383		
1.372	1.191	1.279	1.108	0.383			
0.859	1.022	0.567	0.323				
0.315	0.291						

CALCULATED $F_{\Delta H}$ = 1.530

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Normalized Power Density Distribution
Near Beginning of Life, Unrodded Core,
Hot Full Power, Equilibrium Xenon
(Equilibrium Core)

Figure 4.3-12

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Figure 4.3-13

NORMALIZED POWER DENSITY DISTRIBUTION
NEAR BEGINNING OF LIFE, GROUP D AT HFP INSERTION LIMIT,
HOT FULL POWER, EQUILIBRIUM XENON (EQUILIBRIUM CORE)

0.837	1.157	1.033	1.298	1.193	1.369	0.836	0.310
1.157	0.995	1.224	1.172	1.357	1.198	1.028	0.292
1.033	1.225	1.046	1.338	1.227	1.291	0.573	
1.298	1.171	1.337	1.271	1.366	1.121	0.327	
1.193	1.355	1.225	1.365	0.764	0.387		
1.369	1.193	1.288	1.119	0.387			
0.836	1.020	0.570	0.327				
0.310	0.289						

CALCULATED $F_{\Delta H}$ = 1.484

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Normalized Power Density Distribution Near Beginning of Life, Group D at HFP Insertion Limit, Hot Full Power, Equilibrium Xenon (Equilibrium Core) Figure 4.3-13

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Figure 4.3-14

NORMALIZED POWER DENSITY DISTRIBUTION
NEAR MIDDLE OF LIFE, UNRODDED CORE,
HOT FULL POWER, EQUILIBRIUM XENON (EQUILIBRIUM CORE)

0.933	1.288	1.087	1.355	1.149	1.326	0.843	0.346
1.288	1.072	1.333	1.168	1.355	1.126	0.994	0.318
1.087	1.334	1.099	1.366	1.158	1.245	0.580	
1.355	1.167	1.365	1.206	1.311	1.055	0.341	
1.149	1.354	1.158	1.310	0.759	0.400		
1.326	1.124	1.244	1.055	0.400			
0.843	0.989	0.579	0.341				
0.346	0.316						

CALCULATED $F_{\Delta H} = 1.439$

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Normalized Power Density Distribution Near Middle of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon (Equilibrium Core) Figure 4.3-14

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Figure 4.3-15

NORMALIZED POWER DENSITY DISTRIBUTION
NEAR END OF LIFE, UNRODDED CORE,
HOT FULL POWER, EQUILIBRIUM XENON (EQUILIBRIUM CORE)

0.955	1.269	1.063	1.277	1.107	1.312	0.919	0.448
1.269	1.059	1.271	1.116	1.280	1.117	1.059	0.400
1.063	1.271	1.064	1.281	1.118	1.249	0.653	
1.277	1.115	1.281	1.152	1.285	1.078	0.403	
1.107	1.280	1.118	1.285	0.814	0.461		
1.312	1.116	1.249	1.078	0.461			
0.919	1.056	0.652	0.403				
0.448	0.400						

CALCULATED $F_{\Delta H}$ = 1.373

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Normalized Power Density Distribution Near End of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon (Equilibrium Core) Figure 4.3-15

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Figure 4.3-16

RODWISE POWER DISTRIBUTION IN A TYPICAL ASSEMBLY (G-10) NEAR BOL, HFP, EQUILIBRIUM XENON UNRODDED CORE

1.246	1.240	1.248	1.266	1.276	1.291	1.285	1.292	1.301	1.293	1.287	1.285	1.281	1.273	1.257	1.252	1.261
1.239	1.178	1.200	1.298	1.251	1.285	1.258	1.335	1.370	1.337	1.260	1.359	1.257	1.306	1.210	1.190	1.257
1.245	1.198	1.312	1.382	1.403		1.387	1.388		1.391	1.391		1.411	1.383	1.324	1.214	1.266
1.260	1.295	1.380		1.427	1.423	1.291	1.282	1.384	1.284	1.296	1.430	1.427		1.396	1.314	1.285
1.268	1.346	1.388	1.425	1.328	1.427	1.378	1.284	1.406	1.297	1.383	1.436	1.339	1.440	1.417	1.267	1.296
1.280	1.346		1.418	1.424		1.426	1.416		1.418	1.423		1.436	1.435		1.371	1.312
1.270	1.246	1.377	1.284	1.372	1.423	1.385	1.311	1.423	1.315	1.393	1.435	1.387	1.302	1.401	1.273	1.305
1.274	1.219	1.375	1.271	1.285	1.409	1.308	1.389	1.435	1.284	1.316	1.422	1.302	1.291	1.402	1.251	1.312
1.278	1.249		1.378	1.391		1.416	1.431		1.436	1.425		1.411	1.403		1.385	1.320
1.265	1.311	1.367	1.269	1.280	1.404	1.304	1.396	1.432	1.391	1.314	1.420	1.300	1.290	1.401	1.349	1.310
1.253	1.231	1.362	1.271	1.360	1.413	1.377	1.306	1.417	1.310	1.389	1.431	1.384	1.299	1.398	1.270	1.302
1.254	1.321		1.397	1.407		1.413	1.406		1.412	1.427		1.433	1.431		1.367	1.307
1.233	1.216	1.369	1.398	1.307	1.406	1.362	1.282	1.394	1.288	1.376	1.429	1.333	1.434	1.412	1.262	1.290
1.217	1.256	1.345		1.400	1.400	1.274	1.368	1.382	1.274	1.288	1.423	1.431		1.390	1.306	1.278
1.182	1.185	1.271	1.346	1.372		1.366	1.372		1.380	1.382		1.404	1.386	1.318	1.207	1.258
1.174	1.126	1.157	1.260	1.220	1.327	1.237	1.317	1.356	1.328	1.252	1.382	1.251	1.301	1.204	1.183	1.248
1.165	1.177	1.198	1.225	1.242	1.264	1.263	1.278	1.358	1.383	1.280	1.389	1.276	1.368	1.252	1.245	1.252

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SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Rodwise Power Distribution in a Typical Assembly (G-10) Near BOL, HFP, Equilibrium Xenon, Unrodded Core

Figure 4.3-16

Figure 4.3-17

RODWISE POWER DISTRIBUTION IN A TYPICAL ASSEMBLY (G-10) NEAR EOL, HFP, EQUILIBRIUM XENON, UNRODDED CORE

1.138	1.136	1.142	1.155	1.167	1.180	1.177	1.179	1.185	1.180	1.181	1.186	1.175	1.165	1.155	1.151	1.156
1.133	1.164	1.181	1.181	1.227	1.233	1.236	1.212	1.238	1.213	1.240	1.239	1.235	1.191	1.184	1.180	1.153
1.138	1.179	1.190	1.245	1.266		1.264	1.264		1.266	1.268		1.275	1.256	1.204	1.187	1.160
1.148	1.177	1.243		1.288	1.288	1.276	1.274	1.279	1.277	1.282	1.286	1.288		1.259	1.196	1.173
1.159	1.221	1.262	1.286	1.299	1.292	1.258	1.284	1.288	1.286	1.284	1.301	1.311	1.301	1.280	1.243	1.186
1.169	1.228		1.284	1.290		1.292	1.293		1.296	1.298		1.303	1.301		1.250	1.198
1.163	1.225	1.256	1.270	1.284	1.289	1.262	1.291	1.297	1.295	1.270	1.300	1.268	1.289	1.278	1.252	1.196
1.162	1.198	1.253	1.265	1.276	1.288	1.289	1.266	1.299	1.270	1.297	1.300	1.293	1.286	1.278	1.228	1.197
1.166	1.221		1.266	1.278		1.292	1.296		1.300	1.301		1.296	1.289		1.254	1.204
1.157	1.193	1.248	1.261	1.273	1.285	1.296	1.264	1.298	1.269	1.287	1.300	1.293	1.286	1.278	1.228	1.198
1.152	1.214	1.246	1.262	1.247	1.284	1.258	1.288	1.295	1.294	1.269	1.300	1.269	1.290	1.279	1.254	1.197
1.152	1.210		1.272	1.280		1.295	1.288		1.294	1.298		1.304	1.303		1.252	1.201
1.136	1.200	1.244	1.270	1.286	1.282	1.290	1.277	1.284	1.284	1.263	1.301	1.312	1.303	1.283	1.246	1.190
1.120	1.181	1.220		1.272	1.275	1.266	1.267	1.274	1.274	1.281	1.297	1.300		1.263	1.201	1.177
1.102	1.147	1.183	1.222	1.247		1.252	1.256		1.263	1.268		1.277	1.260	1.209	1.202	1.166
1.089	1.125	1.149	1.195	1.206	1.216	1.223	1.202	1.232	1.210	1.239	1.240	1.238	1.195	1.189	1.185	1.160
1.083	1.091	1.107	1.126	1.144	1.161	1.163	1.169	1.179	1.177	1.180	1.187	1.178	1.169	1.160	1.157	1.163

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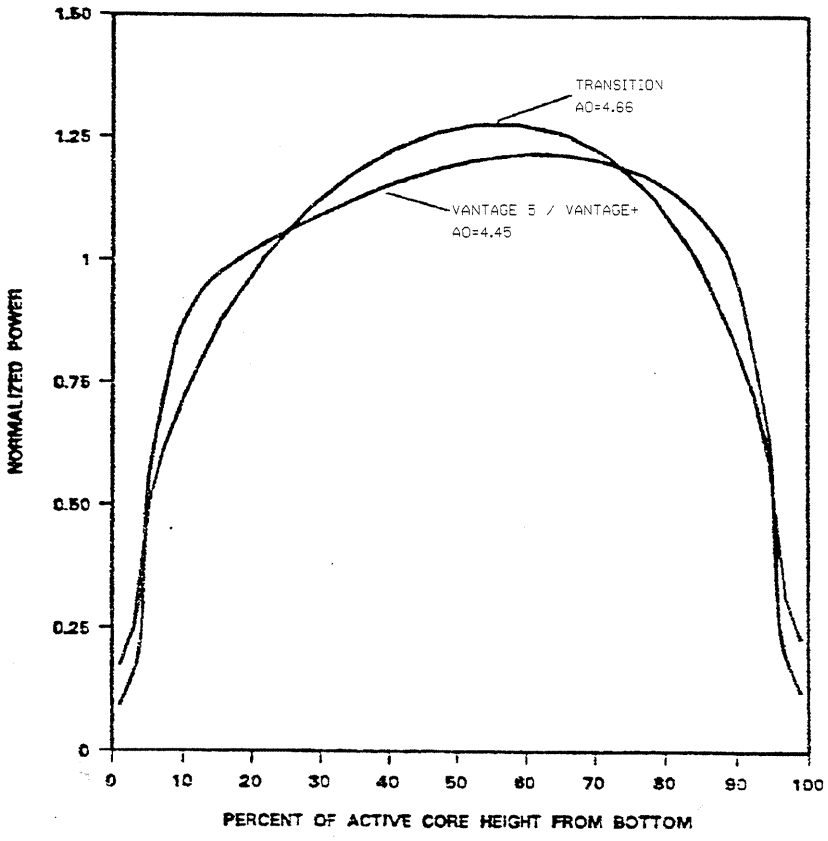
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Rodwise Power Distribution in a Typical Assembly (G-10) Near EOL, HFP, Equilibrium Xenon, Unrodded Core

Figure 4.3-17

Figure 4.3-18
TYPICAL AXIAL POWER SHAPES OCCURRING AT BEGINNING OF LIFE



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Typical Axial Power Shapes Occurring at Beginning of Life Figure 4.3-18

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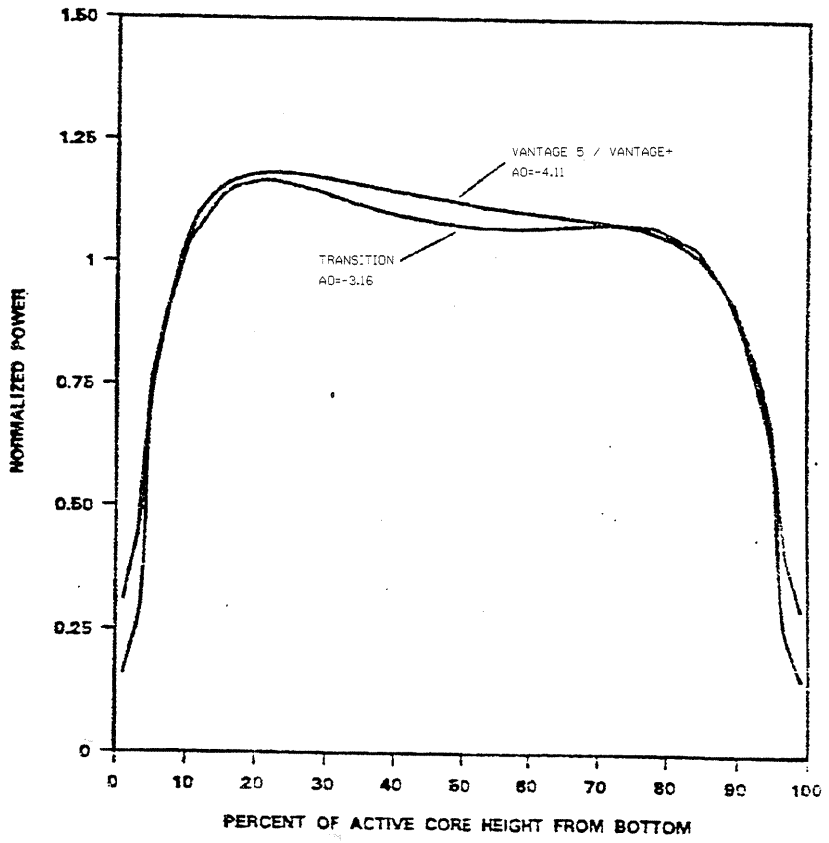
fsar4318.rn(360.jr14325) JR14325@jr14325. Wed Jul 3 11:03:18 EDT 1996

Figure 4.3-19
TYPICAL AXIAL POWER SHAPES OCCURRING AT MIDDLE OF LIFE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Axial Power Shapes Occurring at Middle of Life Figure 4.3-19

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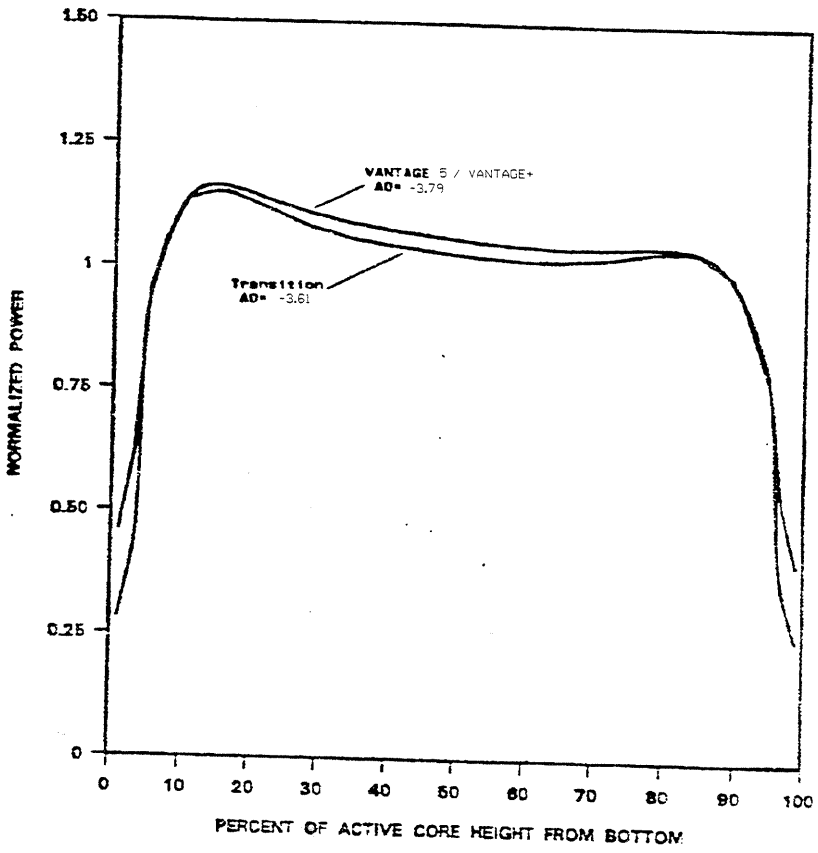
fsar4319.m(361.jr14325) JR14325@jr14325. Wed Jul 3 11:06:12 EDT 1996

Figure 4.3-20

TYPICAL AXIAL POWER SHAPES OCCURRING AT END OF LIFE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Typical Axial Power Shapes Occurring at End of Life
Figure 4.3-20

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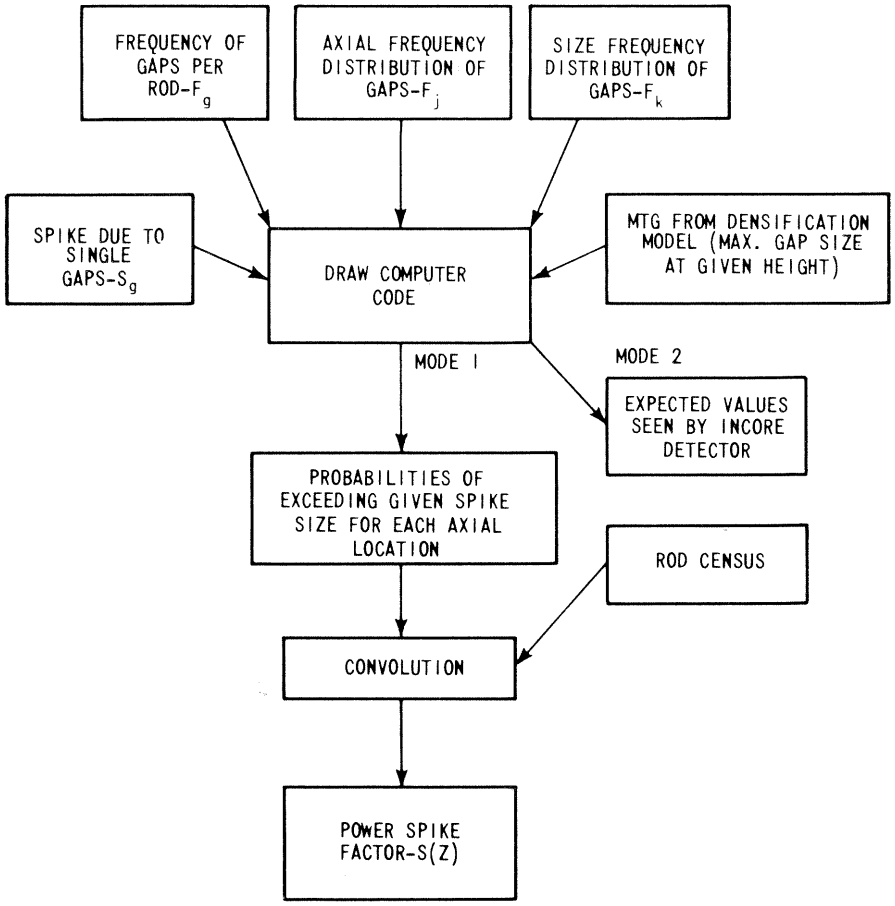
fsar4320.rn(358,jr14325) JR14325@jr14325. Wed Jul 3 10:54:09 EDT 1996

Figure 4.3-22
FLOWCHART FOR DETERMINING SPIKE MODEL



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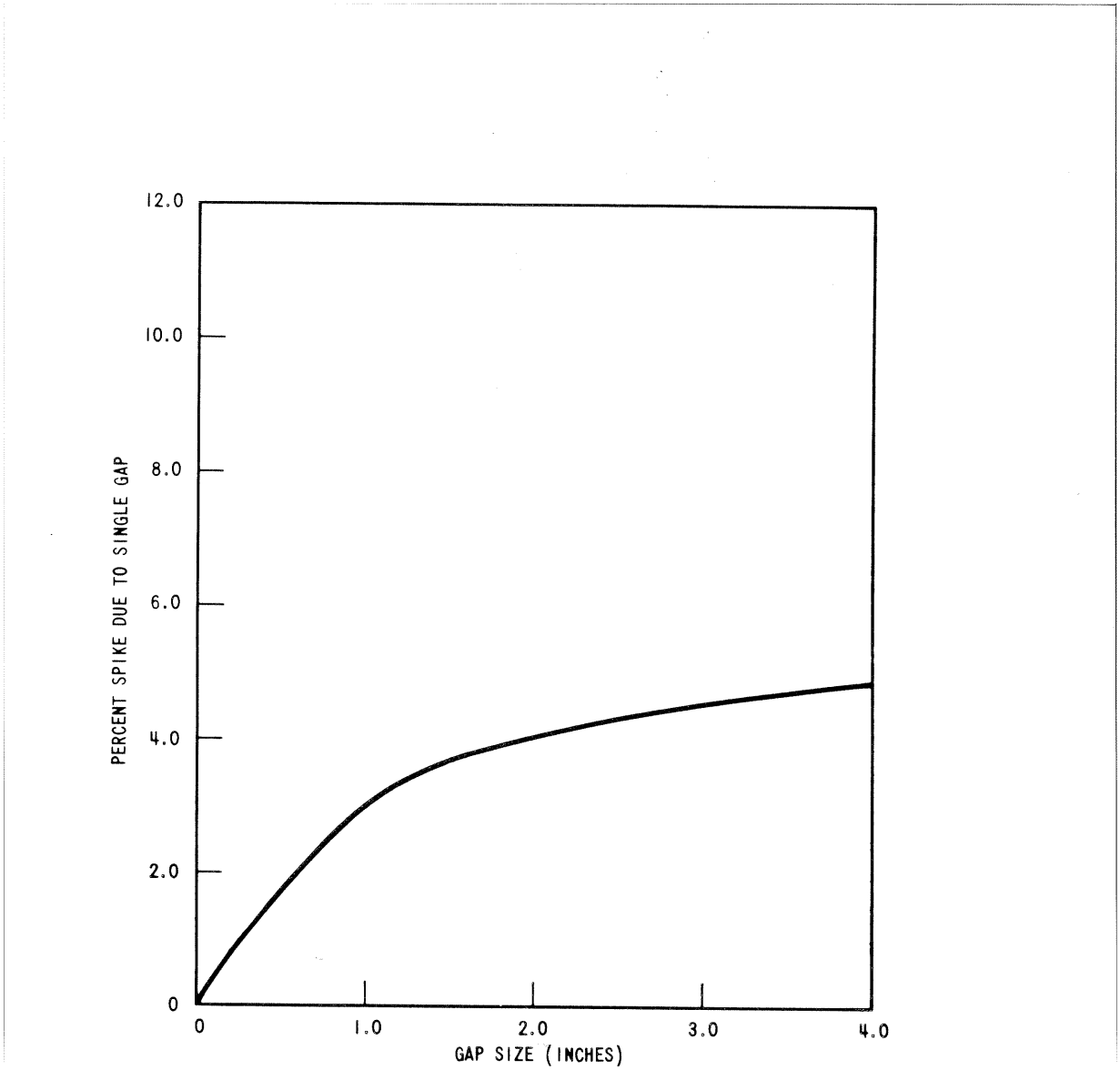
Flowchart for Determining Spike Model
Figure 4.3-22

Figure 4.3-23

PREDICTED POWER SPIKE DUE TO SINGLE NON-FLATTENED GAP IN THE ADJACENT FUEL



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Predicted Power Spike Due to Single Non-Flattened Gap in the Adjacent Fuel

Figure 4.3-23

Figure 4.3-24
POWER SPIKE FACTOR AS A FUNCTION OF AXIAL POSITION

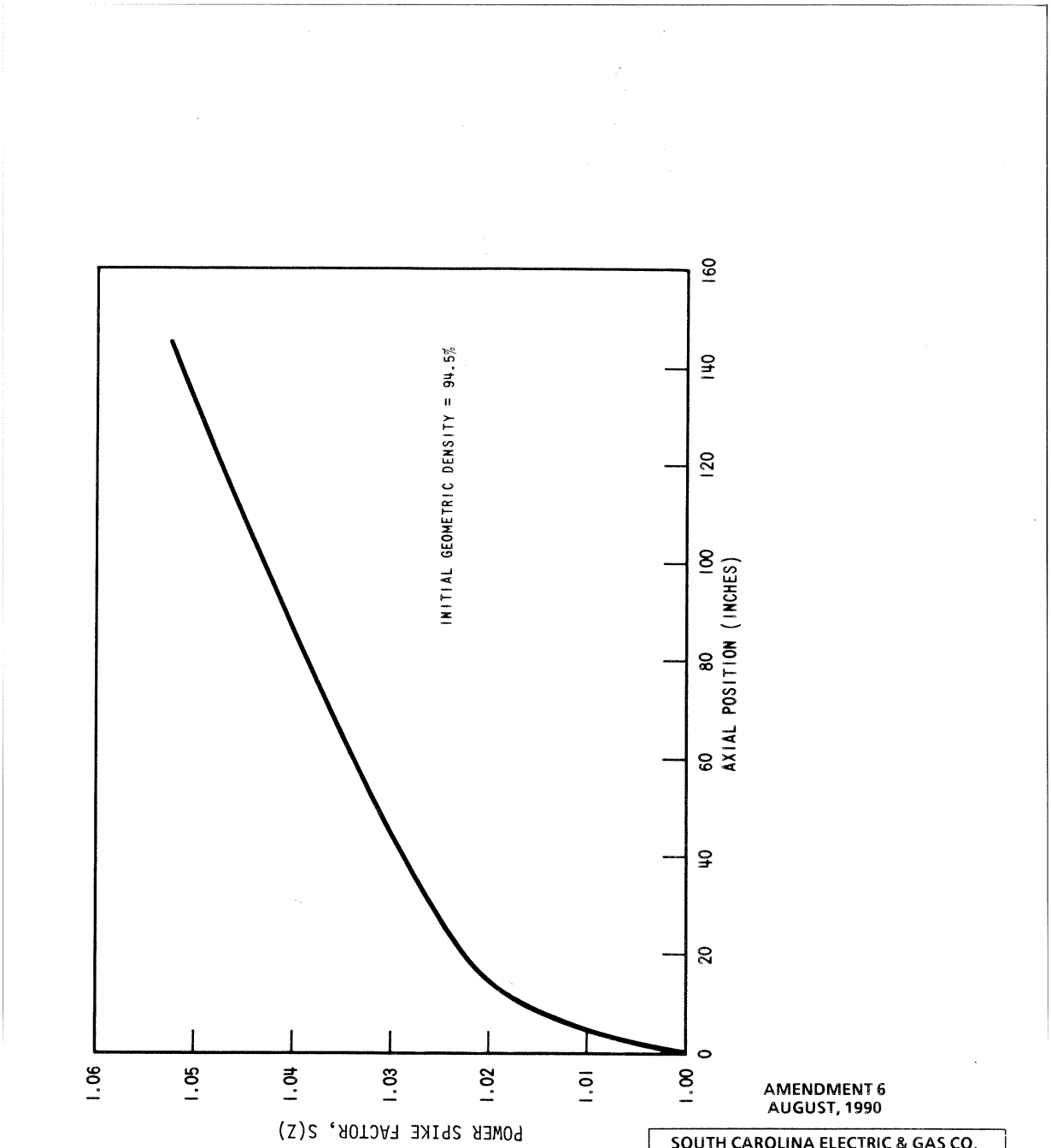
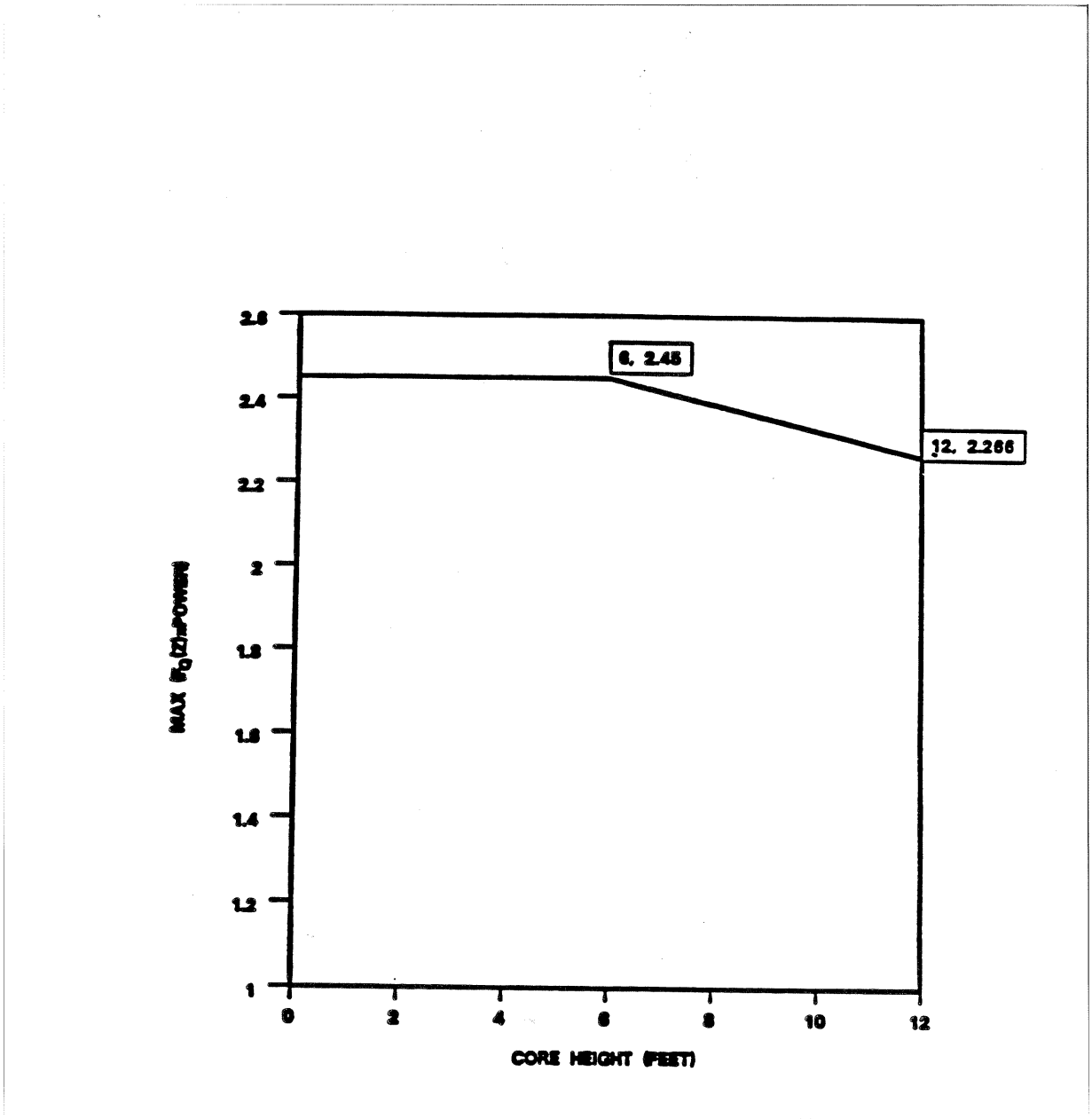


Figure 4.3-25

MAXIMUM F_Q X POWER VERSUS AXIAL HEIGHT DURING NORMAL OPERATION



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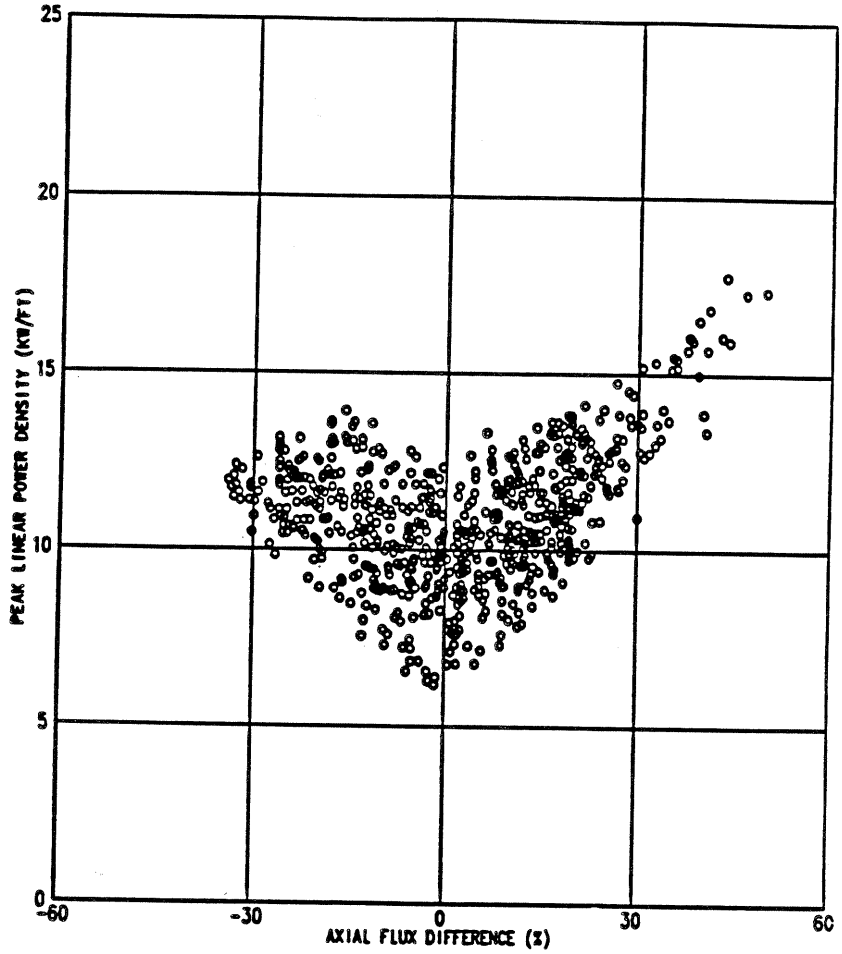
Maximum F_Q x Power Versus Axial Height During Normal Operation

Figure 4.3-25

Figure 4.3-26

PEAK POWER DURING CONTROL ROD MALFUNCTION OVERPOWER TRANSIENTS



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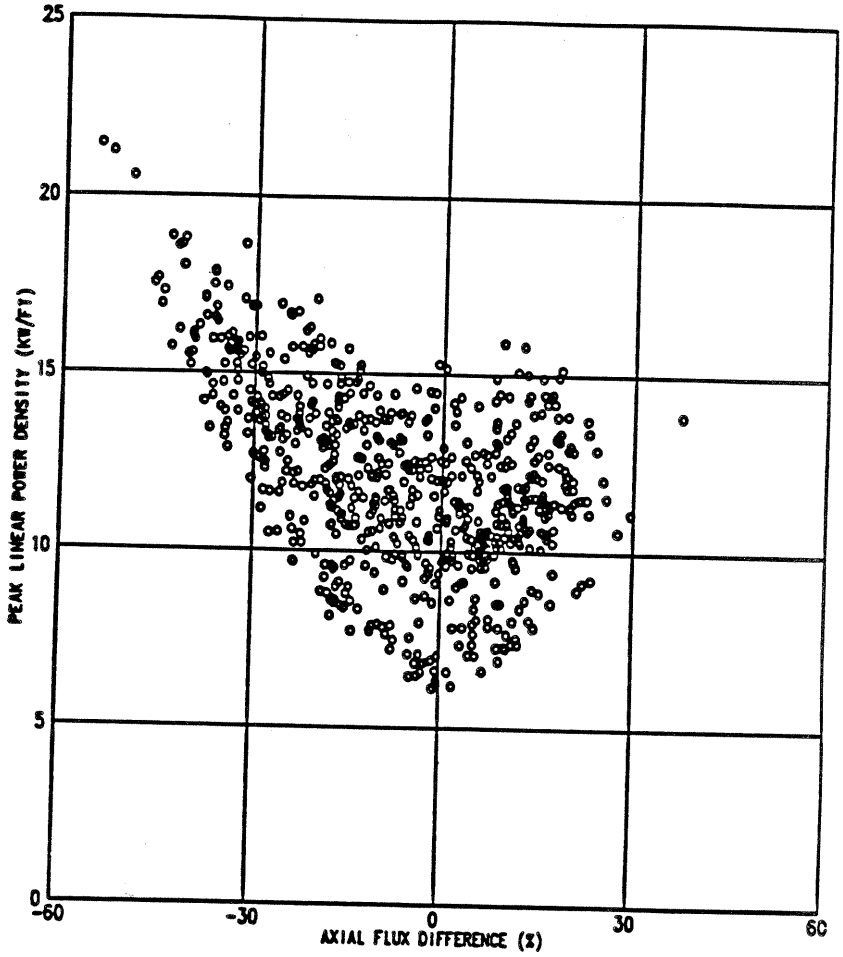
Peak Power During Control Rod
Malfunction Overpower Transients

Figure 4.3-26

Figure 4.3-27
PEAK POWER DURING BORATION/DILUTION OVERPOWER TRANSIENTS



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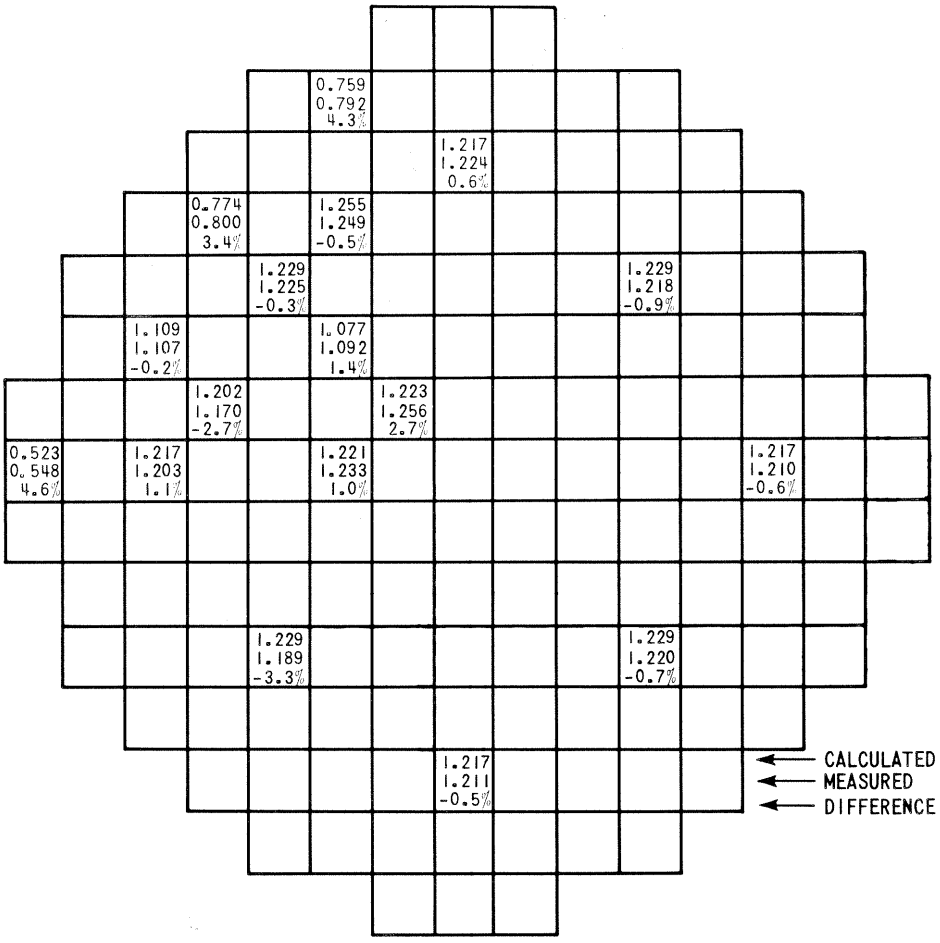
Peak Power During Boration/Dilution
Overpower Transients

Figure 4.3-27

Figure 4.3-28

COMPARISON BETWEEN CALCULATED AND MEASURED RELATIVE FUEL ASSEMBLY POWER DISTRIBUTION



PEAKING FACTORS

$\bar{F}_z$ = 1.5

$F^N_{\Delta H}$ = 1.357

F^N_Q = 2.07 LOCATED AT M-8 SOUTH

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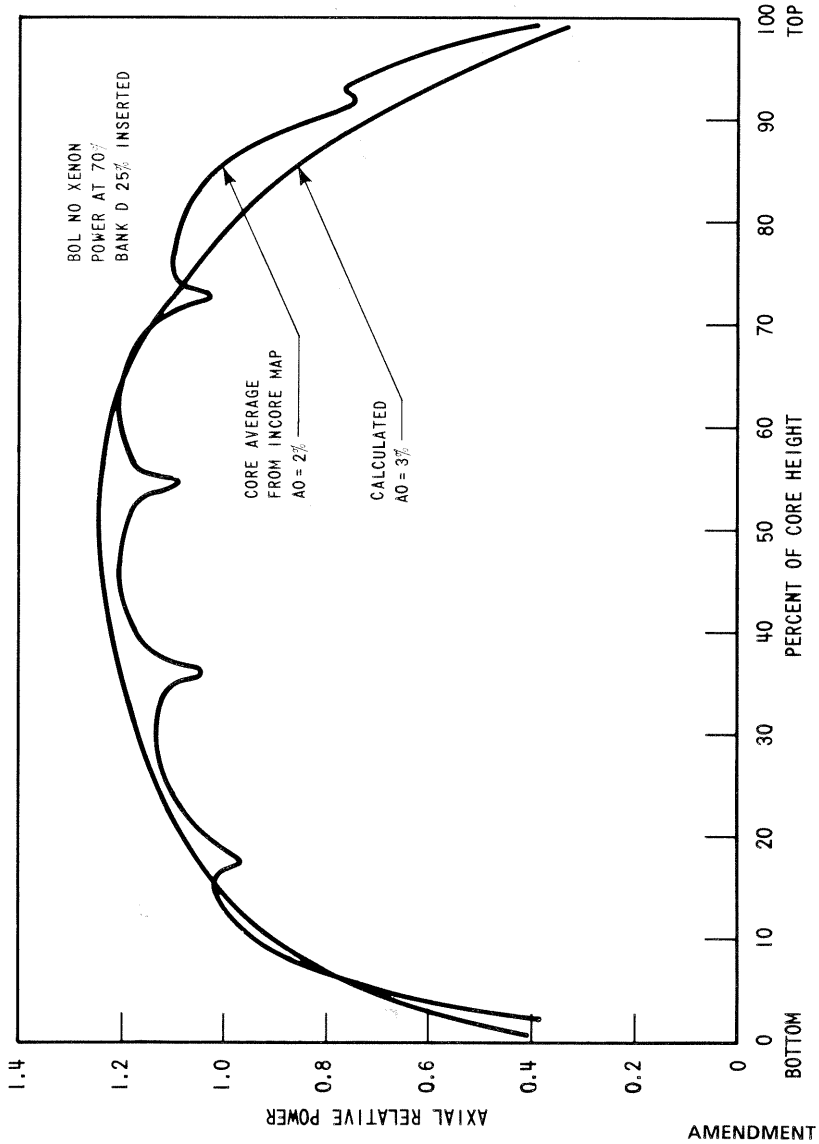
Comparison Between Calculated and Measured Relative Fuel Assembly Power Distribution Figure 4.3-28

Figure 4.3-29
COMPARISON OF CALCULATED AND MEASURED AXIAL SHAPE



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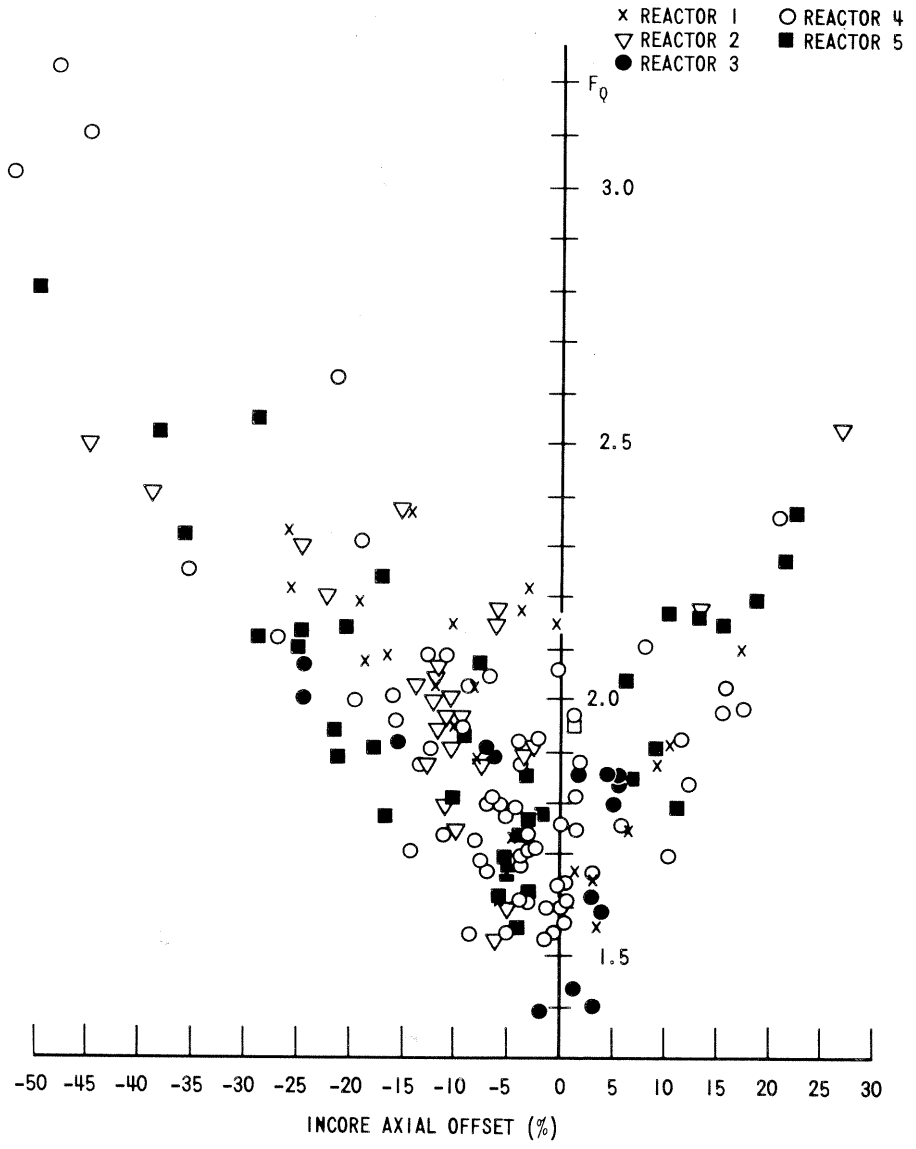
VIRGIL C. SUMMER NUCLEAR STATION

Comparison of Calculated
and Measured Axial Shape

Figure 4.3-29

Figure 4.3-30

MEASURED VALUES OF F_Q FOR FULL POWER ROD CONFIGURATION



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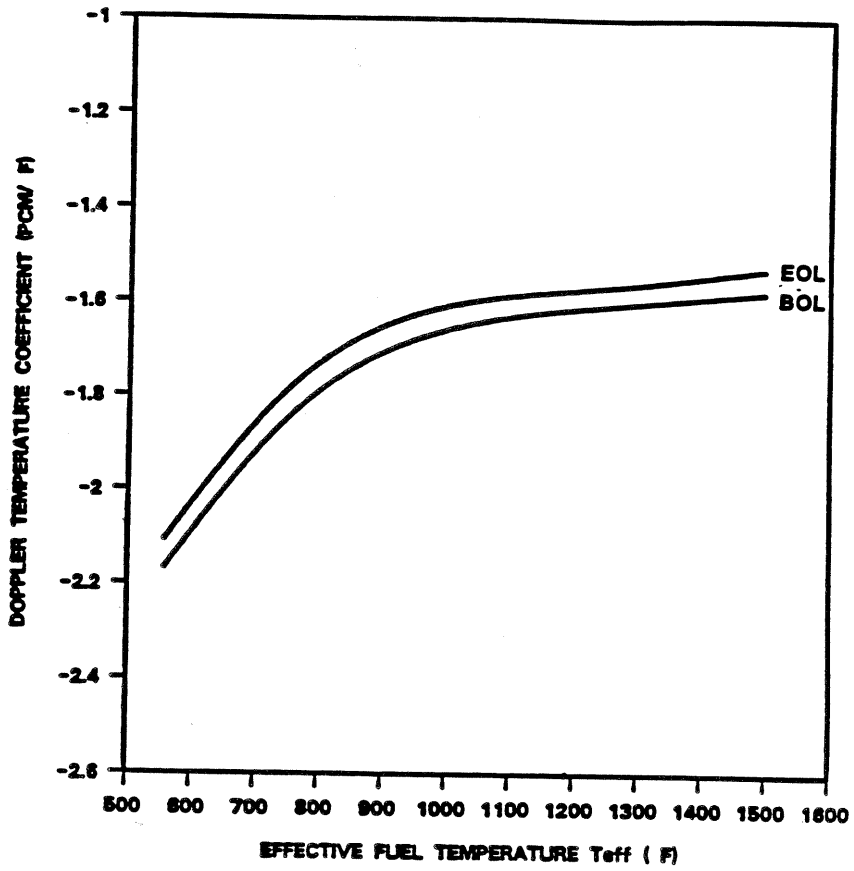
VIRGIL C. SUMMER NUCLEAR STATION

Measured Values of F_Q for
Full Power Rod Configurations

Figure 4.3-30

Figure 4.3-31
DOPPLER TEMPERATURE COEFFICIENT AT BOL AND EOL VERSUS T_{EFF} FOR A TYPICAL RELOAD CORE



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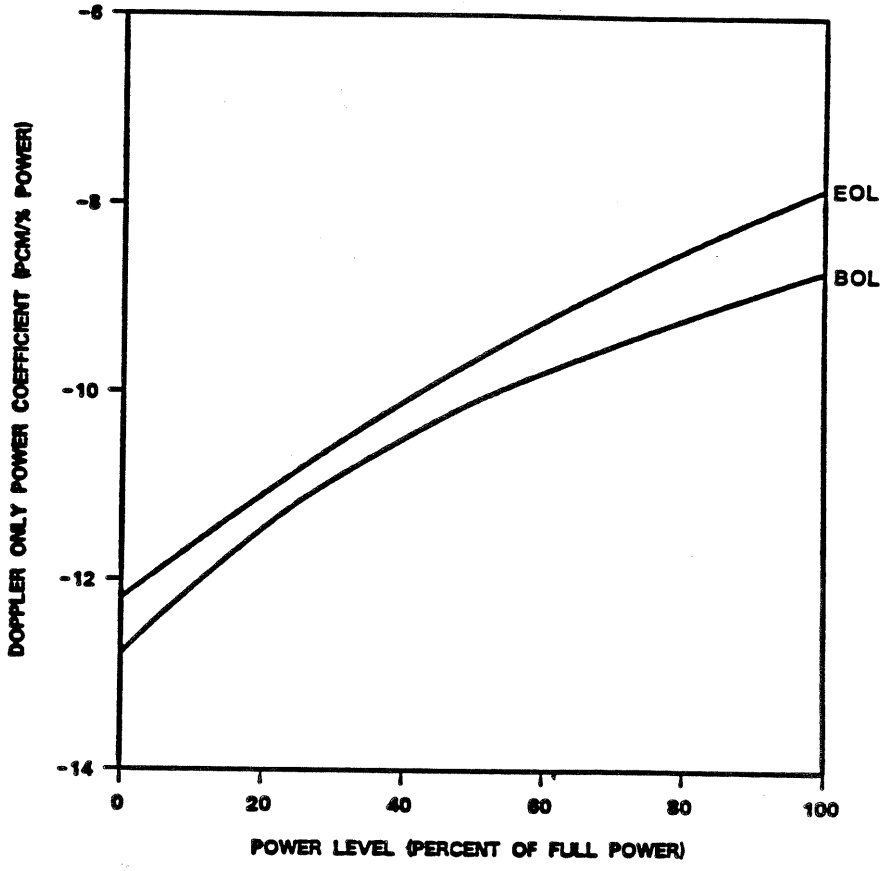
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Doppler Temperature Coefficient at BOL and EOL Versus T_{eff} for a Typical Reload Core Figure 4.3-31

Figure 4.3-32
DOPPLER ONLY POWER COEFFICIENT VERSUS POWER LEVEL AT BOL AND EOL FOR A TYPICAL RELOAD CORE



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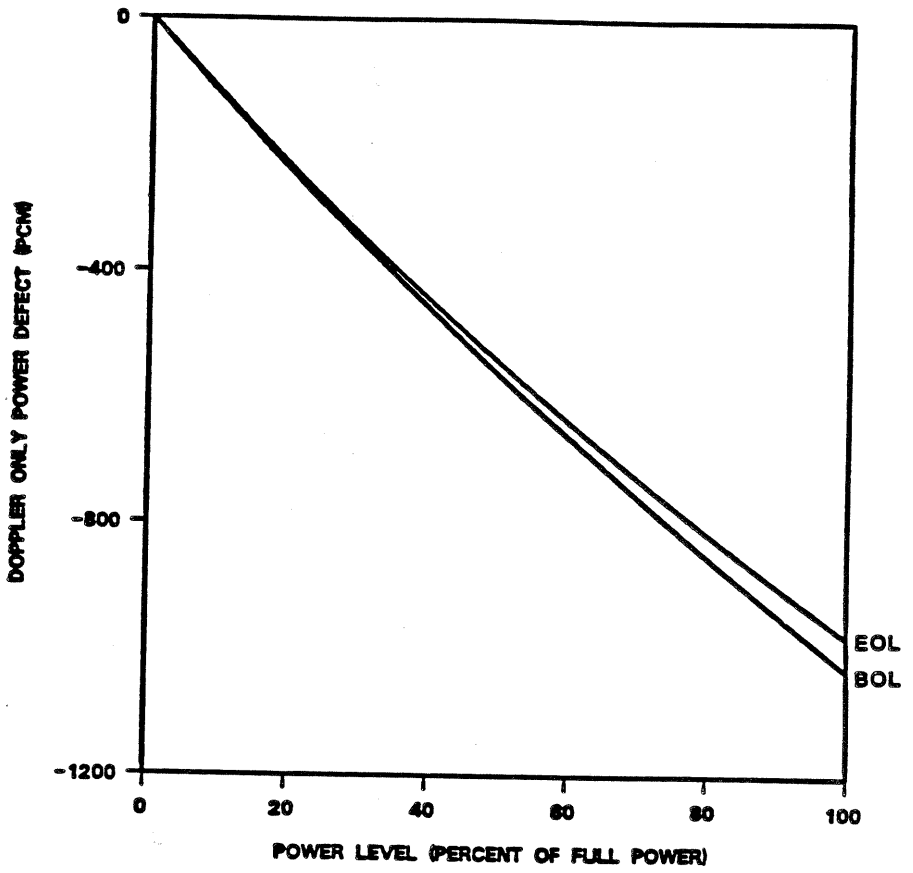
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Doppler Only Power Coefficient Versus Power Level at BOL and EOL for a Typical Reload Core Figure 4.3-32

Figure 4.3-33
DOPPLER ONLY POWER DEFECT VERSUS PERCENT POWER LEVEL AT BOL AND EOL FOR A TYPICAL RELOAD CORE



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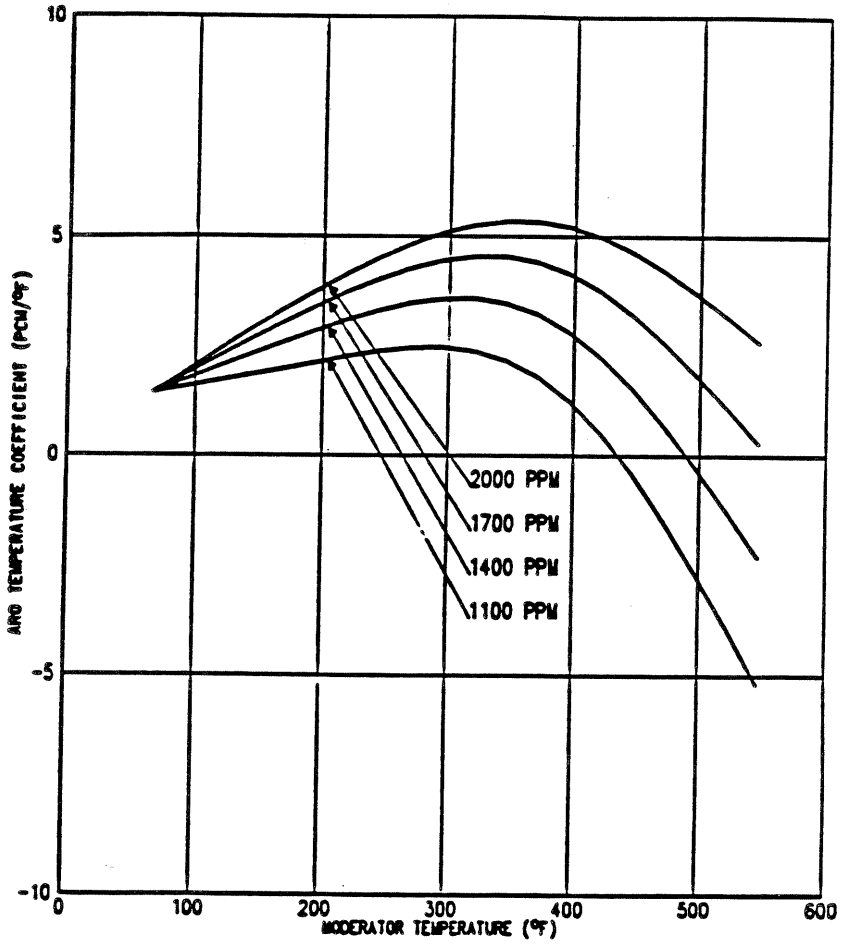
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Doppler Only Power Defect Versus Percent Power BOL and EOL for a Typical Reload Core Figure 4.3-33

Figure 4.3-34
MODERATOR TEMPERATURE COEFFICIENT
BOL, NO RODS, FOR A TYPICAL RELOAD CORE



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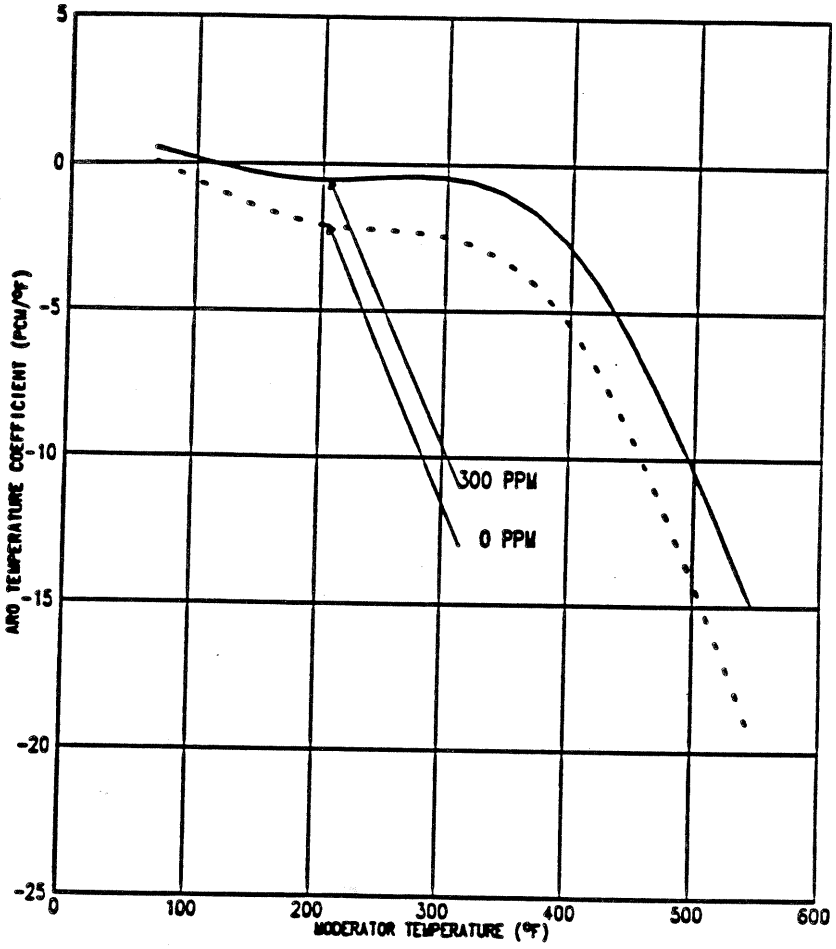
VIRGIL C. SUMMER NUCLEAR STATION

Moderator Temperature Coefficient
BOL, No Rods, for a Typical Reload Core

Figure 4.3-34

Figure 4.3-35
MODERATOR TEMPERATURE COEFFICIENT
EOL FOR A TYPICAL RELOAD CORE



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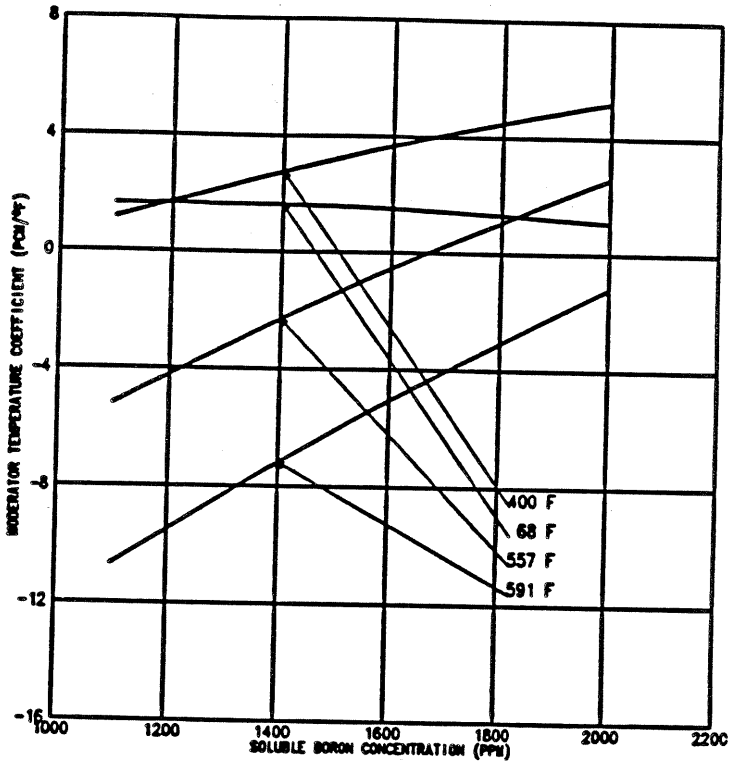
Moderator Temperature Coefficient EOL for a Typical Reload Core Figure 4.3-35

Figure 4.3-36

MODERATOR TEMPERATURE COEFFICIENT AS A FUNCTION OF BORON CONCENTRATION BOL, NO RODS, FOR A TYPICAL RELOAD CORE



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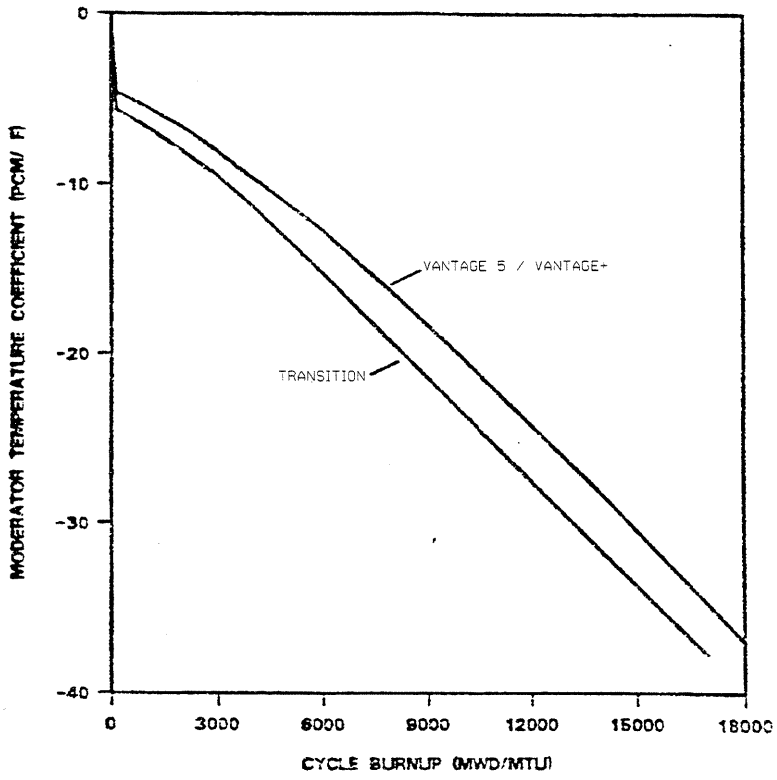
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Moderator Temperature Coefficient as a Function of Boron Concentration BOL, No Rods, for a Typical Reload Core Figure 4.3-36

Figure 4.3-37

HOT FULL POWER TEMPERATURE COEFFICIENT OF CRITICAL BORON CONCENTRATION VERSUS BURNUP



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Hot Full Power Temperature Coefficient at Critical Boron Concentration versus Burnup Figure 4.3-37

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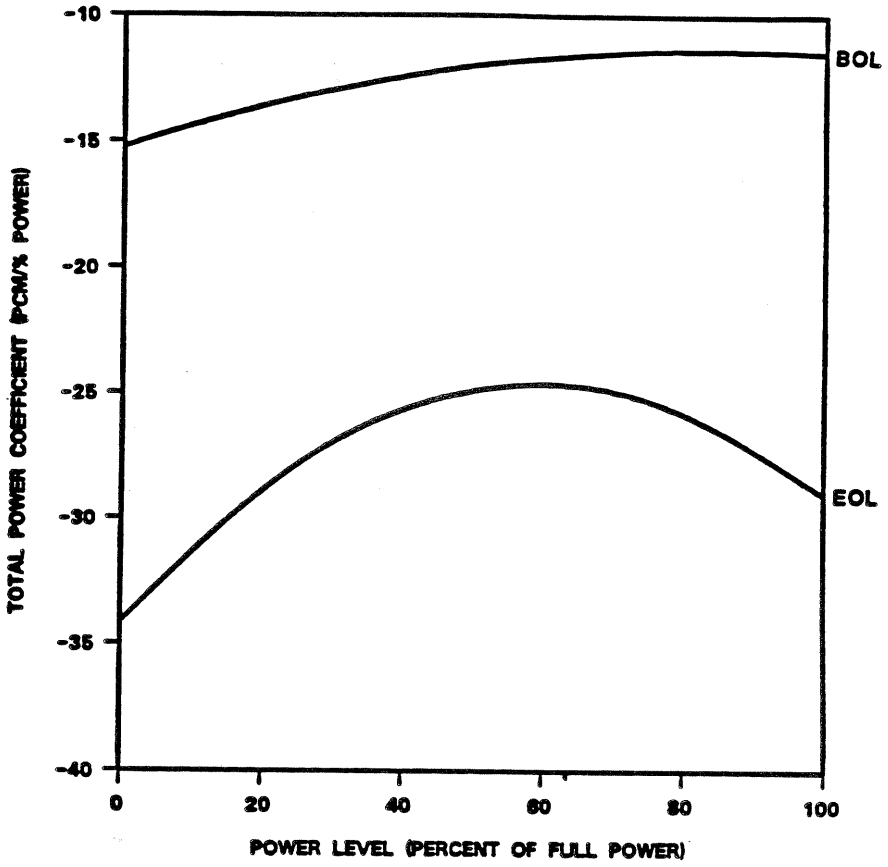
lsar4337.m(362,jr14325) JR14325@jr14325. Wed Jul 3 11:09:35 EDT 1996

Figure 4.3-38

TOTAL POWER COEFFICIENT VERSUS PERCENT POWER FOR BOL AND EOL ON A TYPICAL RELOAD CORE



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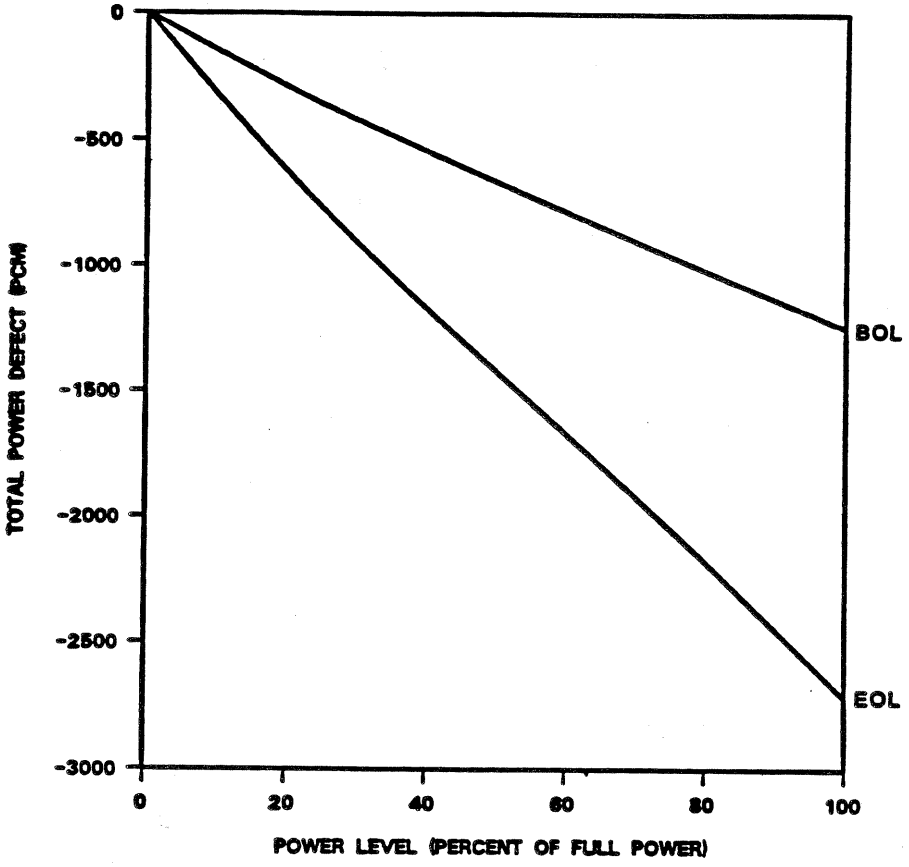
Total Power Coefficient Versus Percent Power for BOL and EOL on a Typical Reload Core Figure 4.3-38

Figure 4.3-39
TOTAL POWER DEFECT BOL, EOL, FOR A TYPICAL RELOAD CORE



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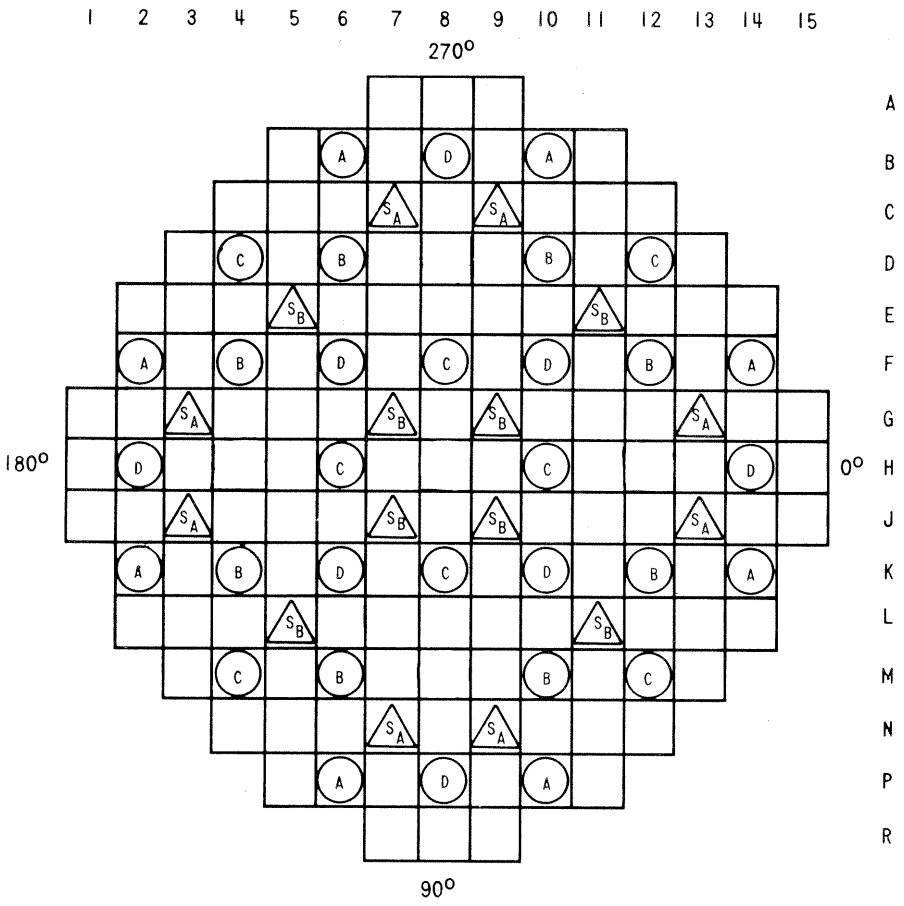
Total Power Defect BOL, EOL, for a Typical Reload Core Figure 4.3-39

Figure 4.3-40

ROD CLUSTER CONTROL ASSEMBLY PATTERN



FUNCTION	NUMBER OF CLUSTERS
CONTROL BANK D	8
CONTROL BANK C	8
CONTROL BANK B	8
CONTROL BANK A	8
SHUTDOWN BANK S_B	8
SHUTDOWN BANK S_A	8

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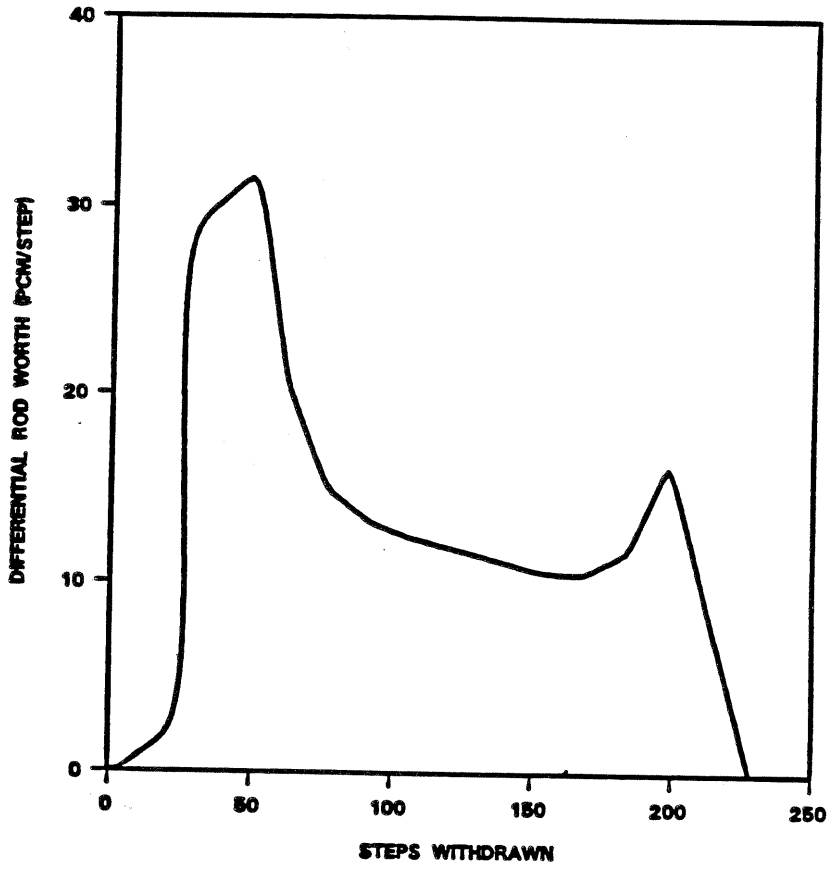
Rod Cluster Control Assembly Pattern
Figure 4.3-40

Figure 4.3-41
ACCIDENTAL SIMULTANEOUS WITHDRAWAL OF TWO CONTROL BANKS EOL, HZP BANKS D AND B MOVING IN THE SAME PLANE



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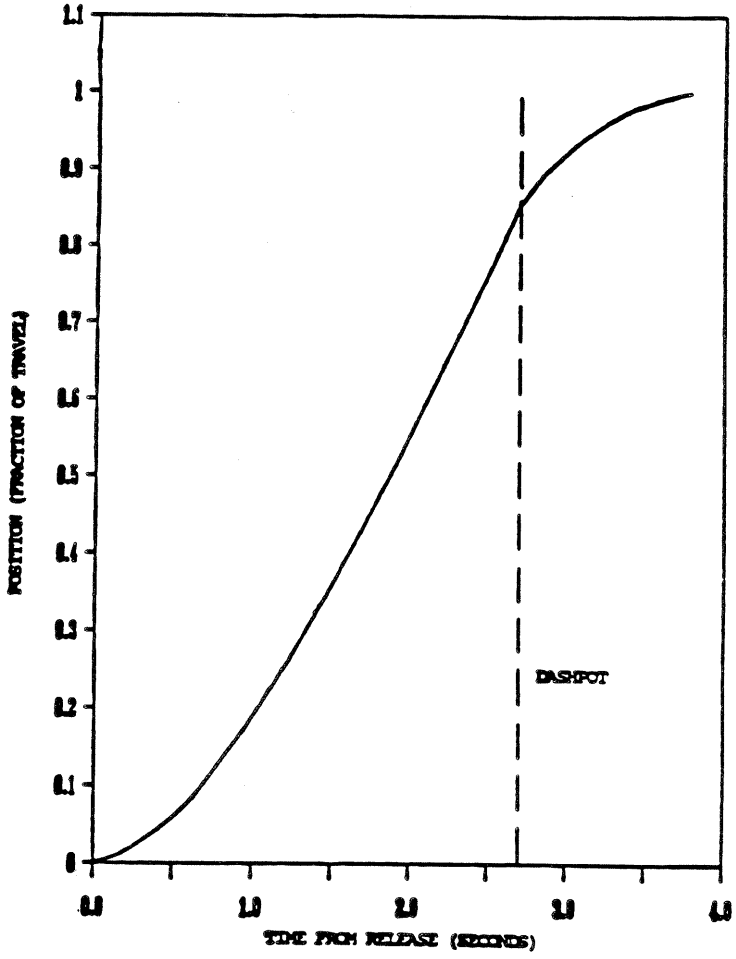
Accidental Simultaneous Withdrawal of Two Control Banks EOL, HZP Banks D and B Moving in the Same Plane Figure 4.3-41

Figure 4.3-42

ROD POSITION VERSUS TIME ON REACTOR TRIP:



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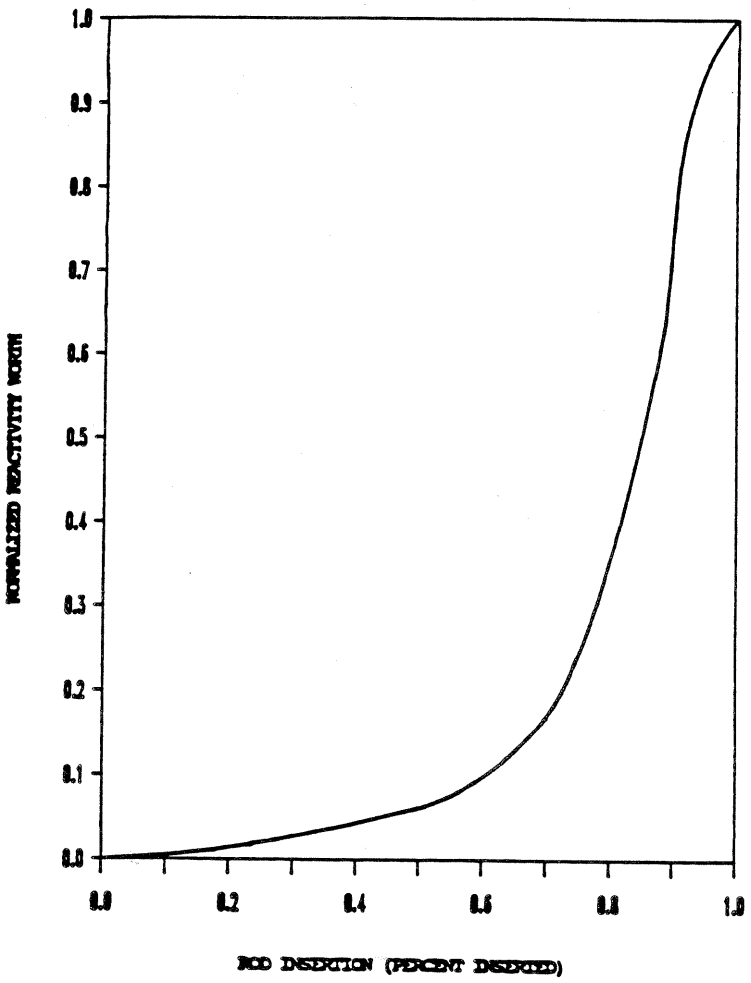
Rod Position Versus Time on Reactor Trip Figure 4.3-42

Figure 4.3-43
NORMALIZED RCCA REACTIVITY WORTH VERSUS PERCENT INSERTION



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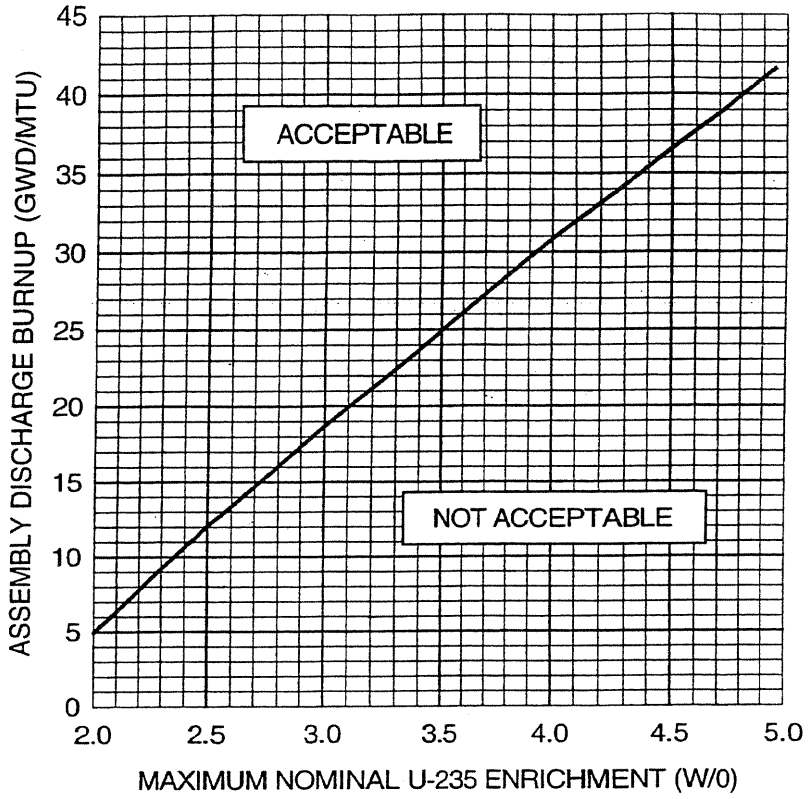
Normalized RCCA Reactivity Worth Versus Percent Insertion Figure 4.3-43

Figure 4.3-44

REQUIRED FUEL ASSEMBLY BURN-UP AS A FUNCTION OF INITIAL ENRICHMENT TO PERMIT STORAGE IN REGION 2 RACKS



Notes

1. Fuel assemblies with enrichments less than 2.0 W/O must meet the burn-up requirements of 2.0 W/O assemblies.
2. Use of the following polynomial fit is acceptable where E = Enrichment W/O:

   Assembly Discharge burnup = $0.1246\ E^3 - 1.91\ E^2 + 20.9205\ E - 30.2482$

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Required Fuel Assembly Burn-up as a Function of Initial Enrichment to permit Storage in Region 2 Racks Figure 4.3-44

Figure 4.3-45
DELETED PER RN 03-017, DECEMBER 2003

Figure 4.3-46

AXIAL OFFSET VERSUS TIME PWR CORE WITH A 12-FT. HEIGHT AND 121 ASSEMBLIES

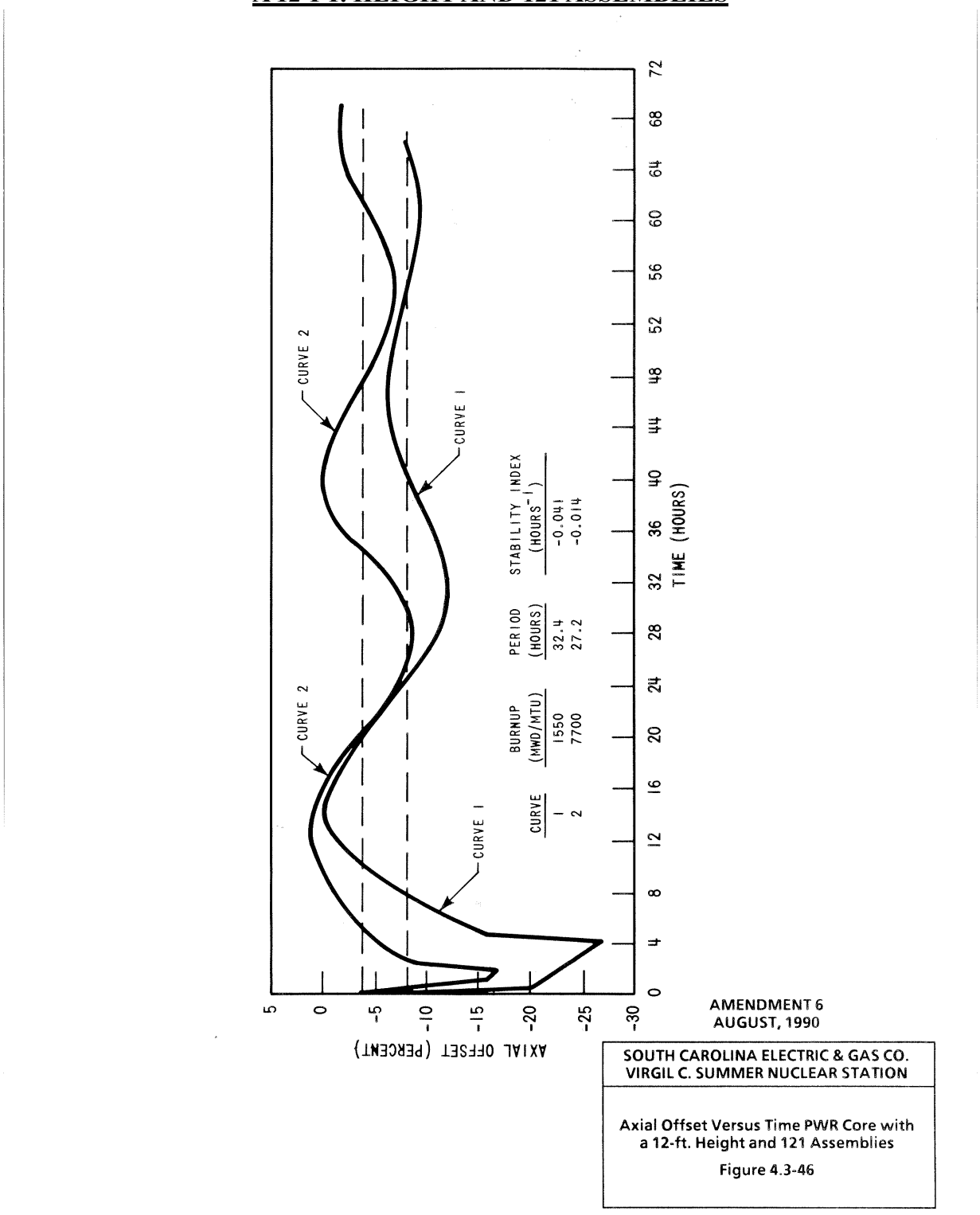
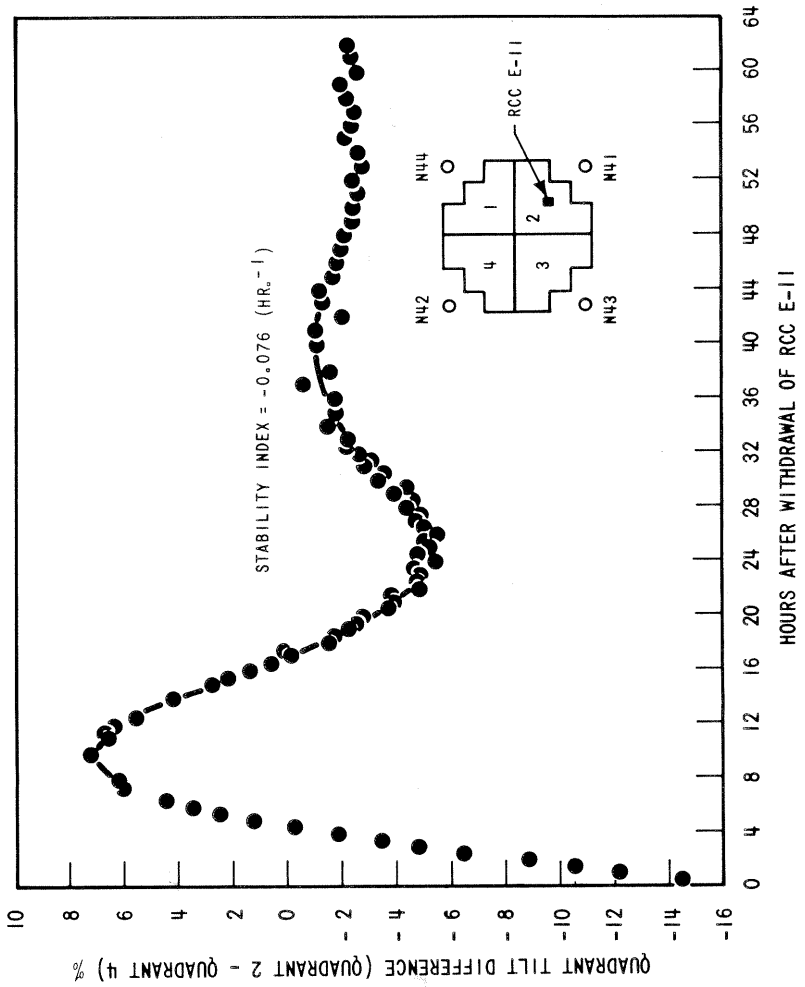


Figure 4.3-47
XY XENON TEST THERMOCOUPLE RESPONSE
QUADRANT TILT DIFFERENCE VERSUS TIME



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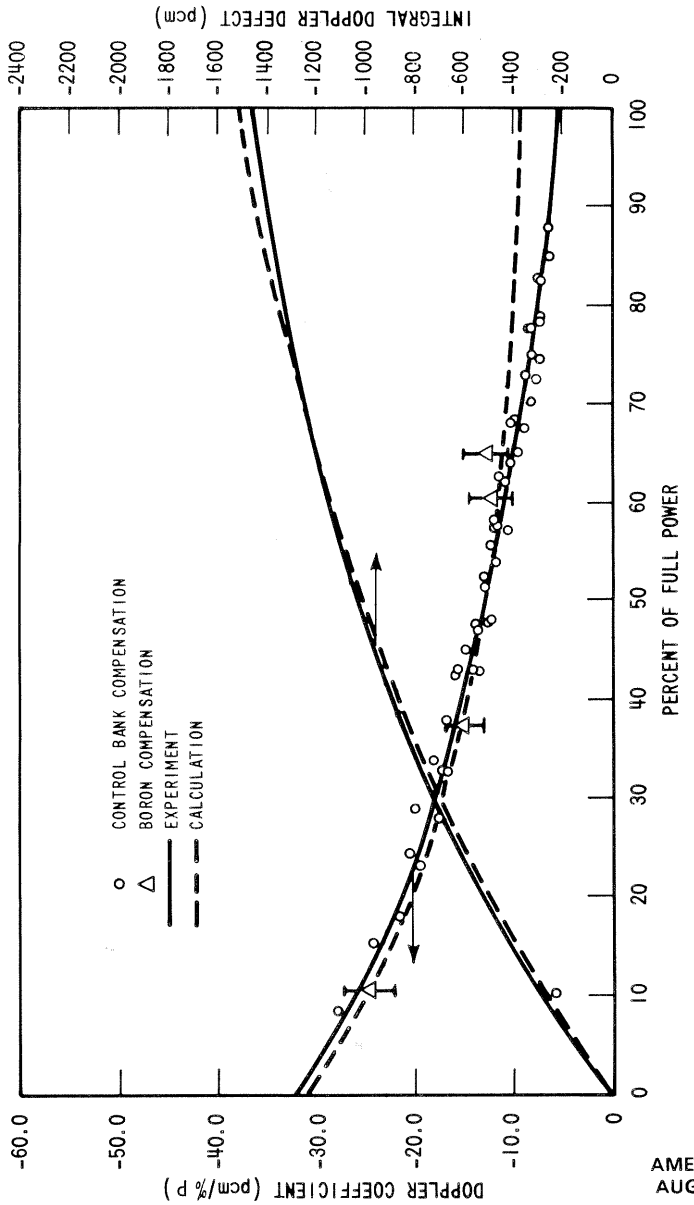
XY Xenon Test Thermocouple Response
Quadrant Tilt Difference Versus Time

Figure 4.3-47

Figure 4.3-48

CALCULATED AND MEASURED DOPPLER DEFECT AND COEFFICIENTS AT BOL, TWO-LOOP PLANT, 121 ASSEMBLIES, 12-FT. CORE



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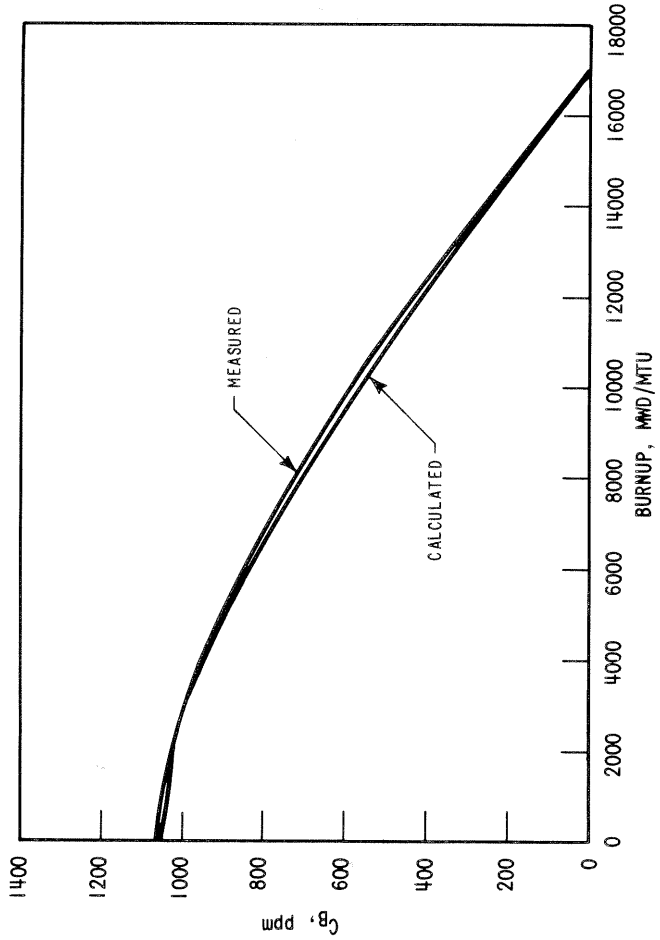
Calculated and Measured Doppler Defect and Coefficients at BOL, Two-Loop Plant, 121 Assemblies, 12-ft. Core

Figure 4.3-48

Figure 4.3-49
COMPARISON OF CALCULATED AND MEASURED BORON CONCENTRATION FOR TWO-LOOP PLANT, 121 ASSEMBLIES, 12-FT. CORE



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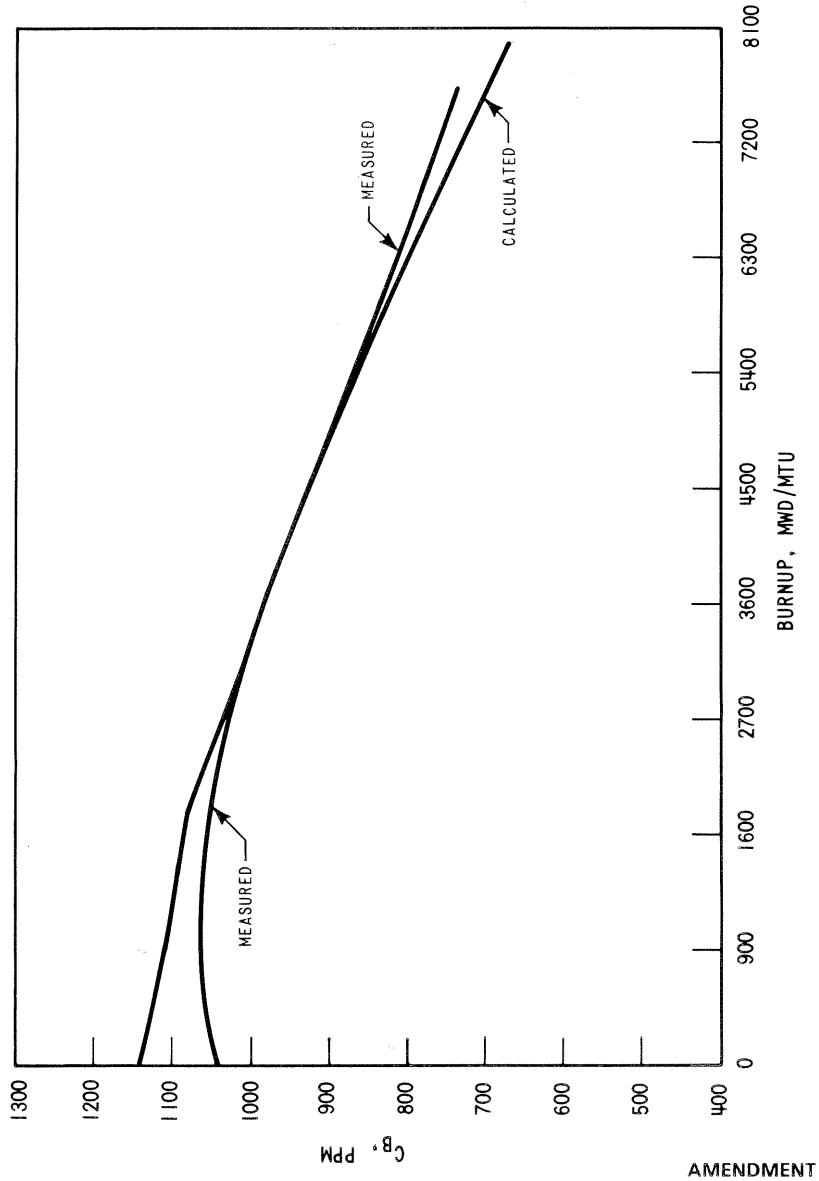
Comparison of Calculated and Measured Boron Concentration for Two-Loop Plant, 121 Assemblies, 12-ft. Core Figure 4.3-49

Figure 4.3-50

COMPARISON OF CALCULATED AND MEASURED C_B IN TWO-LOOP PLANT, 121 ASSEMBLIES, 12-FT. CORE



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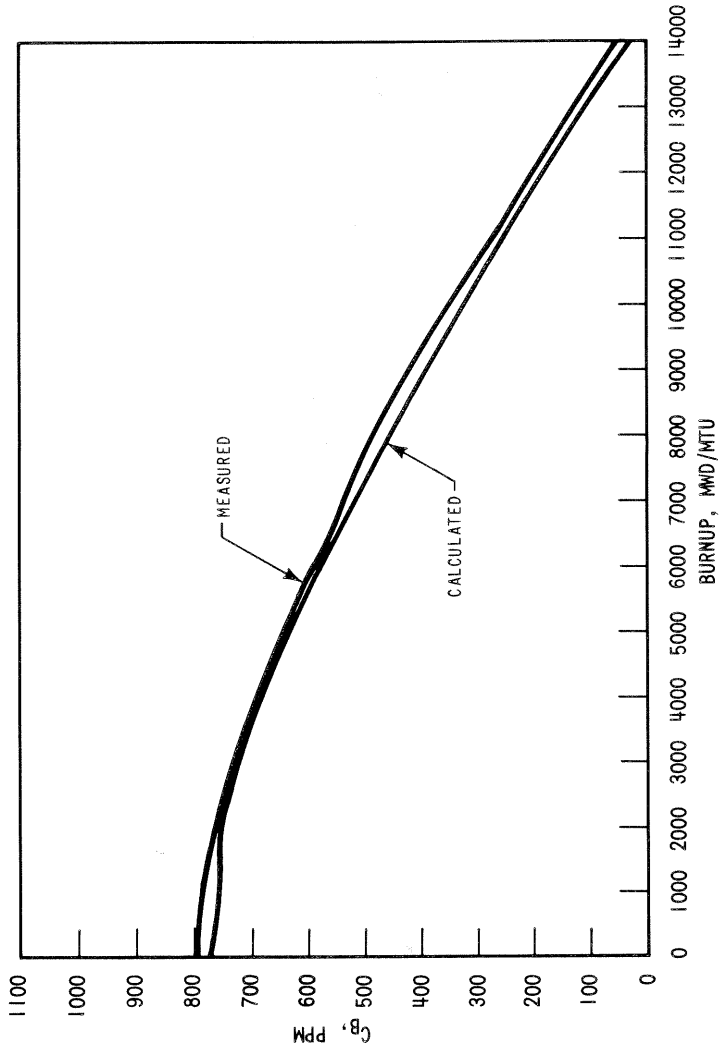
Comparison of Calculated and Measured C_B in Two-Loop Plant, 121 Assemblies, 12-ft. Core

Figure 4.3-50

Figure 4.3-51

COMPARISON OF CALCULATED AND MEASURED C_B IN THREE-LOOP PLANT, 157 ASSEMBLIES, 12-FT. CORE



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Comparison of Calculated and Measured C_B in Three-Loop Plant, 157 Assemblies, 12-ft. Core

Figure 4.3-51

4.4 THERMAL AND HYDRAULIC DESIGN

4.4.1 Design Basis

The overall objective of the thermal and hydraulic design of the reactor core is to provide adequate heat transfer which is compatible with the heat generation distribution in the core such that heat removal by the reactor coolant system or the emergency core cooling system (when applicable) assures that the following performance and safety criteria requirements are met:

1. Fuel damage (defined as penetration of the fission product barrier, i.e., the fuel rod clad) is not expected during normal operation and operational transients (Condition I) or any transient conditions arising from faults of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These will be within the capability of the plant cleanup system and are consistent with the plant design bases.
2. The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged (see above definition) although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.
3. The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.

In order to satisfy the above criteria, the following design bases have been established for the thermal and hydraulic design of the reactor core.

4.4.1.1 Departure from Nucleate Boiling Design Basis

4.4.1.1.1 Basis

There shall be at least a 95% probability (at a 95% confidence level) that departure from nucleate boiling (DNB) will not occur on the most limiting fuel rod during normal operation and operational transients and any transient conditions arising from faults of moderate frequency (Condition I and II events).

The design method employed to meet the DNB design basis is the Revised Thermal Design Procedure (RTDP), Reference 110. Uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer code and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors. Based on the DNB uncertainty factors, RTDP design limit DNBR values are determined such that there is at least a 95% probability at a 95% confidence level that DNB will not occur on the most limiting fuel rod. Plant parameter uncertainties are used to determine the plant uncertainties. Since the parameter uncertainties are considered in determining the design DNBR value, the plant safety analyses are performed using values of input parameters without uncertainties.

For this application, the minimum required DNBR value for fuel analysis is 1.23 for both thimble cold wall cells (3 fuel rods and a thin tube) and typical cells (4 fuel rods).

To maintain DNBR margin to offset DNB penalties such as those due to fuel rod bow (see paragraph 4.4.2.3.4.3), the safety analyses were performed to DNBR limits higher than the design limit DNBR values. The differences between the design limit DNBRs and the safety analysis limit DNBRs results in available DNBR margin. The net DNBR margin, after consideration of all penalties, is available for operating and design flexibility.

For those accident cases where statistical methods are not applied, the Standard Thermal Design Procedure (STDP) is used. (Plant uncertainties are directly accounted for in the calculations.)

4.4.1.1.2 Discussion

By preventing DNB, adequate heat transfer is assured between the fuel clad and the reactor coolant, thereby preventing clad damage as a result of inadequate cooling. Maximum fuel rod surface temperature is not a design basis as it will be within a few degrees of coolant temperature during operation in the nucleate boiling region. Limits provided by the nuclear control and protection systems are such that this design basis will be met for transients associated with Condition II events including overpower transients. There is an additional large DNBR margin at rated power operation and during normal operating transients.

4.4.1.2 Fuel Temperature Design Basis

4.4.1.2.1 Basis

During modes of operation associated with Condition I and II events, the maximum fuel temperature shall be less than the melting temperature of UO_2. The fuel centerline temperatures and power to melt limits are calculated based on methods and fuel melt limits defined in Reference 1. By precluding UO_2 melting, the fuel geometry is preserved and possible adverse effects of molten UO_2 on the cladding are eliminated. This provides sufficient margin for uncertainties in the thermal evaluations as described in Section 4.4.2.10.1.

4.4.1.2.2 Discussion

Fuel rod thermal evaluations are performed at rated power, maximum overpower and during transients at various burnups. These analyses assure that this design basis as well as the fuel integrity design bases given in Section 4.2 are met. They also provide input for the evaluation of Condition III and IV faults given in Chapter 15.0.

4.4.1.3 Core Flow Design Basis

4.4.1.3.1 Basis

A minimum of 91.1% of the thermal flow rate will pass through the fuel rod region of the core and be effective for fuel rod cooling. Coolant flow through the thimble tubes as well as the leakage from the core barrel-baffle region into the core are not considered effective for heat removal.

4.4.1.3.2 Discussion

Core cooling evaluations are based on the thermal flow rate (minimum flow) entering the reactor vessel. A maximum of 8.9% (non-RTDP) of this value is allotted as bypass flow. This includes rod cluster control guide thimble cooling flow, head cooling flow, baffle leakage, and leakage to the vessel outlet nozzle, and includes the effect of thimble plug removal.

4.4.1.4 Hydrodynamic Stability Design Basis

Modes of operation associated with Condition-I and II events shall not lead to hydrodynamic instability.

4.4.1.5 Other Considerations

The above design bases together with the fuel clad and fuel assembly design bases given in Section 4.2.1.1 are sufficiently comprehensive so additional limits are not required.

Fuel rod diametral gap characteristics, moderator-coolant flow velocity and distribution, and moderator void are not inherently limiting. Each of these parameters is incorporated into the thermal and hydraulic models used to ensure the above mentioned design criteria are met. For instance, the fuel rod diametral gap characteristics change with time (see Section 4.2.1.3.1) and the fuel rod integrity is evaluated on that basis. The effect of the moderator flow velocity and distribution (see Section 4.4.2.3) and moderator void distribution (see Section 4.4.2.5) are included in the core thermal (THINC) evaluation and thus affect the design bases.

Meeting the fuel clad integrity criteria covers possible effects of clad temperature limitations. As noted in Section 4.2.1.3.1, the fuel rod conditions change with time. A single clad temperature limit for Condition I or Condition II events is not appropriate since of necessity it would be overly conservative. A clad temperature limit is applied to the loss of coolant accident (Section 15.4.1),control rod ejection accident, Reference 2, and locked rotor accident, Reference 3.

4.4.2 Description

4.4.2.1 (Deleted)

4.4.2.2 Fuel and Cladding Temperatures

Consistent with the thermal-hydraulic design bases described in Section 4.4.1, the following discussion pertains mainly to fuel pellet temperature evaluation. A discussion of fuel clad integrity is presented inSection 4.2.1.3.1.

The thermal-hydraulic design assures that the maximum fuel temperature is below the melting point of UO_2 as defined in Reference 1. This provides sufficient margin for uncertainties in the thermal evaluations as described in Section 4.4.2.10.1. The temperature distribution within the fuel pellet is predominantly a function of the local power density and the UO_2 thermal conductivity. However, the computation of radial fuel temperature distributions combines crud,

oxide, clad gap, and pellet conductances. The factors which influence these conductances, such as gap size (or contact pressure), internal gas pressure, gas composition, pellet density, and radial power distribution within the pellet, etc., have been combined into a semi-empirical thermal model (see Section 4.2.1.3.1) which includes a model for time dependent fuel densification as given in Reference 1. This thermal model enables the determination of these factors and their net effects on temperature profiles.

Fuel rod thermal evaluations (fuel centerline, average and surface temperatures) are performed at several times in the fuel rod lifetime (with consideration of time dependent densification) to determine the maximum fuel temperatures. The principal factors which are employed in the determination of the fuel temperature are discussed in Reference 1.

4.4.2.2.1 Surface Heat Transfer Coefficients

The fuel rod surface heat transfer coefficients during subcooled forced convection and nucleate boiling are presented in Section 4.4.2.8.1.

4.4.2.2.2 Fuel Clad Temperatures

The outer surface of the fuel rod at the hot spot operates at a temperature of approximately 660° F for steady-state operation at rated power throughout core life due to the onset of nucleate boiling. Initially (beginning-of-life), this temperature is that of the clad metal outer surface.

During operation over the life of the core, the buildup of oxides and crud on the fuel rod surface causes the clad surface temperature to increase. Allowance is made in the fuel center melt evaluation for this temperature rise. Since the thermal-hydraulic design basis limits DNB, adequate heat transfer is provided between the fuel clad and the reactor coolant so that the core thermal output is not limited by considerations of clad temperature.

4.4.2.2.3 Treatment of Peaking Factors

The total heat flux hot channel factor, F_Q, is defined by the ratio of the maximum to core average heat flux. As presented in Table 4.3-2 and discussed in Section 4.3.2.2.6, the design value of F_Q for normal operation is 2.45.

This results in a peak local power of 13.9 kW/ft at full power conditions. The centerline temperature at the peak linear power for determination of protection setpoints is below that required to produce melting.

4.4.2.3 Critical Heat Flux Ratio or Departure from Nucleate Boiling Ratio and Mixing Technology

The minimum DNBR’s for the rated power conditions are given in Table 4.4-1. The core average DNBR is not a safety related item as it is not directly related to the minimum DNBR in the core, which occurs at some elevation in the limiting flow channel. Similarly, the DNBR at the hot spot is not directly safety related. The minimum DNBR in the limiting flow channel will be

downstream of the peak heat flux location (hot spot) due to the increased downstream enthalpy rise.

DNBR's are calculated by using the correlation and definitions described in the following Section 4.4.2.3.1 and Section 4.4.2.3.2. The THINC-IV computer code (discussed in Section 4.4.3.4.1) is used to determine the flow distribution in the core and the local conditions in the hot channel for use in the DNB correlation. The use of hot channel factors is discussed in Section 4.4.3.2.1 (nuclear hot channel factors) and in Section 4.4.2.3.4 (engineering hot channel factors).

4.4.2.3.1 Departure From Nucleate Boiling Technology

The WRB-2 (Reference 102) correlation was developed based on CHF data for Westinghouse fuel designs which employ grids with mixing vanes of the same design as the 17 x 17 standard fuel mixing vane design. This includes CHF data with the VANTAGE 5 fuel design.

The applicable ranges of variables for the WRB-2 correlation are:

Pressure	$1440 \le P \le 2490$ psia
Local Mass Velocity	$0.9 \le G_{loc}/10^6 \le 3.7$ lb/ft^2-hr
Local Quality	$-0.1 \le X_{loc} \le 0.3$
Heated Length, Inlet to CHF Location	$L_h \le 14$ feet
Grid Spacing	$10 \le g_{sp} \le 26$ inches
Equivalent Hydraulic Diameter	$0.37 \le d_e \le 0.51$ inch
Equivalent Heated Hydraulic Diameter	$0.46 \le d_h \le 0.59$ inch

Figure 4.4-6 shows measured critical heat flux plotted against predicted critical heat flux using the WRB-2 correlation.

The correlation limit DNBR is 1.17 for both the WRB-1 and WRB-2 correlation.

The W-3 DNB correlation, (Reference 39) and (Reference 108), is used where the primary DNBR correlations are not applicable. The WRB-2 correlation was developed based on mixing vane data and, therefore, is only applicable in the heated rod spans above the first mixing vane grid. The W-3 correlation, which does not take credit for mixing vane grids, is used to calculate DNBR values in the heated region below the first mixing vane grid. In addition, the W-3 correlation is applied in the analysis of accident conditions where the system pressure is below the range of the primary correlations. For system pressures in the range of 500 to 1000 psia, the W-3 correlation limit is 1.45 (Reference 107). For system pressures greater than 1000 psia, the W-3 correlation limit is 1.30. A cold wall factor, Reference 109, is applied to the W-3 DNB correlation to account for the presence of the unheated thimble surfaces.

4.4.2.3.2 Definition of Departure from Nucleate Boiling Ratio

The DNB heat flux ratio (DNBR) as applied to this design for both typical and thimble (cold wall) cells is:

$$DNBR = \frac{q''_{DNB,N}}{q''_{loc}} \quad (4.4\text{-}9)$$

Where:

$$q''_{DNB,N} = \frac{q''_{DNB,EU}}{F} \quad (4.4\text{-}10)$$

and $q''_{DNB,EU}$ is the uniform DNB heat flux as predicted by the WRB-1 or WRB-2 DNB correlation, (Reference 44) and (Reference 102).

F is the flux shape factor to account for nonuniform axial heat flux distributions, Reference 44, with the "C" term modified as in Reference 39.

q''_{loc} is the actual heat flux.

4.4.2.3.3 Mixing Technology

The rate of heat exchange by mixing between flow channels is proportional to the difference in the local mean fluid enthalpy of the respective channels, the local fluid density and flow velocity. The proportionality is expressed by the dimensionless thermal diffusion coefficient (TDC) which is defined as:

$$TDC = \frac{w'}{\rho V a} \quad (4.4\text{-}14)$$

Where:

w' = flow exchange rate per unit length, lb_m/ft-sec

ρ = fluid density, lbm/ft^3

V = fluid velocity, ft/sec

a = lateral flow area between channels per unit length, ft^2/ft

The application of the TDC in the THINC analysis for determining the overall mixing effect or heat exchange rate is presented in Reference 41.

As part of its research and development program, Westinghouse has sponsored and directed mixing tests at Columbia University (Reference 46). These series of tests, using the "R" mixing vane grid design on 13, 26, and 32 inch grid spacing, were conducted in pressurized water loops at Reynolds numbers similar to that of a PWR core under the following single and 2 phase (subcooled boiling) flow conditions:

1. Pressure	1500 to 2400 psia
2. Inlet temperature	332 to 642°F
3. Mass velocity	1.0 to 3.5 x 10^6 lb_m/hr-ft^2
4. Reynolds number	1.34 to 7.45 x 10^5
5. Bulk outlet quality	-52.1 to -13.5%

TDC is determined by comparing the THINC Code predictions with the measured subchannel exit temperatures. Data for 26-inch axial grid spacing are presented in Figure 4.4-8 where the thermal diffusion coefficient is plotted versus the Reynolds number. TDC is found to be independent of Reynolds number, mass velocity, pressure, and quality over the ranges tested. The 2 phase data (local, subcooled boiling) fell within the scatter of the single phase data. The effect of two-phase flow on the value of TDC has been demonstrated by Cadek (Reference 46), Rowe and Angle (Reference 47, Reference 48), and Gonzalez-Santalo and Griffith (Reference 49). In the subcooled boiling region the values of TDC were indistinguishable from the single phase values. In the quality region, Rowe and Angle show that in the case with rod spacing similar to that in PWR reactor core geometry, the value of TDC increased with quality to a point and then decreased, but never below the single phase value. Gonzalez-Santalo and Griffith showed that the mixing coefficient increased as the void fraction increased.

A mixing test program similar to the one described above was conducted at Columbia University for the 17 x 17 geometry and mixing vane grids on 26-inch spacing (Reference 50). The mean value of TDC obtained from these tests was 0.059.

Since the actual reactor grid spacing for the lower region of the VANTAGE 5 and VANTAGE+ design is approximately 20 inches, and approximately 10 inches in the upper region of VANTAGE 5 or VANTAGE+, additional margin is available for these designs, as the value of TDC increases grid spacing decreases (Reference 46).

Based on the above test results, a TDC value of 0.038 is used for the VANTAGE 5 and VANTAGE+ fuel assemblies.

4.4.2.3.4 Hot Channel Factors

The total hot channel factors for heat flux and enthalpy rise are defined as the maximum to core average ratios of these quantities. The heat flux hot channel factor considers the local maximum

linear heat generation rate at a point (the hot spot), and the enthalpy rise hot channel factor involves the maximum integrated value along a channel (the hot channel).

Each of the total hot channel factors considers a nuclear hot channel factor (see Section 4.4.3.2) describing the neutron power distribution and an engineering hot channel factor, which allows for variations in fabrication tolerances.

4.4.2.3.4.1 Heat Flux Engineering Hot Channel Factor, F_Q^F

The kW/ft engineering hot channel factor is used to evaluate the maximum linear heat generation rate in this core. This subfactor is determined by statistically combining the fabrication variances for the fuel pellet diameter, density and enrichment, and has a value of 1.03 at the 95% probability level with 95% confidence. As shown in Reference 104 no DNB penalty need be taken for the short relatively low intensity heat flux spikes caused by variations in the above parameters, as well as fuel pellet eccentricity and fuel rod diameter variation.

4.4.2.3.4.2 Enthalpy Rise Engineering Hot Channel Factor, $F_{\Delta H}^E$

The effect of variations in and fabrication tolerances on the hot channel enthalpy rise is directly considered in the THINC core thermal subchannel analysis (see Section 4.4.3.4.1) under any reactor operating condition. The items considered contributing to the enthalpy rise engineering hot channel factor are discussed below:

1. Pellet diameter, density and enrichment and fuel rod diameter:

   Variations in pellet diameter, density and enrichment, and fuel rod diameter, are considered statistically in establishing the limit DNBR's (see Section 4.4.1.1) for the improved thermal design procedure (Reference 99) employed in this application. Uncertainties in these variables are determined from sampling of manufacturing data.

2. Inlet Flow Maldistribution:

   The consideration of inlet flow maldistribution in core thermal performances is discussed in Section 4.4.3.1.2. A design basis of 5% reduction in coolant flow to the hot assembly is used in the THINC-IV analysis.

3. Flow Redistribution:

   The flow redistribution accounts for the reduction in flow in the hot channel resulting from the high flow resistance in the channel due to the local or bulk boiling. The effect of the nonuniform power distribution is inherently considered in the THINC analysis for every operating condition which is evaluated.

4. Flow Mixing:

   The subchannel mixing model incorporated in the THINC Code and used in reactor design is based on experimental data [Reference 46 to Reference 51] discussed in Section 4.4.3.4.1 and Section 4.4.2.3.3. The mixing vanes incorporated in the spacer grid design induce additional flow mixing between the various flow channels in a fuel assembly as well as between adjacent assemblies. This mixing reduces the enthalpy rise in the hot channel resulting from local power peaking or unfavorable mechanical tolerances.

4.4.2.3.4.3 Effects of Rod Bow on DNBR

The phenomenon of fuel rod bowing, as described in Reference 95, must be accounted for in the DNBR safety analysis of Condition I and II events for each plant application. Applicable generic credits for margin resulting from retained conservatism in the evaluation of the DNBR and/or margin obtained from the measured plant operating parameters (such as $F^N_{\Delta H}$, reactor power or core flow) -- which are less limiting than those required by the plant safety analysis -- can be used to offset the effect of rod bow.

For the safety analysis of the Virgil C. Summer Nuclear Station, sufficient margin was maintained (see Section 4.4.3.11) to accommodate full and low flow DNBR penalties (<2% for the worst case, which is a burnup of 24,000 MWD/MTU) identified in Reference 96.

The maximum rod bow penalties accounted for in the design safety analysis are based on an assembly average burnup of 24,000 MWD/MTU. At burnups greater than 24,000 MWD/MTU, credit is taken for the effect of F^N burndown, due to the decrease in fissionable isotopes and the buildup of fission product inventory, and no additional rod bow penalty is required.

4.4.2.4 Flux Tilt Considerations

Significant quadrant power tilts are not anticipated during normal operation since this phenomenon is caused by some asymmetric perturbation. A dropped or misaligned rod cluster control assembly could cause changes in hot channel factors; however, these events are analyzed separately in Chapter 15.0. This discussion will be confined to flux tilts caused by x-y xenon transients, inlet temperature mismatches, enrichment variations within tolerances and so forth.

The design value of the enthalpy rise hot channel factor $F\frac{N}{\Delta H}$, which includes an 8% uncertainty (as discussed in Section 4.3.2.2.7), is assumed to be sufficiently conservative that flux tilts up to and including the alarm point (see Technical Specifications) will not result in values of $F\frac{N}{\Delta H}$ greater than the assumed in this submittal. The design value of F_Q does not include a specific allowance for quadrant flux tilts.

4.4.2.5 (Deleted)

4.4.2.6 (Deleted)

4.4.2.7 Core Pressure Drops and Hydraulic Loads

4.4.2.7.1 Core Pressure Drops

The analytical model and experimental data used to calculate the pressure drops shown in Table 4.4-1 are described in Section 4.4.2.8. The core pressure drop includes the fuel assembly, lower core plate, and upper core plate pressure drops. The full power operation pressure drop values shown in Table 4.4-1 are the unrecoverable pressure drops across the vessel, including the inlet and outlet nozzles, and across the core. Section 5.1.1 also defines and describes the best estimate flow, the thermal design flow (minimum flow) which is the basis for reactor core thermal performance and the mechanical design flow (maximum flow) which is used in the mechanical design of the reactor vessel internals and fuel assemblies.

Uncertainties associated with the core pressure drop values are discussed in Section 4.4.2.10.2.

4.4.2.7.2 Hydraulic Loads

The fuel assembly hold down springs, Figure 4.2-2, are designed to keep the fuel assemblies in contact with the lower core plate under all Condition I and II events with the exception of the turbine overspeed transient associated with a loss of external load. The hold down springs are designed to tolerate possible over deflection associated with fuel assembly lift off for this case and provide contact between the fuel assembly and the lower core plate following this transient. More adverse flow conditions can occur during a LOCA. These conditions are presented in Section 15.4.1.

Hydraulic loads at normal operating conditions are calculated considering the best-estimate flow which is described in Section 5.1, the best estimate core bypass flow, and a factor to account for uncertainities in the flow rates. Core hydraulic loads at cold plant startup conditions are adjusted to account for the coolant density difference. Conservative core hydraulic loads for a pump overspeed transient, which creates conservatively high flow rates, are evaluated.

Core hydraulic loads were measured during the prototype assembly tests described in Section 1.5. Reference 5 contains a detailed discussion of the results.

4.4.2.8 Correlation and Physical Data

4.4.2.8.1 Surface Heat Transfer Coefficients

Forced convection heat transfer coefficients are obtained from the familiar Dittus-Boelter correlation (Reference 53) with the properties evaluated at bulk fluid conditions:

$$\frac{hD_e}{K} = 0.023\left(\frac{D_e G}{\mu}\right)0.8\left(\frac{C_p \mu}{K}\right)0.4 \qquad (4.4\text{-}15)$$

Where:

h = heat transfer coefficient, Btu/hr-ft^2-°F

De = equivalent diameter, ft

K = thermal conductivity, Btu/hr-ft-°F

G = mass velocity, lb_m/hr-ft^2

m = dynamic viscosity, lb_m/ft-hr

CP = heat capacity, Btu/lb_m-°F

This correlation has been shown to be conservative (Reference 54) for rod bundle geometries with pitch to diameter ratios in the range used by PWRs.

The onset of nucleate boiling occurs when the clad wall temperature reaches the amount of superheat predicted by Thom's (Reference 55) correlation. After this occurrence the outer clad wall temperature is determined by:

$$\Delta T_{sat} = [0.072 \exp(-P/1260)]\,(q'')^{0.5} \qquad (4.4\text{-}16)$$

Where:

ΔT_{sat} = wall superheat, $T_w - T_{sat}$ °F

q" = wall heat flux, Btu/hr-ft^2

P = pressure, psia

T_w = outer clad wall temperature, °F

T_{sat} = saturation temperature of coolant at P, °F

4.4.2.8.2 Total Core and Vessel Pressure Drop

Unrecoverable pressure losses occur as a result of viscous drag (friction) and/or geometry changes (form) in the fluid flow path. The flow field is assumed to be incompressible, turbulent, single-phase water. These assumptions apply to the core and vessel pressure drop calculations for the purpose of establishing the primary loop flow rate. Two (2)-phase considerations are neglected in the vessel pressure drop evaluation because the core average void is negligible. Two (2) phase flow considerations in the core thermal subchannel analyses are considered and the models are discussed in Section 4.4.3.1.3. Core and vessel pressure losses are calculated by equations of the form:

$$\Delta P_L = \left(K + F\frac{L}{D_e}\right)\frac{\rho V^2}{2g_c(144)} \qquad (4.4\text{-}17)$$

Where:

ΔP_L = unrecoverable pressure drop, lb_f/in^2

ρ = fluid density, lb_m/ft^3

L = length, ft

D_e = equivalent diameter, ft

V = fluid velocity, ft/sec

g_c = $32.174 \ \frac{lb_m - ft}{lb_f - sec^2}$

K = form loss coefficient, dimensionless

F = friction loss coefficient, dimensionless

Fluid density is assumed to be constant at the appropriate value for each component in the core and vessel. Because of the complex core and vessel flow geometry, precise analytical values for the form and friction loss coefficients are not available. Therefore, experimental values for these coefficients are obtained from geometrically similar models.

Values are quoted in Table 4.4-1 for unrecoverable pressure loss across the reactor vessel, including the inlet and outlet nozzles, and across the core. The results of full scale tests of core components and fuel assemblies were utilized in developing the core pressure loss characteristic. The pressure drop for the vessel was obtained by combining the core loss with correlation of 1/7th

scale model hydraulic test data on a number of vessels (Reference 56, Reference 57) and form loss relationships (Reference 58). Moody (Reference 59) curves were used to obtain the single phase friction factors.

Tests of the primary coolant loop flow rates will be made (see Section 4.4.4.1) prior to initial criticality to verify that the flow rates used in the design, which were determined in part from the pressure losses calculated by the method described here, are conservative.

4.4.2.8.3 Void Fraction Correlation

There are 3 separate void regions considered in flow boiling in a PWR as illustrated in Figure 4.4-12. They are the wall void region (no bubble detachment), the subcooled boiling region (bubble detachment) and the bulk boiling region.

In the wall void region, the point where local boiling begins is determined when the clad temperature reaches the amount of superheat predicted by Thom's (Reference 55) correlation (discussed in Section 4.4.2.8.1). The void fraction in this region is calculated using Maurer's (Reference 60) relationship. The bubble detachment point, where the superheated bubbles break away from the wall, is determined by using Griffith's (Reference 61) relationship.

The void fraction in the subcooled boiling region (that is, after the detachment point) is calculated from the Bowring (Reference 62) correlation. This correlation predicts the void fraction from the detachment point to the bulk boiling region.

The void fraction in the bulk boiling region is predicted by using homogeneous flow theory and assuming no slip. The void fraction in this region is therefore a function only of the thermodynamic quality

4.4.2.9 Thermal Effects of Operational Transients

DNB core safety limits are generated as a function of coolant temperature, pressure, core power and axial and radial power distributions. Operation within these DNB safety limits ensures that the DNB design basis is met for both steady-state operation and for most anticipated operational transients that are slow with respect to fluid transport delays in the primary system. In addition, for other transients, e.g., uncontrolled rod bank withdrawal at power incident (Section 15.2.2) specific protection functions are provided as described in Section 7.2 and the use of these protection functions are described in Chapter 15.0 (see Table 15.1-3). The thermal response of the fuel rod is discussed in Section 4.4.3.7.

Transients which affect only 1 steam generator are analyzed using a multi-loop system simulation; e.g., the LOFTRAN code (see code description in Section 15.1.8.2). The variation in core inlet temperature distribution is taken into account for such asymmetric events. In general, mixing among the streams from the reactor coolant loops is assumed such that the core reactivity and nuclear power transients are conservatively calculated. Also, in calculating the DNB ratio, the highest inlet temperature from among the reactor coolant loops is used.

Excessive heat removal due to Feedwater System Malfunctions (Section 15.2.10) is an example of an event analyzed in the FSAR which affects only 1 steam generator. The accidental opening of one feedwater control valve with the reactor at power causes excess feedwater to be delivered to 1 steam generator. This results in a reduction in cold leg temperature and an increase in ΔT in the affected reactor coolant loop. For this analysis, no mixing was assumed in the reactor vessel inlet plenum, and the reactivity calculation was based on the loop with the greatest cooldown (the loop with the steam generator to which excess feedwater flow is being delivered), providing a conservatively high prediction of nuclear power. In calculating the DNB ratio during the transient, the initial value of core inlet temperature (including appropriate error allowances) was used. No credit was taken for the cooldown of the reactor coolant system due to the excessive heat removal in the affected steam generator. Thus, margin to core thermal limits is conservatively minimized throughout the transient.

4.4.2.10 Uncertainties in Estimates

4.4.2.10.1 Uncertainties in Fuel and Clad Temperatures

As discussed in Section 4.4.2.2, the fuel temperature is a function of crud, oxide, clad, gap, and pellet conductances. Uncertainties in the fuel temperature calculation are essentially of 2 types: fabrication uncertainties such as variations in the pellet and clad dimensions and the pellet density; and model uncertainties such as variations in the pellet conductivity and the gap conductance. These uncertainties have been quantified in Reference 1. The resulting uncertainties are then used in all evaluations involving the fuel temperature.

In addition to the temperature uncertainty described above, the measurement uncertainty in determining the local power, and the effect of density and enrichment variations on the local power are considered in establishing the heat flux hot channel factor. These uncertainties are described in Section 4.3.2.2.1.

Reactor trip setpoints as specified in the Technical Specification include allowance for instrument and measurement uncertainties such as calorimetric error, instrument drift and channel reproducibility, temperature measurement uncertainties, noise, and heat capacity variations.

Uncertainty in determining the cladding temperature results from uncertainties in the crud and oxide thicknesses. Because of the excellent heat transfer between the surface of the rod and the coolant, the film temperature drop does not appreciably contribute to the uncertainty.

4.4.2.10.2 Uncertainties in Pressure Drops

Core and vessel pressure drops based on the best estimate flow, as described in Section 5.1, are quoted in Table 4.4-1. The uncertainties quoted are based on the uncertainties in both the test results and the analytical extension of these values to the reactor application.

Operating experience to date has indicated that a flow resistance-allowance for possible crud deposition is not required. There has been no detectable long-term flow reduction reported at any Westinghouse plant. Inspection of the inside surfaces of steam generator tubes removed from

operating plants has confirmed that there is no significant surface deposition that would affect system flow. Although all of the coolant piping surfaces have not been inspected, the small piping friction contribution to the total system resistance and the lack of significant deposition on piping near steam generator nozzles support the conclusion that an allowance for piping deposition is not necessary. The effect of crud enters into the calculation of core pressure drop through the fuel rod frictional component by use of a surface roughness factor. Present analyses utilize a surface roughness value which is a factor of 3 greater than the best estimate obtained from crud sampling from several operating Westinghouse reactors.

A major use of the core and vessel pressure drops is to determine the primary system coolant flow rates as discussed in Section 5.1. In addition, as discussed in Section 4.4.4.1, tests on the primary system prior to initial criticality will be made to verify that a conservative primary system coolant flow rate has been used in the design and analyses of the Virgil C. Summer Nuclear Station.

4.4.2.10.3 Uncertainties Due to Inlet Flow Maldistribution

The effects of uncertainties in the inlet flow maldistribution criteria used in the core thermal analyses is discussed in Section 4.4.3.1.2.

4.4.2.10.4 Uncertainty in DNB Correlation

The uncertainty in the DNB correlation (Section 4.4.2.3) can be written as a statement on the probability of not being in DNB based on the statistics of the DNB data. This is discussed in Section 4.4.2.3.2.

4.4.2.10.5 Uncertainties in DNBR Calculations

The uncertainties in the DNBRs calculated by THINC analysis (see Section 4.4.3.4.1) due to uncertainties in the nuclear peaking factors are accounted for by applying conservatively high values of the nuclear peaking factors and including measurement error allowances in the statistical evaluation of the limit DNBR (see Section 4.4.1.1.1) using the Revised Thermal Design Procedure, Reference 110. In addition, conservative values for the engineering hot channel factors are used as discussed in Section 4.4.2.3.4. The results of a sensitivity study (Reference 52) with THINC-IV show that the minimum DNBR in the hot channel is relatively insensitive to variations in the core-wide radial power distribution (for the same value of $F\frac{N}{\Delta H}$).

The ability of the THINC-IV computer code to accurately predict flow and enthalpy distributions in rod bundles is discussed in Section 4.4.3.4.1 and in Reference 63. Studies have been performed (Reference 52) to determine the sensitivity of the minimum DNBR in the hot channel to the void fraction correlation (see Section 4.4.2.8.3); the inlet velocity and exit pressure distributions assumed as boundary conditions for the analysis; and the grid pressure loss coefficients. The results of these studies show that the minimum DNBR in the hot channel is relatively insensitive to variations in these parameters. The range of variations considered in these studies covered the range of possible variations in these parameters. As required in Reference 98, an uncertainty of 4% in DNBR is included in the design procedure to account for any THINC-IV code uncertainty.

4.4.2.10.6 Uncertainties in Flow Rates

The uncertainties associated with loop flow rates are discussed in Section 5.1. For core thermal performance evaluations, a thermal design loop flow is defined which is less than the best estimate loop flow and accounts for both prediction and measurement uncertainties. In addition, another 8.9% of the thermal design flow is assumed to be ineffective for core heat removal capability because it bypasses the core through the various available vessel flow paths described in Section 4.4.3.1.1.

4.4.2.10.7 Uncertainties in Hydraulic Loads

As discussed in Section 4.4.2.7.2, hydraulic loads on the fuel assembly are evaluated for a pump overspeed transient that creates conservatively high flow rates and includes calculational uncertainties.

4.4.2.10.8 Uncertainty in Mixing Coefficient

The value of the mixing coefficient--TDC--used in THINC analysis for this application is 0.038. The results of the mixing tests done on 17 x 17 geometry, as discussed in Section 4.4.2.3.3, had a mean value for TDC of 0.059 for 26-inch grid spacing. Because the actual grid spacing is approximately 20 inches in the lower region of the VANTAGE 5/VANTAGE+ fuel assemblies and approximately 10 inches in the upper region, additional margin is available for these designs, since the value of TDC increases as grid spacing decreases (Reference 46).

4.4.2.11 Plant Configuration Data

Plant configuration data for the thermal hydraulic and fluid systems external to the core are provided in the appropriate Chapters 5.0, 6.0, and 9.0. Implementation of the emergency core cooling system (ECCS) is discussed in Chapter 15.0. Some specific areas of interest are the following:

1. Total coolant flow rates for the reactor coolant system (RCS) and each loop are provided in Table 5.5-1. Flow rates employed in the evaluation of the core are presented in Section 4.4.
2. Total RCS volume including pressurizer and surge line, RCS liquid volume including pressurizer water at steady-state power conditions are given in Table 5.5-1.
3. The flow path length through each volume may be calculated from physical data provided in the above referenced tables.
4. The height of fluid in each component of the RCS may be determined from the physical data presented in Section 5.5. The components of the RCS are water filled during power operation with the pressurizer being approximately 60% water filled.
5. Components of the ECCS are to be located so as to meet the criteria for net positive suction head described in Section 6.3.

6. Line lengths and sizes for the safety injection system are determined so as to guarantee a total system resistance which will provide, as a minimum, the fluid delivery rates assumed in the safety analyses described in Chapter 15.0.
7. The minimum flow areas for components of the RCS are presented in Section 5.5, component and subsystem design.
8. The steady-state pressure drops and temperature distributions through the RCS are presented in Table 5.1-1.

4.4.3 Evaluation

4.4.3.1 Core Hydraulics

4.4.3.1.1 Flow Paths Considered in Core Pressure Drop and Thermal Design The following flow paths or core bypass flow are considered:

1. Flow through the spray nozzles into the upper head for head cooling purposes.
2. Flow entering into the RCC guide thimbles to cool the control rods.
3. Leakage flow from the vessel inlet nozzle directly to the vessel outlet nozzle through the gap between the vessel and the barrel.
4. Flow introduced between the baffle and the barrel for the purpose of cooling these components, and which is not considered available for core cooling.
5. Flow in the gaps between the fuel assemblies on the core periphery and the adjacent baffle wall.

The above contributions are evaluated to confirm that the design value of the core bypass flow is met. The design value of core bypass flow for the Virgil C. Summer Nuclear Station is equal to 8.9% of the total vessel flow assuming removal of all thimble plugs from the core. Of the total allowance, 4.9% is associated with the internals (Items 1, 3, 4, and 5 above) and 4.0% for the core. Calculations have been performed using drawing tolerances on a worst case basis and accounting for uncertainties in pressure losses. Based on these calculations, the core bypass flow for the Virgil C. Summer Nuclear Station is ≤8.9%. This design bypass value is also used in the evaluation of the core pressure drops quoted in Table 4.4-1, and the determination of reactor flow rates in Section 5.1.

Flow model test results for the flow path through the reactor are discussed in Section 4.4.2.8.2.

4.4.3.1.2 Inlet Flow Distributions

Data has been considered from several 1/7 scale hydraulic reactor model tests, Reference 56, Reference 57, and Reference 64, in arriving at the core inlet flow maldistribution criteria to be used in the THINC analyses (see Section 4.4.3.4.1). THINC I analyses made, using this data, have indicated that a conservative design basis is to consider 5% reduction in the flow to the hot

assembly, (Reference 65). The same design basis of 5% reduction to the hot assembly inlet is used in THINC IV analyses.

The experimental error estimated in the inlet velocity distribution has been considered as outlined in Reference 52 where the sensitivity of changes in inlet velocity distributions to hot channel thermal performance is shown to be small. Studies (Reference 52) made with the improved THINC model (THINC IV) show that it is adequate to use the 5% reduction in inlet flow to the hot assembly for a loop out of service based on the experimental data in References 56 and 57.

The effect of the total flow rate on the inlet velocity distribution was studied in the experiments of Reference 56. As was expected, on the basis of the theoretical analysis, no significant variation could be found in inlet velocity distribution with reduced flow rate.

4.4.3.1.3 Empirical Friction Factor Correlations

Two (2) empirical friction factor correlations are used in the THINC-IV computer code (described in Section 4.4.3.4.1).

The friction factor in the axial direction, parallel to the fuel rod axis, is evaluated using the Novendstern-Sandberg correlation (Reference 66). This correlation consists of the following:

1. For isothermal conditions, this correlation used the Moody (Reference 59) friction factor including surface roughness effects.
2. Under single-phase heating conditions a factor is applied based on the values of the coolant density and viscosity at the temperature of the heated surface and at the bulk coolant temperature, and
3. Under 2-phase flow conditions the homogeneous flow model proposed by Owens (Reference 67) is used with a modification to account for a mass velocity and heat flux effect.

The flow in the lateral directions, normal to the fuel rod axis, views the reactor core as a large tube bank. Thus, the lateral friction factor proposed by Idel'chik (Reference 58) is applicable. This correlation is of the form:

$$F_L = A Re_L^{-0.2} \qquad (4.4\text{-}18)$$

Where:

A is a function of the rod pitch and diameter as given in Reference 58.

Re_L is the lateral Reynolds number based on the rod diameter.

Extensive comparisons of THINC-IV predictions using these correlations to experimental data are given in Reference 63, and verify the applicability of these correlations in PWR design.

4.4.3.2 Influence of Power Distribution

The core power distribution which is largely established at beginning-of-life by fuel enrichment, loading pattern, and core power level is also a function of variables such as control rod worth and position, and fuel depletion throughout lifetime. Radial power distributions in various planes of the core are often illustrated for general interest, however, the core radial enthalpy rise distribution as determined by the integral of power up each channel is of greater importance for DNB analyses. These radial power distributions, characterized by $F\frac{N}{\Delta H}$ (defined in Section 4.3.2.2.2) as well as axial heat flux profiles are discussed in the following 2 sections.

4.4.3.2.1 Nuclear Enthalpy Rise Hot Channel Factor, $F\frac{N}{\Delta H}$

Given the local power density q′ (kW/ft) at a point x, y, z in a core with N fuel rods and height H,

$$F^{N}_{\Delta H} = \frac{\text{hot rod power}}{\text{average rod power}} = \frac{\text{Max}\int_{o}^{H} q'(xo, yo, z)dz}{\frac{1}{N}\Sigma_{\text{all rods}}\int_{o}^{H} q'(x, y, z)dz} \qquad (4.4\text{-}19)$$

The way in which $F\frac{N}{\Delta H}$ is used in the DNB calculation is important. The location of minimum DNBR depends on the axial profile and the value of DNBR depends on the enthalpy rise to that point. Basically, the maximum value of the rod integral is used to identify the most likely rod for minimum DNBR. An axial power profile is obtained which, when normalized to the design value of $F\frac{N}{\Delta H}$, recreates the axial heat flux along the limiting rod. The surrounding rods are assumed to have the same axial profile with rod average powers which are typical distributions found in hot assemblies. In this manner worst case axial profiles can be combined with worst case radial distributions for reference DNB calculations. It should be noted again that $F\frac{N}{\Delta H}$ is an integral and is used as such in DNB calculations.

It should be noted again that $F\frac{N}{\Delta H}$ is an integral and is used as such in DNB calculations. Local heat fluxes are obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in horizontal power shapes throughout the core. The sensitivity of the THINC-IV analysis to radial power shapes is discussed in Reference 52.

For operation at a fraction of full power, the design $F\frac{N}{\Delta H}$ used is given by:

$$F_{\Delta H}^{N} = F_{\Delta H}^{RTP}\,[1+PF_{\Delta H}(1-P)] \qquad (4.4\text{-}20)$$

where:

$F_{\Delta H}^{RTP}$ is the limit at Rated Thermal Power (RTP) specified in the Core Operating Limits Report (COLR), $PF_{\Delta H}$ is the Power Factor Multiplier for $F_{\Delta H}^{RTP}$ specified in the COLR, and P is the fraction of Rated Thermal Power.

The permitted relaxation of $F_{\Delta H}^{N}$ is included in the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits [68], thus allowing greater flexibility in the nuclear design.

4.4.3.2.2 Axial Heat Flux Distributions

As discussed in Section 4.3.2.2, the axial heat flux distribution can vary as a result of rod motion, power change, or due to spatial xenon transients which may occur in the axial direction. Consequently, it is necessary to measure the axial power imbalance by means of the ex-core nuclear detectors (as discussed in Section 4.3.2.2.7) and protect the core from excessive axial power imbalance.

The reference axial shape used in establishing core DNB limits (that is overtemperature ΔT protection system setpoints) is a chopped cosine shape with a peak to average value of 1.55. The Reactor Trip System provides automatic reduction of the trip setpoints on excessive axial power imbalance.

To determine the magnitude of the setpoint reduction, the reference shape is supplemented by other axial shapes skewed to the bottom and top of the core. The course of those accidents in which DNB is a concern is analyzed in Chapter 15.0, assuming that the protection setpoints have been set on the basis of these shapes. In many cases, the axial power distribution in the hot channel changes throughout the course of the accident due to rod motion, coolant temperature, and power level changes.

The initial conditions for the accidents for which DNB protection is required are assumed to be those permissible within the relaxed axial offset control strategy for the load maneuvers described in Reference 103. In the case of the loss of flow accident, the hot channel heat flux profile is very similar to the power density profile in normal operation preceding the accident. It is therefore possible to calculate the minimum DNBR for conditions representative of the loss of flow accident as a function of the flux difference initially in the core.

The power shape resulting in the minimum DNBR is selected as the design power shape for non-overpower/overtemperature DNB events. This design shape results in a calculated DNBR that bounds all the normal operation power shapes.

4.4.3.3 Core Thermal Response

A general summary of the steady-state thermal-hydraulic design parameters including thermal output, flow rates, etc., is provided in Table 4.4-1 for all loops in operation.

As stated in Section 4.4.1, the design bases of the application are to prevent DNB and to prevent fuel melting for Condition I and II events. The protective systems described in Chapter 7.0 are designed to meet these bases. The response of the core to Condition II transients is given in Chapter 15.0.

Local fluid conditions during steady-state and transient operation are checked to ensure that they are within the parameter range of the applicable CHF correlation.

4.4.3.4 Analytical Techniques

4.4.3.4.1 Core Analysis

The objective of reactor core thermal design is to determine the maximum heat removal capability in all flow sub channels and show that the core safety limits, as presented in the Technical Specifications are not exceeded while compounding engineering and nuclear effects. The thermal design takes into account local variations in dimensions, power generation, flow redistribution, and mixing. THINC-IV is a realistic three dimensional matrix model which has been developed to account for hydraulic and nuclear effects on the enthalpy rise in the core, References 52, 63 and 111. The behavior of the assembly is determined by superimposing the power distribution among the assemblies upon the inlet flow distribution while allowing for flow mixing and flow distribution between assemblies. The average flow and enthalpy in the hottest assembly is obtained from the core-wide, assembly-by-assembly analysis. The local variations in power, fuel rod and pellet fabrication, and mixing within the hottest assembly are then superimposed on the average conditions of the hottest assembly in order to determine the conditions in the hot channel.

The following sections describe the use of the THINC Code in the thermal-hydraulic design evaluation to determine the conditions in the hot channel and to assure that the safety related design bases are not violated.

4.4.3.4.1.1 Steady-State Analysis

The THINC-IV computer program, as approved by the NRC (Reference 98) is used to determine coolant density, mass velocity, enthalpy, vapor void, static pressure, and DNBR distributions along parallel flow channels within a reactor core under all expected operating conditions. The THINC-IV Code is described in detail in References 52, 63 and 111, including models and correlations used. In addition, a discussion on experimental verification of THINC-IV is given in Reference 63.

The effect of crud on the flow and enthalpy distribution in the core is accounted for directly in the THINC-IV evaluations by assuming a crud thickness several times that which would be expected to occur. This results in slightly conservative evaluations of the minimum DNBR.

Estimates of uncertainties are discussed in Section 4.4.2.10.

4.4.3.4.1.2 Experimental Verification

Extensive experimental verification of THINC-IV is presented in Reference 63.

The THINC-IV analysis is based on a knowledge and understanding of the heat transfer and hydrodynamic behavior of the coolant flow and the mechanical characteristics of the fuel elements. The use of the THINC-IV analysis provides a realistic evaluation of the core performance and is used in the thermal analyses described above.

4.4.3.4.1.3 Transient Analysis

The THINC-IV thermal-hydraulic computer code does not have a transient capability. Since a transient version of the third section of the THINC-I program (Reference 41) does have this capability, this code (THINC-III) continues to be used for transient DNB analysis.

The conservation equations needed for the transient analysis are included in THINC-III by adding the necessary accumulation terms to the conservation equations used in the steady-state (THINC-I) analysis. The input description must now include one or more of the following time dependent arrays:

1. Inlet flow variation,
2. Heat flux distribution,
3. Inlet pressure history.

At the beginning of the transient, the calculation procedure is carried out as in the steady-state analysis. The THINC-III Code is first run in the steady-state mode to ensure conservatism with respect to THINC-IV and in order to provide the steady-state initial conditions at the start of the transient. The time is incremented by an amount determined either by the user or by the program itself. At each new time step the calculations are carried out with the addition of the accumulation terms which are evaluated using the information from the previous time step. This procedure is continued until a preset maximum time is reached.

At preselected intervals, a complete description of the coolant parameter distributions within the array as well as DNBR are printed out. In this manner the variation of any parameter with time can be readily determined.

At various times during the transient, steady-state THINC-IV is applied to show that the application of the transient version of THINC-I is conservative.

The THINC-III Code does not have the capability for evaluating fuel rod thermal response. This is treated by the methods described in Section 15.1.9.

4.4.3.4.2 Fuel Temperatures

As discussed in Section 4.4.2.2, the fuel rod behavior is evaluated utilizing a semi-empirical thermal model which considers, in addition to the thermal aspects, such items as clad creep, fuel swelling, fission gas release, release of absorbed gases, cladding corrosion and elastic deflection, and helium solubility.

4.4.3.4.3 Hydrodynamic Instability

The analytical methods used to assess hydraulic instability are discussed in Section 4.4.3.5.

4.4.3.5 Hydrodynamic and Flow Power Coupled Instability

Boiling flows may be susceptible to thermohydrodynamic instabilities (Reference 87). These instabilities are undesirable in reactors since they may cause a change in thermohydraulic conditions that may lead to a reduction in the DNB heat flux relative to that observed during a steady flow condition or to undesired forced vibrations of core components. Therefore, a thermohydraulic design was developed which states that modes of operation under Condition I and II events shall not lead to thermohydrodynamic instabilities.

Two (2) specific types of flow instabilities are considered for Westinghouse Power operation. These are the Ledinegg of flow excursion type of static instability and the density wave type of dynamic instability.

A Ledinegg instability involves a sudden change in flow rate from one steady-state to another. This instability occurs (Reference 87) when the slope of the reactor coolant system pressure drop-flow rate curve ($\partial\Delta P/\partial G$ internal) becomes algebraically smaller than the loop supply (pump head) pressure drop-flow rate curve ($\partial\Delta P/\partial G$ external). The criterion for stability is thus $\partial\Delta P/\partial G$ internal > $\partial\Delta P/\partial G$ external. The Westinghouse pump head curve has negative slope ($\partial\Delta P/\partial G$ external < 0) whereas the reactor coolant system pressure drop-flow curve has a positive slope ($\partial\Delta P/\partial G$ external < 0) whereas the reactor coolant system pressure drop-flow curve has a positive slope ($\partial\Delta P/\partial G$ internal > 0) over the Condition I and Condition II operational ranges. Thus, the Ledinegg instability will not occur.

The mechanism of density wave oscillations in a heated channel has been described by Lahey and Moody (Reference 88). Briefly, an inlet flow fluctuation produces an enthalpy perturbation. This perturbs the length and the pressure drop of the single phase region and causes quality or void perturbations in the 2-phase regions which travel up the channel with the flow. The quality and length perturbations in the 2-phase region create 2-phase pressure drop perturbations. However, since the total pressure drop across the core is maintained by the characteristics of the fluid system external to the core, then the 2-phase pressure drop perturbation feeds back to the single phase region. These resulting perturbations can be either attenuated or self-sustained.

A simple method has been developed by Ishii (Reference 89) for parallel closed channel systems to evaluate whether a given condition is stable with respect to the density wave type of dynamic instability. This method had been used to assess the stability of typical Westinghouse reactor

designs (Reference 90, Reference 91, Reference 92), including the Virgil C. Summer Nuclear Station, under Condition I and II operation. The results indicate that a large margin to density wave instability exists, e.g., increases on the order of 200% of rated reactor power would be required for the predicted inception of this type of instability.

The application of the method of Ishii (Reference 89) to Westinghouse reactor designs is conservative due to the parallel open channel feature of Westinghouse PWR Cores. For such cores, there is little resistance to lateral flow leaving the flow channels of high power density. There is also energy transfer from channels of high power density to lower power density channels. This coupling with cooler channels has led to the opinion that an open channel configuration is more stable than the above closed channel analysis under the same boundary conditions. Flow stability tests (Reference 93) have been conducted where the closed channel systems were shown to be less stable than when the same channels were cross connected at several locations. The cross connections were such that the resistance to channel to channel cross flow and enthalpy perturbations would be greater than that which would exist in a PWR core which has a relatively low resistance to cross flow.

Flow instabilities which have been observed have occurred almost exclusively in closed channel systems operating at low pressures relative to the Westinghouse PWR operating pressures. Kao, Morgan, and Parker (Reference 94) analyzed parallel closed channel stability experiments simulating a reactor core flow. These experiments were conducted at pressures up to 2200 psia. the results showed that for flow and power levels typical of power reactor conditions, no flow oscillations could be induced above 1200 psia.

Additional evidence that flow instabilities do not adversely affect thermal margin is provided by the data from the rod bundle DNB tests. Many Westinghouse rod bundles have been tested over wide ranges of operating conditions with no evidence of premature DNB or of inconsistent data which might be indicative of flow instabilities in the rod bundle.

In summary, it is concluded that thermohydrodynamic instabilities will not occur under Condition I and II modes of operation for Westinghouse PWR reactor designs. A large power margin, greater than doubling rated power, exists to predicted inception of such instabilities. Analysis has been performed which shows that minor plant to plant differences in Westinghouse reactor designs such as fuel assembly arrays, core power to flow ratios, fuel assembly length, etc. will not result in gross deterioration of the above power margins.

4.4.3.6 Temperature Transient Effects Analysis

Waterlogging damage of a fuel rod could occur as a consequence of a power increase on a rod after water has entered the fuel rod through a clad defect. Water entry will continue until the fuel rod internal pressure is equal to the reactor coolant pressure. A subsequent power increase raises the temperature and, hence, could raise the pressure of the water contained within the fuel rod. The increase in hydrostatic pressure within the fuel rod then drives a portion of the water from the fuel rod through the water entry defect. Clad distortion and/or rupture can occur if the fuel rod internal pressure increase is excessive due to insufficient venting of water to the reactor coolant. This occurs when there is both a rapid increase in the temperature of the water within the fuel rod

and a small defect. Zircaloy clad fuel rods which have failed due to waterlogging (Reference 80, Reference 81) indicate that very rapid power transients are required for fuel failure. Normal operational transients are limited to about 40 cal/gm-min (peak rod), while the Spert tests (Reference 80) indicate that 120 to 150 cal/gm is required to rupture the clad even with very short transients (5.5 msec period). Release of the internal fuel rod pressure is expected to have a minimal effect on the reactor coolant system (Reference 80) and is not expected to result in failure of additional fuel rods (Reference 81). Ejection of fuel pellet fragments into the coolant stream is not expected (Reference 80, Reference 81). A clad breech due to waterlogging is thus expected to be similar to any fuel rod failure mechanism which exposes fuel pellets to the reactor coolant stream. Waterlogging has not been identified as the mechanism for clad distortion or perforation of any Westinghouse Zircaloy-4 fuel rods.

An excessively high fuel rod internal gas pressure could cause clad failure. One of the fuel rod design bases (Section 4.2.1.1.1) is that the fuel rod internal gas pressure does not exceed the nominal coolant pressure even at the overpower condition. During operational transients, fuel rod clad rupture due to high internal gas pressure is precluded by meeting the above design basis.

4.4.3.7 Potentially Damaging Temperature Effects During Transients

The fuel rod experiences many operational transients (intentional maneuvers) during its residence in the core. A number of thermal effects must be considered when analyzing the fuel rod performance.

The clad can be in contact with the fuel pellet at some time in the fuel lifetime. Cladpellet interaction occurs if the fuel pellet temperature is increased after the clad is in contact with the pellet. Clad-pellet interaction is discussed in Section 4.2.1.3.1.

Increasing the fuel temperature results in an increased fuel rod internal pressure. One of the fuel rod design bases is that the fuel rod internal pressures do not exceed the nominal coolant pressure even at the overpower condition (see Section 4.2.1.1.1).

The potential effects of operation with waterlogged fuel are discussed in Section 4.4.3.6, which concluded that waterlogging is not a concern during operational transients.

Clad flattening, as noted in Section 4.2.1.3.1, has been observed in some operating power reactors. Thermal expansion (axial) of the fuel rod stack against a flattened section of clad could cause failure of the clad. This is no longer a concern because clad flattening is precluded during the fuel residence in the core (see Section 4.2.1.3.1).

There can be a differential thermal expansion between the fuel rods and the guide thimbles during a transient. Excessive bowing of the fuel rods could occur if the grid assemblies did not allow axial movement of the fuel rods relative to the grids. Thermal expansion of the fuel rods is considered in the grid design so that axial loads imposed on the fuel rods during a thermal transient will not result in excessively bowed fuel rods (see Section 4.2.1.2.2).

4.4.3.8 Energy Release During Fuel Element Burnout

As discussed in Section 4.4.2.3, the core is protected from going through DNB over the full range of possible operating conditions. At full power nominal operation, the minimum DNBR was found to be 2.21 (for 2900 MWt). This means that for these conditions, the probability of a rod going through DNB is less than 0.01% at a 95% confidence level, based on the statistics of the WRB-2 correlation. In the extremely unlikely event that DNB should occur, the clad temperature will rise due to the steam blanketing at the rod surface and the consequent degradation in heat transfer. During this time, there is a potential for chemical reaction between the cladding and the coolant. However, because of the relatively good film boiling heat transfer following DNB, the energy release resulting from this reaction is insignificant compared to the power produced by the fuel.

1. DNB With Physical Burnout

Westinghouse (Reference 73) has conducted DNB tests in a 25 rod bundle where physical burnout occurred with 1 rod. After this occurrence, the 25 rod test section was used for several days to obtain more DNB data from the other rods in the bundle. The burnout and deformation of the rod did not affect the performance of neighboring rods in the test section during the burnout or the validity of the subsequent DNB data points as predicted by the W-3 correlation. No occurrences of flow instability or other abnormal operation were observed.

2. DNB With Return to Nucleate Boiling

Additional DNB tests have been conducted by Westinghouse (Reference 82) in 19 and 21 rod bundles. In these tests, DNB without physical burnout was experienced more than once on single rods in the bundles for short periods of time. Each time, a reduction in power of approximately 10% was sufficient to re-establish nucleate boiling on the surface of the rod. During these and subsequent tests, no adverse effects were observed on this rod or any other rod in the bundle as a consequence of operating in DNB.

4.4.3.9 Energy Release or Rupture of Waterlogged Fuel Elements

A full discussion of waterlogging including energy release is contained in Section 4.4.3.6. It is noted that the resulting energy release is not expected to affect neighboring fuel rods.

4.4.3.10 Fuel Rod Behavior Effects from Coolant Flow Blockage

Coolant flow blockages can occur within the coolant channels of a fuel assembly or external to the reactor core. The effects of fuel assembly blockage within the assembly on fuel rod behavior is more pronounced than external blockages of the same magnitude. In both cases the flow blockages cause local reductions in coolant flow. The amount of local flow reduction, where it occurs in the reactor, and how far along the flow stream the reduction persists are considerations which will influence the fuel rod behavior. The effects of coolant flow blockages in terms of maintaining rated core performance are determined both by analytical and experimental methods. The experimental data are usually used to augment analytical tools such as computer programs

similar to the THINC-IV program. Inspection of the DNB correlation (Section 4.4.2.3 and Reference 44) shows that the predicted DNBR is dependent upon the local values of quality and mass velocity.

The THINC-IV Code is capable of predicting the effects of local flow blockages on DNBR within the fuel assembly on subchannel basis, regardless of where the flow blockage occurs. In Reference 63, it is shown that for a fuel assembly similar to the Westinghouse design, THINC-IV accurately predicts the flow distribution within the fuel assembly when the inlet nozzle is completely blocked. Full recovery of the flow was found to occur about 30 inches downstream of the blockage. With the reference reactor operating at the nominal full power conditions specified in Table 4.4-1, the effects of an increase in enthalpy and decrease in mass velocity in the lower portion of the fuel assembly would not result in the reactor reaching the DNBR limit.

From a review of the open literature it is concluded that flow blockage in “open lattice cores” similar to the Westinghouse cores causes flow perturbations which are local to the blockage. For instance, A. Oktsubo (Reference 83), et al., show that the mean bundle velocity is approached asymptotically about 4 inches downstream from a flow blockage in a single flow cell. Similar results were also found for 2 and 3 cells completely blocked. P. Basmer (Reference 84), et al., tested an open lattice fuel assembly in which 41% of the subchannels were completely blocked in the center of the test bundle between spacer grids. Their results show the stagnant zone behind the flow blockage essentially disappears after 1.65 L/De or about 5 inches for their test bundle. They also found that leakage flow through the blockage tended to shorten the stagnant zone or, in essence, the complete recovery length. Thus, local flow blockages within a fuel assembly have little effect on subchannel enthalpy rise. The reduction in local mass velocity is then the main parameter which affects the DNBR. If the Virgil C. Summer Nuclear Station was operating at full power and nominal steady state conditions as specified in Table 4.4.1, a reduction in local mass velocity greater than 60% would be required to reduce the DNBR to the DNBR limit. The above mass velocity effect on the DNB correlation was based on the assumption of fully developed flow along the full channel length. In reality a local flow blockage is expected to promote turbulence and thus would not adversely affect DNBR at all (Reference 85).

Coolant flow blockages induce local crossflows as well as promote turbulence. Fuel rod behavior is changed under the influence of a sufficiently high crossflow component. Fuel rod vibration could occur, caused by this crossflow component, through vortex shedding or turbulent mechanisms. If the crossflow velocity exceeds the limit established for fluid elastic stability, large amplitude whirling results. The limits for a controlled vibration mechanism are established from studies of vortex shedding and turbulent pressure fluctuations. The crossflow velocity required to exceed fluid elastic stability limits is dependent on the axial location of the blockage and the characterization of the crossflow (jet flow or not). These limits are greater than those for vibratory fuel rod wear. Crossflow velocity above the established limits can lead to mechanical wear of the fuel rods at the grid support locations. Fuel rod wear due to flow induced vibration is considered in the fuel rod fretting evaluation (Section 4.2).

4.4.3.11 DNBR Margins

The minimum required DNBR value for the VANTAGE 5 or VANTAGE+ fuel analysis are 1.23 for both thimble cold wall cells (3 fuel rods and a thimble tube) and typical cells (4 fuel rods).

To maintain DNBR margin to offset DNB penalties such as those due to fuel rod bow (see Section 4.4.2.3.4.3), the safety analyses were performed to DNBR limits higher than the design limit DNBR values. The differences between the design limit DNBRs and the safety analysis limit DNBRs results in available DNBR margin. The net DNBR margin, after consideration of all penalties, is available for operating and design flexibility.

4.4.3.12 Mixed Core Methodology

The Westinghouse transition core DNB methodology is given in Reference 14. Sufficient DNBR margin (Section 4.4.3.11) is maintained in the safety analysis to offset the transition core penalties.

4.4.4 Testing and Verification

NOTE: Section 4.4.4.1 is being retained for historical purposes only.

4.4.4.1 Tests Prior to Initial Criticality

A reactor coolant flow test, as noted in Table 14.1-58, is performed following fuel loading but prior to initial criticality. Coolant loop pressure drop data is obtained in this test. This data in conjunction with coolant pump performance information allows determination of the coolant flow rates at reactor operating conditions. This test verifies that proper coolant flow rates have been used in the core thermal and hydraulic analysis.

4.4.4.2 Initial Power and Plant Operation

Core power distribution measurements are made at several core power levels (see Section 4.3.2.2.7). These tests are used to ensure that conservative peaking factors are used in the core thermal and hydraulic analysis.

Additional demonstration of the overall conservatism of the THINC analysis was obtained by comparing THINC predictions to incore thermocouple measurements. These measurements were performed on the Zion reactor (Reference 86). No further in-reactor testing is planned.

The reactor coolant system total flow rate determined by heat balance measurement at least once per 18 months with the plant greater than or equal to 90% rated thermal power is included in the Technical Specification surveillance requirement.

4.4.4.3 Component and Fuel Inspections

Inspections performed on the manufactured fuel are delineated in Section 4.2.1.4. Fabrication measurements critical to thermal and hydraulic analysis are obtained to verify that the engineering hot channel factors employed in the design analyses (Section 4.4.2.3.4) are met.

4.4.5 Instrumentation Application

4.4.5.1 Incore Instrumentation

Instrumentation is located in the core so that by correlating movable neutron detector information with fixed thermocouple information radial, axial, and azimuthal core characteristics may be obtained for all core quadrants.

The incore instrumentation system is comprised of thermocouples, positioned to measure fuel assembly coolant outlet temperatures at preselected positions, and fission chamber detectors positioned in guide thimbles which run the length of selected fuel assemblies to measure the neutron flux distribution. Figure 4.4-19 shows the number and location of instrumented assemblies in the core.

The core-exit thermocouples provide a backup to the flux monitoring instrumentation for monitoring power distribution. The routine, systematic, collection of thermocouple readings by the operator provides a data base. From this data base, abnormally high or abnormally low readings, quadrant temperature tilts, or systematic departure from a prior reference map can be deduced.

The movable incore neutron detector system would be used for more detailed mapping if the thermocouple system were to indicate an abnormality. These 2 complementary systems are more useful when taken together than either system alone would be. The incore instrumentation system is described in more detail in Section 7.7.1.9.

The incore instrumentation is provided to obtain data from which fission power density distribution in the core, coolant enthalpy distribution in the core, and fuel burnup distribution may be determined.

The BEACON Power Distribution Monitoring System (PDMS), (Reference 113), for measuring power distribution is available as an alternative to using the movable in-core flux mapping system when power is greater than 25% RTP. This system provides continuous 3-dimensional core power distribution determination and directly relates power distribution to fuel safety limits. This system is described in WCAP-12472-P-A and uses core exit thermocouples, control rod bank position, Tcold, reactor power level, and the nuclear instrumentation power range section signals to develop the power distribution map.

4.4.5.2 Overtemperature and Overpower ΔT Instrumentation

The Overtemperature ΔT trip protects the core against low DNBR. The Overpower ΔT trip protects against excessive power (fuel rod rating protection).

As discussed in Section 7.2.1.1.2, factors included in establishing the overtemperature ΔT and overpower ΔT trip setpoints includes the reactor coolant temperature in each loop and the axial distribution of core power through the use of the 2 section excore neutron detectors.

4.4.5.3 Instrumentation to Limit Maximum Power Output

The output of the 3 ranges (source, intermediate, and power) of detectors, with the electronics of the nuclear instruments, are used to limit the maximum power output of the reactor within their respective ranges.

There are 8 radial locations around the reactor in the primary shield. Seven (7) of these are utilized and have flux measuring detectors installed. One (1) location is a spare. Two (2) Source/Intermediate Range post accident 1E qualified detector assemblies are installed on opposite flat portions of the core containing the startup sources at an elevation corresponding to 1/2 of the core height. Each Source/Intermediate Range detector assembly is comprised of 2 identical fission chamber detectors surrounded by high density polyethylene. The Source Range utilizes the output of both fission chamber detectors and converts the combined signal into an equivalent count rate. The Intermediate Range uses the output of only one of the 2 fission chamber detectors and converts it to percent full power. Additionally, there is a Source Range detector installed in a well that was originally a spare well. It provides input to the remote Source Range instrument. This instrument is installed in the Control Room Evacuation Panel room and is used only in the case of Control Room evacuation. It provides a display and has the capability of providing a signal to the High Flux at Shutdown annunciator in the Control Room. It does not provide any rod control interlocks or any reactor trip signals. Four (4) dual section uncompensated ionization chamber assemblies for the power range are installed vertically at the 4 corners of the core and located equidistant from the reactor vessel at all points. Furthermore, these power range detectors are installed within 1 foot of the reactor vessel in order to minimize neutron flux pattern distortions. Each power range detector provides 2 signals corresponding to the neutron flux in the upper and in the lower sections of a core quadrant. The 3 ranges of detectors are used as inputs to monitor neutron flux from a completely shutdown condition to 120% of full power with the capability of recording overpower excursions up to 200% of full power.

The difference in neutron flux between the upper and lower sections of the power range detectors are used to limit the overtemperature ΔT and overpower ΔT trip setpoints and to provide the operator with an indication of the core power axial offset. In addition, the output of the power range channels are used for:

1. The rod speed control function,
2. To alert the operator to an excessive power unbalance between the quadrants,
3. Protect the core against rod ejection accidents, and

4. Protect the core against adverse power distributions resulting from dropped rods.

Details of the neutron detectors and nuclear instrumentation design and the control and trip logic are given in Chapter 7.0. The limits on neutron flux operation and trip setpoints are given in the Technical Specifications.

4.4.5.4 Loose Parts Monitoring Program (Metal Impact Detection System)

The Virgil C. Summer Nuclear Station Metal Impact Monitor is designed to enable early detection of debris which may collect in the steam generators or the reactor vessel. The developmental prototype of the Westinghouse Metal Impact Monitor is installed in the R. E. Ginna Plant (RGE) to evaluate the long term performance of the system in an operating plant. The system consists of a detector, preamplifier, signal processor and display.

The detectors are high temperature accelerometers mounted on the lower head of each steam generator, on the reactor vessel head flange and on incore instrument conduit near the bottom of the reactor vessel. The system accelerometer sensitivity is 10-100 pico coulombs/g.

Preamplification of the detector signal is accomplished through use of a signal conditioning amplifier. This amplifier consists of a remote charge preamplifier located inside the reactor building and a signal conditioner located outside the reactor building. The signal is converted from the low level accelerometer charge signal to a voltage signal for transmission to the signal processing equipment in the control room.

Mechanical mounting adapters are provided for attaching the accelerometers to the various vessels. These adapters which are larger than the accelerometers use threaded and/or clamping arrangements to insure excellent mechanical attachment. No epoxies or magnetic attachments are used on a permanent basis to insure maximum signal strength and provide reasonable assurance and that the equipment will remain attached under normal and OBE operation.

The preamplifier housing and conduit for the loose parts monitoring system cables within the Reactor Building are designed and installed to withstand the Safe Shutdown Earthquake (SSE).

The Metal Impact Monitor was designed so that rate of impact incidents, as well as, energy of impact may be monitored continuously. Rate and amplitude latching-type alarms are displayed on the front panel of the monitor. Common alarm outputs are provided for connection to the main control room annunciator panel. An audio system produces the sound equivalent in parallel to the impact signal.

Operating procedures detailing response to alarms are used to evaluate problems when detected by the system. Administrative procedures are utilized to ensure that data records are used and maintained for an appropriate period.

Although the metal impact monitor has been designed as a maintenance aid and is not considered as necessary for safe operation of a nuclear power plant, it will be operational during startup testing for obtaining baseline data from which detection sensitivity will be identified and set.

The system is a non-Class 1E system.

The loose parts monitoring system (LMPS) will detect impacts of approximately 0.2 ft/lb at approximately 2 feet from the transducer. This sensitivity meets the requirements of Regulatory Guide 1.133.

Two (2) redundant signal chains consisting of an accelerometer, a charge pre-amplifier, and the required cabling are located to provide broad coverage at the top of the reactor vessel, 2 at the bottom of the reactor vessel and 2 at the bottom of each steam generator. Each redundant channel is physically located to provide mechanical separation inside the containment.

Additionally, each signal chain is connected to it's own signal conditioner, mounted in a common rack, outside the containment. Each channel is therefore active and provides for continuous audio monitoring. The signal processing to provide an automatic alarm is provided on a per "natural collection point" basis with automatic switching between redundant signal chains.

Electrical noise problems are minimized in the Westinghouse LPM system by:

a. Electrically isolating and shielding the accelerometers, pre-amplifiers and connecting cables.

b. Grounding of shields at electronics cabinet only.

c. Digital signal processing is employed to reduce the sensitivity to electrical noise and allows for the use of a unique impact discrimination technique. This allows for maximizing system sensitivity while minimizing susceptibility to false alarms.

Process noise problems are minimized by providing an inhibit function to reduce the sensitivity of the alarm discrimination circuitry during typical plant operation changes, such as:

a. An inhibit card is provided in the rod control system to prevent alarms during control rod motion.

b. Allows for other "owner furnished" input signals (contact closures) to inhibit the sensitivity during start-up or shut down of pumps, opening and closing of valves, etc.

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Table 4.4-1
Thermal and Hydraulic Comparison Table

Design Parameters	CURRENT RTP AND ENGINEERED SAFETY DESIGN RATING
Reactor Core Heat Output, MWt 2900	2900
Reactor Core Heat Output, 10^6 Btu/hr	9898
Heat Generated in Fuel, Z	97.4
System Pressure, Nominal, psia	2250
System Pressure, Minimum Steady State, psia	2200
Minimum DNBR at Nominal Conditions	
Typical Flow Channel	2.34
Thimble (Cold Wall) Flow Channel	2.21
Minimum DNBR Design Limit	1.23
DNB Correlation	WRB-2
Coolant Flow	
Total Thermal Design Flow Rate 10^6 lb/hr	104.0
Minimum Measured Flow Rate, 10^6 lb/hr	106.1
Effective Flow Rate for Heat	
Transfer (Based on TDF), 10^6 lb/hr	94.74
Effective Flow Area for Heat Transfer, ft^2	44.0
Average Velocity Along Fuel Rods, ft/sec	13.7
Average Mass Velocity, 10^6 lb/hr-$ft^{2(2)}$	2.15
Coolant Temperature (Based on TDF)	
Nominal Inlet, °F	552.9
Average Rise in Vessel, °F	68.0
Average Rise in Core, °F	74.8
Average in Core, °F	592.8
Average in Vessel, °F	587.4

Table 4.4-1 (continued)
Thermal and Hydraulic Comparison Table

Design Parameters	CURRENT RTP AND ENGINEERED SAFETY DESIGN RATING
Heat Transfer	
Active Heat Transfer, Surface Area, ft^2	46,780
Average Heat Flux, Btu/hr-ft^2	206,100
Maximum Heat Flux for Normal Operation, Btu/hr-ft^2	504,900 (1)
Average Thermal Output, kW/ft	5.69
Maximum Thermal Output for Normal Operation, kW/ft	13.9
Deleted	
Deleted	
Deleted	

Pressure Drop (3)	Thimble Plug Inserted	Thimble Plug Removed
Across Core, psi	(TPI)	(TPR)
-0% Tube Plugging (552.9°F Inlet Temp)	26.26	23.92
-10% Tube Plugging (536.7°F Inlet Temp)	26.73	24.35
Across Vessel, including nozzle, psi		
-0% Tube Plugging (552.9°F Inlet Temp)	44.67	42.34
-10% Tube Plugging (536.7°F Inlet Temp)	48.53	43.15

(1) This limit is associated with the value of FQ = 2.45.
(2) Based on thermal design flow of 277,800 gpm.
(3) From WCAP-16980-P Table 5-1, based on Mechanical Design Flow of 321,300 gpm.

Table 4.4-4
Comparison of THINC-IV and THINC-1 Predictions With Data from
Representative Westinghouse Two and Three Loop Reactors

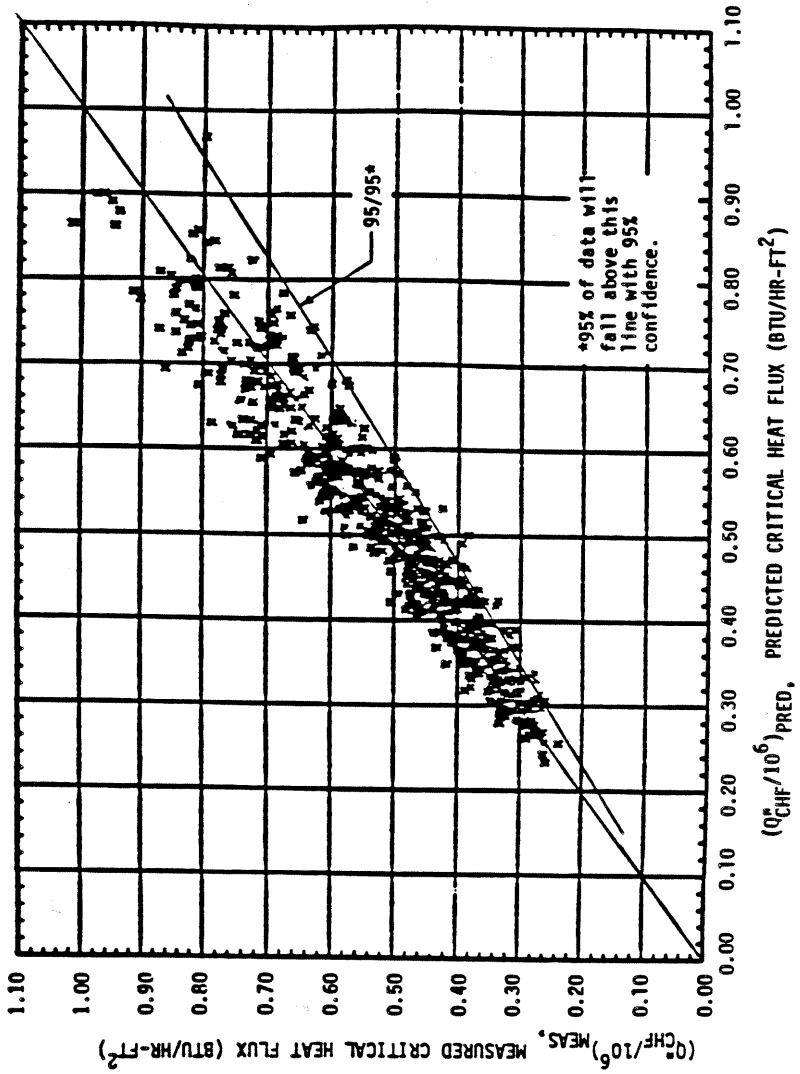
Reactor	Power (MWt)	% Full Power	Measured Inlet Temp (°F)	σ_{MS} (°F) THINC-1	σ (°F) THINC-IV	Improvement (°F) for THINC-IV over THINC-I
Ginna						
	847	65.1	543.7	1.97	1.83	0.14
	854	65.7	544.9	1.56	1.46	0.10
	857	65.9	543.9	1.97	1.82	0.15
	947	72.9	543.8	1.92	1.74	0.18
	961	74.0	543.7	1.97	1.79	0.18
	1091	83.9	542.5	1.73	1.54	0.19
	1268	97.5	542.0	2.35	2.11	0.24
	1284	98.8	540.2	2.69	2.47	0.22
	1284	98.9	541.0	2.42	2.17	0.25
	1287	99.0	544.4	2.26	1.97	0.29
	1294	99.5	540.8	2.20	1.91	0.29
	1295	99.6	542.0	2.10	1.83	0.27

Table 4.4-4 (continued)
Comparison of THINC-IV and THINC-1 Predictions With Data from
Representative Westinghouse Two and Three Loop Reactors

Reactor	Power (MWt)	% Full Power	Measured Inlet Temp (°F)	σ_{MS} (°F) THINC-1	σ (°F) THINC-IV	Improvement (°F) for THINC-IV over THINC-I
Robinson						
	1427.0	65.1	548.0	1.85	1.88	0.03
	1422.6	64.9	549.4	1.39	1.39	0.00
	1529.0	88.0	550.0	2.35	2.34	0.01
	2207.3	100.7	534.0	2.41	2.41	0.00
	2213.9	101.0	533.8	2.52	2.44	0.08

Figure 4.4-3
(DELETED)

Figure 4.4-6
MEASURED VERSUS PREDICTED CRITICAL HEAT FLUX - WRB-2 CORRELATION



AMENDMENT 6
AUGUST, 1990

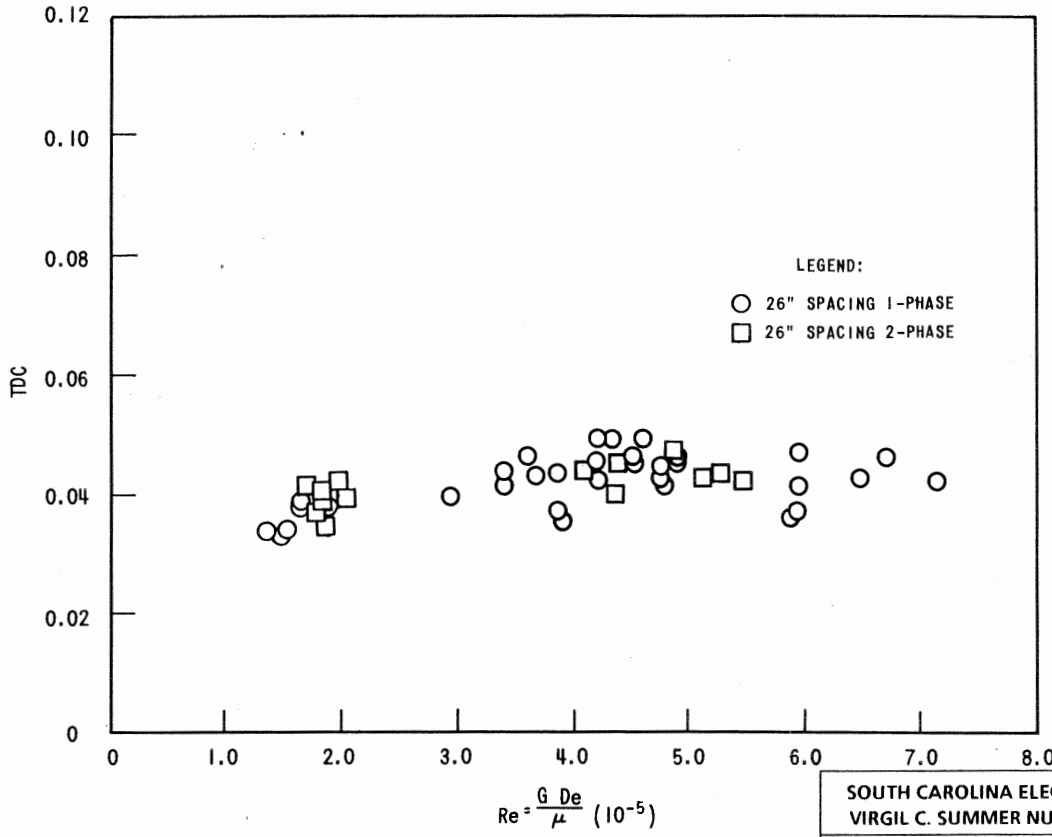
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Measured Versus Predicted Critical Heat Flux - WRB-2 Correlation

Figure 4.4-6

Figure 4.4-8

TDC VERSUS REYNOLDS NUMBER FOR 26" GRID SPACING



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VIRGIL C. SUMMER NUCLEAR STATION

TDC versus Reynolds Number for 26" Grid Spacing

Figure 4.4-8

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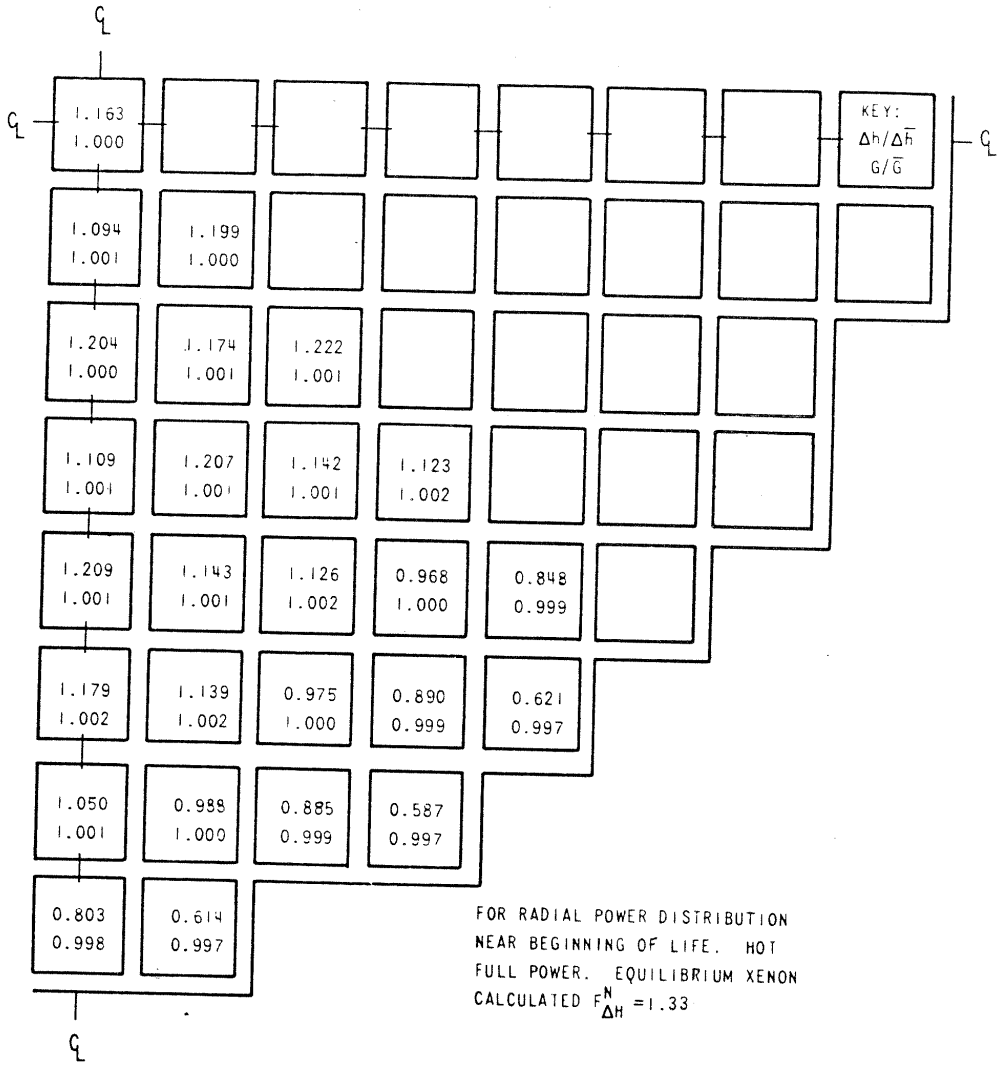
August 1984

Figure 4.4-9
NORMALIZED RADIAL FLOW AND ENTHALPY DISTRIBUTION AT 4 FT. ELEVATION



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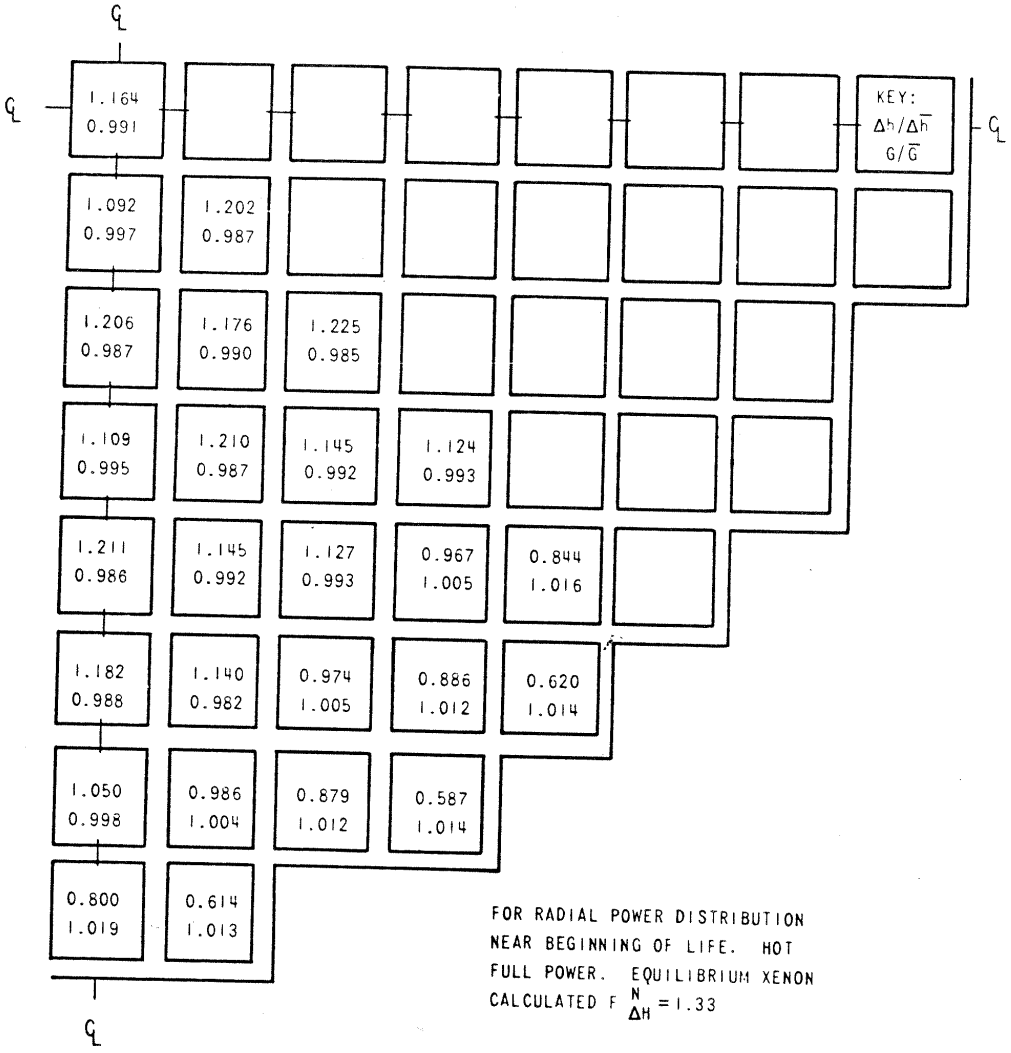
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Normalized Radial Flow and Enthalpy Distribution at 4 ft. Elevation
Figure 4.4-9

Figure 4.4-10
NORMALIZED RADIAL FLOW AND ENTHALPY DISTRIBUTION AT 8 FT. ELEVATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Normalized Radial Flow and Enthalpy Distribution at 8 ft. Elevation
Figure 4.4-10

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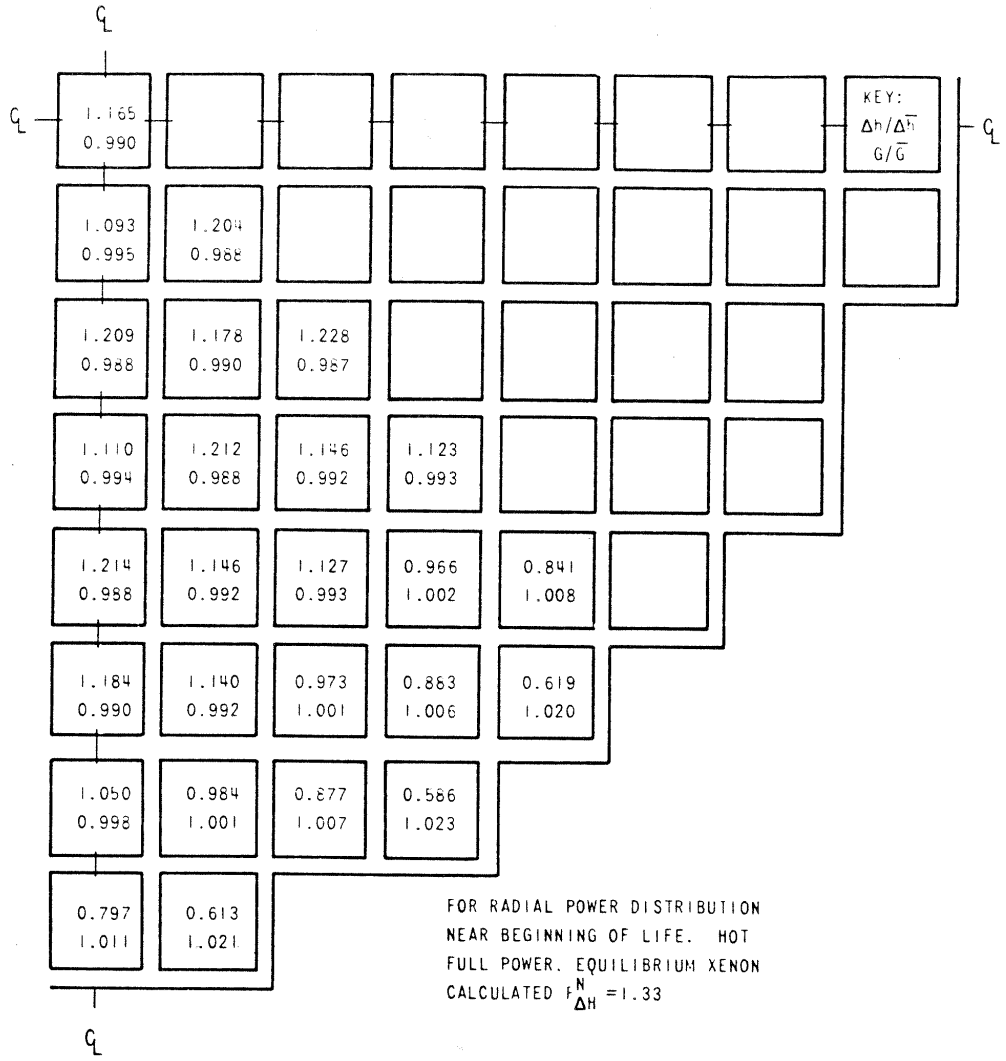
Figure 4.4-11

NORMALIZED RADIAL FLOW AND ENTHALPY DISTRIBUTION AT 12FT. ELEVATION CORE EXIT



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Normalized Radial Flow and Enthalpy Distribution at 12 ft. Elevation Core Exit Figure 4.4-11

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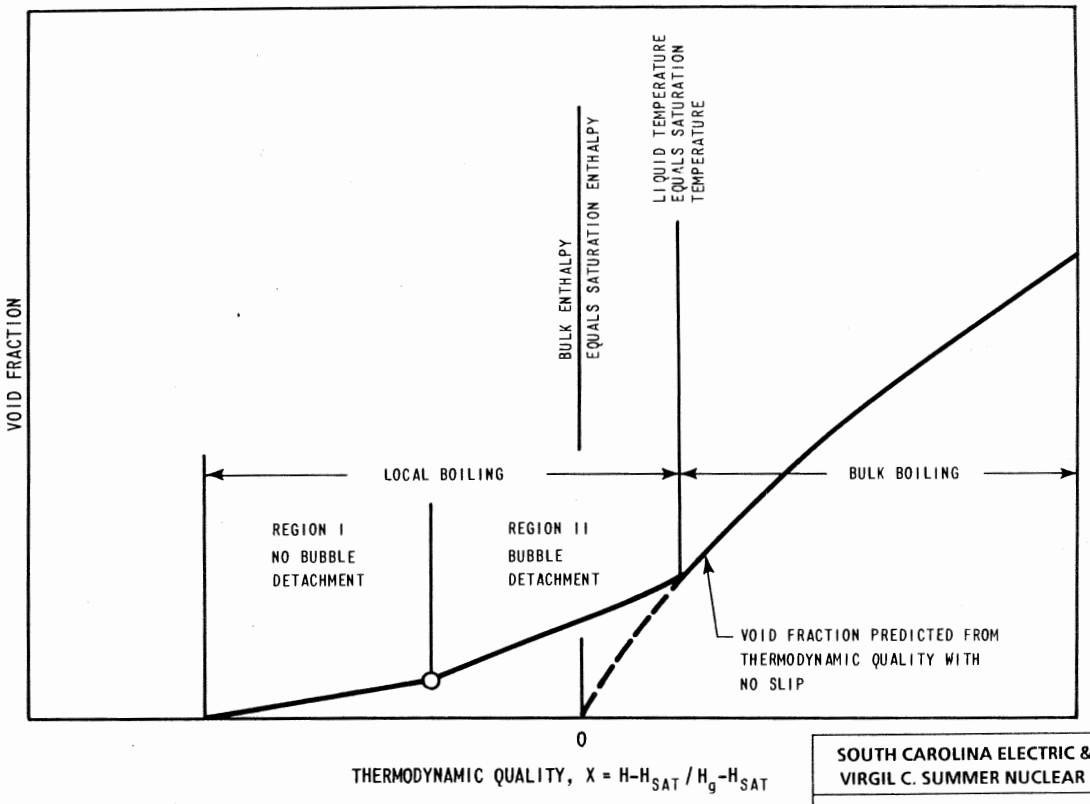
Figure 4.4-12

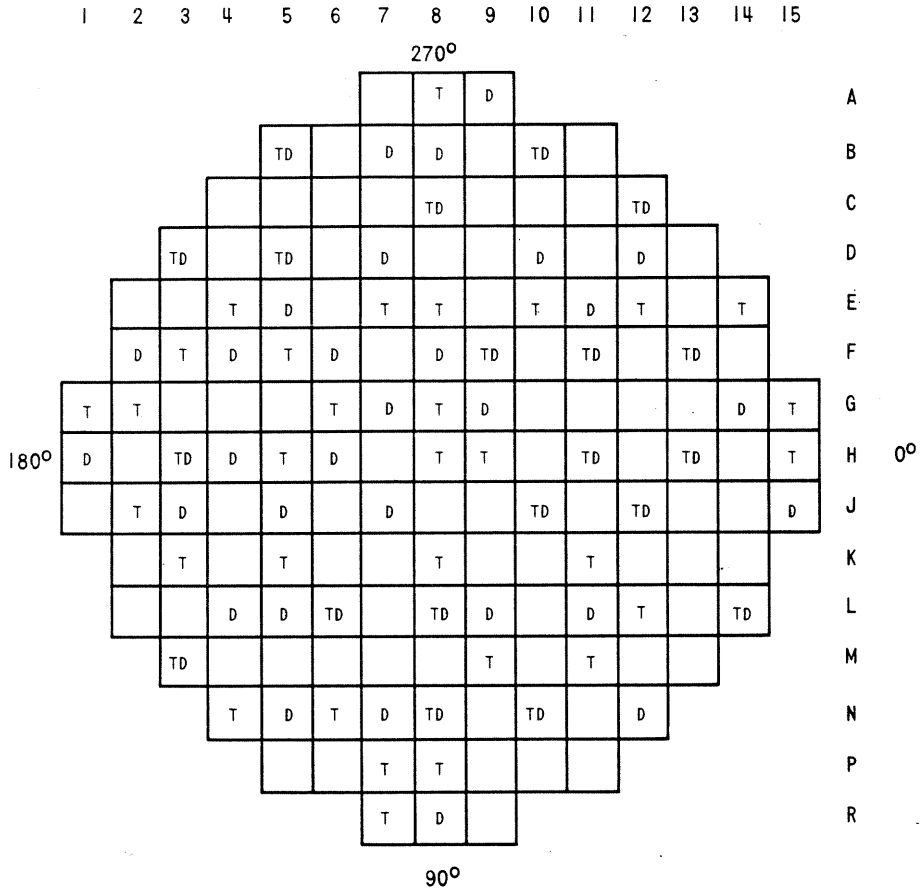
VOID FRACTION VERSUS THERMODYNAMIC QUALITY $H-H_{SAT}/H_G-H_{SAT}$



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Void Fraction versus Thermodynamic Quality $H-H_{SAT}/H_g-H_{SAT}$
Figure 4.4-12

Amendment 0
August 1984

Figure 4.4-19
DISTRIBUTION OF INCORE INSTRUMENTATION



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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Distribution of Incore Instrumentation Figure 4.4-19

V.C. Summer Nuclear Station
Safety Analysis Report

Reactor Coolant System

Chapter 5

Revision 26--Updated Online 06/25/26

This Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 5 - REACTOR COOLANT SYSTEM

5.1 Summary Description

The Reactor Coolant System (RCS) shown in Figure 5.1-1 consists of three similar heat transfer loops connected in parallel to the reactor pressure vessel. Each loop contains a reactor coolant pump, steam generator, and associated piping and valves. In addition, the system includes pressurizer, a pressurizer relief tank, interconnecting piping, and instrumentation necessary for operational control. All of the above components are located in the Reactor Building.

During operation, the RCS transfers the heat generated in the core to the steam generators where steam is produced to drive the turbine generator. Borated demineralized water is circulated in the RCS at a flowrate and temperature consistent with achieving the required reactor core thermal-hydraulic performance. The water also acts as a neutron moderator and reflector, and as a solvent for the neutron absorber (boron) used in chemical shim control.

The RCS pressure boundary provides a barrier against the release of radioactivity generated within the reactor and is designed to ensure a high degree of integrity throughout the life of the plant.

RCS pressure is controlled by the use of the pressurizer where water and steam are maintained in equilibrium by electrical heaters and water sprays. Steam is formed (by the heaters) or condensed (by the pressurizer spray) to minimize pressure variations due to contraction and expansion of the reactor coolant. Spring loaded safety valves and power operated relief valves are mounted on the pressurizer and discharge to the pressurizer relief tank, where the steam is condensed and cooled by mixing with water.

1. Reactor Coolant Pressure Boundary

   The extent of the RCS is defined as:

   a. The reactor vessel including control rod drive mechanism housings.
   b. The reactor coolant side of the steam generators.
   c. Reactor coolant pumps.
   d. A pressurizer attached to one of the reactor coolant loops.
   e. Safety and relief valves.
   f. The interconnecting piping, valves, and fittings between the principal components listed above.
   g. The piping, fittings, and valves leading to connecting auxiliary or support systems up to and including the second isolation valve (from the high pressure side) on each line.

2. RCS Components

   a. Reactor vessel

      The reactor vessel is cylindrical with a welded hemispherical bottom head and a removable flanged and gasketed hemispherical upper head. The vessel contains the core, core supporting structures, control rods, and other parts directly associated with the core.

      The vessel has inlet and outlet nozzles located in a horizontal plane just below the reactor vessel flange but above the top of the core. Coolant enters the vessel through the inlet nozzles and flows down the core barrel-vessel wall annulus, turns at the bottom, and flows up through the core to the outlet nozzles.

   b. Steam generators

      The steam generators are vertical shell and U-tube evaporators with integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel.

   c. Reactor coolant pumps

      The reactor coolant pumps are identical single-speed centrifugal units driven by air cooled, three-phase induction motors. The shaft is vertical with the motor mounted above the pump. A flywheel on the shaft above the motor provides additional inertia to extend pump coastdown. The inlet is at the bottom of the pump; discharge is on the side.

   d. Piping

      The reactor coolant loop piping is specified in sizes consistent with system requirements.

      The hot leg inside diameter is 29 inches and the inside diameter of the cold leg return line to the reactor vessel is 27-1/2 inches. The piping between the steam generator and the pump suction is increased to 31 inches in inside diameter to reduce pressure drop and improve flow conditions to the pump suction.

   e. Pressurizer

      The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads. Electrical heaters are installed through the bottom head of the vessel while the spray nozzle, relief, and safety valve connections are located in the top head of the vessel.

   f. Pressurizer relief tank

      The pressurizer relief tank is a horizontal, cylindrical vessel with hemispherical ends. Steam from the pressurizer safety and relief valves is discharged into the pressurizer relief tank through a sparger pipe under the water level. This condenses and cools the steam by mixing it with water that is near ambient temperature.

   g. Safety and relief valves

      The pressurizer safety valves are of the totally enclosed pop type. The valves are spring loaded, self actuated, and with back pressure compensation features. The power operated

relief valves limit system pressure for large power mismatch. They are operated automatically or by remote manual control. Remotely operated valves are provided to isolate the inlet to the power operated relief valves if excessive leakage occurs.

3. RCS Performance Characteristics

Tabulations of important design and performance characteristics of the RCS are provided in Table 5.1-1.

a. Reactor coolant flow

The reactor coolant flow, a major parameter in the design of the system and its components, is established with a detailed design procedure supported by operating plant performance data, by pump model tests and analyses, and by pressure drop tests and analyses of the reactor vessel and fuel assemblies. Data from all operating plants have indicated that the actual flow has been well above the flow specified for the thermal design of the plant. By applying the design procedure described below, it is possible to specify the expected operating flow with reasonable accuracy.

Three ractor coolant flowrates are identified for the various plant design considerations. The definitions of these flows are presented in the following paragraphs and the application of the definitions is illustrated by the system and pump hydraulic characteristics on Figure 5.1-2.

b. Best estimate flow

The best estimate flow is the most likely value for the actual plant operating condition. This flow is based on the best estimate of the reactor vessel, steam generator, piping flow resistance, and on the best estimate of the reactor coolant pump head flow capacity, with no uncertainties assigned to either the system flow resistance or the pump head. System pressure drops, based on best estimate flow, are presented in Table 5.1-1. Although the best estimate flow is the most likely value to be expected in operation, more conservative flowrates are applied in the thermal and mechanical designs, as noted on Figure 5.1-2.

c. Thermal design flow

Thermal design flow is the basis for the reactor core thermal performance, the steam generator thermal performance, and nominal plant parameters used throughout the design. To provide the required margin, the thermal design flow accounts for flow resistance uncertainties in the reactor vessel, steam generator, and piping as well as uncertainties in the reactor coolant pump head and the methods used to measure flowrate. The combination of these uncertainties, which include a conservative estimate of the pump discharge weir flow resistance, is equivalent to increasing the best estimate RCS flow resistance by approximately 19 percent. The intersection of this conservative flow resistance with the best estimate pump curve, as shown in Figure 5.1-2, establishes the maximum recommended thermal design flow. This procedure provides a flow margin for thermal design of approximately 4.85 percent for initial plant operation with Model D3 steam generators. The current thermal design flow is selected such that adequate margin exists between the thermal design flow and the best estimate flow for the Delta-75 steam

generators with 10 percent tube plugging. The thermal design flow is confirmed each cycle. Tabulations of important design and performance characteristics of the RCS, as provided in Table 5.1-1, are based on the thermal design flow.

d. Mechanical design flow

Mechanical design flow is the conservatively high flow used in the mechanical design of the reactor vessel internals and fuel assemblies. To assure that a conservatively high flow is specified, the mechanical design flow is based on a reduced system resistance (90 percent of the original best estimate) and on increased pump head capability (107 percent of best estimate). The intersection of this flow resistance with the higher pump curve, as shown on Figure 5.1-2, establishes the mechanical design flow. The resulting mechanical design flow of 107,100 gpm is approximately 3.98 percent greater than the original best estimate flow of 103,000 gpm.

Design pump overspeed, due to a turbine generator overspeed of 20 percent, results in a peak reactor coolant flow of 120 percent of the mechanical design flow.

e. Flows with one pump shutdown

The design procedure for calculation of flows with one pump shutdown is similar to the procedure described above for calculating flows with all pumps operating. For the case where reverse flow exists in the idle loop, the system resistance incorporates the idle loop with a locked rotor pump impeller reverse flow resistance as a flow path in parallel with the reactor vessel internals. The thermal design flow uncertainty includes a conservative application of parallel flow uncertainties (reactor internals high, idle loop low) as well as the usual component, pump, and flow measurement uncertainties, thereby resulting in a conservatively low reactor flowrate for the thermal design. The mechanical design flow uncertainty is increased slightly to account for the slightly higher uncertainties at the higher pump flows. Original thermal design, best estimate, and mechanical design flows for the Virgil C. Summer Nuclear Station with two out of three pumps operating are summarized in Table 5.1-1.

4. Interrelated Performance and Safety Function

The interrelated performance and safety functions of the RCS and its major components are listed below:

a. The RCS provides sufficient heat transfer capability to transfer the heat produced during power operation and during the initial phase of plant cooldown to the steam and power conversion system.

b. The system provides sufficient heat transfer capability to transfer the heat produced during the subsequent phase of plant cooldown and cold shutdown to the residual heat removal system.

c. The system heat removal capability under power operation and normal operational transients, including the transition from forced to natural circulation, shall assure no fuel damage within the operating bounds permitted by the reactor control and protection systems.

d. The RCS contains the water used as the core neutron moderator and reflector and as a solvent for chemical shim control.

e. The system maintains the homogeneity of soluble neutron poison concentration and rate of change of coolant temperature such that uncontrolled reactivity changes do not occur.

f. The reactor vessel is an integral part of the RCS pressure boundary and is capable of accommodating the temperatures and pressures associated with the operational transients. The reactor vessel also functions to support the reactor core and control rod drive mechanisms.

g. The pressurizer maintains the system pressure during operation and limits pressure transients. During the reduction or increase of plant load, reactor coolant volume changes are accommodated in the pressurizer via the surge line.

h. The reactor coolant pumps supply the coolant flow necessary to remove heat from the reactor core and transfer it to the steam generators.

i. The steam generators provide high quality steam to the turbine. The tube and tubesheet boundary are designed to prevent or control, to acceptable levels, the transfer of activity generated within the core to the secondary system.

j. The RCS piping serves as a boundary for containing the coolant under operating temperature and pressure conditions and for limiting leakage (and activity release) to the reactor building atmosphere. The RCS piping contains borated water which is circulated at the flowrate and temperature consistent with achieving the reactor core thermal and hydraulic performance.

5.1.1 Schematic Flow Diagram

The RCS is shown schematically in Figure 5.1-3. Included on this figure is a tabulation of principal pressures, temperatures, and the flowrate of the system under normal steady-state full power operating conditions. These parameters are based on the best estimate flow at the pump discharge. RCS volume under the above conditions is presented in Table 5.1-1.

5.1.2 Piping and Instrumentation Diagrams

The piping and instrumentation diagrams of the RCS are shown on Figure 5.1-1 (Sheets 1 through 3). The diagrams show the extent of the systems located within the reactor building and the points of separation between the RCS and the secondary (heat utilization) system.

5.1.3 Elevation Drawings

Elevation and layout drawings showing principal dimensions of the RCS, in relation to supporting and surrounding concrete structures, are shown by Figures 1.2-9 and 1.2-10.

Table 5.1-1
System Design and Operating Parameters

Original System Design And Operating Parameters With Model D3 S/Gs

Plant Design Life, years	40
Nominal Operating Pressure, psig	2,235
Total System Volume Including Pressurizer and Surge Line, ft^3	9,410 (hot)
System Liquid Volume, Including Pressurizer Water at Maximum Guaranteed Power, ft^3	8,850 (hot)
Pressurizer Spray Rate, maximum gpm	700
Pressurizer Heater Capacity, kW	1,400
Pressurizer Relief Tank Volume, ft^3	1,300

Original System Thermal and Hydraulic Data with Model D3 S/Gs

	Original Design	
	3 Pumps Running	2 Pumps Running
NSSS Power, MWt	2,785	1,671
Reactor Power, MWt	2,775	1,666
Thermal Design Flows, gpm/loop		
Active Loop-	98,000	104,200
Idle Loop(1)	-	24,300
Reactor	294,000	184,100
Total Reactor Flow, 10^6 lb/hr	109.6	68.6
Temperatures, °F		
Reactor Vessel Outlet	618.7	602.5
Reactor Vessel Inlet	556.0	547.9
Steam Generator Outlet	555.8	547.7
Steam Generator Steam	540.2	535.8
Feedwater	435	380
Steam Pressure, psia	964	930
Total Steam Flow, 10^6 lb/hr	12.20	6.8
Best Estimate Flows, gpm/loop		
Active Loop	103,000	107,700
Idle Loop(1)	-	23,100
Reactor	309,000	192,300
Mechanical Design Flows, gpm/loop		
Active Loop	107,100	112,400
Idle Loop(1)	-	24,100

Table 5.1-1 (continued)
System Design and Operating Parameters

Reactor	321,300	200,700

Current System Design and Operating Parameters with Delta-75 S/Gs

Plant Design Life, years	40
Nominal Operating Pressure, psig	2235
Total System Volume Including Pressurizer Surge Line, ft^3	9914
System Liquid Volume, Including Pressurizer Water at Maximum Guaranteed Power, ft^3	9354
Pressurizer Spray Rate, maximum gpm	700
Pressurizer Heater Capacity, kW	1366.6
Pressurizer Relief Tank Volume, ft^3	1300

Current System Thermal and Hydraulic Data with Delta-75 S/Gs
Current Design - 3 pumps Operating (3)

	Low Temperature (4)		High Temperature (5)	
	0% SGTP	10% SGTP	0% SGTP	10% SGTP
NSSS Power, MWt	2912	2912	2912	2912
Reactor Power, MWt	2900	2900	2900	2900
Thermal Design Flow, gpm/loop	92,600	92,600	92,600	92,600
Total Reactor Flow, 10^6 lb/hr	106.3	106.3	104.0	104.0
Temperatures, °F				
Reactor Vessel Outlet	607.3	607.3	621.9	621.9
Reactor Vessel Inlet	536.7	536.7	552.9	552.9
Steam Generator Outlet	536.3	536.3	552.6	552.6
Steam Generator Steam	523.7	521.7	540.4	538.4
Feedwater	440	440	440	440
Steam Pressure, psia	839	824	966	950
Total Steam Flow, 10^6 lb/hr	12.77	12.76	12.84	12.83
Best Estimate Flow, gpm/loop	106,200 (7)	--	--	103,000 (8)
Mechanical Design Flow, gpm/loop	107,100	107,100	107,100	107,100
Core Bypass flow, %	8.9	8.9	8.9	8.9

Table 5.1-1 (continued)
System Design and Operating Parameters

	System Pressure Drops[2]	
	Original Design	Current Design[5]
Reactor Vessel ΔP, psi	40.7	41.51
Steam Generator ΔP, psi	37.9	46.52
Hot Leg Piping ΔP, psi	1.8	
Pump Suction Piping ΔP, psi	4.5	
Cold Leg Piping ΔP, psi	1.9	
Total Piping ΔP, psi	8.2	8.22
Pump Head, feet	293	298

(1) Reverse direction in idle loop.
(2) System pressure drops are based on best estimate flow.
(3) Design allows hot full power T_{avg} to range from 572°F to 587.4°F.
(4) At T_{avg} of 572°F.
(5) At T_{avg} of 587.4°F.
(6) Engineered Safeguards Design Rating.
(7) Thimble plugs removed.
(8) Thimble plugs inserted.

Figure 5.1-1, Sheet 1
FSAR FIGURE REFERENCE
DRAWING E-302-601

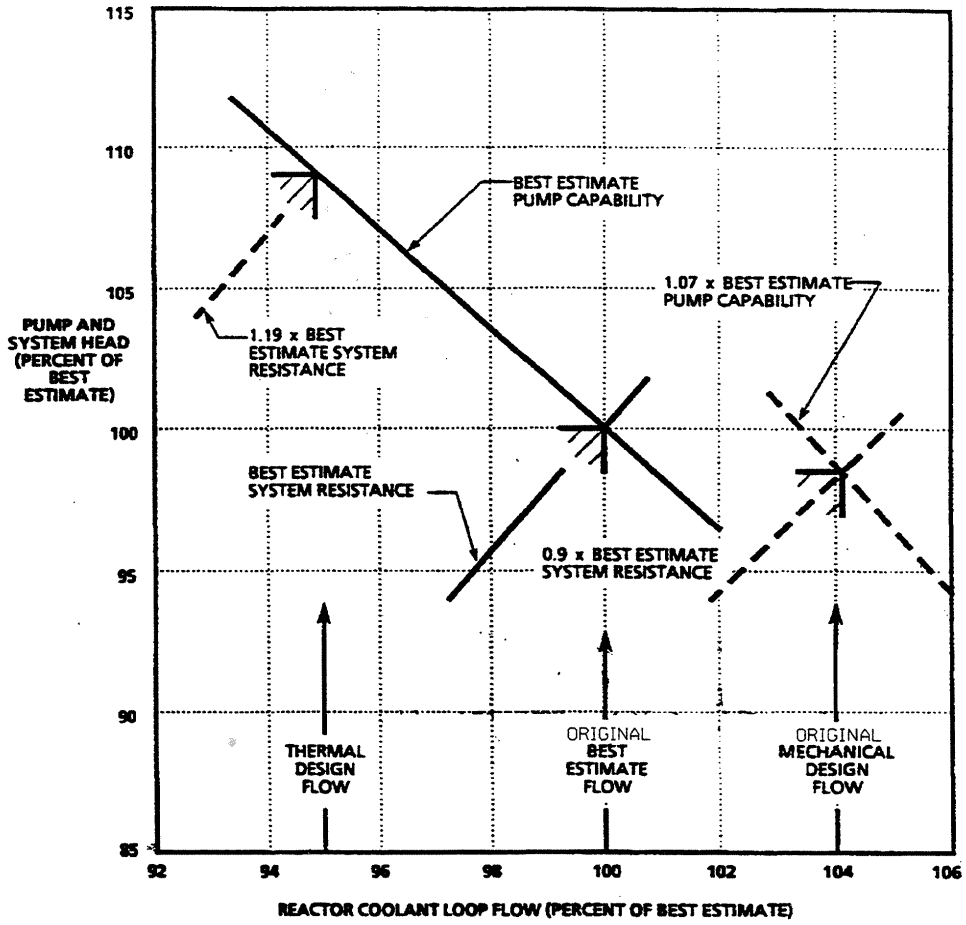
Figure 5.1-1, Sheet 2
FSAR FIGURE REFERENCE
DRAWING E-302-602

Figure 5.1-1, Sheet 3A
FSAR FIGURE REFERENCE
DRAWING E-302-603

Figure 5.1-1, Sheet 3B
FSAR FIGURE REFERENCE
DRAWING E-302-604

Figure 5.1-1, Sheet 3C
FSAR FIGURE REFERENCE
DRAWING E-302-605

Figure 5.1-2
PUMP HEAD FLOW CHARACTERISTICS
ORIGINAL DESIGN CONSIDERATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Pump Head Flow Characteristics Original Design Consideration
Figure 5.1-2

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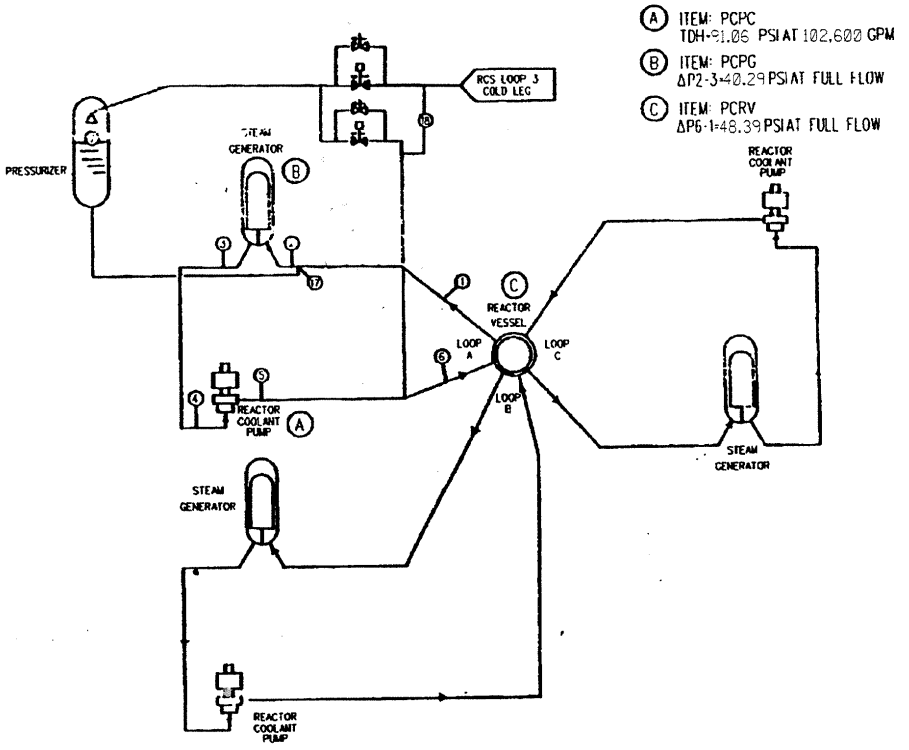
Figure 5.1-3, Sheet 1 of 3

REACTOR COOLANT SYSTEM PROCESS FLOW DIAGRAM



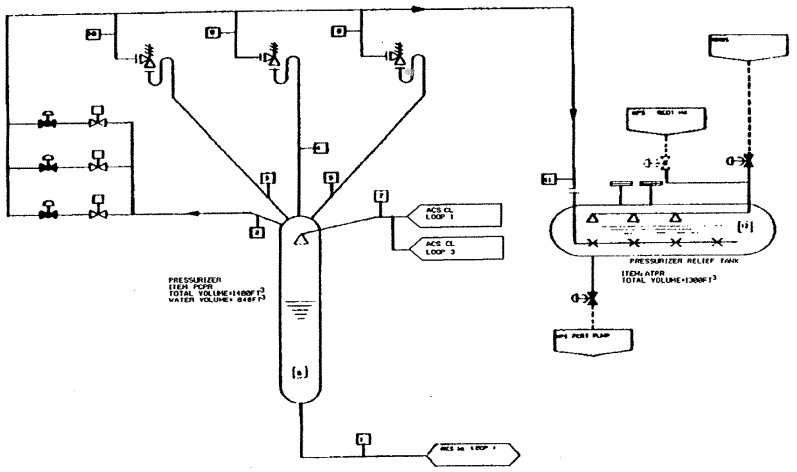
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Coolant System Process Flow Diagram (Sheet 1 of 3) Figure 5.1-3

AMENDMENT 96-02
JULY 1996

fg513sh1.m(347,jr14325)JR14325@jr14325. Mon Jul 1 11:05:17 EDT 1996

Figure 5.1-3, Sheet 2 of 3

REACTOR COOLANT SYSTEM PROCESS FLOW DIAGRAM



NOTES:

PIPING SIZE AND CLASS HAVE NOT BEEN INDICATED. REFER TO (V) PIPING AND INSTRUMENTATION DIAGRAM.

BASED ON Tavg=567.4°F

NORMAL STEADY STATE 100% POWER

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12
FLOW GPM	2.5	0	0	0	0	-	2	0	0	0	0	-
PRESSURE PSIG	2235	2235	2235	2235	2235	2235	2235	3.0	3.0	3.0	3.0	3.0
TEMPERATURE	652	652	652	652	652	652	552.6	120	120	120	120	120

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Reactor Coolant System Process Flow Diagram
(Sheet 2 of 3)

Figure 5.1-3

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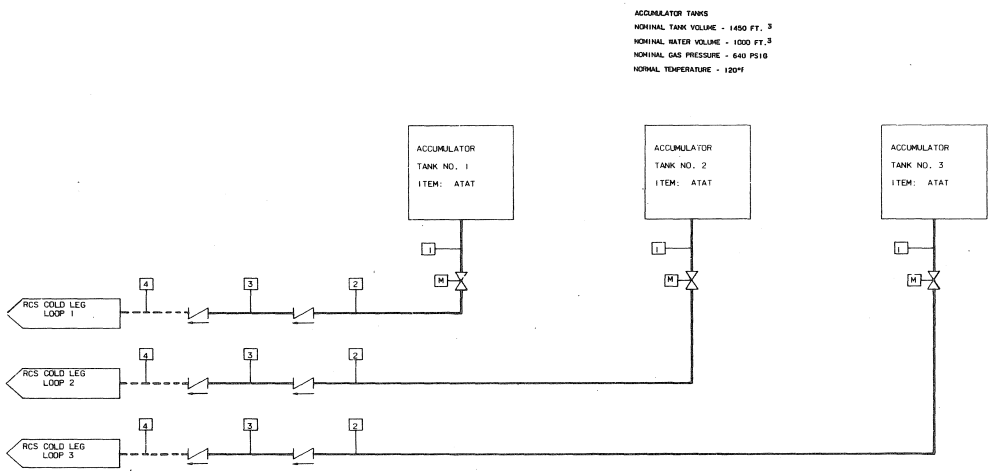
Figure 5.1-3, Sheet 3 of 3

EMERGENCY CORE COOLING SYSTEM PROCESS FLOW DIAGRAM



NOTES:

1. PIPING SIZE AND CLASS HAVE NOT BEEN INDICATED. REFER TO (N) PIPING AND INSTRUMENTATION DIAGRAM.
2. ACCUMULATORS DISCHARGE TO THE REACTOR COOLANT SYSTEM DURING THE REACTOR COOLANT SYSTEM BLOWDOWN PRESSURE TRANSIENT. ACTUAL FLOW RATES DEPEND ON TYPE OF LOSS OF COOLANT ACCIDENT AND SUBSEQUENT PRESSURE TRANSIENT. FLOW DATA PRESENTED IS THE MAXIMUM FLOW THAT OCCURS FOR DOUBLE ENDED GUILLOTINE COLD LEG LOSS OF COOLANT ACCIDENT.

TYPICAL ACCUMULATOR BLOWDOWN (DOUBLE-ENDED GUILLOTINE COLD LEG LOSS OF COOLANT ACCIDENT - NOTE 2)

LOCATION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
FLOW - GPM	10000	10000	10000	10000																		
PRESSURE - PSIG	NOTE 2	NOTE 2	NOTE 2	NOTE 2																		
TEMPERATURE - °F	120	120	120	120																		

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Emergency Core Cooling System
Process Flow Diagram
(Sheet 3 of 3)

Figure 5.1-3

Amendment 0
August 1984

5.2 Integrity of Reactor Coolant Pressure Boundary

This section presents the discussion of the measures employed to provide and maintain the integrity of the reactor coolant pressure boundary (RCPB) for the plant design lifetime. In this context, the RCPB is as defined in Section 50.2 of 10 CFR 50. In that definition, the RCPB extends to the outermost containment isolation valve in system piping which penetrates the containment and is connected to the reactor coolant system (RCS). Since other sections of this report already describe the components of these auxiliary fluid systems in detail, the discussion in this section is limited to the components of the RCS as defined in Section 5.1, unless otherwise noted.

For additional information on the components which are part of the RCPB (as defined in 10 CFR 50), and which are not described in this section, refer to the following sections:

Section 6.3 - For discussions of the RCPB components which are part of the Emergency Core Cooling System.

Section 9.3.4 - For discussions of the RCPB components which are part of the Chemical and Volume Control System.

Section 3.9.2 - For discussions of the design loadings, stress limits and analyses applied to ASME Code Class 2 and 3 components.

The phrase RCS, as used in this section, is as defined in Section 5.1. When the term RCPB is used in this section, its definition is that of Section 50.2 of 10 CFR 50.

5.2.1 Design of Reactor Coolant Pressure Boundary Components

5.2.1.1 Performance Objectives

The performance objectives of RCS are described in Section 5.1. The equipment code and classification list for the components within the RCS are given in Table 3.2-1.

The RCS, in conjunction with the reactor control and protection systems, is designed to maintain the reactor coolant at conditions of temperature, pressure, and flow adequate to protect the core. The design requirement for safety is to prevent conditions of high power, high reactor coolant temperature, or low reactor coolant pressure or combinations of these which could result in a departure from nucleate boiling ratio (DNBR) less than the design limit.

The RCS is designed to provide controlled changes in the boric acid concentration and the reactor coolant temperature. The reactor coolant is the moderator, reflector, and solvent for the chemical shim. As a result, changes in the coolant temperature or boric acid concentration affect the reactivity level in the core.

Whenever the boron concentration of the RCS is changed, plant operation will be such that good mixing is provided in order to ensure that the boron concentration is maintained uniformly throughout the RCS.

The following design bases have been selected to ensure that the uniform RCS boron concentration and temperature will be maintained:

1. Coolant flow is provided by a reactor coolant pump to ensure uniform mixing whenever the boron concentration is changed.
2. The design arrangement of the RCS eliminates deadended sections and other areas of low coolant flow in which nonhomogeneities in coolant temperature or boron concentration could develop.
3. The RCS is designed to operate within the operating parameters, particularly the coolant temperature change limitations.

Before plant cooldown is initiated, the boron concentration in the RCS is increased to the cold shutdown concentration, and the concentration is verified by sampling. Thus, during reactor cooldown, no changes are imposed on the boron concentration.

It is therefore concluded that the temperature changes imposed on the RCS during its normal modes of operation do not cause any abnormal or unacceptable reactivity changes.

Also, the design of the RCS is such that the distribution of flow around the system is not subject to the degree of variation which would be required to produce nonhomogeneities in coolant temperature or boron concentration as a result of areas of low coolant flow rate. An exception to this is the pressurizer, but it is of no concern since, as stated in the paragraph above, temperature changes do not cause unacceptable reactivity changes. Operation with one reactor coolant pump inoperable is possible under certain conditions and, in this case, there would be backflow in the associated loop, even though the pump itself is prevented from rotating backwards by its anti-rotation device. The backflow through the loop would cause departure from the normal temperature distribution around the loop but would maintain the boron concentration in the loop the same as that in the remainder of the RCS.

The range of coolant temperature variation during normal operation is limited and the associated reactivity change is well within the capability of the control rod group movement.

The RCS provides for heat transfer from the reactor to the steam generators under conditions of forced circulation flow and natural circulation flow. The heat transfer capabilities of the RCS are analyzed in Chapter 15 for various transients.

The heat transfer capability of the steam generators is sufficient to transfer, to the steam and power conversion system, the heat generated during normal operation, and during the initial phase of plant cooldown under natural circulation conditions.

During the second phase of plant cooldown and during cold shutdown and refueling, the heat exchangers of the RHRS are employed. Their capability is discussed in Section 5.5.7.

The pumps of the RCS assure heat transfer by forced circulation flow. Design flow rates are discussed in conjunction with the reactor coolant pump description in Section 5.5.1.

Initial RCS tests are performed to determine the total delivery capability of the reactor coolant pumps. Thus, it is confirmed prior to plant operation that adequate circulation is provided by the RCS.

To assure a heat sink for the reactor under conditions of natural circulation flow, the steam generators are at a higher elevation than the reactor. In the design of the steam generators, consideration is given to provide adequate tube area to ensure that the residual heat removal rate is achieved with natural circulation flow.

5.2.1.2 Design Parameters

The design pressure for the RCS is 2485 psig, except for the pressurizer relief line from the safety valves to the pressurizer relief tank, which is 600 psig, and the pressurizer relief tank, which is 100 psig. The design temperature for the RCS is 650°F, except for the pressurizer and its surge line and relief and safety valve inlet lines which are designed for 680°F, and the pressurizer relief line from the safety valve to the pressurizer relief tank, which is designed for 600°F.

Design parameters for the individual components in the RCS are given in the respective component description subsections of Section 5.5. Component hydrostatic testing is accomplished in accordance with the requirements of the ASME Code, Section III. System hydrostatic testing is discussed in Section 5.2.1.5.

5.2.1.3 Compliance with 10 CFR 50, Section 50.55a

RCS components are designed and fabricated in accordance with the rules of 10 CFR 50, Section 50.55a, "Codes and Standards." The actual addenda of the ASME Code applied in the design of each RCS component is listed in Table 5.2-1.

5.2.1.4 Applicable Code Cases

Regulatory Guides 1.84 and 1.85 are discussed in Appendix 3A.

The ASME Code Cases applicable to the manufacture of the Delta-75 replacement steam generators for the V. C. Summer Nuclear Station are:

N-20-3, applicable to the procurement and manufacture of SB-163 tubing

N-40-1, applicable to eddy current inspection data storage

N-474-1, applicable to Alloy 690 material other than tubing

2142, applicable to UNSNO6052 weld consumables

2143, applicable to UNSW86152 weld consumables

Code cases for which the NRC Staff has provided a disposition are listed in Regulatory Guides 1.84 and 1.85.

Code Case N-60-4 is issued for the reactor internals replacement guide tube support pins and nuts. The limitation on maximum yield strength for the code case included in Regulatory Guide 1.85 is satisfied.

5.2.1.5 Design Transients

The following five ASME operating conditions are considered in the design of the RCS.

1. Normal Conditions

   Any condition in the course of startup, operation in the design power range, hot standby, and system shutdown, other than upset, emergency, faulted, or testing conditions.

2. Upset Conditions (Incidents of Moderate Frequency)

   Any deviation from normal conditions anticipated to occur often enough that design should include a capability to withstand the conditions without operational impairment. The upset conditions include those transients which result from any single operator error or control malfunction, transients caused by a fault in a system component requiring its isolation from the system, and transients due to loss of load or power. Upset conditions include any abnormal incidents not resulting in a forced outage and also forced outages for which the corrective action does not include any repair of mechanical damage. The estimated duration of an upset condition shall be included in the design specifications.

3. Emergency Conditions (Infrequent Incidents)

   Those deviations from normal conditions which require shutdown for correction of the conditions or repair of damage in the system. The conditions have a low probability of occurrence but are included to provide assurance that no gross loss of structural integrity will result as a concomitant effect of any damage developed in the system. The total number of postulated occurrences for such events shall not cause more than 25 stress cycles having an Sa value greater than that for 106 cycles from the applicable fatigue design curves of the ASME Code, Section III.

4. Faulted Conditions (Limiting Faults)

   Those combinations of conditions associated with extremely low probability, postulated events whose consequences are such that the integrity and operability of the nuclear energy system may be impaired to the extent that consideration of public health and safety is

involved. Such considerations require compliance with safety criteria as may be specified by jurisdictional authorities.

5. Testing Conditions

   Testing conditions are those pressure overload tests including hydrostatic tests, pneumatic tests, and leak tests specified. Other types of tests shall be classified under normal, upset, emergency, or faulted conditions.

To provide the necessary high degree of integrity for the equipment in the RCS, the transient conditions selected for equipment fatigue evaluation are based upon a conservative estimate of the magnitude and frequency of the temperature and pressure transients resulting from various operating conditions in the plant. To a large extent, the specific transient operating conditions to be considered for equipment fatigue analyses are based upon engineering judgment and experience. The transients selected are representative of operating conditions which prudently should be considered to occur during plant operation and are sufficiently severe or frequent to be of possible significance to component cyclic behavior. The transients selected may be regarded as a conservative representation of transients which, used as a basis for component fatigue evaluation, provide confidence that the component is appropriate for its application over the design life of the plant.

The following design conditions are given in the equipment specifications for RCS components.

The design transients and the number of cycles of each that is normally used for fatigue evaluations are shown in Table 5.2-2. In accordance with the ASME Code, faulted conditions are not included in fatigue evaluations.

Loading combination and allowable stresses for ASME Code, Section III, Class 1 components and supports are given in Tables 5.2-3 and 5.2-4.

5.2.1.5.1 Normal Conditions

The following primary system transients are considered normal conditions:

1. Heatup and cooldown at 100°F per hour.
2. Unit loading and unloading at 5% of full power per minute.
3. Step load increase and decrease of 10% of full power.
4. Large step load decrease with steam dump.
5. Steady-state fluctuations.
6. Thermal stratification in the surge line.

Additionally, a new transient was identified when the Model D3 steam generators were replaced with Delta-75 steam generators. The transient is entitled "Feedwater Heaters out of Service" and

bounds the entire spectrum of feedwater heater malfunctions (both high pressure and low pressure heaters).

1. Heatup and Cooldown at 100°F per Hour

   The design heatup and cooldown cases are conservatively represented by continuous operations performed at a uniform temperature rate of 100°F per hour.(These operations can take place at lower rates approaching the minimum of 0°F per hour. The expected normal rates are 50°F per hour.) For these cases, the heatup occurs from ambient (assumed to be 120°F) to the no-load temperature and pressure condition, and the cooldown represents the reverse situation. In actual practice, the rate of temperature change of 100°F per hour will not be attained because of other limitations such as:

   a. Material ductility considerations which establish maximum permissible temperature rates of change, as a function of plant pressure and temperature, which are below the design rate of 100°F per hour.
   b. Slower initial heatup rates when using pump energy only.
   c. Interruptions in the heatup and cooldown cycles due to such factors as drawing a pressurizer steam bubble, rod withdrawal, sampling, water chemistry, and gas adjustments.

2. Unit Loading and Unloading at 5% of Full Power per Minute

   The unit loading and unloading cases are conservatively represented by a continuous and uniform ramp power change of 5% per minute between 15% load and full load. This load swing is the maximum possible, consistent with operation under automatic reactor control. The reactor temperature will vary with load as prescribed by the reactor control system.

3. Step Load Increase and Decrease of 10% of Full Power

   The ± 10% step change in load demand is a transient which is assumed to be a change in turbine control valve opening due to disturbances in the electrical network into which the plant output is tied. The reactor control system is designed to restore plant equilibrium without reactor trip following a ± 10% step change in turbine load demand initiated from nuclear plant equilibrium conditions in the range between 15% and 100% full load, the power range for automatic reactor control. In effect, during load change conditions, the reactor control system attempts to match turbine and reactor outputs in such a manner that peak reactor coolant temperature is minimized and reactor coolant temperature is restored to its programmed setpoint at a sufficiently slow rate to prevent excessive pressurizer pressure decrease.

   Following a step decrease in turbine load, the secondary side steam pressure and temperature initially increase, since the decrease in nuclear power lags behind the step decrease in turbine load. During the same increment of time, the RCS average temperature and pressurizer pressure also initially increase. Because of the power mismatch between the turbine and

reactor and the increase in reactor coolant temperature, the control system automatically inserts the control rods to reduce core power. With the load decrease, the reactor coolant temperature will ultimately be reduced from its peak value to a value below its initial equilibrium value at the inception of the transient. The reactor coolant average temperature setpoint change is made as a function of turbine pressure measurement. The pressurizer pressure will also decrease from its peak pressure value and follow the reactor coolant decreasing temperature trend. At some point during the decreasing pressure transient, the saturated water in the pressurizer begins to flash, which reduces the rate of pressure decrease. Subsequently, the pressurizer heaters come on to restore the plant pressure to its normal value.

Following a step increase in turbine load, the reverse situation occurs; i.e., the secondary side steam pressure and temperature initially decrease and the reactor coolant average temperature and pressure initially decrease. The control system automatically withdraws the control rods to increase core power. The decreasing pressure transient is reversed by actuation of the pressurizer heaters and eventually the system pressure is restored to its normal value. The reactor coolant average temperature will be raised to a value above its initial equilibrium value at the beginning of the transient.

4. Large Step Load Decrease With Steam Dump

   This transient applies to a step decrease in turbine load from full power of such magnitude that the resultant rapid increase in reactor coolant average temperature and secondary side steam pressure and temperature will automatically initiate a secondary side steam dump that will prevent both reactor trip and lifting of steam generator safety valves. Thus, since the Virgil C. Summer Nuclear Station is designed to accept a step decrease of 95% from full power (complete loss of outside load, but retaining the plant auxiliary load of 5%), the steam dump system provides the heat sink to accept approximately 93.6% of the turbine load. The remaining percentage of the total step change is assumed by the reactor control system control rods. If a steam dump system was not provided to cope with this transient, there would be such a strong mismatch between what the turbine is demanding and what the reactor is delivering that a reactor trip and lifting of steam generator safety valves would occur.

5. Steady-State Fluctuations

   It is assumed that the reactor coolant temperature and pressure at any point in the system vary around the nominal (steady-state) values. For design purposes, two cases are considered:

   a. Initial Fluctuations

      These are due to control rod cycling during the first 20 full power months of reactor operation. Temperature is assumed to vary ± 3°F and pressure by± 25 psi, once during each 2 minute period. The total number of occurrences is limited to 1.5×10^5. These fluctuations are assumed to occur consecutively and not simultaneously with the random fluctuations.

b. Random Fluctuations

Temperature is assumed to vary by ± 0.5°F and pressure by ± 6 psi, once every 6 minutes. With a 6 minute period, the total number of occurrences during the plant design life does not exceed 3.0×10^6.

6. Thermal Stratification in the Surge Line

On December 20, 1988, the NRC issued Bulletin No. 88-11 regarding pressurizer surge line thermal stratification. The Bulletin requested utilities to establish and implement a program to confirm pressurizer surge line integrity in view of the occurrence of thermal stratification.

Thermal stratification in the pressurizer surge line is the direct result of the difference in densities between the pressurizer water and the generally cooler hot leg water. The lighter pressurizer water tends to float on the cooler heavier hot leg water. The potential for stratification is increased as the difference in temperature between the pressurizer and the hot leg increases and as the insurge or outsurge flow rates decrease.

At power, when the difference in temperature between pressurizer and hot leg is relatively small, the extent and effects of stratification have been observed to be small. However, during certain modes of plant heatup and cooldown, this difference in system temperature could be as large as 320°F, in which case the effects of stratification must be accounted for.

The heatup and cooldown transients for the surge line were developed from monitoring data, historical operation, and operator interviews conducted at a large number of plants. The transients were built upon the extensive work done for the Westinghouse Owners Group coupled with plant specific considerations for Virgil C. Summer.

Transients in the surge line are characterized as either insurges, outsurges, or fluctuations. Insurges and outsurges are the more severe transients and result in the greatest change in temperature in the top or bottom of the pipe. An insurge may cool the entire pipe cross section significantly, to very close to the temperature of the RCS hot leg. Conversely, an outsurge can sweep the line and heat the pipe to close to the temperature of the pressurizer.

Fluctuations, as opposed to the insurge-outsurge transients, are caused by relatively insignificant surges and result in variations in the hot-cold interface level. These variations in the interface level do not change the overall global displacement of the pipe and, hence, are analyzed as changes in local stress only.

The redefinition of the thermal fluid transients experienced by the surge line during normal conditions was necessary to reflect the indirectly observed fluid temperature distributions. These redefined thermal fluid transients were developed based on the existing design transient system parameters assumed to exist at the time of the postulated transient and the knowledge gained from the monitoring programs. The redefined thermal fluid transients conservatively account for the thermal stratification phenomena.

7. Feedwater Heaters Out of Service

   These transients occur when one or more feedwater heaters are taken out of service. For conservatism, it is assumed that one entire train of high pressure heaters is removed from service, thereby making the transient bounding with regard to the possibility of either a low pressure or high pressure heater train being removed from service. Upon identification of the transient, power should be reduced to 80% of nominal, and the plant allowed to stabilize. The affected heater train must be taken out of service.

5.2.1.5.2 Upset Conditions

The following primary system transients are considered upset conditions:

1. Loss of load (without immediate reactor trip).
2. Loss of power.
3. Partial loss of flow.
4. Reactor trip from full power.
5. Inadvertent auxiliary spray.
6. Operating basis earthquake (OBE).
7. Excessive feedwater flow.

1. Loss of Load (Without Immediate Reactor Trip)

   This transient applies to a step decrease in turbine load from full power (turbine trip) without immediately initiating a reactor trip and represents the most severe pressure transient on the RCS under upset conditions. The reactor eventually trips as a consequence of a high pressurizer level trip initiated by the Reactor Protection System (RPS). Since redundant means of tripping the reactor are provided as part of the RPS, transients of this nature are not expected, but are included to ensure a conservative design.

2. Loss of Power

   This transient applies to a blackout situation involving the loss of all outside electrical power to the station, followed by reactor and turbine trips. Under these circumstances, the reactor coolant pumps are de-energized and, following coastdown of the reactor coolant pumps, natural circulation builds up in the system to some equilibrium value. This condition permits removal of core residual heat through the steam generators which at this time are receiving feedwater from the Emergency Feedwater System. Steam is removed for reactor cooldown through atmospheric relief valves provided for this purpose.

3. Partial Loss of Flow

   This transient applies to a partial loss of flow from full power, in which a reactor coolant pump is tripped out of service as the result of a loss of power to that pump.

   The consequences of such an accident are a reactor and turbine trip on low reactor coolant flow, followed by automatic opening of the steam dump system and flow reversal in the affected loop. The flow reversal causes reactor coolant, at cold leg temperature, to pass through the steam generator and be cooled still further. This cooler water then flows through the hot leg piping and enters the reactor vessel outlet nozzles. The net result of the flow reversal is a sizable reduction in the hot leg coolant temperature of the affected loop.

4. Reactor Trip From Full Power

   A reactor trip from full power may occur from a variety of causes resulting in temperature and pressure transients in the RCS and in the secondary side of the steam generator. This is the result of continued heat transfer from the reactor coolant in the steam generator. The transient continues until the reactor coolant and steam generator secondary side temperatures are in equilibrium at zero power conditions. A continued supply of feedwater and controlled dumping of steam remove the core residual heat and prevent the steam generator safety valves from lifting. The reactor coolant temperature and pressure undergo a rapid decrease from full power values as the RPS causes the control rods to move into the core.

5. Inadvertent Auxiliary Spray

   The inadvertent pressurizer auxiliary spray transient will occur if the auxiliary spray valve is opened inadvertently during normal operation of the plant. This will introduce cold water into the pressurizer with a very sharp pressure decrease as a result.

6. Operating Basis Earthquake

   The mechanical stresses resulting from the OBE are considered on a component basis. Fatigue analysis, where required by the codes, is performed by the supplier as part of the stress analysis report. The earthquake loads are a part of the mechanical loading conditions specified in the equipment specifications. The origin of their determination is separate and distinct from those transients resulting from fluid pressure and temperature. They are, however, considered in the design analysis. The number of occurrences for fatigue evaluation is given in Section 3.7.3.1.

7. Excessive Feedwater Flow

   The pressure and temperature variations associated with this transient are considered in connection with analyzing the primary and secondary sides of the steam generator, the RCS, and the pressurizer.

This transient is conservatively defined as an umbrella case to cover the occurrence of several events of the same general nature. These include:

- Inadvertent opening of a feedwater control valve;
- Turbine overspeed (110%) with an open feedwater control valve;
- Small steam break with an open feedwater control valve.

The excessive feedwater flow transient results from inadvertent opening of a feedwater control valve when the plant is at hot shutdown and the steam generator is in the no-load condition. The Feedwater, Condensate, and Heater Drain Systems are in operation. The stem of a feedwater control valve has been assumed to fail, with the valve immediately reaching the full-open position. The feedwater flow to the affected loop is assumed to start from essentially zero flow to the value determined by the system resistance and the developed head of all operating feedwater pumps, with no main feedwater flow. Steam flow is assumed to remain at zero, and the temperature of the feedwater entering the steam generator is conservatively assumed to be 32°F. Feedwater flow is isolated on a reactor coolant low T_{avg} signal; a low pressurizer pressure signal actuates the Safety Injection System. Emergency feedwater flow, initiated by the safety injection signal, is assumed to continue with all pumps discharging into the affected steam generator. It is also assumed, for conservatism in the secondary side analysis, that emergency feedwater flows to the steam generators not affected by the malfunctioned valve, in the "unfailed loops." Plant conditions stabilize at the values reached in 600 seconds, at which time emergency feedwater flow is terminated. The plant is then either taken to cold shutdown, or returned to the no-load condition at a normal heatup rate with the Auxiliary Feedwater System under manual control.

For design purposes, this transient is assumed to occur 30 times during the life of the plant.

5.2.1.5.3 Emergency Conditions

No transient is classified as an emergency condition.

5.2.1.5.4 Faulted Conditions

The following primary system transients are considered faulted conditions:

1. Reactor coolant pipe break (large loss of coolant accident).
2. Large steam line break.
3. Steam generator tube rupture.
4. Safe shutdown earthquake (SSE).

1. Reactor Coolant Pipe Break (Large Loss of Coolant Accident)

Following rupture of a reactor coolant pipe resulting in a large loss of coolant, the primary system pressure decreases, causing the primary system temperature to decrease. Because of

the rapid blowdown of coolant from the system and the comparatively large heat capacity of the metal sections of the components, it is likely that the metal will still be at or near the operating temperature by the end of blowdown. It is conservatively assumed that the ECCS is actuated to introduce water at a minimum temperature of 32°F into the RCS. The safety injection signal will also result in reactor and turbine trips.

2. Large Steam Line Break

   This transient is based on the complete severance of the largest steam line. The following conservative assumptions were made:

   a. The reactor is initially in a hot, zero-power condition.
   b. The steam line break results in immediate reactor trip and ECCS actuation.
   c. A large shutdown margin, coupled with no feedback or decay heat, prevents heat generation during the transient.
   d. The ECCS operates at design capacity and repressurizes the RCS within a relatively short time.

   The above conditions result in the most severe temperature and pressure variations which the primary system will encounter during a steam break accident.

3. Steam Generator Tube Rupture

   This accident postulates the double ended rupture of a steam generator tube, resulting in a decrease in pressurizer level and reactor coolant pressure. Reactor trip will occur due to the resulting safety injection signal. In addition, safety injection actuation automatically isolates the feedwater lines by closing the feedwater isolation and control valves. When this accident occurs, some of the reactor coolant blows down into the affected steam generator causing the shell side level to rise. The primary system pressure is reduced below the secondary safety valve setting. Subsequent recovery procedures call for isolation of the steam line leading from the affected steam generator. This accident will result in a transient which is no more severe than that associated with a reactor trip from full power. Therefore it requires no special treatment insofar as fatigue evaluation is concerned, and no specific number of occurrences is postulated.

4. Safe Shutdown Earthquake

   The mechanical dynamic or static equivalent loads due to the vibratory motion of the SSE are considered on a component basis.

5.2.1.5.5 Test Conditions

The following primary system transients under test conditions are discussed:

1. Turbine roll test.
2. Primary side hydrostatic test.
3. Secondary side hydrostatic test.
4. Primary side leakage test.

1. Turbine Roll Test

   This transient is imposed upon the plant during the hot functional test period for turbine cycle checkout. Reactor coolant pump power will be used to heat the reactor coolant to operating temperature (no-load conditions) and the steam generated will be used to perform a turbine roll test. However, the plant cooldown during this test will exceed the 100°F per hour design rate.

   This transient occurs before plant startup and the number of cycles is therefore independent of other operating transients.

2. Primary Side Hydrostatic Test

   The pressure tests include both shop and field hydrostatic tests which occur as a result of component or system testing. This hydrotest is performed at a water temperature which is compatible with reactor vessel material ductility requirements and a test pressure of 3107 psig (1.25 times design pressure). In this test, the RCS is pressurized to 3107 psig coincident with steam generator secondary side pressure of 0 psig. The number of cycles is independent of other operating transients.

3. Secondary Side Hydrostatic Test

   The secondary side of the steam generator is pressurized to 1.25 design pressure with a minimum water temperature of 120°F coincident with the primary side at 0 psig.

   These tests may be performed either prior to plant startup, or subsequently following shutdown for major repairs or both. The number of cycles is therefore independent of other operating transients.

4. Primary Side Leakage Test

   Subsequent to each time the primary system has been opened, a leakage test will be performed. During this test, the primary system pressure is, for design purposes, raised to 2500 psia, with the system temperature above the minimum temperature imposed by reactor vessel material ductility requirements, while the system is checked for leaks. In actual

practice, the primary system is pressurized to less than 2500 psia as measured at the pressurizer, to prevent the pressurizer safety valves from lifting during the test.

During this leakage test, the secondary side of the steam generator must be pressurized so that the pressure differential across the tubesheet does not exceed 1600 psi. This is accomplished with the steam, feedwater, and blowdown lines closed off.

5.2.1.6 Identification of Active Pumps and Valves

Valves in the RCPB are tabulated in Section 3.9.2. These valves are identified as being either active or inactive.

Active valves are those whose operability through a mechanical motion is relied upon to perform a safety function during the transients or events considered in each operating condition category. Inactive valves have no required motion, they must only retain their structural integrity.

There are no active pumps in the RCPB. The reactor coolant pumps are classified as inactive.

The design methods and procedures which are used to show that active valves listed in Section 3.9.2 will operate during a faulted condition are described in Section 3.9.2.4.

5.2.1.7 Design of Active Pumps and Valves

The methods that will be used to assure that pumps required to function and valves required to open or close during (or following) a specified plant condition are described in Section 3.9.2.4.

5.2.1.8 Inadvertent Operation of Valves

Those valves which are used in the isolation of the RCPB during normal plant operation, and are not relied on to function after an accident, are redundant valves and their inadvertent operation will not increase the severity of any transient.

5.2.1.9 Stress and Pressure Limits

Inactive components are designed in accordance with the ASME Code, Section III. The codes and stress limits used for Class 1 components are summarized in Section 5.2.1.10.

5.2.1.10 Stress Analysis for Structural Adequacy

5.2.1.10.1 Loading Conditions

The structural stress analyses performed on the RCS consider the loadings specified as shown in Table 5.2-3. These loads result from thermal expansion, pressure, weight, OBE, SSE, design basis loss of coolant accident, and plant operational thermal and pressure transients.

5.2.1.10.2 Analysis of the Reactor Coolant Loop and Supports

The loads used in the analysis of the reactor coolant loop piping are described in detail below:

1. Pressure

   Pressure loading is identified as either membrane design pressure or general operating pressure, depending upon its application. The membrane design pressure is used in connection with the longitudinal pressure stress and minimum wall thickness calculations in accordance with the ASME Code.

   The term operating pressure is used in connection with determination of the system deflections and support forces. The steady-state operating hydraulic forces based on the system initial pressure are applied as general operating pressure loads to the reactor coolant loop model at changes in direction or flow area.

2. Weight

   A dead weight analysis is performed to meet Code requirements by applying a 1.0 g load downward on the complete piping system. The piping is assigned a distributed mass or weight as a function of its properties. This method provides a distributed loading to the piping system as a function of the weight of the pipe and contained fluid during normal operating conditions.

3. Seismic

   The forcing functions for the coupled building/loop non-linear time history analysis are derived from dynamic response analyses of the reactor building with soil springs subjected to seismic ground motion. Input is in the form of time history ground acceleration that is applied at the anchor point of the soil springs.

   For the OBE and SSE seismic analyses, 2 and 4% critical damping, respectively, are used in the reactor coolant loop/supports system analysis. When combining the results of the SSE seismic analysis with the loss of coolant accident analysis results, 5% critical damping is used for the SSE.

4. Loss of Coolant Accident

   Blowdown loads are developed in the broken and unbroken reactor coolant loops as a result of transient flow and pressure fluctuations following a postulated pipe break in one of the reactor coolant loops branch lines. Structural consideration of dynamic effects of postulated pipe breaks requires postulation of a finite number of break locations. Postulated pipe break locations are given in Section 3.6.2.

   Broken loop time history dynamic analysis is performed for these postulated break cases. Hydraulic models are used to generate time-dependent hydraulic forcing functions used in

the analysis of the reactor coolant loop for each break case. For further description of the hydraulic forcing functions, refer to Section 3.6.2.2.

5. Transients

   The Code requires satisfaction of certain requirements relative to operating transient conditions. Operating transients are tabulated in Section 5.2.1.5.

   The vertical thermal growth of the reactor pressure vessel nozzle centerlines is considered in the thermal analysis to account for equipment nozzle displacement as an external movement.

   The hot moduli of elasticity E, the coefficient of thermal expansion at the metal temperature a, the external movements transmitted to the piping due to vessel growth, and the temperature rise above the ambient temperature °T, define the required input data to perform the flexibility analysis for thermal expansion.

   To provide the necessary high degree of integrity for the RCS, the transient conditions selected for fatigue evaluation are based on conservative estimates of the magnitude and anticipated frequency of occurrence of the temperature and pressure transients resulting from various plant operation conditions.

5.2.1.10.3 Reactor Coolant Loop Models and Methods

The analytical methods used in obtaining the solution consist of the transfer matrix method and stiffness matrix formulation for the static structural analysis, the time-history method for seismic dynamic analysis, and time history integration method for the loss of coolant accident dynamic analysis.

The integrated reactor coolant loops/supports system model is the basic system model used to compute loadings on components, component supports, and piping. The system model includes the stiffness and mass characteristics of the reactor coolant loop piping and components, the stiffness of supports, the stiffnesses of auxiliary line piping which affect the system, and the stiffness of piping restraints. The deflection solution of the entire system is obtained for the various loading cases from which the internal member forces and piping stresses are calculated.

1. Static

   The reactor coolant loop/supports system model, constructed for the WESTDYN computer program, is represented by an ordered set of data which numerically describes the physical system. Figure 5.2-1 shows an isometric line schematic of this mathematical model. The steam generator and reactor coolant pump vertical and lateral support members are described in Section 5.5.14.

   The spatial geometric description of the reactor coolant loop model is based upon the reactor coolant loop piping layout and equipment drawings. The node point coordinates and incremental lengths of the members are determined from these drawings. Geometrical

properties of the piping and elbows along with the modulus of elasticity E, the coefficient of thermal expansion α, the average temperature change from ambient temperature °T, and the weight per unit length are specified for each element. The primary equipment supports are represented by stiffness matrices which define restraint characteristics of the supports. Due to the symmetry of the static loadings, the reactor pressure vessel centerline is represented by a fixed boundary in the system mathematical model. The vertical thermal growth of the reactor vessel nozzle centerline is considered in the construction of the model.

The model is made up of a number of sections, each having an overall transfer relationship formed from its group of elements. The linear elastic properties of the section are used to define the stiffness matrix for the section. Using the transfer relationship for a section, the loads required to suppress all deflections at the ends of the section arising from the thermal and boundary forces for the section are obtained. These loads are incorporated into the overall load vector.

After all the sections have been defined in this matter, the overall stiffness matrix and associated load vector to suppress the deflection of all the network points is determined. By inverting the stiffness matrix, the flexibility matrix is determined. The flexibility matrix is multiplied by the negative of the load vector to determine the network point deflections due to the thermal and boundary force effects. Using the general transfer relationship, the deflections and internal forces are then determined at all node points in the system.

The static solutions for deadweight, thermal, and general pressure loading conditions are obtained by using the WESTDYN computer program. The derivation of the hydraulic loads for the loss of coolant accident analysis of the loop is covered in Section 3.6.4.

2. Seismic

The model used in the static analysis is modified for the dynamic analysis by including the mass characteristics of the piping and equipment. All of the piping loops coupled with the reactor building with soil springs, equipment, and equipment support system are included in the system model. The effect of the equipment motion on the reactor coolant loop/supports system is obtained by modeling the mass and the stiffness characteristics of the equipment in the overall system model.

The steam generator is typically represented by 4 discrete masses. The lower mass is located at the intersection of the centerlines of the inlet and outlet nozzles of the steam generator. The second mass is located at the steam generator upper support elevation, the third mass is located at the feedwater nozzle elevation, and the fourth mass is at the top of the steam generator.

The reactor coolant pump is typically represented by a two discrete mass model. The lower mass is located at the intersection of the centerlines of the pump suction and discharge nozzles.

The reactor vessel and core internals are represented by approximately 14 discrete masses. The masses are lumped at various locations along the length of the vessel and along the length of the representation of the core internals.

The component upper and lower lateral supports are inactive during plant heatup, cooldown, and normal plant operating conditions. However, these restraints become active when the plant is at power and under the rapid motions of the reactor coolant loop components that occur from the dynamic loadings and are represented by stiffness matrices and/or individual tension or compression spring members in the dynamic model. The analyses are performed at the full power condition.

The seismic analysis consists of applying an acceleration time history to a coupled reactor building, reactor coolant loop piping, equipment, and equipment support system.

The time history seismic analyses were performed using the proprietary Westinghouse computer code WECAN.

The reduced modal analysis method and modal superposition method are used in the time history seismic analyses. The reduced modal analysis option is used to determine the natural frequencies and mode shapes for a linear, undamped structure.

The modal superposition method gives a time history solution for the response of an arbitrary structure subjected to known nodal forces or ground acceleration time histories. The structure may include linear and non-linear elements.

The seismic responses of the reactor coolant loop support system are computed by performing a time history analysis for each of the three shock directions. The results of the three shock directions are combined by:

$$R_T = [\Sigma_{i=1}^{i=3} R_i^2]^{1/2}$$

where:

R_T = total combined response where i corresponds to each of three orthogonal shock direction combined responses (two horizontal and one vertical shock).

3. Loss of Coolant Accident

The mathematical model used in the static analyses is modified for the loss of coolant accident analysis to represent the severance of the reactor coolant loop piping at the postulated break location. Modifications include addition of the mass characteristic of the piping and equipment. To obtain the proper dynamic solution, a mass, located at the break, is included in the mathematical model. The natural frequencies and eigenvectors are determined from this pipe break model.

The time-history hydraulic forces at the node points are combined to obtain the forces and acting at the corresponding structural lumped-mass node points.

The dynamic structural solution for the full power loss of coolant accident is obtained by using a modified-predictor-corrector- integration technique and normal mode theory.

When elements of the system can be represented as single acting members (tension or compression members), they are considered as nonlinear elements, which are represented mathematically by the combination of a gap, a spring, and a viscous damper. The force in this nonlinear element is treated as an externally applied force in the overall normal mode solution. Multiple nonlinear elements can be applied at the same node, if necessary.

The time-history solution is performed in program WESTDYN. The input to this subprogram consists of the natural frequencies, normal modes, applied forces, and nonlinear elements. The natural frequencies and normal modes for the modified reactor coolant loop dynamic model are determined with the WESTDYN program. To properly simulate the release of the strain energy in the pipe, the internal forces in the system at the postulated break location due to the initial steady-state hydraulic forces are determined. The release of the strain energy is accounted for by applying the negative of these internal forces as a step function loading. The initial conditions are equal to zero because the solution is only for the transient problem (the dynamic response of the system from the static equilibrium position). The time-history displacement solution of all dynamic degrees of freedom is obtained using subprogram WESTDYN and employing 4% critical damping.

The loss of coolant accident displacements of the reactor vessel is applied in time history form as input to the dynamic analysis of the reactor coolant loop. The loss of coolant accident analysis of the reactor vessel includes all the forces acting on the vessel including internals reactions, cavity pressure loads, and loop mechanical loads. The reactor vessel analysis is described in Section 5.2.1.10.6.

The time-history displacement response of the loop is used in computing support loads and in performing stress evaluation of the reactor coolant loop piping.

The support loads [F] are computed by multiplying the support stiffness matrix [K] and the displacement vector [δ] at the support point. The support loads are used in the evaluation of the supports.

The time-history displacements are used to determine the internal forces, deflections, and stresses at each end of the piping elements. For this calculation the displacements are treated as imposed deflections on the reactor coolant loop masses. The results of this solution are used in the piping stress evaluation.

4. Transients

Operating transients in a nuclear power plant cause thermal and/or pressure fluctuations in the reactor coolant fluid. The thermal transients cause time-varying temperature distributions

across the pipe wall. These temperature distributions resulting in pipe wall stresses may be further subdivided in accordance with the Code into three parts, a uniform, a linear, and a nonlinear portion. The uniform portion results in general expansion loads. The linear portion causes a bending moment across the wall and the nonlinear portion causes a skin stress.

The transients as defined in Section 5.2.1.5 are used to define the fluctuations in plant parameters. A one-dimensional finite difference heat conduction program is used to solve the thermal transient problem. The pipe is represented by at least 50 elements through the thickness of the pipe. The convective heat transfer coefficient employed in this program represents the time varying heat transfer due to free and forced convection. The outer surface is assumed to be adiabatic while the inner surface boundary experiences the temperature of the coolant fluid.

Fluctuations in the temperature of the coolant fluid produce a temperature distribution through the pipe wall thickness which varies with time. An arbitrary temperature distribution across the wall is shown in Figure 5.2-2.

The average through-wall temperature, T_A, is calculated by integrating the temperature distribution across the wall. The integration is performed for all time steps so that T_A is determined as a function of time.

$$T_A(t) = \frac{1}{H}\int_0^H T(X,t)dX$$

The range of temperature between the largest and smallest value of T_A is used in the flexibility analysis to generate the moment loadings caused by the associated temperature changes.

$$M = E\alpha\int_0^H \left(X - \frac{H}{2}\right)T(X,t)dX$$

The equivalent thermal moment produced by the linear thermal gradient as shown in Figure 5.2-3 about the mid-wall thickness is equal to:

$$M_L = E\alpha_1\frac{\Delta T_1}{2}H^2$$

Equating ML and M, the solution for ΔT_1 as a function of time is:

$$\Delta T_1(t) = \frac{12}{H^2}\int_0^H \left(X - \frac{H}{2}\right)T(X,t)dX$$

The maximum nonlinear thermal gradient, ΔT_2, will occur on the inside surface and can be determined as the difference between the actual metal temperature on this surface and half of the average linear thermal gradient plus the average temperature.

$$\Delta T_2(t) = \left|T(0,t) - T_A(t)\right| - \frac{\left|\Delta T_1(t)\right|}{2}$$

5. Load Set Generation

A load set is defined as a set of pressure loads, moment loads, and through-wall thermal effects at a given location and time in each transient. The method of load set generation is based on Reference 2. The through-wall thermal effects are functions of time and can be subdivided into four parts:

a. Average temperature (T_A) is the average temperature through-wall of the pipe which contributes to general expansion loads.

b. Radial linear thermal gradient which contributes to the through-wall bending moment (ΔT_1).

c. Radial nonlinear thermal gradient (ΔT_2) which contributes to a peak stress associated with shearing of the surface.

d. Discontinuity temperature (T_A - T_B) represents the difference in average temperature at the cross sections on each side of a discontinuity.

Each transient is described by at least one load set representing the maximum and minimum stress state during each transient. The construction of the load sets is accomplished by combining the following to yield the maximum (minimum) stress state during each transient.

a. ΔT_1

b. ΔT_2

c. $\alpha_A T_A$ - $\alpha_B T_B$

d. Moment loads due to T_A

e. Pressure loads

This procedure produces at least twice as many load sets as transients for each point.

As a result of the normal mode spectral technique employed in the seismic analysis, the load components cannot be given signed values. Eight load sets are used to represent all possible sign permutations of the seismic moments at each point, thus ensuring the most conservative combination of seismic loads are used in the stress evaluation.

For all possible load set combinations, the primary-plus-secondary and peak stress intensities, fatigue reduction factors (K_e), and cumulative usage factors, U, are calculated. The WESTDYN-7 program is used to perform this analysis in accordance with the ASME

Code, Section III, Subsection NB-3650. Alternatively, detailed finite element stress analyses may be used to determine primary-plus-secondary and peak stress intensities for the load set combinations. Since it is impossible to predict the order of occurrence of the transients over the plant life, it is assumed that the transients can occur in any sequence. This is a very conservative assumption.

The combination of load sets yielding the highest alternating stress intensity range is used to calculate the incremental usage factor. The next most severe combination is then determined and the incremental usage factor calculated. This procedure is repeated until all combinations having allowable cycles $<10^6$ are formed. The total cumulative usage factor at a point is the summation of the incremental usage factors.

5.2.1.10.3.1 Reactor Coolant Loop Analysis Results for Steam Generator Replacement

With the implementation of Leak-Before-Break (LBB) methodology to the V. C. Summer reactor coolant loops, the large RCL breaks have been eliminated from the LOCA analysis inputs. The only sets of LOCA inputs re-analyzed to support steam generator replacement and their associated revised operating conditions were the large auxiliary lines, RHR line/primary coolant loop connection, accumulator line/primary coolant loop connection, and pressurizer surge line/primary coolant loop connection. Documentation of the reactor coolant loop analysis as affected by steam generator replacement is furnished in WCAP-9119, Revision 3. The conclusions of the report indicate that the impact of steam generator replacement will not result in reactor coolant loop piping stresses and fatigue usage that exceeds the ASME Code requirements for normal, upset, emergency, and test conditions. The structural integrity and safety-related design requirements of the RCL will be maintained during all conditions of the design specification.

5.2.1.10.4 Primary Component Supports Models and Methods

The static and dynamic structural analyses employ the matrix method and normal mode theory for the solution of lumped-parameter, multi-mass structural models. The equipment support structure models are dual-purpose since they are required (1) to quantitatively represent the elastic restraints which the supports impose upon the loop, and (2) to evaluate the individual support member stresses due to the forces imposed upon the supports by the loop.

Models for the STRUDL or WECAN computer program are constructed for the steam generator lower, steam generator upper lateral, reactor coolant pump lower, and reactor vessel supports. Structure geometry, topology, and member properties are used in the modeling.

A description of the supports is found in Section 5.5.14. Detailed models are developed using beam elements and plate elements, where applicable.

The computer programs are used with these models to obtain support stiffness matrices and member influence coefficients for the steam generator and reactor coolant pump supports. Unit force along and unit moment about each coordinate axis are applied to the models at the

equipment vertical centerline joint. Stiffness analyses are performed for each unit load for each model.

Joint displacements for applied unit loads are formulated into flexibility matrices. These are inverted to obtain support stiffness matrices which are included in the reactor coolant loop model.

Loads acting on the supports obtained from the reactor coolant loop analysis, support structure member properties, and influence coefficients at each end of each member are input into the WESAN program.

For each support case used, the following is performed:

1. Combine the various types of support plane loads to obtain operating condition loads (normal, upset, or faulted).
2. Multiply member influence coefficients by operating condition loads to obtain all member internal forces and moments.
3. Solve appropriate stress or interaction equations for the specified operating condition. Maximum normal stress, shear stress, and combined load interaction equation values are printed as a ratio of maximum actual values divided by limiting values.

Tables 5.2-16 through 5.2-18 present maximum stresses in each member of the steam generator and reactor coolant pump support structures expressed as a percentage of maximum permissible values for all operating condition loadings. Figures 5.2-10 through 5.2-12 illustrate the support models and show the member locations.

The reactor vessel support structures were analyzed for all loading conditions using a finite element model with the WECAN computer program. Vertical and horizontal forces delivered to the support structures from the reactor vessel shoes were applied to the structure. The maximum stresses in the reactor vessel supports for all loading conditions are presented in Table 5.2-20, expressed as a percentage of the maximum permissible values.

In addition, member compressive axial loads for all Class 1 primary equipment supports do not exceed 0.67 times the critical buckling strength for the faulted condition.

5.2.1.10.5 Analysis of Primary Components

Equipment which serves as part of the pressure boundary in the reactor coolant loop includes the steam generators, the reactor coolant pumps, the pressurizer, and the reactor vessel. This equipment is Safety Class 1 and the pressure boundary meets the requirements of the ASME Code, Section III, Subsection NB. This equipment is evaluated for the loading combinations outlined in Table 5.2-3. The equipment is analyzed for (1) the normal loads of dead-weight, pressure and thermal, (2) mechanical transients of OBE, SSE, and pipe ruptures, and (3) pressure and temperature transients outlined in Section 5.2.1.5.

The results of the reactor coolant loop analysis are used to determine the loads acting on the nozzles and the support/component interface locations. These loads are supplied for all loading conditions on an "umbrella" load basis. That is, on the basis of previous plant analyses, a set of loads is determined which should be larger than those seen in any single plant analysis. The umbrella loads represent a conservative means of allowing detailed component analysis prior to the completion of the system analysis. Upon completion of the system analysis, conformance is demonstrated between the actual plant loads and the loads used in the analyses of the components. Any deviations where the actual load is larger than the umbrella load will be handled by individualized analysis.

Seismic analyses are performed individually for the reactor coolant pumps, the pressurizer, and the steam generators. Detailed and complex dynamic models are used for the dynamic analyses. The response spectra corresponding to the building elevation at the highest component/building attachment elevation is used for the component analysis. Seismic analyses for the steam generators are performed using 2% damping for the OBE and 4% damping for the SSE. The analysis of the reactor coolant pump for determination of loads on the motor, main flange, and pump internals is performed using the damping for bolted steel structures; that is, 4% for the OBE and 7% for the SSE (2% for OBE and 4% for SSE is used in the system analysis). This damping is applicable to the reactor coolant pump since the main flange, motor stand, and motor are all bolted assemblies (see Section 5.5). The reactor pressure vessel is qualified by static stress analysis based on loads that have been derived from dynamic analysis.

RCPB components are further qualified to ensure against unstable crack growth under faulted conditions by performing detailed fracture analyses of the critical areas of this boundary. Actuation of the Emergency Core Cooling System produces relatively high thermal stresses in the system. Regions of the pressure boundary which come into contact with Emergency Core Cooling System water are given primary consideration. These regions include the reactor vessel beltline region, the reactor vessel inlet nozzles, and the safety injection nozzles in the piping system.

Two methods of analysis are used to evaluate thermal effects in the regions of interest. The first method is Linear Elastic Fracture Mechanics (LEFM). The LEFM approach to the design against failure is basically a stress intensity consideration in which criteria are established for fracture instability in the presence of a crack. Consequently, a basic assumption employed in LEFM is that a crack or crack-like defect exists in the structure. The essence of the approach is to relate the stress field developed in the vicinity of the crack tip to the applied stress on the structure, the material properties, and the size of defect necessary to cause failure.

The elastic stress field at the crack-tip in any cracked body can be described by a single parameter designated as the stress intensity factor, K. The magnitude of the stress intensity factor K is a function of the geometry of the body containing the crack, the size and location of the crack, and the magnitude and distribution of the stress.

The criterion for failure in the presence of a crack is that failure will occur whenever the stress intensity factor exceeds some critical value. For the opening mode of loading (stresses perpendicular to the major plane of the crack), the stress intensity factor is designated as K_I and the critical stress intensity factor is designated K_{IC}. Commonly called the fracture toughness, K_{IC}

is an inherent material property which is a function of temperature and strain rate. Any combination of applied load, structural configuration, crack geometry, and size which yields a stress intensity factor K_{IC} for the material will result in crack instability.

The criterion of the applicability of LEFM is based on plasticity considerations at the postulated crack tip. Strict applicability (as defined by ASTM) of LEFM to large structures where plane strain conditions prevail requires that the plastic zone developed at the tip of the crack does not exceed 2.25% of the crack depth. In the present analysis, the plastic zone at the tip of the postulated crack can reach 20% of the crack depth. However, LEFM has been successfully used quite often to provide conservative brittle fracture prevention evaluations, even in cases where strict applicability of the theory is not permitted due to excessive plasticity. Recently, experimental results from Heavy Section Steel Technology (HSST) Program intermediate pressure vessel tests have shown that LEFM can be applied conservatively as long as the pressure component of the stress does not exceed the yield strength of the material. The addition of the thermal stresses, calculated elastically, which result in total stresses in excess of the yield strength, does not affect the conservatism of the results, provided that these thermal stresses are included in the evaluation of the stress intensity factors. Therefore, for faulted condition analyses, LEFM is considered applicable for the evaluation of the vessel inlet nozzle and beltline region.

In addition, it has been well established that the crack propagation of existing flaws in a structure subjected to cyclic loading can be defined in terms of fracture mechanics parameters. Thus, the principles of LEFM are also applicable to fatigue growth of a postulated flaw at the vessel inlet nozzle and beltline region.

For the safety injection and charging line nozzles, which are fabricated from 304 stainless steel, LEFM is not applicable because of extreme ductility of the material. For these nozzles, the thermal effects are evaluated using the principles of Miner's hypothesis of linear cumulative damage in conjunction with fatigue data from constant stress or strain fatigue tests. The cumulative usage fatigue defined as the sum of the ratios of the number of cycles of each transient (n) to the allowable number of cycles for the stress range associated with the transient (N) must not exceed 1.0.

An example of a faulted condition evaluation carried out according to the procedure discussed above is given in Reference 3. This report discusses the evaluation procedure in detail as applied to a severe faulted condition (a postulated loss of coolant accident).

Valves in the RCS are designated ASME Class 1 and are designed and analyzed to the limits outlined in Table 5.2-4. Valves in sample lines connected to the RCS are not considered to be Safety Class 1 nor ASME Class 1. This is because the nozzles where the lines connect to the primary system piping are orificed to a 3/8 inch hole. This hole restricts the flow such that loss through a severance of one of these lines can be made up by normal charging flow.

To support steam generator replacement, the primary components (i.e., the reactor vessel, reactor internals, reactor coolant pumps, and pressurizer) were reevaluated with the Delta-75 steam generators modeled in the system, and with a NSSS power of 2912 MWt. Revised RCS design transients were compared with the original design basis transients. Where the revised transients

indicated a more severe loading, the original evaluation was revisited. The results of the evaluations indicate that, in most cases, the conservatively determined results of the original analyses remain bounding for these new conditions. As with the original stress report performed by Chicago Bridge and Iron, Inc. (CBI), the maximum range of primary plus secondary stress intensity exceeds the $3S_m$ limit defined by the ASME Code for the outlet nozzles and support pads, inlet nozzles and support pads, and closure head flange. The stress intensities calculated by CBI were not affected by the steam generator replacement. CBI performed a simple elastic-plastic analysis according to Paragraph NB-3228.3 of the ASME Code to justify these values. These results are not affected. The fatigue usages for all components which had stress intensities in excess of the Code limits were all less than the Code limit of 1.0. Some of the pressurizer components were calculated to experience a slight increase in fatigue usage; however, the cumulative fatigue usage factors for all pressurizer components evaluated remain less than 1.0. In all cases, the acceptance limits specified by the appropriate section of the ASME Code Edition applicable for that component were not exceeded. Details regarding the analysis of the reactor vessel and reactor vessel internals are furnished in References 14 and 15.

5.2.1.10.6 Reactor Vessel Support LOCA Loads

5.2.1.10.6.1 Introduction

As indicated in Section 3.6, postulated breaks in the reactor coolant loop piping, except for branch line connections, have been eliminated. Reactor coolant loop piping branch nozzle (i.e., accumulator connection, pressurizer surge line, residual heat removal, etc.) breaks are postulated.

5.2.1.10.6.2 Interface Information

Gilbert Associates, Inc. is responsible for reactor containment design and analysis. Stiffness of the primary shield wall beneath the reactor vessel supports and asymmetric cavity pressurization loading was provided by Gilbert to Westinghouse.

All other input information was developed within Westinghouse. These items are as follows: reactor internals properties, loop mechanical loads and loop stiffness, internal hydraulic pressure transients, and reactor support stiffnesses. These inputs allowed formulation of the mathematical models and performance of the analyses, as will be described.

5.2.1.10.6.3 Loading Conditions

As indicated in Section 3.6, postulated breaks in the reactor coolant loop piping, except for branch line connections, have been eliminated. Reactor coolant loop piping branch nozzle (i.e., accumulator connection, pressurizer surge line, residual heat removal, etc.) breaks are postulated.

The reactor internals hydraulic pressure transients were calculated, including the assumption that the structural motion is coupled with the pressure transients. This phenomenon has been referred to as hydroelastic coupling or fluid-structure interaction. The hydraulic analysis considers the fluid-structure interaction of the core barrel by accounting for the deflections of constraining boundaries which are represented by masses and springs. The dynamic response of the core barrel

in its beam bending mode responding to blowdown forces compensates for internal pressure variation by increasing the volume of the more highly pressurized regions. The analytical methods used to develop the reactor internals hydraulics are described in WCAP-8708 (Reference 12).

5.2.1.10.6.4 Reactor Vessel and Internals Modeling

The reactor vessel and internals general assembly is shown in Figure 3.9-1. The reactor vessel is restrained by two mechanisms: (1) the three attached reactor coolant loops with the steam generator and reactor coolant pump primary supports and (2) six reactor vessel supports, one beneath each reactor vessel nozzle. The reactor vessel supports are described in Section 5.5.14 and are shown in Figures 5.5-7, 5.2-4, and 5.2-5. The support shoe provides restraint in the horizontal directions and for downward reactor vessel motion.

The mathematical model of the reactor pressure vessel is a three-dimensional nonlinear finite element model which represents the dynamic characteristics of the reactor vessel and its internals in six geometric degrees of freedom. The model was developed using the WECAN computer code. The model consists of three concentric structural submodels connected by nonlinear impact elements and stiffness matrices. The first submodel represents the reactor vessel shell and the associated support system. The second submodel represents the reactor core barrel, neutron panels, lower support plate, tie plates, and secondary core support components. This submodel is physically located inside the first, and is connected to it by a stiffness matrix at the internals support ledge. Core barrel to vessel shell impact is represented by nonlinear elements at the core barrel flange, core barrel outlet nozzle, and lower radial support locations. The third and innermost submodel represents the upper support plate, guide tubes, support columns, upper and lower core plates, and fuel. The third submodel is connected to the first and second by stiffness matrices and nonlinear elements. The first, second, and third submodels are shown in Figures 5.2-6a, 5.2-6b, and 5.2-6, respectively.

The hydrodynamic mass matrices are a function of the properties of two cylinders with a fluid in the cylindrical annulus; specifically, inside and outside of the annulus, density of the fluid, and length of the cylinders. Vertical segmentation of the reactor core barrel allows inclusion of radii variations along the reactor core barrel height and approximates the effects of reactor core barrel beam deformation. These mass matrices were inserted between selected nodes on the core barrel and reactor vessel shell submodels as shown in Figure 5.2-7.

The structure is divided into a finite number of members or elements. The inertia and stiffness matrices, as well as the force array, are first calculated for each element in the local coordinates. Employing appropriate transformation, the element global matrices and arrays are then computed. Finally, the global element matrices and arrays are assembled into the global structural matrices and arrays, and used for dynamic solution of the differential equation of motion for the structure.

5.2.1.10.6.5 Analytical Methods

The time history effects of the cavity pressurization loads, internals loads, and loop mechanical loads are combined and applied simultaneously to the applicable nodes of the mathematical

model of the reactor vessel and internals. The analysis is performed by numerically integrating the differential equations of motion to obtain the transient response. The output of the analysis includes, among other things, the displacements of the reactor vessel and the loads in the reactor vessel supports. The loads from the postulated pipe break on the vessel supports are combined with other applicable faulted condition loads and subsequently used to calculate the stresses in the supports. Also, the reactor coolant loop is analyzed by applying the reactor vessel displacements to the reactor coolant loop model. The resulting loads and stresses in the piping, components, and supports are then combined with those from the loop dynamic blowdown analysis and the adequacy of the system is verified. Thus, the effect of vessel displacements upon loop response and the effect of loop blowdown upon vessel displacements are both evaluated.

5.2.1.10.6.6 Results of the Analysis

As previously discussed, the application of LBB methodology at V. C. Summer excludes the large RCL breaks from requiring analysis. The most limiting breaks considered for the dynamic analysis of V. C. Summer are the accumulator line break (cold leg) and pressurizer surge line break (hot leg).

LOCA loads applied to the V. C. Summer reactor pressure vessel system consist of reactor internal hydraulic loads (vertical and horizontal) and reactor coolant loop mechanical loads. All the loads are calculated individually and combined in a time history manner.

Reactor coolant loop mechanical loads are applied to the reactor pressure vessel nozzles by the primary coolant loop piping, and are given in Table 5.2-13.

The severity of a postulated break in a reactor vessel is related to two factors: the distance from the vessel to the break and the break opening area. Due to the interaction between the internals structure and the decompression wave, cold leg breaks result in larger reactor internal hydraulic forces. The reactor pressure vessel system LOCA analysis results consist of time history displacements and impact forces. The accumulator line break and the surge line break displacements are given in Table 5.2-14. Also, the reactor vessel/internals interface loads for these two breaks are given in Table 5.2-15. The results given in Tables 5.2-14 and 5.2-15 were compared with the original results from the reactor pressure vessel inlet nozzle break (large break). This comparison showed that the system LOCA response for the accumulator line break and the surge line break at uprated plant conditions with the Delta-75 steam generators are bounded by the main line loop breaks, eliminated by the application of leak-before-break methodology. Consequently, there is no adverse impact on the structural integrity of the V. C. Summer reactor internals.

5.2.1.10.7 Stress Criteria for Class 1 Components and Component Supports

1. Components

   All Class 1 components are designed and analyzed for the design, normal, and upset conditions to the rules and requirements of the ASME Code, Section III. The design analysis or test methods and associated stress or load allowable limits used in evaluation of faulted

conditions are those that are defined in Appendix F of the ASME Code with supplementary options outlined below:

a. Elastic System Analysis and Component Inelastic Analysis

This is an acceptable method of evaluation for faulted conditions if the rules provided below are met for component supports, and if primary stress limits for components are taken as greater of 0.70 S_u or S_y + 1/3 (S_u - S_y) for membrane stress and greater of 0.70 S_{ut} or S_y + 1/3 (S_{ut} - S_y) for membrane-plus-bending stress, where material properties are taken at appropriate temperature.

If plastic component analysis is used with elastic system analysis or with plastic system analysis, the deformations and displacements of the individual system members will be shown to be no larger than those which can be properly calculated by the analytical methods used for the system analysis.

b. Elastic/Inelastic System Analysis and Component/Test Load Method

The test load method given in F-1370(d) is an acceptable method of qualifying components in lieu of satisfying the stress/load limits established for the component analysis.

2. Component Supports

All Class 1 component supports are designed and analyzed, as discussed in Section 5.2.1.10.4, for the design, normal, upset, and faulted conditions. Allowable stresses for the Class 1 component supports are provided in Table 5.2-5.

Loading combinations and allowable stresses for ASME Code, Section III, Class 1 components and component supports are given in Tables 5.2-3, 5.2-4, and 5.2-5. For faulted condition evaluations, the effects of the SSE and loss of coolant accident are combined using the square root of the sum of the squares method. Justification for this method of load combination has been submitted to the NRC as WCAP-9279 and WCAP-9283.

5.2.1.10.8 Computer Program Descriptions

The following computer programs have been used in dynamic and static analyses to determine mechanical loads, stresses, and deformations of Seismic Category I components and equipment. These are described and verified in Reference 4.

1. WESTDYN - static and dynamic analysis of redundant piping systems.
2. STHRUST - hydraulic loads on loop components from blowdown information.
3. WESAN - reactor coolant loop equipment support structures analysis and evaluation.
4. WECAN - finite element structural analysis

5.2.1.11 Analysis Methods for Faulted Conditions

The methods used for the evaluation of the faulted conditions are contained in Section 5.2.1.10.

5.2.1.12 Protection Against Environmental Factors

A discussion of the protection provided for the principal components of the RCS against environmental factors is found in Section 3.11.

5.2.1.13 Compliance with Code Requirements

A brief description of the analyses and methods used to assure compliance with the applicable codes is provided in Section 5.2.1.10.

5.2.1.14 Stress Analysis for Emergency and Faulted Conditions Loadings

The stress analysis used for emergency and faulted condition loadings is discussed in Section 5.2.1.10.

5.2.1.15 Stress Levels in Category I Systems

Summary results of the typical analyses of the Category I systems are included in the latest revisions of Westinghouse Reports WCAP-9119, Vol. II and Vol. I; WCAP-9803, Vol. IV; and WCAP-9802, Vol. III.

5.2.1.16 Analytical Methods for Stresses in Pumps and Valves

The pressure boundary portions of the Class 1 pump in the RCS (the reactor coolant pumps) are designed and analyzed according to the requirements of NB-3400.

The pressure boundary portions of Class 1 valves in the RCS are designed and analyzed according to the requirements of NB-3500. These valves are identified in Section 3.9.2.

5.2.1.17 Analytical Methods for Evaluation of Pump Speed and Bearing Integrity

The reactor coolant pump shaft is designed so that its operating speed is below the first shaft critical speed as discussed in Section 5.5.1.3.6.

Reactor coolant pump bearing integrity is discussed in Section 5.5.1.3.4.

5.2.1.18 Operation of Active Valves Under Transient Loadings

The tests and analyses that are performed on active valves to assure operation under transient loadings are described in Section 3.9.2.4.

5.2.1.19 Field Run Piping

There is no field run safety class piping. All safety class piping down to one inch is depicted on and fabricated to plan and section drawings and any applicable analyses are performed accordingly. Approved design criteria are used for pipe hanger design.

5.2.2 Overpressurization Protection

5.2.2.1 Location of Pressure Relief Devices

Pressure relief devices for the RCS comprise the three pressurizer safety valves and three power operated relief valves shown in Figure 5.1-1, Sheet 2; these discharge to the pressurizer relief tank through a common header. Other relief valves in the reactor building that discharge to the pressurizer relief tank are itemized in Table 5.2-6.

5.2.2.2 Mounting of Pressure Relief Devices

The NSSS supplier provides protection pads for the pressurizer. The architect engineer designs the supports for the safety relief valves and the attached piping in accordance with the installation guidelines and suggests physical layout criteria provided by the NSSS supplier. The architect engineer determines the reactions on the valves and attached piping to limit the piping reaction loads to acceptable values.

5.2.2.3 Report on Overpressure Protection

The pressurizer is designed to accommodate pressure increases (as well as decreases) caused by load transients. The spray system condenses steam to prevent the pressurizer pressure from reaching the setpoint of the power operated relief valves during a step reduction in power level equivalent to 10% of full rated load.

The spray nozzle is located in the top head of the pressurizer. Spray is initiated when the pressure controlled spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing compensated error signal until it reaches a maximum value. The compensated error signal is the output of Proportional plus Integral plus Derivative (PID) controller, the input to which is an error signal based on the difference between actual pressure and a reference pressure.

The pressurizer is equipped with power operated relief valves which limit system pressure for a large power mismatch, and thus prevent actuation of the fixed high pressure reactor trip. The relief valves are operated automatically or by remote manual control. The operation of these valves also limits the undesirable opening of the spring-loaded safety valves. Remotely operated stop valves are provided to isolate the power operated relief valves if excessive leakage occurs. The relief valves are designed to limit the pressurizer pressure to a value below the high pressure trip setpoint for all design transients up to and including the design percentage step load decrease with steam dump but without reactor trip.

Output signals from the pressurizer pressure protection channels are isolated and used for pressure control. These are used to control pressurizer spray and heaters and power operated relief valves. Pressurizer pressure is sensed by fast response pressure transmitters with a time response of better than 0.2 seconds.

In the event of a complete loss of heat sink, e.g., no steam flow, protection of the RCS against overpressure is afforded by pressurizer and steam generator safety valves along with any of the following reactor trip functions:

1. Reactor trip on turbine trip (if the turbine is tripped at above 50% power);
2. High pressurizer pressure reactor trip;
3. Overtemperature ΔT reactor trip;
4. Low feedwater flow reactor trip; or
5. Low-low steam generator water level reactor trip.

The ASME Code pressure limit is 110% of the 2485 psig design pressure. This limit is not exceeded as discussed in Reference 5. The report describes in detail the pressure relief devices, location, reliability, and sizing. Transient analysis data are provided for the worst cases that require safety valve actuation as well as those cases which do not.

A detailed functional description of the process equipment associated with the high pressure trip is provided in Reference 6.

The upper limit of overpressure protection is based upon the positive surge of the reactor coolant produced as a result of turbine trip under full load, i.e., a 100% load mismatch assuming that the core continues to produce full power with no steam dump. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2500 psia and a total accumulation of 3%.

The actual installed capacity of the safety valves is always greater than the capacity calculated from the sizing analysis and is indicated so by the ratio of safety valve flow to peak surge rate being greater than 1.0. Note that no credit is taken for the relief capability provided by the power operated relief valves during this surge.

The RCS design and operating pressure together with the safety, power relief and pressurizer spray valve setpoints, and the protection system setpoint pressures are listed in Table 5.2-7.

System components whose design pressure and temperature are less than the RCS design limits are provided with overpressure protection devices and redundant isolation means. System discharge from overpressure protection devices is collected in the pressurizer relief tank.

As specified in NUREG 0660, item II.K.3 Table C.3 item 3, SCE&G will report safety/relief valve failures and challenges during startup testing and plant operation.

5.2.2.4 ECCS Check Valve Testing

Check valves on the discharge side of low and high head safety injection systems, and the safety injection accumulator subsystems that are classified as ASME Code, Category AC, are listed in Table 5.2-7a.

The ECCS check valve system, shown by Figure 5.2-8, provides the means for leak testing individual check valves, classified Category AC, on the discharge side of the low head safety injection systems and safety injection accumulator subsystems independent of other valves. Testing of these valves will be performed during plant startup following refueling shutdowns on a performance-based frequency. Reactor coolant pressure will be at least 1000 psig. ECR 50650 added a back pressure regulator set at approximately 400 psig to allow controlled leakage to the PRT. By installing a back pressure regulator around XVT00037-SI, a method of preventing pressure building up in an isolated system is provided. This is done to reduce the potential for leakage into and pressurization of interfacing systems.

Acceptance criteria for leakage are in accordance with Technical Specification 3.4.6.2. Test results are documented in accordance with the ASME Code of Record, prescribed under 10 CFR 50.55a. These check valves are normally tested during plant startup following a refueling shutdown. Should a valve be found to leak excessively, it will be repaired and retested prior to a return to normal operation.

5.2.2.5 RCS Pressure Control During Low Temperature Operation

Administrative procedures are developed to aid the operator in controlling RCS pressure during low temperature operation.

Cold overpressurization protection will be provided by the RHR suction relief valves during low RCS temperature operation. Analysis has shown that one RHR suction relief valve is sufficient to prevent violation of 10 CFR 50, Appendix G limits due to anticipated mass and heat input transients.

5.2.2.5.1 System Operation

The RHR system is normally lined up to the RCS with the reactor shut down, primary coolant temperature ≤350°F, and pressure ≤450 psig. The RHR suction relief valves are set at 450 psig and provide the necessary overpressurization protection during cold plant operations. Annunciators are provided in the control room to alert the operator if reactor coolant temperature is < 300°F and any of the RHR suction isolation valves are not open.

5.2.2.5.2 Evaluation of Low Temperature Overpressure Transients

Pressure Transient Analyses

ASME Section III, Appendix G, establishes guidelines and limits for RCS pressure primarily for low temperature conditions (≤350°F). The relief system discussed in Section 5.2.2.5 satisfies these conditions as discussed in the following paragraphs.

Transient analyses were performed to ensure that an RHR relief setpoint of 450 psig is sufficient. This setpoint maintains RCS pressure within acceptable limits following all credible overpressurization incidents occurring in the plant during low temperature, water solid operation.

The mass input transient analysis was performed assuming the most severe event involving a single centrifugal charging pump. Specifically, a loss of air incident is postulated, whereby the flow control valve on the charging line fails open and, simultaneously, the flow control valve on the letdown line fails closed.

The heat input mechanism considered for analysis involved an RCS pump startup in one loop with a water solid condition and temperature asymmetry in the RCS, whereby the steam generators were at a higher temperature than the remainder of the system. A 50°F mismatch was assumed to exist between the RCS (100°F) and the secondary side of the steam generators. (At lower temperatures, the mass input case is the limiting transient condition.)

Both analyses took into account the single failure criteria and, therefore, the operation of one RHR suction relief valve was assumed to be available for pressure relief. Consistent with WCAP-14040-NP-A, Revision 2 (Reference 7), the design credits the fact that overpressure events mostly occur during isothermal conditions in the RCS and therefore use the steady state Appendix G limit in judging the adequacy of the RHR relief valve capacity and lift setting. Calculated peak pressures for both the design basis mass and heat addition transients remain substantially less than the allowable limits, which are reflected in the heatup and cooldown limit curves for normal operation within the Technical Specifications. Thus, low temperature overpressure transients do not constitute impairment to vessel integrity or plant safety.

OBE Evaluation

A fluid systems evaluation has been performed to analyze the potential for overpressure transients following an OBE. The basis of the evaluation assumes the plant air system is inoperable since it is not seismically qualified. The results of the evaluation follow and demonstrate that overpressure transients following an OBE are not a concern.

1. A loss of plant air during the first part of plant cooldown (i.e., decay heat removal via SG, normal CVCS letdown, and just prior to placing the Residual Heat Removal System (RHRS) on line at 350°F) would cause the low pressure letdown isolation valves to fail close and the charging flow control valve to fail open. These conditions would create a net mass addition to the RCS causing the pressure to increase. However, the pressure increase would be

acceptable since the pressurizer safety valves would limit system pressure (2485 psig) within allowable values (Technical Specification Figures 3/4 4-26 and 3/4 4-27).

2. A loss of plant air during the second part of plant cooldown (i.e., decay heat removal via the RHRS and temperature less than 350°F) would cause the low pressure letdown valve to fail close and charging flow control valve to fail open similar to that discussed above. These conditions would create a net mass addition to the system which would be relieved by the RHR relief valves which are set at 450 psig and thus maintain the pressure within allowable values.

   The flow paths of the common relief headers from the pressurizer safety and RHRS relief valves to the pressurizer relief tank are assured following an OBE by design of the headers for seismic loads.

For the various modes described above, the pressurizer safety and RHRS relief valves provide pressure relief for the postulated transients following an OBE and thus maintain the primary system within the allowable pressure/temperature limits.

5.2.2.5.3 Administrative Procedures

Although the system described in Section 5.2.2.5.1 is installed to maintain RCS pressure within allowable limits, administrative procedures are recommended for minimizing the potential for any transient that could actuate the overpressure relief system. The following discussion highlights these procedural controls, listed in hierarchy of their function in preventing RCS cold overpressurization transients.

Of primary importance is the basic method of operation of the plant. Normal plant operating procedures will maximize the use of a pressurizer cushion (steam/N_2 bubble) during periods of low pressure, low temperature operation. This cushion will dampen the plants' response to potential transient generating inputs, providing easier pressure control with the slower response rates.

An adequate cushion eliminates some potential transients such as reactor coolant pump induced heat input and slows the rate of pressure rise for others. In conjunction with the previously discussed alarms, this provides reasonable assurance that most potential transients can be terminated by operator action before the overpressure relief system actuates.

However, for those modes of operation when water solid operation may still be possible, procedures will further highlight precautions that minimize the potential for developing an overpressurization transient. The following specific recommendations will be made:

1. Do not isolate the residual heat removal inlet lines from the reactor coolant loop unless the charging pumps are stopped. This precaution is to assure there is a relief path from the reactor coolant loop to the residual heat removal suction line relief valves when the RCS is at low pressure (less than 500 psi) and is water solid.

2. Whenever the plant is water solid and the reactor coolant pressure is being maintained by the low pressure letdown pressure control valve (PCV-145), low pressure letdown from the RHRS (via HCV-142) must be in operation. During this mode of operation, all three letdown orifices must also remain open.
3. If all reactor coolant pumps have stopped for more than 5 minutes during plant heatup, and the reactor coolant temperature is greater than the charging and seal injection water temperature, do not attempt to restart a pump unless a steam bubble is formed in the pressurizer. This precaution will minimize the pressure transient when the pump is started and the cold water previously injected by the charging pumps is circulated through the warmer reactor coolant components. The steam bubble will accommodate the resultant expansion as the cold water is rapidly warmed.
4. If all reactor coolant pumps are stopped and the RCS is being cooled down by the residual heat exchangers, a non-uniform temperature distribution may occur in the reactor coolant loops. Do not attempt to restart a reactor coolant pump unless a steam bubble is formed in the pressurizer.
5. During plant cooldown, all steam generators should be connected to the steam header to assure a uniform cooldown of the reactor coolant loops.
6. At least one reactor coolant pump must remain in service until the reactor coolant temperature is reduced to 160°F.

These special precautions backup the normal operational mode of maximizing periods of steam bubble operation so that cold overpressure transient prevention is continued during periods of transitional operations.

The specific plant configurations of ECCS testing and alignment to prevent developing cold overpressurization transients during these limited periods of plant operation, given as follows:

1. To preclude inadvertent ECCS actuation during heatup and cooldown, procedures require blocking the pressurizer pressure safety injection signal when pressurizer pressure has decreased below 1985 psig and the steamline safety injection signal when T_{avg} decreases below 552°F.
2. During further cooldown, closure and power lockout of the accumulator isolation valves and power lockout of the non-operating charging pumps will be performed with the RCS pressure maintained between 900 and 950 psig, providing additional backup to step 1 above.
3. The recommended procedure for periodic ECCS pump performance testing will be to test the pumps during normal power operation or at hot shutdown conditions. This precludes any potential for developing a cold overpressurization transient.

   Should cold shutdown testing of the pumps be desired, it will be recommended that the test be done when the vessel is open to atmosphere, again precluding overpressurization potential.

If cold shutdown testing with the vessel closed is necessary, the procedures will require charging pump discharge valve closure and RHRS alignment to both isolate potential ECCS pump input and to provide backup benefit of the RHRS relief valves.

4. "S" signal circuitry testing, if done during cold shutdown, will also require RHRS alignment and non-operating charging pump power lockout to preclude developing cold overpressurization transients.

The above procedural recommendations covering normal operations with a steam bubble, transitional operations where potentially water solid, followed by specific testing operations provide in-depth cold overpressure prevention, augmenting the installed overpressure relief system.

5.2.3 General Material Considerations

5.2.3.1 Material Specifications

Material specifications used for the principal pressure retaining applications in each component comprising the RCPB are listed in Table 5.2-8 for ASME Class 1 primary components and Table 5.2-9 for ASME Class 1 and 2 auxiliary components. The materials are procured in accordance with the material specification requirements and include the special requirements of the ASME Code, Section III, plus Addenda and Code Cases as are applicable and appropriate to meet Appendix B of 10 CFR 50 in the Federal Register, Vol. 35, No. 125. In some cases, Table 5.2-9 may not be totally inclusive of the material specifications used in the listed applications. However, the listed specifications are representative of those materials utilized. All of the materials used are procured in accordance with ASME Code requirements.

The welding materials used for joining the ferritic base materials of the RCPB conform to or are equivalent to ASME Material Specifications SFA 5.1, 5.2, 5.5, 5.17, 5.18, and 5.20. They are tested and qualified to the requirements of ASME Section III rules. In addition the ferritic materials of the reactor vessel beltline are restricted to the following maximum limits of copper, phosphorous, and vanadium to reduce sensitivity to irradiation embrittlement in service:

Element	Base Metal (%)	Weld Metal (%)
Copper	0.10 (Ladle) 0.12 (Check)	0.10
Phosphorous	0.012 (Ladle) 0.017 (Check)	0.015
Vanadium	0.05 (Check)	0.05 (as residual)

Regulatory Guides 1.34, 1.43, 1.50, and 1.66 are discussed in Appendix 3A.

The welding materials used for joining the austenitic stainless steel base materials of the RCPB conform to ASME Material Specifications SFA 5.4 and 5.9. They are tested and qualified to the requirements of ASME Section III rules.

The welding materials used for joining nickel-chromium-iron alloy in similar base material combination and in dissimilar ferritic or austenitic base material combination conform to ASME Material Specifications SFA 5.11 and 5.14. They are tested and qualified to the requirements of ASME Section III rules and are used only in procedures which have been qualified to these same rules.

5.2.3.2 Compatibility With Reactor Coolant

All of the ferritic low alloy and carbon steels which are used in principal pressure retaining applications are provided with corrosion resistant cladding on all surfaces that are exposed to the reactor coolant. This cladding material has a chemical analysis which is at least equivalent to the corrosion resistance of Types 304 and 316 austenitic stainless steel alloys or nickel-chromium-iron alloy, martensitic stainless steel, and precipitation hardened stainless steel. Ferritic low alloy and carbon steel nozzles are safe ended with either stainless steel wrought materials, stainless steel weld metal analysis A-7, or nickel-chromium iron alloy weld metal F-Number 43. The latter buttering material requires further safe ending with austenitic stainless steel base material after completion of the post weld heat treatment when the nozzle is larger than a 4 inch nominal inside diameter and/or the wall thickness is greater than 0.531 inches. The reactor vessel main coolant nozzles are safe ended with nickel-chromium-iron alloy weld metal F-Number 43 and will necessitate dissimilar metal field welds of nickel-chromium-iron alloy to austenitic stainless steel.

The cladding on ferritic type base materials receives a post weld heat treatment.

All of the austenitic stainless steel and nickel-chromium-iron alloy base materials with primary pressure retaining applications are used in the solution anneal heat treat condition. These heat treatments are as required by the material specifications.

During subsequent fabrication, these materials are not heated above 800°F other than locally by welding operations. The solution annealed surge line material is subsequently formed by hot bending followed by a resolution annealing heat treatment.

All other austenitic stainless steel piping in contact with reactor coolant is required to be bent at temperatures above 1200°F. If the bending is performed below 1950°F, piping is solution annealed after bending. All stainless steel piping is cooled rapidly between temperatures of 1500°F and 800°F after bending or annealing.

Degreasing is also required prior to subjecting piping to elevated temperatures before, during, or after bending to prevent carbonization. Austenitic stainless steel material is subsequently tested in accordance with Practice E and the accompanying test Practice A of ASTM A 262.

5.2.3.3 Compatibility With External Insulation and Environmental Atmosphere

In general, all of the materials listed in Tables 5.2-8 and 5.2-9 which are used in principal pressure retaining applications and which are subject to elevated temperature during system operation are in contact with thermal insulation that covers their outer surfaces.

The thermal insulation used on the RCPB is either a metallic reflective stainless steel type or a mass type which is encapsulated in stainless steel.

In the event of coolant leakage, the ferritic materials will show increased general corrosion rates. Where minor leakage is anticipated from service experience, such as valve packing, pump seals, etc., only materials which are compatible with the coolant are used. These are as shown in Tables 5.2-8 and 5.2-9. Ferritic materials exposed to coolant leakage can be readily observed as part of the inservice visual and/or nondestructive inspection program to assure the integrity of the component for subsequent service.

5.2.3.4 Chemistry of Reactor Coolant

The RCS chemistry specifications are given in Table 5.2-10.

The RCS water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications.

The Chemical and Volume Control System provides a means for adding chemicals to the RCS which control the pH of the coolant during initial startup and subsequent operation, scavenge oxygen from the coolant during startup and control the oxygen level of the coolant due to radiolysis during all power operations subsequent to startup, and to chemically degasify and oxygenate the RCS during shutdowns for refueling operations. The oxygen content and pH limits for power operations are shown in Table 5.2-10.

The pH control chemical employed is Lithium-7 hydroxide. This chemical is chosen for its compatibility with the materials and water chemistry of borated water/stainless steel/zirconium/ inconel systems. In addition, lithium is produced in solution from the neutron irradiation of the dissolved boron in the coolant. The Lithium-7 hydroxide is introduced into the RCS via the charging flow. The solution is prepared in the laboratory and poured into the chemical mixing tank. Reactor makeup water is then used to flush the solution to the suction header of the charging pumps. The concentration of Lithium-7 hydroxide in the RCS is maintained in the range specified for pH control. If the concentration exceeds this range, the cation bed demineralizer is employed in the letdown line in series operation with the mixed bed demineralizer. Since the amount of lithium to be removed is small and its buildup can be readily calculated and determined by analysis, the flow through the cation bed demineralizer is not required to be full letdown flow.

During reactor startup from the cold condition, hydrazine is employed as an oxygen scavenging agent. The hydrazine solution is introduced into the RCS in the same manner as described above for the pH control agent.

Dissolved hydrogen is employed to control and scavenge oxygen produced due to radiolysis of water in the core region. Sufficient partial pressure of hydrogen is maintained in the volume control tank such that the specified equilibrium concentration of hydrogen is maintained in the reactor coolant. A self-contained pressure control valve maintains a minimum pressure in the vapor space of the volume control tank. This can be adjusted to provide the correct equilibrium hydrogen concentration.

During reactor shutdown for subsequent refueling operations or to open the RCS, hydrogen peroxide is utilized to chemically degasify the reactor coolant and also may be utilized to oxygenate to RCS causing a release of corrosion products from the reactor vessel for subsequent cleanup using the CVCS system.

Components with stainless steel sensitized in the manner expected during component fabrication and installation will operate satisfactorily under normal plant chemistry conditions in PWR systems because chlorides, fluorides, and oxygen are controlled to very low levels.

5.2.4 Fracture Toughness

5.2.4.1 Compliance with Code Requirements

Assurance of adequate fracture toughness of ferritic materials in the RCPB (ASME Section III Class I Components) is provided by compliance with the requirements for fracture toughness testing included in NB 2300 of Section III of the ASME Code, Summer 1972 Addenda, and 10 CFR 50, Appendix G, to the extent possible. A summary of the fracture toughness data for the reactor pressure vessel material is given in Tables 5.2-11 and 5.2-21, and Figures 5.2-16 through 5.2-23.

The fracture toughness of the reactor vessel beltline region has been evaluated according to the requirements of the Pressurized Thermal Shock (PTS) rule (Reference 20). Using the PTS rule and surveillance capsule data (Reference 21), the evaluation documented in WCAP-16306-NP, Revision 0 (Reference 22), shows a maximum calculated RT_{PTS} value for the most limiting plate, A9154-1, of 152°F at 32 EFPY and 159°F at 56 EFPY. The limiting RT_{PTS} values are well below the screening criteria of 270°F specified in the PTS rule.

Ferritic bolting materials used in the RCPB are fabricated in accordance with the following addenda of the ASME Code Section III, all of which predate the issuance of 10 CFR 50, Appendix G:

Reactor Vessel (closure head bolts)	1971 Edition, thru Summer 1971 Addenda
Steam Generator (manway bolts)	1971 Edition, thru Summer 1971 Addenda

Pressurizer (manway bolts)	1971 Edition, thru Summer 1971 Addenda
Reactor Coolant Pump (main flange and seal housing bolts)	1971 Edition, thru Summer 1972 Addenda

These materials comply with the fracture toughness requirements of the applicable code. These requirements are compared to the requirements of 10 CFR Part 50, Appendix G below.

	Test Temperature	ft. lbs	MLE
1971 Edition, Summer 1971 Addendum	-	35	-
1971 Edition, Summer 1972 Addendum	≤40°F	-	25
10 CFR 50 Appendix G, 1980	Lower of preload or service temp. (usually ~50°F)	45	25

The fracture toughness data available for these materials are shown in Table 5.2-22.

5.2.4.2 Acceptable Fracture Energy Levels

Initial upper shelf fracture energy levels for materials of the reactor vessel beltline region (including welds) meet the minimum 75 foot-pound shelf energy requirement of 10 CFR 50, Appendix G.

5.2.4.3 Operating Limitations During Startup and Shutdown

Startup and shutdown operating limitations are based on the properties of the core region materials of the reactor pressure vessel. These limitations are reflected within the Technical Specifications in the form of heatup and cooldown limit curves which show allowable combination of pressure and temperature for specific temperature change rates. The heatup and cooldown limit curves for normal operation are derived in WCAP-16305-NP, Revision 0 (Reference 23) using the methodology from WCAP-14040-NP-A, Revision 4 (Reference 7).

As outlined in WCAP-16305-NP, Revision 0, heatup and cooldown limit curves are calculated using the unirradiated RT_{NDT} (reference nil-ductility temperature) corresponding to the limiting beltline region material of the reactor vessel. The adjusted RT_{NDT} (ART) of the limiting material in the core region of the reactor vessel is determined by using the unirradiated reactor vessel material fracture toughness properties, estimating the radiation-induced ΔRT_{NDT}, and adding a margin. The unirradiated RT_{NDT} is designated as the higher of either the drop weight nil-ductility transition temperature (NDTT) or the temperature at which the material exhibits at least 50 ft-lb of impact energy and 35-mil lateral expansion (transverse to the major rolling direction for late material) minus 60°F.

RT_{NDT} increases as the material is exposed to fast-neutron radiation. Therefore, to find the most limiting RT_{NDT} at any time period in the reactor's life, ΔRT_{NDT} due to the radiation exposure associated with that time period must be added to the unirradiated RT_{NDT} (IRT_{NDT}). The extent of the shift in RT_{NDT} is enhanced by certain chemical elements (such as copper and nickel) present in the reactor vessel steels. Regulatory Guide 1.99, Revision 2 (Reference 24) is used to predict radiation embrittlement and for the calculation of Adjusted Reference Temperature (ART) values ($IRT_{NDT} + \Delta RT_{NDT}$ + margin for uncertainties) at the ¼ T and ¾ T locations, where T is the thickness of the vessel at the beltline region measured from the clad/base metal interface. The most limiting ART values are used in the generation of heatup and cooldown limit curves for normal operation.

As required by Appendix G to 10 CFR Part 50, the Technical Specification heatup limit curves also include temperature limits for inservice leak tests and hydrotests which are used to define additional pressure-temperature limits for core operation (i.e., criticality limit curves) to provide additional margin during actual power production.

5.2.4.3.1 Temperature Difference Between the Pressurizer and Reactor Coolant Loop

Thermal stratification in the pressurizer surge line is a direct result of the difference in temperatures between the pressurizer water and the generally cooler RCS water during plant startup and shutdown. The hotter, lighter pressurizer water tends to float on the cooler, heavier RCS water. The potential for thermal stratification is directly proportional to the difference in temperature (system ΔT) between the pressurizer and the RCS. The potential for stratification is increased as the system ΔT increases. At power, when the system ΔT is relatively small, the extent and effects of thermal stratification have been observed to be negligible. However, during certain modes of plant startup and shutdown, the system ΔT could be as large as 320°F, in which case the effects of thermal stratification are significant.

As required by the NRC Bulletin 88-11, the effects of thermal stratification of the surge line were included in a structural and fatigue analysis of the piping. The analysis demonstrated that the pipe stress and fatigue factors conform the ASME Code limits for all anticipated thermal stratification conditions up to a system ΔT limit of 320°F.

In order to remain within the design basis parameters of this analysis, a system ΔT limit of 320°F is necessary during plant startup and shutdown.

5.2.4.4 Compliance with Reactor Vessel Material Surveillance Program Requirements

Refer to Section 5.4.

5.2.4.5 Reactor Vessel Annealing

Refer to Section 5.4.

5.2.5 Austenitic Stainless Steel

The unstabilized austenitic stainless steel material specifications used for the RCPB, systems required for reactor shutdown, and systems required for emergency core cooling are listed in Tables 5.2-8 and 5.2-9.

The unstabilized austenitic stainless steel material for the reactor vessel internals which are required for emergency core cooling for any mode of normal operation or under postulated accident conditions and for core structural load bearing members are listed in Table 5.2-12.

The above tabulated materials are procured in accordance with the material specification requirements and include the special requirements of the ASME Code, Section III, plus Addenda and Code Cases as are applicable to meet Appendix B of 10 CFR 50 in the Federal Register, Vol. 35, No. 125.

Regulatory Guide 1.44 is discussed in Appendix 3A.

5.2.5.1 Cleaning and Contamination Protection Procedures

It is required that austenitic stainless steel materials used in the fabrication, installation, and testing of nuclear steam supply components and systems be handled, protected, stored, and cleaned according to recognized and accepted methods which are designed to minimize contamination which could lead to stress corrosion cracking. The rules covering these controls are stipulated in process specifications. As applicable, these process specifications supplement the equipment specifications and purchase order requirements of every individual austenitic stainless steel component or system procured for the NSSS, regardless of the ASME Code Classification. The site cleaning procedures recommended in Regulatory Guide 1.37 are discussed in Appendix 3A.

To assure that manufacturers and installers adhere to the requirements of these specifications, surveillance of operations is conducted either in residence at the manufacturer’s plant and the construction site or, when residency is not practical, during periodic engineering and quality assurance visitations and audits at these locations. Any deviation from these rules requires corrective action.

5.2.5.2 Solution Heat Treatment Requirements

The austenitic stainless steels listed in Tables 5.2-8, 5.2-9, and 5.2-12 are utilized in the final heat treated condition required by the respective ASME Code Section II material specification for the particular type or grade of alloy.

5.2.5.3 Material Inspection Program

Austenitic stainless steel materials of product forms with simple shapes need not be corrosion tested provided that the solution heat treatment is followed by water quenching. Simple shapes are defined as all plates, sheets, bars, pipe and tubes, as well as forgings, fittings, and other shaped

products which do not have inaccessible cavities or chambers that would preclude rapid cooling when water quenched. When testing is required, the tests are performed in accordance with ASTM A 262-70, Practice A or E, as amended by Westinghouse Process Specification 84201 MW.

5.2.5.4 Unstabilized Austenitic Stainless Steels

The unstabilized austenitic stainless steels used in the RCPB and components are listed in Tables 5.2-8 and 5.2-9.

The materials are used in the as-welded condition as discussed in Section 5.2.5.2. The control of the water chemistry is stipulated in Section 5.2.3.4.

5.2.5.5 Prevention of Intergranular Attack of Unstabilized Austenitic Stainless Steels

Unstabilized austenitic stainless steels are subject to intergranular attack (IGA) provided that three conditions are present simultaneously. These are:

1. An aggressive environment, e.g., an acidic aqueous medium containing chlorides or oxygen.
2. A sensitized steel.
3. A high temperature.

If any one of the three conditions described above is not present, intergranular attack will not occur. Since high temperatures cannot be avoided in all components in the NSSS, Westinghouse relies on the elimination of conditions 1 and 2 to prevent intergranular attack on wrought stainless steel components.

The water chemistry in the RCS of a Westinghouse Pressurized Water Reactor (PWR) is rigorously controlled to prevent the intrusion of aggressive species. In particular, the maximum permissible oxygen and chloride concentrations are 0.10 ppm and 0.15 ppm, respectively. Reference 8 describes the precautions taken to prevent the intrusion of chlorides into the system during fabrication, shipping, and storage. The use of hydrogen overpressure precludes the presence of oxygen during operation. The effectiveness of these controls has been demonstrated by both laboratory tests and operating experience. The long time exposure of severely sensitized stainless in early plants to PWR coolant environments has not resulted in any sign of intergranular attack. Reference 8 describes the laboratory experimental findings and the Westinghouse operating experience. The additional years of operations since the issuing of Reference 8 have provided further confirmation of the earlier conclusions. Severely sensitized stainless steels do not undergo any intergranular attack in Westinghouse PWR coolant environments.

In spite of the fact there never has been any evidence that PWR coolant water attacks sensitized stainless steels, Westinghouse considers it good metallurgical practice to avoid the use of sensitized stainless steels in the NSSS components. Accordingly, measures are taken to prohibit the purchase of sensitized stainless steels and to prevent sensitization during component fabrication. Wrought austenitic stainless steel stock used for components that are part of the

RCPB, systems required for reactor shutdown, systems required for emergency core cooling, and reactor vessel internals that are relied upon to permit adequate core cooling for normal operation or under postulated accident conditions is utilized in one of the following conditions:

1. Solution annealed and water quenched.
2. Solution annealed and cooled through the sensitization temperature range within less than approximately 5 minutes.

It is generally accepted that these practices will prevent sensitization. Westinghouse has verified this by performing corrosion tests (ASTM 393) on as-received wrought material.

Westinghouse recognizes that the heat affected zones of welded components must, of necessity, be heated into the sensitization temperature range, 800 to 1500°F. However, severe sensitization, i.e., continuous grain boundary precipitates of chromium carbide, with adjacent chromium depletion, can still be avoided by control of welding parameters and welding processes.

The heat input (1) and associated cooling rate through the carbide precipitation range are of primary importance. Westinghouse has demonstrated this by corrosion testing a number of weldments.

(1) Heat input is calculated according to the formula:

$$H=\frac{(E)(I)(60)}{S}$$

Where: H = joules/in; E = volts; I = Amperes; and S = Travel Speed in inches/minute.

Of 25 production and qualification weldments tested, representing all major welding processes, an a variety of components, and incorporating base metal thicknesses from 0.10 to 4.0 inches, only portions of two were severely sensitized. Of these, one involved a heat input of 120,000 joules, and the other involved a heavy socket weld in relatively thin walled material. In both cases, sensitization was caused primarily by high heat inputs relative to the section thickness. However, in only the socket weld did the sensitized condition exist at the surface, where the material is exposed to the environment. The component has been redesigned to eliminate this weld.

Westinghouse controls the heat input in all austenitic pressure boundary weldments by:

1. Prohibiting the use of block welding.
2. Limiting the maximum interpass temperature to 350°F.

3. Exercising approval rights on all welding procedures.

To further assure that these controls are effective in preventing sensitization, Westinghouse per WCAP-8678 (Reference 16) conducted additional intergranular corrosion tests of qualification mock-ups of primary pressure boundary and core internal component welds, including the following:

1. Reactor vessel safe ends.
2. Pressurizer safe ends.
3. Surge line and reactor coolant pump nozzles.
4. Control rod drive mechanisms head adapters.
5. Control rod drive mechanisms seal welds.
6. Control rod extensions.
7. Lower instrumentation penetration tubes.

To summarize, Westinghouse has a four point program designed to prevent intergranular attack of austenitic stainless steel components.

1. Control of primary water chemistry to ensure a benign environment.
2. Utilization of materials in the final heat treated condition and the prohibition of subsequent heat treatments in the 800 to 1500°F temperature range.
3. Control of welding processes and procedures to avoid heat affected zone sensitization.
4. Confirmation that the welding procedures used for the manufacture of components in the primary pressure boundary and of reactor internals do not result in the sensitization of heat affected zones.

Both operating experience and laboratory experiments in primary water have conclusively demonstrated that this program is 100% effective in preventing intergranular attack in Westinghouse NSSS's utilizing unstabilized austenitic stainless steel.

5.2.5.6 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitization Temperatures

Unstabilized austenitic stainless steels are not normally exposed to the sensitization range of 800 to 1500°F during fabrication into components except as described in Section 5.2.3.2. If, during the course of fabrication, the steel is inadvertently exposed to the sensitization temperature range, 800 to 1500°F, the material may be tested in accordance with ASME A393 or A262 as amended by Westinghouse Process Specification 84201 MW to verify that it is not susceptible to intergranular attack, except that testing is not required for:

1. Cast metal or weld metal with a ferrite content of 5% or more.

2. Material with a carbon content of 0.03% or less that is subjected to temperatures in the range of 800 to 1500°F for less than one hour.
3. Material exposed to special processing provided the processing is properly controlled to develop a uniform product and provided that adequate documentation exists of service experience and/or test data to demonstrate that the processing will not result in increased susceptibility to intergranular stress corrosion.

If it is not verified that such material is not susceptible to intergranular attack, the material will be resolution annealed and water quenched or rejected.

5.2.5.7 Control of Delta Ferrite in Austenitic Stainless Steel Welding

Regulatory Guide 1.31 describes a method for implementing General Design Criterion 1 of Appendix A to 10 CFR 50 and Appendix B to 10 CFR 50 with regard to control of welding austenitic stainless steel components and systems. The Interim Regulatory Position of this guide, March 1974, describes an alternative method of control. The following paragraphs describe the methods used by Westinghouse and the verification of these methods for austenitic stainless steel welding on this application. Additional discussion on the recommendations of Regulatory Guide 1.31 is given in Appendix 3A.

The welding of austenitic stainless steel is controlled to mitigate the occurrence of microfissuring or hot cracking in the weld. Although published data and experience have not confirmed that fissuring is detrimental to the quality of the weld, it is recognized that such fissuring is undesirable in a general sense. Also, it has been well documented in the technical literature that the presence of delta ferrite is one of the mechanisms for reducing the susceptibility of stainless steel welds to hot cracking. However, there are insufficient data to specify a minimum delta ferrite level below which the material will be prone to hot cracking. It is assumed that such a minimum lies somewhere between 0 and 3% delta ferrite.

The scope of these controls discussed herein encompasses welding processes used to join stainless steel parts in components designed, fabricated, or stamped in accordance with the ASME Code, Section III Class 1, 2, and core support components. Delta ferrite control is appropriate for the above welding requirements except where no filler metal is used or for other reasons such control is not applicable. These exceptions include electron beam welding, autogenous gas shielded tungsten arc welding, explosive welding, and welding using fully austenitic welding materials.

The fabrication and installation specifications require welding procedure and welder qualification in accordance with Section III, and include the delta ferrite determinations for the austenitic stainless steel welding materials that are used for welding qualification testing and for production processing. Specifically, the undiluted weld deposits of the "starting" welding materials are required to contain a minimum of 5% delta ferrite(2) as determined by chemical analysis and calculation using the appropriate weld metal constitution diagrams in Section III. When new

(2) The equivalent ferrite number may be substituted for percent delta ferrite.

welding procedure qualification tests are evaluated for these applications, including repair welding of raw materials, they are performed in accordance with the requirements of Section III and Section IX.

The results of the destructive and nondestructive tests are reported in the procedure qualification record in addition to the information required by Section III.

The "starting" welding materials used for fabrication and installation welds of austenitic stainless steel materials and components meet the requirements of Section III. The austenitic stainless steel welding material conforms to ASME weld metal analysis A-7, Type 308 for all applications except Type 308L weld metal analysis may be substituted for consumable inserts when used for weld root closures. Bare weld filler metal, including consumable inserts, used in inert gas welding processes conform to ASME SFA-5.9, and are procured to contain not less than 5% delta ferrite according to Section III. Weld filler metal materials used in flux shielded welding processes conform to ASME SFA-5.4 or SFA-5.9 and are procured in a wire-flux combination to be capable of providing not less than 5% delta ferrite in the deposit according to Section III. Welding materials are tested using the welding energy inputs to be employed in production welding.

Combinations of approved heats and lots of "starting" welding materials are used for all welding processes. The welding quality assurance program includes identification and control of welding material by lots and heats as appropriate. All of the weld processing is monitored according to approved inspection programs which include review of "starting" materials, qualification records, and welding parameters. Welding systems are also subject to quality assurance audit including calibration of gages and instruments; identification of "starting" and completed materials; welder and procedure qualifications; availability and use of approved welding and heat treating procedures; and documentary evidence of compliance with materials, welding parameters, and inspection requirements. Fabrication and installation welds are inspected using nondestructive examination methods according to Section III rules.

To further assure the reliability of these controls, Westinghouse has completed a verification program, which is described in Reference 9. The program has been approved as a valid approach to verify the Westinghouse hypothesis and is considered an acceptable alternative to production weld testing for conformance with the NRC Interim Position on Regulatory Guide 1.31. The Regulatory Staff’s acceptance letter and topical report evaluation were received on December 30, 1974. The results of the verification program, which do not support the original hypothesis, are summarized in Reference 10.

It should be noted that the criteria discussed above concerning delta ferrite determinations were incorporated in the Virgil C. Summer Nuclear Station components that were involved in the Westinghouse verification program; these components cannot necessarily be identified. Those components not involved in the verification program were fabricated in accordance with applicable ASME Code requirements, which do not include delta ferrite determinations. Therefore, the delta ferrite determinations performed on the Virgil C. Summer Nuclear Station components are in addition to the applicable ASME Code requirements.

5.2.6 Pump Flywheels

The integrity of the reactor coolant pump flywheel is assured on the basis of the following design and quality assurance procedures.

5.2.6.1 Design Basis

The calculated stresses at operating speed are based on stresses due to centrifugal forces. The stress resulting from the interference fit of the flywheel on the shaft is less than 2000 psi at zero speed, but this stress becomes zero at approximately 600 rpm because of radial expansion of the hub. The primary coolant pumps run at approximately 1190 rpm and may operate briefly at overspeeds up to 109% (1295 rpm) during loss of outside load. For conservatism, however, 125% of operating speed was selected as the design speed for the primary coolant pumps. The flywheels are given a preoperational test of 125% of the maximum synchronous speed of the motor.

5.2.6.2 Fabrication and Inspection

The flywheel consists of two thick plates bolted together. The flywheel material is produced by a process that minimizes flaws in the material and improves its fracture toughness properties, such as vacuum degassing, vacuum-melting, or electroslag remelting. Each plate is fabricated from A533, Grade B, Class 1 steel. Supplier certification reports are available for all plates and demonstrate the acceptability of the flywheel material on the basis of the requirements of Regulatory Guide 1.14.

No welding, including repair welding, is performed on the flywheels. The tensile (from material certifications) and Charpy-V-notch data for the flywheel discs are tabulated in Tables 5.2-23 and 5.2-24.

Flywheel blanks are flame-cut from the A533, Grade B, Class 1 plates with at least 1/2 inch of stock left on the outer and bore radii for machining to final dimensions. The finished machined bores, keyways, and drilled holes are subjected to magnetic particle or liquid penetrant examinations. The finished flywheels are subjected to 100% volumetric ultrasonic inspection per Paragraphs NB-2532.1 and NB-2532.2 of the ASME Code, Section III.

The reactor coolant pump motors are designed such that the flywheel is available by removing the cover to provide access to allow an inservice inspection program in accordance with requirements of Section XI of the ASME Code and the recommendations of Regulatory Guide 1.14 (see Appendix 3A).

5.2.6.3 Acceptance Criteria and Compliance with Regulatory Guide 1.14

The reactor coolant pump motor flywheel conforms to the following material acceptance criteria.

1. The nil-ductility transition temperature (NDTT) of the flywheel material is obtained by two drop weight tests (DWT) which exhibit "no-break" performance at 20°F in accordance with

ASTM E-208. The above drop weight tests demonstrate that the NDTT of the flywheel material is no higher than 10°F.

2. A minimum of three Charpy V-notch specimens from each plate are tested at ambient (70°F) temperature in accordance with the specification ASTM E-23. The Charpy V-notch (C_v) energy in both the parallel and normal orientation with respect to the rolling direction of the flywheel material is at least 50 foot pounds at 70°F to demonstrate that RT_{NDT} is no higher than 10°F. A lower bound K_{Ic} versus temperature curve from tests of SA-533 Grade B, Class 1 and SA-508 Class 2 steels is provided in ASME Boiler and Pressure Vessel Code, Section XI, Appendix A, Figure A-4200-1. The temperature scale of this figure is referenced to RT_{NDT}, the reference nil-ductility temperature. The fracture toughness K_{Ic} given in Figure A-4200-1 is based on lower bound data from static fracture toughness tests. Reference of this curve to the guaranteed RT_{NDT} of +10°F gives a minimum static fracture toughness of 150 ksi in1/2 at 90°F. The expected normal operating temperature of the Virgil C. Summer Nuclear Station reactor coolant pump motor flywheels is in excess of 110°F. Therefore, the minimum static fracture toughness requirement of 150 ksi in1/2 is exceeded. A lower bound K_{Id} reference curve (see Figure 5.2-3) has been constructed from dynamic fracture toughness data generated in A533, Grade B, Class 1 steel (Reference 11). All data points are plotted on the temperature scale relative to the NDTT. The construction of the lower bound curve below which no single test point falls, combined with the use of dynamic data when flywheel loading is essentially static, together represent a large degree of conservatism. Reference of this curve to the guaranteed NDTT of +10°F indicates that, at the predicted flywheel operating temperature of 110°F, the minimum fracture toughness is in dynamic stress intensity factor must be at least 100 KSI-$in^{1/2}$. This conforms to the Regulatory Guide 1.14 requirement that the dynamic stress intensity factor must be at least 100 KSI-$in^{1/2}$.

Precautionary measures taken to preclude missile formation from primary coolant pump components assure that the pumps will not produce missiles under any anticipated accident condition. Each component of the primary pump motors has been analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy case.

Thus, it is concluded that flywheel plate materials are suitable for use and can meet Regulatory Guide 1.14 acceptance criteria on the bases of suppliers certification data.

5.2.7 Reactor Coolant Pressure Boundary Leakage Detection Systems

Leakage detection systems are required to detect and, to the extent practical, identify the source of reactor coolant leakage. The airborne radiation monitoring system, described in Sections 11.4 and 12.2.4, provides input which is sensitive to leakage detection when activity is present in reactor coolant. Portions of this system, in addition to quantitative leak detection systems located in the reactor building, enable the operator to adequately locate and analyze the RCPB leakage.

5.2.7.1 Leakage Detection Method

Leakage detection system instrumentation sensitivity is 1 gpm or less. Response time of less than one hour is consistent with the requirements of General Design Criterion 30. Sufficient range overlap and multiple instruments ensure shorter overall response time for leakage detection. Reactor building sump level instrumentation is Seismic Category I. The various methods of leakage detection employed are discussed in Sections 5.2.7.1.1 through 5.2.7.1.4 and 5.2.7.8.

5.2.7.1.1 Activity Detection

Consistent with the recommendations of Regulatory Guide 1.45 (see Appendix 3A), radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS leakage but have recognized limitations on achieving the recommended response time of one hour or less when there are few fuel cladding defects and reactor coolant activity levels are low.

The reactor building air sample line radiation monitor (RM-A2) is the most sensitive to reactor coolant leakage. Alarms are provided to alert the operator to the onset of or changes in reactor coolant leakage. The monitor is typically set to provide the most sensitive response without causing an excessive number of spurious alarms in order to provide an early indication of the onset of or changes in reactor coolant leakage, and an audible alarm is provided in the control room when the monitor’s setpoint is exceeded. Section 12.2.4 discusses airborne radiation monitoring instrumentation, sensitivities, and setpoints. The radiation monitor (RM-A2) satisfies the seismic requirements of Regulatory Guide 1.45.

Leakage from the RCPB into the component cooling water system is detected by process radiation monitors (RM-L2A and RM-L2B). These radiation monitors are described in Section 11.4.

5.2.7.1.2 Detection by Temperature, Pressure, or Drain Flows

Reactor building temperature and pressure monitors provide indirect indication of gross RCPB leakage. However, the most sensitive leakage detection system, other than activity detection, is the reactor building cooling unit condensate drain flow alarm. A flow meter is located in the common condensate drain header from the reactor building cooling units (see Figures 5.2-9 and 9.3-5). The flow meter actuates an alarm in the control room, should a flow rate exceeding 0.75 gpm nominal occur. The response time for this system to indicate a 1 gpm reactor coolant leak is approximately 20 minutes. The reactor building temperature and pressure monitors and the flow switches satisfy the seismic requirements of Regulatory Guide 1.45.

5.2.7.1.3 Leak Detection Sumps

The Reactor Building Sump is used to collect and quantify leakage originating in the Reactor Building. Detection of leakage is accomplished by obtaining a flow rate into the sump from comparison of level changes over a specified time period. Whenever the measured flow rate into the sump from unidentified sources exceeds 1 gallon per minute, a "greater than 1 gpm" alarm is

actuated. To ensure reliability, the level monitor for the RB sump is Seismic Category I. This detection method satisfies the requirements of Regulatory Guide 1.45 as one of the diverse methods for determination of reactor coolant leakage employed in the design of Virgil C. Summer Nuclear Station.

The Incore Instrument Sump, although not credited in the VCSNS SER nor in Technical Specifications, provides another means to collect and quantify unidentified leakage originating in the Reactor Building.

The CRDM condensate drain line flow transmitter installed under ECR 50677 monitors leakage in the range of 0.5 gpm to 1.0 gpm. The new flow transmitter provides enhanced RCS leak detection but is not credited in the VCSNS SER nor in the Technical Specifications.

5.2.7.1.4 Indirect Detection

Low pressurizer level indication or a discrepancy between net letdown and makeup flow, if unexplained, are good indications of reactor coolant leakage.

5.2.7.2 Indication in Control Room

Display instrumentation for the variables providing indirect indication for the leakage detection systems has audible alarms and measured variable recording devices in the control room. Instrumentation is of sufficient redundancy and quantity to assure that leakage is monitored. Regulatory Guide 1.45 is discussed in Appendix 3A.

5.2.7.3 Limits for Reactor Coolant Leakage

RCPB leakage is defined as leakage through a fault in an RCS component body, pipe wall, or vessel wall. Leakage past seals, packing, and gaskets is not PRESSURE BOUNDARY LEAKAGE. Unidentified leakage limitations are discussed in the Technical Specifications. Unidentified leakage is expected to be less than 1 gpm. Identified leakage less than 10 gpm is acceptable provided that it does not interfere with detection of unidentified leakage by the leakage detection systems.

5.2.7.4 Unidentified Leakage

Unidentified leakage is any RCS leakage which is not identified or controlled leakage (see Section 5.2.7.5).

5.2.7.5 Maximum Allowable Total Leakage

The maximum allowable total leakage includes controlled leakage and identified leakage.

Controlled leakage is defined as seal water flow to reactor coolant pump seals. Operation is limited if this flow exceeds 33 gpm with the supply modulating valve fully open and reactor

coolant system pressure at 2235 psig, nominal. Flow instrumentation is provided for the purpose of monitoring this leakage.

Identified leakage includes the following:

1. Leakage into closed systems, such as flange seals and valve leakoffs to collection tanks, normal letdown, sampling of auxiliary systems, and pressurizer relief valve discharge to pressurizer relief tank. These leakage paths contain temperature elements to indicate leakage flow, as well as high level tank, high flow rate, and radiation monitor alarms in auxiliary systems.
2. Other leakages not related to the RCPB which do not interfere with leakage detection system operation.
3. Reactor coolant leakage through a steam generator (not a steam generator tube rupture) to the secondary system. This leakage is limited to less than a total of 150 gal/day from each steam generator. This leakage is monitored by radiation monitors RM-L3 and RM-A9, as well as by periodic sampling discussed in Section 11.4.

5.2.7.6 Differentiation between Identified and Unidentified Leaks

The leakage detection system provides for differentiation between identified and unidentified leakage since identified leakage flows into closed containers or does not interfere with detection system operation. The leakage detection system provides both qualitative and quantitative information for use by the operator in determining the location and magnitude of leakage.

5.2.7.7 Sensitivity and Operability Tests

Proper functioning of leak detection instrumentation is assured by testing and calibration procedures. Sensitivity and calibration of radiation monitoring equipment are discussed in Sections 11.4 and 12.2.4.

5.2.7.8 Intersystem Leakage

Reliable methods of intersystem leakage detection for systems connected to the reactor coolant system are described below:

1. Safety Injection System

   Safety injection system cold leg connection leakage will be detected by lifting of residual heat removal relief valves 8864A or 8864B.

   Safety injection system hot leg connection leakage will be detected by lifting of residual heat removal relief valve 8865.

   Accumulator connection leakage will be detected by:

a. Redundant high accumulator level indication and alarm, and/or

b. Redundant high accumulator pressure indication and alarm.

High head cold leg injection and high head hot leg recirculation line leakage is not of concern since these are normally exposed to charging flow.

2. Residual Heat Removal System

Residual heat removal suction connection leakage will be detected by lifting of residual heat removal suction relief valves 8708A or 8708B accompanied by increased pressurizer relief tank level and temperature indication and alarm.

Residual heat removal discharge connection leakage will be detected by lifting of residual heat removal relief valves 8864A or 8864B.

3. Waste Processing System

Cold leg leakage into the waste processing system will be collected in the reactor coolant drain tank and detected by:

a. An increased load on the collection system, and/or

b. Lifting of reactor coolant drain tank relief valve 7169.

Leakage from the reactor vessel flange leakoff connection will be detected by high temperature indication and alarm from the leakage piping.

4. Pressurizer Relief Tank

Reactor coolant system leakage to the pressurizer relief tank will be detected by:

a. High temperature indication and alarm in the pressurizer safety valve and power operated relief valve discharge lines, and/or

b. High temperature or high level indication and alarms in the pressurizer relief tank, and

c. The acoustical type leak monitoring system and pressurizer safety valve alarm, and

d. PORV position indication.

5. Chemical and Volume Control System

Since the only chemical and volume control system to reactor coolant system connections are utilized for reactor coolant system letdown and charging, intersystem leakage detection is not relevant.

6. Valve Leakage

As discussed in Section 9.3.3.2, Item 10, and illustrated by Figures 9.3-13 and 9.3-13a, valve packing box leakage from various systems is monitored by means of level switches.

7. Main Steam System

   Steam generator tube leakage will be detected by:

   a. Use of steam generator blowdown and sampling (see Sections 9.3.2 and 10.4.8) which includes use of radiation monitors, RM-L3 and RM-L10 (see Section 11.4.2) and/or
   b. Main plant vent exhaust radiation monitor, RM-A3 (see Section 11.4.2) and/or
   c. Turbine room sump radiation monitor, RM-L8 (see Section 11.4) and/or
   d. Condenser exhaust monitor, RM-A9 (see Section 11.4).

8. Component Cooling Water System

   As discussed in Section 11.4.2, radiation monitors, RM-L2A and/or RM-L2B, will detect intersystem leakage into the component cooling water system.

   Residual heat removal heat exchanger leakage will be detected by high temperature indication and alarm.

   Reactor coolant drain tank heat exchanger leakage will be detected by:

   a. High temperature indication and alarm and/or
   b. High flow indication.

   Reactor coolant pump thermal barrier leakage will be detected by:

   a. High temperature indication and alarm and/or
   b. High flow indication and alarm.

   Reactor coolant pump upper and lower bearing leakage will be detected by:

   a. High temperature indication and alarm and/or
   b. High flow indication.

   Letdown heat exchanger leakage will be detected by:

   a. High temperature indication and alarm and/or
   b. High flow indication.

   Seal water heat exchanger leakage will be detected by:

a. High temperature indication and alarm and/or

b. High flow indication.

Residual heat removal pump leakage will be detected by:

a. High temperature indication and alarm and/or

b. High flow indication.

5.2.8 Inservice Inspection Program

Refer to Section 5.7.

5.2.9 References

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15. WCAP-13777, *Addendum to Final (Summary) Stress Report 157" PWR Vessel Virgil C. Summer Nuclear Station Revision 2 (Uprating/Steam Generator Replacement Evaluation)*, June 1993.

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Table 5.2-1
Applicable Code Addenda for RCS Components

Reactor Vessel	ASME III, 1971 Ed.
Steam Generator (Δ75)	ASME III, 1971 Ed. through Summer ‘71 (Design & Analysis) ASME III, 1986 Ed. (Construction)
Pressurizer	ASME III, 1971 Ed. through Summer ‘71
CRDM Housing	
Full Length	ASME III, 1971 Ed. through Winter ‘72
Part Length	ASME III, 1971 Ed through Winter ‘72
CRDM Head Adapter	ASME III, 1971 Ed. through Summer ‘71
Reactor Coolant Pump	ASME III, 1971 Ed. through Summer ‘72
Reactor Coolant Pump Seal Pressure Boundary	ASME III, 1989 Ed. through 1990
Reactor Coolant Pressure Boundary Pipe:	
(1) 1 1/2" CVCS Seal Injection Line	ASME III, 1974 Ed through Summer ‘76
(2) 1" and smaller Class 1 Piping	ASME III, 1974 Ed through Summer ‘75
(3) 29" I.D. Hot Leg Pipe, 31" I.D. Cross Over Leg Pipe, 27.5" I.D. Cold Leg Pipe	ASME III, 1971 Ed. through Winter '71
(4) Class I Pipe Fatigue Qualification	ASME III, 1977 Ed. through Summer ‘79
(5) All other piping	ASME III, 1971 Ed. through Summer ‘73
Valves	
Pressurizer Safety	ASME III, 1971 Ed. through Winter ‘72
Other	ASME III, 1971 Ed. through Summer ‘71

Table 5.2-2
Summary of Reactor Coolant System Design Transients

Normal Conditions		Occurrences
1.	Heatup and cooldown at 100°F/hr (pressurizer cooldown 200°F/hr)	200 (each)
2.	Unit loading and unloading at 5% of full power/min	13,200 (each)
3.	Step load increase and decrease of 10% of full power	2,000 (each)
4.	Large step load decrease	200
5.	Steady-state fluctuations	
	a. Initial Fluctuations	1.5×10^5
	b. Random Fluctuations	3.0×10^6
6.	Feedwater Heater Out of Service	40
Upset Conditions		
1.	Loss of load, (without immediate reactor trip)	80
2.	Loss of power	40
3.	Partial loss of flow	80
4.	Reactor trip from full power	400
5.	Inadvertent auxiliary spray	10
6.	Operating basis earthquake (20 earthquakes of 20 cycles each)	400
7.	Excessive Feedwater Flow	30
Faulted Conditions (1)		
1.	Reactor coolant branch line pipe break	1
2.	Large steam line break	1
3.	Steam generator tube rupture	(included in 4 above, reactor trip from full power)
4.	Safe Shutdown Earthquake	1

Table 5.2-2 (continued)
Summary of Reactor Coolant System Design Transients

Test Conditions		Occurrences
1.	Turbine roll test	10
2.	Primary side hydrostatic test	5
3.	Secondary side hydrostatic test	5
4.	Primary side leakage test	50

(1) In accordance with the ASME Boiler and Pressure Vessel Code, Section III, faulted conditions are not included in fatigue evaluation.

Table 5.2-3
Loading Combinations for ASME Class 1 Components and Supports

Condition Classification	Loading Combination
Design	Design Pressure, Design Temperature, Deadweight, Operating Basis Earthquake
Normal	Normal Condition Transients, Deadweight
Upset	Upset Condition Transients, Deadweight, Operating Basis Earthquake
Faulted	Faulted Condition Transients, Deadweight, Safe Shutdown Earthquake or (Safe Shutdown Earthquake and Pipe Rupture Loads)

Table 5.2-4
Allowable Stresses for ASME Section III Class 1 Components[1]

Operating Condition Classification	Vessels/Tanks	Piping	Pumps	Valves	Component Supports
Normal	ASME Section III	ASME Section III	ASME Section III	ASME Section III	See Section 5.2.1.10.7
Upset	ASME Section III	ASME Section III	ASME Section III	ASME Section III	See Section 5.2.1.10.7
Faulted	ASME Section III	ASME Section III	ASME Section III	(2)	See Section 5.2.1.10.7
	See Section 5.2.1.11	See Section 5.2.1.11	See Section 5.2.1.11 (No active Class 1 pump used)		

P_e, P_m, P_b, Q_t, C_p, S_n, & S_m as defined by Section III ASME Code

(1) A test of the components may be performed in lieu of analysis.
(2) Class 1 Valve Faulted Condition Criteria.

Table 5.2-4(Continued)
Allowable Stresses for ASME Section III Class 1 Components(1)

	Active		Inactive
a)	Calculated P_m from paragraph NB3545.1 with Internal Pressure $P_s = 1.25P_s$ $P_m \leq 1.5S_m$	a)	Calculated P_m from paragraph NB3545.1 with Internal Pressure $P_s = 1.50P_s$ $P_m \leq 2.4S_m$ or 0.7 Su
b)	Calculated Sn from paragraph NB345.2 with $C_p = 1.5$ $P_s = 1.25P_s$ $Q_t^2 = 0$ Ped = 1.3X value of Ped from equations of NB3545.2 (b)(1) $S_n \leq 3S_m$	b)	Calculate Sn from paragraph NB3545.2 with $C_p = 1.5$ $P_s = 1.50P_s$ $Q_t^2 = 0$ Ped = 1.3X value of Ped from equations of NB3545.2 (b)(1) $S_n \leq 3S_m$

(1) A test of the components may be performed in lieu of analysis.

Table 5.2-5
Allowable Stresses for Primary Equipment Supports

Loading Conditions	Stress Limits
Design/Normal	AISC, Seventh Edition(1), Part 1, Allowable Stresses
Upset	AISC, Seventh Edition, Part 1, Allowable Stresses
Faulted	Stresses ≤ yield strength of material. Local yielding is permitted but limited so that the structural integrity of the system is maintained. As an alternative to the above, 80 percent of L_T(2) may be used.

(1) Specification for the Design, Fabrication and Erection of Structural Steel for Buildings.
(2) L_T = The limits established for the analysis need not be satisfied if it can be shown from the test of a prototype or model that the specified loads (dynamic or static equivalent) do not exceed 80 percent of L_T, where L_T is the ultimate load or load combination used in the test. In using this method, account is taken of the size effect and dimensional tolerances (similitude relationships) which may exist between the actual component and the tested models to assure that the loads obtained from the test are a conservative representation of the load carrying capability of the actual component under postulated loading for faulted conditions.

Table 5.2-6
Relief Valve Discharge to the Pressurizer Relief Tank

Reactor Coolant System		
3	Pressurizer Safety Valves	Figure 5.1-1, Sheet 2
3	Pressurizer Power Operated Relief Valves	Figure 5.1-1, Sheet 2
1	Reactor Vessel Head Vent System Letdown Line	Figure 5.5-13
Emergency Core Cooling System		
3	Low Head Safety Injection/Residual Heat Removal Pump Discharge Lines	Figure 6.3-1, Sheet 2
Residual Heat Removal System		
2	Residual Heat Removal Pump Suction Line from the Reactor Coolant System Hot Legs	Figure 5.5-4
Chemical and Volume Control System		
2	Charging Pump Suction	Figure 9.3-16, Sheet 2
1	Seal Water Return Line	Figure 9.3-16, Sheet 1
1	Letdown Line	Figure 9.3-16, Sheet 1

Table 5.2-7
Reactor Coolant System Design Pressure Settings

	PSIG
Hydrostatic Test Pressure	3107
Design Pressure	2485
Safety Valves (Begin to Open)	2485
High Pressure Reactor Trip	2380
Power Relief Valves	2335 (1) (2)
High Pressure Alarm	2310 (2)
Pressurizer Spray Valves (Full Open)	2310 (2)
Pressurizer Spray Valves (Begin to Open)	2260 (2)
Proportional Heaters (Begin to Operate)	2250 (2)
Operating Pressure	2235
Proportional Heater (Full Operation)	2220 (2)
Backup Heaters On	2210 (2)
Low Pressure Alarm	2210 (2)
Pressurizer Relief Valve Interlock	1985
Low Pressure Reactor Trip	1870

(1) At 2335 psig, a pressure signal initiates actuation (opening) of these valves. Remote manual control is also provided.
(2) Setpoint is affected by integral portion of controller.

Table 5.2-7a
Check Valves Classified as Category AC

Valve Tag Number	Valve Tag Number	Valve Tag Number
8998A	8992A	8973B
8998B	8992B	8973C
8998C	8992C	8974A
8997A	8990A	8974B
8997B	8990B	8956A
8997C	8990C	8956B
8995A	8988A	8956C
8995B	8988B	
8995C	8948A	
8993A	8948B	
8993B	8948C	
8993C	8973A	

Table 5.2-8
Reactor Coolant Pressure Boundary Materials
Class 1 Primary Components

CLASS 1 PRIMARY COMPONENTS	
Reactor Vessel Components	
Shell & Bottom Head Plates (other than core region)	SA533 Gr A, B, or C, Class 1 or 2 (Vacuum treated)
Shell Plates (core region) (Vacuum treated)	SA533 Gr A or B, Class 1
Shell, Flange & Nozzle Forgings Nozzle Safe Ends	SA508 Class 2 and 3 Weld Filler Metal Alloy 600 except "A" Hot Leg which is Alloy 690
Replacement Reactor Vessel Closure Head (Forging)	SA508, Gr 3, CL 1
CRDM Appurtenances – Upper Head	SB166 N0690TT and SA182 Type F304
Instrumentation Tube Appurtenances - Lower Head	SB166 or 167
Closure Studs, Inserts and Adaptors	SA-540 Gr B-24 Class 3 (as modified by Code Case 1605)
Closure Nuts, Washers	SA-540 Gr B-23/24 Class 3
Core Support Pads	SB166 with Carbon less than 0.10%
RV Level & Vent Pipe	SB167 N0690TT and SA312 Type 316LN
Vessel Supports, Seal Ledge	SA516 Gr 70 Quenched & Tempered or SA533 Gr A, B or C, Class1 or 2. (Vessel supports may be of weld metal buildup of equivalent strength)
Head Lifting Lugs	SA508, Gr 3, CL 1
Cladding & Buttering	Stainless steel weld Metal Analysis A-7 and Ni-Cr-Fe Weld Metal F-Number 43 (Alloy 600 except Buttering on "A" Hot Leg which is Alloy 690)
Instrument Port Head Adaptor	SB166 N0690TT and SA182, GR F304
Steam Generator Components	
Shell	SA508 Class 3a
Pressure Forgings (including nozzles and tubesheet)	SA508 Class 3a
Nozzle Safe Ends	Forged Stainless Steel
Channel Head	SA508 Class 3a
Tubes	SB163 Ni-Cr-Fe Thermally treated, procured to Code Case N-20-3

Table 5.2-8 (continued)
Reactor Coolant Pressure Boundary Materials
Class 1 Primary Components

Steam Generator Components (Cont'd)	
Cladding	Austenitic Stainless
Channel Head Surfaces	Steel 309L/308L
Tubesheet Primary Side Surfaces	Ni-Cr-Fe (N06082/W86182)
Closure Studs	SA193 Gr B-7
Closure Nuts	SA194 Gr 7
Pressurizer Components	
Pressure Plates	SA533 Gr A, B or C, Class 1 or 2
Pressure Forgings	SA508 Class 2 or 3
Nozzle Safe Ends	SA182 or 376 Type 316 or 316L and Ni-Cr-Fe Weld Metal F-Number 43
Cladding and Buttering	Stainless Steel Weld Metal Analysis A-7 and Ni-Cr-Fe Weld Metal F-Number 43
Closure Bolting	SA193 Gr B-7
Pressurizer Safety Valve Forgings	SA182 Type F316
Reactor Coolant Pump	
Pressure Forgings	SA182 F304, F316, F347 or F348
Pressure Casting	SA351 Gr CF8, CF8A, or CF8M
Tube & pipe	SA213, SA376 or SA312- Seamless Type 304 or 316
Pressure Plates	SA240 Type 304 or 316
Bar Material	SA479 Type 304 or 316
Closure Bolting	SA193, SA320, SA540, SA453, Gr 660
Flywheel	SA533 Gr B, Class 1

Table 5.2-8 (continued)
Reactor Coolant Pressure Boundary Materials
Class 1 Primary Components

Reactor Coolant Piping	
Reactor Coolant Pipe	SA376 Gr 304N
Reactor Coolant Fittings	SA351 Gr CF8A
Branch Nozzles	SA182 Code Case 1423-2 Gr 304N
Surge Line	SA376 Gr 304, 316 or F304N
Auxiliary Piping 1/2" through 12" and wall schedules 40S through 80S (ahead of second isolation valve)	ANSI B36.19
All other Auxiliary Piping (ahead of second isolation valve)	ANSI B36.10
Socket Weld Fittings	ANSI B16.11
Piping Flanges	ANSI B16.5
Full Length Control Rod Drive Mechanism	
Latch Housing	SA182 Type F304
Rod Travel Housing	SA182 Type F304
Welding Materials	SFA5.4 and 5.9 Type 308 or 308L

Table 5.2-9
Reactor Coolant Pressure Boundary Materials
Class 1 and 2 Auxiliary Components

Valves	
Bodies	SA182 Type F316 or SA351 Gr CF8 or CF8M
Bonnets	SA182 Type F316 or SA351 Gr CF8 or CF8M
Discs	SA182 Type F316 or SA564 Gr 630 Cond 1100°F Heat Treatment or SA351 Gr CF8 or CF8M
Pressure Retaining Bolting	SA453 Gr 660
Pressure Retaining Nuts	SA453 Gr 660 or SA194 Gr 6
Auxiliary Heat Exchangers	
Heads	SA240 Type 304
Nozzle Necks	SA182 Gr F304
Tubes	SA213 TP 304
Tubesheets	SA182 Gr F304
Shells	SA240 and SA312 Type 304
Auxiliary Pressure Vessels, Tanks, Filters, etc,	
Shells & Heads	SA240 Type 304 or SA264 consisting of SA537 CL1 with SA240 Type 304 L Cladding
Flanges & Nozzles	SA182 Gr F304 and SA350 Gr LF2, with SA240 Type 304 L Cladding
Piping	SA312 and SA240 TP304 or TP316 Seamless
Pipe Fittings	SA403 WP304 Seamless
Closure Bolting & Nuts	SA193 Gr B7 and SA194 Gr 2H

Table 5.2-9 (continued)
Reactor Coolant Pressure Boundary Materials
Class 1 and 2 Auxiliary Components

Auxiliary Pumps	
Pump Casing & Heads	SA351 Gr CF8 or CF8M, SA182 Gr F304 or F316
Flanges & Nozzles	SA182 Gr F304 or F316, SA403 Gr WP316L Seamless
Piping	SA312 TP304 or TP316 Seamless
Stuffing or Packing Box Cover	SA351 Gr CF8 or CF8M, SA240 TP304 or TP316
Pipe Fittings	SA403 Gr WP316L Seamless
Closure Bolting & Nuts	SA193 Gr B6, B7, or B8M and SA194 Gr 2H or Gr 8M, SA193 Gr B6, B7 or B8M; SA453 Gr 660; and Nut 8, SA194 Gr 2H, Gr 8M, and Gr 6

Table 5.2-10
Reactor Coolant Water Chemistry Specification

Electrical Conductivity	Affected by the concentration of boric acid and alkali present. Expected range is < 1 to 40 μMhos/cm at 25°C.
Solution pH	Affected by the concentration of boric acid and alkali present. Expected values range between 4.2 (high boric acid concentration) to 10.5 (low boric acid concentration) at 25°C.
Oxygen, ppm, maximum	Oxygen concentration of the reactor coolant is maintained below 0.1 ppm for plant operation above 250°F. Hydrazine may be used to chemically scavenge oxygen during heatup.
Chloride, ppm, maximum	0.15
Fluoride, ppm, maximum	0.15
Hydrogen, cc (STP)/kg H_2O	
Reactor Power Level above 1 MWt, excluding decay heat during subcritical operation.	25-50
Total Suspended Solids	
ppm, maximum	1.0
pH Control Agent (Li^7OH)	Lithium concentration is coordinated with the boron concentration.
Boric Acid, ppm B	Variable from 0 to approximately 4000

Table 5.2-11
Reactor Vessel Unirradiated Toughness Data (Transverse)

Component	Heat Number	Material Type	Cu %	P %	NDTT (°F)	Min. 50 Ft-Lb 35 Mil Temp. (°F)	RT_{NDT} (°F)	Avg. Upper Shelf (ft-lb)
Replacement Closure Head	F14362-010	SA508,GR3 CL 1	-	-	-34	86	-34	195.5
Vessel Flange	5301-V-1	SA508 Class 2	-	-	0	<60	0	172
Inlet Nozzle	436B-1	SA508 Class 2	-	-	-20	<40	-20	130
Inlet Nozzle	436B-2	SA508 Class 2	-	-	0	<60	0	114.5
Inlet Nozzle	436B-3	SA508 Class 2	-	-	-20	<40	-20	135
Outlet Nozzle	437B-1	SA508 Class 2	-	-	-10	<50	-10	146
Outlet Nozzle	437B-2	SA508 Class 2	-	-	-10	<50	-10	165
Outlet Nozzle	437B-3	SA508 Class 2	-	-	0	<50	0	150
Nozzle Shell	C9955-2	A533-B-Class 1	0.13	0.010	-20	78	18	100.5
Nozzle Shell	C0123-2	A533-B-Class 1	0.12	0.009	-30	86	26	91
Inter. Shell	A9154-1	A533-B-Class 1	0.10	0.009	-20	90	30	80.5
Inter. Shell	A9153-2	A533-B-Class 1	0.09	0.006	-20	40	-20	106.5
Lower Shell	C9923-2	A533-B-Class 1	0.08	0.005	-10	70	10	91.5
Lower Shell	C9923-1	A533-B-Class 1	0.08	0.005	-30	70	10	106
Trans. Ring	A9249-1	A533-B-Class 1	-	-	-40	23	-37	107
Bottom Head	A9231-2	A533-B-Class 1	-	-	-10	42	-10	134
Core Region Weld	-	-	0.05	0.013	-50	16	-44	84
Weld HAZ	-	-	-	-	-70	-37	-70	130

Table 5.2-12
Reactor Vessel Internals for Emergency Core Cooling

Forgings	SA182 Type F304
Plates	SA240 Type 304
Pipes	SA312 Type 304 Seamless or SA376 Type 304
Tubes	SA213 Type 304
Bars	SA479 Type 304
Castings	SA351 Gr CF8 or CF8A
Bolting	Westinghouse PD Spec. 70041 EA Westinghouse PD Spec. 15106 DA
Nuts	SA193 Gr B8
Locking Devices	SA479 Type 304
Weld Buttering	Stainless Steel Weld Metal Analysis A-7
Guide tube support pins and nuts	SA-193 Gr B&M Type 316 per Code Case N-60-4

Table 5.2-13
Reactor Coolant Mechanical Loads

LOAD COMPONENT*	ACCUMULATOR LINE BREAK (REF. 25)	PRESSURIZER SURGE LINE BREAK (REF. 25)
Axial Load (Fx)(Kips)	1652.6	1656.6
Vertical Load (Fy)(Kips)	-48.0	28.0
Lateral Load (Fz) (Kips)	-5.0	2.0
Axial Moment (Mx) (Ft-Kips)	310.3	121.7
Vertical Moment (My) (Ft-Kips)	83.8	4.4
Lateral Moment (Mz) (Ft-Kips)	-329.2	350.3

*These loads are break release load from the respective break location piping nozzles that were conservatively applied in the Reactor Vessel LOCA Analysis.

Table 5.2-14
Maximum RPV Displacements (Node #3)

LOAD COMPONENT	ACCUMULATOR LINE BREAK	PRESSURIZER SURGE LINE BREAK
UX (in)		
Max.	+ .0022	+ .02825
Min.	- .0046	- .0267
UY (in)		
Max.	+ .0048	- .113
Min.	- .0143	- .00401
UZ (in)		
Max.	+ .0520	0.0
Min.	2.1E-5	- .04

Table 5.2-15
Summary of Reactor Vessel Internals Interface Loads

INTERFACE COMPONENT	ACCUMULATOR LINE BREAK (LBS)	PRESSURIZER SURGE LINE BREAK (LBS)
Vessel/Barrel Flange (Hor.)	0.87E6	0.17E6
Vessel/Barrel Flange (Vert.)	2.9E6	2.37E6
Core Barrel Outlet Nozzle (Hor.)	0.4E6	0.21E6
Vessel/Upper Support Flange (Hor.)	1.5E5	-
Vessel Head/Upper Support Flange (Vert.)	1.1E6	.61E6
Lower Radial Key (Hor.)	3.20E6	2.41E6

Table 5.2-16
Steam Generator Lower Support Members Stresses

Member	Member Stress (% of allowable/loading condition)		
	Normal	Upset	Faulted
13	-	83 (1)	97 (1) (2)
14	-		
15	-		
16	-		
17	-		
18	-		
20	-	81 (1)	99 (1) (2)
22	-		
24	-		
26	-		
43	27	65	93
44			
45			
46			

(1) Includes the effects of pipe supports and platform attachments.
(2) Conservatively includes faulted conditions thermal loads added to SRSS (SSE, LOCA).

Table 5.2-17
Steam Generator Upper Support Member Stresses

Member	Member Stress (% of allowable/loading condition)		
	Normal	Upset	Faulted
(26,28) Snubbers *	-	-	-
70	-	25.9	25
71	-	41.1	41
72	-	37	35
36-69	-	54.5	78

* Snubbers have been eliminated.

Table 5.2-18
Reactor Coolant Pump Support Member Stresses

Member	Member Stress (% of allowable/loading condition)		
	Normal	Upset	Faulted
4	-	58	81
5	-	-	-
6	-	43	75
7 8 9	16	89	93

Table 5.2-19
Deleted per Amendment 95-04

Table 5.2-20
Deleted

Table 5.2-21
Reactor Vessel Beltline Material Fracture Toughness Data

Beltline Material	Plate No.	Cu (%)	P (%)	RT_{NDT}* (°F)	Upper Shelf Energy (ft-lb)	32/56 EFPY Fluence **** (10^{19}N/cm^2)	32/56 EFPY ΔRT_{NDT}** (°F)
Nozzle Shell	C-9955-2	.13	.010	18	103,106.5,93	--	--
Nozzle Shell	C0123-2	.12	.009	26	97,87,89	--	--
Inter. Shell	A9154-1	.10	.009	30	82.5,76.5,83	3.92/6.80	87.9/94.8
Inter. Shell	A9153-2	.09	.006	-20	101,108,111.5	3.92/6.80	78.4/84.6
Lower Shell	C9923-1	.08	.005	10	104,114,100	3.92/6.80	69.0/74.4
Lower Shell	C9923-2	.08	.005	10	93,94,88	3.92/6.80	69.0/74.4
Core Region Welds	***	.05	.013	-44	79,87,87	1.36/2.35	45.8/51.9
Weld HAZ	A9154-1	-	-	-70	137,135,118	1.36/2.35	45.8/51.9

* Determined from drop weight tests and full Charpy curve tests normal to the major working direction. Value reported is the higher of the NDTT temperature or the temperature 60°F below the 50 ft-lb/35 mil lateral expansion temperature.

** Based on WCAP-16298-NP, Revision 0, using methods identified in Regulatory Guide 1.99 Revision 2. Most limiting material is plate A9154-1. Test specimens from this plate are included in the reactor vessel surveillance program. The values were determined using results of capsules U, V, X, W, and Z test reports.

*** All core region welds were made with RACO INMM wire (heat no. 4P4784) and Linde 124 flux (lot no. 3930). The same heat of weld wire and lot of flux was also used to fabricate the surveillance program weldment. A post weld heat treatment at 1100°F-1175°F for 12 hours was applied to all the weld test material.

**** Calculated fast neutron fluence (E > 1.0 MeV) values at the inner surface of the reactor vessel (per WCAP-16298-NP, Revision 0). These values were projected using results of the Capsule Z radiation analysis.

Table 5.2-22
Bolting Material Fracture Toughness Data

Component	Test Number	Test Temp (°F)	Material	Charpy V-Notch (Ft-LB)	Lateral Expansion (Mils)
RV Closure Heat Studs	Heat 80751 Bar 66	10	A540-B24	50-51-52	31-30-32
Heat Studs	Bar 66-1	10	A540-B24	55-54-56	35-30-35
Heat Studs	Bar 70	10	A540-B24	57-56-57	36-33-35
Heat Studs	Bar 70-1	10	A540-B24	52-51-50	28-28-29
Heat Studs	Bar 75	10	A540-B24	48-51-48	32-33-28
Heat Studs	Bar 75-1	10	A540-B24	51-52-53	29-32-32
Heat Studs	Bar 81	10	A540-B24	50-47-51	28-26-27
Heat Studs	Bar 81-1	10	A540-B24	54-55-54	32-31-30
Steam Generator Closure Studs *	See Note	50°F Max	SA193 GrB7	45	25
Steam Generator Closure Studs *	See Note	50°F Max	SA194 GrB7	45	25
Pressurizer Manway Bolts	To 4560	40	SA193 GrB7	89-86.5-86.5	59-60-59
Reactor coolant heat pump seal housing bolts	8082109	10	SA193 GrB23	72-74.5-72.5	50-51-49

* Specific test data available in Steam Generator Final Data Package for each Steam Generator. Data shown is per Design Specification 411A78, Rev.3

Table 5.2-22 (continued)
Bolting Material Fracture Toughness Data

Component	Test Number	Test Temp (°F)	Material	Charpy V-Notch (Ft-LB)	Lateral Expansion (Mils)
Reactor Coolant Pump Main Flange Bolts	heat 123123 lot 1	35	SA540 1324c14	73,74,75 79,81,81 68,74,71 83,85,81	45,47,45 46,48,49 40,45,41 51,44,43
Reactor Coolant Pump Main Flange Bolts	heat 123123 lot 3	35		77,76,76 75,70,70 58,58,60	51,47,49 44,41,41 38,37,37
Reactor Coolant Pump Main Flange Bolts	heat 123123 lot 7	35		62,63,62 70,68,66	39,37,37 42,41,39
Reactor Coolant Pump Main Flange Bolts	heat 123123 lot 8	35		63,63,62 64,69,65	33,37,34 38,42,39
Reactor Coolant Pump Main Flange Bolts	heat 123123 lot 9	35		62,62,63 65,64,64	35,37,36 38,38,38

Table 5.2-23
Flywheel Disc Tensile Data

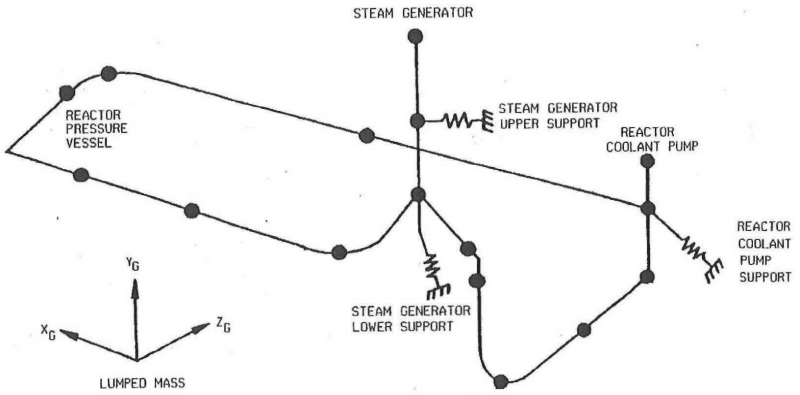
Motor Unit	Melt Number	Yield Strength (psi)	Tensile Strength (psi)
01	B9109	70,000	98,500
		68,700	84,000
	D1985	68,700	90,900
		72,700	92,400
02	D1985	68,700	90,900
		72,700	92,400
	D1985	68,700	90,900
		72,700	92,400
03	B9694	66,700	87,900
		66,500	85,400

Table 5.2-24
Flywheel Disc Charpy V-Notch Data

Motor Unit	Melt Number	Lateral Expansion (in)	Charpy V-Notch (ft-lb)	Orientation (longitudinal (L) or transverse (T))	Test Temperature (°F)	T_{NDT}* (°F)	RT_{NDT} (°F)
01	B9109	0.090, 0.091, 0.092	120, 110, 118	(T)	70	10	10
		0.099, 0.098, 0.099	155, 148, 163	(L)	70	10	10
	D1985	0.053, 0.058, 0.059	70, 66, 69	(T)	30	10	10
		0.068, 0.061, 0.063	83, 88, 79	(L)	30	10	10
02	D1985	0.053, 0.058, 0.059	70, 66, 69	(T)	30	10	10
		0.068, 0.061, 0.063	83, 88, 79	(L)	30	10	10
	D1985	0.053, 0.058, 0.059	70, 66, 69	(T)	30	10	10
		0.068, 0.061, 0.063	83, 88, 79	(L)	30	10	10
03	D9694	0.078, 0.083, 0.082	100, 106, 98	(T)	70	10	10
		0.099, 0.099, 0.098	198, 200, 199	(L)	70	10	10
	D1295	0.058, 0.057, 0.064	62, 68, 70	(T)	70	10	10
		0.096, 0.095, 0.098	148, 150, 158	(L)	70	10	10

* Based on two drop weight tests exhibiting no break performance @ 20°F.

Figure 5.2-1
REACTOR COOLANT LOOP SUPPORTS SYSTEM
DYNAMIC STRUCTURAL MODEL

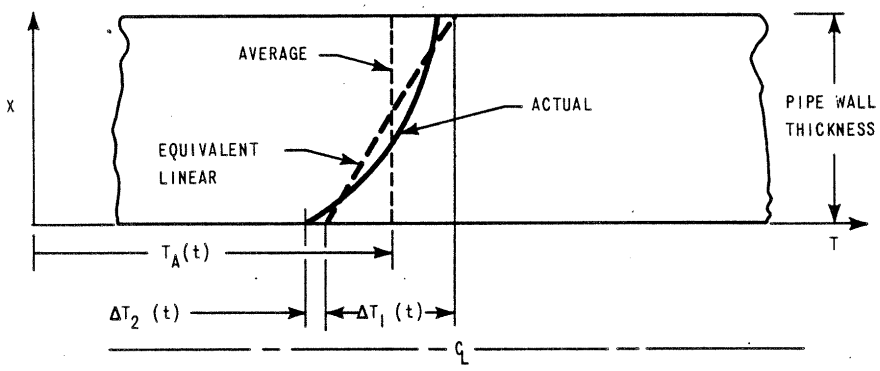


RCL GLOBAL COORDINATE SYSTEM

AMENDMENT 02-01
MAY 2002

SOUTH CAROLINA ELECTRIC AND GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Coolant Loop Supports System, Dynamic Structural Model Figure 5.2-1

Figure 5.2-2
THROUGH-WALL THERMAL GRADIENTS

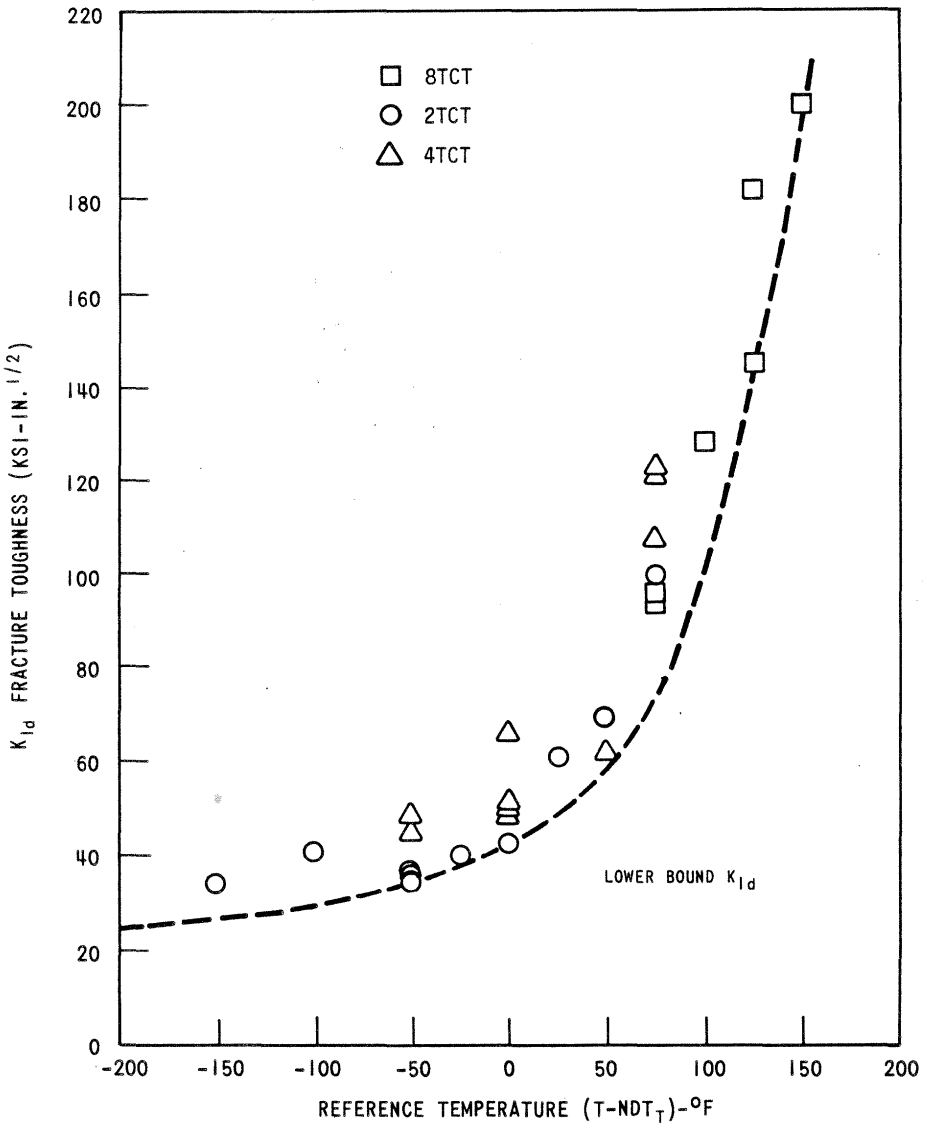


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Through - Wall Thermal Gradients
Figure 5.2-2

Amendment 0
August 1984

Figure 5.2-3

K_{Id} LOWER BOUND FRACTURE TOUGHNESS
A533V (REFERENCE WCAP-7623)
GRADE B CLASS 1



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
K_{Id} Lower Bound Fracture Toughness A533V (Reference WCAP - 7623) Grade B Class 1 Figure 5.2-3

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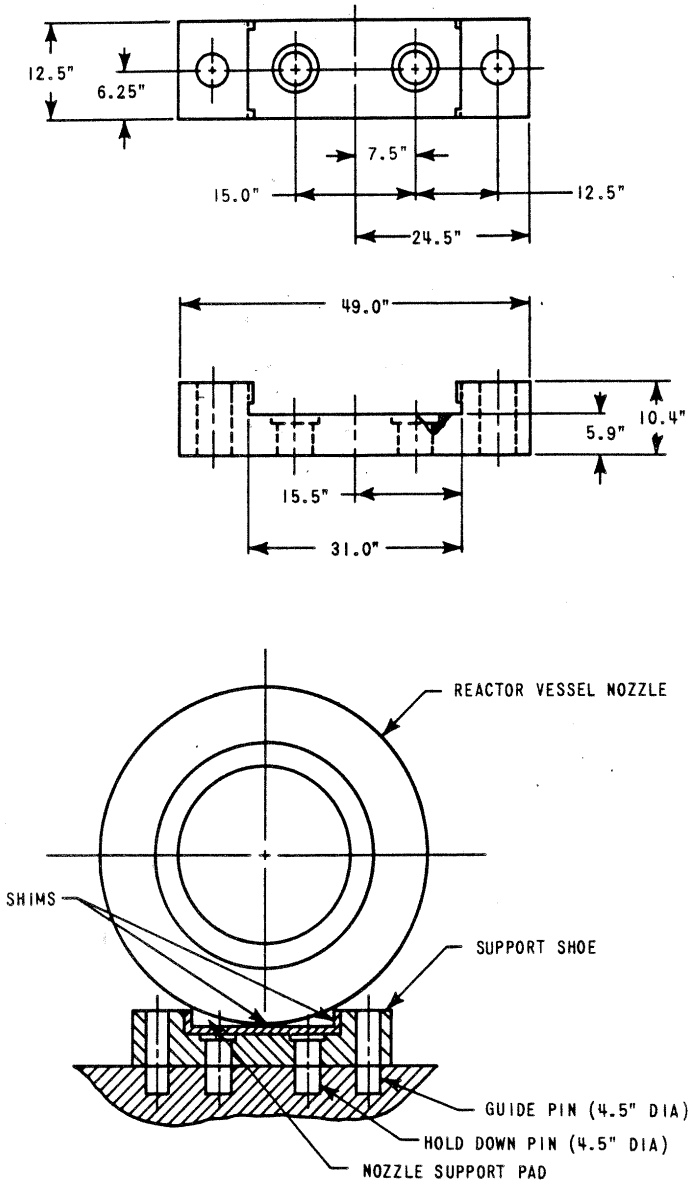
August 1984

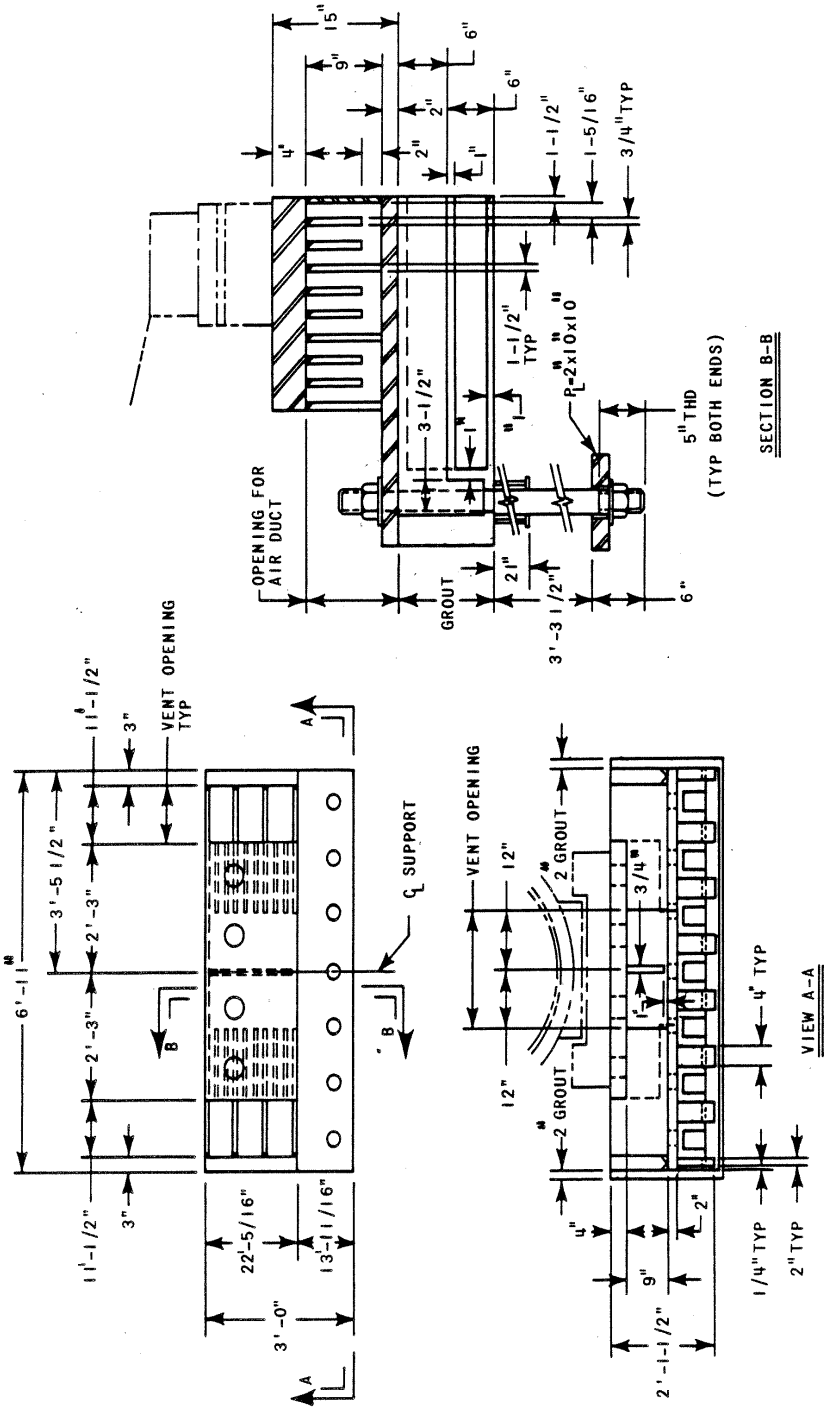
Figure 5.2-4
REACTOR VESSEL SUPPORT SHOE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Vessel Support Shoe
Figure 5.2-4

Amendment 0
August 1984

Figure 5.2-5
REACTOR VESSEL SUPPORT BOX



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Vessel Support Box
Figure 5.2-5

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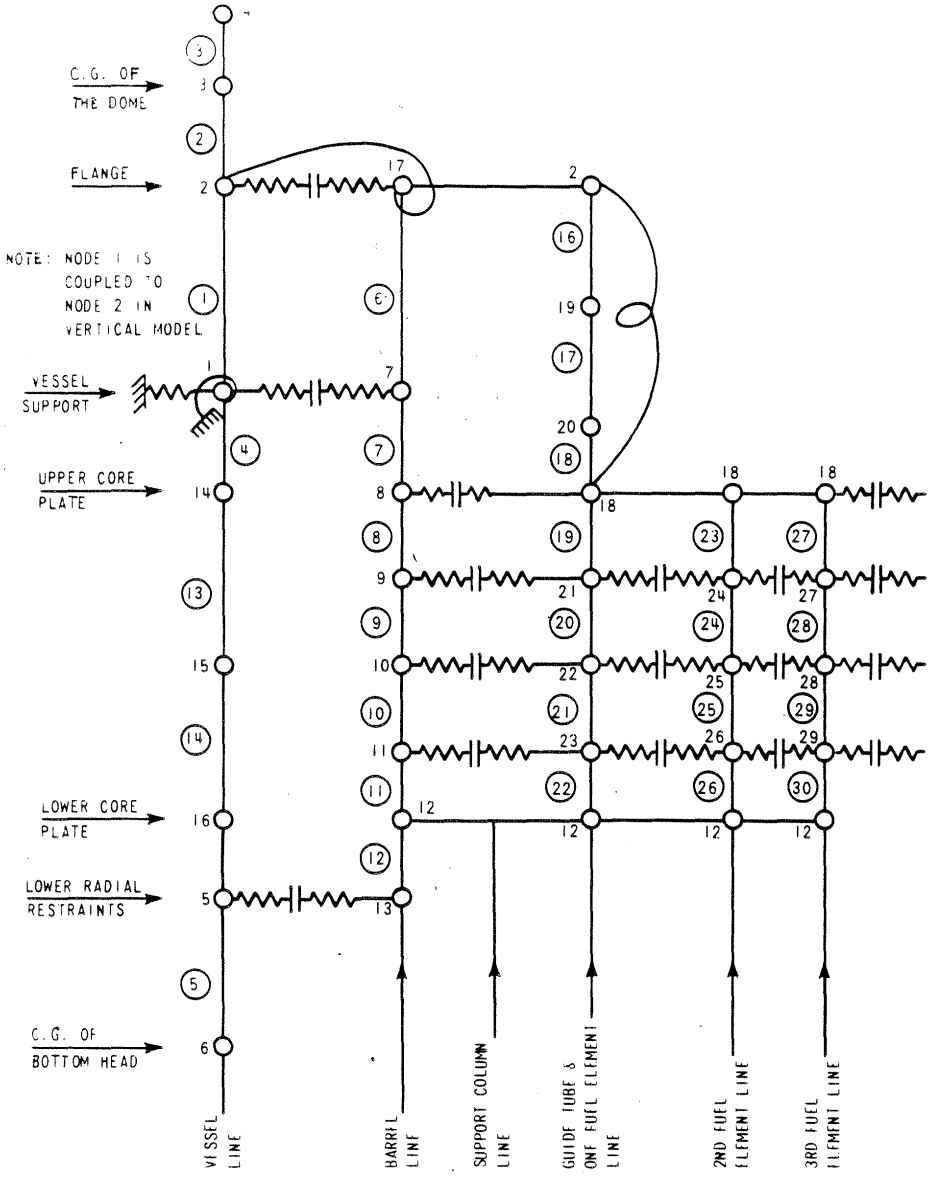
August 1984

Figure 5.2-6

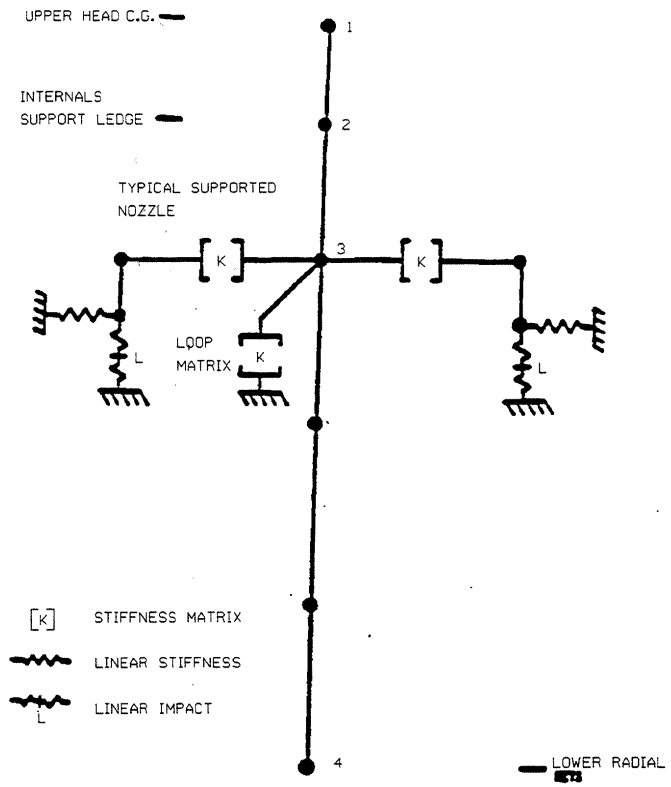
MATHEMATICAL MODEL FOR HORIZONTAL RESPONSE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Mathematical Model for Horizontal Response
Figure 5.2-6

Amendment 0
August 1984

Figure 5.2-6a
REACTOR VESSEL SHELL
FINITE ELEMENT 1ST SUBMODEL



Reactor Vessel and Typical Supported Nozzle

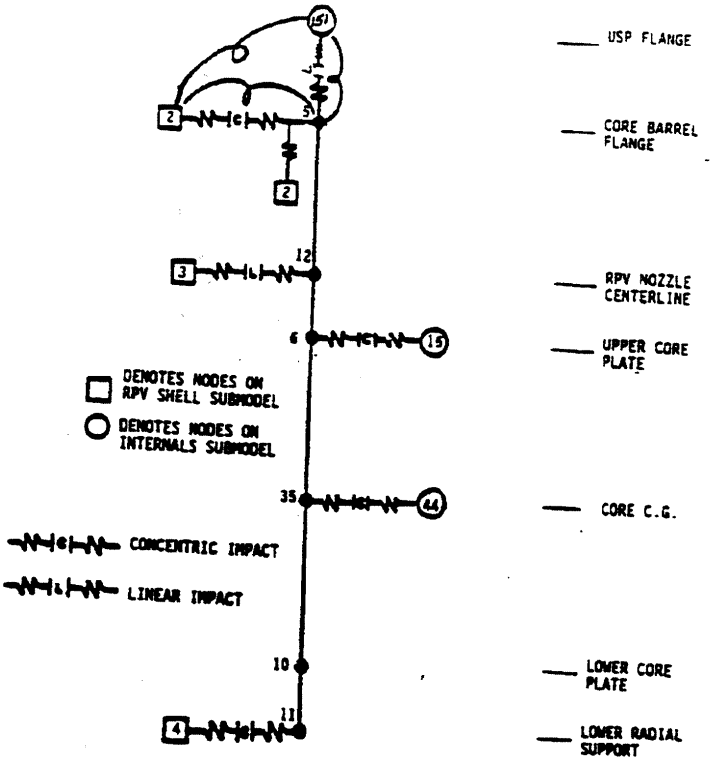
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Vessel Shell Finite Element 1st Submodel Figure 5.2-6 (a)

AMENDMENT 96-02
JULY 1996

isar526a.m(366,jr14325) JR14325@jr14325. Mon Jul 8 11:16:24 EDT 1996

Figure 5.2-6b

REACTOR CORE BARREL
FINITE ELEMENT 2ND SUBMODEL



Core Barrel Submodel

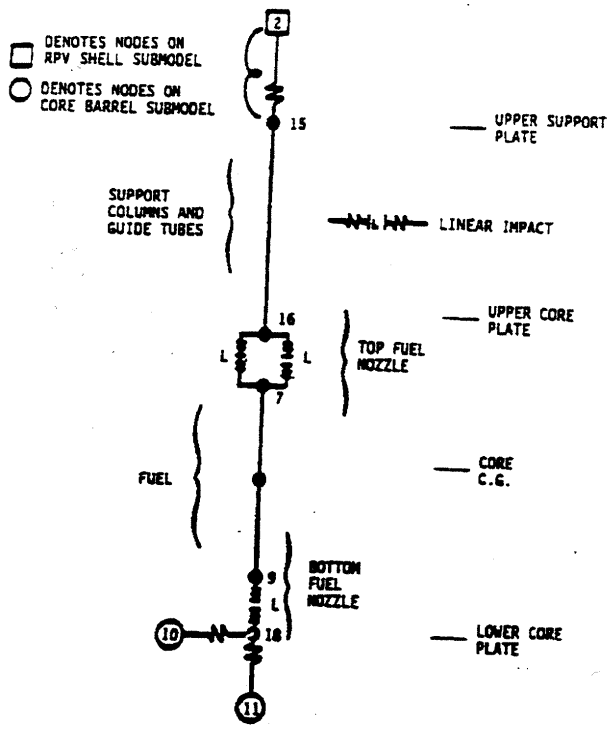
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Core Barrel Finite Element 2nd Submodel Figure 5.2-6 (b)

AMENDMENT 96-02
JULY 1996

isar526b.m(352,jr14325) JR14325@jr14325. Mon Jul 1 12:07:29 EDT 1996

Figure 5.2-6c

CORE SUPPORT AND FUEL
FINITE ELEMENT 3RD SUBMODEL



Internals Submodel

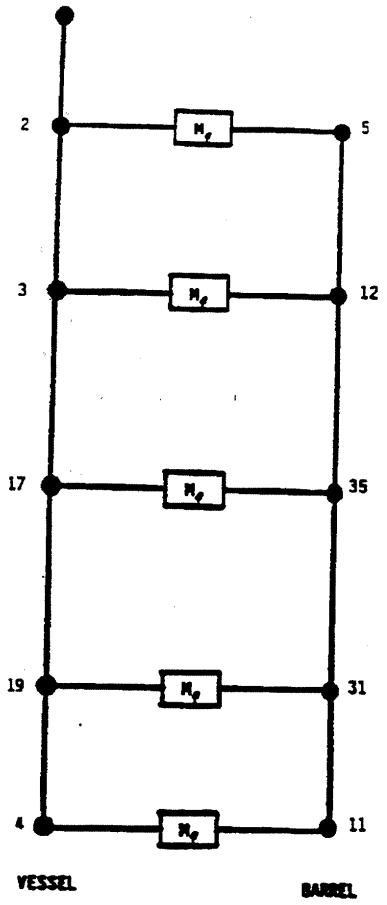
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Core Support and Fuel Finite Element 3rd Submodel Figure 5.2-6 (c)

AMENDMENT 96-02
JULY 1996

fsar526c.m(353,jr14325) JR14325@jr14325. Mon Jul 1 12:14:03 EDT 1996

Figure 5.2-7

VESSEL - CORE BARREL
FINITE ELEMENT INTERFACE MODEL



Hydrodynamic Masses in Vessel/Barrel Downcomer Annulus

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Vessel - Core Barrel Finite Element Interface Model Figure 5.2-7

AMENDMENT 96-02
JULY 1996

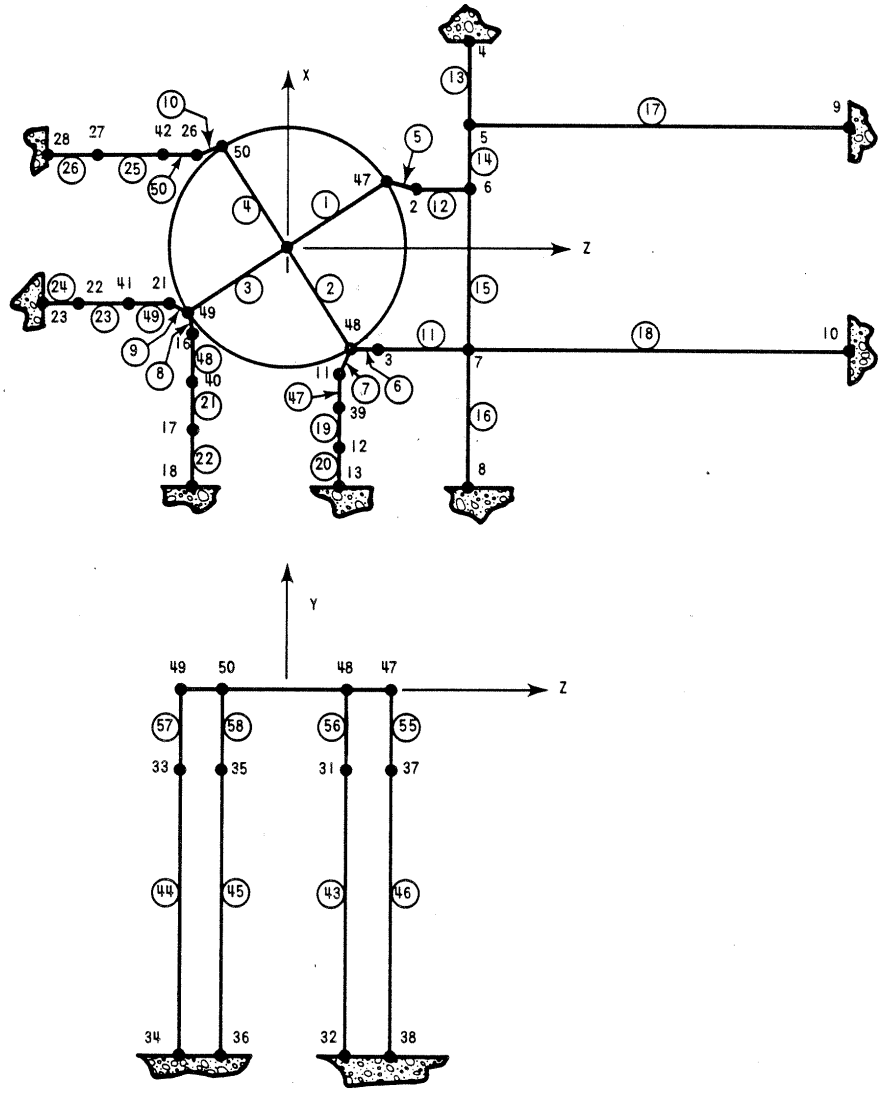
Figure 5.2-8
FSAR FIGURE REFERENCE
DRAWING D-302-812

Figure 5.2-8A
FSAR FIGURE REFERENCE
DRAWING D-302-717

Figure 5.2-9
FSAR FIGURE REFERENCE
DRAWING C-317-824 SHEET 3

Figure 5.2-10

STEAM GENERATOR LOWER SUPPORT MODEL

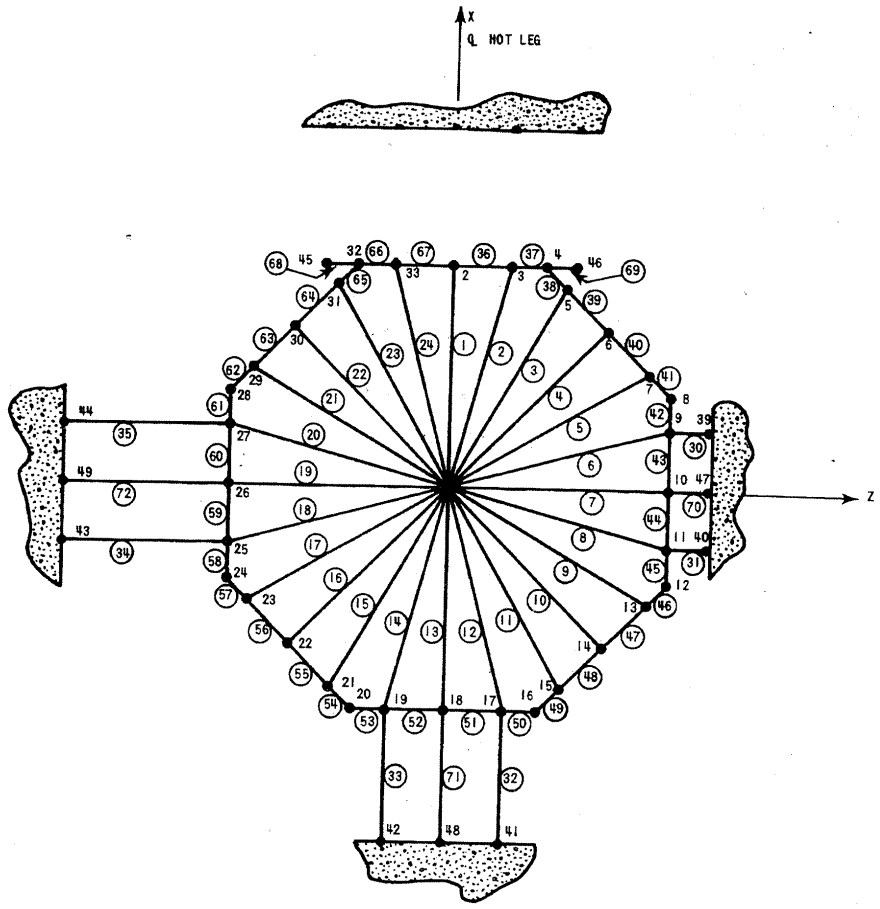


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Steam Generator Lower Support Model Figure 5.2-10

Amendment 0
August 1984

Figure 5.2-11

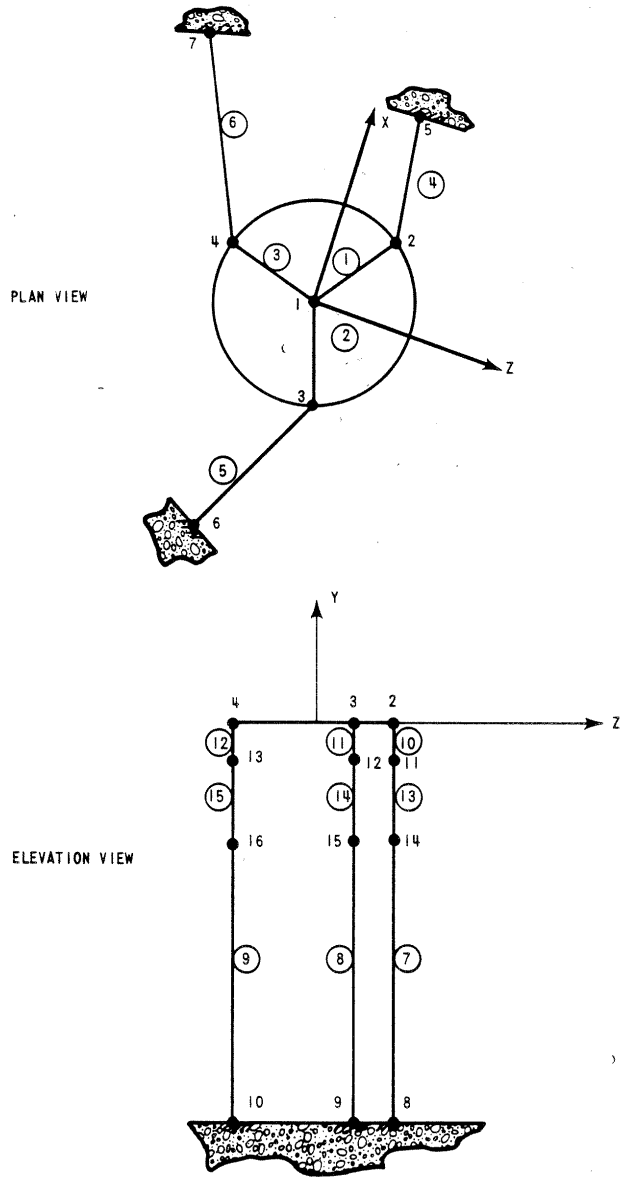
STEAM GENERATOR UPPER SUPPORT MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Steam Generator Upper Support Model Figure 5.2-11

Amendment 02-01
May 2002

Figure 5.2-12
REACTOR COOLANT PUMP SUPPORT MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Coolant Pump Support Model
Figure 5.2-12

Amendment 0
August 1984

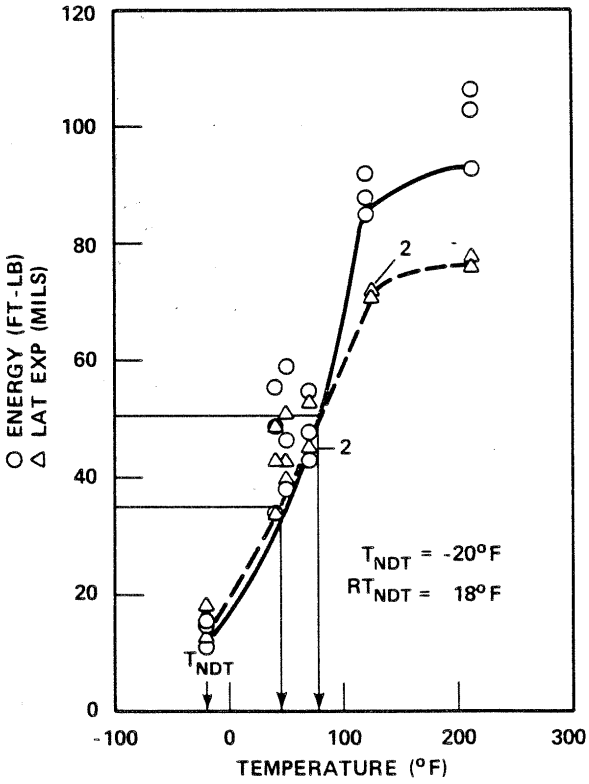
Figure 5.2-13
DELETED PER RN 00-001

Figure 5.2-14
DELETED PER RN 00-001

Figure 5.2-15
DELETED BY AMENDMENT 1, AUGUST 1985

Figure 5.2-16

CHARPY V - NOTCH CURVE FOR NOZZLE SHELL PLATE C9955 - 2

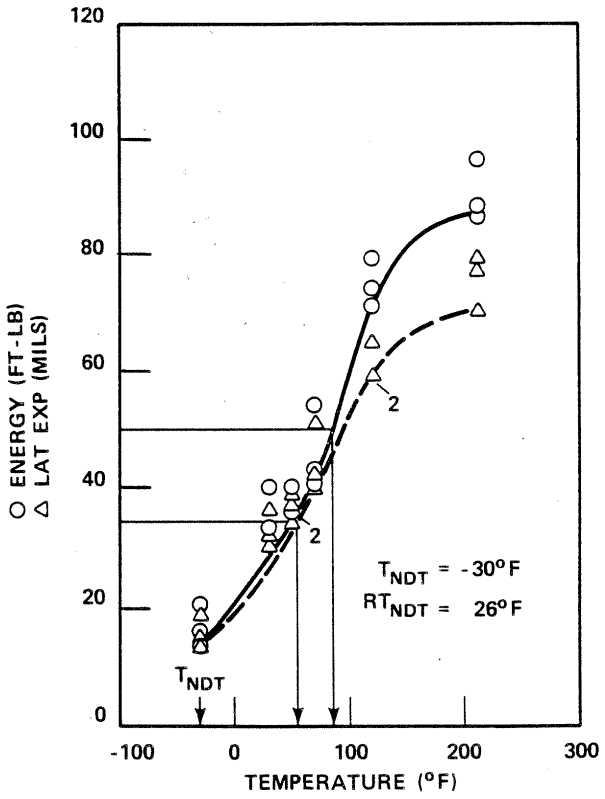


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Charpy V - Notch Curve for Nozzle Shell Plate C9955 - 2 Figure 5.2-16

Amendment 0
August 1984

Figure 5.2-17

CHARPY V - NOTCH CURVE FOR NOZZLE SHELL PLATE C0123 - 2

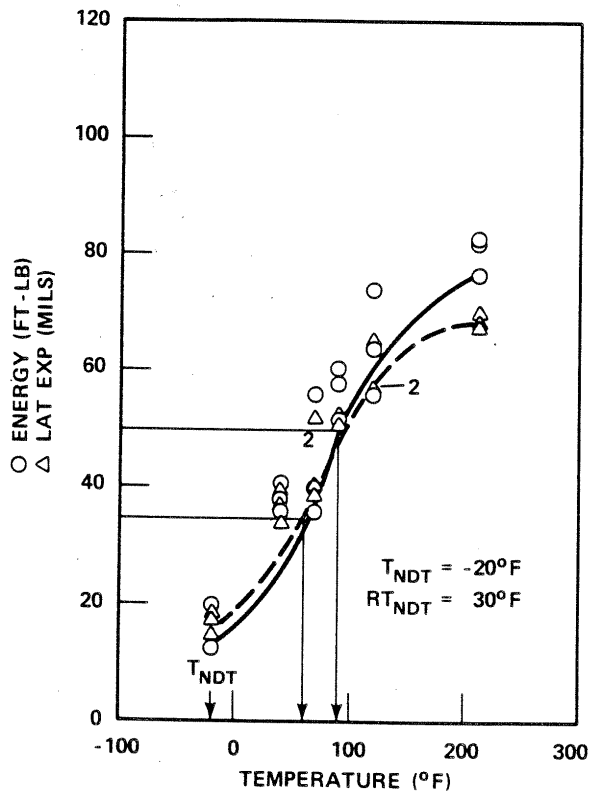


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Charpy V - Notch Curve for Nozzle Shell Plate C0123 - 2
Figure 5.2-17

Amendment 0
August 1984

Figure 5.2-18

CHARPY V - NOTCH CURVE FOR INTERMEDIATE SHELL PLATE A9154 - 1

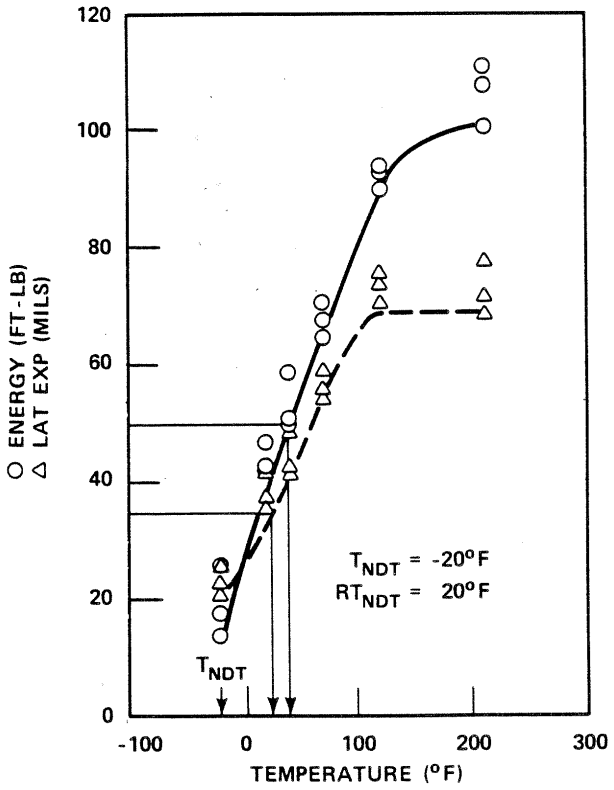


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Charpy V - Notch Curve for Intermediate Shell Plate A9154 - 1 Figure 5.2-18

Amendment 0
August 1984

Figure 5.2-19

CHARPY V - NOTCH CURVE FOR INTERMEDIATE SHELL PLATE A9153 - 2

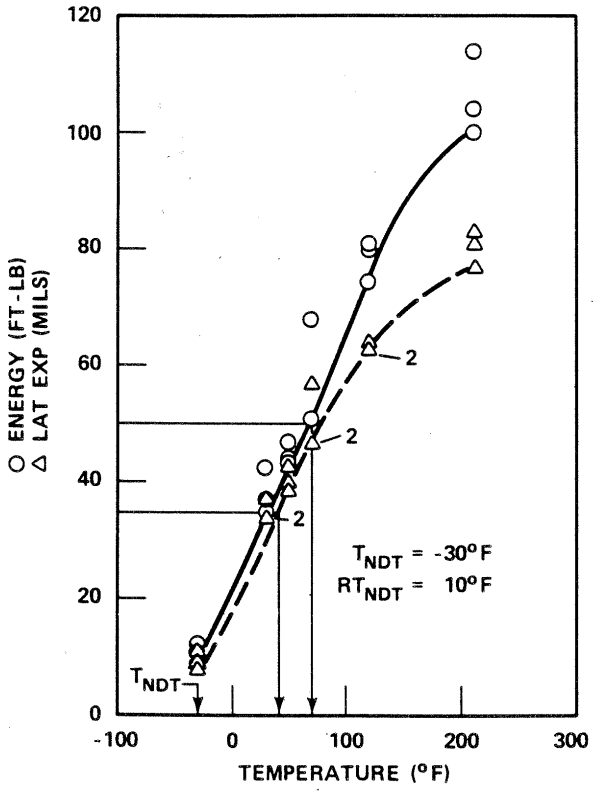


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Charpy V - Notch Curve for Intermediate Shell Plate A9153 - 2 Figure 5.2-19

Amendment 0
August 1984

Figure 5.2-20

CHARPY V - NOTCH CURVE FOR LOWER SHELL PLATE C9923 - 1

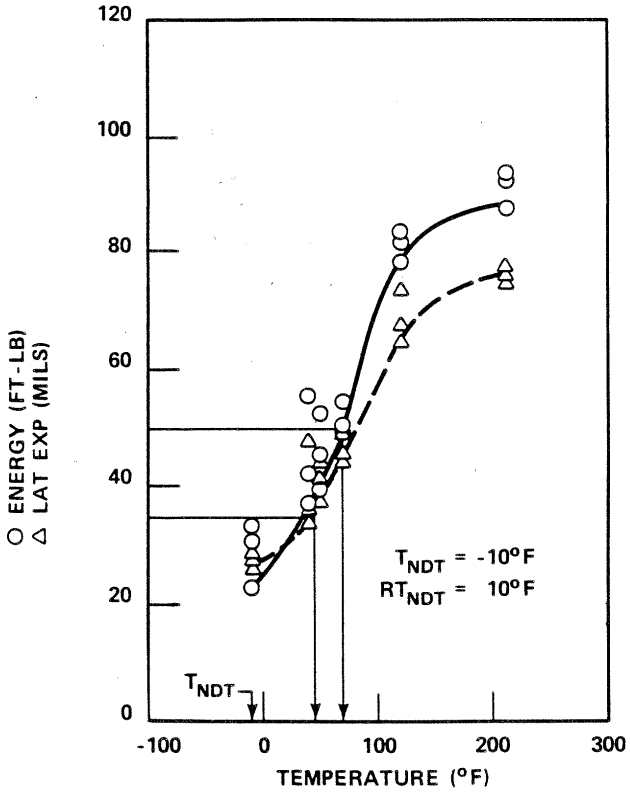


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Charpy V - Notch Curve for Lower Shell Plate C9923 - 1 Figure 5.2-20

Amendment 0
August 1984

Figure 5.2-21

CHARPY V - NOTCH CURVE FOR LOWER SHELL PLATE C9923 - 2

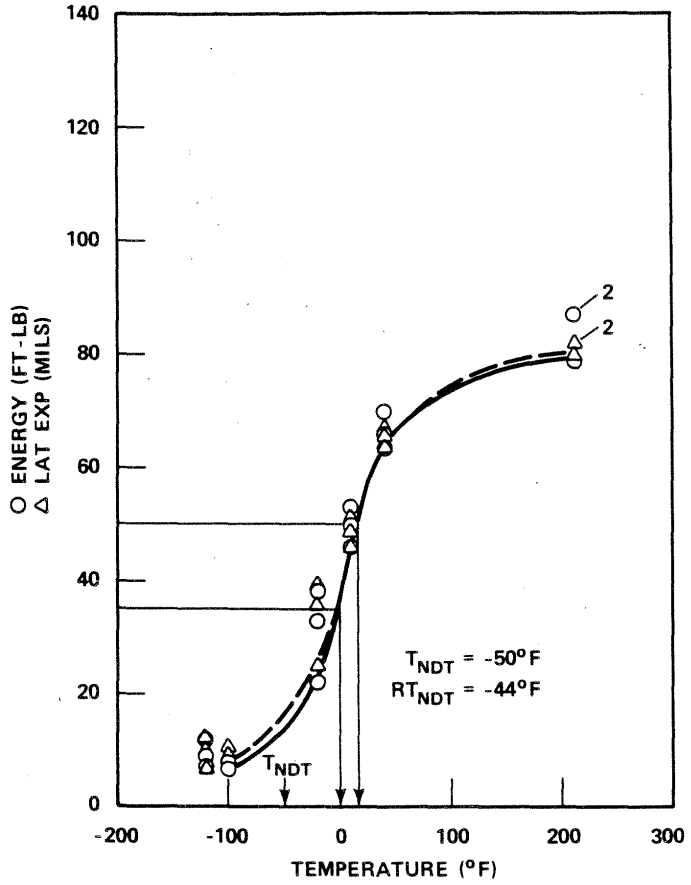


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Charpy V - Notch Curve for Lower Shell Plate C9923-2 Figure 5.2-21

Amendment 0
August 1984

Figure 5.2-22

CHARPY V - NOTCH CURVE FOR CORE BELTLINE REGION WELD

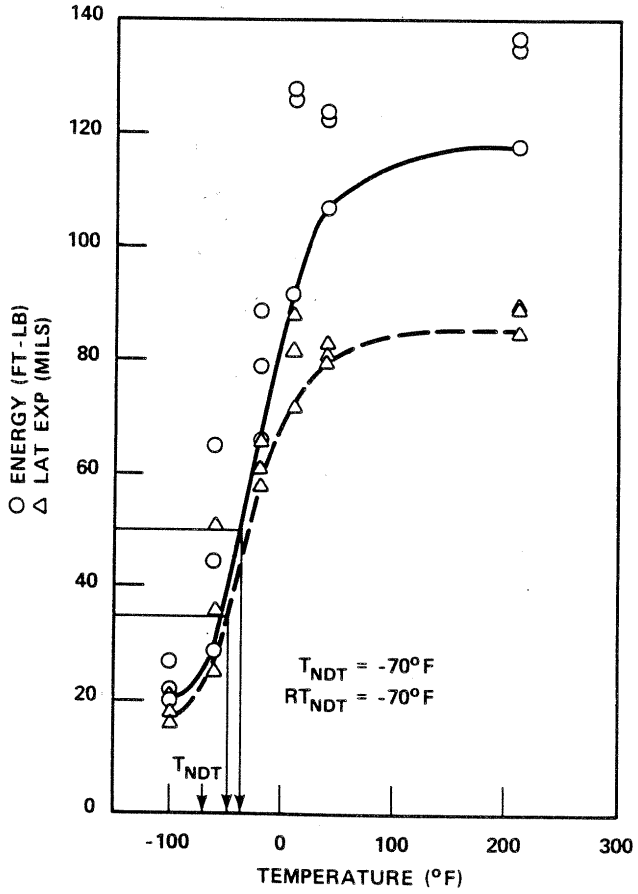


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Charpy V - Notch Curve for Core Beltline Region Weld
Figure 5.2-22

Amendment 0
August 1984

Figure 5.2-23

CHARPY V - NOTCH CURVE FOR CORE BELTLINE REGION HAZ METAL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Charpy V - Notch Curve for Core Beltline Region Haz Metal Figure 5.2-23

Amendment 0
August 1984

5.3 Thermal Hydraulic System Design

5.3.1 Analytical Methods and Data

The thermal and hydraulic design bases of the Reactor Coolant System (RCS) are summarized in Table 5.1-1 and described further in Sections 4.3 and 4.4 in terms of core heat generation rates, departure from nucleate boiling ratio (DNBR), analytical models, peaking factors, and other relevant aspects of the reactor.

5.3.2 Operating Restrictions on Pumps

The minimum net positive suction head (NPSH) and minimum seal injection flowrate must be established before operating the reactor coolant pumps. With the minimum 6 gpm seal injection flowrate established, the operator will have to verify that the system pressure satisfies NPSH requirements and that the seal controlled bleed-off flow satisfies seal flow requirements.

5.3.3 Power-Flow Operating Map (BWR)

Not applicable to pressurized water reactors.

5.3.4 Temperature-Power Operating Map

The NSSS is designed to operate with a full power average coolant temperature ranging from 572°F to 587.4°F. The relationship between RCS temperature and power is shown in Figure 5.3-1 for thermal design conditions with a T_{avg} of 587.4°F at a core power of 2900 MWt.

The effects of reduced core flow due to inoperative pumps are discussed in Sections 5.5.1, 15.2.5, and 15.3.4.

5.3.5 Load Following Characteristics

The RCS is designed on the basis of steady-state operation at full power heat load. The reactor coolant pumps utilize single speed motors as described in Section 5.5 and the reactor power is controlled to maintain average coolant temperature at a value which is a linear function of load, as described in Section 7.7. Operation with one pump out of service requires adjustment only in reactor trip system setpoints as discussed in Section 7.2.

5.3.6 Transient Effects

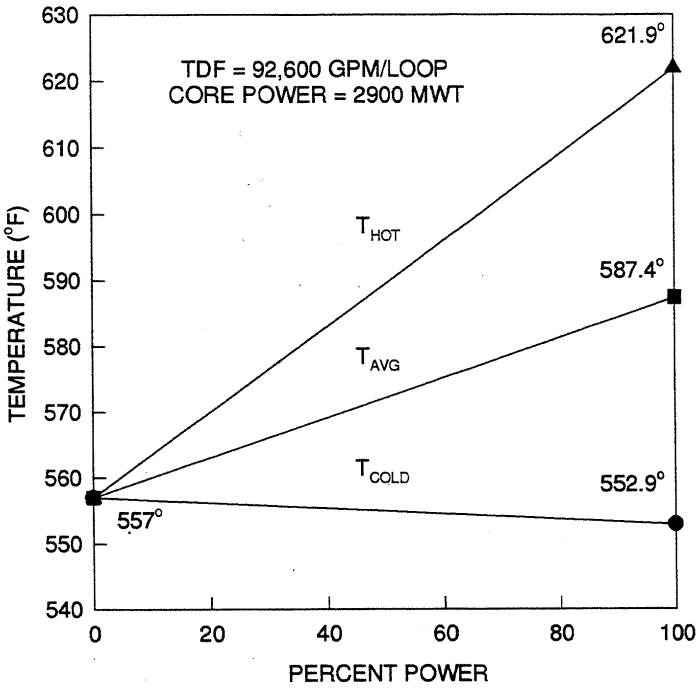
\Transient effects on the RCS are evaluated in Chapter 15.

5.3.7 Thermal and Hydraulic Characteristics Summary Table

The thermal and hydraulic characteristics are given in Tables 4.3-1, 4.4-1, and 5.1-1.

Figure 5.3-1

REACTOR COOLANT SYSTEM TEMPERATURE - PERCENT POWER MAP



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Coolant System Temperature - Percent Power Map Figure 5.3-1

Amendment 96-02
July 1996

5.4 Reactor Vessel and Appurtenances

Section 5.4 has been divided into four principal subsections, viz., design bases, description, evaluation, and tests and inspections for the reactor vessel and its appurtenances consistent with the requirements of the introductory paragraph of Section 5.4 of the "Standard Format and Content of Safety Analyses Reports for Nuclear Power Plants, Revision 1." The following specific information required by the guide is cross referenced below.

	Guide Reference	FSAR Section(s)
5.4.1	Protection of Closure Studs	5.4.2.2
5.4.2	Special Processes for Fabrication and Inspection	5.2.5, 5.4.2.1, 5.4.4
5.4.3	Features for Improved Reliability	5.4.1, 5.4.2.1
5.4.4	Quality Assurance Surveillance	5.4.2, 5.4.4
5.4.5	Materials and Inspections	5.2.3, 5.2.4, 5.4.4
5.4.6	Reactor Vessel Design Data	Table 5.4-1
5.4.7	Reactor Vessel Schematic (BWR)	Not Applicable

5.4.1 Design Bases

5.4.1.1 Codes and Specifications

The vessel is Safety Class 1. Design and fabrication of the reactor vessel is carried out in strict accordance with ASME Section III, Class 1.

Material specifications are in accordance with the ASME Code requirements and are given in Section 5.2.3.

5.4.1.2 Design Transients

Cyclic loads are introduced by normal power changes, reactor trip, startup, and shutdown operations. These design base cycles are selected for fatigue evaluation and constitute a conservative design envelope for the projected plant life. Vessel analysis results in a usage factor that is less than 1.

With regard to the thermal and pressure transients involved in the loss of coolant accident, the reactor vessel is analyzed to confirm that the delivery of cold emergency core cooling water to the vessel following a loss of coolant accident does not cause a loss of integrity of the vessel.

The results of the analysis required by the design specifications prove that the vessel is in compliance with the fatigue and stress limits of Section III of the ASME Boiler and Pressure Vessel Code. The loadings and transients specified for the analysis are based on the most severe conditions expected during service. The heatup and cooldown rates imposed by plant operating

limits are 50°F per hour for normal operations and 100°F per hour under abnormal or emergency conditions. These rates are reflected in the vessel design specifications.

A control rod housing failure does not cause propagation of failure to adjacent housings or to any other part of the Reactor Coolant System (RCS) boundary.

Design transients are discussed in detail in Section 5.2.1.5.

5.4.1.3 Protection Against Non-Ductile Failure

Protection against non-ductile failure is discussed in Section 5.2.4.

5.4.1.4 Inspection

The internal surface of the reactor vessel is capable of inspection periodically using visual and/or nondestructive techniques over the accessible areas. During refueling, the vessel cladding is capable of being inspected in certain small areas between the closure flange and the primary coolant inlet nozzles, and, if deemed necessary, the core barrel is capable of being removed, making the entire inside vessel surface accessible.

The closure head is examined visually during each refueling. Optical devices permit a selective inspection of the cladding, control rod drive mechanism nozzles, and the gasket seating surface. The knuckle transition piece inspection is eliminated with the single piece forged Replacement Reactor Vessel Closure Head. The closure studs can be inspected periodically using visual, magnetic particle and/or ultrasonic techniques.

5.4.2 Description

The reactor vessel fabricated by Chicago Bridge and Iron, Inc., is cylindrical, with a welded hemispherical bottom head and a removable, bolted, flanged, and gasketed, hemispherical upper head. The reactor vessel flange and head are sealed by two hollow metallic O-rings. Seal leakage is detected by means of two leakoff communications: one between the inner and outer ring and one outside the outer O-ring. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core.

A Replacement Reactor Vessel Closure Head was designed by Westinghouse and fabricated by Doosan Heavy Industrial for installation in RF-23 in the spring of 2017. The replacement is a single piece forging eliminating the dome to flange weld. Head adapters are installed for CRDMs and are of an alloy 690 material and weld, which is much less susceptible to cracking then the original alloy 600 components. The head adapters are a tubular member welded to the head assembly. The assembly eliminates a lower canopy seal weld with a full penetration bimetal weld to the latch housing.

Part length and spare rod locations have been eliminated in the new design with dedicated core exit thermocouple nozzles with custom nozzle assemblies, which eliminated the canopy seals. Dedicated alloy 690 one inch pipe connections are also installed for head vent and reactor vessel

level indicator function. Inlet and outlet nozzles are located symmetrically around the vessel. Outlet nozzles are arranged on the vessel to facilitate optimum layout of the RCS equipment. The inlet nozzles are tapered from the coolant loop vessel interfaces to the vessel inside wall to reduce loop pressure drop.

The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear incore instrumentation. Each nozzle consists of a tubular member made of Inconel. Each tube is attached to the inside of the bottom head by a partial penetration weld.

Internal surfaces of the vessel which are in contact with primary coolant are weld overlay with 0.125 inch minimum of stainless steel. The exterior of the reactor vessel is insulated with canned stainless steel reflective sheets. The insulation is a minimum of three inches thick and contoured to enclose the top, sides, and bottom of the vessel. All the insulation modules are removable but the access to vessel side insulation is limited by the surrounding concrete.

The reactor vessel nozzle insulation consists of a noncrushable nonmetalic material clad with stainless steel.

5.4.2.1 Fabrication Processes

1. The use of severely sensitized stainless steel as a pressure boundary material has been prohibited and has been eliminated by both a select choice of material and by programming the method of assembly.

   Refer to Appendix 3A for a discussion of Regulatory Guide 1.44.

2. Minimum preheat requirements have been established for pressure boundary welds using low alloy weld material. Special preheat requirements have been added for stainless steel cladding of low stressed areas. Controlled limitations are placed on preheat requirements by Westinghouse. The purpose of placing limitations on preheat requirements is the addition of precautionary measures to decrease the probabilities of weld cracking by decreasing temperature gradients, lower susceptibility to brittle transformation, prevention of hydrogen embrittlement, and reduction in peak hardness.

   Refer to Appendix 3A for a discussion of Regulatory Guide 1.50.

3. The rod Travel Housing threads are chrome plated to prevent possible galling of the mated parts. Guide studs employed are materially qualified to prevent possible galling of their installation interfaces/threads.
4. At all locations in the reactor vessel where stainless steel and Inconel are joined, the final joining beads are Inconel weld metal in order to prevent cracking.
5. Core region shells fabricated of plate material have longitudinal welds which are angularly located away from the peak neutron exposure experienced in the vessel, where possible.

6. The location of full penetration weld seams in the upper closure head and vessel bottom head is restricted to areas that permit accessibility during inservice inspection.
7. The stainless steel clad surfaces are sampled to assure that composition and delta ferrite requirements are met.
8. The procedure qualification for cladding low alloy steel (SA508, GR 3, Class 1) requires a special evaluation to assure freedom from underclad cracking.

Refer to Appendix 3A for a discussion of Regulatory Guide 1.43.

Principal design parameters of the reactor vessel are given in Table 5.4-1.

5.4.2.2 Protection of Closure Studs

Procedures require the closure studs, nuts, and washers to be removed from the reactor cavity in preparation for refueling. These items may be placed in storage racks and stored at convenient locations on the reactor building operating deck prior to removal of the reactor closure head.

The reactor closure studs are removed from the refueling cavity prior to flooding and are never exposed to the borated refueling cavity water. The stud holes in the reactor vessel flange are sealed with special plugs before removing the reactor closure, thus preventing leakage of the borated refueling water into the stud holes.

5.4.3 Evaluation

5.4.3.1 Steady-State Stresses

Evaluation of steady-state stresses is discussed in Section 5.2.1.10.

5.4.3.2 Fatigue Analysis Based on Transient Stresses

Fatigue analysis of transient stresses is discussed in Sections 5.2.1.5 and 5.2.1.10.

5.4.3.3 Thermal Stresses Due to Gamma Heating

The stresses due to gamma heating in the vessel wall are also calculated by the vessel vendor and combined with the other design stresses.

They are compared with the code allowable limit for mechanical plus thermal stress intensities to verify that they are acceptable. The gamma stresses are low and thus have a negligible effect on the stress intensity in the vessel.

5.4.3.4 Thermal Stresses Due to Loss of Coolant Accident

Fracture mechanics evaluation of the reactor vessel due to thermal stresses following a loss of coolant accident is discussed in Section 5.2.1.10.

5.4.3.5 Heatup and Cooldown

Heatup and cooldown requirements for the reactor vessel material are discussed in Section 5.2.4 and the Technical Specifications.

5.4.3.6 Irradiation Surveillance Programs

10 CFR 50, Appendix H, requires that neutron dosimetry be present to monitor the reactor vessel and measure damage associated with fast neutron exposure (neutron fluence). The originally installed internal surveillance capsules are not sufficient to provide this monitoring capability throughout the Virgil C. Summer Nuclear Station extended license period.

ECR 50571 changed the methodology of the Irradiation Surveillance Program at the Virgil C. Summer Nuclear Station. During Refueling Outage 15, the last in-vessel surveillance specimen was removed from its in-vessel location and new dosimetry capsules were installed exterior to the reactor vessel (ex-vessel) for the measurement of neutron exposure.

Presented below are both a description of the new ex-vessel dosimetry program as well as a description of the former in-vessel program, used for the plant's first 14 operating cycles.

5.4.3.6.1 Ex-Vessel Irradiation Surveillance Program

5.4.3.6.1.1 Summary

An Ex-Vessel Neutron Dosimetry system is installed to monitor neutron fluence in the reactor vessel and vessel support structure. Passive neutron sensors are positioned in the reactor cavity annulus, between the reactor vessel and the biological shield wall. These sensor capsules are connected to, and supported by, stainless steel bead chains, which are suspended from a support bar installed just below the reactor vessel inlet and outlet nozzles. Capsules are then raised and lowered into position (from beneath the Reactor Vessel) to periodically remove the sensors for evaluation. This design ensures a correct and repeatable axial and azimuthal placement of the dosimetry relative to well-known reactor features, which is essential for a long-term monitoring program.

5.4.3.6.1.2 Background

The Code of Federal Regulations, Title 10, Part 50, Appendix H, requires that neutron dosimetry be present to monitor the reactor vessel throughout plant life and that material specimens be used to measure damage associated with the end-of-life fast neutron exposure of the reactor vessel. The Ex-Vessel Neutron Dosimetry Program is designed to provide a verification of fast neutron exposure distributions within the reactor vessel wall and to establish a mechanism to enable long term monitoring of those portions of the reactor vessel and vessel support structure that could experience significant radiation induced increases in reference nil ductility transition temperature (RT_{NDT}) over the service lifetime of the plant.

When used in conjunction with data from internal surveillance capsules and the results of neutron transport calculations, the reactor cavity neutron measurements allow the projection of embrittlement gradients through the reactor vessel wall with a minimum degree of uncertainty. Minimizing the uncertainty in the neutron exposure projections will help to assure that the reactor can be operated in the least restrictive mode possible with respect to:

- 10 CFR 50 Appendix G pressure/temperature limit curves for normal heatup and cooldown of the RCS,
- Emergency Response Guideline (ERG) pressure/temperature limit curves, and
- Pressurized thermal shock (PTS) RT_{NDT} screening criteria.

The installed ex-vessel surveillance program satisfies the regulatory guidance provided in the Generic Aging Lessons Learned (GALL) Report (NUREG-1801), Section XI.M31 Reactor Vessel Surveillance; which states in part:

> *A plant with a surveillance program containing capsules with projected fast neutron fluence exceeding a 60-year fluence at the end of 40 years, i.e., a lead factor greater than 1.5, should remove the capsules when they reach the 60-year exposure. One of these capsules should be tested to meet the requirements of ASTM E185 and the remaining capsules should be placed in storage without material testing. Subsequently, an alternative dosimetry program will need to be instituted to monitor reactor vessel neutron exposure through the license renewal period.*

5.4.3.6.1.3 Sensor Sets

To achieve its goals, the Ex-Vessel Neutron Dosimetry Program employs advanced sensor sets which consist of both encapsulated dosimeters and gradient chains.

Encapsulated dosimeters include radiometric monitors and are employed at discrete locations within the reactor cavity to measure axial variations in neutron spectrum over the core height, particularly near the top of the fuel where back scattering of neutrons from primary loop nozzles and reactor vessel support structures can produce significant differences.

Radiometric monitors include cadmium-shielded foils of the following metals: copper, titanium, iron, nickel, niobium, and cobalt-aluminum. Cadmium shielded fast fission reactions include U-238 and Np-237 in vanadium encapsulated oxide detectors. Bare iron and cobalt monitors are also included.

Stainless steel gradient chains are used in conjunction with the encapsulated dosimeters to complete the mapping of the neutron environment between the discrete locations chosen for spectrum determinations. At each of the azimuthal locations selected for spectrum measurements, stainless steel gradient chains extend over the full height of the active fuel.

Gradient chains are stainless steel bead chains which connect and support the dosimeter capsules containing the radiometric monitors. These segmented chains provide iron, nickel, and cobalt reactions that are used to complete the determination of the axial and azimuthal gradients. The

high purity iron, nickel, and cobalt-aluminum foils contained in the multiple foil sensor sets provide a direct correlation with the measured reaction rates from these gradient chains. These cross-comparisons permit the use of the gradient measurements to derive neutron flux distributions in the reactor cavity with a high level of confidence.

The design of the dosimetry support system and the gradient chains/chain stops ensures correct and repeatable axial and azimuthal placement of the dosimetry relative to well-known reactor features.

5.4.3.6.1.4 Physical Installation

The Ex-Vessel Neutron Dosimeters are located in the annular space between the reactor vessel reflective insulation and the primary biological shield wall. The dosimetry loops are suspended from a stainless steel support bar that is installed just below the reactor vessel nozzles (approximately eight inches above the top of the active fuel).

Located between the A-Loop inlet and B-Loop outlet nozzles, the gradient chain loops are aligned at 270, 285, 300, and 315 degrees (reactor coordinates). The bar is supported from above by two 1/8-inch stainless steel support chains. The support chains are, in turn, attached to spring hook attachment plates that are field-welded to the carbon steel reactor cavity liner plate.

These sensor sets consist of a small (1.0 x 0.5 x 3.875 inch-long) aluminum dosimeter capsule connected to and supported by a stainless steel bead chain. Clamps are installed at the bottom of each chain loop, which are in turn attached to the grating platform beneath the reactor vessel, to prevent relative movement of the capsule during plant operation.

5.4.3.6.1.5 Supporting Analysis

At the conclusion of the first irradiation cycle, the multiple foil sensor sets will be removed from the reactor cavity for evaluation. At the same time, replacement dosimetry will be installed in the reactor cavity to provide monitoring for subsequent irradiation cycles.

The evaluation of the dosimetry sets includes radiochemical analysis of each RM sensor. All laboratory procedures conform to the latest version of ASTM dosimetry standards and practices established for light-water reactor applications. Equivalent full-power reaction rates will be computed from the measured specific activities based on the irradiation history. The chemical composition of the stainless steel gradient chain is determined by taking the ratio of the Mn-54, Co-58, and Co-60 specific activities as measured in the pure metal foils and as measured in the bead chain segments adjacent to the dosimetry capsules containing the foils.

Plant specific discrete ordinates transport theory calculations will be performed to determine the neutron and gamma ray environment within the reactor geometry. The specific methods applied are consistent with those described in WCAP-15557, "Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology," S. L. Anderson, August 2000, and meet the requirements of Regulatory Guide RG-1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," March 2001.

Analysis from the prior in-vessel surveillance capsules (U withdrawn at End of Cycle (EOC) 1, V withdrawn at EOC 3, X withdrawn at EOC 5, W withdrawn at EOC 10, Z withdrawn at EOC 14, and Y withdrawn at EOC 15) provides a consistent set of calculations and measurements detailing the integrated neutron exposure of the Virgil C. Summer reactor vessel from plant startup. The analysis of the ex-vessel neutron dosimetry removed at EOC 16 will build upon that work. This will provide the greatest accuracy in determining the fast neutron exposure rate distribution incident on and through the reactor vessel wall and will provide a sound basis for planning future evaluations of ex-vessel neutron dosimetry.

5.4.3.6.2 In-Vessel Irradiation Surveillance Program

5.4.3.6.2.1 Summary

In the In-Vessel Irradiation Surveillance Program, the evaluation of the radiation damage was based on pre-irradiation testing of Charpy V-notch and tensile specimens and post-irradiation testing of Charpy V-notch, tensile, and 1/2 T (thickness) compact tension (CT) fracture mechanics test specimens. The program was directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach. The program conformed with ASTM-E-185 "Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels," and 10 CFR 50, Appendix H.

5.4.3.6.2.2 Specimen Capsules

The reactor In-Vessel Surveillance Program used six specimen capsules. The capsules were located in guide baskets welded to the outside of the neutron shield pads and were positioned directly opposite the center portion of the core. The capsules were removed when the vessel head was removed and could be replaced when the internals are removed.

Each surveillance capsule contained the following materials:

a. Transverse orientation specimen from the limiting core region intermediate shell course plate A9154-1.

b. Longitudinal orientation specimen from the limiting core region intermediate shell course plate A9154-1.

c. Specimen of weldment joining sections of materials from intermediate shell plate A9154-1 and adjoining lower shell course plate C9923-2. The weldment is fabricated from the same heat of weld wire (Heat Number 4P4784) and Linde 124 flux (Lot Number 3930) as used to fabricate the core region girth and vertical weld seams.

d. Heat affected zone of plate A9154-1.

Each specimen was composed of the same material as the plate or weldment represented by the specimen. The copper and phosphorous content and fracture toughness data of each beltline plate and the core region weldments are provided in Table 5.2-21. The originally installed location of each capsule in the reactor vessel is shown on Figure 5.4-1.

The six capsules contained 54 tensile specimens, 360 Charpy V-notch specimens (which include weld metal and weld heat affected zone material), and 72 CT specimens. Archive material sufficient for two additional capsules will be retained.

The test specimen types, and their orientation, for each surveillance material were as follows:

	Quantity of Test Specimen Types		
Surveillance Material	Charpy	Tensile	1/2 - CT
Plate A9154-1 (transverse orientation)	15	3	4
Plate A9154-1 (longitudinal orientation)	15	3	4
Weld metal	15	3	4
Heat Affected Zone of Plate A9154-1	15	-	-

Dosimeters, including Ni, Cu, Fe, Co-Al, Cd shielded Co-Al, Cd shielded Np-237, and Cd shielded U-238, were placed in filler blocks drilled to contain them. The dosimeters permit evaluation of the flux seen by the specimens and the vessel wall. In addition, thermal monitors made of low melting point alloys were included to monitor the maximum temperature of the specimens. The specimens were enclosed in a tight fitting stainless steel sheath to prevent corrosion and ensure good thermal conductivity. The complete capsule was helium leak tested. As part of the surveillance program, a report of the residual elements in weight percent to the nearest 0.01 percent was made for surveillance material and as deposited weld metal.

Each of the six capsules contained the following specimens:

Material	Number of Charpys	Number of Tensiles	Number of CTs
Limiting Base Material(1)	15	3	4
Limiting Base Material(2)	15	3	4
Weld Metal(3)	15	3	4
Heat Affected Zone	15	-	-

(1) Specimens oriented in the major rolling or working direction.
(2) Specimens oriented normal to the major rolling or working direction.
(3) Weld metal to be selected per ASTM-E-185.

5.4.3.6.2.3 Removal Schedule

The schedule for removal of specimen capsules from the reactor vessel was as follows:

Capsule	Location (deg)	Capsule Lead Factor	Removal time(1)	Calculated Fluence (n/cm^2) (2)
U	343	3.32	1.12 (EOC 1)	6.542×10^{18}
V	107	3.72	2.93 (EOC 3)	1.538×10^{19}
X	287	3.84	5.03 (EOC 5)	2.543×10^{19}
W	110	3.40	10.78 (EOC 10)	4.664×10^{19}
Z	340	3.40	16.67 (EOC 14)	6.712×10^{19}
Y	290	3.40	17.28 (EOC 15)	(3)

(1) Effective full power years from plant startup. End of Cycle (EOC) value given in parenthesis. Note that core thermal power was uprated from 2775 to 2900 MW_{th} with operating cycle 10.
(2) Plant specific evaluation per WCAP-16298-NP, Revision 0 (Reference 2) using Capsule Z dosimetry data.
(3) Placed in storage for possible future use.

5.4.3.6.3 Measurement of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

Measurement of Integrated Fast Neutron Flux and Fluence at the Irradiation Samples, and a description of how they were derived, are included in WCAP-16298-NP (Reference 2).

5.4.3.6.4 Calculation of Integrated Fast Neutron (E 1.0 MeV) Flux at the Irradiation Samples

Calculations of Integrated Fast Neutron Flux and Fluence at the Irradiation Samples, and a description of the methodology used, are included in WCAP-16298-NP (Reference 2).

5.4.3.7 Capability for Annealing the Reactor Vessel

There are no special design features which would prohibit the insitu annealing of the vessel. In the unlikely case that an annealing operation is required to restore the properties of the vessel material opposite the reactor core because of neutron irradiation damage, a metal temperature greater than 650°F would be applied for a maximum period of 168 hours. Various modes of heating may be used depending on the temperature.

The reactor vessel materials surveillance program is adequate to accommodate the annealing of the reactor vessel. Sufficient specimens are available to evaluate the effects of the annealing treatment.

5.4.4 Tests and Inspections

The reactor vessel quality assurance program is given in Table 5.4-2.

Inservice inspection is in accordance with the ASME Code, Section XI.

5.4.4.1 Ultrasonic Examinations

During fabrication, angle beam inspection of 100 percent of plate material is performed to detect discontinuities that may be undetected by longitudinal wave examination, in addition to the design code straight beam ultrasonic test.

5.4.4.2 Penetrant Examinations

The partial penetration welds for the control rod drive mechanism head adaptors and the bottom instrumentation tubes are inspected by dye penetrant after the root pass in addition to code requirements. Core support block attachment welds are inspected by dye penetrant after the first layer of weld metal and after each 1/2 inch of weld metal.

5.4.4.3 Magnetic Particle Examinations

The magnetic particle examination requirements below are in addition to the magnetic particle examination requirements of Section III of the ASME Code.

All magnetic particle examinations of materials and welds shall be performed in accordance with the following:

1. Prior to the final post weld heat treatment (only by the Prod, Coil or Direct Contact Method).
2. After the final post weld heat treatment (only by the Yoke Method).

The following surfaces and welds shall be examined by magnetic particle methods. The acceptance standards shall be in accordance with Section III of the ASME Code.

5.4.4.3.1 Surface Examinations

1. Magnetic particle examines all exterior vessel and heat surfaces after the hydrostatic test.
2. Magnetic particle examines all inside diameter surfaces of carbon and low alloy steel products that have their properties enhanced by accelerated cooling. This inspection to be performed after forming and machining (if performed) and prior to cladding.

5.4.4.3.2 Weld Examinations

Magnetic particle examines weld metal buildup for vessel supports, closure head lifting lugs, and refueling seal ledge to the reactor vessel after the first layer and each 1/2 inch of weld metal is

deposited. All pressure boundary welds are examined after back chipping or back grinding operations.

5.4.4.4 Inservice Inspection

The full penetration welds in the following areas of the installed irradiated reactor vessel are available for visual and/or nondestructive inspection.

1. Vessel shell (from the inside surface).
2. Primary coolant nozzles (from the inside surface).
3. Closure head (from the inside and outside surfaces). Bottom head (from the outside surface).
4. Closure studs, nuts, and washers.
5. Field welds between the reactor vessel, nozzles, and the main coolant piping.
6. Vessel flange seal surface.

The design considerations which have been incorporated into the system design to permit the above inspections are as follows:

1. All reactor internals are completely removable. The tools and storage space required to permit these inspections are provided.
2. The closure head is stored dry on the reactor operating deck during refueling to facilitate direct visual inspection.
3. All reactor vessel studs, nuts, and washers can be removed to dry storage during refueling.
4. Removable plugs are provided in the primary shield. The insulation covering the nozzle welds may be removed.
5. Access holes are provided in the lower internals barrel flange to allow remote access to the reactor vessel internal surfaces between the flange and the nozzles without removal of the internals.

The reactor vessel presents access problems because of the radiation levels and remote underwater accessibility to this component. Because of these limitations on access to the reactor vessel, several steps have been incorporated into the design and manufacturing procedures in preparation for the periodic nondestructive tests which are required by the ASME inservice inspection code. These are:

1. Shop ultrasonic examinations are performed on all internally clad surfaces to acceptance and repair standards to assure an adequate cladding bond to allow later ultrasonic testing of the base metal from inside surface. The size of cladding bonding defect allowed is 1/4 inch by 3/4 inch, with the greater direction parallel to the weld in the region bounded by 2T (T = wall thickness) on both sides of each full penetration pressure boundary weld. Unbonded areas exceeding 0.442 square inches (3/4 inch diameter) in all other regions are rejected.

2. The design of the reactor vessel shell is a clean, uncluttered cylindrical surface to permit future positioning of the test equipment without obstruction.
3. The weld deposited clad surface on both sides of the welds to be inspected are specifically prepared to assure meaningful ultrasonic examinations.
4. After the shop hydrostatic testing, selected areas of the reactor vessel are ultrasonically tested and mapped to facilitate the inservice inspection program.

The vessel design and construction enables inspection and compliance with the ASME Code, Section XI, 1974 Edition.

5.4.5 References

1. Soltesz, R. G., et al, *Nuclear Rocket Shielding Methods, Modification, Updating, and Input Data Preparation, Volume 5 - Two-Dimensional Discrete Ordinates Technique*, WANL-PR-(LL)-034, August 1970.
2. C. M. Burton, J. Conermann, E. T. Hayes, *Analysis of Capsule Z from The South Carolina Electric & Gas Company V. C. Summer Unit 1 Reactor Vessel Radiation Surveillance Program*, WCAP-16298-NP, Revision 0, August 2004.
3. Bamford, W. H., et al, *Technical Basis for the Embedded Flaw Process for Repair of Reactor Vessel Head Penetrations*, WCAP-15987-P Revision 2-P-A (Proprietary), December 2003.
4. Letter from Chief Robert J. Pascarelli (NRC) to Mr. Thomas D. Gatlin, *Virgil C. Summer Nuclear Station, Unit 1 – Alternative Request Weld Repair for Reactor Vessel Upper Head Penetrations (TAC NO. MF3546)*, April 30, 2014.

Table 5.4-1
Reactor Vessel Design Parameters

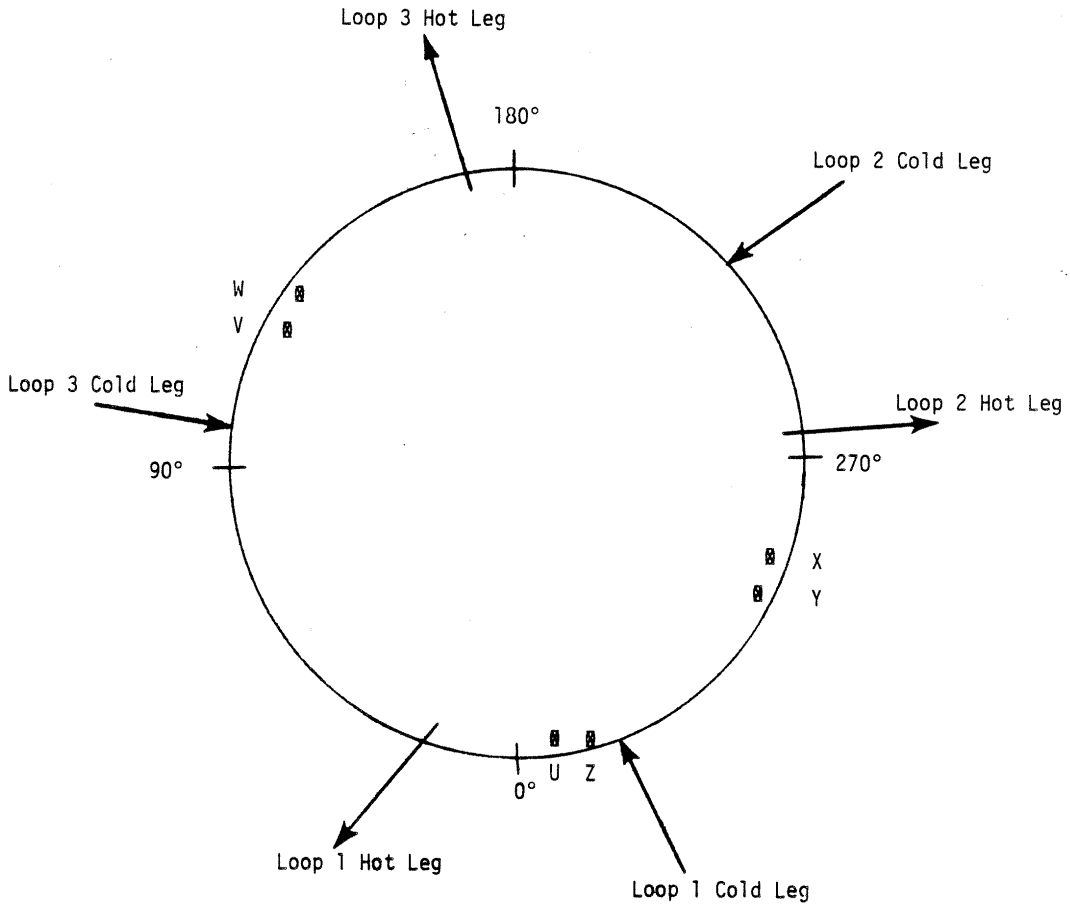
Design/Operating Pressure, psig	2485/2317
Design Temperature, °F	650
Overall Height of Vessel and Closure Head, ft-in (bottom head outside diameter to top of control rod mechanism adapter)	41
Thickness of Insulation, in (minimum)	3
Number of Reactor Closure Head Studs	58
Diameter of Reactor Closure Head/Studs, in (minimum shank)	5-13/16
Inside Diameter of Flange, in	149-15/16
Outside Diameter of Flange, in	184
Inside Diameter at Shell, in	157
Inlet Nozzle Inside Diameter, in	27-1/2
Outlet Nozzle Inside Diameter, in	29
Clad Thickness, in (minimum)	1/8
Lower Head Thickness, in (minimum)	4-7/8
Vessel Belt-Line Thickness, in (minimum)	7-3/4
Closure Head Thickness, in	5-3/4

Table 5.4-2
Reactor Vessel Quality Assurance Program

Forgings	RT[1]	UT[1]	PT[1]	MT[1]
1. Flanges		Yes		Yes
2. Studs, Nuts		Yes		Yes
3. Head Adapters		Yes	Yes	
4. Head Adapter Tube		Yes	Yes	
5. Instrumentation Tube		Yes	Yes	
6. Main Nozzles		Yes		Yes
7. Nozzle Safe Ends (If forging is employed)		Yes	Yes	
Plates		Yes		Yes
Weldments				
1. Main Seam	Yes	Yes		Yes
2. CRD Head Adapter Connection			Yes	
3. Instrumentation Tube Connection			Yes	
4. Main Nozzle	Yes	Yes		Yes
5. Cladding		Yes	Yes	
6. Nozzle Safe Ends (If forging)	Yes	Yes	Yes	
7. Nozzle Safe Ends (If weld deposit)	Yes	Yes	Yes	
8. Head Adapter Forging to Head Adapter Tube	Yes		Yes	
9. All Ferritic Welds Accessible after Hydrotest		Yes		Yes
10. All Non-Ferritic Welds Accessible after Hydrotest		Yes	Yes	
11. Seal Ledge				Yes
12. Head Lift Lug				Yes
13. Core Pad Welds			Yes	

(1) RT - Radiographic, UT - Ultrasonic, PT - Dye Penetrant, MT - Magnetic Particle

Figure 5.4-1
SURVEILLANCE CAPSULE LOCATIONS



Specimen	L
U	343°
V	107°
W	110°
X	287°
Y	290°
Z	340°

Amendment 0
August 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Surveillance Capsule Locations

Figure 5.4-1

5.5 Component and Subsystem Design

5.5.1 Reactor Coolant Pumps

5.5.1.1 Design Bases

The reactor coolant pump ensures an adequate core cooling flowrate, and hence sufficient heat transfer, to maintain a departure from nucleate boiling ratio (DNBR) greater than 1.30 within the parameters of operation. The required net positive suction head is by conservative pump design always less than that available by system design and operation.

Sufficient pump rotation inertia is provided by a flywheel, in conjunction with the impeller and motor assembly, to provide adequate flow during coastdown. This flow, following an assumed loss of pump power, provides the core with adequate cooling.

The reactor coolant pump motor is tested, without mechanical damage, at overspeeds up to and including 125% of normal speed. The integrity of the flywheel during a LOCA is demonstrated in Reference 1. Reference 1 is undergoing generic review by the NRC.

The reactor coolant pump is shown in Figure 5.5-1. The reactor coolant pump design parameters are given in Table 5.5-1.

Code and material requirements are provided in Section 5.2.

5.5.1.2 Design Description

The reactor coolant pump is a vertical, single stage, centrifugal, shaft seal pump designed to pump large volumes of reactor coolant at high temperatures and pressures.

The pump consists of three areas from bottom to top. They are the hydraulics, shaft seals, and the motor.

1. The hydraulic section consists of an impeller, diffuser, casing, thermal barrier heat exchanger, lower radial bearing, bolting ring, motor stand, and pump shaft.
2. The shaft seal section consists of three identical sealing stages. Each stage consists of a hydrodynamic end face mechanical seal. For each stage, there is a separate tubular seal staging flow coil that allows flow around the stage so that the differential pressure across each stage is approximately one-third of reactor coolant system (RCS) pressure during normal operation. An additional sealing mechanism, termed the abeyance seal, is included in the shaft seal section to mitigate the effects caused by failure of all three mechanical seals. The three sealing stages and the abeyance seal are contained within the main flanges and seal housing.
3. The motor section consists of a vertical solid shaft, squirrel cage induction type motor, an oil lubricated double tilting pad Kingsbury type thrust bearing, two oil lubricated radial bearings, and a flywheel.

Attached to the bottom of the pump shaft is the impeller. The reactor coolant is drawn up through the impeller, discharged through passages in the diffuser, and out through the discharge nozzle in the side of the casing. Above the impeller is a thermal barrier heat exchanger which limits heat transfer between hot system water and seal injection water.

High pressure seal injection water is introduced through the thermal barrier wall. A portion of this water flows up around the bearing through the seals; the remainder flows down through the thermal barrier where it acts as a buffer to prevent system water from entering the radial bearing and seal section of the unit. The thermal barrier heat exchanger provides a means of cooling system water to an acceptable level in the event that seal injection flow is lost. The water lubricated journal type pump bearing, mounted above the thermal barrier heat exchanger, has a self-aligning spherical seat.

The reactor coolant pump motor bearings are of conventional design. The radial bearings are the segmented pad type, and the thrust bearings are tilting pad Kingsbury bearings. All are oil lubricated. The lower radial bearing and the thrust bearings are submerged in oil, and the upper radial bearing is oil fed from an impeller integral with the thrust runner.

The motor is an air-cooled, Class F thermalastic epoxy insulated, squirrel cage induction motor. The rotor and stator are of standard construction and are cooled by air. Six resistance temperature detectors are located throughout the stator to sense the winding temperature. The top of the motor consists of a flywheel and an anti-reverse rotation device.

Each of the reactor coolant pumps is equipped for continuous monitoring of reactor coolant pump shaft and frame vibration levels. Shaft vibration is measured by two relative shaft probes mounted on top of the pump seal housing. The probes are mounted in the same horizontal plane near the pump-to-motor coupling. Frame vibration is measured by two velocity velomitors located 90 degrees apart in the same horizontal plane and mounted at the top of the motor support stand. Proximeters and converters convert the probe signals to linear output which is displayed on monitor meters in the control room. The monitor meters automatically indicate the highest output from the relative probes and velomitors; manual selection allows monitoring of individual probes.

Indicator lights display caution and danger limits of vibration, which are adjustable over the full range of the motor scale.

All parts of the pump in contact with the reactor coolant are austenitic stainless steel except for special parts, such as seals and bearings. Component cooling water is supplied to the two oil coolers on the pump motor and to the pump thermal barrier heat exchanger.

In addition, the reactor coolant pumps receive pump shaft seal cooling water from the Chemical and Volume Control System (CVCS). The component cooling water supply to the thermal barrier is provided as a backup heat sink to the CVCS cooling water flow to the reactor coolant pump seals. A failure of the Component Cooling Water System (CCWS) supply to the thermal barrier would not jeopardize operation of the reactor coolant pump or cause loss of reactor coolant. The individual CCWS return lines from the upper and lower bearing oil coolers, as well as the return line from the thermal barrier, are equipped with seismically qualified flow indicators powered

from the vital bus (associated). These flow indicators actuate alarms on the main control board. The temperature indicator and alarms on the CCWS return lines are located on the main control board. The reactor coolant pump motor bearing temperatures are supplied as input to the process computer. A high temperature causes the computer to alarm and identify the out-of-limit temperatures. The CCWS isolation valve monitor lights, which would indicate valve closure, are located on the main control board.

The operator action necessary to trip the reactor and stop the reactor coolant pumps is not complicated and is a direct logical result of the event symptoms alarmed and indicated. An operator response time of 10 minutes is conservative and appropriate for this event during normal operation.

Actual tests performed by Westinghouse Electric Corporation on reactor coolant pumps of the type provided for the Virgil C. Summer Nuclear Station show that interruption of the CCWS flow for 10 minutes or less will not result in damage to the pump.

The pump shaft, seal housing, thermal barrier, main flange, and motor stand can be removed from the casing without disturbing the reactor coolant piping. The flywheel is available for inspection by removing the cover.

The performance characteristic, shown in Figure 5.5-2, is common to all of the fixed speed mixed flow pumps and the "knee" at about 45% design flow introduces no operational restrictions since the pumps operate at full speed.

5.5.1.3 Design Evaluation

5.5.1.3.1 Pump Performance

The reactor coolant pumps are sized to deliver flow at rates which equal or exceed the required flowrates. Initial RCS tests confirm the total delivery capability. Thus, assurance of adequate forced circulation coolant flow is provided prior to initial plant operation.

The Reactor Trip System ensures that pump operation is within the assumptions used for loss of coolant flow analyses, which also assures that adequate core cooling is provided to permit an orderly reduction in power if flow from a reactor coolant pump is lost during operation.

The original shaft seals from the pump manufacturer have been replaced with hydrodynamic shaft seals from another seal manufacturer. An extensive test program has been conducted for several years to develop the controlled leakage shaft seal for pressurized water reactor applications. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The shaft sealing system design consists of three identical seal stages that function based on hydrodynamic operating principles. Each of the three individual sealing stages is designed to withstand full RCS pressure for an extended period of time with the RCP idle and for a limited

period of time with the pump running at nominal speed. This design capability is to allow for a controlled shutdown.

The seal is designed to operate with a thin fluid film gap. The design allows short-term contact of the seal face rings, particularly during low pressure pump starts. The stationary seal face ring material is resin-impregnated carbon graphite. For the rotating face ring material, tungsten carbide is used because of its good fracture resistance, good thermal conductivity, and favorable tribologic properties.

In addition to the flow passes across the seal, there is flow through around each seal stage through a tubular coil. The coil is part of a subassembly designated the pressure breakdown device (PBD). The leakage flow across a given seal stage is in parallel with the coil for that stage so the pressure differential across the PBD and the seal stage must be equal. The design flow rate of each staging coil is 2.5 gpm with a differential pressure across the coil of 750 psid. Each coil acts as an orifice to reduce the pressure available at each seal stage. With three stages in the shaft sealing system, a pressure drop of approximately one-third of RCS pressure occurs across each stage during normal operation. An increase in leakage across one seal will cause the pressure differential across that stage to decrease. Because the total pressure drop across the three stages is constant, the total pressure differential increase across the two non-leaking seals will be equal to the decrease in pressure differential across the leaking seal stage. The RCP seal flow schematic is shown in Figure 5.5-18.

The effect of loss of offsite power on the pump itself is to cause a temporary stoppage in the supply of injection flow to the pump seals and also of the cooling water for seal and bearing cooling. The emergency diesel generators are started automatically due to loss of offsite power so that seal injection flow is automatically restored.

5.5.1.3.2 Coastdown Capability

It is important to reactor operation that the reactor coolant continues to flow for a short time after a reactor trip. In order to provide this flow in a station blackout condition, each reactor coolant pump is provided with a flywheel. Thus, the rotating inertia of the pump, motor, and flywheel is employed during the coastdown period to continue the reactor coolant flow. The coastdown flow transients are provided in the figures in Section 15.3.

The pump/motor system is designed for Seismic Category 1. The integrity of the bearings is described in Section 5.5.1.3.4. Hence, it is concluded that the coastdown capability of the pumps is maintained even under the most adverse case of a loss of offsite power coincident with the safe shutdown earthquake (SSE). Core flow transients and figures are provided in Section 15.2.

5.5.1.3.3 Flywheel Integrity

Demonstration of integrity of the reactor coolant pump flywheel is discussed in Section 5.2. Additional discussion is contained in Reference 1.

5.5.1.3.4 Bearing Integrity

The design requirements for the reactor coolant pump bearings are primarily aimed at ensuring a long life with negligible wear, so as to give accurate alignment and smooth operation over long periods of time. The surface bearing stresses are held at a very low value and even under the most severe seismic transients do not begin to approach loads which cannot be adequately carried for short periods of time.

Because there are no established criteria for short time stress-related failures in such bearings, it is not possible to make a meaningful quantification of such parameters as margins to failure, safety factors, etc. A qualitative analysis of the bearing design, embodying such considerations, gives assurance of the adequacy of the bearing to operate without failure.

Low oil levels in the lube oil sumps signal an alarm in the control room and require shutting down of the pump. Each motor bearing contains embedded temperature detectors, and so initiation of failure, separate from loss of oil, is indicated and alarmed in the control room as a high bearing temperature. This, again, requires pump shutdown. If these indications are ignored and the bearing proceeded to failure, the low melting point of Babbitt metal on the pad surfaces ensures that sudden seizure of the shaft will not occur. In this event the motor continues to operate, as it has sufficient reserve capacity to drive the pump under such conditions. However, the high torque required to drive the pump will require high current which will lead to the motor being shutdown by the electrical protection systems.

5.5.1.3.5 Locked Rotor

It may be hypothesized that the pump impeller might severely rub on a stationary member and then seize. Analysis has shown that under such conditions, assuming instantaneous seizure of the impeller, the pump shaft fails in torsion just below the coupling to the motor, disengaging the flywheel and motor from the shaft. This constitutes a loss of coolant flow in the loop. Following such a postulated seizure, the motor continues to run without any overspeed, and the flywheel maintains its integrity, as it is still supported on a shaft with two bearings. Flow transients are provided in the figures in Section 15.4 for the assumed locked rotor.

There are no other credible sources of shaft seizure other than impeller rubs. Any seizure of the pump bearing is precluded by graphite in the bearing. Any seizure in the seals results in a shearing of the elastomer drive key of the rotating face ring. The motor has adequate power to continue pump operation even after the above occurrences. Indications of pump malfunction in these conditions are initially by high temperature signals from the bearing water temperature detector. Following these signals, pump vibration levels are checked. Excessive vibration indicates mechanical trouble and the pump is shutdown for investigation.

5.5.1.3.6 Critical Speed

The reactor coolant pump shaft is designed so that its operating speed is below its first critical speed. This shaft design, even under the most severe postulated transient, gives low values of actual stress.

5.5.1.3.7 Missile Generation

Each component of the pump is analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing. Further discussion and analysis of missile generation are contained in Reference 1.

5.5.1.3.8 Pump Cavitation

The minimum net positive suction head required by the reactor coolant pump at running speed is approximately a 192 foot head (approximately 85 psi). In order for the controlled leakage seal to operate correctly, it is necessary to have a minimum differential pressure of 75 psi across the seal assembly. When the net positive suction head requirement is met, the minimum differential pressure requirement for the seal is exceeded. The primary loop pressure is established to ensure sufficient net positive suction head is available to avoid pump cavitation.

5.5.1.3.9 Pump Overspeed Considerations

For turbine trips actuated by either the Reactor Trip System or the Turbine Protection System, the generator and reactor coolant pumps are maintained connected to the external network for at least 30 seconds to prevent any pump overspeed condition (see Section 8.2).

An electrical fault requiring immediate trip of the generator (with resulting turbine trip) could result in an overspeed condition. However, the turbine control system and the turbine intercept valves limit the overspeed to less than 120%. In case a generator trip de-energizes the pump buses, the reactor coolant pump motors will be transferred to offsite power within 6 to 10 cycles. Further discussion of pump overspeed considerations is contained in Reference 1.

5.5.1.3.10 Anti-Reverse Rotation Device

Each of the reactor coolant pumps is provided with an anti-reverse rotation device in the motor. This anti-reverse mechanism consists of five pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate, and two shock absorbers.

After the motor has slowed and come to a stop, the dropped pawls engage the ratchet plate and, as the motor tends to rotate in the opposite direction, the ratchet plate also rotates until it is stopped by the shock absorbers. The rotor remains in this position until the motor is energized again. When the motor is started, the ratchet plate is returned to its original position by the spring return.

As the motor begins to rotate, the pawls drag over the ratchet plate. When the motor reaches sufficient speed, the pawls are bounded into an elevated position and are held in that position by friction resulting from centrifugal forces acting upon the pawls. Considerable shop testing and plant experience with the design of these pawls have shown high reliability of operation.

5.5.1.3.11 Shaft Seal Leakage

Leakage along the reactor coolant pump shaft is controlled by three shaft seals arranged in series such that reactor coolant leakage to the containment is essentially zero. Charging flow is directed to each reactor coolant pump via a ≤ 5 micron seal water injection filter. The flow is injected into the reactor coolant pump through a pipe in the thermal barrier flange and is directed down to a point between the pump shaft bearing and the thermal barrier cooling coils. Here the flow enters the shaft annulus; a portion flows down past the thermal barrier cooling cavity, labyrinth seals, and into the RCS; the remainder flows up the pump shaft annulus cooling the lower shaft bearing. This flow provides a controlled flow through the seal. Above the seal, most of the flow leaves the pump via the controlled bleed-off line and routed back to volume control tank. Minor flow passes through the seal face of the three stages and eventually diverted to reactor coolant drain tank via number 3 seal leakoff line. This arrangement assures essentially zero leakage of reactor coolant or trapped gases from the pump.

5.5.1.3.12 Seal Discharge Piping

Discharge pressure of the controlled bleed-off flow is reduced to that of the volume control tank. The controlled bleed-off flow is piped to a common manifold, through the seal water return filter, and through the seal water heat exchanger where the temperature is reduced to that of the volume control tank. There is no number 1 or number 2 seal leakoff piping. The number 3 leakoff line dumps number 3 seal leakage to the reactor coolant drain tank. An alternate overflow path with a vent line is provided to divert the number 3 seal leakage to the reactor building floor drain, in case there is a blockage in the number 3 leakoff line.

5.5.1.3.13 Loss of Component Cooling Water or Seal Injection

Component cooling water is provided to the reactor coolant pump thermal barrier heat exchanger, as well as to the upper and lower motor bearing oil coolers. In addition, seal injection flow is supplied to the pumps from the CVCS. These cooling supplies are discussed in the following paragraph and are shown schematically in Figure 5.5-16. Detailed flow diagrams of the CVCS and the CCWS are shown in FSAR Figures 9.3-16 and 9.2-5, respectively.

Consequences of the loss of either of these supplies are also discussed in the following paragraphs.

Seal injection flow, at a slightly higher pressure and at a lower temperature than the RCS, enters the pump through a pipe connection on the thermal barrier flange (see Figure 5.5-17) and is directed to a point between the pump radial bearing and the thermal barrier heat exchanger. Here the flow splits with a portion flowing down through the thermal barrier labyrinth (where it acts as a buffer to prevent reactor coolant from entering the radial bearing and seal section of the pump) and into the RCS. The remainder of the seal injection water flows up through the pump radial bearing and the shaft seals and is discharged via the seal leakoffs.

The pump shaft seal section consists of three identical seal stages in series, which are contained within a seal housing. Each seal stage is capable of withstanding full reactor pressure. The seal

schematic diagram is shown in Figure 5.5-18. The seal is a hydrodynamic end face mechanical seal that is designed to operate with a thin fluid film gap. Normal flow across the seal face is less than 0.1 gpm. There is a tubular coil that allows flow around each of the three stages so that, during normal operation, the differential pressure across each stage is about one-third of RCS pressure. The flow through this coil is referred to as controlled bleed-off (CBO). Most of the seal injection flow (directed to the seals) is discharged through this staging coil. Normal CBO flow is about 2.5 gpm. CBO from the third staging coil is routed back to the volume control tank. Leakage across the third stage seal face flows directly to the reactor coolant drain tank via a gravity drain line. This arrangement minimizes leakage of water and vapor into containment.

The thermal barrier is a welded assembly consisting of a flanged cylindrical shell, a series of concentric stainless steel cans, a heat exchanger coil assembly, and two flanged water connections.

Component cooling water enters the thermal barrier through a flanged connection on the thermal barrier flange (see Figure 5.5-17). The cooling water flows through the inside of the coiled stainless steel tubing in the heat exchanger and exits through another flanged connection on the thermal barrier flange. During normal operation, the thermal barrier limits the heat transfer from the reactor coolant to the pump internals.

The upper bearing assembly contains an oil-cooled pivoted-pad radial guide bearing (upper guide bearing), as well as a double acting oil-cooled Kingsbury-type thrust bearing (see Figure 5.5-19). The thrust bearing shoes are positioned above and below a common runner to accommodate thrust in both directions. The shoes are mounted on equalizing pads, which distribute the thrust load equally to all the shoes.

The oil is circulated through an external oil-to-water shell and tube heat exchanger (oil cooler) to which component cooling water is supplied.

The lower guide bearing is a pivoted-pad radial bearing, similar to the upper guide bearing.

The entire lower guide bearing assembly is located in the lower oil reservoir, which contains an integral oil-to-water coil type heat exchanger (see Figure 5.5-19).

Component cooling water is supplied to this heat exchanger.

Should a loss of seal injection to the RCPs occur, the pump radial bearing and seals are lubricated by reactor coolant flowing up through the pump. Under these conditions, the CCWS continues to provide flow to the thermal barrier heat exchanger and the heat exchanger, functioning in its backup capacity, cools the reactor coolant before it enters the pump radial bearing and the shaft seal area. The loss of seal injection flow may result in a temperature increase in the pump bearing area, a temperature increase in the seal area, and a resultant increase in the number 1 seal leak rate; however, pump operation can be continued (for up to 24 hours), provided these parameters remain within the allowable limits. Extended periods without seal injection may result in particulates from the RCS causing premature seal face wear.

Should a loss of CCW to the RCPs occur, the CVCS continues to provide seal injection flow to the RCPs; the seal injection flow is sufficient to prevent damage to the seals with a loss of thermal barrier cooling. Consequently, the RCP can continue to run following a loss of thermal barrier cooling provided that pump seal temperatures remain within allowable limits. However, the loss of CCW to the motor bearing oil coolers will result in an increase in oil temperature and a corresponding rise in motor bearing metal temperature. It has been demonstrated by testing that the reactor coolant pumps will incur no damage as a result of a CCW flow interruption of 10 minutes.

Two safety related transmitters are provided to redundantly monitor component cooling water flow to the upper and lower reactor coolant pump bearings. Two additional safety related transmitters are provided to redundantly monitor component cooling water flow to the reactor coolant pump thermal barriers. These transmitters provide flow indication and actuate low flow alarms in the control room.

A discussion of the loss of seal injection is provided above. This discussion justifies the use of non-safety grade instrumentation for seal injection flow since loss of seal injection is not limiting in terms of continued pump operation and does not require immediate operator action.

As discussed above, a loss of CCW to the motor bearing oil coolers will result in an increase in oil temperature and a corresponding rise in motor bearing temperature. Since the loss of CCW to the thermal barrier does not, in itself, affect operation of the RCP, a simultaneous loss of CCW to the thermal barrier and to the motor bearing oil coolers is no worse than a loss of CCW only to the motor bearing oil coolers. Westinghouse contends that the loss of CCW to the RCPs will not result in an instantaneous seizure of a single pump and, further, that instantaneous seizure of two pumps simultaneously is not a credible ultimate consequence.

Instead, it is Westinghouse’s technical opinion that a more realistic ultimate consequence will be an abbreviated coastdown. If a limiting condition of the babbitt metal is considered, an increasing coefficient of friction, as well as an increasing retarding torque, is expected. However, in view of the large rotational inertia of the pump/motor assembly, Westinghouse maintains that an instantaneous seizure will not result.

Because an initial seizure is not expected, it is not possible to define a precise point in time at which a sequential seizure would be anticipated. Therefore, for the purpose of defining the time expected between sequential seizures, the following discussion will be presented in terms of sequential occurrences of reaching a "high" bearing temperature. The upper thrust bearing exhibits the limiting temperature; therefore, an upper thrust bearing temperature of 240°F has been chosen arbitrarily as the "high" temperature. It should be noted that the use of this value does not imply pump seizure at this temperature.

Variables affecting the steady state operating temperature of the bearings include the following:

a. Surface finish of the bearing and runner.

b. Bearing (and oil pumping mechanism) clearances.

c. Inlet temperature of water to heat exchanger (oil cooler).

d. Condition of oil-to-water heat exchanger (oil cooler) (i.e., extent of fouling).

e. Condition of oil.

f. Amount of oil in oil pot.

g. Oil temperature.

These variables would be expected to interact concurrently in a manner which individualizes the performance of the bearings during actual steady state plant operation.

In order to quantify the resultant variation in performance, Westinghouse has collected data from an operating plant. The data demonstrate that the upper thrust bearings operate at different steady state temperatures (i.e., 128°F, 132°F, 135°F, and 145°F). It should be noted that the data were collected from a four loop plant; the following evaluation based on this data is applicable to a three loop plant (i.e., Virgil C. Summer).

Using these actual steady state operating values (A-128°F, B-132°F, C-135°F, D-145°F) and assuming a conservative 5°F/minute linear heatup rate after a loss of CCW, sequential occurrences of reaching the high bearing temperature could be expected at the time intervals tabulated below (see Figures 5.5-20 and 5.5-21).

Sequential Motors	Δ Operating Temperature (°F)	Time Interval (minutes)
A and B	4	0.8
B and C	3	0.6
C and D	10	2.0
A and C	7	1.4
B and D	13	2.6
A and D	17	3.4

To summarize, two bearings sequentially reaching a temperature of 240°F could be expected at a minimum time interval of 0.6 minutes and at a maximum time interval of 3.4 minutes.

Westinghouse has obtained motor bearing heatup data. These test data show actual values of bearing temperatures following a loss of CCW. The test data presented in Figure 5.5-22 will be examined relative to the above discussion. The test runs, which were performed at different times using different motors, demonstrate similar heatup rates; this fact supports the assumption of identical linear heatup rates made in the previous discussion. In addition, the average heatup rates evidenced in the test data are less than 3.3°F/minute, which substantiates the use of 5°F/minute as a conservative value. The actual test data, although limited, are supportive of the assumptions posed in defining the time intervals tabulated above.

In conclusion, Westinghouse contends that single or multiple pump seizures as the result of a loss of CCW to the RCPs is not a credible event. However, in our judgment and based on the above discussion, two RCP motor upper thrust bearings could sequentially reach a "high" bearing temperature of 240°F at a minimum time interval of 0.6 minutes (or approximately 40 seconds).

Section 15.4.4 of the Virgil C. Summer FSAR presents the analysis of a single RCP locked rotor. It should be pointed out that the Section 15 analysis assumes an instantaneous seizure of a reactor coolant pump rotor on a non-mechanistic basis. Westinghouse contends that a postulated mechanistic instantaneous seizure of a pump rotor due to a loss of CCW to the RCP will not occur and is not a credible event.

However, in response to the NRC request, the results of a second non-mechanistic instantaneous seizure occurring at 40 seconds after a first non-mechanistic instantaneous seizure have been evaluated. Although a Section 15 approach was utilized to evaluate this situation, Westinghouse does not recognize a postulated mechanistic instantaneous locked rotor as a credible consequence of the loss of CCW to the RCPs.

Assuming that a second pump seizure occurs 40 seconds after a first pump seizure, no noticeable change is seen in the RCS pressure and the clad temperature transients. Furthermore, even if the time interval between the sequential seizures is reduced to 10 seconds, no noticeable change is seen in the RCS pressure and the clad temperature transients.

The hypothetical seizure of one RCP results in a low flow reactor trip approximately one second after the initiation of the event. As a result of the fast reactor trip and the consequential decrease in core heat flux, the RCS pressure and the clad temperature reach the peak values at about 2.5 seconds and then start to decrease.

Because the core has been shut down, at 40 seconds–or even 10 seconds–after a pump seizure, the RCS pressure and the clad temperature transients have decreased to a point at which a second pump seizure results in no noticeable change in the transients.

Operating procedures are provided for a loss of component cooling water and seal injection to the reactor coolant pumps and/or motors. Included in these operating procedures is the provision to trip the reactor if component cooling water flow, as indicated by the instrumentation discussed previously, is lost to the reactor coolant pump motors and cannot be restored within 10 minutes. The reactor coolant pumps will also be tripped following the reactor trip.

This section provides a description of testing performed and the test results which constitute the basis of reactor coolant pump operation for 10 minutes without CCW with no resultant damage. Two RCP motors have been tested with interrupted CCW flow; these tests were conducted at the Westinghouse Electro Mechanical Division. In both cases, the reactor coolant pumps were operated to achieve "hot" (2230 psia, 552°F) equilibrium conditions. After the bearing temperatures stabilized, the cooling water flow to the upper and lower motor bearing oil coolers was terminated and bearing (upper thrust, lower thrust, upper guide, and lower guide) temperatures were monitored. A bearing metal temperature of 185°F was established as the

maximum test temperature. When that temperature was reached, the cooling water flow was restored.

In both tests, the upper thrust bearing exhibited the limiting temperatures. Figure 5.5-21 shows the upper thrust bearing temperature versus time. In both cases, 185°F was reached in approximately 10 minutes.

The maximum test temperature of 185°F is also the suggested alarm setpoint temperature and the suggested trip temperature is 195°F. It should be noted that the melting point of the babbitt bearing metal exceeds 400°F.

The information presented above constitutes the basis of the RCP qualification for 10 minute operation without CCW with no resultant damage.

5.5.1.4 Tests and Inspections

The reactor coolant pumps can be inspected in accordance with the ASME Code, Section XI, for Inservice Inspection of Nuclear Reactor Coolant Systems.

Any full penetration welds in the pressure boundary are prepared with a smooth surface transition between weld metal and parent metal for radiographic inspection. However, the pump casing is cast in one piece, eliminating welds in the casing.

Support feet are cast integral with the casing to eliminate a weld region.

The design enables disassembly and removal of the pump internals for usual access to the internal surface of the pump casing.

The reactor coolant pump quality assurance program is given in Table 5.5-2.

5.5.2 Steam Generators

5.5.2.1 Design Bases

The replacement steam generators installed in the V. C. Summer plant are Westinghouse Delta-75, feedring type steam generators. To facilitate replacement in the plant, the geometric characteristics of the Delta-75 steam generators are identical to the original D3 steam generators. Additionally, the Delta-75 steam generators must provide an equal or better level of performance than the original steam generators. The Delta-75 steam generators are expected to supply steam at about 1.3% higher than the original D3 steam generators at a plant thermal rating of 2787 MWt. At the Engineered Safeguards Power Rating of 2912 MWt, the Delta-75 steam generators are expected to deliver steam at about 2.0% above that projected for the original D3 steam generators.

The steam generators are designed and analyzed according to the requirements of Section III of the ASME Code, 1971 Edition through Summer 1971 Addenda, and constructed according to the

1986 Edition. To minimize the impact on steam generator supports and seismic considerations, the total weight of each empty Delta-75 steam generator is ≤ 360 tons.

Steam generator design data are given in Table 5.5-3. The design sustains transient conditions given in Section 5.2.1. Although the required secondary side ASME classification is Class 2, Class 1 requirements are applied for all pressure retaining portions of the steam generator. Assurance of adequate fracture toughness of all pressure boundary materials is, therefore, as described in Section 5.2.4 and complies with Article NB-2300 of Section III of the ASME Code. Rupture of a steam generator tube is discussed in Section 15.4.3.

The internal moisture separation equipment is designed to ensure that moisture carryover does not exceed 0.10% by weight under the following conditions:

1. Steady-state operation up to 100% of full load steam flow, with water at the normal operating level.
2. Loading or unloading at a rate of 5% of full load power steam flow per minute in the range from 15% to 100% of full load steam flow.
3. A step load change of 10% of full power in the range from 15% to 100% full load steam flow.

The water chemistry in the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces. The water chemistry of the steam side and its effectiveness in corrosion control is discussed in Section 10.3.5.

5.5.2.2 Design Description

The original VCSNS steam generators were Model D3 type, which employed the use of an integral preheater at the feedwater inlet. The original steam generators were replaced during the Refuel 8 outage, approximately September 1994, with Westinghouse Delta-75 steam generators. The Delta-75 steam generator has the same profile dimensions as the original D3 steam generator. Like the D3 steam generator, the Delta-75 is a vertical shell and U-tube evaporator with integral moisture separation equipment. The Delta-75 steam generator is shown in Figure 5.5-3. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical partition plate extending from the head to the tubesheet. Manways are provided for access to both sides of the divided head. The feedwater inlet on the original D3 steam generators was located several feet above the top surface of the tubesheet, on the cold leg or return side of the U-tube bundle. The incoming feedwater was forced through a back and forth path within the preheater by several staggered tube support plates. This path allowed the feedwater temperature to be rapidly heated almost to saturation temperature before entering the boiler section. In the Delta-75, the feedwater inlet is located at approximately 2/3 of the steam generator height and is distributed equally around the circumference of the steam generator shell. Feedwater enters the tube bundle by flowing downward between the steam generator external shell and inner wrapper barrel. An open area at the bottom of the wrapper barrel permits the feedwater to enter the tube bundle. The simplified design of the Delta-75 steam

generator supports a more simplified steam generator operating procedure and eliminates some of the low power operating restrictions applied to the D3 steam generators. The total steam generator heat transfer surface area is increased in the Delta-75 to account for the thermal performance characteristics of the preheater. Steam is generated and flows upward through the moisture separators and through the flow restrictor outlet nozzle at the top of the steam drum. The Delta-75 utilizes high efficiency centrifugal steam separators, which remove most of the entrained water. Chevron dryers are employed to increase the steam quality to a minimum of 99.90% (0.10% moisture).

The steam generator channel head and tubesheet are protected from the primary water by applying an autogenous weld deposited stainless steel cladding to the primary surfaces of the channel head and Inconel to the tubesheet. The cladding surface is machined to a smooth condition and electropolished, thereby reducing the collection of radioactive contamination inside the steam generators during refueling and maintenance periods.

Steam generator materials of construction are listed in Table 5.2-8. All materials are selected and fabricated in accordance with the requirements of the ASME Code, Section III, and Code Case N-20-3. The steam generator tubing material is Alloy 690. Alloy 690 material represents the state of the art technology for heat transfer tubing. The tubing receives a heat treatment process after forming which results in a grain boundary structure which has been shown by test to be exceptionally resistive to primary water stress corrosion cracking (PWSCC), which initiates tube degradation in the expansion region within the tubesheet area and has resulted in the majority of tube plugging in the original D3 steam generators at V. C. Summer. The tube expansion process used for the replacement steam generator is not expected to result in similar strain levels or patterns as observed in the original D3 steam generators. Alloy 690 tubing material is also exceptionally resistive to outer diameter stress corrosion cracking (ODSCC), which has affected the secondary side of the tubes in operating plants at the tube support plate intersections.

Ferritic material in the primary side of the steam generators includes the following: channel head casting, tubesheet, primary nozzles, manway covers, and manway studs and nuts. Fracture toughness data for the steam generator bolting materials are shown in Table 5.2-22. Fracture toughness data for the channel head, tubesheet, and associated weldments will be consistent with ASME Code. As-built data generally show the test data to far exceed the ASME Code minimum values. The materials of construction and general design of the steam generator shell of the Delta-75 have resulted in a reduction in the number of pressure boundary welds required for assembly of the shell.

5.5.2.3 Design Evaluation

5.5.2.3.1 Forced Convection

The effective heat transfer coefficient is determined by the physical characteristics of the Delta-75 steam generator and the fluid conditions in the primary and secondary systems for the nominal 100% design case. It includes a conservative allowance for fouling and uncertainty. A designed heat transfer area is provided to permit the achievability of the full-design heat-removal rate. Although margin for tube fouling is available, operating experience to date has not indicated that

steam generator thermal performance decreases over a long term period. Adequate tube surface area is selected to ensure that the full design heat removal rate is achieved.

5.5.2.3.2 Natural Circulation Flow

The steam generators, which provide a heat sink, are at a higher elevation than the reactor core, which is the heat source. Thus, natural circulation is assured for the removal of decay heat.

5.5.2.3.3 Tube and Tubesheet Stress Analyses

Tube and tubesheet stress analyses of the steam generator, which are discussed in Section 5.2, confirm that the steam generator tubesheet will withstand the loading caused by a loss of reactor coolant (LOCA). Routine inservice inspections of the steam generator tubing will assess tubing integrity and adequacy for continued operation based upon the 40% depth of indication limit specified by Section XI of ASME Code. Tube degradation existing at this level will maintain integrity consistent with the recommendations of Regulatory Guide 1.121 during the transient events identified in Section 5.2.

5.5.2.3.4 Corrosion

The Delta-75 steam generator utilizes thermally treated Alloy 690 tube material. This material is used in the replacement steam generators at North Anna Unit 1 and Indian Point Unit 3. Thermally treated Alloy 690 tubing is also used in a number of plants, which include the Turkey Point replacements, Surry replacements, D. C. Cook Unit 2 replacements, and Prairie Island replacements, Wolf Creek, Seabrook, and Millstone Unit 3.

To date, the only form of tube degradation which has been identified in Model F-type units is fretting wear between the tube and steam generator anti-vibration bars (AVB). Only a small number of tubes (expected to be less than 1% total over the life of the steam generators) would be subject to this phenomena. The AVB design in the Delta-75 steam generators maintains smaller, more tightly controlled tube-to-AVB gaps, increased tube-to-AVB contact area, and utilize more AVBs than do the Model F steam generators. These factors should greatly lower the potential for tube fretting at AVB intersections in the Delta-75 steam generators.

5.5.2.3.5 Compatibility of Steam Generator Tubing with Primary and Secondary Coolant

As previously discussed, the Alloy 690 tubing installed in the Delta-75 steam generators at V. C. Summer has been shown by test (and operating experience) to be exceptionally resistant to both PWSCC and ODSCC. The Delta-75 Alloy 690 tubing specification is in accordance with the requirements of ASME Code Case N-20-3, ASME Code Section III, ASME Code Section II Specification SB-163, and meets the EPRI Guidelines for Procurement of Alloy 690 steam generator tubing, NP-6743-L, February 1991.

The steam generator tube expansion process employed in the tubesheet region results in reduced residual stress levels compared to the original D3 steam generators. This reduced residual stress will lower the potential for PWSCC in this region. Additionally, no evidence of PWSCC has been

identified in either the Model F type steam generators operating today, or the replacement steam generators manufactured by Westinghouse.

The potential for ODSCC to develop in the Delta-75 steam generators is also greatly reduced. The axial flow paths around the steam generator tubes provided by the trifoil support design significantly reduce crevice area and contaminant hideout potential. The stainless steel tube support plate material does not represent a potential for magnetite generation or general corrosion product buildup. Also, the most recent revision of the EPRI Secondary Water Chemistry Guidelines has incorporated a sodium-chloride molar ratio control philosophy, which will help to maintain an as neutral as possible crevice chemistry within the entire steam generator secondary side.

5.5.2.3.6 Flow Induced Vibration

The potential for tube wall degradation attributable to mechanical or flow induced excitation is exceptionally low in a feedring type steam generator design. Flow induced vibration at the tube support plate intersections has not been observed in Model F type steam generators.

5.5.2.3.7 Tube Denting

Localized steam generator tube diameter reductions were first discovered during the April 1975 steam generator inspection at the Surry Unit 2 plant. This discovery was evidenced by eddy current signals, resembling those produced by scanning dents, and by difficulty in passing the standard 0.700 inch diameter eddy current probe through the tubes at their intersections with the support plates. Subsequent to the initial finding, steam generator inspections at other operating plants revealed essentially identical results.

The phenomenon of tube denting is attributed to a localized buildup of corrosion products (due to magnetite generation in the support plate crevice) in the tube-to-tube support plate crevice, which eventually deforms the tube wall as the corrosion products continue to build. The implementation of All Volatile Treatment (AVT) chemistry on the secondary side of the steam generator has minimized the potential of denting. Additionally, the Delta-75 steam generators at the V. C. Summer plant employ stainless steel tube support plates, which should preclude the formation of corrosion products within the crevice. The Delta-75 tube support plates employ a limited contact trifoil hole shape which permits axial flow around the tube, which also minimizes the buildup of corrosion products in this area. The original D3 steam generators utilized carbon steel support plates with drilled tube holes of a diameter approximately 0.013 inch larger in diameter than the tubes, which can be filled with corrosion products.

5.5.2.4 Test and Inspections

The steam generator quality assurance program is given in Table 5.5-4. During manufacture, cleaning is performed on the primary and secondary sides of the steam generator in accordance with written procedures which follow the guidance of Regulatory Guide 1.37 and other industry standards, such as those developed by the American Society of Testing and Materials (ASTM). Radiographic inspections, liquid penetrant inspections, magnetic particle inspections, ultrasonic

inspections, and the implementation of the associated acceptance criteria for each are instituted according to the requirements of the ASME Code.

The steam generators are designed to permit inservice inspections in accordance with the requirements of Section XI to the ASME Code, and steam generator tubing eddy current examination consistent with the requirements of V. C. Summer Technical Specifications 3/4.4.5, “Steam Generator Tube Integrity,” and 6.8.4.k, “Steam Generator Program.”

When required, tests, using a Lithium or radioactive Sodium tracer, are conducted to properly account for moisture carryover in the plants calorimetric and precision RCS flow measurement.

5.5.3 Reactor Coolant Piping

5.5.3.1 Design Bases

The RCS piping is designed and fabricated to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. Stresses are maintained within the limits of Section III of the ASME Nuclear Power Plant Components Code. Code and material requirements are provided in Section 5.2.

Materials of construction are specified to minimize corrosion/erosion and ensure compatibility with the operating environment.

The piping in the RCS is Safety Class 1 and is designed and fabricated in accordance with the ASME Code, Section III, Class 1 requirements.

Stainless steel pipe conforms to ANSI B36.19 for sizes 1/2 inch through 12 inches and wall thickness Schedules 40S through 80S. Stainless steel pipe outside of the scope of ANSI B36.19 conforms to ANSI B36.10.

The minimum wall thicknesses of the loop pipe and fittings are not less than that calculated using the ASME Code, Section III, Class 1 formula of Paragraph NB-3641.1 (3) with an allowable stress value of 17,550 psi. The pipe wall thickness for the pressurizer surge line is Schedule 160. The minimum pipe bend radius is five nominal pipe diameters; ovality does not exceed 6%.

All butt welds, branch connection nozzle welds, and boss welds are of a full penetration design.

Processing and minimization of sensitization are discussed in Sections 5.2.3 and 5.2.5.

Flanges conform to ANSI B16.5.

Socket weld fittings and socket joints conform to ANSI B16.11.

Inservice inspection is discussed in Section 5.2.8.

5.5.3.2 Design Description

Principal design data for the reactor coolant piping are given in Table 5.5-5.

The piping is seamless forged; the fittings are cast without longitudinal welds and electroslag welds. Piping and fittings comply with the requirements of the ASME Code, Section II, Parts A and C, Section III, and Section IX.

The RCS piping is specified in the smallest sizes consistent with system requirements. This design philosophy results in the reactor inlet and outlet piping diameters given in Table 5.5-5. The line between the steam generator and the pump suction is larger to reduce pressure drop and improve flow conditions to the pump suction.

The reactor coolant piping and fittings which make up the loops are austenitic stainless steel. There is no electroslag welding on these components. All smaller piping which comprises part of the RCS such as the pressurizer surge line, spray and relief line, loop drains, and connecting lines to other systems is also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is carbon steel. All joints and connections are welded, except for the pressurizer code safety valves, where flanged joints are used. Thermal sleeves are installed at some points in the system where high thermal stresses could develop due to rapid changes in fluid temperature during normal operational transients. These points include:

1. The pressurizer surge line connection at the pressurizer.
2. Pressurizer spray line connection at the pressurizer.

Piping connections from auxiliary systems are made above the horizontal centerline of the reactor coolant piping, with the exception of:

1. Residual heat removal pump suction lines, which are 45° down from the horizontal centerline. This enables the water level in the RCS to be lowered in the reactor coolant pipe while continuing to operate the Residual Heat Removal System (RHRS), should this be required for maintenance.
2. Loop drain lines and the connection for temporary level measurement of water in the RCS during refueling and maintenance operation.
3. The differential pressure taps for flow measurement, which are downstream of the steam generators on the first 90° elbow. The tap arrangement is discussed in Section 5.6.
4. The pressurizer surge line, which is attached at the horizontal centerline.
5. The safety injection connections to the hot leg, for which inservice inspection requirements and space limitations dictate location on the horizontal centerline.

Penetrations into the coolant flow path are limited to the following:

1. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force.
2. The reactor coolant sample system taps protrude into the main stream to obtain a representative sample of the reactor coolant.
3. The resistance temperature detector (RTD) hot leg scoops extend into the reactor coolant at locations 120° apart in the cross sectional plane. In the original design, these scoops collected a representative temperature sample for the RTD manifold. In the current design, they provide a convenient location for the narrow range thermowell mounted RTDs.
4. The wide range temperature detectors and the cold leg fast response temperature detectors are located in resistance temperature detector wells that extend into the reactor coolant pipes.

The RCS piping includes those sections of piping interconnecting the reactor vessel, steam generator, and reactor coolant pump. It also includes the following:

1. Charging line and alternate charging line from the system isolation valve up to the branch connections on the reactor coolant loop.
2. Letdown line and excess letdown line from the branch connections on the reactor coolant loop to the system isolation valve.
3. Pressurizer spray lines from the reactor coolant cold legs to the spray nozzle on the pressurizer vessel.
4. Residual heat removal lines to or from the reactor coolant loops up to the designated check valve or isolation valve.
5. Safety injection lines from the designated check valve to the reactor coolant loops.
6. Accumulator lines from the designated check valve to the reactor coolant loops.
7. Loop fill, loop drain, sample (1), and instrument (1) lines to or from the designated isolation valve to or from the reactor coolant loops.
8. Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel inlet nozzle.
9. Resistance temperature detector scoop element, pressurizer spray scoop, sample connection (1) with scoop, reactor coolant temperature element installation boss, and the temperature element well itself.
10. All branch connection nozzles attached to reactor coolant loops.
11. Pressure relief lines from nozzles on top of the pressurizer vessel up to and through the power operated pressurizer relief valves and pressurizer safety valves.
12. Seal injection water and labyrinth differential pressure lines to or from the reactor coolant pump inside reactor building.

13. Auxiliary spray line from the isolation valve to the pressurizer spray line header.
14. Sample lines (1) from pressurizer to the isolation valve.

Details of the materials of construction and codes used in the fabrication of reactor coolant piping and fittings are discussed in Section 5.2.

5.5.3.3 Design Evaluation

Piping load and stress evaluation for normal operating loads, seismic loads, blowdown loads, and combined normal, blowdown, and seismic loads are discussed in Section 5.2.1.

5.5.3.3.1 Material Corrosion/Erosion Evaluation

The water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications.

The design and construction are in compliance with the ASME Code, Section XI. Pursuant to this, all pressure containing welds out to the second valve that delineates the RCS boundary are available for examination with removable insulation.

Components constructed with stainless steel will operate satisfactorily under normal plant chemistry conditions in pressurized water reactor systems because chlorides, fluorides, and particularly oxygen are controlled to very low levels (see Section 5.2.3).

Periodic analysis of the coolant chemical composition is performed to monitor the adherence of the system to desired reactor coolant water quality listed in Table 5.2-10. Maintenance of the water quality to minimize corrosion is accomplished using the CVCS and process sampling system which are described in Sections 9.3.4 and 9.3.2, respectively.

5.5.3.3.2 Sensitized Stainless Steel

Sensitized stainless steel is discussed in Sections 5.2.3 and 5.2.5.

5.5.3.3.3 Contaminant Control

Contamination of stainless steel and Inconel by copper, low melting temperature alloys, mercury, and lead is prohibited. Only selected lubricants, which are not deleterious to stainless steel, are used.

1. Liquid filled lines with a 3/8 inch flow restricting orifice qualify as Safety Class 2a; in the event of a break in one of these Safety Class 2a lines, the normal makeup system is capable of providing makeup flow while maintaining pressurizer water level. Instrument impulse lines connected to the pressurizer steam space above the water level have been upgraded to Safety Class 1, since failure of these lines could cause automatic operation of the ECCS systems.

Prior to application of thermal insulation, the austenitic stainless steel surfaces are cleaned and analyzed to a halogen limit of 0.0015 mg Cl/dm^2 and 0.0015 F/dm^2.

5.5.3.3.4 Alloy 600 Dissimilar Metal Welds

The RCS Piping includes Alloy 600 dissimilar metal welds at the Reactor Vessel Nozzles, Steam Generator Nozzles, Pressurizer Surge Line Nozzle, Pressurizer Safety Valves, Power Operated Relief Valves, and Pressurizer Spray Nozzle.

A thru-wall leak was identified on the Reactor Vessel "A" Loop Hot Leg Nozzle to Pipe Weld during Refuel 12. The weld was completely removed and a pipe spool piece was welded in place. The root cause was determined to be PWSCC. The Reactor Vessel Nozzle to Pipe Weld was made using Alloy 690. Alloy 690 is a material with more resistance to PWSCC.

Due to the high susceptibility to PWSCC in the Reactor Vessel Hot Leg Nozzle to Pipe Welds, mitigative measures were taken during Refuel 13. The Mechanical Stress Improvement Process (MSIP) is a remediation process for pipe-to-pipe and pipe-to-nozzle welds that are susceptible to stress corrosion cracking from welding induced residual stresses. MSIP equipment applies a narrow permanent radial deformation adjacent to a pipe weld that redistributes the residual stresses in the weld region producing compressive stress at the inside diameter of the weld joint. This process removes one of the three factors (material susceptibility, environment, and high residual tensile stresses) required to create PWSCC in RCS components. MSIP was applied to the Reactor Vessel "B" and "C" Loop Hot Leg Nozzle to Pipe Welds.

The Pressurizer Nozzle Alloy 600 dissimilar metal welds were mitigated during Refuel 17 by the application of a full structural weld overlay. This weld overlay was applied to each of the nozzles on the pressurizer utilizing alloy 52M filler metal which is high in chromium and more resistant to PWSCC (consistent with alloy 690). This pre-emptive mitigation provided a full structural overlay to each of the nozzles and provides an ultrasonic NDE inspectable geometry which meets the ASME volumetric inspection requirements. The pre-weld overlay geometry did not meet the volumetric inspection requirements of the ASME XI code. Application of the weld overlay also provides a beneficial compressive stress to the underlying pipe, safe end, nozzle, and welds.

5.5.3.4 Tests and Inspections

The RCS piping quality assurance program is given in Table 5.5-6.

Volumetric examination is performed throughout 100% of the wall volume of each pipe and fitting in accordance with the applicable requirements of Section III of the ASME Code for all pipe 27-1/2 inches and larger. All unacceptable defects are eliminated in accordance with the requirements of the same section of the code.

A liquid penetrant examination is performed on both the entire outside and inside surfaces of each finished fitting in accordance with the criteria of the ASME Code, Section III. Acceptance standards are in accordance with the applicable requirements of the ASME Code, Section III.

The pressurizer surge line conforms to SA-376 Grade 304, 304N, or 316 with supplementary requirements S2 (transverse tension tests) and S6 (ultrasonic test). The S2 requirement applies to each length of pipe. The S6 requirement applies to 100% of the piping wall volume.

The end of pipe sections, branch ends, and fittings is machined back to provide a smooth weld transition adjacent to the weld path. All butt welds are ground smooth to permit inservice inspection in accordance with the ASME Code, Section XI. There is one pipe-to-pipe weld ("A" Hot Leg).

5.5.4 Steam Outlet Flow Restrictor (Steam Generator)

5.5.4.1 Design Bases

Each steam generator is provided with a flow restrictor having several small diameter venturi-type throats. The flow restrictors are designed to limit steam flowrate consequent to the unlikely event of a steam line rupture, thereby reducing the cooldown rate of the primary system and limiting stresses of internal steam generator components.

The flow restrictor is designed to minimize unrecovered pressure loss coincident with limiting accident flowrate to an acceptable value.

Although it is not considered to be part of the pressure vessel boundary, the restrictor is constructed of material specified in Section III of the ASME Code and is Seismic Category 1.

5.5.4.2 Design Description

The flow restrictor is an assembly of seven smaller nozzles installed within the steam outlet nozzle of the steam generator. Upper and lower internal discs support an outer circle of six nozzles and one central nozzle. The discs and outer cylinder are made of steel plates and pipe and the venturi nozzles are Inconel. The flow restrictor assembly is welded into the main steam generator outlet by a circumferential weld between the rim of the outer cylinder and the inside surface of the outlet nozzle.

5.5.4.3 Design Evaluation

The equivalent throat diameter of the steam generator outlet is 16 inches and the resultant pressure drop through the restrictors at 100% steam flow is approximately 3.4 psig. The steam side weld to the outlet nozzle is in compliance with manufacturing and quality control requirements of the ASME Code, Section III, and is Seismic Category 1.

5.5.4.4 Tests and Inspections

The restrictors are not a part of the steam system boundary. No tests or inspections of the restrictors are anticipated beyond those performed in the fabricator’s shop.

5.5.5 Main Steam Line Isolation System

The main steam line isolation system is discussed in Sections 10.3.2 and 10.3.3. The discussion presented in the referenced sections includes information on measures taken to reduce potential leakage of radioactivity to the environment in the event of a main steam line break.

5.5.6 Reactor Core Isolation Cooling System

Not applicable to pressurized water reactors.

5.5.7 Residual Heat Removal System

The RHRS transfers heat from the RCS to the CCWS to reduce the temperature of the reactor coolant to the cold shutdown temperature at a controlled rate during the second part of normal plant cooldown and maintains this temperature until the plant is started up again.

During the first phase of cooldown, the temperature of the RCS is reduced by transferring heat from the RCS to the steam and power conversion system through the steam generators.

Parts of the RHRS also serve as parts of the Emergency Core Cooling System (ECCS) during the injection and recirculation phases of a loss of coolant accident (see Section 6.3).

The RHRS is also used to transfer refueling water between the refueling cavity and the refueling water storage tank (RWST) at the beginning and end of the refueling operations.

5.5.7.1 Design Bases

RHRS design parameters are listed in Table 5.5-7.

The RHRS is placed in operation approximately 4 hours after reactor shutdown when the temperature and pressure of the RCS are approximately 350°F and less than 425 psig, respectively. The RHRS heat exchanger design heat load is based upon transferring 1/2 of the decay heat load at 20 hours after reactor shutdown (for the original RTP of 2775 MWt) with 5600 gpm CCWS flow (CCWS temperature is limited to 120°F maximum and will decrease towards 105°F as the cooldown proceeds) and 3750 gpm RHRS flow. With the current licensed RTP of 2900 MWt, each RHRS heat exchanger is capable of transferring 1/2 of the decay heat load at 24 hours after reactor shutdown with the same flowrates and CCWS temperature given above.

At the original RTP of 2775 MWt, the coupled RHRS/CCWS/SWS system is capable of cooling the RCS from 350°F beginning at 4 hours after reactor shutdown from an extended run at full power to 200°F within 4 hours after the start of the RHRS cooldown and to 140°F within 16 hours after the start of the RHRS cooldown. With the current licensed RTP of 2900 MWt, the coupled RHRS/CCW/SWS system is still capable of cooling the RCS from 350°F beginning at 4 hours after reactor shutdown from an extended run at full power to 200°F within 4 hours after the start of the RHRS cooldown and to 140°F within 20 hours after the start of the RHRS cooldown. The

RHRS heat load during the transient includes the heat from one RCP (RCP off after RCS reaches 160°F), core decay heat, and the sensible heat of the RCS metal and fluid; also, RCS cooldown rate is limited to 50°F/hr.

5.5.7.1.1 Compliance with BTP RSB 5-1

The safe shutdown design basis of the Virgil C. Summer Nuclear Station is hot standby. Under abnormal conditions, the plant is designed to remain in a safe hot standby condition until (a) normal systems can be restored to permit either return to power operation or cooldown to cold shutdown conditions, or (b) sufficient systems capability can be restored (depending on plant condition) to permit cooldown to cold shutdown conditions under abnormal plant conditions. This design basis is considered to constitute a safe design.

BTP RSB 5-1 establishes specific design requirements that address the various system functions that are required to achieve and maintain a safe hot standby and cold shutdown conditions. BTP RSB 5-1 requires plants with construction permits docketed after January 1, 1978, to comply in full with the design requirements of the BTP. Plants with construction permits docketed prior to January 1, 1978 (including Virgil C. Summer Nuclear Station) are required to address the BTP technical requirements and demonstrate partial compliance.

The following is a discussion of the Virgil C. Summer Nuclear Station compliance with the technical requirements of BTP RSB 5-1. This discussion demonstrates that under the postulated condition of BTP RSB 5-1 the Virgil C. Summer Nuclear Station can be maintained in a safe hot standby condition and taken to RHRS initiation conditions within approximately 36 hours, including credit for limited manual actions outside the control room to operate and/or repair a limited number of components that are not safety-grade or single failure proof.

Itemized below are the technical requirements of BTP RSB 5-1 followed by a general discussion of the Virgil C. Summer Nuclear Station compliance. The technical requirements section is then followed by more detailed discussion in sections entitled Cold Shutdown Scenario, Single Failure Evaluation, and Natural Circulation.

1. Provide safety-grade steam generator dump valves, operators, air, and power supplies which meet the single failure criterion.

   One safety grade steam generator power operated relief valve is provided for each of the three steam generators. Safety grade remote operators and power supplies are not required since hot standby can be achieved and maintained using the safety grade steam generator safety valves. The steam generator power operated relief valves are provided with handwheels and can be operated locally to permit plant cooldown. See the cold shutdown scenario and single failure evaluation provided below (Part II, Removal of Residual Heat).

2. Provide the capability to cooldown to cold shutdown in a reasonable period of time assuming the most limiting single failure and loss of offsite power or show that manual actions inside or outside containment or return to hot standby until the manual actions or maintenance can be performed to correct the failure provides an acceptable alternative.

If a condition occurred requiring cold shutdown of the plant, design features permit the maintenance of a hot standby condition for an indefinite period of time. The plant is capable of being cooled via natural convection and reaching RHRS initiating conditions including the time required to perform any manual actions.

3. Provide the capability to depressurize the RCS with only safety-grade systems assuming a single failure and loss of offsite power or show that manual actions inside or outside containment or remaining at hot standby until manual actions or repairs are complete provides an acceptable alternative.

   The plant can be maintained in a safe hot standby condition while any required manual actions are taken. See the cold shutdown scenario and single failure evaluation provided below (Part IV, Depressurization).

4. Provide the capability for borating with only safety-grade systems assuming a single failure and loss of offsite power or show that manual actions inside or outside containment or remaining at hot standby until manual actions or repairs are complete provides an acceptable alternative.

   The plant can be maintained in a safe hot standby condition while any required manual actions are taken. See the cold shutdown scenario and single failure evaluation provided below (Part III, Boration and Makeup).

5. Provide the system and component design features necessary for the prototype testing of both the mixing of the added borated water and the cooldown under natural circulation conditions with and without a single failure of a steam generator atmospheric dump valve.

The Virgil C. Summer Nuclear Station's ability to address boron mixing and cooldown test in natural circulation was originally to be demonstrated through referencing testing which was to be conducted at the Diablo Canyon nuclear plant. Since that time, other plants have demonstrated the following results.

During natural circulation testing at Farley 2, North Anna II, Salem II, and Sequoyah I, the following observations were made:

a. All plants (three or four loop) exhibited very similar RCS behavior indicating similar RCS characteristics.
b. By directly comparing North Anna and Farley natural circulation test results, these plants effectively exhibited identical behavior in terms of: time to stability following the reactor coolant pump trip; core flow distribution; core power distribution; and flow rates as indicated by the loop delta T's.

Results of the boron mixing and cooldown tests at Sequoyah, Salem, and North Anna indicate that:

a. The results of the North Anna test conclusively demonstrated the ability of the RCS to mix boron under natural circulation conditions as was also demonstrated by Salem and Sequoyah.

b. The tests performed at Salem and North Anna were performed at the end of cycle with a decay heat level on the order of 1% of the rated power where the Sequoyah test was done with nuclear heat of approximately 2% of the rated power. These power levels (and flow) are nominally lower than those expected following an emergency condition since the operator would initiate a boration quickly following the reactor trip to assure shutdown margin.

c. The capability of the RCS to perform a natural circulation cooldown at a rate of approximately 50°F/hr was demonstrated by all of these tests. This is at a higher rate than the Westinghouse emergency procedures (25°F/hr).

d. All plants demonstrated that no core temperature distribution anomalies were induced by the addition of boric acid into the RCS or the cooldown process while using natural circulation.

Since the tests at all plants successfully and conclusively demonstrated the capability of the plant to mix boric acid and cool down under natural circulation conditions, there would be no benefit from the Virgil C. Summer Nuclear Station performing this test.

a. Commit to providing specific procedures for cooling down using natural circulation and submit a summary of these procedures.

   Specific procedures for cooling down using natural circulation are provided in the Virgil C. Summer Nuclear Station "EOPs" which includes natural circulation cooldown with boron mixing. A summary of the procedures is provided in the cold shutdown scenario and single failure evaluation provided below.

b. Provide a seismic Category 1 AFW supply for at least 4 hours at Hot Shutdown plus cooldown to the RHRS cut-in based on the longest time (for only onsite or offsite power and assuming the worst single failure), or show that an adequate alternate Seismic Category 1 source will be available.

   Sufficient emergency feedwater is provided in the Seismic Category 1 condensate storage tank to permit 2 hours of operation at hot standby plus cooldown to RHR initiation conditions. In addition, a long term source of Emergency Feedwater is provided by a connection to the Seismic Category 1 Service Water System. See the cold shutdown scenario and single failure evaluation provided below (Part II, Removal of Residual Heat).

c. Provide for collection and containment of RHR pressure relief or show that adequate alternative methods of disposing of discharge are available.

   The RHR relief valves discharge to the pressurizer relief tank located inside containment.

5.5.7.1.2 Cold Shutdown Scenario

The safe shutdown design basis of Virgil C. Summer Nuclear Station is hot standby. The plant can be maintained in a safe hot standby condition while manual actions are taken to permit achievement of cold shutdown conditions following a SSE with loss of offsite power. Under such conditions, the plant is capable of achieving RHR initiation conditions (approximately 350°F and less than 425 psia), including the time required for any manual actions. To achieve and maintain cold shutdown, four key functions must be performed. These are: (1) circulation of the reactor coolant, (2) removal of residual heat, (3) boration and makeup, and (4) depressurization.

1. Circulation of Reactor Coolant

   Circulation of the reactor coolant has two stages in a cooldown from hot standby to cold shutdown. The first stage is from hot standby to 350°F. During this stage, circulation of the reactor coolant is provided by natural circulation with the reactor core as the heat source and steam generators as the heat sink. Steam release from the steam generators is initially via the steam generator safety valves and occurs automatically as a result of turbine and reactor trip. Steam release for cooldown is via the steam generator power operated relief valves. If air and control power are available, these valves will be operated from the main control board. A backup air compressor can be manually loaded on the diesel generator buses. If these power sources are not available, communications will be established between the control room and auxiliary operators at the valves. These valves can be manually operated by handwheel. The steam generator power operated relief valves are easily accessible for local operation at floor level or by permanently installed platforms in the Seismic Category 1 penetration access area. The ability to operate these valves locally by handwheel was verified in the plant hot functional testing program. As a result of the installed noise reduction features on the valve, noise levels were sufficiently low that plant personnel were able to communicate with the control room and operate the valves with no difficulty.

   The status of each steam generator can be monitored using Class 1E instrumentation located in the control room. Separate indication channels for both steam generator pressure and water level are available.

   Feedwater to the steam generators is provided from the Emergency Feedwater System which has a 500,000 gallon Seismic Category 1 condensate storage tank (160,054 usable gallons are reserved for emergency feedwater, see Section 9.2.6.1) as the primary source and two separate Seismic Category 1 piping subsystems. The first subsystem is composed of two motor driven pumps each powered from a different emergency power train, and the second subsystem incorporates a turbine driven pump which can receive motive steam from either of two steam generators. Backup is from the Seismic Category 1 Service Water System. There are additional sources of feedwater backup which can be manually accessed. The operation of the Emergency Feedwater System can be monitored using Class 1E instrumentation located in the control room.

   The second stage of reactor coolant circulation is from 350°F to cold shutdown. During this stage, circulation of the reactor coolant is provided by the residual heat removal pumps.

2. Removal of Residual Heat

   Removal of residual heat also has 2 stages in a cooldown from hot standby to cold shutdown. The first stage is from hot standby to 350°F.

   During this stage, the steam generators act as the means of heat removal from the RCS. When the operators are ready to begin the cooldown, the steam generator power operated relief valves are opened slightly. As the cooldown proceeds, the operators will occasionally adjust these valves to increase the amount they are open. This allows a reasonable cooldown rate to be maintained. Feedwater makeup to the steam generators is provided from the Emergency Feedwater System. The Emergency Feedwater System has the ability to remove decay heat by providing feedwater to all three steam generators for extended periods of operation.

   The second stage is from 350°F to cold shutdown. During this stage, the RHRS is brought into operation. The residual heat removal exchangers in the RHRS act as the means of heat removal from the RCS. In the RHR heat exchanger, the residual heat is transferred to the Component Cooling System which transfers the heat to the Service Water System. The Component Cooling and the Service Water Systems are both designed to Seismic Category 1. The RHRS includes two residual heat removal pumps and two residual heat removal heat exchangers. Each RHR pump is powered from different emergency power trains and each RHR heat exchanger is cooled by a different component cooling loop. If any component in one RHR loop becomes inoperable, cooldown of the plant is not compromised; however, the time for cooldown would be extended.

   The operation of the RHRS can be monitored using Class 1E instrumentation in the control room.

3. Boration and Makeup

   Boration is accomplished using portions of the CVCS. Boric acid 4 wt. % (approximately 7,000 ppm) from the boric acid tanks is supplied to the suction of the centrifugal charging pumps by the boric acid transfer pumps. The centrifugal charging pumps inject the borated water into the RCS via the normal charging and/or reactor coolant pump seal injection flow paths. The two boric acid tanks, two boric acid transfer pumps, centrifugal charging pumps, and the associated piping are of Seismic Category 1 design. There is sufficient boric acid capacity to provide for a cold shutdown with the most reactive rod withdrawn. The boric acid transfer pumps are each powered from different emergency power trains. The boric acid tank level can be monitored using Class 1E instrumentation in the control room to verify the operability of the boration portion of the CVCS.

   Makeup, in excess of that required for boration, can be provided from the RWST using centrifugal charging pumps and the same injection flow paths as described for boration. Two motor operated valves, each powered from different emergency power trains and connected in parallel, will transfer the suction of the charging pumps to the RWST. Makeup from the RWST can be monitored using Class 1E instrumentation in the control room.

4. Depressurization

   Depressurization is normally accomplished using the reactor coolant pumps and the normal spray lines to the pressurizer.

   Depressurization can be accomplished using the pressurizer power operated relief valves after boration and RCS cooldown to 450°F. This method consists of (1) discharging reactor coolant from the pressurizer to the pressurizer relief tank via the pressurizer power operated relief valves, and (2) allowing the pressurizer to cool via ambient heat losses as the RCS is maintained at 350°F via natural circulation.

5. Maintaining RCS Temperature and Pressure Without Letdown

   Letdown is isolated by fail closed air operated valves and is assumed to be unavailable during accident conditions. The cold shutdown scenario of maintaining RCS temperature and pressure without letdown is considered the limiting cold shutdown scenario and is presented to demonstrate cold shutdown capability under abnormal conditions. As additional components are assumed to be available, the cold shutdown scenario is simplified. For example, as the reactor vessel head vent valves or the pressurizer PORVs are assumed to be available, the boration and makeup function or the depressurization function, respectively, is simplified as RCS letdown becomes available.

   In performing the cooldown, the operator will integrate the functions of heat removal, boration and makeup, and depressurization so that these functions can be accomplished without letdown from the RCS. Boration, cooldown, and depressurization will be accomplished in a series of short steps arranged to keep RCS temperature and pressure and pressurizer level in the desired relationships. The boration requirements will be evaluated by the operator prior to initiating cooldown and depressurization. Based on initial plant conditions, the operator and/or the contents of the boric acid tanks. Once the plant is cooled to 350°F and depressurized to 425 psia, RHRS operation is initiated and the RCS is taken to cold shutdown conditions.

   To demonstrate that boration and depressurization can be done without letdown, a simpler scenario can be used. First the operators integrate the cooldown and boration functions, taking advantage of the RCS inventory contraction resulting from the cooldown. Finally, the operators use auxiliary spray from the CVCS to depressurize the plant to RHRS initiating conditions. The SCE&G calculation to demonstrate this capability assumes worst case boration requirements based on core end of life/peak xenon conditions and the following RCS initial conditions following plant trip:

RCS Temperature	557°F
RCS Pressure	2250 psia
Pressurizer Water Volume	350 ft^3
Pressurizer Steam Volume	1050 ft^3

The cooldown from 557°F to 350°F decreases the volume of water in the RCS by approximately 1420 cubic feet. This assumes that the pressurizer is not cooled and the water level is maintained at the initial condition. Makeup for contraction is supplied by 4 wt. % boric acid stored in the boric acid tanks at 70°F. A boric acid tank volume of approximately 1170 cubic feet is required to maintain the reactor within the technical specification shutdown requirements at 350°F. A boric acid tank volume of approximately 1170 cubic feet will expand to approximately 1310 cubic feet as it is heated to the RCS temperature of 350°F. The volume required for boration requirements at 350°F is less than the contraction volume available at 350°F.

To calculate if depressurization can be accomplished without letdown and without taking the plant water solid, it was assumed that the pressurizer was at saturated conditions with 350 cubic feet of water, 1050 cubic feet of steam, and the pressurizer metal at 653°F (2250 psia). It was further assumed that no additional water would be removed from the pressurizer by the cooldown contraction. With these assumptions, including the effect of heat input from the pressurizer metal, it was determined that spraying in approximately 450 cubic feet of 70°F water would provide saturated conditions at 425 psia (450°F) with a water volume of 913 cubic feet and a steam volume of 487 cubic feet.

Once depressurized to 425 psia, RHRS operation is initiated and cooldown is continued to cold shutdown conditions. The cooldown from 350°F to 200°F further decreases the volume of water in the RCS. This assumes that the pressurizer is not cooled and the pressurizer water level is maintained at the level resulting from depressurization. There is no additional boration required in going from Mode 4 (350°F) to Mode 5 (200°F). This is expected since the shutdown margin requirements are less restrictive in Mode 5 than in Mode 4.

The results of the calculations described above demonstrate that, based on the assumed initial conditions, boration and depressurization with 4 wt. % (approximately 7,000 ppm) boric acid can be accomplished without letdown and without taking full credit for the available volume created by the cooldown contraction. Should boration without letdown prove impractical due to any combination of plant conditions or equipment failures, letdown can be achieved by discharging RCS inventory via the pressurizer power operated relief valves or the reactor vessel head vent valves.

6. Instrumentation

Class 1E instrumentation is available in the control room to monitor the key functions associated with achieving cold shutdown. This instrumentation is discussed in Section 7.5 (Safety Related Display Instrumentation) and includes the following:

a. RCS wide range temperature

b. RCS wide range pressure

c. Pressurizer water level

d. Steam generator water level (per steam generator)

e. Steam line pressure (per steam line)

f. RWST level

g. Boric acid tank level (per boric acid tank)

h. Reactor building pressure

This instrumentation is sufficient to monitor the key functions associated with cold shutdown and to maintain the RCS within the desired pressure, temperature, and inventory relationships. Operation of the auxiliary systems that service the RCS can be monitored by the control room operator, if desired, via remote communication with an operator in the plant.

5.5.7.1.3 Single Failure Evaluation

1. Circulation of the Reactor Coolant

   a. From Hot Standby to 350°F (refer to FSAR Figures 5.1-1, 10.3-1, and 10.3-4) - Three reactor coolant loops and steam generators are provided, any two of which can provide sufficient natural circulation flow to provide adequate core cooling. Even with the most limiting single failure (of a steam generator power operated relief valve), two of the reactor coolant loops and steam generators remain available.

   b. From 350°F to cold shutdown (refer to FSAR Tables 5.5-7, 5.5-8, and Figure 5.5-4); two RHR pumps are provided, either one of which can provide adequate circulation of the reactor coolant.

2. Removal of Residual Heat

   a. From Hot Standby to 350°F [refer to FSAR Figures 10.3-1, 10.3-4, 10.4-16, 9.2-2 (Sheets 1 through 4), and 9.2-3].

      (1) Steam generator power operated relief valves - Three are provided (one per steam generator), any two of which are sufficient for residual heat removal. In the event of a single failure, two power operated relief valves remain available.

      (2) Emergency feedwater pumps - Two motor driven and one steam driven emergency feedwater pumps are provided. In the event of a single failure, two pumps remain available, either of which can provide sufficient feedwater flow.

      (3) Flow control valves - Air operated, fail open valves are provided. In the event of a single failure of one flow control valve (which effects flow to one steam generator from either a motor driven pump or the steam driven pump), emergency feed flow can still be provided to all three steam generators from the other pumps.

      (4) Backup source - A backup source of emergency feedwater can be provided to the suction of the emergency feedwater pumps from either train of the Seismic Category 1 Service Water System.

   b. From 350°F to 200°F [refer to FSAR Table 5.5-15 and Figure 5.5-4, and Figures 9.2-1, 9.2-2 (Sheets 1 through 4), 9.2-3, and 9.2-4].

(1) RHR Suction Isolation Valves 8701A and 8702A (RHR Pump 1) and 8701B and 8702B (RHR Pump 2) - The two valves in each RHR subsystem are each powered from different emergency power trains. Failure of either power train could prevent initiation of RHR cooling in the normal manner from the control room. In the event of such a failure, the affected valve can be de-energized and opened with its handwheel. Another method of operating these valves is by the use of alternate temporary power. Any other single failure can be tolerated as it would only affect one of the RHR subsystems, and adequate cooling can be provided by the redundant subsystem.

(2) RHR pumps 1 and 2 - Each pump is powered from a different emergency power train. In the event of a single failure, either pump can provide sufficient RHR flow.

(3) RHR heat exchangers 1 and 2 - If either heat exchanger is unavailable for any reason, the remaining heat exchanger is unavailable for any reason, the remaining heat exchanger can provide sufficient heat removal capability.

(4) RHR Flow Control Valves HCV603A and B - If either of these normally open fail open valves closes spuriously, sufficient RHR cooling can be provided by the unaffected RHR train.

(5) RHR/SIS Cold Leg Isolation Valves 8888A and B - If either of these normally open, motor operated valves, which are powered from different emergency power trains, closes spuriously, sufficient RHR cooling can be provided by the unaffected RHR train. The affected valve can be de-energized and opened with its handwheel.

(6) CCWS - Two redundant subsystems are provided for safety related loads. Either subsystem can provide sufficient heat removal via one of the RHR heat exchangers.

(7) Service Water System - Two redundant subsystems are provided for safety related loads. Either subsystem can provide sufficient heat removal via one of the CCW heat exchangers.

3. Boration and Makeup (refer to FSAR Figures 5.1-1, 6.3-1, and 9.3-16)

a. Boric Acid Tanks 1 and 2 - Two boric acid tanks are provided. Each tank contains sufficient 4% (approximately 7,000 ppm) boric acid to borate the RCS for cold shutdown.

b. Boric Acid Transfer Pumps 1 and 2 - Each pump is powered from a different emergency power train. In the event of a single failure, either pump can provide sufficient boric acid flow.

c. Isolation Valve 8104 - If valve 8104, which is supplied from emergency power and is normally closed, cannot be opened due to power train or operator failure, it can be opened locally with its handwheel. If valve 8104 cannot be opened with its handwheel, an alternate flow path is available via (1) air operated, fail open valve FCV-113A and normally closed manual valve 8439, or (2) gravity feed through normally closed manual valves 8329 and 8331.

d. Refueling Water Storage Tank Isolation Valves LCV-115B and LCV-115D - Each valve is powered from a different emergency power train, only one of these normally closed motor

operated valves needs to be opened to provide a makeup flow path from the RWST to the centrifugal charging pumps.

e. Centrifugal Charging Pumps A, B, and C - Pumps A and B are powered from a different emergency power train. In the event of a single failure, any one pump can provide sufficient boration or makeup flow.

f. Charging Pump Suction Isolation Valves 8130A, B and 8131A, B - If one of these normally open motor operated valves--each of which is powered from a different emergency power train--closes spuriously, operator action can be used to de-energize the valve operator and reopen the valve with its handwheel.

g. Normal Charging Flow Control Valve FCV-122 - This normally open valve fails open on loss of air or power. If FCV-122 closes spuriously, the charging pumps can operate on their miniflow circuits until operator action can open bypass valve 8403.

h. Normal Charging Isolation Valves 8107 and 8108 - If either of these normally open, motor operated valves--each of which is powered from a different emergency power train--closes spuriously, operator action can be used to de-energize the valve operator and reopen the valve with its handwheel.

i. Normal Charging Isolation Valve 8146 - If the normally open valve closes spuriously, alternate charging valve 8147, which fails open, can be used.

j. Charging Pump Discharge Isolation Valves 8132 A, B, and 8133 A, B - If one of these normally open motor operated valves--each of which is powered from a different emergency power train--closes spuriously, operator action can be used to de-energize the valve operator and reopen the valve with its handwheel. Power to valves 8133A, B is normally locked out to prevent spurious operation. Reference FSAR Section 6.3.2.20.

k. Reactor Coolant Pump Seal Injection Isolation Valve 8105 - If this normally open motor operated valve closes spuriously, operator action can be used to de-energize the valve operator and reopen the valve with its handwheel (also see item p.).

l. Reactor Coolant Pump Seal Injection Flow Control Valve HCV-186 - This normally open valve fails open on loss of air or power. If HCV-186 closes spuriously, the charging pumps can operate on their miniflow circuits until operator action can open bypass valve 8389 (also see item p.).

m. Reactor Coolant Pump Seal Injection Valves 8102 A, B, and C - If any of these normally open motor operated valves closes spuriously, operator action can be used to de-energize the valve operator and reopen the valve with its handwheel.

n. Cold Leg Injection Isolation Valves 8801 A and B - Each valve is powered from a different emergency power train; only one of these normally closed motor operated valves needs to be opened to provide a makeup path and source for boration.

o. Reactor Vessel Head Vent Valves 8095 A, B, and 8096 A, B - These valves fail as-is on loss of power. They are arranged with two valves in series in each of two parallel paths. The isolation valves in series in each flow path are powered from separate emergency power supplies. One normally closed isolation valve and one normally open valve are

located in each flow path. This valving and power supply arrangement ensures that one path from the reactor vessel head can be opened assuming a single failure. One path is sufficient to permit letdown from the RCS to augment boration and makeup operations.

p. If total RCP seal injection flow falls below 10 gpm, the Alternate Seal Injection (ASI) System (part of CVCS) is designed to automatically supply a total of 20 gpm RWST water downstream of HCV-186 and XVT-8105. The ASI system is an ASME Code Class 2 system (pressure boundary); however, the power source for the ASI pump (XPP0230) is from an NNS power supply.

4. Depressurization (refer to FSAR Figure 9.3-16)

   a. Pressurizer Power Operated Relief Valves PCV-444B and PCV-445A - These normally closed valves fail closed on loss of air or power. However, the valves are redundant, are powered by separate emergency electrical power supplies, and have backup seismic category air supply accumulators. The operability of either valve is sufficient to permit depressurization.

   b. Auxiliary Spray Valve 8145 - This normally closed valve fails closed on loss of air or power. If 8145 is stuck closed as a result of a single failure, the redundant Seismic Category 1 pressurizer PORVs can be used to depressurize the RCS as described in the alternate method for depressurization.

5. Instrumentation

   Sufficient instrumentation is provided to monitor from the control room the key function associated with cold shutdown. All necessary indications are redundant. Thus, in the event of a single failure, the operator can make comparisons between duplicate information channels or between functionally related channels in order to identify the particular malfunction. Refer to FSAR Section 7.5 (Safety Related Display Instrumentation) for applicable details.

6. Qualification

   The equipment discussed in the cold shutdown scenario is safety grade with the following exceptions. These are few in number and of such a nature that local manual actions and/or equipment repair could be performed while the plant is maintained in the hot standby condition while preparations are made to go to cold shutdown. These manual actions would not prevent the plant from achieving RHRS initiations within 36 hours.

   a. Steam generator power operated relief valves - These air operated valves are provided with safety grade remote operators; however, remote control provisions are control grade. Hot standby can be achieved and maintained using the safety grade steam generator safety valves. The steam generator power operated relief valves are provided with handwheels which can be operated locally to permit plant cooldown.

   b. Charging line isolation valves (8146, 8147), Charging line auxiliary spray valve (8145) - Seal injection line hand control valve (HCV-186). Charging line flow control valve (FCV-122).

These air operated valves are not provided with safety grade remote operators, air supplies, or power supplies. Their failure consequences were discussed in Parts 3 and 4 of the single failure evaluation.

c. RHRS Flow Control Valve HCV-603 A/B - This air operated valve is not provided with a safety grade remote operator, air supply, or power supply. Its failure consequence was discussed in Part 2 of the single failure evaluation.

d. Pressurizer relief tank - This tank is a non-nuclear safety class and non-Seismic Category 1 tank. Its failure does not affect the ability of the Virgil C. Summer Nuclear Station to achieve cold shutdown.

e. Pressurizer power operated relief valves - These air operated valves are not supplied with safety grade remote operators; however, they are powered from separate vital DC electrical power supplies and two of them have Seismic Category 1 air supply accumulators. These valves are discussed in Part 4 of the cold shutdown scenario.

5.5.7.1.4 Natural Circulation

The natural circulation capabilities of the Virgil C. Summer Nuclear Station are compared with three and four loop test results in Section 5.5.7.1.1, Item 5.

5.5.7.2 System Description

The RHRS, as shown in Figure 5.5-4, consists of two residual heat exchangers, two residual heat removal pumps, and the associated piping, valves, and instrumentation necessary for operational control. The inlet lines to the RHRS are connected to the hot legs of two reactor coolant loops, while the return lines are connected to each of the cold legs and to two hot legs of the reactor coolant loops. These return lines are also the ECCS low head cold leg injection/recirculation lines and the hot leg recirculation lines (see Figure 6.3-1).

The RHRS suction lines are isolated from the RCS by two motor operated valves in series and a relief valve, all located inside the reactor building. Each discharge line is isolated from the RCS by two check valves located inside the reactor building and by a motor operated valve located outside the reactor building. (The check valves and the motor operated valve on each discharge line are not shown as part of the RHRS; these valves are shown as part of the ECCS, see Figure 6.3-1.)

During RHRS operation, reactor coolant flows from the RCS to the residual heat removal pumps, through the tube side of the residual heat exchangers, and back to the RCS. The heat is transferred to the component cooling water circulating through the shell side of the residual heat exchangers.

Coincident with operation of the RHRS, a portion of the reactor coolant flow may be diverted from downstream of the residual heat exchangers to the CVCS low pressure letdown line for cleanup and/or pressure control. By regulating the diverted flowrate and the charging flow, the RCS pressure may be controlled. Pressure regulation is necessary to maintain the pressure range

dictated by the fracture prevention criteria requirements of the reactor vessel and net positive suction head requirements of the reactor coolant pumps.

The RCS cooldown rate is manually controlled by regulating the reactor coolant flow through the tube side of the residual heat exchangers. A line containing a flow control valve bypasses each residual heat exchanger and is used to maintain a constant return flow to the RCS. Instrumentation is provided to monitor system pressure, temperature, and total flow.

The RHRS is also used for filling the refueling cavity before refueling. After refueling operations, water is pumped back to the refueling water storage tank until the water level is brought down to the flange of the reactor vessel. The remainder of the water is removed via a drain connection at the bottom of the refueling cavity.

When the RHRS is in operation, the water chemistry is the same as that of the reactor coolant. Provision is made for the process sampling system to extract samples from the flow of reactor coolant downstream of the residual heat exchangers. A local sampling point is also provided on each residual heat removal train between the pump and heat exchanger.

The RHRS functions in conjunction with the high head portion of the ECCS to provide injection of borated water from the refueling water storage tank into the RCS cold legs during the injection phase following a loss of coolant accident.

In its capacity as the low head portion of the ECCS, the RHRS provides long term recirculation capability for core cooling following the injection phase of the loss of coolant accident. This function is accomplished by aligning the RHRS to take fluid from the reactor building sump, cool it by circulation through the residual heat exchangers, and supply it to the core directly as well as via the centrifugal charging pumps.

The use of the RHRS as part of the ECCS is more completely described in Section 6.3.

5.5.7.2.1 Component Description

The materials used to fabricate RHRS components are in accordance with the applicable code requirements. All parts of components in contact with borated water are fabricated or clad with austenitic stainless steel or equivalent corrosion resistant material.

Portions of the system that are designed to carry ECCS fluid outside containment during the recirculation phase of ECCS operation are designed to minimize leakage to the atmosphere as described in Section 6.3.2.11.3.

Component codes and classifications are given in Section 3.2 and component parameters are listed in Table 5.5-8.

5.5.7.2.1.1 Residual Heat Removal Pumps

Two pumps are installed in the RHRS. The pumps are sized to deliver reactor coolant flow through the residual heat exchangers to meet the plant cooldown requirements. The use of two separate residual heat removal trains assures that cooling capacity is adequately maintained should one pump become inoperative.

The residual heat removal pumps are protected from overheating and loss of suction flow by minimum flow bypass lines that assure flow to the pump suction. A valve located in each minimum flow line is regulated by a signal from the flow switch located in each heat exchanger discharge header. The control valves open when RHR discharge flow to the RCS reaches the minimum flow setpoint, which is set to prevent RHR pump flow from approaching the minimum design flow of 500 gpm. The control valves close when flow reaches the close setpoint at nearly the maximum range of the flow switch, or approximately 1500 gpm.

A pressure sensor in each pump discharge header provides a signal for an indicator in the control room. A high pressure alarm is also actuated by the pressure sensor. The two pumps are vertical, centrifugal units with mechanical seals on the shafts. All pump surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

5.5.7.2.1.2 Residual Heat Exchangers

Two residual heat exchangers are installed in the system. The heat exchanger design is based on heat load and temperature differences between reactor coolant and component cooling water existing at 20 hours after reactor shutdown from an extended full power run at 2775 MWt when the temperature difference between the two systems is small. For the current licensed RTP of 2900 MWt, the corresponding decay heat level occurs at 24 hours after reactor shutdown.

The installation of two heat exchangers in separate and independent residual heat removal trains assures that the heat removal capacity of the system is adequately maintained if one train becomes inoperative.

The residual heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell. The tubes are welded to the tubesheet to prevent leakage of reactor coolant.

5.5.7.2.1.3 Residual Heat Removal System Valves

Valves that perform a modulating function are equipped with two sets of packings and an intermediate leakoff connection that discharges to the drain header.

Manual and motor operated valves have backseats to facilitate repacking and to limit stem leakage when the valves are open. Leakage connections are provided where required by valve size and fluid conditions.

5.5.7.2.2 System Operation

5.5.7.2.2.1 Reactor Startup

Generally, while at cold shutdown condition, decay heat from the reactor core is being removed by the RHRS. The number of pumps and heat exchangers in service depends upon the heat load at the time.

At initiation of the plant startup, the RCS is completely filled, and the pressurizer heaters are energized. The RHRS is operating and is connected to the CVCS via the low pressure letdown line to control reactor coolant pressure. During this time, the RHRS acts as an alternate letdown path. The manual valves downstream of the residual heat exchangers leading to the letdown line of the CVCS are opened. The control valve in the line from the RHRS to the letdown line of the CVCS is then manually adjusted in the control room to permit letdown flow. Failure of any of the valves in the line from the RHRS to the CVCS has no safety implications, either during startup or cooldown.

After the reactor coolant pumps are started, the residual heat removal pumps are stopped but pressure control via the RHRS and the low pressure letdown line is continued until the pressurizer steam bubble is formed. Indication of steam bubble formation is provided in the control room by the damping out of the RCS pressure fluctuations, and by pressurizer level indication. The RHRS is then isolated from the RCS and the system pressure is controlled by normal letdown and the pressurizer spray and pressurizer heaters.

5.5.7.2.2.2 Power Generation and Hot Standby Operation

During power generation and hot standby operation, the RHRS is not in service but is aligned for operation as part of the ECCS.

5.5.7.2.2.3 Reactor Cooldown

Reactor cooldown is defined as the operation which brings the reactor from no-load temperature and pressure to cold shutdown conditions.

The initial phase of reactor cooldown is accomplished by transferring heat from the RCS to the steam and power conversion system through the use of the steam generators.

When the reactor coolant temperature and pressure are reduced to approximately 350°F and less than 425 psig, approximately 4 hours after reactor shutdown, the second phase of cooldown starts with the RHRS being placed in operation. It should be noted that given the decay heat models and the RCP heat assumed, the RHRS system, under worst case design conditions, cannot begin to cooldown the RCS until approximately 6 hours after an extended full power run at the current licensed RTP of 2900 MWt (although it can be placed into service in parallel with the steam dump system at approximately 4 hours after reactor shutdown). Plant procedures do verify that heat removal occurs via RHRS before fully transferring from the steam dump system.

Startup of the RHRS includes a warmup period during which time reactor coolant flow through the heat exchangers is limited to minimize thermal shock. The rate of heat removal from the reactor coolant is manually controlled by regulating the coolant flow through the residual heat exchangers. By adjusting the control valves downstream of the residual heat exchangers the mixed mean temperature of the return flows is controlled. Coincident with the manual adjustment, each heat exchanger bypass valve is regulated to give the required total flow.

The reactor cooldown rate is limited by RCS equipment cooling rates based on allowable stress limits, as well as the operating temperature limits of the CCWS. As the reactor coolant temperature decreases, the reactor coolant flow through the residual heat exchangers is increased by adjusting the control valve in each heat exchanger's tube side outlet line.

Assuming that only one heat exchanger and pump are in service and that the heat exchanger is supplied with component cooling water at design flow and at a temperature not exceeding 120°F, the coupled RHRS/CCWS/SWS system is capable of reducing the RCS temperature from 350°F at 6 hours after shutdown from an extended full power run at the current licensed RTP of 2900 MWt to 200°F within 30 hours from the beginning of the cooldown. The RHRS heat load during the transient includes the heat from one RCP, core decay heat, and the sensible heat of the RCS metal and fluid.

As cooldown continues, the pressurizer is filled with water and the RCS is operated in the water solid condition.

At this stage, pressure control is accomplished by regulating the charging flowrate and the rate of letdown from the RHRS to the CVCS.

After the reactor coolant pressure is reduced and the temperature is 140°F or lower, the RCS may be opened for refueling or maintenance once the remaining shutdown operations are considered complete.

5.5.7.2.2.4 Refueling

Both residual heat removal pumps are utilized during refueling to pump borated water from the refueling water storage tank to the refueling cavity. During this operation, the isolation valves in the inlet lines of the RHRS are closed, and the isolation valves from the refueling water storage tank are opened.

Station operating procedures include instructions for draining the RCS for vessel head removal prior to refueling operations. The instruction includes the installation of clear hose between one of the RCS loop drains and the pressurizer relief line vent to provide level indication after the pressurizer level indication is off scale. The procedure also states that after the RCS level has reached 4 to 12 inches below the reactor vessel flange, draining operations are secured. These actions ensure that air will not be introduced into the RHRS via the RCS during refueling operations.

The reactor vessel head is lifted. The refueling water is then pumped into the reactor vessel through the normal RHRS return lines and into the refueling cavity through the open reactor vessel. After the water level reaches the normal refueling level, the refueling water storage tank supply valves are closed, the inlet isolation valves are opened, and residual heat removal is resumed.

During refueling, the RHRS is maintained in service with the number of pumps and heat exchangers in operation as required by the heat load.

Following refueling, the residual heat removal pumps are used to drain the refueling cavity to the top of the reactor vessel flange by pumping water from the RCS to the refueling water storage tank.

5.5.7.3 Design Evaluation

5.5.7.3.1 System Availability and Reliability

General Design Criterion 34 requires that a system to remove residual heat be provided. The safety function of this system is to transfer fission product decay heat and other residual heat from the core at a rate sufficient to prevent fuel or pressure boundary design limits from being exceeded. Safety grade systems are provided in the plant design to perform this safety function. The NSSS safety grade systems which perform this function, for all plant conditions except a LOCA, are: the RCS and steam generators, which operate in conjunction with the Emergency Feedwater System, and the steam generator safety valves; and the RHRS which operates in conjunction with the reactor plant CCWS and the Service Water System. The BOP safety grade systems which perform this function, for all plant conditions except LOCA, are: the Emergency Feedwater System, the steam generator safety valves, which operate in conjunction with the RCS and the steam generators; and the reactor plant CCWS and Service Water Systems, which operate in conjunction with the RHRS. For LOCA conditions, the safety grade system which performs the function of removing residual heat from the reactor core is the ECCS, which operates in conjunction with the reactor plant CCWS and the Service Water System.

The Emergency Feedwater System, along with the steam generator safety valves, provides a completely separate, independent, and diverse means of performing the safety function of removing residual heat, which is normally performed by the RHRS when RCS temperature is less than 350°F. The Emergency Feedwater System is capable of performing this function for an extended period of time following plant shutdown.

The RHRS is provided with two residual heat removal pumps and two residual heat removal heat exchangers arranged in two separate, independent flow paths. To assure reliability, each residual heat removal pump is connected to a different vital bus. Each residual heat removal train is isolated from the RCS on the suction side by two motor operated valves in series. Each motor operated valve receives power via a separate motor control center and the two valves in series in each train receive their power from a different vital bus. Each suction isolation valve is also independently and diversely interlocked to one of two RCS wide range pressure instruments to prevent opening the valves when the RCS pressure is above 425 psig. Independence is

accomplished by aligning each RCS wide range pressure transmitter to a different vital bus. Diversity is accomplished through the use of two RCS wide range pressure instruments which employ different pressure sensing principles. Also, at strategically identified local high points, the RHRS is provided with indicating air-traps to ensure the RHRS remains void free (reference NRC GL 2008-01).

RHRS operation for normal conditions is accomplished from the control room. The redundancy in the RHRS design provides the system with the capability to maintain its cooling function even with major single failures, such as failure of an RHR pump, valve, or heat exchanger since the redundant train can be used for continued heat removal. See Table 5.5-15 for a single active failure analysis of the RHRS.

Although such major system failures are within the system design basis, there are other less significant failures which can prevent opening of the RHR suction isolation valves from the control room. Since these failures are of a minor nature, improbable to occur, and easily corrected outside the control room, with ample time to do so, they have been realistically excluded from the engineering design basis. Such failures are not likely to occur during the limited time period in which they can have any effect (i.e., when opening the suction isolation valves to initiate RHR operation); however, even if they should occur, they have no adverse safety impact and can be readily corrected. In such a situation, the Emergency Feedwater System and steam generator safety valves can be used to perform the safety function of removing residual heat and can be used to continue the plant cooldown below 350°F, until the RHRS is made available.

One failure which can prevent opening the RHR suction isolation valves from the control room is a failure of an electrical power train. Such a failure is extremely unlikely to occur during the few minutes per year operating time, during which it can have any consequence. If such an unlikely event should occur, several alternatives are available. The most realistic approach would be to obtain restoration of offsite power, which can be expected to occur in less than 1/2 hour. Other alternatives are to restore the emergency diesel generator to operation, to bring in an alternate power source, or to open the affected valves with their manual handwheels.

The only impact of either of the above types of failure is some delay in initiating RHR operation, while action is taken to open the RHR suction isolation valves. This delay has no adverse safety impact because of the capability of the Emergency Feedwater System and steam generator safety relief valves to continue to remove residual heat.

The safe shutdown design basis of the Virgil C. Summer Nuclear Station is hot standby, as it is for all other Westinghouse designed pressurized water reactors. Hot standby is a safe and stable plant condition which can be maintained for an extended period of time following any Condition II, III, or IV event. In the hot standby condition, residual heat removal, in compliance with GDC 34, is provided by the Emergency Feedwater System in conjunction with the steam generator safety valves. Cross connections from the Service Water System to the Emergency Feedwater System provide a long term (i.e., greater than 7 days) source of emergency feedwater.

In view of the above described capability, the RHRS is not required to fully comply with the single failure requirement of GDC 34. For most major single failures, the RHRS does fully

comply with the single failure criterion. The only situation where full compliance is not provided is for opening the RHR suction isolation valves (to initiate RHR cooling) in the event of the failure of one of the safeguards power trains. In the event of such a failure, sufficient time is available to either compensate for the single failure by manual actions inside (i.e., by opening a suction valve with its manual handwheel) or outside (by providing an alternate temporary power supply to a suction valve) the containment or to restore the failed safeguards power train to operation.

See Section 5.5.7.1.1 for compliance with BTP RSB 5-1.

The maximum cooldown rate which can result if both RHR flow control valves and both RHR bypass valves all simultaneously fail in such a manner as to permit maximum flow through the RHR heat exchangers (a low probability event considering the few hours a year when it could cause any effect) depends on several factors including the RHR flow rate, the CCWS flow rates and temperatures, and other heat loads on the CCWS. One of the key factors is the RCS temperature since the heat removal rate depends on the temperature differential between the RHR (RCS) flow and the component cooling water flow in the RHR heat exchanger. Typically, it is impossible to maintain a cooldown rate even as high as the design rate of 50°F/hr when the RCS temperature is less than 250°F, even with the maximum flow through the RHR heat exchangers.

Even if maximum flow through the RHR heat exchangers was experienced at the instant of initiating RHR operation and no operator action was taken, it is unlikely that the cooldown would exceed 100°F in the first hour. The cooldown rate in the subsequent hours would be much less than 100°F/hr. The maximum possible cooldown rate from 350°F to 250°F would not exceed 200°F/hr. Calculations have been done which show that, from a stress standpoint, a cooldown rate greater than 200°F/hr is acceptable for such a hypothetical cooldown from 350°F to 250°F even though, as discussed above, the actual maximum rate of cooldown at or below 250°F is not expected to exceed 50°F/hr.

Although such a hypothetical cooldown event is acceptable assuming no operator action, it should be noted that the operator can significantly limit the maximum possible cooldown rate by merely stopping one of the RHR pumps.

5.5.7.3.2 Leakage Provisions and Activity Release

In the event of a loss of coolant accident or during normal recirculation mode, radioactive fluid may be recirculated through part of the RHRS exterior to the reactor building. If the residual heat removal pump seal should fail, the water would spill out on a floor in a shielded compartment. Each residual heat removal pump compartment contains a sump which is equipped with an alarm system set to indicate leakage of greater than 45 gpm. The alarm system is annunciated in the control room so the operator can determine the location of the leak. Redundant sump pumps are capable of handling leakage flows up to 50 gpm each. In the case of failure of both sump pumps, each residual heat removal pump room has a water tight volume of at least 200 ft^3 to accommodate a 50 gpm leak for at least 30 minutes. This provides protection against pump flooding in the event of a 50 gpm leak. Any leakage, whether handled by the residual heat removal pump room sumps or the Auxiliary Building sump pumps, is directed to holdup tanks in

the liquid waste processing system. Residual heat removal piping and pumps in each cubicle can be remotely isolated by motor operated valves so they can be drained and flushed prior to being repaired.

The maximum discharge rate from a moderate energy pipe crack in the RHRS is approximately 714 gpm.

Since such a leak rate would have no effect on core cooling until it resulted in emptying the RCS loops, the time available to the operator to take action is at least 73 minutes.

The operator would be alerted to the leak by decreasing pressurizer level and the pressurizer low level alarm. Depending on the location of the crack, the operator could also be alerted by RHR pump compartment sump level alarms. The only action necessary to recover from the event is to close the suction isolation valve(s) of the affected RHR train and to initiate cooling on the other RHR train, if it is not already operating. Depending on the amount of water lost before isolating the leak, the operator may be required to makeup to the RCS.

5.5.7.3.3 Overpressurization Protection

Each inlet line to the RHRS is equipped with a pressure relief valve which protects the system from inadvertent overpressurization during plant cooldown or startup. Each valve has a relief flow capacity of 900 gpm at a set pressure of 450 psig. Analyses have been conducted to confirm the capability of the RHRS relief valve to prevent overpressurization of the RHRS. All credible events were examined for their potential to overpressurize the RHRS. These events included normal operating conditions, infrequent transients, and abnormal occurrences. The analyses confirmed that one relief valve has the capability to keep the RHRS maximum pressure within 10 CFR 50 Appendix G limits.

Each discharge line from the RHRS to the RCS is equipped with a pressure relief valve to relieve the maximum possible back-leakage through the valves separating the RHRS from the RCS. Each valve has a relief flow capacity of 20 gpm at a set pressure of 600 psig. These relief valves are located in the ECCS (see Figure 6.3-1).

The fluid discharged by the suction side relief valves is collected in the pressurizer relief tank. The fluid discharged by the discharge side relief valves is collected in the recycle holdup tanks of the boron recycle system.

5.5.7.3.4 Prevention of Exposure of the RHRS to Normal RCS Operating Pressure

The design of the RHRS includes two motor operated gate isolation valves in series on each inlet line between the high pressure RCS and the lower pressure RHRS. They are closed during normal operation and are only opened for residual heat removal and RCS cold overpressure protection during a plant cooldown after the RCS pressure is reduced to less than 425 psig and the RCS temperature is reduced to approximately 350°F. During a plant startup, the inlet isolation valves are shut after drawing a bubble in the pressurizer and prior to increasing RCS pressure above 425 psig. Power to the isolation valves is manually locked out during normal operation.

The two inlet isolation valves in each residual heat removal subsystem are independently and diversely interlocked with pressure signals to prevent their being opened whenever the RCS pressure is greater than approximately 425 psig. The autoclosure interlock of these valves has been removed as per WCAP-11835. An alarm has been added to alert the operator if the valves are not closed when the RCS pressure increases above the alarm setpoint of 520 psig.

The use of two independently powered motor operated valves in each of the twp inlet lines, along with an independent and diverse pressure interlock to prevent them from being opened, and a RCS pressure high with RHR suction valves not closed alarm assures a design which meets applicable single failure criteria. Not only more than one single failure, but also different failure mechanisms, must be postulated to defeat the function of preventing possible exposure of the RHR system to normal RCS operating pressure. This protective interlock design, in combination with alarm, administrative controls, and plant operating procedures, provides the means for accomplishing the protective function. For further information on the instrumentation and control features, see Section 7.6.2.

The RHR inlet isolation valves are provided with red-green position indicator lights on the main control board and a ESF monitor light for proper valve position. ESF monitor light is independent and diverse from valve position indication.

Isolation of the low pressure RHRS from the high pressure RCS is provided on the discharge side by two check valves in series. These check valves are located in the ECCS and their testing is described in Section 5.2.2.4.

5.5.7.3.5 Shared Function

The safety function performed by the RHRS is not compromised by its normal function which is normal plant cooldown. The valves associated with the RHRS are normally aligned to allow immediate use of this system in its engineered safety features mode of operation. The system has been designed in such a manner that two redundant flow circuits are available, assuring the availability of at least one train for safety purposes.

The normal plant cooldown function of the RHRS is accomplished through a suction line arrangement which is independent of any safety function. The cold leg cooldown return lines are arranged in parallel redundant circuits and are utilized also as the low head injection lines to the RCS. Utilization of the same return circuits for cold leg cool down lends assurance to the proper functioning of these lines for engineered safety features purposes.

5.5.7.3.6 Radiological Consideration

The highest radiation levels experienced by the RHRS are those which would result from a loss of coolant accident. Following a loss of coolant accident, the RHRS is used as part of the ECCS. During the recirculation phase of emergency core cooling, the RHRS is designed to operate for up to a year pumping water from the reactor building sump, cooling it, and returning it to the reactor building to cool the core.

Since, except for some valves and piping, the RHRS is located outside the reactor building, most of the system is not subjected to the high levels of radioactivity in the reactor building post accident environment.

The operation of the RHRS does not involve a radiation hazard for the operators since the system is controlled remotely from the control room. If maintenance of the system is necessary, the portion of the system requiring maintenance is isolated by remotely operated valves and/or manual valves with stem extensions which allow operation of the valves from a shielded location. The isolated piping is drained and flushed before maintenance is performed.

5.5.7.4 Tests and Inspections

Periodic visual inspections and preventive maintenance are conducted during plant operation according to normal industrial practice.

The instrumentation channels for the residual heat removal pump flow instrumentation devices are calibrated during each refueling operation if a check indicates that recalibration is necessary.

Due to the role the RHRS has in sharing components with the ECCS, the residual heat removal pumps are tested as a part of the ECCS testing program (see Section 6.3.4). Preoperational testing is discussed in Chapter 14.

5.5.8 Reactor Coolant Cleanup System

The CVCS provides reactor coolant cleanup and is discussed in Section 9.3.4. The radiological considerations are discussed in Chapter 11.

5.5.9 Main Steam Line and Feedwater Piping

Main steam line and feedwater piping are discussed in Sections 10.3 and 10.4.7, respectively.

5.5.10 Pressurizer

5.5.10.1 Design Bases

The general configuration of the pressurizer is shown in Figure 5.5-6. The design data of the pressurizer are given in Table 5.5-9. Codes and material requirements are provided in Section 5.2.

The pressurizer provides a point in the RCS where liquid and vapor can be maintained in equilibrium under saturated conditions for pressure and control purposes.

Stress analysis of the pressurizer components was performed at the plant conditions associated with steam generator replacement. While a slight increase in the fatigue usage for several of the pressurizer components was noted, the acceptance limits of Section III of the ASME Code were not exceeded. Therefore, the pressurizer components will not be overstressed or subject to fatigue usage during the remainder of the projected plant lifetime.

5.5.10.1.1 Pressurizer Surge Line

The surge line is sized to limit the pressure drop between the RCS and the safety valves with maximum allowable discharge flow from the safety valves. Overpressure of the RCS does not exceed 110% of the design pressure.

The surge line and thermal sleeve at the pressurizer end are designed to withstand the thermal stresses resulting from volume surges of relatively hotter or colder water which may occur during operation.

The pressurizer surge line nozzle diameter is given in Table 5.5-9 and the pressurizer surge line dimensions are shown in Figure 5.1-1, Sheet 2.

5.5.10.1.2 Pressurizer

The volume of the pressurizer is equal to or greater than the minimum volume of steam, water, or total of the two which satisfies the following requirements:

1. The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.
2. The water volume is sufficient to prevent the heaters from being uncovered during a 10% step load increase to full power.
3. The steam volume is large enough to accommodate the surge resulting from 50% reduction of full load with automatic reactor control and 40% steam dump without the water level reaching the high level reactor trip point.
4. The steam volume is large enough to prevent water relief through the safety valves following a loss of load with the high water level initiating a reactor trip, without reactor control or steam dump.
5. The pressurizer will not empty following reactor trip and turbine trip.
6. The emergency core cooling signal is not activated during reactor trip and turbine trip.

5.5.10.2 Design Description

5.5.10.2.1 Pressurizer Surge Line

The pressurizer surge line connects the pressurizer to one reactor hot leg. The line enables continuous coolant volume pressure adjustments between the RCS and the pressurizer.

5.5.10.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all surfaces exposed to the reactor coolant. A stainless steel liner or tube is used in lieu of cladding in some nozzles.

The high strength welds joining the component parts of the pressurizer are the four girth welds joining the upper head, three shell barrels, and the lower head, and the three longitudinal welds joining the three sections of the shell barrels. The various weld and flux combinations used in these welds are listed in Table 5.5-18 along with the appropriate fracture toughness test information.

The surge line nozzle and removable electric heaters are installed in the bottom head. The heaters are removable for maintenance or replacement. A thermal sleeve is provided to minimize stresses in the surge line nozzle. A screen at the surge line nozzle and baffles in the lower section of the pressurizer prevent an insurge of cold water from flowing directly to the steam/water interface and assist mixing.

Spray line nozzles, relief, and safety valve connections are located in the top head of the vessel. Spray flow is modulated by automatically controlled air operated valves. The spray valves can also be operated manually in the control room.

A small continuous spray flow is provided through a manual bypass valve around the power operated spray valves to assure that the pressurizer liquid is homogeneous with the coolant and to prevent excessive cooling of the spray piping.

During an outsurge from the pressurizer, flashing of water to steam, and generating of steam by automatic actuation of the heaters, keep the pressure above the minimum allowable limit. During an insurge from the RCS, the spray system, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the power operated relief valves for normal design transients. Heaters are energized on high water level during insurge to heat the subcooled surge water that enters the pressurizer from the reactor coolant loop.

SA533 Grade A Class 2 material was used in the Virgil C. Summer pressurizer. (SA533 Grade A Class 2 material was not used in primary side (RCPB) pressure retaining applications of the Virgil C. Summer steam generators.) The actual fracture toughness data for the SA533 Grade A Class 2 material in the pressurizer are tabulated in Table 5.5-17.

Material specifications are provided in Table 5.2-8 for the pressurizer, pressurizer relief tank, and the surge line. Design transients for the components of the RCS are discussed in Section 5.2.1.5. Additional details on the pressurizer design cycle analysis are given in Section 5.5.10.3.5.

The pressurizer nozzle weld overlays as noted in Section 5.5.3.3.4 identified that the overlay weld filler material used was alloy 52M. This high chromium weld filler metal is compatible with the carbon steel, stainless steel, and existing Inconel materials in the underlying components. This weld metal was applied utilizing a temperbead method to eliminate the need for pre and post weld heat treatment.

5.5.10.2.2.1 Pressurizer Support

The skirt type support is attached to the lower head and extends for a full 360 degrees around the vessel. The lower part of the skirt terminates in a bolting flange with bolt holes for securing the

vessel to its foundation. The skirt type support is provided with ventilation holes around its upper perimeter to assure free convection of ambient air past the heater plus connector ends for cooling.

5.5.10.2.2.2 Pressurizer Instrumentation

Refer to Chapter 7 and Section 5.6 for details of the instrumentation associated with pressurizer pressure, level, and temperature.

5.5.10.2.2.3 Spray Line Temperatures

Temperatures in the spray lines from two loops are measured and indicated. Alarms from these signals are actuated by low spray water temperature. Alarm conditions indicate insufficient flow in the spray lines.

5.5.10.2.2.4 Safety and Relief Valve Leakage Monitoring

Monitoring of the status of the pressurizer safety and relief valves is by the following methods:

a. Temperature detectors in the piping downstream of the valves. (An increase in discharge line temperature is an indication of leakage through the valve.)
b. Acoustical type monitors to detect safety valve leakage.
c. Pressure/temperature/level of the pressurizer relief tank.
d. Valve limit switches on the pressurizer power operated relief valves which indicate valve open/closed position.

All four methods for detecting leakage through the pressurizer safety and relief valves are monitored in the control room.

5.5.10.3 Design Evaluation

5.5.10.3.1 System Pressure

Whenever a steam bubble is present within the pressurizer, RCS pressure is maintained by the pressurizer. A safety limit has been set to ensure that the RCS pressure does not exceed the maximum transient value allowed under the ASME Code, Section III, and thereby assure continued integrity of the RCS components.

Evaluation of plant conditions of operation which follow indicates that this safety limit is not reached.

During startup and shutdown, the rate of temperature change is controlled by the operator. Heatup rate is controlled by pump energy and by the pressurizer electrical heating capacity. This heatup rate takes into account the continuous spray flow provided to the pressurizer. When the reactor core is shutdown, the heaters are de-energized.

When the pressurizer is filled with water (i.e., during initial system heatup) and near the end of the second phase of plant cooldown, RCS pressure is maintained by the letdown flowrate via the RHRS.

5.5.10.3.2 Pressurizer Performance

The normal operating water volume at full load conditions is 60% of the free internal vessel volume. Under part load conditions, the water volume in the vessel is reduced for proportional reductions in plant load to 25% of free vessel volume at zero power level. The various plant operating transients are analyzed and the design pressure is not exceeded with the pressurizer design parameters as given in Table 5.5-9.

5.5.10.3.3 Pressure Setpoints

The RCS design and operating pressure together with the safety, power relief and pressurizer spray valves setpoints, and the protection system setpoint pressures are listed in Table 5.2-7. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

5.5.10.3.4 Pressurizer Spray

Two separate, automatically controlled spray valves with remote manual overrides are used to initiate pressurizer spray. In parallel with each spray valve is a manual throttle valve which permits a small continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open and to help maintain uniform water chemistry and temperature in the pressurizer. Temperature sensors with low alarms are provided in each spray line to alert the operator to insufficient bypass flow. The layout of the common spray line piping to the pressurizer forms a water seal which prevents the steam buildup back to the control valves. The spray rate is selected to prevent the pressurizer pressure from reaching the operating setpoint of the power relief valves during a step reduction in power level of 10% of full load.

The pressurizer spray lines and valves are large enough to provide adequate spray using as the driving force the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force. The spray valves and spray line connections are arranged so that the spray will operate when one reactor coolant pump is not operating. The line may also be used to assist in equalizing the boron concentration between the reactor coolant loops and the pressurizer.

A flow path from the CVCS to the pressurizer spray line is also provided. This additional facility provides auxiliary spray to the vapor space of the pressurizer during cooldown if the reactor coolant pumps are not operating. The thermal sleeves on the pressurizer spray connection and the spray piping are designed to withstand the thermal stresses resulting from the introduction of cold spray water.

5.5.10.3.5 Pressurizer Design Analysis

The occurrences for pressurizer design cycle analysis are defined as follows:

1. The temperature in the pressurizer vessel is always, for design purposes, assumed to equal saturation temperature for the existing RCS pressure, except in the pressurizer steam space subsequent to a pressure increase. In this case, the temperature of the steam space will exceed the saturation temperature since an isentropic compression of the steam is assumed.

   The only exception of the above occurs when the pressurizer is filled solid during plant startup and cooldown.

2. The temperature shock on the spray nozzle is assumed to equal the temperature of the nozzle minus the cold leg temperature. The temperature shock on the surge nozzle is assumed to equal the pressurizer water space temperature minus the hot leg temperature.
3. Pressurizer spray is assumed to be initiated instantaneously to its design value as soon as the RCS pressure increases 40 psi above the nominal operating pressure. Spray is assumed to be terminated as soon as the RCS pressure falls 40 psi below normal operating pressure.
4. Unless otherwise noted, pressurizer spray is assumed to be initiated once per occurrence of each transient condition. The pressurizer surge nozzle is also assumed to be subject to one temperature transient per transient condition, unless otherwise noted.
5. At the end of each transient, except the faulted conditions, the RCS is assumed to return to a load condition consistent with the plant heatup transient.
6. Temperature changes occurring as a result of pressurizer spray are assumed to be instantaneous. Temperature changes occurring on the surge nozzle are also assumed to be instantaneous.
7. Whenever spray is initiated in the pressurizer, the pressurizer water level is assumed to be at the no load level.

5.5.10.4 Tests and Inspections

The pressurizer is designed and constructed in accordance with the ASME Code, Section III.

To implement the requirements of the ASME Code, Section XI, the following welds are designed and constructed to present a smooth transition surface between the parent metal and the weld metal. The path is ground smooth for ultrasonic inspection.

1. Support skirt to the pressurizer lower head.
2. Surge nozzle to the lower head.
3. Nozzles to the safety, relief, and spray lines.
4. Nozzle to safe end attachment welds.

5. All girth and longitudinal full penetration welds.
6. Manway attachment welds.

The liner within the safe end nozzle region extends beyond the weld region to maintain a uniform geometry for ultrasonic inspection.

The pressurizer nozzles for the surge, spray, safety, and relief lines had full structural weld overlays applied during Refuel 17. These weld overlays were designed to ensure that a smooth surface was applied such that the ultrasonic inspection volumetric requirements are maintained. The result of the weld overlays resulted in 100% ultrasonic inspection volumetric coverage of the respective nozzles and underlying welds and components. A Performance Demonstration Initiative (PDI) linear phased array inspection technique was used to perform the post weld overlay inspections.

Peripheral support rings are furnished for the removable insulation modules.

The pressurizer quality assurance program is given in Table 5.5-10.

5.5.11 Pressurizer Relief Tank

5.5.11.1 Design Bases

Design data for the pressurizer relief tank are given in Table 5.5-11. Codes and materials of the tank are given in Section 5.2.

The tank design is based on the requirement to absorb a discharge of pressurizer steam equal to 110% of the volume above the full power pressurizer water level setpoint. The tank is not designed to accept a continuous discharge from the pressurizer.

The volume of water in the tank is capable of absorbing the heat from the assumed discharge, assuming an initial temperature of 120°F and increasing to a final temperature of 200°F. If the temperature in the tank rises above 120°F during plant operation, the tank is cooled by spraying in cool water and draining out the warm mixture to the waste processing system.

5.5.11.2 Design Description

The pressurizer relief tank condenses and cools the discharge from the pressurizer safety and relief valves. Discharge from smaller relief valves located inside the containment is also piped to the relief tank. In addition, in the event that the reactor vessel head vent system (RVHVS) is used, the pressurizer relief tank receives the discharge from the RCS. An itemized list identifying the discharges to the pressurizer relief tank is provided in Table 5.2-6. The tank normally contains water and a predominantly nitrogen atmosphere; however, provision is made to permit the gas in the tank to be periodically analyzed to monitor the concentration of hydrogen and/or oxygen.

By means of its connection to the waste processing system, the pressurizer relief tank provides a means for removing any noncondensable gases from the RCS which might collect in the pressurizer vessel.

Steam is discharged through a sparger pipe under the water level. This arrangement provides for condensing and cooling the steam by mixing it with water that is near ambient temperature. The tank is also equipped with an internal spray and a drain which are used to cool the tank following a discharge. A flanged nozzle is provided on the tank for the pressurizer discharge line connection to the sparger pipe.

5.5.11.2.1 Pressurizer Relief Tank Pressure

The pressurizer relief tank pressure transmitter provides an indication of pressure relief tank pressure. An alarm is provided to indicate high tank pressure.

5.5.11.2.2 Pressurizer Relief Tank Level

The pressurizer relief tank level transmitter supplies a signal for an indicator with high and low level alarms.

5.5.11.2.3 Pressurizer Relief Tank Water Temperature

The temperature of the water in the pressurizer relief tank is indicated, and an alarm actuated by high temperature informs the operator that cooling to the tank contents is required.

5.5.11.3 Design Evaluation

The volume of water in the tank is capable of absorbing a discharge of 110% of the pressurizer steam volume above the full power water level setpoint. Water temperature in the tank is maintained at the nominal containment temperature.

The rupture disks on the relief tank have a relief capacity equal to or greater than the combined capacity of the pressurizer safety valves. The tank design pressure is twice the calculated pressure resulting from the maximum design safety valve discharge described above. The tank and rupture disc holders are also designed for full vacuum to prevent tank collapse if the contents cool following a discharge without nitrogen being added.

The discharge piping from the safety and relief valves to the relief tank is sufficiently large to prevent backpressure of the safety valves from exceeding 20% of the setpoint pressure at full flow.

5.5.12 Valves

5.5.12.1 Design Bases

As noted in Section 5.2, all valves out to and including the second valve normally closed or capable of automatic or remote closure, larger than 3/4 inch, are Safety Class 1, and ASME III, Code Class 1 valves. All 3/4 inch or smaller valves in liquid filled lines connected to the RCS are Class 2 since the interface with the Class 1 piping is provided with suitable orificing for such valves. Pressurizer instrument root valves connected to the steam space above the normal water level have been upgraded to Safety Class 1 since failure of these valves could cause automatic operation of the ECCS systems. Design data for the RCS valves are given in Table 5.5-12.

To ensure that the valves meet the design objectives, the materials specified for construction must minimize corrosion/erosion and ensure compatibility with the environment. Leakage is minimized to the extent practicable by design and Class 1 stresses are maintained within the limits of the ASME Code, Section III and the limits specified in Section 5.5.1.

5.5.12.2 Design Description

Valves in the RCS which are in contact with the coolant are constructed primarily of stainless steel. Other materials in contact with the coolant, such as for hard surfacing and packing, are special materials.

Manual and motor operated valves of the RCS which are 3 inches and larger are provided with double-packed stuffing boxes and intermediate lantern ring leakoff connections. Throttling control valves, regardless of size, are provided with double-packed stuffing boxes and with stem leakoff connections. Leakoff connections on valves, normally operated in a radioactive fluid, are piped to a closed collection system. Leakage to the atmosphere is essentially zero for these valves.

Gate valves at the engineered safety features interface are wedge design and are essentially straight through. The wedges are flex-wedge or solid. All gate valves have backseats. Globe valves are "T" and "Y" style. Check valves are swing type for sizes 2-1/2 inches and larger. All check valves which contain radioactive fluid are stainless steel and do not have body penetrations other than the inlet, outlet, and bonnet. The check hinge is serviced through the bonnet.

The accumulator check valve is designed such that at the required flow the resulting pressure drop is within the specified limits. All operating parts are contained within the body. The disc has limited rotation to provide a change of seating surface and alignment after each valve opening.

5.5.12.3 Design Evaluation

The design/analysis requirements for Class 1 valves, as discussed in Section 5.2, limit stresses to levels which ensure the structural integrity of the valves. In addition, the testing programs described in Section 3.9.2.4 demonstrate the ability of the valves to operate as required during anticipated and postulated plant conditions.

Reactor coolant chemistry parameters are specified in the design specifications to assure the compatibility of valve construction materials with the reactor coolant.

5.5.12.4 Tests and Inspections

RCS valves are tested in accordance with the requirements of the ASME Code, Section III. The tests and inspections discussed in Section 3.9.2.4 are performed to ensure the operability of active valves. In-place operational testing is performed on valves as required by the Technical Specifications.

There are no full penetration welds within valve body walls. Valves are accessible for disassembly and internal visual inspection to the extent practical. Plant layout configurations determine the degree of inspectability. The valve quality assurance program is given in Table 5.5-13.

Inservice inspection is discussed in Section 5.2.8.

5.5.13 Safety and Relief Valves

5.5.13.1 Design Bases

The combined capacity of the pressurizer safety valves is designed to accommodate the maximum surge resulting from complete loss of load. This objective is met without reactor trip or any operator action by the opening of the steam safety valves when steam pressure reaches the steam side safety setting.

The pressurizer power operated relief valves are designed to limit pressurizer pressure to a value below the fixed high pressure reactor trip setpoint for most transients. Conservative analyses indicate that, for the 95% load rejection transient, the high pressure reactor trip setpoint would be reached. No credit is taken for automatic operation of these valves to mitigate the consequences of an accident. They are designed to fail to the closed position on loss of air supply.

5.5.13.2 Design Description

The pressurizer safety valves are totally enclosed pop type. The valves are spring loaded, self-actuated, and with backpressure compensation features.

The pipe connecting the pressurizer nozzles to their respective code safety valves are shaped in the form of a loop. The low point of the loops is drained continuously to the pressurizer liquid space to remove any condensation formed in the safety valve inlet pipes.

The pressurizer power operated relief valves are pneumatic actuated valves which respond to a signal from a pressure sensing system or to manual control. Remotely operated stop valves are provided to isolate the power operated relief valves if excessive leakage develops.

Pressurizer safety and relief valve leakage monitoring is discussed in Section 5.5.10.2.2.4. Refer to Section 5.2 for a discussion of discharge line supports.

Design parameters for the pressurizer spray control, safety, and power relief valves are given in Table 5.5-14.

5.5.13.3 Design Evaluation

The pressurizer safety valves prevent RCS pressure from exceeding 110% of system design pressure in compliance with the ASME Nuclear Power Plant Components Code.

The pressurizer power relief valves prevent actuation of the fixed reactor high pressure trip for all design transients except the design step load decreases with steam dump. For this event, peak pressure will exceed the trip setpoint but remains below the safety valve setpoint. The relief valves limit undesirable opening of the spring-loaded safety valves. Note that setpoint studies to date indicate that the pressure rise in a three-loop plant for the design step load decrease of 10% from full power is limited to 60 psi. These studies also indicate that the design step load decrease of 10% under N-1 loop operation is limited to approximately 50 psi. In both cases, the pressure rise is not sufficient to actuate the power operated relief valves and, thus, this design is conservative.

5.5.13.4 Tests and Inspections

All safety and relief valves are subjected to hydrostatic tests, seat leakage tests, operational tests, and inspections as required. For safety valves that are required to function during a faulted condition, additional tests are performed. These tests are described in Section 3.9.2.4.

There are no full penetration welds within the valve body walls. Valves are accessible for disassembly and internal visual inspection.

5.5.14 Component Supports

Component supports allow virtually unrestrained lateral thermal movement of the loops during plant operation and provide restraint to the loops and components during accident conditions. The loading combinations and design stress limits are discussed in Section 5.2.1.10. The design maintains the integrity of the RCS boundary for normal and accident conditions and satisfies the requirements of the piping code. Results of piping and supports stress evaluation will be presented in Section 5.2.1.10. The normal operating temperatures for the RCS supports are 50°F to 400°F.

5.5.14.1 Description

The support structures are of welded steel construction and are either linear type or plate and shell type. Vessel skirts and saddles are fabricated from plate and shell elements to accommodate a biaxial stress field. Linear supports are tension and compression struts, beams, and columns. Attachments are of integral and nonintegral types. Integral attachments are welded, cast, or forged to the pressure boundary component by lugs, shoes, rings, and skirts. Nonintegral attachments are bolted, pinned, or bear on the pressure boundary component.

The supports permit unrestrained thermal growth of the supported systems, but restrain vertical, lateral, and rotational movement resulting from seismic and pipe break loadings. This is accomplished using pin-ended columns for vertical support and girders, bumper pedestals, and tie rods for lateral support.

Shimming and grouting enable adjustment of all support elements during erection to achieve correct fit-up and alignment.

1. Vessel

   Supports for the reactor vessel (see Figure 5.5-7) are individual air cooled rectangular box structures beneath the vessel nozzles bolted to the primary shield wall concrete. Each box structure consists of a horizontal top plate that receives loads from the reactor vessel shoe, a horizontal bottom plate supported by and transferring loads to the primary shield wall concrete, and connecting vertical plates. The supports are air cooled to maintain the supporting concrete temperature within acceptable levels.

2. Steam Generator

   The lower supports for the steam generator (see Figure 5.5-8) consist of four vertical pin-ended columns bolted to the bottom of the steam generator support pads; and lateral support girders and pedestals that bear against horizontal bumper blocks bolted to the side of the generator support pads. The upper lateral steam generator support consists of a ring girder around the generator shell supported by struts. Loads are transferred from the equipment to the ring girder by means of a number of bumper blocks between the girder and generator shell.

3. Pump

   The reactor coolant pump supports (see Figure 5.5-9) consist of three pin-ended structural steel columns and three lateral tie bars. A large diameter bolt connects each column and tie rod to a pump support pad. The outer ends of all three tie rods have slotted pin holes to permit unrestrained lateral movement of the pump during plant heatup and cooldown but provide lateral restraint for accident loadings.

4. Pressurizer

   The pressurizer (see Figure 5.5-10) is supported at its base by bolting the flangering to the supporting concrete slab. In addition, upper lateral support is provided near the vessel center of gravity by four "V frames" or struts extending horizontally from the compartment walls and bearing against the vessel lugs.

5.5.14.2 Evaluation

Detailed evaluation ensures the design adequacy and structural integrity of the reactor coolant loop and the primary equipment supports system. This detailed evaluation is made by comparing

the analytical results with established criteria for acceptability. Structural analyses are performed to demonstrate design adequacy for safety and reliability of the plant in case of a large or small seismic disturbance and/or loss of coolant accident conditions. Loads that the system is designed to encounter, of 10 during its lifetime (thermal, weight, pressure, and operating basis earthquake [OBE]), are applied and stresses are compared to allowable values, as described in Section 5.2.1.10.

All RCS supports are designed for concurrent loadings from deadweight, pressure, postulated pipe ruptures in the RCS as identified in WCAP-8082 and WCAP-13206, and the SSE. As indicated in Section 3.6, postulated breaks in the reactor coolant loop piping, except for branch line connections, have been eliminated. Reactor coolant loop piping branch nozzle (i.e., accumulator connection, pressurizer surge line, residual heat removal, etc.) breaks are postulated. Additionally, steam line breaks, and safety and relief line breaks, are considered in the design of steam generator and pressurizer supports, respectively. Included under the considerations for pipe rupture loads are the effects of RCS hydraulic loads, jet impingement, thrust, and asymmetric pressures about the supported components.

The pipe rupture analysis which is performed for the reactor vessel support loads includes nonaxisymmetric pressure distributions on the internals.

A detailed dynamic model of the reactor vessel and internals includes the stiffnesses of the reactor vessel support and the attached piping. Hydraulic forces are developed in the internals for the postulated break; these forces are characterized by time dependent forcing functions on the vessel and core barrel. In the derivation of these forcing functions, the fluid-structure (or hydroelastic) interaction in the downcomer region between the barrel and the vessel is taken into account. As a result of the loop branch pipe breaks, loop mechanical loads are also applied to the vessel. The loads from these three sources, the internals reactions, reactor cavity pressure loads, and the loop mechanical forces, are applied simultaneously in a nonlinear elastic dynamic time history analysis on the model of the vessel, supports, and internals. The results of this analysis are the dynamic loads on the reactor vessel supports and vessel time history displacements. The maximum loads are combined with other applicable loads, such as seismic and deadweight, and applied statically to the vessel support structure.

Although considered in the design, it is expected on the basis of past experience that asymmetric pressure loadings on the major components will be negligible.

For public health and safety, the SSE and design basis loss of coolant accident, resulting in a rapid depressurization of the system, are required design conditions. For these loadings, the basic criteria ensure that the severity of the accident will not be increased, thus maintaining the system in a safe condition. The rupture of a reactor coolant loop pipe will not violate the integrity of the unbroken leg of the loop. To ensure the integrity and stability of the reactor coolant loop support system and a safe shutdown of the system under loss of coolant accident and the worst combined (Normal + SSE + LOCA) loadings, the stresses in the unbroken piping of a broken loop, the unbroken loop piping, and the supports system are analyzed. The results of design analysis are provided in Section 5.2.1.10.

5.5.14.3 Tests and Inspections

The design and fabrication are specified in accordance with the AISC Specifications for the "Design, Fabrication, and Erection of Structural Steel for Buildings," 1969 Edition and applicable portions of the ASME Boiler and Pressure Vessel Code. Welder qualifications, welding procedures, and inspection of welded joints are specified to be in accordance with Section IX of the ASME Code.

5.5.15 Reactor Vessel Head Vent System

5.5.15.1 Design Basis

The basic function of the RVHVS is to remove non-condensable gases or steam from the reactor vessel head. This system is designed to mitigate a possible condition of inadequate core cooling or impaired natural circulation resulting from the accumulation of noncondensable gases in the RCS. The design of the RVHVS is in accordance with the requirements of NUREG-0578 and subsequent definitions and clarifications (References 2 and 3).

5.5.15.2 Design Description and Evaluation

5.5.15.2.1 General Description

The RVHVS is designed to remove non-condensable gases or steam from the RCS via remote manual operations from the control room. The system discharges to the pressurizer relief tank. The RVHVS is designed to vent a volume of hydrogen, noncondensable gases, etc., at system design pressure and temperature approximately equivalent to 1/2 of the RCS volume in 1 hour.

An H_2 burn from a 100% zircaloy/H_2O reaction has been addressed and it has been determined that containment integrity would not be breached. Therefore, contained venting outside containment is not considered necessary.

The flow diagram of the RVHVS is shown in Figure 5.5-13. The RVHVS consists of two parallel flow paths with redundant isolation valves in each flow path. The venting operation uses only one of the flow paths at any time.

The physical layout of the RCS hot leg piping is such that its entire volume can be vented via the RVHVS.

The equipment design parameters are listed in Table 5.5-16.

As indicated above, normally the venting from the RVHVS is contained by the pressurizer relief tank. However, venting to containment could occur if the rupture disc ruptures. In that case, the location of the PRT is such that excellent gas communication exists within the secondary shield area that any gas that escapes from the PRT will be readily mixed with the containment atmosphere with additional mixing being promoted by the Reactor Building Ventilation System.

The active portion of the system consists of 4 two-inch motor operated isolation valves connected to the reactor vessel head vent pipe. The isolation valves in series in each flow path are powered by opposite vital power supplies. The isolation valves are fail as is, active valves. One normally closed isolation valve and one normally open valve are located in each flow path. Leakage past the vent valves during normal plant operation is detected by the pressurizer relief tank instrumentation. All of the isolation valves are qualified to IEEE - 323-1974, 344-1975, and 382-1972 and to the requirements of Regulatory Guide 1.48 as described in Appendix 3A.

If one single active failure prevents a venting operation through one flow path, the redundant path is available for venting. Similarly, the two isolation valves in each flow path provide a single failure method of isolating the venting system. With two valves in series, the failure of any one valve or power supply will not inadvertently open a vent path. Thus, the combination of safety grade train assignments and valve failure modes will not prevent vessel head venting nor venting isolation with any single active failure.

The RVHVS has two normally de-energized valves in series in each flow path. Power lockout capability to all four isolation valves is provided by administrative control at the motor control load center. This arrangement eliminates the possibility of a spuriously opened flow path.

The system is operated from the control room. The position indication from each valve is monitored in the control room by status lights. Position indication is unavailable in the control room when the motor control breaker is open.

The RVHVS is connected to the head vent pipe as shown on Figure 5.5-13. The system is orificed to limit the blowdown from a break downstream of the first orifice to within the capacity of one of the centrifugal charging pumps.

A break of the RVHVS line upstream of the first orifice would result in a small LOCA of not greater than one inch diameter. Such a break is similar to those analyzed in WCAP-9600 (Reference 4). Since a break in the head vent line would behave similarly to the hot leg break case presented in WCAP-9600, the results presented therein are applicable to a RVHVS line break. This postulated vent line break, therefore, results in no calculated core uncovery.

The Replacement Reactor Vessel Closure Head has changed the piping for the head vent. The new piping has an orifice approximately 6 feet from the head vent penetration. This permitted the movement of the Class 1 to Class 2 ASME Code boundary. The new Class 1 to Class 2 transition is at the first orifice. The piping analysis requirements remain the same since piping of NPS one inch or less which has been classified as Class 1 may be designed in accordance with the design requirements of ASME subsection NC (Class 2). The Class 2 piping is from the outlet of the first orifice to the second orifice. Piping and components downstream of the second orifice are non-nuclear safety but seismically supported up to the 12 inch pressurizer relief line.

The system provides for venting the reactor vessel head by using only safety grade equipment. The RVHVS satisfies applicable requirements and industry standards including ASME Code classification, safety classification, single-failure criteria, and environmental qualification.

5.5.15.2.2 Supports

The vent system piping is supported to ensure that the resulting loads and stresses on the piping and on the vent connection to the vessel head are acceptable.

The head vent piping supports were totally re-designed with the Replacement Reactor Vessel Closure Head and the Integrated Head Assembly (IHA). The head vent riser inside the IHA is attached to the support columns, Figure 5.5-14 shows the two types of piping supports. Clearance in the support allows for axial pipe movement/thermal growth.

The horizontal head vent piping is run above the IHA walkway with clamp type supports as shown on Figure 5.5-15. All of these supports are designed for axial pipe thermal movement and radial restraint.

All of these pipe supports are designed in accordance with ASME Section III NF Class 2 requirements.

5.5.15.3 Analytical Considerations

The analysis of the reactor vessel head vent piping is based on the following plant operation conditions defined in the ASME Code Section III:

1. Normal Condition:

   Pressure, deadweight, and thermal expansion analysis of the vent pipe during

   a. normal reactor operation with the two inboard vent isolation valves closed and
   b. post-refueling venting.

2. Upset Condition:

   Loads generated by the OBE response spectra.

3. Faulted Condition:

   Loads generated by the SSE and by valve thrust during venting. In accordance with ASME Code Section III, faulted conditions are not included in fatigue evaluations.

The Class I piping used for the reactor vessel head vent is one inch schedule 160 and, therefore, in accordance with ASME Code Section III, is analyzed following the procedures of NC-3600 for Class II piping.

For plant operating conditions listed above, the piping stresses are shown to meet the requirements of equations (8), (9), (10), or (11) of ASME III, Section NC-3600 with a design temperature of 650°F and a design pressure of 2485 psig.

5.5.16 References

1. *Reactor Coolant Pump Integrity in LOCA*, WCAP-8163, September 1973.
2. Letter from D. B. Vassallo (NRC) to all Applicants for an Operating License, *Followup Actions Resulting From the NRC Staff Reviews Regarding the Three Mile Island Unit 2 Accident*, and Enclosure 4: Installation of Remotely Operated High Point Vents in the Reactor Coolant System, September 27, 1979.
3. Letter from D. B. Vassallo (NRC) to all Applicants for an Operating License, *Discussion of Lessons Learned Short Term Requirements*, Enclosure 1, pp. 44-49, Reactor Coolant System Venting, November 9, 1979.
4. *Report on Small Break Accidents for Westinghouse NSSS System*, WCAP-9600, June 1979, (specifically Case F, Section 3.2).
5. *Basis for Heatup and Cooldown Limit Curves*, WCAP-7924-A, April 1975.
6. WCAP-13480, Revision 1, *Westinghouse Delta-75 Steam Generator Design and Fabrication Information for the V. C. Summer Nuclear Station*, October 1993.
7. ECR 50897, Replacement Reactor Service Structure Integrated Head Assembly (IHA).
8. ECR 50868 Replacement Reactor Vessel Closure Head (RRVCH).

Table 5.5-1
Reactor Coolant Pump Design Parameters

Unit Design Pressure, psig	2485
Unit Design Temperature, °F	650(1)
Unit Overall Height, ft	26
Seal Water Injection, gpm	8
Seal Water Return, gpm	2.5
Cooling Water Flow, gpm	195
Maximum Continuous Cooling Water Inlet Temperature, °F	105
Pump	
Capacity, gpm	100,700
Developed Head, ft	279
NPSH Required, ft	Figure 5.5-2
Suction Temperature, °F	554.6
Pump Discharge Nozzle, Inside Diameter, in.	27-1/2
Pump Suction Nozzle, Inside Diameter, in.	31
Speed, rpm	1180
Water Volume, ft^3	81
Weight (dry), lbs.	199,000
Motor	
Type	Drip proof, squirrel cage induction air-coole
Power, Hp	7000
Voltage, volts	6900
Phase	3
Frequency, Hz	60
Insulation Class	Class F, thermoplastic epoxy insulation
Starting Current	3000 amp @ 6900 volts
Input, hot reactor coolant	501 amp
Input, cold reactor coolant	635 amp

Table 5.5-1 (continued)
Reactor Coolant Pump Design Parameters

Motor (Continued)

Pump Moment of Inertia, lb-ft^2 maximum	
Flywheel	70,000
Motor	22,500
Shaft	520
Impeller	1,980

(1) Design temperature of pressure retaining parts of the pump assembly exposed to the reactor coolant and injection water on the high pressure side of the controlled leakage seal shall be that temperature determined for the parts of a primary loop temperature of 650°F.

Table 5.5-2
Reactor Coolant Pump Quality Assurance Program

	RT (1)	UT (1)	PT (1)	MT (1)
Castings	Yes		Yes	
Forgings				
1. Main Shaft		Yes	Yes	
2. Main Studs		Yes		Yes
3. Flywheel (Rolled Plate)		Yes		
Weldments				
1. Circumferential	Yes		Yes	
2. Instrument Connections			Yes	

(1) RT - Radiographic
UT - Ultrasonic
PT - Dye Penetrant
MT - Magnetic Particle

Table 5.5-3
Steam Generator Design Data

Design Pressure, reactor coolant side, psig	2485
Design Pressure, steam side, psig	1185
Design Temperature, reactor coolant side, °F	650
Design Temperature, steam side, °F	600
Total Heat Transfer Surface Area, ft^2	75,185
Maximum Moisture Carryover, wt percent	0.10
Overall Height, ft-in.	67-8
Number of U-Tubes	6307
U-Tube Outer Diameter, in.	0.688
Tube Wall Thickness, nominal, in.	0.040
Number of Manways	4
Inside Diameter of Manways, in.	16
Number of Handholes	8
Inside Diameter of Handholes, in.	4" and 6"
Design Fouling Factor hr-ft^2-°F/BTU	0.00011

Table 5.5-4
Steam Generator Quality Assurance Program

	RT[1]	UT[1]	PT[1]	MT[1]	ET[1]
Tubesheet					
1. Forging		Yes		Yes	
2. Cladding		Yes[2]	Yes[3]		
Channel Head					
1. Casting	Yes			Yes	
2. Cladding			Yes		
Secondary Shell & Head					
1. Plates		Yes			
Tubes		Yes			Yes
Nozzles (Forgings)		Yes		Yes	
Weldments					
1. Shell, longitudinal	Yes		Yes		
2. Shell, circumferential			Yes		
3. Cladding (channel head-tubesheet joint cladding restoration)					
4. Steam and feedwater nozzle to shell					
5. Support brackets					
6. Tube to tubesheet					
7. Instrument connections (primary and secondary)					
8. Temporary attachments after removal					
9. After hydrostatic test (all welds and complete channel head - where accessible)					

Table 5.5-4 (continued)
Steam Generator Quality Assurance Program

	RT(1)	UT(1)	PT(1)	MT(1)	ET(1)
10. Nozzle safe ends (if forgings)	Yes		Yes		
11. Nozzle safe ends (if weld deposit)			Yes		

(1) RT - Radiographic
UT - Ultrasonic
PT - Dye Penetrant
MT - Magnetic Particle
ET - Eddy Current

(2) Flat Surfaces Only

(3) Weld Deposit Areas Only

Table 5.5-5
Reactor Coolant Piping Design Parameters

Reactor Inlet Piping, inside diameter, in.	27-1/2
Reactor Inlet Piping, nominal wall thickness, in.	2.32
Reactor Outlet Piping, inside diameter, in.	29
Reactor Outlet Piping, nominal wall thickness, in.	2.45
Coolant Pump Suction Piping, inside diameter, in.	31
Coolant Pump Suction Piping, nominal wall thickness, in.	2.60
Pressurizer Surge Line Piping, nominal pipe size, in.	14
Pressurizer Surge Line Piping, nominal wall thickness, in.	1.406
Reactor Coolant Loop Piping	
Design/Operating Pressure, psig	2485/2235
Design Temperature, °F	650
Pressurizer Surge Line	
Design Pressure, psig	2485
Design Temperature, °F	680
Pressurizer Safety Valve Inlet Line	
Design Pressure, psig	2485
Design Temperature, °F	680
Pressurizer (Power-Operated) Relief Valve Inlet Line	
Design Pressure, psig	2485
Design Temperature, °F	680
Pressurizer Relief Tank Inlet Line	
Design Pressure, psig	600
Design Temperature, °F	600

Table 5.5-6
Reactor Coolant Piping Quality Assurance Program

	RT(1)	UT(1)	PT(1)
	Yes		Yes
Fittings and Pipe (Forgings)		Yes	Yes
Weldments			
1. Circumferential	Yes		Yes
2. Nozzle to runpipe (Except no RT for nozzles less than 6 inches)	Yes		Yes
3. Instrument Connections			Yes
Castings	Yes		Yes (after finishing)
Forgings		Yes	Yes (after finishing)

(1) RT - Radiographic
UT - Ultrasonic
PT - Dye Penetrant

Table 5.5-7
Design Bases for Residual Heat Removal System Operation

Residual Heat Removal System Startup	~ 4 hours after Reactor Shutdown
Reactor Coolant System Initial Pressure, psig	~ 425
Reactor Coolant System Initial Temperature, °F	~ 350
Component Cooling Water Design Temperature, °F	105
Cooldown Time, Hours After Initiation of Residual Heat	~ 16 (1)
Removal System Operation (CCWS Supply Temperature not exceeding 120°F)	~ 20 (2)
Reactor Coolant System Temperature at End of Cooldown, °F	140
Decay Heat Generation at 20 Hours After Reactor Shutdown, BTU/hr	60.6×10^6 (1)

(1) Core Power = 2775 MWt
(2) Core Power = 2900 MWt

Table 5.5-8
Residual Heat Removal System Component Data

Residual Heat Removal Pumps		
Number	2	
Design Pressure, psig	600	
Design Temperature, °F	400	
Design Flow, gpm	3750	
Design Head, ft	240	
NPSH at 3750 gpm, ft	14	
Motor Power, HP	300	
Residual Heat Exchangers		
Number	2	
Design Heat Removal Capacity	30.3×10^6 BTU/hr	
	Tube Side	Shell Side
Design Pressure, psig	600	150
Design Temperature, °F	400	200
Design Flow, lb/hr	1.86×10^6	2.8×10^6
Inlet Temperature, °F	139	105
Outlet Temperature, °F	123	116
Material	Austenitic Stainless Steel	Carbon Steel
Fluid	Reactor Coolant	Component Cooling Water

Table 5.5-9
Pressurizer Design Data

Design Pressure, psig	2485
Design Temperature, °F	680
Surge Line Nozzle Diameter, in.	14
Heatup Rate of Pressurizer Using Heaters Only, °F/hr	55
Internal Volume, ft^3	1400

Table 5.5-10
Pressurizer Quality Assurance Program

	RT[1]	UT[1]	PT[1]	MT[1]
Heads				
1. Plates		Yes		
2. Cladding			Yes	
Shell				
1. Plates		Yes		
2. Cladding			Yes	
Heaters				
1. Tubing [2]		Yes	Yes	
2. Centering of element	Yes			
Nozzle (Forgings)		Yes	Yes [3]	Yes [3]
Weldments				
1. Shell, longitudinal	Yes			Yes
2. Shell, circumferential	Yes			Yes
3. Cladding			Yes	
4. Nozzle Safe End (if forging)	Yes		Yes	
5. Instrument Connection			Yes	
6. Support Skirt		Yes		Yes
7. Temporary Attachments (after removal)				Yes
8. All external pressure boundary welds after shop hydrostatic test				Yes

(1) RT - Radiographic
UT - Ultrasonic
PT - Dye Penetrant
MT - Magnetic Particle

(2) Or a UT and ET

(3) MT or PT

Table 5.5-11
Pressurizer Relief Tank Design Data

Design Pressure, psig		100
Rupture Disc Release Pressure, psig	Nominal:	91
	Range:	86-100
Design Temperature, °F		340
Total Rupture Disc Relief Capacity, lb/hr at 100 psig		1.6×10^6

Table 5.5-12
Reactor Coolant System Valve Design Parameters

Design/Normal Operating Pressure, psig	2485/2235
Preoperational Plant Hydrotest, psig	3107
Design Temperature, °F	650

Table 5.5-13
Reactor Coolant System Valves Quality Assurance Program

	RT[1]	UT[1]	PT[1]
Boundary Valves, Pressurizer Relief and Safety Valves			
Castings - (larger than 4 inches)	Yes		Yes
(2 inches to 4 inches)	Yes[2]		Yes
Forgings - (larger than 4 inches)	[3]	[3]	Yes
(2 inches to 4 inches)			Yes

(1) RT - Radiographic
UT - Ultrasonic
PT - Dye Penetrant

(2) Weld Ends Only

(3) Either RT or UT

Table 5.5-14
Pressurizer Valves Design Parameters

Pressurizer Spray Valves	
Number	2
Design Pressure, psig	2485
Design Temperature, °F	650
Design Flow, for valves full open, each, gpm	350
Pressurizer Safety Valves	
Number	3
Maximum Relieving Capacity, ASME rated flow, lb/hr	420,000
Set Pressure, psig	2485
Design Temperature, °F	650
Fluid	Saturated steam
Transient Condition, °F	(Superheated steam) 680
Backpressure:	
Normal, psig	3 to 5
Expected during discharge, psig	350
Pressurizer Power Relief Valves	
Number	3
Design Pressure, psig	2485
Design Temperature, °F	650
Relieving Capacity, at 2350 psig, lb/hr (per valve)	210,000
Fluid	Saturated steam
Transient Condition, °F	(Superheated steam) 680

Table 5.5-15
Single Active Failure Analyses of the Residual Heat Removal System

Component	Malfunction	Comments
1. RHR suction isolation valve (8701 A or B or 8702 A or B)	Fails to open	RHR cooling restricted to one train. Cooldown time extended.
2. RWST/RHR suction isolation valve (8809 A or B)	Fails to close	RHR cooling restricted to one train. Cooldown time extended.
3. RHR pump (no. 1 or 2)	Fails to operate	RHR cooling restricted to one train. Cooldown time extended.
4. Flow instrument (602A or 602B)	Fails low	Miniflow valve (FCV 602A or FCV 602B) opens. Slight increase in RHR pump flow in one train. Slight extension in cooldown time.
5. Miniflow valve (FCV 602A or FCV 602B)	Fails to close	Slight increase in RHR pump flow in one train. Slight extension in cooldown time.
6. Flow instrument (605A or 605B)	Fails low	Bypass valve opens. Cooldown in one train reduced. Cooldown time extended.
7. Flow instrument (605A or 605B)	Fails high	Bypass valve closes. Constant total return flow in one train to the RCS cannot be maintained. No adverse effects.
8. Bypass valve (FCV 605A or FCV 605B)	Fails to close	Cooldown in one train reduced. Cooldown time extended.

Table 5.5-15 (continued)
Single Active Failure Analyses of the Residual Heat Removal System

Component	Malfunction	Comments
9. Bypass valve (FCV 605A or FCV 605B)	Fails to open	Constant total return flow in one train to the RCS cannot be maintained. No adverse effects.
10. RHR heat exchanger (no. 1 or 2)	Fails to function	RHR cooling restricted to one train. Cooldown time extended.
11. Flow control valve (HCV 603A or HCV 603B)	Fails to open	RHR cooling restricted to one train. Cooldown time extended.
12. Flow control valve (HCV 603A or HCV 603B)	Fails to open	Cannot control cooldown rate in one train, thus requiring that cooling be restricted to the other train. Cooldown time extended.

See Sections 5.5.7.3.3 and 5.5.7.3.4, respectively, for a discussion of Overpressurization Protection and Prevention of Exposure of the RHR System to Normal RCS Pressures.

Table 5.5-16
Reactor Vessel Head Vent System Equipment Design Parameter

Valves	
Number (include two manual valves)	6
Design pressure, psig	2485
Design temperature, °F	650
Piping	
Normal vent line nominal diameter, in.	1 - 3/4
RVHVS flow path line, nominal diameter, in.	1
Design pressure, psig	2485
Design temperature, °F	650

Table 5.5-17
Fracture Toughness Data for SA533 Grade A Class 2 Material

Component	Component Part	Test Number	Charpy V-Notch (ft-lb)	Lateral Expansion (in.)	Orientation Longitudinal (L) Transverse (T)	Test Temperature (°F)	T_{NOT} (°F)	RT_{NDT} (°F)
Pressurizer (1581)	Lower Head	T03639	82, 85, 80 90, 90, 78	.074, .071, .068 .063, .072, .072	T L	70 10	10	10
Pressurizer (1581)	Upper Head	T03625	53, 54, 53 75, 74, 91	.052, .051, .048 .060, .070, .071	T L	70 10	10	10
Pressurizer (1581)	Shell Barrel	T03328	78, 82, 81	.056, .057, .049	L	10	-*	-
Pressurizer (1581)	Shell Barrel	T03704	65, 59, 56	.051, .056, .059	T	70	0	10
Pressurizer (1581)	Shell Barrel	T03605	78, 78, 85	.065, .071, .066	T	70	10	10

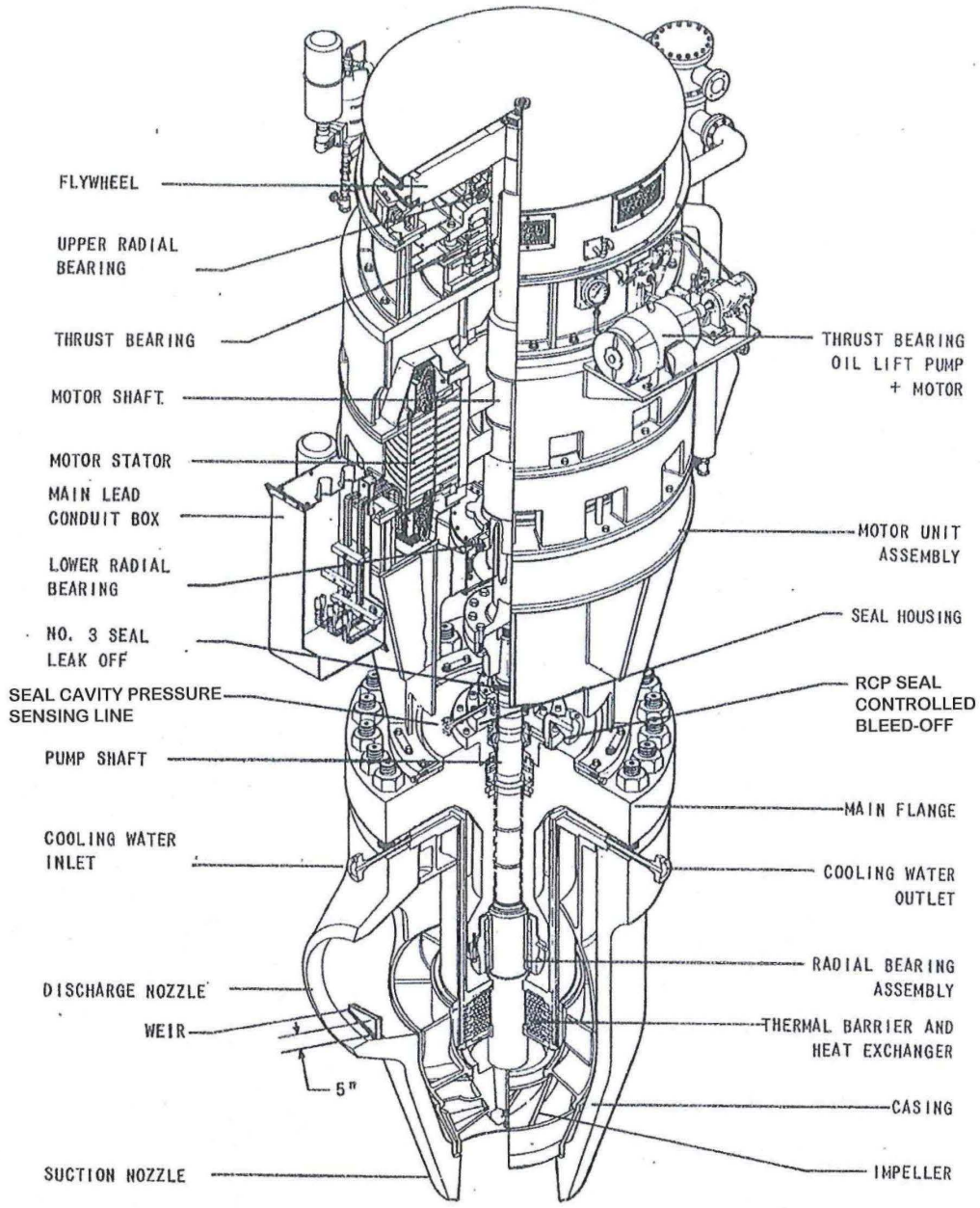
* Drop weight test results not available.

Table 5.5-18
Pressurizer Weld Data

Material	Weld Process	Test Number Electrode	Test Number Flux	Drop WT @ 20°F[1]	Charpy V-Notch FT-LB[1]	TestTemp. (°F)	Lat. Expansion (Mils)	RT_{NDT} °F
SFA 5.18	SAW	2755	3970	2 NB	130-127-134	70	59-57-61	10
SFA 5.18	SAW	3864	3970	2 NB	121-111-130	70	80-71-73	10
SFA 5.18	SAW	4113	4553	2 NB	111-114-112	70	84-78-79	10
SFA 5.18	SAW	3882	4080	2 NB	126-126-124	70	61-61-52	10
SFA 5.18	SAW	4098	4553	2 NB	108-106-106	70	80-78-78	10
SFA 5.18	SAW	2881	4080	2 NB	120-138-144	70	93-92-64	10
SFA 5.18	SAW	2755	3561	-	94-94-87	10	66-66-61	10
SFA 5.5	SMAW	3418	-	2 NB	210-257-219	70	91-71-80	10
SFA 5.5	SMAW	3991	-	2 NB	73-78-57	70	57-62-41	10
SFA 5.5	SMAW	3415	-	2 NB	82-84-84	70	61-67-61	10
SFA 5.5	SMAW	3419	-	2 NB	91-92-101	70	70-71-76	10
SFA 5.5	SMAW	3401	-	-	Average 65	10	-	30
SFA 5.5	SMAW	4507	-	2 NB	80-79-74	70	67-76-64	10
SFA 5.5	SMAW	3993	-	2 NB	102-104-100	70	81-77-80	10
SFA 5.5	SMAW	4503	-	2 NB	52-75-76	70	43-61-51	10
SFA 5.5	SMAW	2165	-	-	Average 52	10	-	30

(1) Where complete charpy or drop weight data was not obtained, RT_{NDT} was estimated in accordance with the guidelines of MTEB 5-2 and Westinghouse WCAP-7924A, “Basis for Heat-up and Cooldown Curves”.

Figure 5.5-1
REACTOR COOLANT CONTROLLED LEAKAGE PUMP



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Coolant Controlled Leakage Pump Figure 5.5-1

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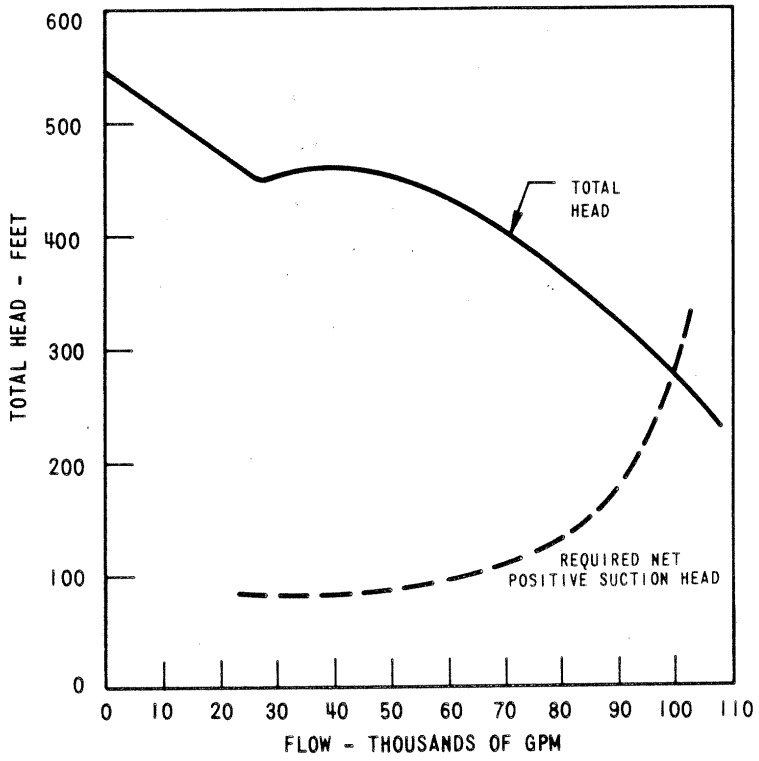
Figure 5.5-2

REACTOR COOLANT PUMP ESTIMATED PERFORMANCE CHARACTERISTIC



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Coolant Pump Estimated Performance Characteristic
Figure 5.5-2

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August 1984

Figure 5.5-3
MODEL DELTA-75 STEAM GENERATOR

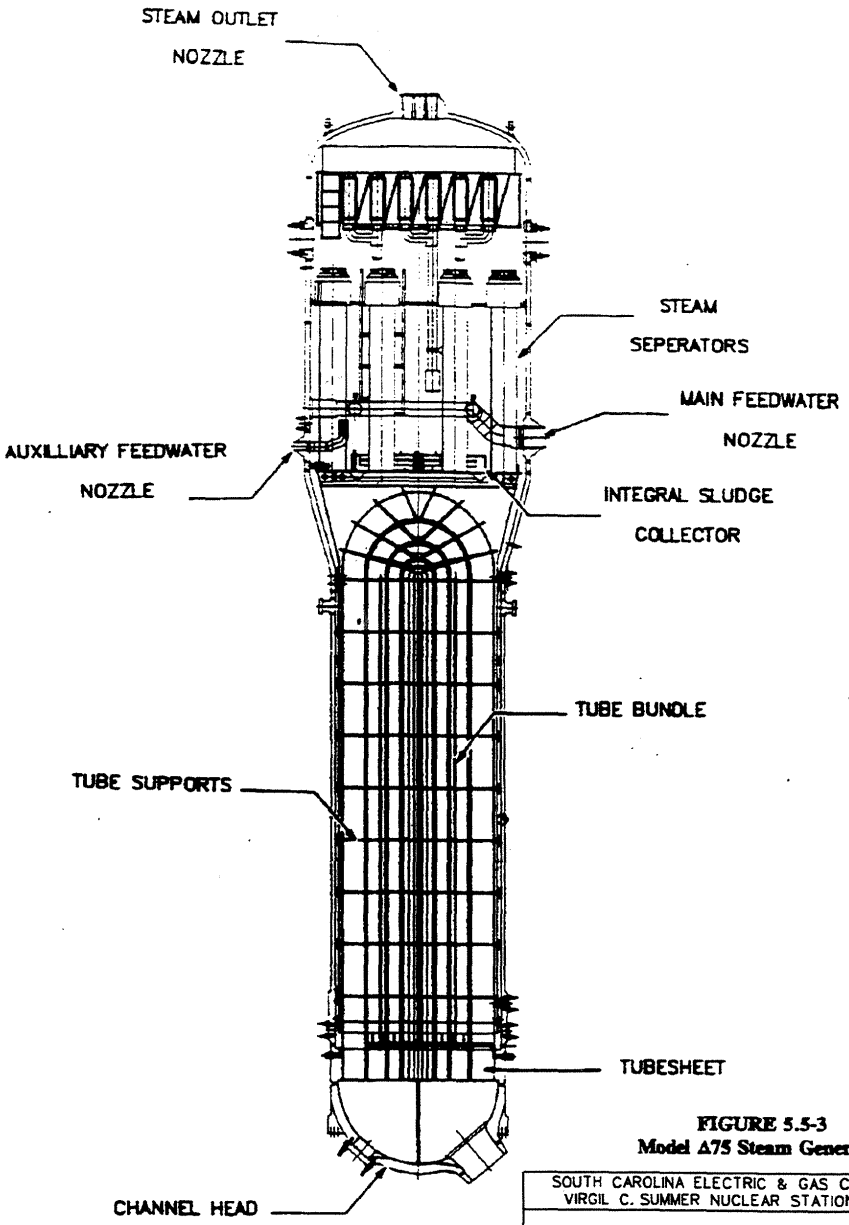


FIGURE 5.5-3
Model Δ75 Steam Generator

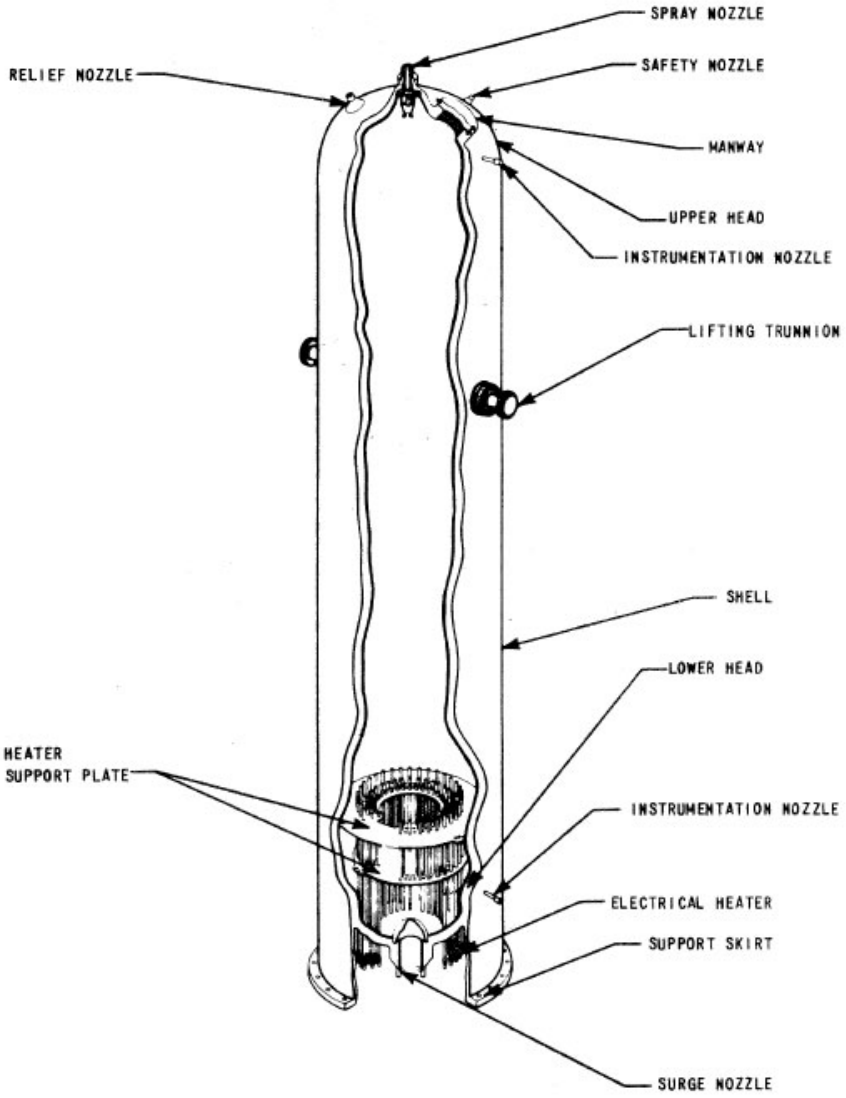
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Model DELTA-75 Steam Generator
Figure 5.5-3

AMENDMENT 96-02
JULY 1996

fsar553.m(355.jr14325) JR14325@jr14325. Mon Jul 1 13:21:27 EDT 1996

Figure 5.5-4
FSAR FIGURE REFERENCE
DRAWING E-302-641

Figure 5.5-6
PRESSURIZER



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Pressurizer
Figure 5.5-6

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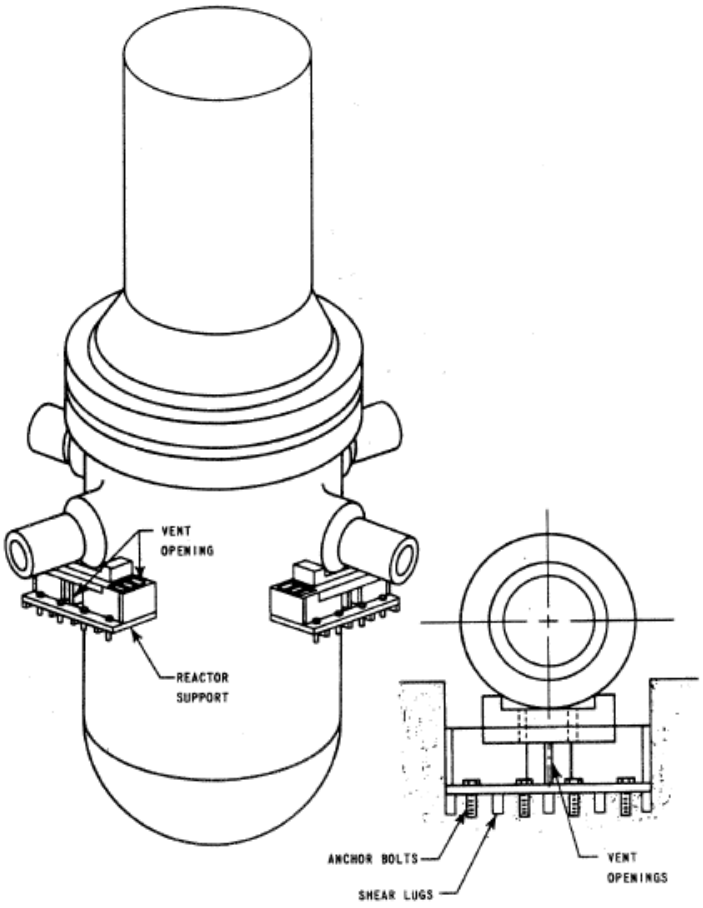
August 1984

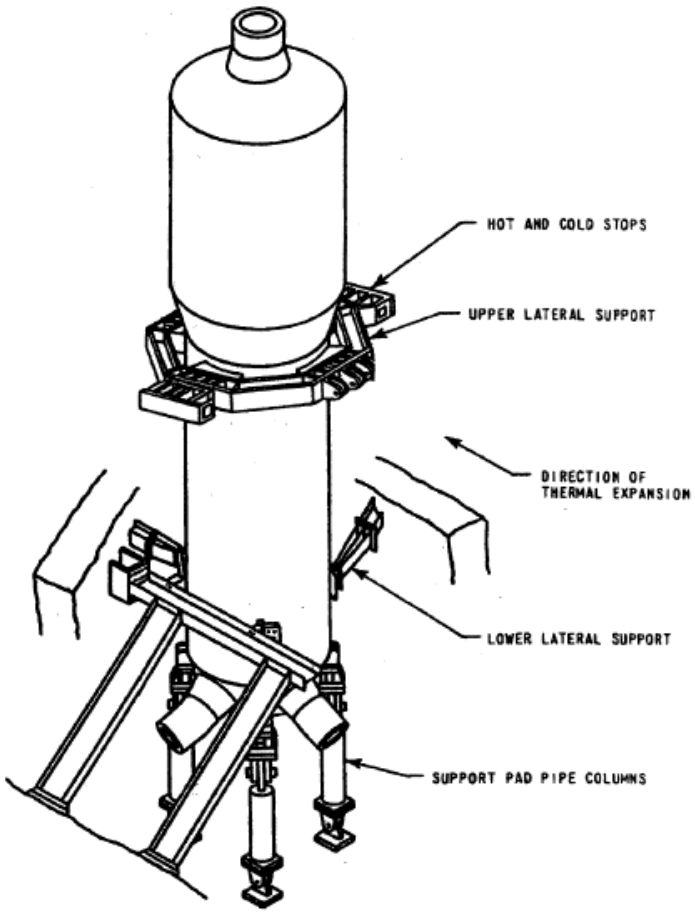
Figure 5.5-7
REACTOR VESSEL SUPPORTS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Vessel Supports
Figure 5.5-7

Amendment 0
August 1984

Figure 5.5-8
STEAM GENERATOR SUPPORTS



SOUTH CAROLINA ELECTRIC AND GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Steam Generator Supports Figure 5.5-8

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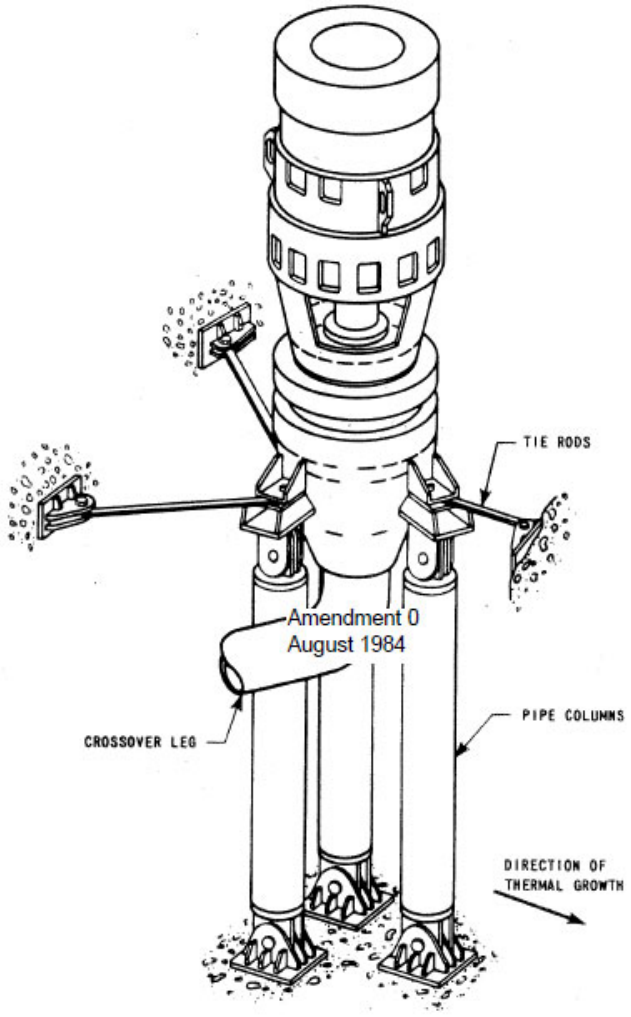
Figure 5.5-9
REACTOR COOLANT PUMP SUPPORTS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Coolant Pump Supports
Figure 5.5-9

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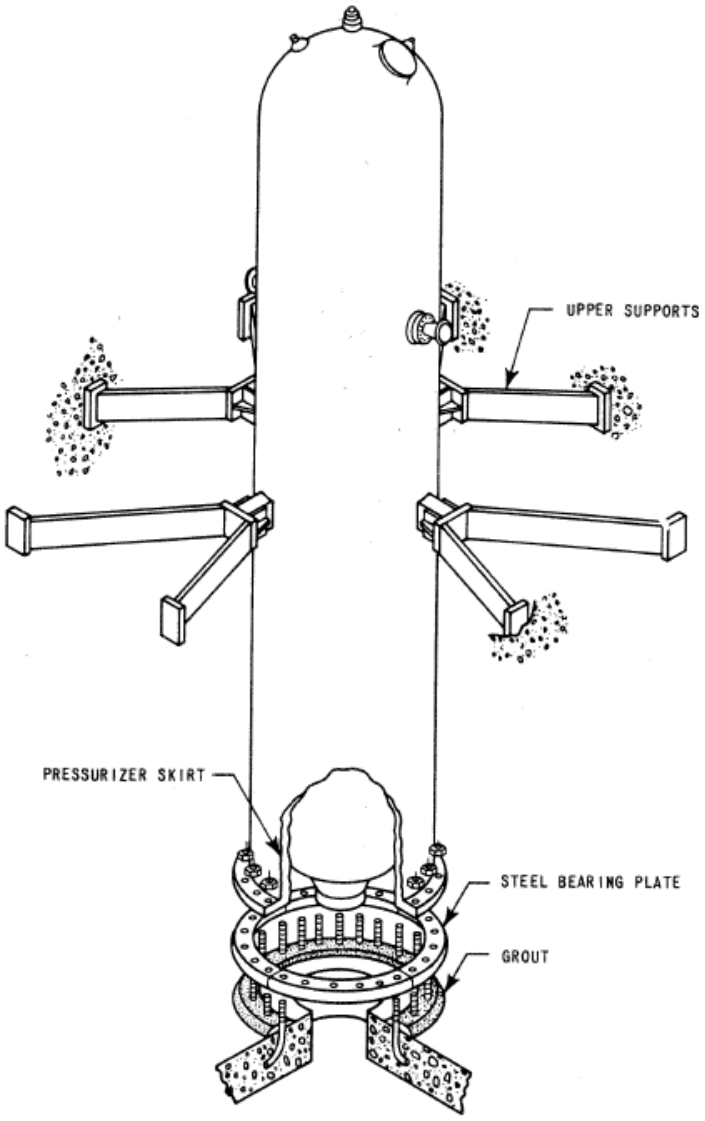
August 1984

Figure 5.5-10
PRESSURIZER SUPPORTS

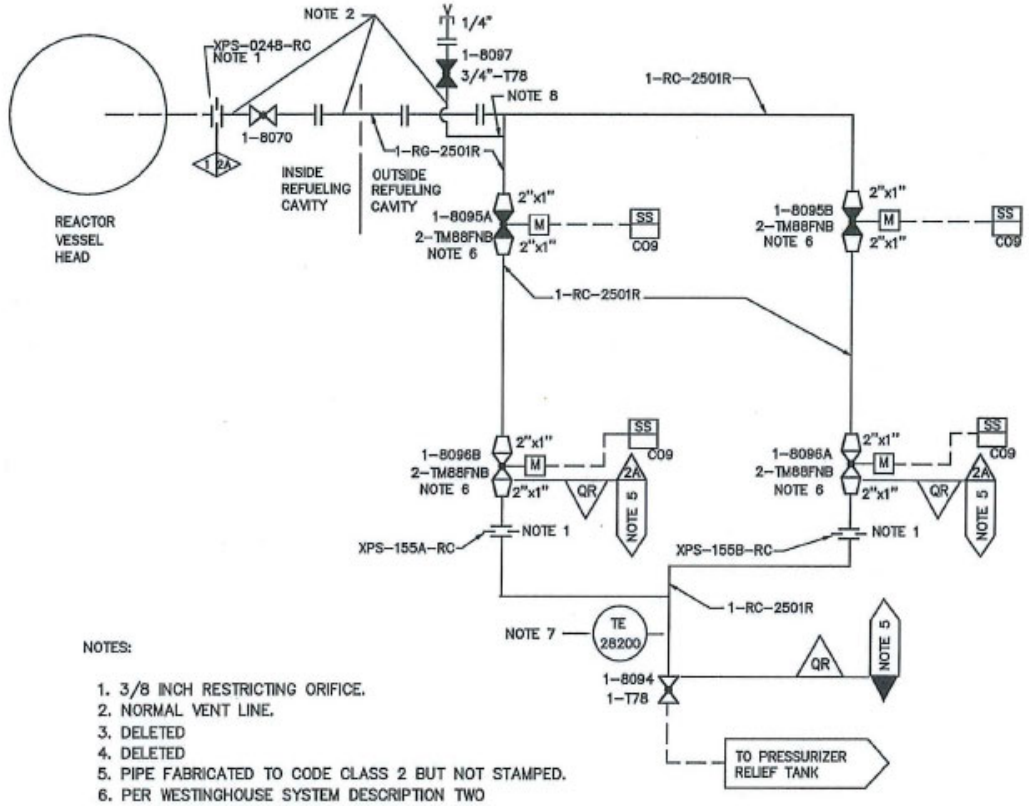


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Pressurizer Supports Figure 5.5-10

Amendment 0
August 1984

Figure 5.5-11
(DELETED BY AMENDMENT 95-04)
Figure 5.5-12
(DELETED BY AMENDMENT 95-04)

Figure 5.5-13
SCHEMATIC FLOW DIAGRAM
OF THE REACTOR VESSEL HEAD VENT SYSTEM



NOTES:

1. 3/8 INCH RESTRICTING ORIFICE.
2. NORMAL VENT LINE.
3. DELETED
4. DELETED
5. PIPE FABRICATED TO CODE CLASS 2 BUT NOT STAMPED.
6. PER WESTINGHOUSE SYSTEM DESCRIPTION TWO SEPARATE VALVE LINEUP CONFIGURATIONS ARE ACCEPTABLE FOR THESE VALVES, THEY ARE:
   1. XVT-8095A & B CLOSED; XVT-8096A & B OPEN
   2. XVT-8095A & B OPEN; XVT8096A & B CLOSED
7. STRAP ON SURFACE MOUNTED T/C.
8. PROVIDE FLOW RESTRICTOR PER NOTE 9, SEE DWG. E-302-002, FLOW DIAGRAM LEGEND
9. FOR CONVENTIONAL PIPING SPECIFICATIONS, SEE GAI SPECIFICATION SP329-4461-00, PAGE 29, (WESTINGHOUSE PIPE CLASS CONVERSION TO ENGINEER'S PIPE LINE SPECIFICATION).

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Schematic Flow Diagram of the Reactor Vessel Head Vent System

Figure 5.5-13

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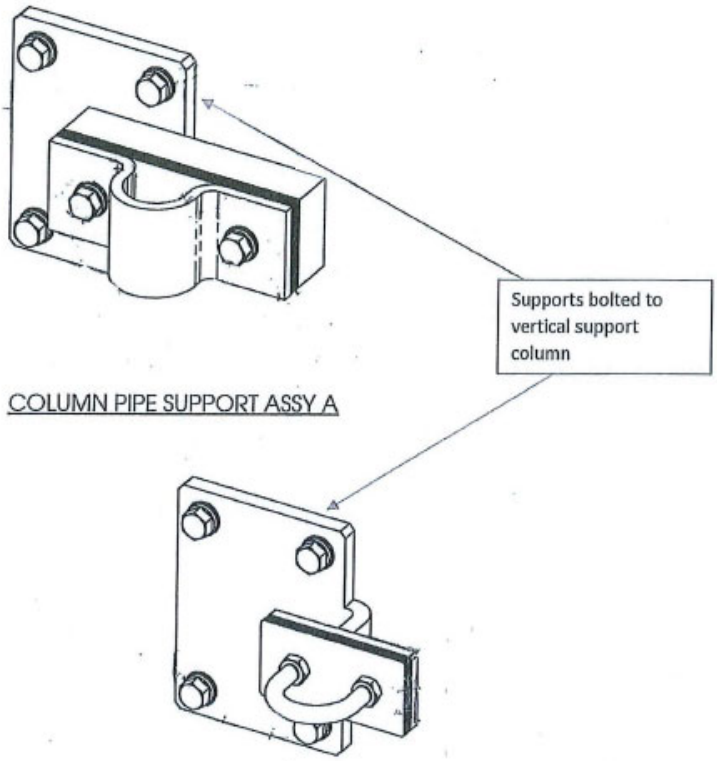
Figure 5.5-14

REACTOR VESSEL HEAD VENT SYSTEM PIPE SUPPORTS FOR VERTICAL PIPE RUN INSIDE THE INTEGRATED HEAD ASSEMBLY



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Reactor Vessel Head Vent System
Pipe Supports for Vertical Pipe Run
Inside the Integrated Head Assembly
Figure 5.5-14

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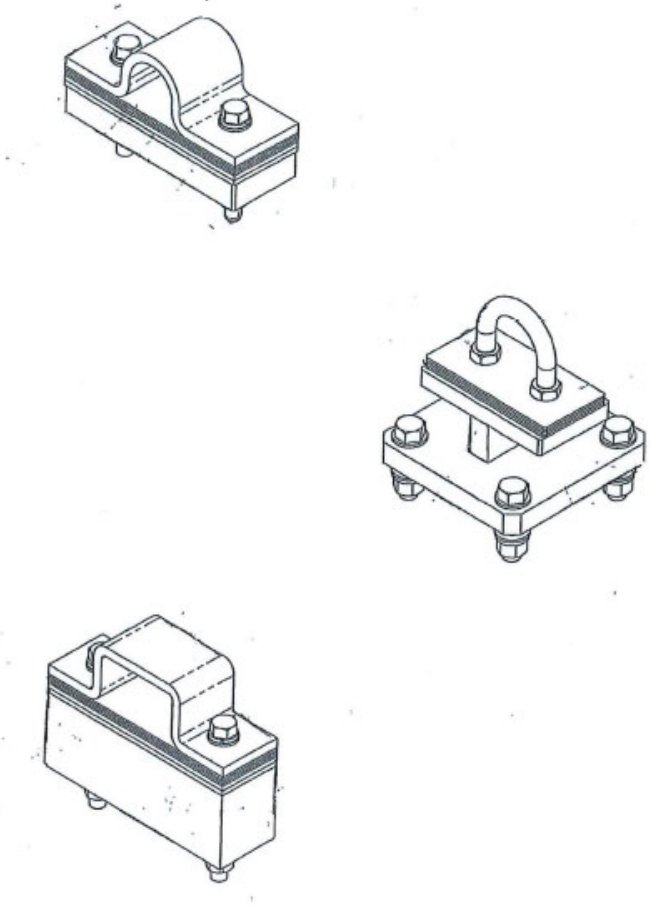
Figure 5.5-15

REACTOR VESSEL HEAD VENT SYSTEM PIPE SUPPORTS FOR IHA WALKWAY



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Reactor Vessel Head Vent System
Pipe Supports for IHA Walkway

Figure 5.5-15

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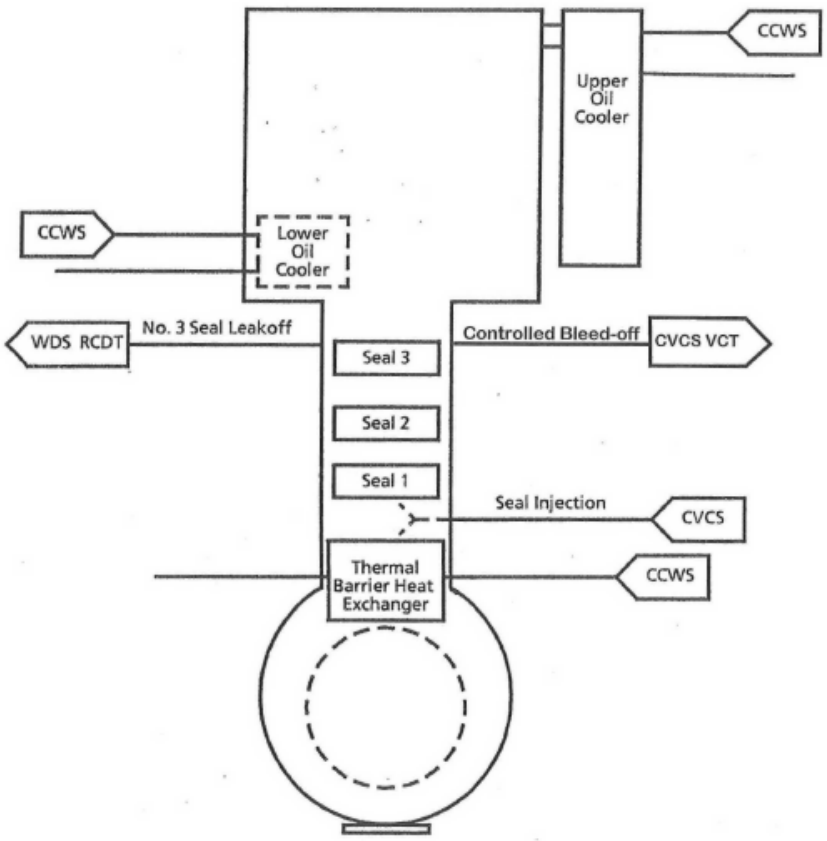
Figure 5.5-16
RCP COOLING SUPPLIES



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
RCP Cooling Supplies
Figure 5.5-16

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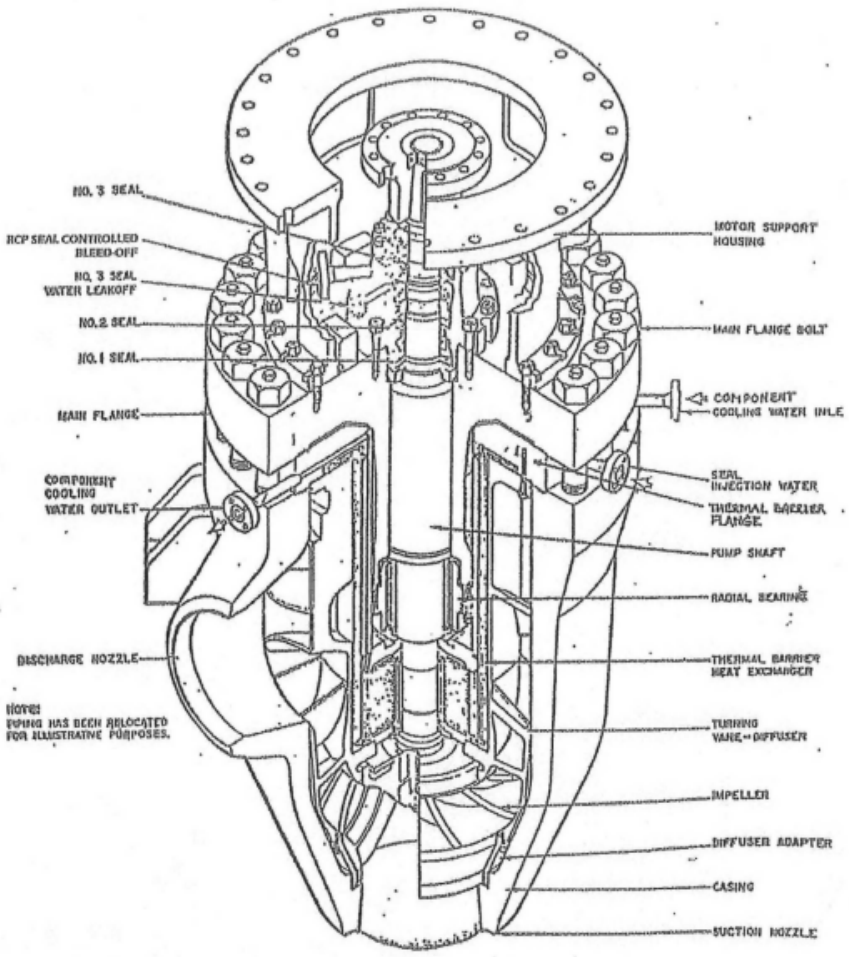
Figure 5.5-17
REACTOR COOLANT PUMP



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Reactor Coolant Pump

Figure 5.5-17

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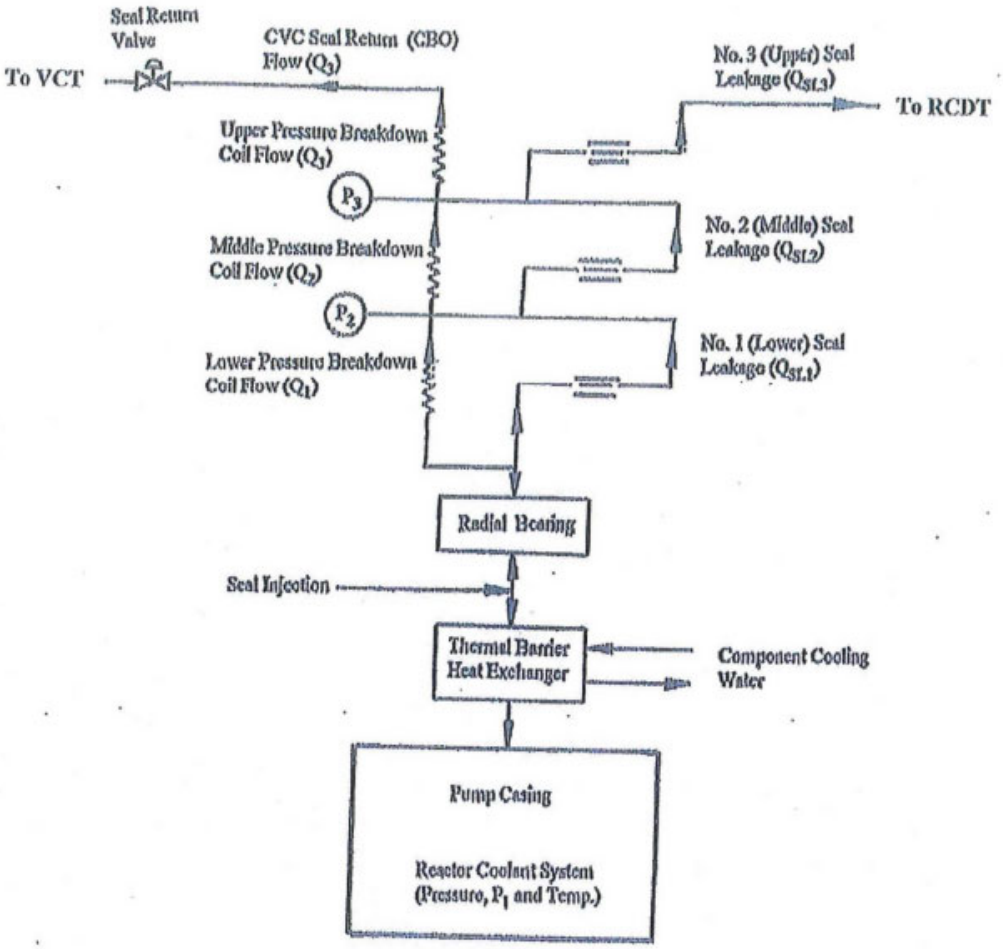
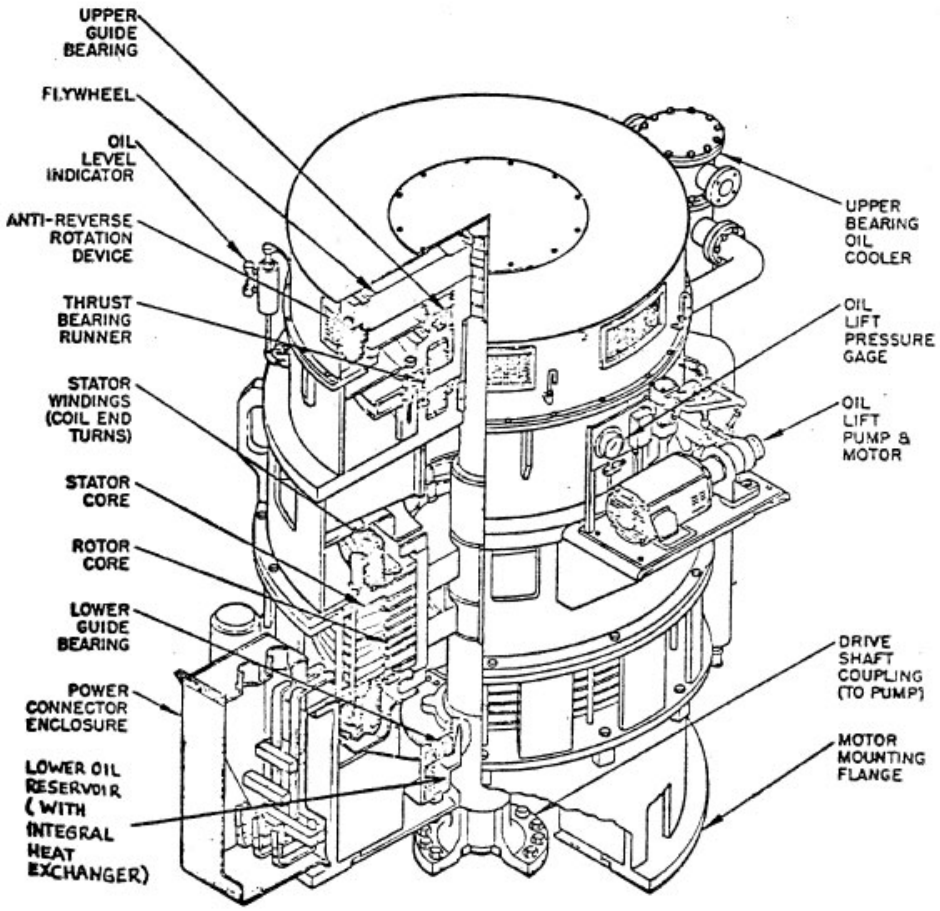
Figure 5.5-18
RCP SEAL FLOW SCHEMATIC



	SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reformatted July 2016	RCP Seal Flow Schematic Figure 5.5-18

Figure 5.5-19
REACTOR COOLANT PUMP MOTOR



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VIRGIL C. SUMMER NUCLEAR STATION

Reactor Coolant Pump Motor

Figure 5.5-19

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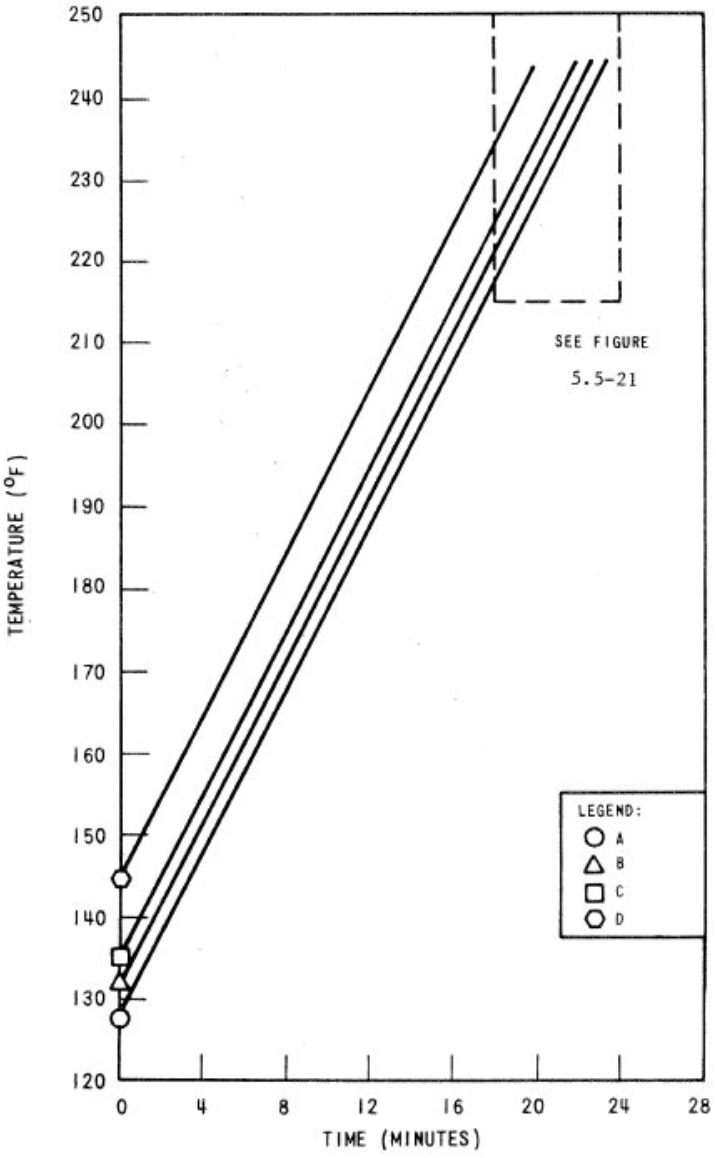
August 1984

Figure 5.5-20

RCP MOTOR BEARING HEATUP DATA FOR LOSS OF CCW



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RCP Motor Bearing Heatup Data
for Loss of CCW

Figure 5.5-20

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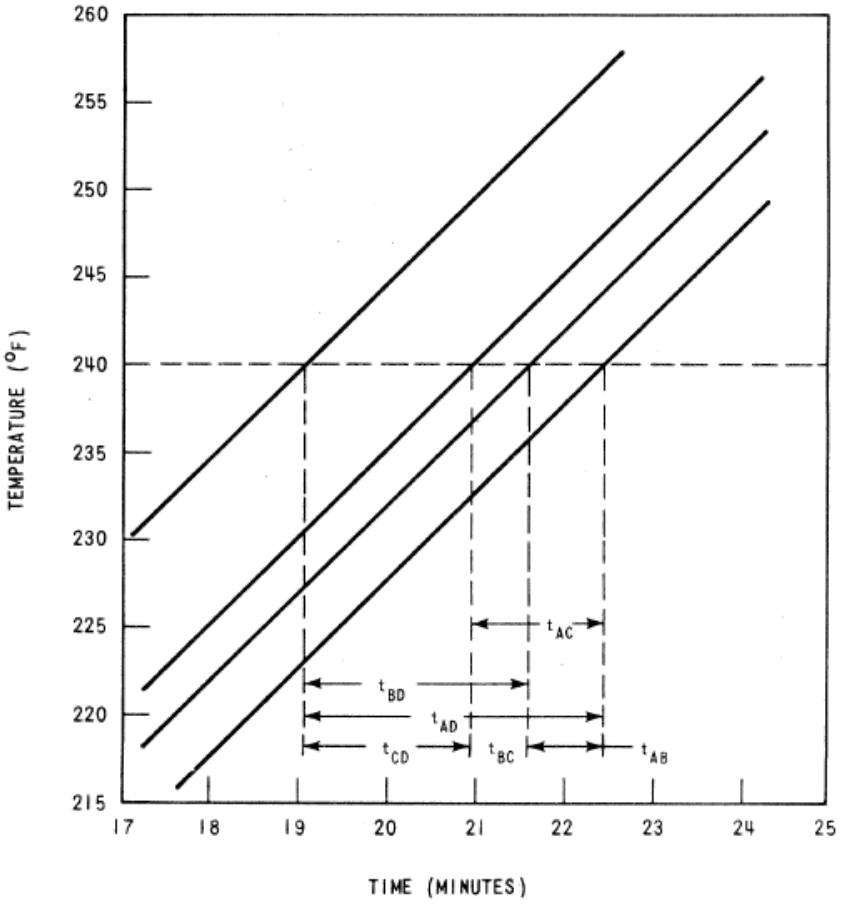
Figure 5.5-21

RCP MOTOR BEARING HEATUP DATA FOR LOSS OF CCW - DETAILS



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VIRGIL C. SUMMER NUCLEAR STATION

RCP Motor Bearing Heatup Data
for Loss of CCW - Details

Figure 5.5-21

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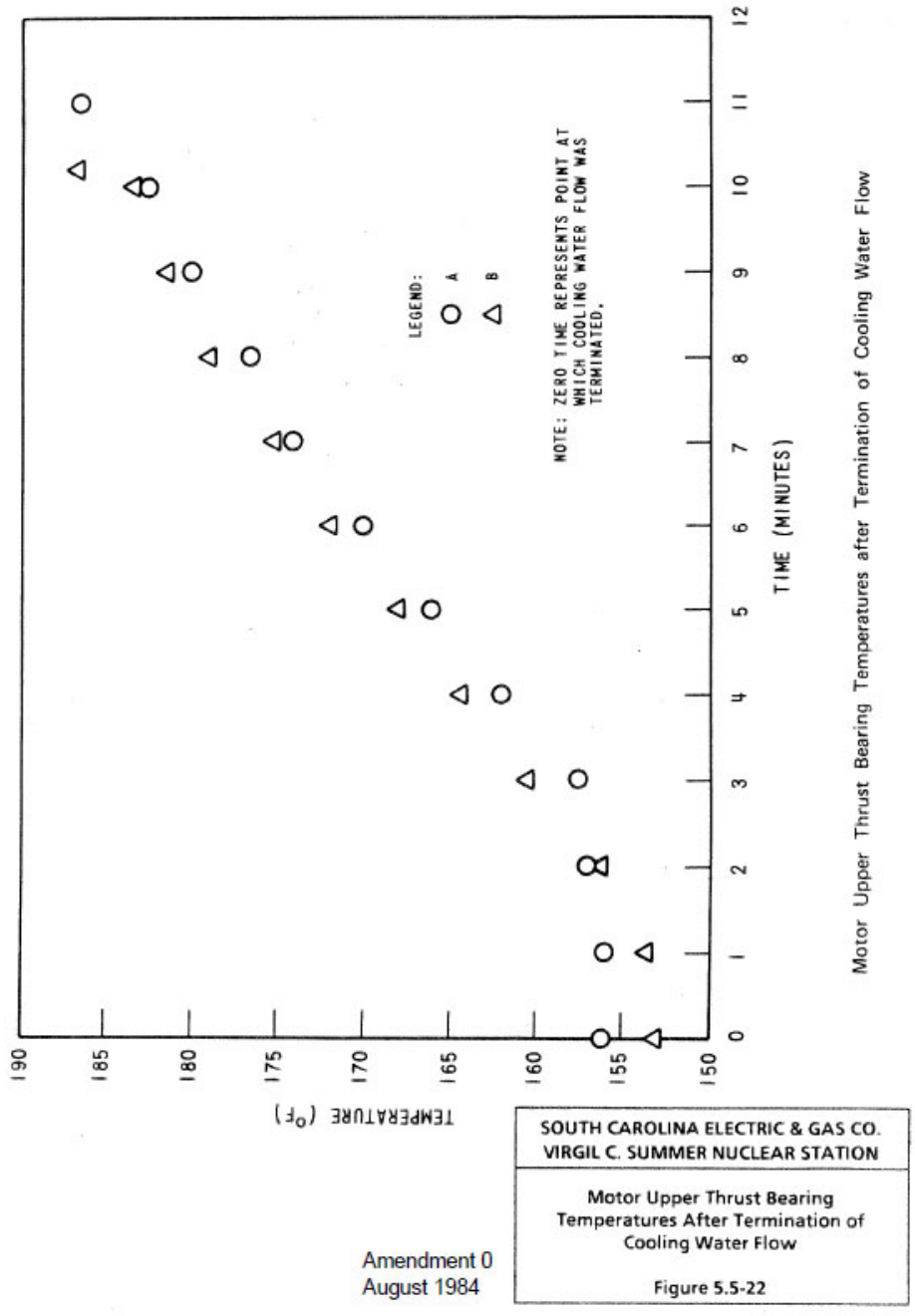
August 1984

Figure 5.5-22

MOTOR UPPER THRUST BEARING TEMPERATURES AFTER TERMINATION OF COOLING WATER FLOW



5.6 Instrumentation Requirements

Process control instrumentation is provided for the purpose of acquiring data on the pressurizer and on a per loop basis for the key process parameters of the Reactor Coolant System (including the reactor coolant pump motors), as well as for the Residual Heat Removal System. The pick-off points for the Reactor Coolant System are shown in Figure 5.1-1 (Sheets 1 through 3); and for the Residual Heat Removal System in Figures 5.5-4 and 6.3-1, Sheet 3. In addition to providing input signals for the protection system and the plant control systems, the instrumentation sensors furnish input signals for monitoring and/or alarming purposes for the following parameters:

1. Temperatures
2. Flows
3. Pressures
4. Water levels
5. Valve position

In general, these input signals are used for the following purposes:

1. Provide input to the reactor trip system for reactor trips as follows:
    a. Overtemperature ΔT
    b. Overpower ΔT
    c. Low pressurizer pressure
    d. High pressurizer pressure
    e. High pressurizer water level
    f. Low primary coolant flow

It is noted that the following parameters, which are also sensed so as to generate an input to the reactor trip system, while not part of the Reactor Coolant System, are included here for purposes of completeness:

    g. Feedwater flow
    h. Multiple steam generator water level
    i. Turbine first stage pressure
2. Provide input to the Engineered Safety Features Actuation System as follows:
    a. Pressurizer low pressure

It is noted that the following parameters, which are also sensed so as to generate an input to the Engineered Safety Features Actuation System, while not part of the Reactor Coolant System, are included here for purposes of completeness:

b. High steamline differential pressure

c. High steamline flow coincident with lo-lo reactor coolant average temperature (T_{avg})

d. High containment pressure

e. Low steamline pressure

3. Furnish input signals to the non-safety-related systems, such as the plant control systems and surveillance circuits, so that:

a. T_{avg} is maintained within prescribed limits. The resistance temperature detector instrumentation is identified on Figure 5.1-1, Sheet 3.

b. Pressurizer level control, using T_{avg} to program the setpoint, maintains the coolant level within prescribed limits.

c. Pressurizer pressure is controlled within specified limits.

d. Steam dump control, using T_{avg} control, accommodates sudden loss of generator load.

e. Information is furnished to the control room operator and to local stations for monitoring.

The following is a functional description of the system instrumentation. Unless otherwise stated, all indicators, recorders, and alarm annunciators are located in the control room.

1. Temperature Monitoring Instrumentation

a. Narrow Range Hot and Cold Leg Temperature

The hot and cold loop temperature signals required for input to the protection and control functions are obtained using thermowell mounted RTDs installed in each reactor coolant loop.

The hot leg temperature measurement in each loop is accomplished using three fast response, narrow range, dual element RTDs mounted in thermowells. The hot leg thermowells are located within the three scoops previously used for the RTD bypass manifold at locations 120° apart in the cross sectional plane. The scoops were modified by drilling a flow hole in the top of the scoops so that water flows in through the existing holes in the leading edge of the scoop, past the RTD, and out through the new drilled hole.

Due to temperature streaming, the three fast response hot leg RTDs are electronically averaged to generate the hot leg temperature.

The cold leg temperature measurements in each loop are accomplished by one fast response, narrow range, dual element RTD. The existing cold leg RTD bypass penetration nozzle was modified to accept the thermowell and RTD. Temperature streaming in the cold leg is not a concern due to the mixing action of the reactor coolant pump

Signals from these instruments are used to compute the reactor coolant ΔT (temperature of the hot leg, T_{hot}, minus the temperature of the cold leg, T_{cold}) and the T_{avg}. These temperatures are indicated on the main control board for each loop. In addition, high T_{avg},

T_{ref} deviation, overtemperature setpoint, overpower setpoint, and ΔT setpoint, are recorded on the main control board.

b. Cold Leg and Hot Leg Temperatures

Temperature detectors, located in the thermometer wells in the cold and hot leg piping of each loop, supply signals to wide range temperature recorders and indicators for loops A and B on the main control board. This information is used by the operator to control coolant temperature during startup and shutdown.

c. Pressurizer Temperature

There are two temperature detectors in the pressurizer: one in the steam phase and one in the water phase. Both detectors supply signals to temperature indicators and high temperature alarms in the control room. The steam phase detector, located near the top of the vessel, is used during startup to determine water temperature when the pressurizer is completely filled with water. The water phase detector, located at an elevation near the center of the heaters, is used during cooldown when the steam phase detector response is slow due to poor heat transfer.

d. Surge Line Temperature

This detector supplies a signal for a temperature indicator and a low temperature alarm in the control room. Low temperature is an indication that the continuous spray rate is too small.

e. Safety and Relief Valve Discharge Temperatures

Temperatures in the pressurizer safety and relief valve discharge lines are measured and supply signals for a high temperature alarm and indicator in the control room. An increase in a discharge line temperature is an indication of leakage through the associated valve.

f. Spray Line Temperatures

Temperatures in the spray lines from two loops are measured and indicated on the main control board. Alarms from these signals are actuated by low spray water temperature. Alarm conditions indicate insufficient flow in the spray lines.

g. Pressurizer Relief Tank Water Temperature

The temperature of the water in the pressurizer relief tank is indicated on the main control board. An alarm actuated by high temperature informs the operator that cooling of the tank contents is required.

h. Reactor Vessel Flange Leakoff Temperature

The temperature in the leakoff line from the reactor vessel flange o-ring seal leakage monitor connections is indicated on the main control board. An increase in temperature above ambient is an indication of o-ring seal leakage. High temperature actuates an alarm.

i. Reactor Coolant Pump Motor Temperature Instrumentation

(1) Thrust Bearing Upper and Lower Shoes Temperature

Resistance temperature detectors are provided with one located in the shoe of the upper and one in the shoe of the lower thrust bearing. Monitoring of these detectors is provided by the plant computer which actuates a high temperature alarm at the computer.

(2) Stator Winding Temperature

The stator windings contain six resistance type detectors, two per phase, imbedded in the windings. A signal from one of these detectors is monitored by the plant computer which actuates a high temperature alarm at the computer.

(3) Upper and Lower Bearing Temperature

Resistance temperature detectors are located one in the upper and one in the lower radial bearings. Monitoring of these detectors is provided by the plant computer which actuates a high temperature alarm at the computer.

j. Reactor Head Vent Piping Temperature Instrumentation

(1) A temperature element is installed on the common line downstream of the motor operated valves to detect any potential leakage across the valve seats during Power Operation.

2. Flow Indication

a. Reactor Coolant Loop Flow

Flow in each reactor coolant loop is monitored by three differential pressure measuring detectors at a piping elbow tap in each reactor coolant loop and indicated on the main control board. These measurements on a two out of three coincidence circuit provide a low flow signal to actuate a reactor trip.

b. Safety Valve Flow

An acoustical type sensor is provided downstream of each safety valve to detect flow through the safety valves. The sensor activates an alarm in the control room when flow is detected. Control room indication is provided to enable the plant operator to determine which valve is open.

3. Pressure Indication

a. Pressurizer Pressure

Three pressurizer pressure transmitters provide signals for individual indicators in the control room for actuation of both a low pressure trip and a high pressure trip. One of the signals may be selected by the operator for indication on a pressure recorder. Three transmitters provide low pressure signals for safety injection initiation. Three transmitters provide signals for safety injection signal unblock during plant startup. An additional transmitter is used, along with a reference pressure signal, to develop a demand signal for a three-mode controller. The lower portion of the controller’s output range operates the

pressurizer heaters. For normal operation, a small group of heaters is controlled by variable power to maintain the pressurizer operating pressure. If the pressure error signal falls towards the bottom of the variable heater control range, all pressurizer heaters are turned on.

The upper portion of the controller's output range operates the pressurizer spray valves and one power relief valve. The spray valves are proportionally controlled in a range above normal operating pressure with spray flow increasing as pressure rises. If the pressure rises significantly above the proportional range of the spray valves, a power relief valve (interlocked with a separate transmitter so as to prevent spurious operation) is opened. A further increase in pressure will actuate a high pressure reactor trip. A separate transmitter (interlocked also with another transmitter to prevent spurious operation) provides power relief valve operation for two additional valves upon high pressurizer pressure. A signal interlock between transmitter is required to open (or keep open) the power relief valve.

b. This item deleted.

c. Reactor Coolant Loop Pressures

Two transmitting channels are provided. Both transmitters provide a recorder signal and an indication of reactor coolant pressure on two of the hot legs. These are wide range transmitters which provide pressure indication over the full operating range. The recorder, together with the indicators, serve as a guide to the operator for manual pressurizer heater and spray control and letdown to the Chemical and Volume Control System during plant startup and shutdown. An amplifier signal from the lower portion of the range of one of the channels is indicated on the main control board to provide improved legibility at the lower pressures.

The two wide range channels provide the permissive signals for the residual heat removal loop suction line isolation valve interlock circuit.

d. Pressurizer Relief Tank Pressure

The pressurizer relief tank pressure transmitter provides a signal to an indicator and a high pressure alarm in the control room.

e. Reactor Coolant Pump Motor Oil Pressure and Level

(1) Oil Pressure

Pressure switches are provided on the high pressure oil lift system. Low oil pressure actuates an alarm on the main control board. In addition, an interlock system prevents starting of the pump until the oil lift pump is started manually prior to starting the reactor coolant pump motor and actuates a status light to indicate adequate oil pressure. A local pressure gauge is also provided.

(2) Lower Oil Reservoir Liquid Level

A level switch is provided in the motor lower radial bearing oil reservoir. The switch actuates a high or low level alarm in the control room

(3) Upper Oil Reservoir Liquid Level

A level switch is provided in the motor upper radial bearing and thrust bearing oil reservoir. The switch actuates a high or low level alarm in the control room.

4. Liquid Level Indication

a. Pressurizer Water Level

Three pressurizer liquid level transmitters provide signals for use in the Reactor Control and Protection System, the Emergency Core Cooling System, and the Chemical and Volume Control System. Each transmitter provides an independent high water level signal that is used to actuate an alarm and a reactor trip. The transmitters also provide independent low water level signals that activate an alarm. Each transmitter also provides a signal for a level indicator that is located on the main control board.

In addition to the above, signals may be selected for specific functions as follows:

(1) Any one of the three level transmitter signals may be selected by the operator for display on a level recorder located on the main control board. This same recorder is used to display a pressurizer reference liquid level signal.

(2) Two of the three transmitters perform the following functions: (A selector switch allows the third transmitter to replace either of these two.)

(a) One transmitter provides a signal which actuates an alarm when the liquid level falls to a fixed level setpoint. The same signal trips the pressurizer heaters "off" and closes the letdown line isolation valves.

(b) One transmitter supplies a signal to the liquid level controller for charging flow control and initiation of a low flow (hi demand) alarm. This signal is compared to the reference level. If the actual level is lower than the reference level, a low alarm is actuated. If the actual level exceeds the reference level, a high level alarm and all pressurizer backup heaters are energized.

A fourth independent pressurizer level transmitter that is calibrated for low temperature conditions provides water level indication on the main control board during startup, shutdown, and refueling operations.

b. Pressurizer Relief Tank Level

The pressurizer relief tank level transmitter supplies a signal for an indicator on the main control board for high and low level alarms.

c. Reactor Vessel Level

The reactor vessel level system provides a direct reading of reactor vessel level on the main control board which can be used by the operator in conjunction with the core subcooling monitor to identify the possibility of inadequate core cooling conditions. Details of the reactor vessel level system are provided in Section 7.6.9.

5. Valve Position

   The pressurizer power operated relief valves are provided with limit switches for safety grade indication of valve open/closed position in the control room.

6. Core Subcooling Indication

   The core subcooling monitor provides continuous monitoring of the margin to saturation in the reactor core (i.e., the amount of subcooling) on the main control board. The core subcooling monitor utilizes inputs from the hot leg RTDs, Reactor Coolant System pressure sensors, and selected incore thermocouples. Details of the core subcooling monitor system are provided in Section 7.5.5.

   The Reactor Coolant System design and operating pressure together with the safety, power relief, and pressurizer spray valve setpoints, as well as the protection system setpoint pressures, are listed in Table 5.2-7.

   The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops instrumentation and control accuracy and response characteristics, and system relief valve characteristics.

   Process control instrumentation for the Residual Heat Removal System is provided for the following purposes:

   a. Furnish input signals for monitoring and/or alarming purposes for:
      (1) Temperature indications
      (2) Pressure indications
      (3) Flow indications
   b. Furnish input signals for control purposes of such processes as follows:
      (1) Control valve in the residual heat removal pump bypass line so that it opens at flows below a preset limit and closes at flows above a preset limit.
      (2) Residual heat removal inlet valves control circuitry. See Section 7.6 for the description of the interlocks and requirements for automatic closure.
      (3) Control valve in the residual heat removal heat exchanger bypass line to control temperature of reactor coolant returning to reactor coolant loops during plant cooldown.
      (4) Residual heat removal pump circuitry for starting residual heat removal pumps on "S" signal.

5.7 INSERVICE INSPECTION PROGRAM (INCLUDING PRESERVICE INSPECTION)

During the design phase of the Virgil C. Summer Nuclear Station, careful consideration has been given to access, where practical, for the performance of preservice and inservice examinations.

5.7.1 Applicable Codes and Standards

The inservice inspection program (including preservice inspection) is administered in accordance with the applicable codes and standards as addressed in 10 CFR 50.55a.

Deviations from Code requirements are allowed and/or prescribed by various means. These deviations may be permitted via NRC approved Relief Requests, Code Cases which are adopted by the NRC in various Regulatory Guides, Generic Letters, and exceptions described in 10 CFR 50.55a. Any deviations from the Code requirements will be documented in the inservice inspection program (i.e., ISI, IST, and Repair and Replacement).

5.7.1.1 Preservice Inspection

The initial preservice inspection for Class 1, 2, and 3 components was performed to the extent practical in accordance with IWB-2100, IWC-2100, and IWD-2100 of the ASME B&PV Code Section XI (1974 edition through Summer 1975 addenda).

5.7.1.2 First Inspection Interval - January 1, 1984 Through December 31, 1993

During the first 10 year inspection interval, for Class 1, 2, and 3 components (except as noted below), the preservice inspections for repairs, replacements, and inservice inspections were performed to the extent practical to the ASME B&PV Code Section XI (1977 edition through Summer 1978). Per 10 CFR 50.55a(b)(2)(iv), examination of Code Class 2 pipe welds in the Residual Heat Removal System, Emergency Core Cooling System, and Containment Heat Removal System shall be determined by the requirements of paragraph IWC-1220, Table IWC-2520 Category C-F and C-G, and paragraph IWC-2411 of the ASME B&PV Code Section XI (1974 edition through Summer 1975 addenda). For V. C. Summer, these systems are defined as Residual Heat Removal (RH), Safety Injection (SI), Service Water (SW), Reactor Building Spray (SP), and Component Cooling Water (CC). For ASME Class 1, 2, and 3 component supports, preservice inspections for repairs and replacements and inservice inspection are performed to the extent practical in accordance with the ASME B&PV Code Section XI (1977 edition through Summer 1978) and subsection IWF of the ASME B&PV Code Section XI (1980 edition through Winter 1981). Inservice testing of Class 1, 2, and 3 valves is performed to the extent practical in accordance with subsection IWV of the ASME B&PV Code Section XI (1977 edition through Summer 1978). Inservice testing of Class 1, 2, and 3 pumps is performed to the extent practical in accordance with the ASME B&PV Code Section XI (1980 edition).

5.7.1.3 Second Inspection Interval - January 1, 1994 Through December 31, 2003

The second 10 year interval was performed to the requirements of Section XI of the ASME B&PV Code as prescribed by 10 CFR 50.55a. The latest edition of Section XI approved for use on January 1, 1994 was the 1989 edition.

5.7.1.4 Third Inspection Interval - January 1, 2004 Through December 31, 2013

The third 10 year inservice inspection interval will meet the requirements of Section XI of the ASME B&PV Code as prescribed by 10 CFR 50.55a. The latest edition of Section XI approved for use on January 1, 2004 was the 1998 edition, with addenda through 2000. However, as later editions are incorporated into 10 CFR 50.55a, the provisions of the later Code may be incorporated, in part or in whole, as allowed by 10 CFR 50.55a during the interval. The inservice inspection plans will designate the applicable edition and addenda to the corresponding inspection items. The inservice testing program for ASME Class 1, 2, and 3 pumps and valves will be implemented in accordance with the ASME OM Code, 1998 edition, with addenda through 2000 as prescribed by 10 CFR 50.55a.

Note to 5.7.1.4:

During the third and subsequent 10 year inspection intervals, preservice inspections for repairs and replacements and inservice inspection will be performed to the extent practical to the ASME B&PV Code Section XI [edition and addenda to be determined by the latest edition and addenda incorporated by reference in 10 CFR 50.55a(a), 12 months prior to the start of the inspection interval as per 10 CFR 50.55a(g)(4)(ii)]. Per IWA-2430(b), "The inspection interval shall be determined by calendar years following placement of the power unit into commercial service" as determined by the regulation of the Federal Power Commission, Chapter I - Title 18, Code of Federal Regulations Part 191, paragraph 9.D. Sub paragraph IWA-2430(c) further states that, "Each inspection interval may be decreased or extended (but not cumulatively) by as much as 1 year." For the purpose of determining the beginning and end of future ten year inspection intervals, the plant began commercial operation on January 1, 1984.

5.7.1.5 Fourth Inspection Interval - January 1, 2014 Through December 31, 2023

The fourth 10 year inservice inspection interval will meet the requirements of Section XI of the ASME B&PV Code as prescribed by 10 CFR 50.55a. The latest edition of Section XI approved for use on January 1, 2014 was the 2007 edition, with addenda through 2008. However, as later editions are incorporated into 10 CFR 50.55a, the provisions of the later Code may be incorporated, in part or in whole, as allowed by 10 CFR 50.55a during the interval. The inservice inspection plans will designate the applicable edition and addenda to the corresponding inspection items. The inservice testing program for ASME Class 1, 2, and 3 pumps, valves, and snubbers will be implemented in accordance with the ASME OM Code, 2004 edition, with addenda through 2006 as prescribed by 10 CFR 50.55a.

5.7.2 Provisions for Access to Reactor Coolant Pressure Boundary

Provisions for adequate access have been verified by a review of all the drawings applicable to the layout and arrangement of the reactor coolant and associated auxiliary systems within the boundaries established in accordance with the requirements of IWB-1200 and IWC-1200.

Specific provisions made for inspection access in the design of the reactor vessel, system layout, and other major primary coolant components to ensure compliance with the requirements of IWA-1500 and IWB-2600 are as follows:

1. Reactor internals are completely removable. The tools and storage space required to permit reactor internals removal for these inspections are provided.
2. The reactor vessel shell in the core area is designed with a clean, uncluttered cylindrical inside surface to permit future positioning of test equipment without obstruction.
3. The reactor vessel cladding is improved in finish by the vessel manufacturer by grinding to the extent necessary to permit meaningful examination of the vessel welds and adjacent base metal in accordance with the Code.
4. The cladding to base metal interface is ultrasonically examined by the vessel manufacturer to assure satisfactory bonding to allow the volumetric inspection of the vessel welds and base metal from the vessel inside surface.
5. The reactor closure head is stored dry on the operating floor during refueling, allowing direct access for inspection.
6. The insulation on the vessel closure and lower heads is removable, allowing access for the visual and nondestructive examination of head welds.
7. Reactor vessel studs, nuts, and washers are removed for dry storage during refueling, allowing inspection in parallel with refueling operations.
8. Access holes in the core barrel flange allow access for remote visual examination of the clad surface of the vessel without removal of the lower internals assembly.
9. Access holes are provided in the primary shield, providing access for the surface and visual examination of the primary nozzle safe end welds.
10. Manways are provided in the steam generators to provide access for internal inspection.
11. A manway is provided in the pressurizer top head to allow access for internal inspection.
12. Where practical, the insulation covering component and piping welds and adjacent base metal are designed for ease of removal and replacement in areas where external inspection is planned.
13. Openings are provided in the operating floor concrete above the reactor coolant pumps to permit removal of the pump motor to provide internal inspection access to the pumps.

14. The primary loop compartments are designed to allow personnel entry during refueling operations to permit direct inspection access to the external portion of piping and components.

Provisions are made for inspection access in the design of Class 2 components to ensure compliance with the requirements of IWC-2600.

The use of conventional nondestructive volumetric test techniques can be applied to the inspection of all primary loop components except for the reactor vessel. The reactor vessel presents special problems because of the radiation levels and remote underwater accessibility to this component.

As indicated above, the only sophisticated remote inspection equipment currently required is for inspection of the reactor vessel. The baseline preservice inspection is performed onsite by Westinghouse utilizing a remote reactor vessel ultrasonic inspection tool which will perform the Code required inspection of the circumferential and longitudinal shell welds, the flange to vessel weld, the ligaments between the flange holes, the nozzle to vessel welds, and the nozzle to safe end to pipe welds.

5.7.3 Equipment for Inservice Inspections

The vessel inspection tool has two major structural components, the center column assembly which is supported and aligned from the vessel internals support flange by the head assembly. These two structures form the rigid base assembly from which the scanning arm and drive assemblies are mounted and operated. Two configurations of the tool can be arranged depending on the areas of the vessel to be examined. In Figure 5.7-1, the scanning arm and transducer array, necessary to examine the vessel shell welds, are mounted on the main carriage assembly. The main carriage assembly can traverse the full length of the vessel up and down the center column and also provide 360 degrees circumferential rotation around the inside of the vessel. In Figure 5.7-2, the nozzle scanning assembly is mounted beneath the main carriage and can be rotated for 360 degrees to provide alignment with any of the vessel nozzles. The tool, in this configuration, can be installed in the vessel without removal of the lower internals package. The scanning attachment for the examination of the vessel flange weld and ligaments can be installed on the tool in either of the two configurations described above. Figures 5.7-1 and 5.7-2 show the inspection tool in both these configurations.

5.7.4 Recording and Comparing Data

For reactor vessel scanning, a data acquisition system is used which combines simplicity with operational reliability and adaptability. It employs an electronic system with a receiver or data channel for each transducer unit. The signal received from the transducer is transmitted through an electronic distance amplitude correction device and, depending on the amplitude, gated through individual transigates to a printer. Simultaneously with the gated signal, information is received from the position indication encoder system which provides position coordinates. The resultant indication is printed on a recording device together with its position reference.

Following the completion of the scan of the areas scheduled for inspection, the tool operator(s) will, operating on manual control, return the transducer array to each of the indication position coordinates and evaluate the nature of the indication to sufficient extent to be able to determine the size, shape, and location. Special transducer arrays with variable angle search units are provided to assist in this activity.

For manual ultrasonic scanning, such as examination of a circumferential pipe weld, Westinghouse Nuclear Energy Systems has prepared a set of standard operator procedures to ensure that inspection results are recorded in a manner which will avoid any ambiguity in interpretation. The procedure specifies how any indication must be recorded with respect to scan direction and weld orientation, and how datum points, from which the location of indications are measured, are to be selected. Figure 5.7-3 shows a typical data sheet for recording instrument calibration settings for the volumetric examination of a circumferential pipe weld.

The data from the various baseline examinations, collected in accordance with the above procedures, were assembled into a comprehensive report tabulating the results.

The report describes the scope of the inspection, the procedures utilized, the equipment utilized, names and qualifications of the operators, and the examination results including instrument calibration criteria in sufficient detail to ensure repeatability for each examination.

5.7.5 Reactor Vessel Acceptance Standards

The reactor vessel acceptance standards to be used during preoperational mapping of the vessel by ultrasonic examination met the requirements of IWB-3000.

5.7.6 Coordination of Inspection Equipment with Access Provisions

The only area where it is expected that high radiation levels will prohibit the access of personnel for direct examination of component areas or systems is the reactor vessel. The special design provisions and tooling required to perform the Code required examinations in these areas have been discussed above. Westinghouse is carrying out a continuing program of radiation surveys during refueling programs in operating plants to ensure that possible future problem areas are detected at an early stage. Should additional experience in the maintenance and inspection of operating plants indicate that other areas exist where access will be either limited or impossible, steps will be taken to develop any remotely operated inspection equipment considered necessary to meet the commitments of examinations required by Section XI of the Code.

HISTORICAL DATA ONLY

The detailed inservice inspection program is presented in the Technical Specifications, Section 3/4.4.10. This program is based on Section XI of the ASME Code. It is anticipated that the results obtained from compliance with the Technical Specifications and the state of the art will be evaluated before establishing a long term inspection program. The data collected during the first five years of operation, along with the overall operating experiences, will be reviewed to determine the overall inspection program to be implemented for the lifetime of the facility.

5.7.7 Preservice and Inservice Inspection of Class 1, 2, and 3 Components

5.7.7.1 Component Subject to Examination or Inspection

All ASME Code, Section III, Class 1 components subject to examination or inspection will be examined or tested, as applicable, in accordance with the requirements of Article IWB-2000 ASME Code Section XI.

All ASME Code, Section III, Class 2 components subject to examination or inspection will be examined or tested, as applicable, in accordance with the requirements of Article IWC-2000 ASME Code Section XI. The Technical Specifications specify Code Class 2 components requiring weld examinations, including the type(s) of examination as specified by Article IWC-2000 ASME Code Section XI.

ASME Code, Section III, Class 3 components, if any, subject to examination or inspection will be examined or tested in accordance with Article IWD-2000 ASME Code Section XI and any additional requirements of the Technical Specifications.

Code Class 2 and 3 pumps will be inservice tested in accordance with the ASME Code of Record, prescribed under 10 CFR 50.55a.

Code Class 1, 2, and 3 valves will be inservice tested in accordance with the ASME Code of Record, prescribed under 10 CFR 50.55a.

5.7.7.2 Accessibility

The design and arrangement of Code Class components, where possible, provides suitable access to welds for nondestructive testing and visual inspections. Special platforms are provided at the circumferential welds on the steam generator shells. Weld preparation, spacing, and clearance for welds on Code Class 2 components that are to be nondestructively examined are in accordance with ASME Section XI.

In general, the plant piping and equipment arrangement is designed with consideration for maintenance and inspection. Should accessibility prevent a particular inspection or examination from being performed adequately, this condition will be resolved in accordance with ASME Section XI and/or 10 CFR 50.55a.

5.7.7.3 Examination Techniques and Procedures

The examination techniques and procedures utilized are in accordance with the applicable requirements of ASME Section XI. Nondestructive examinations and visual procedures are in accordance with the requirements of ASME Section XI Code and its applicable references.

5.7.7.4 Inspection Frequency

Class 1 components are inspected in accordance with a schedule which satisfies the requirements of Article IWB-2000 ASME Code Section XI.

Class 2 components are inspected in accordance with a schedule which satisfies the requirements of Article IWC-2000 ASME Code Section XI.

Class 3 components, if any, are inspected in accordance with a schedule which satisfies the requirements of Article IWD-2000 ASME Code Section XI.

5.7.7.5 Examination Categories and Requirements

The inspection categories and requirements for Class 1 components are in compliance with Article IWB-2000 ASME Code Section XI.

The inspection categories and requirements for Class 2 components are in compliance with Article IWC-2000 ASME Code Section XI.

The inspection categories and requirements for Class 3 components, if any, are in compliance with Article IWD-2000 ASME Code Section XI.

5.7.7.6 Evaluation of Examination Results

The evaluation of Class 1, 2, and 3 component examination results complies with the requirements of Articles IWA-3000 and IWB-3000, IWC-3000, or IWD-3000 of the ASME Code Section XI, as appropriate. The acceptance standard(s) for indications detected during the examination are those of ASME Code Section XI. When acceptance standards are not addressed in the ASME Code Section XI, those of the construction code, ASME Section III, are used. When specified, Section III edition and addenda are applied for the acceptance standard.

Repair procedures for flaws discovered during examination are developed in accordance with the requirements of Article IWA-4000 ASME Code Section XI and its applicable references for Class 1, 2, and 3 components.

5.7.7.7 System Pressure Tests

System pressure tests for Class 1 items comply with the testing and examination criteria of Articles IWA-5000 and IWB-5000, ASME Code Section XI.

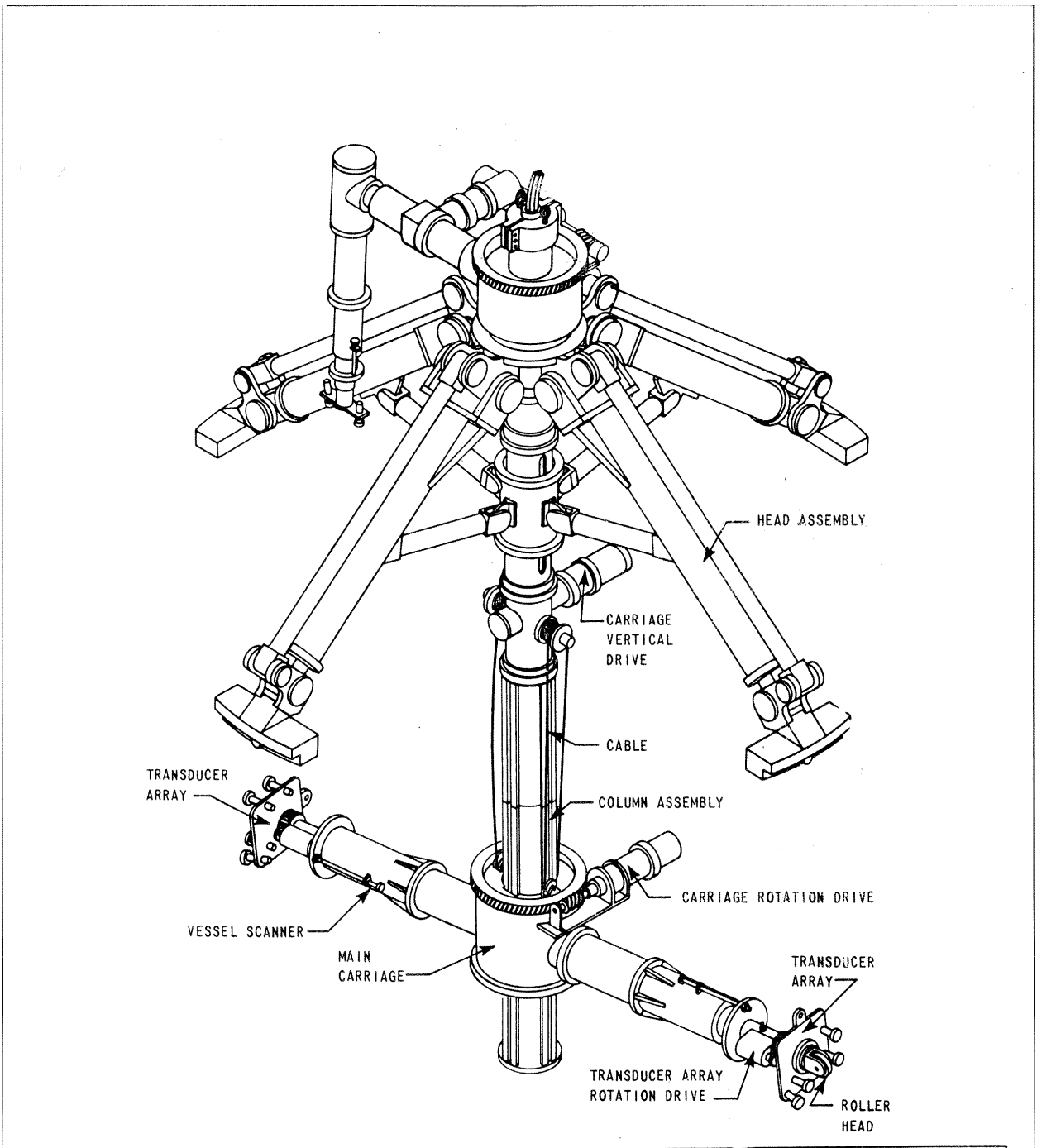
System pressure tests for Class 2 items comply with the testing and examination criteria of Articles IWA-5000 and IWC-5000, ASME Code Section XI.

System pressure tests for Class 3 items, if any, comply with the testing and examination criteria of Articles IWA-5000 and IWD-5000, ASME Code Section XI.

5.7.8 Augmented Inservice Inspection to Protect Against Postulated Piping Failures

Design measures have been taken to ensure that the reactor vessel and essential equipment within or outside of the containment, including components of the reactor coolant pressure boundary and other safety-related components, have been adequately protected against the effects of blowdown jet, reactive forces, and pipe whip resulting from postulated rupture of piping located inside or outside of containment. These measures are discussed in Section 3.6. As explained earlier in this section, high energy fluid system piping is inspected in accordance with ASME XI. Augmented inspection of high energy fluid system piping between containment isolation valves is not deemed necessary.

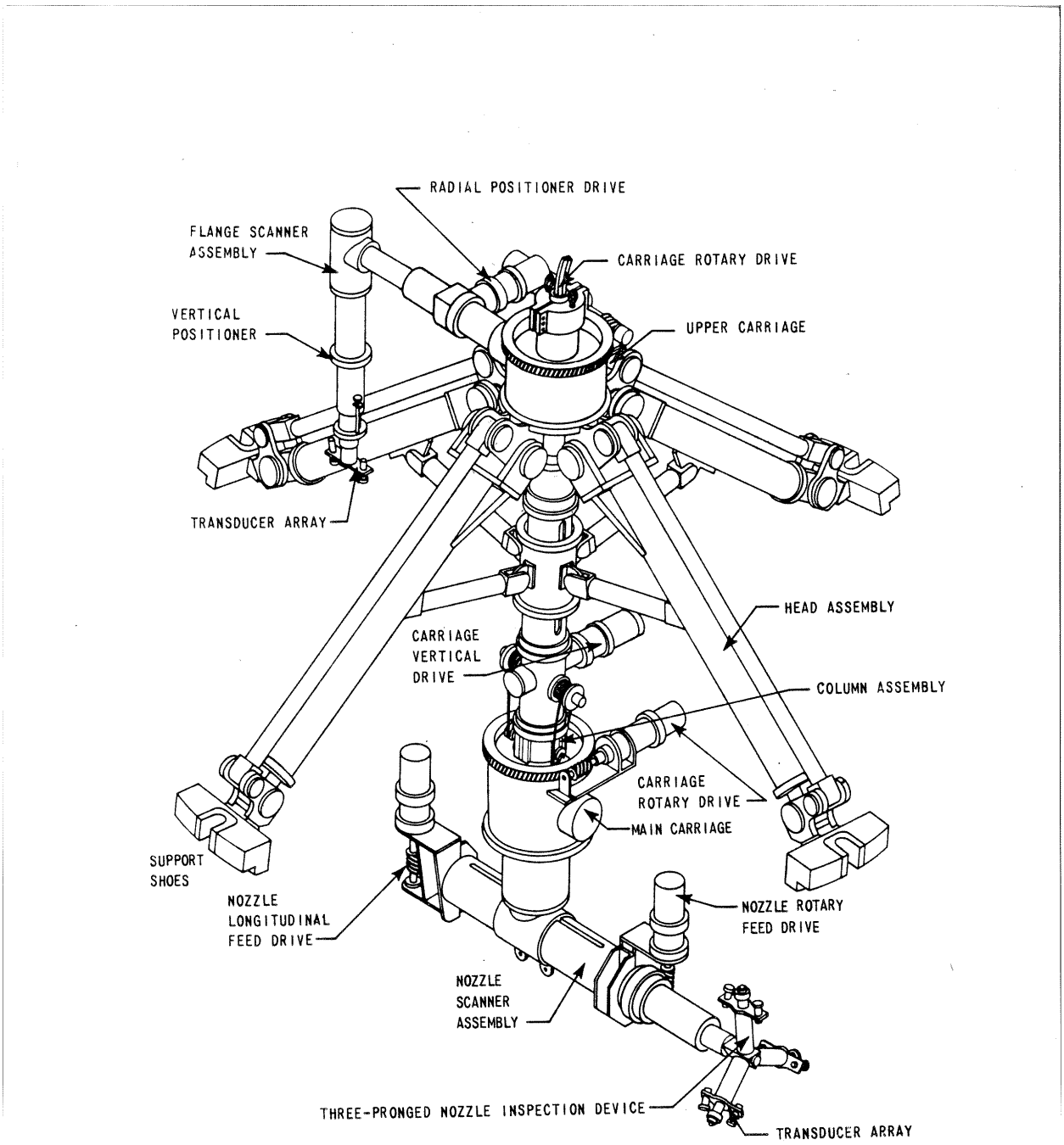
Figure 5.7-1
TOOL DETAILS (VESSEL SCANNER)



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Tool Details (Vessel Scanner)
Figure 5.7-1

Amendment 0
August 1984

Figure 5.7-2
TOOL DETAILS (NOZZLE AND FLANGE SCANNER)



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Tool Details (Nozzle and Flange Scanner) Figure 5.7-2

Amendment 0
August 1984

Figure 5.7-3

SAMPLE WELD DATA SHEET (SHEET 1 OF 2)

WELD DATA SHEET

Date:

Operators:

Weld No._____

Instrument Serial No. _____

Check List: Reject____ Damping____ Filter Out Rep. Rate 1000 T-Jack

SU Cable Length____ Reference Block____ Serial No.____

Search Unit _____ _____ _____ _____ _____ _____
Type MHz Size Beam Style Serial No.

Primary Reference Response _____dB_____Gain

Calibration

Set S/RT hole to 7.5 div. amplitude, mark distance amplitude curve from other holes.

Transfer

1. On Ref. Block but off holes. Perform transfer method using straight beam search unit to give correction or a second angle beam search unit.

Search Unit _____ _____ _____ _____ _____ _____
Type 2X above MHz Size Beam Style Serial No.

2. Attenuate (dB) response for good signal. Note Signal amplitude_____
3. On vessel wall adjust gain to set signal amplitude as in 2 above.
   Record gain: _____
   gain

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Sample Weld Data Sheet (Sheet 1 of 2)
Figure 5.7-3

Amendment 0
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Figure 5.7-3
SAMPLE WELD DATA SHEET (SHEET 2 OF 2)

WELD DATA SHEET (Continued)

4. Record transfer corrected gain_____

5. Scanning at 4. -14 dB_____dB_____Gain
Indications exceeding DAC line to be investigated and recorded showing their position and dimensions in the weldment.

6. Evaluate Indication at 5. +14 dB_____dB_____Gain
couplant:

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Sample Weld Data Sheet (Sheet 2 of 2)
Figure 5.7-3

Amendment 0
August 1984

V.C. Summer Nuclear Station
Safety Analysis Report

Engineered Safety Features

Chapter 6

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 6 - ENGINEERED SAFETY FEATURES

The central safety objective in reactor plant design and operation is control of reactor fission products. The methods used to assure this objective are:

1. Design of the reactor core in conjunction with the reactor control and protection systems to preclude release of fission products from the fuel (Chapter 4 and 7).
2. Retention of fission products in the Reactor Coolant System (Chapters 5 and 6).
3. Retention of fission products by the containment for operational and accidental releases beyond the reactor coolant boundary (Sections 3.8 and 6.2).
4. Limiting or optimizing fission product dispersal to minimize population exposure for an accidental release beyond the containment (Chapter 2 and 11).

The engineered safety features are the provisions in the plant which embody methods 2 and 3 above to prevent the occurrence, or to ameliorate the effects, of serious accidents.

6.1 GENERAL

The engineered safety features are:

1. Containment

   The reactor building provides a virtually leaktight barrier to the escape of fission products. Detailed information on the containment is provided in Section 6.2.1.

2. Reactor Building Heat Removal Systems

   These systems serve to reduce reactor building pressure and temperature. These systems are discussed in detail in Section 6.2.2.

3. Reactor Building Air Purification and Cleanup Systems

   The function of these systems is to provide air purification and cleanup services to the Reactor Building. These systems are discussed in Section 6.2.3.

4. Containment Isolation System

   This system provides containment isolation capability for the various system lines penetrating the containment. Detailed discussions of this system are presented in Section 6.2.4.

5. Combustible Gas Control System

   This system acts to control the concentration of hydrogen, oxygen, and other combustible gas which may be released to the reactor building to assure containment integrity. This system is discussed in Section 6.2.5.

6. Containment Leakage Testing

   Containment leakage testing provisions are discussed in Section 6.2.6.

7. Emergency Core Cooling System

   This system delivers borated water to the reactor core to provide core cooling following postulated accidents. The boron, together with the control rods provides sufficient negative reactivity for safe shutdown following design basis accidents. The Emergency Core Cooling System is discussed in detail in Section 6.3.

8. Habitability Systems

   These systems provide the control room with adequate shielding, air purification, and climatic control. These systems are discussed in Section 6.4.

9. Fission Product Removal and Control Systems

   The fission product removal systems include the high efficiency particulate air filters in the Reactor Building cooling system and the control room emergency filter plenums. This equipment is discussed in Section 6.5.

6.2 CONTAINMENT SYSTEMS

6.2.1 Containment Functional Design

6.2.1.1 Design Bases

6.2.1.1.1 Reactor Building

The safety design basis for the Reactor Building is the requirement that the releases of radioactive material subsequent to a reactor accident do not result in doses which exceed the guideline values specified by 10 CFR 50.67. To satisfy this requirement, a design containment leak rate is specified in conjunction with performance requirements for the other engineered safety features. The containment must withstand the temperatures and pressures resulting from a spectrum of postulated loss of coolant (LOCA) and secondary system pipe break accidents without leakage in excess of the design leak rate of 0.2% per day. The radiological consequences of the most severe hypothetical LOCA are presented in Section 15.4

The Reactor Building design pressure of 57 psig is above the peak calculated pressure of 53.0 psig resulting from the postulated double ended guillotine rupture (DER) of a main steam line. The bounding case, the 1.40 ft^2 DER at 25% power, is conservatively analyzed assuming an electrical channel A (CH-A) failure resulting in loss of one diesel generator (DG) and failure to isolate Emergency Feedwater (EFW) to the faulted steam generator.

The peak calculated Reactor Building temperature is 372.7°F. This peak calculated temperature results from the postulated 1.4 ft^2 DER at 102% power, assuming failure of a main steam isolation valve (MSIV) to close and a safety injection pump to start.

General containment design information is presented in Table 6.2-1. Figures 6.2-68 through 6.2-81 provide additional information on the general arrangement of Reactor Building structures and components.

6.2.1.1.1.1 Spectrum of Postulated Accidents

Five (5) postulated Reactor Coolant System pipe ruptures and 25 main steam line breaks have been analyzed to determine the peak Reactor Building pressure and temperature following an accident. For analytical purposes, it was assumed that each accident was coincident with loss of offsite power and a failure of at least 1 engineered safety feature.

The 5 postulated Reactor Coolant System pipe ruptures analyzed are as follows:

1. A double-ended pump rupture of the reactor coolant pump suction (DEPS) with maximum safety injection and 2 operable trains of the Reactor Building Spray (SP) System.
2. A DEPS with maximum safety injection and failure of 1 train of SP.
3. A DEPS with maximum safety injection, 2 operable trains of SP, and failure of 1 train of Reactor Building Cooling Units (RBCU).

4. A DEPS with minimum safety injection and failure of 1 train of emergency diesel generator coincident with a loss of offsite power.
5. A double-ended hot leg guillotine break (DEHL).

The mass and energy release information used for these enveloping Reactor Coolant System accidents is discussed in Section 6.2.1.3.10.1. The CONTEMP LT containment analysis code is used for this analysis and its use is discussed in Section 6.2.1.3.3.1.

The main steam line breaks (MSLB) analyzed to determine both peak reactor building pressure and peak reactor building temperature are listed in Table 6.2-1. The mass and energy release data developed for these breaks is discussed in Section 6.2.1.3.10.3. The main steam line breaks are analyzed using the CONTEMPT LT/26 (Reference 27) containment analysis code discussed in Section 6.2.1.3.3.1.

Post accident pressure reduction is accomplished through the operation of the Reactor Building Spray System and Reactor Building cooling units and by the Reactor Building structures. The performance of the Reactor Building Spray System and Reactor Building cooling units is discussed in Section 6.2.1.3.4. Structural heat removal is also discussed in Section 6.2.1.3.4.

6.2.1.1.2 Subcompartments

The analysis of the pressures existing at any time in the reactor compartment and steam generator compartment is discussed in Section 6.2.1.3. This analysis is based upon mass and energy inputs described in Section 6.2.1.3.10. The compartment volumes and vent openings were obtained from design drawings and are consistent with the structural capacity of the walls discussed in Sections 3.8.1 and 3.8.3. All vent areas were calculated based upon “net” cross sectional flow areas through pertinent openings in compartment walls and slabs. Net flow area is defined as the gross opening area minus any obstructions (piping, insulation, etc.), which are located in the particular opening. No credit was taken for the movement of obstructions or insulation in the analyses.

6.2.1.2 System Design

The design features of the Reactor Building and internal structures, as well as general arrangement drawings, are presented in Sections 3.8.1 and 3.8.3.

The codes, standards, and guides applied to the design of the Reactor Building and internal structures are included in Sections 3.8.1.2. and 3.8.3.2.

6.2.1.2.1 Design Provisions For Missiles and Pipe Whip

Design provisions are incorporated to protect the Reactor Building structure and Engineered Safety Features Systems against loss of function from dynamic effects that could occur following postulated accidents. The integrity of containment is maintained and functional capability of Engineered Safety Feature Systems is not compromised following postulated accidents that involve pipe rupture with subsequent pipe whip and jet impingement, and postulated accidents that involve missile impact. Design provisions include the following:

1. Physical separation of the redundant portions of Engineered Safety Features System.
2. Pipe rupture restraints that limit pipe movement following postulated pipe rupture.
3. Physical barriers, such as walls, floors, backfill, etc., to separate and protect equipment, as required.
4. Jet impingement shields, located where required, to protect specific piping or components from jet impingement from a postulated pipe break.
5. Detailed stress analyses to determine specific cases where provision of a shield or barrier is not required. This occasionally occurs in the path of low energy jets where sufficient stress margin is available in the pipe or component design to tolerate the impact.

Detailed discussion of design provisions for protection against postulated pipe rupture is presented in Section 3.6.

Detailed discussion of design provisions for protection against the effects of postulated missiles, both internal and external, is presented in Section 3.5.

6.2.1.2.2 External Loading

Inadvertent operation of the Reactor Building Spray System can result in a negative differential pressure in the Reactor Building. The external design pressure of the Reactor Building is 3.5 psig. Analysis of inadvertent Reactor Building Spray System operation is discussed in Section 6.2.1.3.6.

The external design pressure for tornado pressure loading is discussed in Section 3.3.

1. Reactor Building Pressure Equalization

   A narrow range differential pressure transmitter provides signals for monitoring Reactor Building internal pressure. Control room alarms are actuated by this pressure channel when the differential pressure approaches the baseline positive or negative pressure. Administrative procedures are implemented following the alarm to adjust Reactor Building pressure to within the required baseline pressure limits.

2. Inadvertent Reactor Building Spray

   During normal operation, inadvertent Reactor Building spray can occur only when performing the periodic inservice testing of one spray loop. An inadvertent safety injection signal to the spray loop discharge valve during spray loop test is the worst single failure.

6.2.1.2.3 Reactor Building Heating, Ventilating, and Air Conditioning System Functional Capability

The following Reactor Building ventilation systems operate continuously during normal plant operation to maintain suitable Reactor Building ambient temperature, pressure and humidity:

1. Reactor Building cooling units.
2. Reactor Building reactor compartment cooling system.
3. Reactor Building secondary compartment cooling system.
4. Integrated Head Assembly CRDM Cooling Fans

The Reactor Building charcoal cleanup system may operate intermittently during normal plant operation to maintain suitable radiation levels inside the Reactor Building.

The 36 inch Reactor Building Purge System may be operated during cold shutdown and refueling to maintain suitable radiation levels inside the Reactor Building. During the other modes of plant operation (Modes 1-4), the valves are locked closed and operation of the system is not permitted.

The 6 inch alternate Reactor Building Purge System may be operated up to 1000 hours per year during modes 1-4, to maintain suitable moisture and radiation levels inside the Reactor Building.

Details of the operation of these systems are presented in Sections 6.2.2, 6.2.5, 6.5.1, and 9.4.8.

6.2.1.3 Design Evaluation

6.2.1.3.1 Reactor Building Peak Pressure and Temperature Analysis

In the event of a loss of coolant accident, much of the released reactor coolant will flash to steam. This release of mass and energy raises the temperature and pressure of the atmosphere within the Reactor Building. A rupture of a main steam pipe produces similar effects. The severity of the temperature and pressure peaks depends upon the nature, size, and location of the rupture.

A steam line break yields higher Reactor Building pressure than does a feedwater line break inside the Reactor Building. The same amount of water is added to the Reactor Building in each case. However, a steam line break causes the water to be added as superheated vapor, while a feedwater line break adds liquid with much lower enthalpy to the Reactor Building atmosphere. The feedwater line break is not considered to be as limiting as the main steam line break or primary system LOCA and, therefore, was not analyzed.

6.2.1.3.1.1 Peak Pressure Analysis

In order to identify the worst case, the spectrum of hypothetical main stream line break and LOCA events described in Section 6.2.1.1.1.1, based upon the initial conditions specified in Tables 6.2.2 and 6.2-33, respectively, has been analyzed using the CONTEMPT LT computer program discussed in Section 6.2.1.3.3.1.

The break resulting in the maximum calculated pressure in the Reactor Building is the 1.40 ft^2 DER at 25% power main steam line break assuming a CH A failure. The peak pressure in the Reactor Building is conservatively calculated to be 53.0 psig, at 1800 seconds following the break.

The following peak pressure analyses were performed:

1. Loss of Coolant Accident Analyses

   The loss of coolant accidents analyzed; information concerning break type, peak pressure, and temperature, and single active failure are presented in Table 6.2-3.

   Figure 6.2-1 presents the calculated pressure as a function of time for the DEPS break with minimum safety injection.

   Figure 6.2-2 presents the calculated pressure as a function of time for the spectrum of pump suction DEPS break with maximum safety injection.

   Figure 6.2-3 presents the calculated pressure as a function of time for the double ended guillotine hot leg break (DEHL). This case was only run until the time at which the peak containment pressure is achieved. The break results in the peak RB pressure (45.53 psig) for the spectrum of LOCAs that is less than the Technical Specification 6.8.4.g calculated peak pressure (Pa) of 46.0 psig, and accounts for the reactor vessel up-flow modification.

   Methods used, initial conditions, and single active failures assumed are discussed in Section 6.2.1.3.3.

   PAD5 implementation impacts the LOCA containment analyses for DEPS and DEHL due to an increase in core stored energy from 3.19 full power seconds (fps) to 3.45 fps. Evaluation of the DEPS and DEHL breaks resulted in an increase in containment pressure of +0.12 psig and RB peak pressure remains <Pa (i.e., DEHL peak pressure of 45.65 psig). The limiting Peak pressures shown in Figures 6.2-1 through 6.2-3 remain representative of LOCA containment pressure response.

2. Main Steam Line Break Analysis

   Figure 6.2-4 presents the calculated pressure versus time for the 1.40 ft^2 DER at 25% power main steam line break assuming a CH-A failure (the design basis accident).

   Methods used, initial conditions, and failures assumed for main steam line break analyses are discussed in Section 6.2.1.3.3.

   Table 6.2-3 presents a summary for each main steam line break analyzed.

   An evaluation of the impact of PAD5 implementation on the MSLB containment analysis determined that MSLB mass and energy (M&E) releases were not sensitive to the changes that result from PAD5 implementation. Therefore, the transient M&E releases inside or outside containment remain valid for use as input to the containment integrity analysis or the outside containment compartment temperature response analysis.

6.2.1.3.1.2 Peak Temperature Analysis

The spectrum of steam line breaks listed in Table 6.2-1a, based upon the initial conditions specified in Table 6.2-2, has been analyzed using the CONTEMPT LT/26 (Reference 27) computer program discussed in Section 6.2.1.3.3.

The steam line break resulting in the maximum calculated temperature in the Reactor Building is the 1.4 ft^2 DER at 102% power with MSIV and SI failures. The peak temperature in the Reactor Building is calculated to be 372.7° F, 19 seconds after the break.

The following peak temperature analyses were performed.

1. Main Steam Line Break Analyses

   The main steam line break accidents analyzed; information concerning break type, peak temperature, and pressure; times of peak temperature and pressure; and active failures assumed are presented in Table 6.2-3.

   Figure 6.2-5a illustrates calculated temperature versus time for the worst case (temperature) main steam line break (1.4 ft^2 DER at 102% power with MSIV and SI failures).

   Figure 6.2-5b illustrates the calculated temperature as a function of time for a spectrum of main steam line split ruptures.

   Figure 6.2-5c and Figure 6.2-5d illustrate the condensing steam heat transfer coefficient and the Reactor Building liner and interior concrete wall temperatures versus time for the worst case (temperature) main steam line break.

6.2.1.3.2 Long Term Reactor Building Performance

The long term system behavior during the design basis accident main steam line break and the worst case DEPS guillotine (minimum safety injection) LOCA have been evaluated to verify the ability of the ECCS and Reactor Building heat removal systems to maintain the Reactor Building pressure and temperature below design limits following a postulated high energy pipe rupture. This evaluation is based upon conservative predictions of the performance of these engineered safety features.

The primary system loss of coolant accident releases more energy into the Reactor Building over the course of the accident than the design basis accident main steam line break. The design basis accident mass and energy release is terminated after 1800 seconds. Since the plant operators are required to take action to terminate emergency feedwater flow to the faulted steam generator at 10 minutes, as discussed in Section 10.4.9.3, the analysis performed is conservative. Therefore, for long term Reactor Building performance, the LOCA is analyzed to 1440 hours and the design basis accident main steam line break is analyzed to 1800 seconds. The long term values of the Reactor Building parameters at 1440 hours for LOCA and 1800 seconds for the design basis accident main steam line break are presented in Table 6.2-4 and are shown graphically by Figures

6.2-1, 6.2-7 and Figures 6.2-4, 6.2-6, and 6.2-6a, respectively. The reactor vessel upflow modification has no impact on long-term Reactor Building parameters.

Figures 6.2-8 through 6.2-14 are presented to demonstrate the long term cooling capability of the Reactor Building. The following conservative assumptions were used in the analysis:

1. No leakage.
2. Reactor Building Spray System is operated for a period of up to 40 days.
3. Reactor Building Cooling Units are operated for a period of up to 40 days.
4. Boiling in the reactor vessel is suppressed after 40 days by aligning the ECCS to the RCS hot legs and cold legs simultaneously after 8 hours during the hot leg recirculation phase.

The following parameters are illustrated by the figures indicated:

1. Total energy absorbed by passive heat sinks:
   a. Design basis accident main steam line break, Figure 6.2-8.
   b. LOCA, DEPS, minimum safety injection, Figure 6.2-9.
2. Condensing film heat transfer coefficients:
   a. Design basis accident main steam line break, Figure 6.2-10.
   b. LOCA, DEPS, minimum safety injection, Figure 6.2-11.
3. Reactor Building cooling units heat removal rate:
   a. Design basis accident main steam line break, Figure 6.2-12.
   b. LOCA, DEPS, minimum safety injection,Figure 6.2-13.
4. Residual Heat Removal System heat rate, Figure 6.2-14 (LOCA).

The accident chronology for the design basis accident main steam line break is given in Table 6.2-5.

The accident chronology for the DEPS with minimum safety injection, DEPS with maximum injection, DEHL LOCA scenarios are given in Tables 6.2-6a, 6.2-6b. and 6.2-6c respectively.

6.2.1.3.3 Methods of Analyses

6.2.1.3.3.1 Description of Computer Code

Calculation of Reactor Building pressure and temperature transients were performed using the digital computer code, CONTEMPT LT. CONTEMPT LT will model up to 4 containment volumes, consisting of primary system, wetwell, drywell, or dual containment. Only the primary system and drywell options are used. Transient phenomena within the Reactor Coolant System

affect containment conditions by means of convective mass and energy transport through the pipe break. The containment drywell is separated into 2 regions. The first region consists of the air steam phase; the second, the water phase. Sufficient relationships to describe the transient are provided by the equations of conservation of mass and energy as applied to each region, together with appropriate boundary conditions.

Two (2) versions of the CONTEMPT-LT computer program are used for analysis of Reactor Building pressure and temperature transients. CONTEMPT-LT/26 was used for analysis of MSLB and LOCA transients for steam generator replacement. Subsequent revision of LOCA Reactor Building pressure and temperature analysis used CONTEMPT-LT/28, which is described in NUREG/CR-0255 (Reference 47). CONTEMPT-LT/28 is an update to version LT/26 described in this section. The analytical assumptions described in Section 6.2.1.3.3.2 apply to both versions of the program. No modifications to any models have been made CONTEMPT-LT/28 by SCE&G. The only significant modeling change resulting from the change to LT/28 from LT/26 is the use of the Uchida condensing heat transfer coefficient, rather than Tagami, for the condensing heat transfer to concrete and steel heat sinks during the LOCA transient, as described in Section 6.2.1.3.4.1. Containment pressure-temperature analysis for MSLB has not been revised since steam generator replacement and reflects the use of CONTEMPT-LT/26. Analysis of the double-ended hot leg rupture pressure and temperature transients has also not been revised since use of LT/28 was adopted.

The applicability of the CONTEMPT computer code to the containment pressure/temperature analyses can be verified by the Carolinas Virginia Tube Reactor (CVTR) experiments (Reference 24). An excerpt from Reference 24 states the following:

> "The CVTR DBA tests and analyses have demonstrated that the CONTEMPT containment response analytical model will predict reasonably accurately the containment atmosphere pressure-temperature response provided correct assignment of condensing steam heat transfer coefficients and other key parameters are made. But, when common assumptions currently used for the heat transfer coefficient (Tagami) or similar were employed, the CVTR DBA test results indicated that the peak pressure prediction obtained from CONTEMPT was conservative by about 45%. However, the magnitude of overprediction of pressure depends on the blowdown conditions and other factors such that for a large pipe rupture (or fast blowdown), underestimating the heat transfer coefficient probably has a lesser effect on the peak pressure predictions (15% or less)."

CONTEMPT is basically a 1 node containment code. The containment temperature stratification, as measured in the CVTR tests, cannot be predicted by a 1 volume model which necessarily uses average overall heat transfer coefficients, such as Uchida (Reference 5) or Tagami (Reference 4). However, the Uchida and Tagami correlation have been shown by the CVTR data and the work of Slaughterbeck (Reference 25) to be conservative for containment analysis.

6.2.1.3.3.2 Assumptions

The following are the major assumptions made in analysis:

1. Discharge mass and energy flow rates through the Reactor Coolant System break or main steam line break are established from the coolant blowdown and core thermal transient analysis described in Section 6.2.1.3.10
2. At the break point, the discharge water and corresponding energy are introduced into the vapor region. An energy balance is then made in 3 stages:
   a. Transfer of water and energy from the sump if the liquid region can boil.
   b. Determination of the masses of liquid and vapor in the atmosphere and the pressure and temperature of the atmosphere.
   c. Condensation of liquid from the vapor region to the liquid region and calculation of the liquid temperature.

   CONTEMPT LT/26 models condensate removal based upon the heat transferred to the containment heat sinks. For the main steam line break analysis, 92% of all condensate is assumed to be removed from the vapor region and added to the sump. For the LOCA analysis the isolated condensate model is not used. The use of the isolated condensate model results in a short term superheated temperature transient for dry steam blowdowns until containment sprays are actuated.

$$\dot{m} = F^{*} q (h_v - h_1)$$

Where:

$\dot{m}$	=	Rate of mass transfer of condensate from vapor region to pool region.
q	=	Heat transfer rate used to calculate condensate dropout rate.
h_v	=	Specific enthalpy of vapor in vapor region.
h_1	=	Specific enthalpy of liquid in vapor region.
F	=	Fraction of condensate formed on walls or cooling coils which is dropped into the pool region (F = 0.92).

3. Homogeneous mixing. The steam-air mixture has uniform properties, more specifically, thermal equilibrium between the air and steam.
4. Air is considered to be an ideal gas; water and steam tables are employed for thermodynamic properties.

During the transient, there is energy transfer from the steam-air and water regions to the internal structure and equipment within the Reactor Building shell. The temperature distribution through each of the heat conducting structures is determined by solving the 1 dimensional, multi-region heat conduction equation. Continuity of temperature and heat flow is assumed at composition interfaces. Boundary conditions are applied to the external surfaces of heat conducting structures as appropriate.

The following modifications have been made to CONTEMPT LT/26:

1. As originally programmed, CONTEMPT LT/26 used the Uchida heat transfer coefficient even if the heat structure were superheated; a heat transfer coefficient of 2.0 Btu/hr ft^2 °F (11.4w/m^2 °K) should be used. The following equations are now employed:

   $q_1 = h_u A (T_s - T_w)$
   $q_2 = h_s A (T_v - T_w)$

   Where:

q_1, q_2	=	Heat transfer rate.
h_u	=	Uchida heat transfer coefficient.
h_s	=	Superheated heat transfer coefficient.
	=	2.0 Btu/hr-ft^2-°F(11.4 w/m^2-°K).
T_s	=	Containment vapor saturation temperature.
T_w	=	heat structure wall temperature.
T_v	=	Containment vapor temperature.
A	=	Heat structure surface area ($ft^{2)}$.

2. The greater heat transfer rate is used: the Uchida transfer coefficient is used when the structure wall temperature is below saturation, while the superheated heat transfer coefficient is used when the structure surface is at, or above, saturation temperature.
3. Modifications have also been made to allow use of a tabular input for the condensing heat transfer coefficient and a constant forced convection heat transfer coefficient for each heat structure rather than using Uchida and natural convection coefficient of 2.0 Btu/hr-ft^2- °F.

4. These changes allow the isolated condensate model to be used in determining component temperature transients without restricting the heat transfer to the conservatively low values used in containment analysis.
5. A line change was also made to correct an error involving the driving potential for the structural heat sinks. This change corrected the energy imbalance that existed between heat removal from the vapor region and that absorbed by the passive heat sinks.

Provision is made in the computer analysis for the effects of several engineered safety features; including Reactor Building spray, Reactor Building cooling units and recirculation of sump water. Heat removal from the containment steam-air phase by Reactor Building spray is determined by allowing the spray water temperature to rise to the steam-air temperature.

6.2.1.3.3.3 Initial Conditions

The initial conditions used in the peak pressure main steam line break and LOCA analyses are presented in Tables 6.2-2 and 6.2-33, respectively. The net free volume used is conservatively calculated from design drawings when establishing the heat sinks used for the ECCS analysis.

Under all operating conditions, the Reactor Building Cooling Systems maintain the following range of temperature and relative humidity conditions:

1. Temperature, 50° F to 120° F.
2. Relative humidity, 30% to 100%.

Under all operating conditions, Reactor Building pressure is maintained below 1.5 psig, the design limit achieved by manually relieving Reactor Building pressure, when required, as discussed in Section 6.2.1.2.2.

The initial conditions used in the peak temperature main steam line break analyses are the same as those used for the peak pressure analyses with the exception that initial Reactor Building pressure is 0.0 psig. (Used for breaks with no entrainment.) This maximizes the time it takes to reach the containment pressure setpoints for main steam isolation and Reactor Building spray actuation. It also reduces the mass of air available to absorb energy, resulting in higher containment vapor temperatures.

The use of the maximum Reactor Building operating temperature and a nominal relative humidity of 30% results in the highest calculated Reactor Building pressures.

Reactor Building heat removal through passive heat sinks and by the Reactor Building Spray System and cooling units is discussed in Section 6.2.1.3.4.

6.2.1.3.3.4 Failure of Engineered Safety Features

For the LOCA analyses, the peak containment temperature and pressure occur in the short term, near the end of blowdown and thus are not extremely sensitive to single failures. Long term

pressures and temperatures are; however, maximized with the assumed failure of an emergency diesel resulting in the loss of 1 train of Reactor Building Spray, 1 Reactor Building cooling unit, and 1 train of ECCS.

For the DEPS guillotine breaks, the 4 cases analyzed are as follows:

1. A double-ended pump rupture of the reactor coolant pump suction (DEPS) with a maximum safety injection and 2 operable trains of Reactor Building Spray (SP) System.
2. A DEPS with maximum safety injection and failure of 1 train of SP.
3. A DEPS with maximum safety injection, 2 operable trains of SP, and failure of 1 train of Reactor Building Cooling Units (RBCU).
4. A DEPS with minimum safety injection and failure of 1 train of emergency diesel generator coincident with a loss of offsite power.

The main steam line break analyses conservatively assume one or more active failures. The active failures considered are as follows:

1. Electrical channel A (CH-A) failure, resulting in minimum Reactor Building heat removal from sprays and fan coolers and failure to isolate the flow to the broken loop steam generator, resulting in a 1000 gpm flow rate to that steam generator.
2. Main steam isolation valve (MSIV) on the broken loop steam generator fails to close, increasing the steam inventory released to the Reactor Building.
3. Main feedwater isolation valve fails (FWIV) to close, resulting in continued flow of feedwater.
4. Failure of a safety injection pump (SI) to operate.
5. Failure of 1 emergency diesel to start, resulting in minimum Reactor Building heat removal from sprays and fan coolers.
6. Failure of an emergency feedwater flow control valve to isolate flow to the faulted SG.

A summary of each main steam line break analyzed and its associated failures is shown in Table 6.2-1a.

The single active failure analysis of the systems relied upon to limit the mass and energy release and containment pressure/temperature response for the main steam line breaks are presented in the sections listed below:

1. Main steam, Section 10.3.3
2. Feedwater, Section 10.4.7.2.3
3. Emergency feedwater, Table 10.4-8
4. Reactor Building cooling, Tables 6.2-50 and 6.2-52

A summary of each main steam line break and LOCA analyzed is presented in Table 6.2-3.

6.2.1.3.4 Energy Sinks

6.2.1.3.4.1 Reactor Building Structures

Provision is made in the Reactor Building pressure transient analysis for heat storage in both interior and exterior walls. Every wall is divided into a large number of nodes. For each node, a conservation of energy equation expressed in finite difference form accounts for transient conduction into and out of the node and temperature rise of the node. Table 6.2-7 presents a detailed summary of the structural heat sinks. This summary includes the detailed information used in the ECCS analysis. For the Reactor Building peak pressure and long term analyses, the total amount of steel used was conservatively reduced from the values reported for the ECCS analysis.

The heat sinks were modeled for use in the CONTEMPT-LT computer code as shown by Table 6.2-8. The criteria used for mesh point spacing is based upon the work of Clausing (Reference 3).

1. Concrete
   a. Mesh point of 0.05 inches for the first 3 inches.
   b. Mesh point spacing greater than, or equal to, 0.5 inches through the remaining thickness.
2. Steel
   Mesh point spacing of 0.05 inches to 0.08 inches.

The modeling of the Reactor Building liner/air/concrete was done using a volume weighted average for the steel/air mixture in the gap between the liner and the concrete. To assure conservatism, the thermal conductivity and volumetric heat capacity were halved.

The containment liner surface temperature and interior concrete surface temperature, as calculated by CONTEMPT LT/26 for worst case temperature main steam line break, are given by Figure 6.2-5d.

The thermophysical properties used in the peak pressure analyses are shown in Table 6.2-9. These represent conservatively low thermal conductivity and volumetric heat capacity values found in the literature.

The protective coatings on surfaces such as the Reactor Building liner and internal concrete were not considered in the analysis. This exclusion is based upon the following assumption.

If it is assumed that these coatings do not affect the steam condensation film coefficient, which most probably is the case, then the inclusion of an extra heat transfer “resistor”, such as the coating, affects the overall heat transfer coefficient, U, by only 0.01%. This does not affect the Reactor Building pressure significantly.

Condensing film heat transfer coefficients are discussed in items 1 and 2, below:

1. Tagami

   During the blowdown period of a LOCA, heat transfer to steel heat sinks from the Reactor Building vapor region is based upon the Tagami (Reference 4) condensing heat transfer coefficient. Heat transfer to concrete heat sinks during blowdown is based on the Uchida correlation discussed later.

   The Tagami heat transfer coefficient increased parabolically to a peak value at the end of blowdown. Following the end of blowdown, the Uchida condensing heat transfer coefficient is used for both concrete and steel heat sinks.

   Tagami presents a plot of the maximum value of h as a function of "coolant energy transfer speed", defined as:

   $$\frac{\text{total coolant energy transferred into containment}}{\text{(containment vessel volume) (time interval to peak pressure)}}$$

From this equation, the maximum heat transfer coefficient, h, for steel is calculated as follows:

$$h_{max} = 75\left(\frac{E}{t_p V}\right)^{0.60}$$

Where:

h_{max}	=	Maximum value of h (Btu/hr-ft^2-°F).
t_p	=	Time from start of accident to end of blowdown (sec.).
V	=	Reactor Building volume (ft^3).
E	=	Initial coolant blowdown energy (Btu).

The parabolic increase from the steady-state value of 2.0 Btu/hr-ft^2 -°F is given by the following equation:

$$h_s = h_{max} \left(\frac{t}{t_p} \right)^{1/2} ; 0 < t \leq t_p$$

Where:

h_s	=	Heat transfer coefficient for steel (Btu/hr-ft^2-°F).
t	=	Time from the start of accident (sec.).

For concrete, the heat transfer coefficient is taken as 40% of the value calculated for steel.

The Tagami condensing film heat transfer coefficient used for the DEPS with minimum safety injection is given by Figure 6.2-11.

2. Uchida

The main steam line break analysis uses the Uchida (Reference 5) correlation, rather than Tagami, for the condensing steam heat transfer coefficient. LOCA analysis uses the Uchida correlation for condensing heat transfer to concrete heat sinks during blowdown and for both concrete and steel heat sinks after the end of blowdown.

The Uchida correlation results in a lower heat transfer coefficient and, is therefore, the more conservative of the 2 for the main steam line break analyses. Slaughterbeck (Reference 25) presents a discussion of the basis of heat transfer coefficients used for containment analysis.

Using the Tagami correlation with the peak heat transfer coefficient occurring when the main steam isolation valves close would result in higher heat transfer to the containment heat sinks. The Tagami correlation was not used due to the difficulty in defining the end of the turbulent portion of the blowdown.

The Uchida condensing film heat transfer coefficient is based primarily upon the mass ratio of air to steam in a nonturbulent environment. The Uchida correlation gives much lower heat transfer coefficients during the initial phase of the transient. The Uchida correlation, therefore, results in a conservative estimate of the heat removed from the vapor region during the main steam line blowdown.

The Uchida condensing steam heat transfer coefficients used during the worst case (pressure and temperature) main steam line breaks are presented by Figures 6.2-10 and Figure 6.2-5c, respectively.

6.2.1.3.4.2 Reactor Building Spray

When a spray drop enters the hot saturated steam-air environment, the vapor pressure of the water at its surface is much less than the partial pressure of the steam in the atmosphere. Hence, there will be diffusion of steam to the drop surface and condensation on the drop. This mass flow will carry energy to the drop. Simultaneously, the temperature difference between the atmosphere and the drop will cause a heat flow to the drop. Both of these mechanisms will cause the spray drop temperature and vapor pressure to rise. The vapor pressure of the drop will eventually become equal to the partial pressure of the steam and the condensation will cease. The temperature of the drop will be essentially equal to the temperature of the steam-air mixture.

The terminal velocity of the drop can be calculated using the formula given by Weinberg (Reference 6) where the drag coefficient, C_D, is a function of the Reynolds (Re) number:

$$V^2 = \frac{4Dg(\rho - \rho_m)}{3C_D\rho_m}$$

Assuming a 700 micron drop size from the Reactor Building spray nozzles, the terminal velocity is less than 7 ft/sec. For a 1000 micron drop, the velocity would be less than 10 ft/sec. The Nusselt number for heat transfer, Nu, and the Nusselt number for mass transfer, Nu′ (Sherwood Number), can be calculated from the empirical relations given by Ranz and Marshall (Reference 7):

$$Nu = 2 + 0.6\,(Re)^{1/2}\,(Pr)^{1/3}$$

$$Nu' = 2 + 0.6\,(Re)^{1/2}\,(Sc)^{1/3}$$

The Prandtl (Pr) number and the Schmidt (Sc) number for the conditions assumed are approximately 0.7 and 0.6, respectively. Both of these are sufficiently independent of pressure, temperature, and composition that they are assumed constant under containment conditions (Reference 8, and Reference 9). The coefficients of heat transfer (h_c) and mass transfer (k_G) are calculated from Nu and Nu′ respectively. The equations describing the temperature rise of a falling drop are as follows:

$$\frac{d}{dt}(Mu) = mh_g + q$$

$$\frac{d}{dt}(M) = m$$

Where:

$$q = h_c A\,(T_s - T)$$

$$m = k_G A\,(P_s - P_v)$$

These equations can be integrated numerically to find the internal energy and mass of the drop as a function of time as it falls through the atmosphere. Analysis shows that the liquid drop temperature rises to the steam-air temperature in less than 0.5 seconds. This temperature increase occurs before the drop has fallen 5 feet. These results demonstrate that the Reactor Building spray will be 100% effective in removing heat from the Reactor Building atmosphere.

The Reactor Building Spray System is actuated based upon Hi-3 containment pressure. For the full double ended rupture main steam line break and Reactor Coolant System LOCA analyses, the pressure setpoint is reached well before the 10 seconds required for diesel generator startup. Reactor Building spray is assumed to actuate at 52 seconds for the LOCA and 53.1 seconds for the large main steam line breaks following accident initiation. This is conservative based upon the following:

1.	Diesel Start Time	10 seconds
2.	Time for RB Spray Pump to reach full capacity	5 seconds
3.	Time required to fill RB Spray piping and ring headers	32 seconds
4.	Total Elapsed Time	47 seconds

Note: As a conservatism, filling of RB Spray piping is not credited during the 5 second pump acceleration phase.

Actuation timing calculations for the smaller main steam line breaks are presented in Table 6.2-47b.

6.2.1.3.4.3 Reactor Building Cooling Units

Heat removal by the Reactor Building cooling units is dependent upon the number of units operating, unit start and stop times, and the heat removal rate. The heat removal rate is dependent upon the Reactor Building atmosphere temperature and a number of thermal-physical cooler design parameters. The cooling coils of a Reactor Building cooling unit remove energy directly from the vapor region of the containment which results in reduced energy and pressure.

Heat removal due to Reactor Building cooling unit operation is simulated in the CONTEMPT code by specifying input values from a heat removal rate versus Reactor Building atmosphere temperature curve. The design values given on Figure 6.2-15, conservatively reduced to 60% to account for potential performance degradation, are used for MSLB analysis. LOCA analysis utilizes the RBCU performance curve corresponding to a conservative tubeside fouling factor of 0.0014 (Reference 46) shown on Figure 6.2-15. That curve is based on analytical results calculated by American Air Filter according to the methods described in Topical Report TR-7101A (Reference 16). That analysis assumes the following boundary conditions:

Cooling water inlet temperature:	95° F
Cooling water flow:	2000 gpm
Tubeside fouling factor:	0.0014

The resulting performance curve gives a higher heat removal rate than the 60% design performance curve used in MSLB analysis, but still conservative compared to the design curve. All three curves are shown together for comparison on Figure 6.2-15.

The Reactor Building cooling units are calculated to be fully operational within 86.5 seconds following loss of offsite power. A description of the timing involved is presented in Section 6.2.2.2.2.2. The time used in the analyses is 86.5 seconds for the large main steam line breaks and the LOCA analyses. Actuation timing calculations for the main steam line breaks are presented in Table 6.2-47b.

6.2.1.3.4.4 Sump Water Recirculation Heat Exchangers

During the post accident long term cooling period, safety injection pumps (charging pumps and RHR pumps) supply recirculated water from the Reactor Building recirculation sumps to the reactor vessel. The RHR heat exchangers are placed in operation during the recirculation phase to remove energy directly from the reactor vessel to the outside environment.

The RHR heat exchangers are of the shell and U-tube type. Physical and thermal characteristics of each heat exchanger are specified in Table 6.2-1, as are the coolant inlet temperatures and flow rates.

6.2.1.3.5 Systems for Protection Against Negative Pressure Inside the Reactor Building

A narrow range differential pressure transmitter provides signals for monitoring the Reactor Building internal pressure. Control room alarms are actuated by this pressure channel when the differential pressure approaches the baseline pressure. Administrative procedures are used following actuation of the alarm to adjust Reactor Building pressure to within the required baseline pressure limits.

During normal operation, inadvertent Reactor Building spray can occur when doing the periodic inservice testing on 1 spray loop. An inadvertent safety injection signal to the spray loop discharge valve during spray loop testing is the worst single failure.

6.2.1.3.6 Reactor Building Analysis, Negative Pressure

Inadvertent operation of the Reactor Building Spray System causes depressurization of the Reactor Building due to the cooling effect of the spray water. A theoretical maximum depressurization can be calculated by assuming that the temperature of the Reactor Building atmosphere ultimately reaches the spray water temperature. (The evaporative cooling phase is not controlling for this case. See Reference 10). Thus, the partial pressure of the air will simply change by a ratio of the absolute temperatures, while the vapor pressure will be equal to the saturation value at the spray water temperature. The theoretical maximum depressurization is:

$$P_d = P_o - \left[P_a \frac{T_{sp}}{T_o} + P_g(T_{sp}) \right]$$

Where:

P_d	=	Depressurization.
P_o	=	Initial pressure.
P_a	=	Initial air partial pressure.
$P_g (T_{sp})$	=	Water vapor partial pressure evaluated at T_{sp}.
T_{sp}	=	Spray water temperature.
T_o	=	Initial atmospheric temperature.

Using an initial temperature, pressure and relative humidity of 120°F, -0.1 psig, and 100%, respectively, for the Reactor Building atmosphere and a spray water temperature of 40° F, depressurization results in an external pressure of 3.5 psig. Therefore, the maximum external pressure does not exceed the design pressure given in Section 6.2.1.2.2.

6.2.1.3.7 Function Capability of the Normal Reactor Building Ventilation System

The normal ambient operating temperatures of the Reactor Building under various operating modes are indicted in Section 6.2.2.1.2. A single failure analysis is presented in Table 6.2-52. The maximum acceptable local compartment or area temperatures are described in Section 3.11.1.1. Instrumentation and alarms for the reactor building ventilation system are discussed in Section 9.4.8.

6.2.1.3.8 Accident Pressure and Temperature Monitoring

The Reactor Building pressure and temperature and Reactor Building recirculation sump temperature instrumentation (including recording capability) is discussed in Section 7.5. The qualification of this instrumentation (including recording capability) is discussed in Section 7.5. The qualification of this instrumentation for use in the post accident containment environment is discussed in Sections 3.10, 3.11, and 7.4. The recorders are located in the control room, thus assuring accessibility to control room personnel during a LOCA.

6.2.1.3.9 Reactor Building Subcompartment Pressurization

Reactor Building subcompartments (steam generator compartments, pressurizer compartment, reactor cavity area) have been analyzed with respect to the appropriate design basis break to determine the peak pressure differential for pipe rupture. Each compartment has been broken down into volumes and flow paths. The steam generator and reactor cavity compartments were analyzed using the RELAP4/MOD5 (Reference 30) code without air. The incompressible flow option without momentum flux was used for the momentum equation. Critical flow was predicted by the homogeneous equilibrium model, using the stagnation conditions of each node, consistent with the homogeneous equilibrium model critical flow table on RELAP4/MOD5. The transient pressure behavior of the pressurizer compartment has been calculated by the COMPARE-MOD 1 computer program (Reference 37). Results of these analyses have been used in the compartment structural design.

The Subcompartments have been analyzed for the largest break(s) possible in each compartment. A summary is given below:

1. Pressurizer compartment - spray line and surge line breaks (see Section 6.2.1.3.9.1)
2. Steam generator compartments - double ended hot leg and cold leg breaks (see Section 6.2.1.3.9.2)
3. Reactor cavity - cold leg break, 150 in^2 area (see Section 6.2.1.3.9.3).

The mass/energy release for each break used in subcompartment pressurization analyses is provided in Section 6.2.1.3.10.2.

The differential pressure on compartment walls is spatially varied for structural evaluation, where applicable. The vent parameters are realistically evaluated to provide a realistic pressure distribution following the accident.

The steam-water atmosphere was used to describe the initial conditions of Reactor Building subcompartments. The initial atmosphere within a subcompartment is modeled by a homogeneous water-steam mixture with an average density equivalent to the dry air model.

In addition, 100% entrainment has been assumed. The resulting calculated and design pressures are presented in Table 6.2-11. The analysis of each subcompartment is discussed separately in Sections 6.2.1.3.9.1 through 6.2.1.3.9.3.

The impact of the replacement steam generators and changes in plant operating parameters have been evaluated on the Reactor Building subcompartment analyses. Since the completion of the FSAR design analyses the Leak-Before-Break (LBB) Methodology has been applied in the plant design to the large primary piping. This eliminates the dynamic effects of postulated primary pipe ruptures from the design basis. Therefore, application of LBB means that the 150 in^2 cold leg break, DECL break and DEHL breaks need not be considered in the structural design basis. Continued use of these original bases results in a conservative design for the steam generator compartments and the reactor cavity which bounds any potential effects of the replacement steam generators and changes in the plant operating conditions.

For the pressurizer compartments, no reduction in break size is possible since the LBB methodology has only been applied to the large primary piping. Since the revised design power operating power parameters will allow for reduced Reactor Coolant System (RCS) temperatures, an increase in the pressurizer surge and spray line mass releases must be considered. The increase in the releases from previous analysis are conservatively bounded by increasing the surge and spray line mass releases by factors of 1.15 and 1.10, respectively. The corresponding enthalpies are conservatively bounding for the lower RCS temperature. The results of this analysis are shown in Section 6.2.1.3.9.1.

6.2.1.3.9.1 Pressurizer Compartment Analysis

The pressurizer and surge tank compartments have been analyzed for pressure response from spray line and surge line breaks, respectively, using the COMPARE-MOD 1 computer program (Reference 37). In each case, a 2 node model has been used. Figures 6.2-18 and 6.2-19 show the nodalization and appropriate parameters for the pressurizer compartment and surge tank compartment, respectively. Major relief areas for the pressurizer compartment include an opening at elevation 437’-6” and grating at elevation 488’-6”. For the surge tank compartment, the major relief area is directly to the steam generator compartment.

The mass/energy releases are discussed in Section 6.2.1.3.10.2. Mass/energy releases for the spray line rupture have been conservatively extended past the information provided by the NSSS vendor to permit calculation of the necessary transient differential pressure.

Figures 6.2-20 and 6.2-21 depict the pressure-time history for the pressurizer and surge tank compartments following the appropriate break. Differential pressures are also shown by these figures. Peak calculated and differential pressure are 41.9 psia (26.0 psid) and 45.0 psia (30.6 psid) for the pressurizer and surge tank compartments, respectively.

The peak calculated and design differential pressures for the pressurizer compartment are presented in Table 6.2-11.

The above mentioned calculated pressures are without margin. As shown by the valves in Table 6.2-11, the available margin between the calculated differential pressure and the structural design pressure is 59% for the pressurizer compartment and 68% for the surge tank compartment.

6.2.1.3.9.2 Steam Generator Compartment Analysis

The steam generator compartments were initially analyzed to determine the peak pressures on the compartment walls and the forces and moments acting upon the steam generator and reactor coolant pump supports. The general layout of the steam generator compartments is illustrated by Figure 6.2-22.

The analysis was performed using the RELAP4/MOD5 code (Reference 30). Flow paths between nodes were modeled using inertial flow bounded by the homogeneous equilibrium critical flow model where significant changes in area occurred. In addition, all flow paths out of the break nodes were limited by the homogeneous equilibrium critical flow model regardless of geometry.

Initially, each steam generator compartment was analyzed for both the double ended hot and cold leg breaks. Models were set up to include significant restrictions and changes in area where practical.

From results of the initial studies it was determined that the loop C steam generator compartment was the worst case. Both the overall lower compartment pressure and specific nodal pressures due to geometric considerations were higher in loop C.

The loop C steam generator compartment was then modeled to include more definition and to establish loadings on the reactor coolant pump and steam generator.

The impact of the replacement steam generators and changes in plant operating parameters have been evaluated on the Reactor Building subcomponent analyses. Since the completion of the FSAR design analyses, the Leak-Before-Break (LBB) Methodology has been applied in the plant design to the large primary piping. This eliminates the dynamic effects of postulated primary pipe rupture from the design basis. Therefore, application of LBB means that the 150 in^2 cold leg break, DECL break and DEHL breaks need not be considered in the structural design basis. Continued use of these original bases results in a conservative design for the steam generator compartments and the reactor cavity which bounds any potential effects of the replacement steam generators and changes in the plant operating conditions.

6.2.1.3.9.2.1 Initial Steam Generator Compartment Models

The initial models for each loop were similar. In general, these models were comprised of 2 nodes below the steam generator and reactor coolant pump, 5 or 6 nodes between elevations 426.5’ and 436’, one node between elevations 436’ and 459.5’ and one node between elevations 459.5’ and 475.4’. Elevation 436’ was chosen as a dividing line because the steam generator supports and inservice inspection platforms form a natural boundary. The boundary at elevation 426.5’ is not real but does provide vertical symmetry for the break nodes.

The nodal arrangements, analytical results and model descriptions for the initial models are summarized by Table 6.2-11a. Tables 6.2-12 through 6.2-14a present model descriptions and results. Figures 6.2-22a through 6.2-22k illustrate nodal arrangements and results.

6.2.1.3.9.2.2 Final Loop C Steam Generator Compartment Models

A 20 node loop C steam generator compartment model was analyzed to determine nodal sensitivity and loadings on the reactor coolant pump due to a cold leg break. The volume between elevations 436’ and 451’ (top of reactor coolant pump) was divided into 5 nodes. The increase nodalization did not result in increased pressure in the break nodes since flow out of these nodes chokes early in the transient.

A 25 node compartment model was analyzed to determine nodal sensitivity and loadings on the steam generator due to a hot leg break. This model was similar to the 20 node model previously described but included more nodes around the steam generator above elevation 459.5’. The resultant peak pressure in break node 7 increased by less than 6%. This result was expected since the peak in node 7 is an inertial peak.

Forces and moments on the reactor coolant pump and steam generator were determined using results from the 20 and 25 node model, respectively.

The nodal arrangements, analytical results, model descriptions, and forces and moments data are summarized by Table 6.2-15. Tables 6.2-15a through 6.2-15f present model descriptions, and forces, and moments data. Figures 6.2-23 through 6.2-26 illustrate nodal arrangements, results and forces, and moments data.

6.2.1.3.9.2.3 Discussion of Results

From the tables and figures noted in Sections 6.2.1.3.9.2.1 and 6.2.1.3.9.2.2 it can be seen that the overall pressure response of the lower steam generator compartments (23 psid) is well below the design pressure of 41.2 psid.

A peak pressure of 47.9 psid was calculated (Node 4, cold leg) around the reactor coolant pump near the refueling canal wall.

A short term inertial peak of 45.9 psid (Node 7, hot leg) between the steam generator and secondary shield wall was calculated.

To study the impact of the above calculated pressures on the structural design, a simplified model of the lower steam generator compartment was developed. An analysis was performed using this model to evaluate the effects of the calculated pressures. Analytical results were compared to the results of a similar analysis for design pressure. It was determined that the design forces and moments for the above calculated pressures are less than for the design pressure. This reduction is due to the decrease in overall pressure even though pressure is increased locally.

6.2.1.3.9.3 Reactor Cavity Analysis

The impact of the replacement steam generators and changes in plant operating parameters have been evaluated on the Reactor Building subcomponent analyses. Since the completion of The FSAR design analyses the Leak-Before-Break (LBB) Methodology has been applied in the plant

design to the large primary piping. This eliminates the dynamic effects of postulated primary pipe ruptures from the design basis. Therefore, application of LBB means that the 150 in^2 cold leg break, DECL break and DEHL breaks need not be considered in the structural design basis. Continued use of these original bases results in a conservative design for the steam generator compartments and the reactor cavity which bounds any potential effects of the replacement steam generators and changes in the plant operating conditions.

1. Analyses

   A pressurization analysis of the reactor cavity and penetration areas of the primary shield was performed using the RELAP4/MOD5 code (Reference 30) to predict pressures and forces and moments resulting from a postulated rupture. The analysis was performed by considering the maximum break size which could occur in the primary shield pipe penetrations. Cold leg and hot leg guillotine breaks are limited by restrictions imposed upon pipe movement by the penetration, supports, and loop geometry. Cold leg break geometry is illustrated by Figure 6.2-27. Due to the break geometry, the cold leg break area is larger than the hot leg break area. The maximum cold leg break area is limited to a value less than 150 in^2, the value used for mass/energy releases (see Section 6.2.1.3.10.2).

   The general layout of the reactor cavity area is illustrated by Figure 6.2-28. A break in the loop B cold leg was selected for analysis because of the small inspection port opening. Dimensions on Figure 6.2-28 represent cold conditions. Thermal expansion under hot conditions was included in the calculation of the various model parameters in the RELAP4/MOD5 code. Insulation was assumed to move against the reactor vessel and/or piping, as appropriate, instantaneously with not change in thickness. Further details are provided by Figures 6.2-65 through 6.2-67.

   A nodalization sensitivity study was performed for the forces and moments. Axes used in the orientation of the reactor vessel are illustrated by Figure 6.2-29. Forces in the x and z directions and the moment about y axis are the major components. These major components were considered in the acceptance of the nodalization sensitivity study.

   Three (3) reactor cavity modes, incorporating 22, 31, and 33 nodes, were analyzed. The 22 node model included 3 nodes in the cold leg penetration and 15 nodes in the reactor vessel annulus. The 31 node model also used 3 nodes in the penetration but used 24 nodes in the annulus. The 33 node model incorporated 5 nodes in the penetration and 24 nodes in the annulus.

   Information presented for the reactor cavity models include penetration, reactor vessel annulus, and overall models, as well as forces and moments. A cross reference between various models and appropriate tables and figures is presented by Table 6.2-16. Tables 6.2-16a through 6.2-16c address control volumes; Tables 6.2-17 through 6.2-17b, flow paths; and Tables 6.2-18 through 6.2-18b, force/moment areas. Figures 6.2-30 through 6.2-32a illustrate penetration nodes, reactor vessel annulus nodes, and overall model schematics.

2. Results

   The results from the 3 models are the pressures in each node and the resulting forces and moments. The peak differential pressure with respect to containment pressure is tabulated for each node and differential pressure transient for the break node and reactor vessel annulus nodes adjacent to the break are also shown. In addition, forces and moments are tabulated for each model. A cross reference is provided by Table 6.2-18c. Tables 6.2-16a through 6.2-16c present peak differential pressures. Tables 6.2-18d through 6.2-18f present forces and moments. Figures 6.2-33 through 6.2-33e illustrate transient differential pressures for selected nodes.

   The peak pressures listed in Table 6.2-16a through Table 6.2-16c are well below the design pressures in the penetration and reactor vessel annulus.

   Peak forces and moments of interest are presented by Table 6.2-18g for each of the 3 models. The results of the nodalization sensitivity study indicate reasonable agreement among the 3 models.

   Since the 33 node model is the most detailed, the numbers for this model are used for the design evaluation. A transient representation of forces and moments for the 33 node model is provided by Figures 6.2-34 through 6.2-35a.

6.2.1.3.10 Mass and Energy Releases

Rupture of any of the piping carrying pressurized high temperature reactor cooling water, termed a loss of cooling accident (LOCA), or rupture of a secondary system steam line within the containment will result in release of steam and water into the containment. This in turn will result in an increase in the containment pressure and temperature. In order to evaluate the response of the containment to such accidents, the rate of release as a function of time must be evaluated. Section 6.2.1.3.10.1 describes the long term releases following a LOCA in the primary cooling system. These results are used to evaluate the overall effect of such releases on the containment. Section 6.2.1.3.10.3 describes the releases resulting from rupture of a secondary system steam line located within the containment.

6.2.1.3.10.1 LOCA Mass and Energy Release

6.2.1.3.10.1.1 LOCA Release Rate Transient

The LOCA transient is typically divided into 4 phases:

1. Blowdown - which includes the period from accident initiation (when the reactor is at steady state operation) to the time that the RCS pressure reaches initial equilibrium with containment.
2. Refill - the period of time when the lower plenum is being filled by accumulator and safety injection water. At the end of blowdown, a large amount of water remains in the cold legs,

downcomer, and lower plenum; therefore to conservatively consider the refill period for the purpose of containment mass and energy releases, this water is instantaneously transferred to the lower plenum. This allows an uninterrupted release of mass and energy to containment. Thus the refill period is conservatively neglected in the mass and energy release calculation.

3. Reflood - begins when the water from the lower plenum enters the core and ends when the core is completely quenched.
4. Post-Reflood (Froth) - describes the period following the reflood transient. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs, and is superheated in the steam generators. After the broken loop steam generator cools, the break flow becomes 2 phase.

Tables 6.2-19a-6.2-19b through 6.2-22, 6.2-25, and 6.2-26 provide the tabulations of the current long term mass and energy release rates versus time for all 4 phases over the spectrum of breaks analyzed.

6.2.1.3.10.1.2 Mass and Energy Release Analyses For Postulated Loss-of Coolant Accidents

The evaluation model used for the long term LOCA mass and energy release calculations used was the March 1979 model described in Reference 38. This evaluation model has been reviewed and approved by the NRC, and has been used in the analyses of other dry containment plants.

A discrepancy between volumetric heat capacities used in WCAP-10325-P-A (Reference 38) and those documented in more recent ASME Code documents was identified. This condition was addressed in PWROG-17034-P-A (Reference 49), where the NRC determined, with various generic methodology issues addressed, the continued use of WCAP-10325-P-A is acceptable for performing LOCA mass and energy release analysis for plants with large dry containments.

The analyses presented in this section have also been performed to evaluate any potential effects the reactor vessel upflow conversion had on the mass and energy releases. This design change was shown to have a negligible effect on the calculated LOCA mass and energy releases.

For the long term mass and energy release calculations, operating temperatures for the highest average coolant temperature at full power (see Table 5.1-1) were selected as the bounding analysis conditions. The RCS temperature conditions for the rerating analysis for the long term LOCA transients are also bounding for asymmetric loop flow considerations. The modeled core power level of 2958 MWt, adjusted for calorimetric error (+2% of power), was the basis in the analysis. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures which are at the maximum levels attained in steady state operation. Additionally, an allowance of +6.3° F is reflected in the temperatures in order to account for instrument error and deadband. The initial RCS pressure in this analysis is based in a nominal value of 2250 psia. Also included is an allowance of +54 psia, which accounts for the uncertainty on pressurizer pressure. The resulting limiting pressure of 2304 psia affects the blowdown phase results, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value until the point at which it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure (2304 psia). Additionally, the RCS has a higher fluid density at 2304 psia (assuming a constant temperature) and subsequently has a higher RCS mass available for release. Thus, 2304 psia initial pressure was selected as the limiting case for the long term mass and energy release calculations. These assumptions conservatively maximize the mass and energy in the RCS.

The selection of fuel allowance for the long term mass and energy calculations and subsequent LOCA containment integrity calculation is based on the need to conservatively maximize the core stored energy. The margin in core stored energy is integral to the methodology and is based on a statistical combination of effects including fuel type, power level, manufacturing tolerances, and densification.

Margin in RCS volume of 3% (which is composed of 1.6% allowance for thermal expansion, and 1.4% for uncertainty) is modeled.

Regarding safety injection flow, the mass and energy calculation considers both minimum and maximum safety injection flow rates. Further details concerning these assumptions are contained in Section 6.2.1.3.10.1.9.

6.2.1.3.10.1.3 LOCA Break Size and Location

Generic studies have been performed with respect to the effect on LOCA mass and energy releases to postulated break size. The double-ended guillotine break has been found to be limiting due to larger mass flow rates during the blowdown phase of the transient. During the reflood and froth phases, the break size has little effect on the releases.

Three (3) distinct locations in the reactor coolant loop can be postulated for pipe rupture:

1. Hot leg (between vessel and steam generator)
2. Cold leg (between pump and vessel)
3. Pump suction (between steam generator and pump)

The break location analyzed and described herein is the double-ended pump suction guillotine break (10.48 ft^2). Pump suction break mass and energy releases have been calculated for the blowdown, reflood, and post-reflood phases of the LOCA.

The following information provides a discussion on each break location. The double-ended hot leg guillotine has been shown in previous studies to result in the highest blowdown mass and energy release rates. Although the core flooding rate would be highest for this break location, the amount of energy released from the steam generator secondary side is minimal because the majority of the fluid, which exists the core, bypasses the steam generators in venting to containment. As a result, the reflood mass and energy releases are reduced significantly as compared to either the pump suction or cold leg break locations where the core exit mixture must pass through the steam generators before venting through the break.

For the hot leg break, there is no reflood peak as determined by generic studies (i.e., from the end of the blowdown period the releases would continually decrease). Therefore, the reflood (and subsequent post reflood) releases are not calculated for a hot leg break. The mass and energy releases for the hot leg break blowdown phase have been included in the scope of this containment integrity analysis.

The cold leg break location has also been found in previous studies to be much less limiting in terms of the overall containment peak pressure. The cold leg blowdown is faster than that of the pump suction break and more mass is released into the containment. However, the core heat transfer is greatly reduced and this results in a considerably lower energy release into containment. Studies have determined that the blowdown transient for the cold leg is, in general, less limiting than that for the pump suction break. During reflood, the flooding rate is greatly reduced and the energy release rate into the containment is also reduced. Therefore, the cold leg break analysis is not usually performed.

The pump suction break combines the effects of the relatively high core flooding rate as in the hot leg break and the addition of the stored energy in the steam generators.

As a result, the pump suction break yields the highest energy flow rates during the post-blowdown period by including all of the available energy of the Reactor Coolant System in calculating the releases to containment. This break location has been determined to be the limiting break for typical dry containment plants. The choice of this break location, as the limiting break analyzed for the V. C. Summer plant, is consistent with other dry containment plants for the post-blowdown phase of the event.

In summary, the analysis of the limiting break location for a dry containment has been performed. The double-ended pump suction guillotine break has historically been considered to be the limiting break location for the post-blowdown phase of the event by virtue of its consideration of all energy sources present in the RCS. The analyses presented support the conclusions of the double-ended pump suction (DEPS) as the limiting break case for the post-blowdown period, considering both the minimum and maximum safety injection cases. This break location provides a mechanism for the release of the available energy in the Reactor Coolant System, including both the broken and intact loop steam generators.

6.2.1.3.10.1.4 LOCA Mass and Energy Release Data

The following items ensure that the mass and energy releases are conservatively calculated for maximum containment pressure:

1. Maximum expected operating temperature of the Reactor Coolant System.
2. Allowance in temperature for instrument error and deadband (+6.3°F).
3. Margin in volume of 3% (which is composed of 1.6% allowance for thermal expansion and 1.4% for uncertainty).
4. Nominal core power level of 2900 MWt.

5. Allowance for calorimetric error (+ 2% of power).
6. Conservative coefficients of heat transfer (i.e. steam generator primary/secondary heat transfer and Reactor Coolant System metal heat transfer).
7. Allowance in core stored energy that is based on a statistical combination of effects including fuel type, power level, manufacturing tolerances, and densification.
8. Allowance for RCS pressure uncertainty (+ 54 PSI).
9. A maximum containment backpressure equal to design pressure (57 psig)
10. Minimum RCS loop flow (92,600 gpm/loop)
11. SGTP leveling (0 percent uniform)

6.2.1.3.10.1.5 Blowdown Mass and Energy Release Data

The SATAN-VI code is used for computing the blowdown transient and is the same as that used for the ECCS calculation in Reference 39. The methodology for the use of this model is described in Reference 38.

Tables 6.2-19a, 6.2-19b, and 6.2-20 present calculated mass and energy releases or the blowdown phase of the break analyzed for the DEPS minimum ECCS, DEPS maximum ECCS, and DEHL breaks, respectively. Break flow time histories from each side of the guillotine break are tabulated, where Break Flow Path No. 1 represents the flow from the reactor vessel outlet side of the break and Break Flow Path No. 2 represents the flow from the reactor vessel inlet side of the break. The mass and energy release for the blowdown phase terminate in less than 20 seconds, after the initiation of the postulated accident.

6.2.1.3.10.1.6 Reflood Mass and Energy Release Data

The WREFLOOD code is used for computing the reflood transient, is a modified version of that used in the ECCS calculation in Reference 39. The methodology for the use of this model is described in Reference 38.

To clarify the mass and energy evaluation model described in Reference 38 steam/water mixing in the broken loop has been included in this analysis. This assumption is justified and is supported by test data, summarized as follows:

The model assumes a complete mixing condition (i.e., thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of 2 distinct physical processes. The first is a 2 phase interaction with condensation of steam by cold injection water. The second is a single phase mixing of condensate and injection water. Since the mass and energy of the steam released is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that need be considered. (Any spillage directly heats only the sump.)

The most applicable steam/mixing test data has been reviewed for validation of the containment integrity reflood steam/water mixing model. This data is that generated in the 1/3 scale test (Reference 40), which are the largest scale data available and thus most closely simulates the flow regimes and gravitational effects that would occur in a PWR. These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

From the entire series of 1/3 scale tests, a group corresponds almost directly to containment integrity reflood conditions. The injection flow rates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in Reference 38. For all these tests the data clearly indicates the occurrence of very effective mixing with rapid steam condensation. The mixing model used in containment integrity reflood calculation is therefore, wholly supported by the 1/3 scale steam/water mixing data.

Additionally, the following justification is also noted. The limiting break for the containment integrity peak pressure analysis during post-blowdown phase is the double-ended pump suction break. For this break, there are 2 flow paths available in the RCS by which mass and energy may be released to containment. One (1) is through the outlet of the steam generator, the other via reverse flow through the reactor coolant pump. Steam, which is not condensed by ECCS injection in the intact RCS loops passes around the downcomer and through the broken loop cold leg and pump in venting to containment. This steam also encounters ECCS injection water as it passes through the broken loop cold leg; complete mixing occurs and a portion of it is condensed. It is this portion of steam, which is condensed, that is taken credit for in this analysis. This assumption is justified based upon the postulated break location and the actual physical presence of the ECCS injection nozzle. A description of the test and test results is contained in References 38 and 40.

The methodology previously discussed and described in Reference 38 has been utilized and approved on Dockets for Catawba Units 1 and 2, Indian Point 2 and 3, McGuire Units 1 and 2, Sequoyah Units 1 and 2, Millstone 3, Shearon Harris Unit 1, and Beaver Valley Unit 2.

Tables 6.2-21 and 6.2-22 present the calculated mass and energy release for the reflood phase of the double-ended pump suction break with minimum and maximum safety injection respectively. Flow time histories from each side of the double-ended pump suction break are tabulated where Break Flow Path No. 1 represents the flow through the outlet of the steam generator and Break Flow Path No. 2 represents reverse flow through the reactor coolant pump. A significantly higher mass and energy release occurs during the period the accumulators are injecting (from 22.3 to 43.8 seconds for minimum and maximum safety injection as illustrated in Table 6.2-21 and Table 6.2-22). The transient of the principal parameters during reflood are given in Tables 6.2-23 and 6.2-24 for the minimum and maximum safety injection double-ended pump suction break case.

6.2.1.3.10.1.7 Post-Reflood Mass and Energy Release Data

The FROTH code is used for computing the post-reflood transient. The methodology for the use of this model is described in Reference 38. The mass and energy rates calculated by FROTH are used in the containment analysis until the time of containment depressurization.

After depressurization, the mass and energy release from decay heat is based on the 1979 ANSI/ANS Standard, Shown in Reference 41, and the following input:

1. Decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.
2. Decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.
3. Fission rate is constant over the operating history of maximum power level.
4. The factor accounting for neutron capture in fission products was taken from Table 10 of Reference 41.
5. Operating time before shutdown is 3 years.
6. The total recoverable energy associated with 1 fission has been assumed to be 200 Mev/fission.
7. Two (2) sigma uncertainty (2 times the standard deviation) has been applied to the fission product decay.

Table 6.2-34 gives the core generated decay heat used in the long term mass and energy release calculation.

Tables 6.2-25 and 6.2-26 present the 2 phase (froth) mass and energy release data for the double-ended pump suction break minimum and maximum safety injection cases. Flow time histories from each side of the double-ended pump suction break are tabulated, where Break Flow Path No. 1 represents the flow through the outlet of the steam generator and Break Flow Path No. 2 represents reverse flow through the reactor coolant pump.

6.2.1.3.10.1.8 Mass and Energy Sources

The sources of mass considered in the LOCA mass and energy release analysis are given in Tables 6.2-27, 6.2-28, and 6.2-29. These sources are the Reactor Coolant System, accumulators, and pumped safety injection.

The energy inventories considered in the LOCA mass and energy release analysis are given in Tables 6.2-30, 6.2-31, and 6.2-32.

The components included in the mass and energy calculations are:

1. Reactor Coolant System water
2. Accumulator water
3. Pumped Injection water
4. Decay heat
5. Core stored energy

6. Reactor Coolant System metal
7. Steam generator metal
8. Steam generator secondary energy
9. Secondary transfer of energy (feedwater into and steam out of the steam generator secondary)

In the mass and energy release data presented, no Zirc-water reaction heat was considered because the clad temperature did not rise high enough for the energy released by this reaction to be of any significance.

System parameters needed to perform confirmatory analyses are provided in Table 6.2-33.

The consideration of the various energy sources in the mass and energy release analysis provides assurance that all available sources of energy has been included in this analysis. Thus, the review guidelines presented in the Standard Review Plan have been satisfied.

The mass and energy inventories are presented at the following times, as appropriate:

1. Time zero (initial conditions)
2. End of blowdown time
3. End of refill time
4. End of reflood time
5. Time of full depressurizations

The methods and assumptions used to release the various energy sources are given in Reference 38 except as noted in Section 6.2.1.3.10.1.6, which has been approved as a valid evaluation model by the Nuclear Regulatory Commission.

6.2.1.3.10.1.9 Application of Single Failure Criteria

An analysis of the effects of the single failure criteria has been performed on the mass and energy release rates for the (DEPS) break. For the DEPS results presented in this report an inherent assumption in the generation of the mass and energy release is that offsite power is lost. This results in the actuation of the emergency diesel generators, required to power the safety injection system. This is not an issue for the blowdown period, which is limited by the DEHL break.

Three (3) cases have been analyzed for the effects of a single failure. The double-ended pump suction case with both minimum and maximum safety injection for the 2900 MWt rerated conditions was analyzed. In the case of minimum safety injection, the single failure, postulated to occur, is the loss of an emergency diesel generator. This results in the loss of 1 pumped safety injection train, thereby, minimizing the safety injection flow and the loss of 1 train of RB spray and RBCU. For the case of maximum safety injection, two separate single failures are postulated to occur. One failure is the loss of 1 train of RB spray. The other is the loss of 1 train of RBCU.

The analysis of both minimum and maximum safety injection cases ensures that the effect of all credible single failures is bounded.

6.2.1.3.10.2 Short Term Mass and Energy Releases

The model used to perform the short term blowdown analysis is fully described in Reference 12. The release rates used for the reactor cavity, steam generator compartment, and pressurizer compartment analyses are listed in the following tables:

1. Reactor cavity blowdown for 150 in^2 cold leg break.
2. Cold leg DEG.
3. Hot leg DEG.
4. Double ended pressurizer surge line break, Table 6.2-44.
5. Pressurizer spray line break, Table 6.2-45.

As indicated in Section 3.6, postulated breaks in the reactor coolant loop piping, except for branch line connections, have been eliminated through the use of Leak-Before-Break (LBB) methodology. The mass and energy releases previously used are retained; however, as bounding values to serve as the basis for the Reactor Building subcompartment pressurization analyses described in Section 6.2.1.3.9. The RCS temperature conditions for the rerating analysis for the short term LOCA transients are also bounding for asymmetric loop flow considerations.

6.2.1.3.10.3 Mass And Energy Release Analyses (Containment Response) For Postulated Secondary System Pipe Ruptures Inside Containment

6.2.1.3.10.3.1 Method of Analysis

The analysis of the main steam line break (MSLB) inside containment includes a calculation of the mass and energy release from the blowdown and the corresponding containment response. The mass and energy releases following a steam line rupture are dependent upon the configuration of the plant steam system and containment design, as well as the plant operating conditions and size of the rupture. The cases examined in this study were chosen to determine a limiting case, in terms of containment temperature and pressure response.

The following items must be considered for a steam line rupture inside containment analysis:

- nuclear kinetics characteristics and power generation in the reactor core,
- stored energy in both the primary reactor system and the secondary steam plant,
- main and auxiliary feedwater systems operation,
- safety systems operation (e.g. reactor trip, steam line isolation, ECCS),
- break size and location, and
- blowdown characteristics.

The analyses utilize a steam line break mass and energy release methodology which considers all of these factors, such that conservative steam line break blowdown transients may be determined.

The methods described in Reference 28 were used to generate the mass and energy release information. These methods form the basis for the assumptions and models used in the calculation of the mass and energy releases resulting from a steam line rupture. Reference 28 presents an extensive analysis of the nature of the effluent releases following a postulated main steam line rupture, as well as a discussion of the methods and models and models used.

Transient mass and energy releases following a postulated secondary side pipe break are calculated using the LOFTRAN code (Reference 32). LOFTRAN is used for studies of the transient response of a PWR system to specified perturbations in process parameters. The code stimulates a multi-loop system including the reactor vessel, hot and cold leg piping, steam generator (shell and tube sides), and the pressurizer. A neutron point kinetics model is used and the reactivity effects of the moderator, fuel, boron, and rods are included. The secondary side of the steam generator is modeled as a homogeneous saturated mixture. Protection and control systems are simulated, as well as the Safety Injection System. The calculation of the secondary side break flow is based on the Moody critical flow correlation (Reference 42) with fl/D=0.

6.2.1.3.10.3.2 Definition of Cases

The postulated break area can have competing effects on blowdown results. Larger break areas result in larger break mass flow rates. However, larger breaks also result in earlier generation of protective trip signals following the break and a reduction of both the power reduction by the plant and amount of high energy fluid available to be released to the containment.

To determine the effects of plant power level and break area on the mass and energy releases from a ruptured steam line, a spectrum of cases have been evaluated. For plant power levels of 102%, 75%, 50%, 25%, and 0% of the Engineered Safeguards Design (ESD) rating, 4 break sizes have been defined.

1. A full double-end rupture (DER) of main steam line. Note that integral steam generator flow restrictors limit the maximum break size to 1.4 ft^2 in any 1 steam line.
2. A large DER having an area just larger than that at which water entrainment occurs.
3. A small DER having an area just smaller than that at which water entrainment occurs.
4. A small split rupture defined as the largest break size in which the isolation signals must be generated by high containment pressure signals and result in no water entrainment on the break effluent.

Table 6.2-47a shows the steam line break mass and energy release to containment cases which were analyzed. Note that, at full power, no entrainment was predicted in any of the DER cases. However, full power large and small DER break sizes were analyzed, both with no entrainment, to provide a sensitivity. For the steam line break mass and energy releases to containment cases analyzed, a number of failures have been considered either individually, or in combination with other failures. The failures considered are: failure of the emergency feedwater runout control

system to function, failure of a single train of the Safety Injection System, and failure of a main feedwater isolation valve to close.

Failure of a main steam isolation valve to close has not been explicitly considered as part of the mass and energy release calculation, but is included separately with the containment response portion of this analysis.

6.2.1.3.10.3.3 Mass And Energy Release Calculation Assumptions

The key assumptions made in the calculation of mass and energy releases for determination of the containment response analysis are discussed below.

6.2.1.3.10.3.3.1 Reactor Coolant System

Table 6.2-46b identifies the nominal plant design parameters considered in this analysis.

Initial Power Level

Steam line breaks can be postulated to occur with the plant in any operating condition ranging from zero to full power. Since steam generator mass decreases with increasing power level, breaks occurring at lower power levels will generally result in a greater total mass release to containment. However, because of increased stored energy in the primary plant, increased heat transfer in the steam generator, and additional heat generation in the fuel, the energy release to the containment from breaks postulated to occur while at power, may be greater than for breaks occurring with the plant at a zero power condition. Additionally, steam pressure and the dynamic conditions in the steam generators change with pressure and the dynamic conditions in the steam generators change with increasing power and have a significant influence on both the rate of blowdown and the amount of moisture entrained in the fluid leaving the break.

Because of the opposing effects (mass versus energy release) of changing power level on steam line break releases, no single power level can be singled out as a worst case initial condition for containment response following a steam line break. Therefore, several different power levels from zero to full power conditions were investigated.

In general, the plant initial conditions for each case are assumed to be at the nominal value, with appropriate uncertainties included. Table 6.2-46c identifies the values assumed for RCS flowrate, pressurizer pressure, RCS vessel average temperature, pressurizer water volume, steam generator water level, and feedwater enthalpy corresponding to each power level analyzed.

Core Decay Heat

Core residual heat generation assumed is based on the 1979 ANS Decay Heat + 2σ model.

Reactor Coolant Metal Heat Capacity

As the primary plant cools, the temperature of the primary coolant drops below the temperature of the reactor coolant piping, the reactor vessel, and the reactor coolant pumps. As this occurs, the heat stored in the metal is available to be transferred to the faulted steam generator. The effects of stored heat in the RCS metal mass are included in the results using conservative thick metal masses and heat transfer coefficients. However, stored heat does not have a major impact on the calculated mass and energy releases.

Core Reactivity Coefficients

Conservative core reactivity coefficients corresponding to end-of-cycle conditions were chosen to maximize the reactivity feedback effects resulting from the steam line break. Use of maximum reactivity feedback maximizes the potential for a post trip return to power, this conservatively maximizes heat transfer to the steam generator. The most reactive control rod assembly assumed to be stuck out of the core.

Rod Control

The rod control system was assumed to be in manual operation for all analyses.

6.2.1.3.10.3.3.2 Secondary System

Main Feedwater System

The rapid depressurization which occurs following a steam line rupture typically results in large amounts of water being added to the steam generators through the Main Feedwater System. Rapid closing feedwater control valves in the main feedwater lines limit this effect. The feedwater addition which occurs prior to closing of the feedwater line control valves influences the steam generator blowdown in several ways. First, the rapid addition increase the amount of entrained water in large break cases by lowering the bulk quality of the steam exiting the rupture. Secondly, because the water entering the steam generator is subcooled, it lowers the steam pressure thereby reducing the flow rate out of the break. As the steam generator pressure decreases, some of the fluid in the feedwater lines downstream of the control valves will flash into the steam generators providing additional secondary fluid which may exit out the rupture. Finally, the increased flow causes an increase in the heat transfer rate from the primary to secondary system resulting in greater energy being released out the break. Since these are competing effects on the total mass and energy release, no worst case feedwater transient can be defined for all plant conditions.

In the analysis, the worst effects of each variable have been assumed. For example, moisture entrainment for each break is calculated assuming conservatively small feedwater additions such that the entrained water is minimized. Determination of total steam generator inventory, however, is based on conservatively large feedwater additions as described below.

For double-ended-ruptures, main feedwater flow to the intact steam generators was modeled by assuming a constant feedwater flow until feedwater isolation. This minimizes the fluid inventory in the intact generators at the time of isolation, which reduces their cooling effect. This conservatively maximizes the energy which must be released through the break. The mass of

feedwater added to the affected steam generator prior to feedline isolation is based upon the conservative assumption that the feedwater flow is at pump runout for the full-time period from initiation of the break until feedline isolation is complete. Feedline isolation may be provided by either the feedwater isolation valve or closure of both the feedwater regulating valve and the feedwater bypass control valve. The total response time of 10 seconds includes a 1.5 second instrument response time and 8.5 second valve stroke time.

For the split breaks, feedwater flow to all generators was increased proportionally with the steam releases from the steam generators.

Following feedwater isolation, as the steam generator pressure decreases, some of the fluid in the feedwater lines downstream of the isolating valve may flash to steam if the feedwater temperature exceeds the saturation pressure. This unisolatable feedwater line volume is an additional source of high energy fluid that was assumed to be discharged out of the break and is conservatively maximized in this analysis.

Emergency Feedwater System

Generally, within the first 30 seconds following a steam line break, the Emergency Feedwater System will be initiated on any 1 of several protection system signals. Addition of emergency feedwater to the steam generators will increase the secondary mass available for release to containment as well as increase the heat transferred to the secondary fluid. The emergency feedwater flow rates were developed with the following conservatisms incorporated. The flow rates to the faulted loop were assumed to be conservatively high, maximizing the available mass for release to containment, and flow rates to the intact loops were assumed to be conservatively low, minimizing the available mass for secondary side heat removal.

The Emergency Feedwater System is designed to automatically isolate flow to the faulted steam generator and to limit flow to the faulted steam generator to less than 1000 gpm. With proper operation, emergency feedwater flow to the faulted generator is not more than 1000 gpm and generally automatically terminated within 48 seconds of detecting high flow to a depressurized SG. For conservatism, however, the emergency feedwater flow to the faulted generator was assumed to be 200 gpm until operator action is taken to terminate flow.

Steam Generator Fluid Mass

Conservative initial steam generator masses were used in all of the cases analyzed. The initial masses for the faulted steam generator were calculated as the mass corresponding to the programmed level + 5% of narrow range span. The initial masses for the intact steam generators were calculated as the mass corresponding to the programmed level -5% of narrow range span. Although the effect is not significant, this conservatively maximizes the secondary inventory available for release to containment, while minimizing the heat transfer capability of the intact steam generators.

Steam Generator Reverse Heat Transfer

Once steam line isolation is complete, those generators in the intact loops become sources of energy which can be transferred to the faulted steam generator. This energy transfer occurs via the primary coolant. As the primary plant cools, the temperature of the RCS coolant flowing in the steam generator tubes drops below the temperature of the secondary fluid in the intact steam generators resulting in energy being returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steam line. The effects of reverse steam generator heat transfer are included in the results.

Break Flow Model

Piping discharge resistances were not included in the calculation of the releases from the steam line ruptures (Moody, Curve, Reference 42, for an fl/D = 0 was used).

6.2.1.3.10.3.3.3 Protection System

The protection systems available to mitigate the effects of a main steam line break accident inside containment are listed below along with the corresponding actuation signals modeled. The setpoints and delay times modeled in this analysis are provided in Tables 6.2-46d, 6.2-47a, and 6.2-47b.

Reactor Trip

The following reactor trip signals were modeled in this analysis:

- Low pressurizer pressure
- Safety Injection System actuation
- Overpower ΔT
- High-1 containment pressure

Safety Injection

The following safety injection signals (SIS) were modeled in the analysis:

- Low pressurize pressure
- Low steam line pressure
- High-1 containment pressure

Steam Line Isolation

Main steam isolation valve actuation was modeled following receipt of any of the following:

- Low steam line pressure
- High-2 containment pressure

Feedwater Isolation

The following feedwater system isolation signals were modeled in this analysis:

- Low pressurizer pressure
- Low steam line pressure
- High-1 containment pressure

6.2.1.3.10.3.3.4 Safety System Failure Considerations

To minimize the number of cases to be analyzed, multiple failures were assumed in many, but not all, of the steam line break mass and energy release to containment cases analyzed. The following failures in the mass and energy release calculations are postulated which may significantly affect the containment results. The failure of a main steam isolation valve has been considered separately in the containment response analysis.

Failure of One Train of the Safety Injection System

A minimum Safety Injection System (SI) flow rate corresponding to the failure of one safety injection train was assumed in this analysis. A minimum SI flow is conservative since the reduced boron addition maximizes a return to power resulting from the RCS cooldown. The higher power generation increases heat transfer to the secondary side, maximizing both mass and energy flow out of the break. The delay time to achieve full SI flow was assumed to be 27 seconds.

Failure of Feedwater Isolation Valve (FWIV) in Faulted Loop

If the FWIV in the feedwater line to the faulted steam generator is assumed to fail in the open position, main feedwater would continue from the condensate pumps until isolation is provided via closure of the feedwater regulating valve and feedwater bypass control valve. Also, the unisolatable feedwater line volume will increase by the volume of the feedwater line between the isolation valve and the feedwater regulating valve and bypass control valve. This additional inventory would then be available to be released to containment.

Failure to Automatically Isolate Emergency Feedwater

The Emergency Feedwater System is designed to isolate emergency feedwater flow to the faulted steam generator via closure of control valves. Failure to automatically close a control valve to the faulted generator results in the addition of up to 1000 gpm of emergency feedwater flow to the faulted generator until operator action is taken to terminate the flow. The increased emergency feedwater flow conservatively provides additional steam generator inventory, which is available to be released to the Reactor Building. Furthermore, the increased emergency feedwater flow serves to maintain a higher pressure in the faulted generator, thus providing additional driving force for the mass and energy release.

Failure of Emergency Diesel

Failure of an emergency diesel to start results in the loss of one motor driven emergency feedwater pump and one train of the SI within the mass and energy calculations. Within the containment response analysis, one train of RB cooling would also be lost.

Failure of Electrical Channel

A loss of an electrical channel (CH-A) is postulated at event initiation. Within the mass and energy calculations, this results in loss of power to the feedwater control valves, feedwater isolation valves, and the main steam isolation valves; prevents the startup of one emergency diesel thus resulting in the loss of one motor driven emergency feedwater pump and one train of the SI; and prevents automatic isolation of emergency feedwater to the faulted SG. Within the containment response analysis, one train of RB cooling would also be lost.

Failure of Main Steam Line Isolation Valve (MSIV)

Failure of the faulted loop MSIV delays isolation of the intact loops and results in a larger unisolatable steam line volume. Prior to steam line isolation, all loops are feeding the break. Steam line isolation terminates fluid discharge from the intact steam generators while the faulted steam generator continues to blowdown. After isolation, reverse flow continues until the unisolatable volume is depleted. This failure is not explicitly considered within the mass and energy release, but is considered separately in the containment response analysis.

6.2.1.3.10.3.4 Results

Table 6.2-47a provides a summary of the mass and energy cases analyzed for use in the MSLB containment analysis. For each case, the initial NSSS power level, break size, single failure(s) assumed (if any), and entrainment assumptions are identified. The time of reactor trip (along with the actuation signal), feedwater isolation, and steam line isolation are provided for each case. Note that for cases that credit High-1 containment pressure or High-2 containment pressure the actuation times were determined iteratively from preliminary LOFTRAN and containment response analyses and confirmed in the final analysis.

Furthermore, in order to reduce the number of iterations during this process, the time to reach the High-1 setpoint was delayed until the High-2 setpoint was reached for the purpose of safeguards actuation. This delays actuation of the Safety Injection System and feedwater isolation, as well as reactor trip.

Tables of mass and energy release rates for the limiting containment pressure case and limiting containment temperature case are provided on Tables 6.2-48a and 6.2-48b, respectively.

6.2.1.3.11 Minimum Containment Pressure Analysis for Performance Capability Studies of Emergency Core Cooling System

A conservatively low containment backpressure is calculated for each LOCA transient in the Large Break LOCA analysis, presented in Section 15.4.1. The containment backpressure for the transient that produced the analysis PCT result is provided in Figure 15.4-21. The containment backpressure is calculated using the methods and assumptions described in Section 15.4.1.1.4.2. Input parameters including the containment initial conditions, net free containment volume, and starting time and number of containment cooling systems used in the analysis are presented in Tables 15.4-1b and 15.4-1c. Passive heat sink material thickness and surface area are shown in Table 6.2-60.

6.2.1.4 Testing and Inspection

Containment leak rate testing is discussed in Section 6.2.6.

Testing and inservice inspection requirements for the Reactor Building are discussed in Section 3.8.1.7.

6.2.1.5 Instrumentation Requirements

The instrumentation to monitor containment conditions and perform the post accident monitoring function is discussed in Section 7.5. In addition, Reactor Building pressure instrumentation channels serve as inputs to both the Reactor Protection System and Engineered Safety Features Actuation System, discussed in Sections 7.2 and 7.3, respectively.

Qualification of safety related balance of plant instrumentation inside the Reactor Building is based upon the peak environmental conditions following the postulated design basis accident main steam line break and is discussed in Section 3.11.2.2.2. Qualification parameters are presents in Table 3.11-3.

Qualification of NSSS safety related instrumentation inside the Reactor Building is discussed in Section 3.11.2.2.1.

6.2.1.6 Materials

Safety-related coating systems are used for concrete and carbon steel surfaces. Both of these coating systems satisfy the quality assurance requirements of Reference 13. In addition, the selected coating manufactures have documented test results certifying compliance with References 14 and 15 requirements for coating materials used inside containment.

The estimated quantity of unqualified paint inside containment is covered in calculation DC03190-025.

The amount of exposed organic material exposed directly to the containment atmosphere is considered negligible.

Metallic material for engineered safety features equipment are discussed in Sections 6.2.3.6, 6.2.4.5 and 6.2.5.6.

6.2.2 Reactor Building Heat Removal Systems

Post accident Reactor Building heat removal is provided by 2 systems acting in concert. One (1) system is the Reactor Building Spray System and the other is the Reactor Building Cooling System. Each of these systems also performs other functions. The Reactor Building Spray System removes iodine, which may be released from the core following a loss of coolant accident (LOCA) (see Section 6.2.3). The Reactor Building Cooling System removes heat from the Reactor Building during normal operation. The reactor building cooling system is composed of four dual-speed fan and coil Reactor Building Cooling Units (RBCUs) arranged in two Groups, with a pair of RBCUs constituting each Group associated with a train. Under accident conditions, each fan in the RBCU is powered by a Class 1E emergency bus, and its associated coil is cooled by a Service Water system train. The accident analysis credits only one RBCU in only one Group operating at slow speed. This system also functions to remove particulate fission products from the post accident Reactor Building atmosphere as discussed in Section 6.5.1.

6.2.2.1 Design Bases

6.2.2.1.1 Post Accident Reactor Building Heat Removal Systems Design Bases

The design bases for the post accident Reactor Building heat removal systems are as follows:

1. The 2 systems, acting in concert, with the most disabling single failure as discussed in item 2 below, will limit the peak Reactor Building pressure to less than the Reactor Building design pressure of 57 psig. The heat sources considered in this analysis are discussed in Section 6.2.1.3.
2. The most disabling single failure is considered to be a loss of offsite power and failure of one onsite diesel generator to operate. This situation will result in the operation of one Reactor Building Spray Subsystem and one Reactor Building cooling unit. Other single failures will allow at least this amount of equipment to function.
3. Equipment inside the Reactor Building which is required to remove post accident heat is qualified to operate in the post accident Reactor Building environment.
4. Portions of these systems which are required to remove post accident heat are designed to withstand the most severe post accident pressure transient.
5. Portions of these systems which are required to remove post accident heat are qualified to experience the safe shutdown earthquake (SSE) without loss of function.
6. Portions of these systems which are required to remove post accident heat are protected from the dynamic effects of pipe rupture in accordance with the criteria presented in Section 3.6.
7. Reactor Building heat removal systems are designed for periodic testing and inspection.
8. Reactor Building heat removal systems are Seismic Category 1. The Reactor Building Spray System components are Safety Class 2a except the sodium hydroxide storage tank and

related discharge lines which are Safety Class 2b. The Reactor Building Cooling System components are Safety Class 2b.

9. The Reactor Building heat removal systems are designed to satisfy containment depressurization requirements discussed in Section 6.2.1.
10. At strategically identified local high points, the Reactor Building Spray System is provided with indicating air-traps and vented orifices to ensure the Reactor Building Spray System remains void free (reference NRC GL 2008-01).

6.2.2.1.2 Reactor Building Cooling System Design Bases for Normal Operation

Design bases for the Reactor Building Cooling System during normal operation are as follows:

1. Operation of any 3 Reactor Building cooling units during normal power operation maintains average Reactor Building ambient air temperature at, or below, 120°F.
2. Operation of any 2 Reactor Building cooling units under loss of offsite power conditions is sufficient to remove the residual heat to bring the plant into a hot or cold shutdown condition.
3. Operation of any 2 Reactor Building cooling units during containment leak rate tests maintains an average Reactor Building ambient temperature with minimum stratification.
4. The system duct arrangement results in general Reactor Building air circulation and provides for discharge of cooled air in close proximity to suction inlets of various subsystems. These subsystems are described in Section 9.4.
5. System instrumentation provides for continuous monitoring of equipment and sounding of alarms to alert the operator to high vibration, smoke, high temperature, abnormally high coil condensate rate, or motor trip.

6.2.2.2 System Design

6.2.2.2.1 Reactor Building Spray System

This section discusses the design of the Reactor Building Spray System with respect to Reactor Building heat removal and its functions in common with fission product removal. Features that relate solely to fission product removal are described in Section 6.2.3.

The system diagram for the Reactor Building Spray System is provided as Figure 6.2-46. The system consists of 2 independent and redundant subsystems, each consisting of a pump, 2 Reactor Building sump isolation valves, 1 refueling water storage tank (RWST) isolation valve, 1 sodium hydroxide storage tank isolation valve, 1 discharge isolation valve, 3 ring headers, 165 spray nozzles, and connecting piping, manual maintenance valves, and check valves. The items shared by the 2 subsystems are the injection water source, the RWST; sodium hydroxide storage tank; and the full flow test line to the RWST. There are no shared active components. This design ensures single failure protection. Reactor Building Spray System component data are presented in Table 6.2-49. A single failure analysis is provided by Table 6.2-50.

6.2.2.2.1.1 System Design Features

Three (3) spray header and nozzle assemblies are provided for each spray subsystem. The headers are stainless steel ring manifolds that uniformly distribute the water mixture to each spray nozzle. Each spray subassembly has 165 spray nozzles and provides full coverage. Five (5) nozzles are located on the inner header and 80 on each of the middle and outer headers. The nozzles are attached to the headers with screwed nipple connectors. Figure 6.2-47 shows the spray header arrangement and nozzle orientation. The sizes and locations of headers inside the Reactor Building are listed Table 6.2-51.

The location of the Reactor Building Spray System ring headers within the Reactor Building dome and the position of the spray nozzles in the ring headers provide for 100% spray coverage of the operating floor with both spray loops operating. For the case of minimum engineered safety features, i.e., only one spray loop available, 93% of the Reactor Building at the operating floor level is covered by the spray.

During both normal and post accident plant operation, the Reactor Building cooling units and associated discharged ductwork supply cooling air flow to the unsprayed regions below the operating floor. This cooling air flow establishes a connective flow path whereby air or air/steam mixtures from the unsprayed regions and from inside the secondary shield walls are directed upward into the suction areas of the Reactor Building cooling units. Thus, the Reactor Building cooling units provide, for the normal or accident case, the required mixing and recirculation of Reactor Building atmosphere for the volumes between and lowest elevation inside the Reactor Building and the elevation of the Reactor Building cooling units (approximately 67 feet above the operating floor).

The spray nozzles are one piece, stainless steel units that deliver water at a nominal rate 15.2 gpm with a pressure differential of 40 psi across the nozzle. Flow is delivered in a hollow cone pattern with an included angle of approximately 60 degrees.

Orifices are located in each individual spray header and the common header supply line to compensate for the differences in elevation of the different headers and to balance Reactor Building Spray System characteristics with pump characteristics.

In the event of LOCA, water from the spray nozzles and water spilled through the break in the Reactor Coolant System is collected in either the A or the B Reactor Building recirculation sumps. Each of these two sumps has a suction line to one residual heat removal (RHR) pump and a suction line to one Reactor Building spray pump. Each recirculation sump is irregular in shape as shown in Figures 1.2-3 and 1.2-4. The overall plan dimensions of each sump are approximately 17 feet by 28 feet. Each of the recirculation sumps is surrounded by a 6 inch high curb. One side of Sump B abuts directly against the adjacent secondary compartment wall and does not have the 6 inch curb. The basement floor of the Reactor Building is at elevation 412’. The floor level of the recirculation sump area is at elevation 408’. There are four individual deep sump pits for the RHR and spray pump suctions – one RHR and one spray deep pit located in each of Sump A and Sump B. The deep pits are 4 foot by 4 foot in plan extending down to elevation 400’. The centerline of the suction pipe within each deep pit is at elevation 402’.

A schematic vertical section through a typical deep sump pit is shown in Figure 6.2-48. A removable welded stainless steel bar grating walkway is provided over the sump for a personnel access walkway and to support maintenance in the area. The grating is designed to remain in place during plant operation. The top of the grating walkway cover over the sumps is at elevation 412'-9". A large opening is provided through the grating to ensure adequate flow to the pumps through the opening for the postulated worst case assuming full blockage of the grating by debris transported to the sump following the postulated pipe break.

Each of the four deep sump pits is protected by a strainer assembly against the entry of potential types and quantities of debris generated as the result of hypothetical, postulated LOCA pipe break events. The RHR and Spray strainer modules are interconnected by a cross-duct to allow water to flow from one module to the other conservatively assuming one of the strainer modules becomes heavily blocked by postulated debris.

Each strainer assembly is composed of a single square module, the header box, equipped with 44 hollow fins, 11 on each of the 4 sides of the strainer header box. The fins are connected laterally to the approximately 4.75 foot high sides of the header box located directly over each sump pit. The fins are of varied length designed to fit within the available space in the sump. Each vertically oriented strainer fin consists of 18 gauge stainless steel sheet, perforated with 1/16 inch diameter holes. The performance of the strainer is enhanced by the extremely low approach velocity to the perforated fins of less than 0.1 inch/second. The area ratio of holes is about 41 percent and the surfaces of the fins are corrugated to increase their surface area. As the water level rises in the strainer during filling, air can escape through the fins and through the vent holes provided at the top of the strainer header box. This design ensures that there is no risk of air ingestion due to trapped air pockets during filling.

The total strainer surface areas provided are:

Sump A:	A RHR	-	1404 sq ft	Total Sump A: 2938 sq ft
	A Spray	-	1534 sq ft	
		-		
Sump B:	B RHR	-	1251 sq ft	Total Sump B: 2380 sq ft
	B Spray	-	1129 sq ft	

The design of both the Sump A and Sump B strainers includes a closed cross duct connecting the RHR and Spray header boxes within the sump. The cross duct design consists of 1/4 inch thick stiffened stainless steel plates. The cross duct provides a flow area approximately 5 inches high by 30 inches wide for flow between the interior of the two header boxes. The cross duct connection to the header boxes is located on the side and near the top of the header boxes. The cross duct is designed and fabricated to the same criteria as the strainers. The cross duct serves to provide additional redundancy to the strainer design for both the Sump A and Sump B. For a postulated event where the fin strainers on either the RHR or Spray sides of the sump are assumed to be

blocked by debris generated by the postulated LOCA pipe break event, the flow into the unblocked strainer header box provides sufficient recirculation flow through the cross duct to satisfy the NPSH requirements for the pumps on both the RHR and Spray sides of that sump.

The header boxes, strainer fins, and cross ducts are designed, fabricated, and installed in accordance with ASME Code and Seismic Category 1 requirements. Each strainer fin bank consisting of 11 fins is supported as an integral unit by bolting each fin to a horizontal truss located along the top and also along the bottom of each fin bank. The trusses are bolted to the header box assemblies. Each fin is also securely pinned at the bottom and bolted at the top to the header box assembly. Adjustable vertical supports for each fin bank are provided beneath the horizontal truss at the bottom of the fin bank to the sump floor at elevation 408'. The top of each header box consists of 3/8 inch stainless steel plate with stiffeners. A solid 3/8 inch thick hinged hatch cover plate for personnel access down into the deep pit is secured to the top of each header box by bolting all four sides of the personnel access hatch plate to the welded flange assembly on the header box top plate.

The bottom surface of each hatch cover plate is designed and fabricated to fit tightly with no gap when secured with the bolts against the continuous bearing bar located around the perimeter of the opening beneath the hatch cover plate. The continuous tight metal to metal closure with no gap precludes any potential debris entry without the need for any gasket material under the hinged cover plate.

Vortex formation was investigated at the controlling locations including at the engineered opening through the grating walkways over the sumps and also above the strainers. The controlling location is at the engineered opening through the grating where the cross section area is smaller and flow rate larger. The grating is assumed to be fully blocked by debris and the combined RHR and Spray streams flow through the engineered opening.

At the start of recirculation, the water level is assumed to be at the controlling minimum elevation of 414.6 feet corresponding to a small break LOCA. This is conservative in that the debris assumed to be blocking flow through the walkway grating could not be generated by a postulated small break LOCA rather only by postulated large break LOCA. The calculated Froude number corresponding to the flow rate and associated velocity through the engineered opening for this conservative case is 0.241. The critical submergence 15.3 inches maximum at the engineered opening is less than the minimum submergence of 22.2 inches to the engineered opening for the small break LOCA. Therefore, no air ingestion down into the sump through vortexing will occur.

Sump design features that prevent the generation of flow irregularities include:

1. Perforated fin and header design. As the water level rises in the strainer during filling, air can escape through the fins and also through 3/8 inch diameter vent holes located close to the top of the strainer header box. As the sump pit fills, a small air pocket may form in the top of the strainer header box. To allow the air pocket to escape, each strainer assembly is designed with 24 vent holes of 3/8 inch diameter close to the top of the strainer header box. Vent holes are covered by perforated sheet having 1/16 inch diameter holes. The pumps are activated well after the strainers are fully submerged and any air pocket within the strainer assembly has been displaced by water. As a result, ingestion of an air pocket into the pump intake is not considered to be a credible scenario. Air ingestion through the vent holes is similarly considered an incredible scenario due to the submergence of the strainers at the holes being much greater than the critical submergence at the holes.
2. The generation of vortices within the 4 foot by 4 foot plan deep sump pit standpipe at the inlet to the Reactor Building Spray System suction piping is prevented by the following:
   a. An established fluid velocity within the standpipe of less than 1 foot per second.
   b. A minimum submergence from the suction piping inlet to the minimum water level at the start of recirculation of at least 12.6 feet.
3. Generator of flow disturbances at the suction piping inlet is minimized by the inclusion of a 24 inch by 12 inch reducer which provides for a gradual change in fluid velocity between the standpipe and suction piping.
4. The location of the Reactor Building spray pumps relative to the top of the recirculation sumps (35 feet, minimum elevation difference) provides the fluid system conditions that ensure dissipation of any flow irregularities that might be generated within the sumps. These positive fluid system conditions are as follows:
   a. A minimum elevation head of 35 feet of water at the pump suction nozzles.
   b. The significant lengths of piping (75 and 100 feet) from the sump outlets to the pump suction nozzles.

Design of the RWST includes an internal vortex baffle at the entrance to the 20 inch suction connection through which cooling water is supplied to the RHR, safety injection Reactor Building spray pumps during operation in the safety injection mode. This internal baffle consists of a 4 foot by 4 foot by 4 foot, stainless steel box with open sides, which directs cooling water flow into the 20 inch suction nozzle from 2 sides along the horizontal centerline of the baffle. This designed control of the flow path into the 20 inch suction nozzle prevents formation of vortices even under conditions of low fluid level in the RWST.

The recirculation water enters the strainer fins through the perforated steel sheet (1/16 inch diameter holes) and flows horizontally within the hollow fin corrugations into the header box. Due to the extremely low approach velocity to the perforated fins of less than 0.1 inches/second it is expected that most of the entrained particulate debris falls out of the flow stream to the sump floor. The top of the sump header box consists of stiffened 3/8 inch plate with a 3/8 inch plate

single leaf bolted personnel hatch cover plate to permit entry into the deep sumps for inspection. All material in the sump area, including liner plate, strainer assembly, deep pit access ladder, etc., is stainless steel to prevent corrosion degradation.

Debris which washes down to the sump and passes through the strainer is evaluated for both blockage and erosion of downstream systems and components. The size of the debris is limited by the 1/16 inch round holes in the perforated plate strainer. Systems and component downstream effects are analyzed based on the methodology in WCAP-16406, Rev. 1 (Reference 48). The analysis was completed as part of the response for Generic Letter 2004-02.

The potential for clogging the sump screens with debris is reduced by minimizing the use of non-metallic, high temperature insulation and by not using displaceable components, such as sand plugs, to provide vent area.

For a discussion of the potential for sump screen clogging, refer to Section 6.3.2.6.1.

Compliance with Regulatory Guide 1.82 is discussed in Appendix 3A.

High temperature insulation used inside the Reactor Building is generally stainless steel, reflective type insulation. Insulation encased in stainless steel is used on the sloping portion of the 6 reactor vessel nozzles and between the pipe restraint collars and Reactor Coolant System piping in the vicinity of the primary shield.

There are 2 independent pipe lines connecting the sump to the suction of the spray pumps. These lines are independent of the 2 lines for the Residual Heat Removal System. The lines from the sump can be isolated by remote, manually controlled, motor operated valves. These valves have relief valves installed to prevent pressure locking due to thermal expansion of fluid trapped between the double-disc gate following closure. Each line is enclosed in a concentric guard pipe which is connected to a protective chamber completely surrounding the isolation valve closest to the Reactor Building.

The guard pipe and protective chamber collect any leakage due to a passive failure of the sump line up to and including the first isolation valve and thus prevent draining the sump to the Auxiliary Building. Passive failures beyond the first isolation valve can be isolated by the first isolation valve The guard pipes and protective chambers are designed to a pressure of 57 psig at a temperature of 300° F.

All outdoor system piping is insulated and has heat tracing. The outdoor sodium hydroxide storage tank is neither insulated nor heat traced. This tank contains a 20 to 22% sodium hydroxide solution which is liquid at temperatures above 13° F.

6.2.2.2.1.2 System Operation

During normal plant operation, the Spray System is in standby condition with the suction aligned to receive water from the RWST. Operation of the system is initiated automatically following a LOCA or MSLB by signals from the Engineered Safety Features (ESF) Actuation System when

the Reactor Building pressure increases to the actuation set point. The Spray System can also be started manually from the control room by the operator. A description of the ESF actuation signals is presented in Section 7.3.

If there is a spray actuation signal, the Reactor Building spray pumps are loaded onto the onsite diesel generators following a loss of offsite power (see Chapter 8). The total time for RB Spray water to start being delivered through the spray nozzles to the RB atmosphere is 47 seconds following LOCA initiation. This includes a 10 second start time for EDGs, 5 seconds for the spray pump to reach full capacity (during this 5 second pump acceleration time, no filling of lines is assumed), and 32 seconds to fill the RB spray line up to the nozzles. For conservatism, it is assumed in the Reactor Building pressure analysis that spray starts 52 seconds after the LOCA occurs.

Each spray subsystem is started by separate ESF containment isolation Phase A and spray actuation signals. Normally, both subsystems operate; however, they are independent and can operate individually. The design basis for Reactor Building heat removal is one spray subsystem operating in conjunction with one Reactor Building cooling unit (with one RHR pump and one charging pump providing emergency core cooling water).

During the injection phase following a LOCA, the spray pumps receive fluid from the RWST and sodium hydroxide storage tank. The solutions are carried through the pump discharge lines to the spray headers and are then sprayed into the Reactor Building atmosphere through the spray nozzles. The spray is collected in the bottom of the Reactor Building with water from ECCS and the Reactor Coolant System in the Reactor Building recirculation sumps. During the recirculation phase, the spray pumps may take suction from the sumps, in the Reactor Building.

The spray droplets absorb heat as they fall through the steam-air atmosphere in the Reactor Building, thereby reducing Reactor Building atmosphere temperature.

A nominal spray flow of 2500 gpm is provided by each spray subsystem. When the system is receiving water from the RWST (injection phase) the flow nominally includes 50 gpm of a 20 to 22 weight percent solution of sodium hydroxide. This flow (nominal 2500 gpm) is delivered into the Reactor Building through 165 nozzles at a rate of 15.2 gpm per nozzle. The nozzles are arranged on ring headers in the top of the Reactor Building such that the spray from each subsystem covers essentially the same volume.

There are 4 significant operating combinations of Reactor Building spray pumps and Emergency Core Cooling System (ECCS) pumps:

1. Reactor Building Spray System design case: 1 Reactor Building spray pump; 1 residual heat removal (RHR) pump; and 1 charging pump operating (loss of offsite power and malfunction of one emergency diesel generator).
2. Normal case: 2 Reactor Building spray pumps; 2 RHR pumps; and 2 charging pumps (all ECCS pumps) operating.
3. One (1) Reactor Building spray pump inoperable, all ECCS pumps operating.

4. One (1) RHR pump operating, 2 charging pumps and 2 Reactor Building spray pumps operating

The sodium hydroxide solution is gravity fed into the Reactor Building spray pump suction lines. The system is so designed that the sodium hydroxide storage tank empties at approximately the same time as does the refueling water storage tank (RWST) (e.g., the rate of change, proportional to the initial level, of the 2 liquid levels is the same) for Cases 1 and 2, above. This provides nominally constant sodium hydroxide flow rates for these 2 cases. The design flow rates are approximately 50 gpm to the single operating spray pump for Case 1 and approximately 45 gpm/pump for Case 2.

In Case 3, the initial flow of sodium hydroxide to the single operating Reactor Building spray pump is approximately 55 gpm. However, at this rate of flow from the sodium hydroxide storage tank, the liquid level lags the drop in liquid level in the RWST, since the equilibrium sodium hydroxide flow rate for this case is 73 gpm. (The equilibrium flow rate is the flow rate at which the sodium hydroxide storage tank level drops at the same proportional rate as does the RWST liquid level. This is the stable operating condition for the Reactor Building Spray System. The sodium hydroxide flow rate is unstable under any other condition and the sodium hydroxide flow rate gradually changes toward the equilibrium rate.) As a result, pressure head differential begins building up on the sodium hydroxide side of the Reactor Building Spray System at the junction of the sodium hydroxide and RWST lines. However, as the total pressure head on the sodium hydroxide side must balance the total pressure head on the RWST side of the junction, the sodium hydroxide flow rate increases as necessary to create an additional flow loss to offset the differential pressure head. The flow rate continues to increase as the system adjusts toward a stable operating condition at the equilibrium flow rate.

The rate at which the sodium hydroxide flow increases depends upon the flow impedance of the sodium hydroxide circuit from the sodium hydroxide storage tank to the junction with the line from the RWST. If the impedance is very low, the flow rate increases very rapidly to the equilibrium rate. An increase in the impedance slows the rate of change of flow rate. Thus, the rate at which the sodium hydroxide flow rate increases from the initial rate can be controlled through discrete design of the impedance characteristics of the sodium hydroxide circuit. Flow characteristics of the circuit from the RWST must also be properly designed. Impedance elements must be limited to characteristics and locations that do not reduce the minimum available net positive suction head at the pump to less than the minimum required, or to zero, anywhere in the circuit from the RWST to the Reactor Building spray pumps.

Properly sized pressure loss inducing orifices are located in the common and individual sodium hydroxide lines (in conjunction with orifices in the individual spray pump lines from the RWST) to create sufficient and properly distributed flow impedance such that, in Case 3, flow increases to a maximum rate of 65 gpm at the end of the injection phase (“lo-lo” level in the RWST).

In the fourth case, the initial sodium hydroxide flow rate is approximately 42 gpm per Reactor Building spray pump. The equilibrium flow rate for this case is 34.5 gpm per pump. In this case, the liquid level in the sodium hydroxide storage tank drops at an increased rate compared to the liquid level in the RWST. The result is the reverse of the situation in Case 3. The sodium

hydroxide flow rate decreases from the initial rate toward the equilibrium rate as the injection phase continues.

Upon receipt of the RWST “lo-lo” level signal in conjunction with the safety injection signal, the Reactor Building recirculation sump isolation valves (3004A & B and 3005A & B) automatically open. (See Section 7.6.11 for a discussion of the switch over logic.)

A design evaluation of the Reactor Building Spray System has been performed to track the fluid levels in the refueling water storage tank and sodium hydroxide tank during emergency safeguards operation. Refer to Section 6.2.2.3.1.4.

Sump water temperature data shown by Figures 6.2-6 and 6.2-7 were obtained from results of the transient analyses performed for both the main steam line break and the LOCA. The conservative assumptions applicable to the generation of this data are listed in Section 6.2.1.3.2. One of these assumptions, used in determining the temperature data illustrated by Figure 6.2-7, is that the Reactor Building Spray System is operated for up to 40 days to provide Reactor Building cooling following the design basis LOCA.

During post recirculation operations, the Reactor Building recirculation sump water can be sampled with the normal and Post-Accident Sampling System to monitor the pH. If additional sodium hydroxide is required, the sodium hydroxide feed line valve(s) from the sodium hydroxide storage tank is (are) opened and the sodium hydroxide solution is gravity fed into the Reactor Building spray pump suction line(s). The sodium hydroxide solution will flow into the pump suction line only when the Reactor Building pressure is less than or equal to atmospheric pressure.

A flow test line connecting spray pump discharge lines to the RWST provides a return loop for use in conducting periodic operating tests.

6.2.2.2.2 Reactor Building Cooling System

The system diagram for the Reactor Building Cooling System is provided as Figure 6.2 49. Design and performance data are included on this figure. Plan and elevation drawings of the system ductwork are provided as Figures 6.2 50 and 6.2 51. A single failure analysis is provided by Table 6.2-52.

6.2.2.2.2.1 System Design Features

The system consists of 4 plenums arranged to discharge filtered and cooled air into a common air supply main. The cooling air is further distributed from the supply main to the upper portions of the Reactor Building through supply air outlets in the supply main and to the lower elevations of the Reactor Building through vertical supply ducts connected to the supply main. Non-engineered safety features systems are provided for normal ventilation, cooling and filtering of the Reactor Building atmosphere and for transfer of heat to the Industrial Cooling Water System. These systems are described in Section 9.4.

Each plenum includes moisture separators, high efficiency particulate air (HEPA) filters, filter bypass opening and dampers, cooling coils and an axial flow fan driven by separate high speed and slow speed motors. The moisture separators and HEPA filters are arranged in vertical banks in the plenum. Air enters the plenum through vertical openings in two of the plenum walls or through a bypass opening in the plenum roof if the bypass damper is open. Air entering through the bypass opening is not filtered and passes directly to the cooling coils.

The Reactor Building cooling unit fans operate at high speed during normal periods and at slow speeds during post LOCA periods and during Reactor Building leak rate testing. The units are serviced by cooling water from the Industrial Cooling System during normal periods and by service water during post LOCA or loss of offsite power conditions. For normal operation, 3 out of 4 fans operate. For LOCA, one fan in each train operates.

The plenums are arranged along the perimeter of the Reactor Building with the base of each at elevation 514'. Two (2) of the Reactor Building cooling units are supplied with electrical power from the A channel and the other two from the B channel of the Class 1E electric system.

A single supply and return cooling water main serves the two Reactor Building cooling units powered from the A channel of the Class 1E system. A separate, single supply and return main serves the two units powered from the B channel. These two sets of cooling water mains are separated from each other.

Each Reactor Building cooling unit is provided with lighted service platforms inside the plenums with access doors for inspection, maintenance and replacement of filters, motor and fans. Information on monitoring and control of these units is presented in Section 6.2.2.5.2.

The Reactor Building cooling units are designed and constructed in accordance with the following codes, standards, and guides:

1. Title 10, Code of Federal Regulation, Part 50, Appendices A and B.
2. *Health and Safety Information*, Atomic Energy Commission, Issue No. 306, March 31, 1971.
3. *Standard Test Code For Air Moving Devices*, Air Moving and Conditioning Association, Bulletin No. 210.
4. Boiler and Pressure Vessel Code, Sections III and IX, American Society of Mechanical Engineers, 1973.
5. *Standard Test Code for Sound Ratings, Air Moving Devices,* Air Moving and Conditioning Association, Bulletin No. 300.
6. *Structural Welding Code*, American Welding Society, AWS D1.1 72.
7. Military Specifications MI- F-51079 and MIL-STD-282.
8. *Type Test of Continuous Duty Class 1 Motors Installed Inside the Containment of Nuclear Power Generating Stations*, (Proposed Standard), Institute of Electrical and Electronic Engineers, IEEE 334-1971.

9. *High Efficiency Air Filter Units*, Underwriters Laboratories, Bulletin UL-586.
10. *Air Filter Units*, Underwriters Laboratories, Bulletin UL-900.
11. Regulatory guide 1.52 *Design,* T*esting and Maintenance Criteria for Atmospheric Cleanup System Air Filtration and Absorption Units of Light Water Cooled Nuclear Power Plants* (see Appendix 3A).

6.2.2.2.2.2 System Operation

The automatic change in operating mode from normal to emergency involves changing from motors operating at high speed to motors operating at slow speed, changing the unit cooling water from that supplied by the Industrial Cooling Water System to that from the Service Water System, and automatically closing the Reactor Building HEPA filter bypass damper. The active RBCU discharge valves will automatically align so that 2 of the 4 valves, one per train, will open when their associated RBCU fans are selected to run; the other two valves will close when their RBCU fans are not selected to run. The units, when operating in the normal mode, are tripped upon the receipt of a safety injection or loss of offsite power signal and are then automatically started at slow speed in accordance with the ESF actuation system and the ESF loading sequence of the related emergency diesel generator. A description of the ESF loading sequence is provided in Section 7.3.

In the following discussion, the times given for the occurrence of events are referenced to the time at which the ESF loading sequence gives a start signal to the first electrical load. See Section 7.3 for information on the relationship between this time and the time of occurrence of the input signal which initiates the ESF loading sequence.

The slow speed motors are energized at approximately 25 seconds after the referenced time. An additional 8 seconds are required after energizing the slow speed motor for air flow to reach operating values. Thus, the total “air-side” switchover from normal to emergency operation is completed approximately 33 seconds after the reference time. The safety injection or loss of offsite power signals also initiate closing of the industrial cooling water supply and return valves connected to piping serving the plenum cooling coils. Following receipt of either of these signals, the ESF loading sequence energizes the service water pumps 10 seconds after the reference time and energizes the service water booster pumps 35 seconds after the reference time. The service water booster pumps require approximately 5 seconds after the motor is energized to reach the operating value for water flow. The total “water-side” valve switchover from normal to emergency operation is completed approximately 86.5 seconds after the reference time.

The Reactor Building cooling units can be manually operated from the control room at either high or slow speed. Control room selector switches also determine which one of the 2 A and which 1 of the 2 B electrical power channel units starts in response to an ESF loading sequence signal. The plenum unit HEPA filter bypass damper is in the open position during normal operation and is automatically closed upon receipt of a safety injection signal. Additionally, this damper can be manually opened or closed from the control room during the normal mode of operation. The damper can also be manually closed from the control room during operation in the emergency

mode. The damper fails closed upon loss of electric power. The effects of the HEPA filter upon removal of fission products in the Reactor Building are discussed in Chapter 15.

6.2.2.3 Design Evaluation

An evaluation of the Reactor Building heat removal systems relative to their effect upon the Reactor Building pressure transient analysis is presented in Section 6.2.1.

6.2.2.3.1 Reactor Building Spray System

6.2.2.3.1.1 Net Positive Suction Head to Reactor Building Spray Pumps

It is important that the net positive suction head (NPSH) at the suction of the Reactor Building spray pumps be maintained at or above the minimum required value to assure the long term availability of the pumps. The NPSH available is a function of Reactor Building pressure, water temperature, static head of water, friction losses in the pump suction piping and pressure drop across the sump strainer as follows:

$$NPSH_a = P_c - P_s + \Delta H_z - \Delta H_f - \Delta H_s$$

Where:

$NPSH_a$	=	NPSH available at the pump suction.
P_c	=	Reactor Building pressure.
P_s	=	Saturation pressure of the pumped water.
ΔH_z	=	Elevation pressure due to the height of water above the pump nozzle.
ΔH_f	=	Pressure loss due to friction in the suction line.
ΔH_s	=	Pressure loss across the sump strainer.

The pressure in the Reactor Building (P_c) will always equal or exceed the vapor pressure of the water in the sump because water will evaporate from the sump to increase the vapor pressure of the atmosphere if P_c starts to decrease below P_s. Generally, the partial pressure of the air in the atmosphere will maintain P_c greater than P_s. For conservatism, no containment overpressure is assumed, i.e., $P_c = P_s$. This is consistent with the guidance provided in Regulatory Guide 1.1. The elevation of the pump shaft centerline is 377 feet. The minimum sump water elevation in the Reactor Building during recirculation is 414.6 feet for small break LOCA with water holdup in the reactor vessel cavity. Therefore, the minimum elevation head is:

(414.6 feet - 377 feet) = 37.6 feet

Friction losses are calculated using the runout flow (3300 gpm) rather than the design flow (2500 gpm). The minimum required NPSH at 3300 gpm is 17 feet based on vendor data. Head friction losses through the piping, fittings and valves have been determined and yield a calculated head loss of 5.96 feet for Pump A and 6.16 feet for Pump B (Reference 44). The pressure drop through the sump strainers was determined experimentally by small scale testing with chemical effects from aluminum corrosion precipitants. The maximum pressure drop through the strainer is 4.09 psid at 70° F for the maximum debris loading case.

A summary of the results is as follows:

	NPSH Available (ft)	NPSH Required (ft)	Margin (ft)
Pump A	22.1	17	5.1
Pump B	21.9	17	4.9

Design of the recirculation sumps prevents formation of vortices without the use of vortex suppressors. Plan and elevation drawings of the sump and piping to the Reactor Building spray pumps are provided by Figures 6.2-82 through 6.2-84. Preoperational testing established suction paths through the sump lines to the Reactor Building spray pumps for the purpose of determining the actual piping friction losses at full flow. The as-tested head loss for each train is 4.6 feet (Reference 45).

The potential effects of Reactor Building spray water and reactor blowdown liquid becoming trapped (also called holdup volume) in areas of the Reactor Building and unavailable for post accident recirculation are considered in sump level analysis. Spray flow entering the refueling cavity drains through an 8 inch line to elevation 412' for recirculation. (This drain line is temporarily flanged off during refueling and contains no valves.) Spray flow entering the southern portion of the refueling cavity may drain into the reactor cavity through the reactor cavity seal ring. This is a small gap, so water accumulation in the reactor cavity would be very slow. The spray water may also drain through the access openings for inservice inspection of the reactor vessel “safe-end- welds”. Most of the water flowing into these openings will drain out through pipe sleeves due to a unique baffle arrangement around each reactor vessel nozzle which prevents

drainage to the reactor cavity. Spray flow landing on the 463 ft operating deck drains to the 412' elevation through the equipment hatch and two stair wells. There is no curbing around the equipment hatch.

Leakage from breaks in the large Reactor Coolant System piping, including a “safe-end-weld” break, will drain to the recirculation sumps since leakage into the reactor cavity is prevented by the baffle arrangement previously mentioned. Flow exits the loop compartments by one of the three openings in the secondary shield wall and travels around the containment annulus to the recirculation sumps. After the water from the reactor coolant blowdown and Reactor Building spray collects above the Reactor Building floor to an elevation of 415 feet, it can enter the incore instrument pit through a ventilation opening in the shield wall that is part of the incore instrument chase. The volume of water collected in the incore instrument pit will vary, depending upon the height of the recirculation water above the Reactor Building floor.

The sump water elevation for the NPSH calculations assumed water fills the reactor cavity to the 430.75 ft elevation where it will spill out the loop openings in the primary shield wall. This is a conservative assumption which bounds any possible hold up concerns in the reactor vessel cavity. Holdup water volumes are also considered for droplet accumulation on vertical surfaces, steam in the containment free volume, water accumulation on the 463 ft and 436 ft floors, as well as transit water volumes in the spray and spill flows.

6.2.2.3.1.2 Spray Nozzles

Reactor Building spray nozzles are discussed in Section 6.2.3.2.

6.2.2.3.1.3 Leakage Considerations

Following a postulated LOCA the Residual Heat Removal System and the Reactor Building Spray System are operational. During the recirculation phase, leakage could occur through component flanges, pump shaft seals, valve flanges, and valve stems. Although leakage rates have been assumed for these sources, maintenance and periodic system testing will preclude all but a small percentage of the assumed leakage. Values for the expected maximum leakage through such components are listed in Table 6.2-52b for Reactor Building Spray System components and Table 6.3-4 for Residual Heat Removal System components. The radiological assessment of this operational leakage is discussed in Section 15.4.1.3. Radioactivity release rates are listed in Table 15.4 10.

6.2.2.3.1.4 Drawdown Analysis

A design evaluation analysis has been performed to track fluid levels in the refueling water storage tank (RWST) and sodium hydroxide storage tank (SHST) during each of the 4 operating combinations outlined in Section 6.2.2.2.1.2. The analysis involves modeling all pumps and associated piping that take suction from the RWST and SHST as input to the PIPF computer program. This computer program then performs a steady state pressure balance on the piping network. The PIPF Computer Code (Reference 29) was approved by the NRC on March 29, 1978, for use in hydraulic analyses, providing 3 criteria were satisfied:

1. Fluid is low temperature and incompressible.
2. Energy conservation can be omitted.
3. For transient calculations, flow rate changes are slow and smooth.

In this analysis, the fluid is water at 70 F in solution with boric acid or sodium hydroxide. Energy is neither added to nor removed from the fluid, except through the pumps. The pumps are modeled to maintain a uniform flow rate throughout the transient. Models of the Reactor Building Spray System and Emergency Core Cooling System for each of the 4 operating combinations are shown by Figures 6.2-51a through 6.2-51d.

The drawdown transient is modeled by determining the steady state flow from the tanks at the initial levels. The volume of fluid drawn from the tanks during a 5 minute interval (or smaller, if desired) is calculated from the above flow. Tank levels are then adjusted and another steady state balance is performed. The procedure is repeated until the RWST reaches a predetermined level, at which time drawdown is terminated.

Since sodium hydroxide concentrations range between 20 and 22% by weight and initial tank levels for both the RWST and SHST range between min-max values, 2 separate modes of analysis were considered. First, a minimum pH mode was analyzed in which the sodium hydroxide fluid concentration and initial tank level were at minimum values, while the RWST was a maximum value. Secondly, a maximum pH mode, in which the initial conditions were reversed, was considered. All 4 operating combinations were analyzed for each pH mode.

Input parameters used in the analysis are given in Tables 6.2-52c through 6.2-52f. Table 6.2-52c is a compilation of system branch data. Table 6.2-52d lists pump head data. Table 6.2-52e gives tank parameters. Table 6.2-52f lists specific volume and viscosity for the minimum and maximum concentrations of sodium hydroxide solution.

Drawdown transients for each of the 4 cases at both minimum and maximum sodium hydroxide initial conditions are plotted on Figures 6.2-51e through 6.2-51l. Summary tables for each initial sodium hydroxide condition are provided as Tables 6.2-52g and 6.2-52h. The analysis shows that the RWST and SHST drawdown uniformly.

The pH values of the spray solution, as a function of time during the injection and recirculation phases, for the 4 operating combinations of Reactor Building spray pumps and ECCS pumps are

shown by Figures 6.2-51m through 6.2-51bb . Supplemental analyses have been performed to support a larger RCS volume, due to steam generator replacement, with RCS boron levels ranging from 0-2000 ppm. These analyses show a small increase (0.2 to 0.3) in the sump and spray pH values during the recirculation phase of the accident.

6.2.2.3.1.5 Preoperational Water Test

The model used to predict the results of chemical drawdown outlined in Section 6.2.2.3.1.4 has been verified by comparison to a site preoperational water test. The test involved filling the refueling water storage tank and sodium hydroxide storage tank with grade A water and conducting one complete drawdown using each of the 4 operating combinations of the Reactor Building spray pumps and ECCS pumps for a portion of the transient. A comparison of the site test results to the analytical predictions is shown for each pump configuration in Figures 6.2-51cc, 6.2-51dd, 6.2-51ee, and 6.2-51ff.

The good correlation between site test results and analytical prediction confirms the validity of the model used in the chemical drawdown analysis of Section 6.2.2.3.1.4.

6.2.2.3.2 Reactor Building Cooling System

The Reactor Building cooling units are sufficiently separated to confine the effects of pipe whip, jet impingement of external missiles to one unit. The 2 units powered from the A channel of the Class 1E electric system are located on the opposite side of the Reactor Building from the 2 units supplied from the B channel. Also the cooling water supply and return mains to these units are physically separated as is the A and B channel wiring.

Each unit can operate independently of the others and the discharge from each unit is isolated from the common air supply main by gravity operated dampers.

Reactor Building Cooling System components that must remain intact following a LOCA include: the 4 plenums and all internal components, plenum discharge ducts, common air supply main, and the 6 vertical supply ducts from the common air supply main to the lower elevation of the Reactor Building.

Design considerations employed to assure that components noted above will remain intact following a LOCA include:

1. Qualification of the plenum and components as described in American Air Filter (AAF) Topical Report, AAF-TR-7101 (Reference 16).
2. Testing and qualification of the fan motor assembly in accordance with IEEE-334 (Reference 17) as indicated in Reliance Electric Test Report NUC-9 (Reference 18).
3. Testing and qualification of the HEPA filter bypass damper.
4. A seismic analysis for the duct systems and HEPA filter bypass dampers.

5. Design of the Reactor Building cooling unit plenum housing suitable for a 2 pound pressure differential and provision of plenum housing relief valves so that this differential is not exceeded during the LOCA pressure transient.
6. Design of duct systems suitable for a 2 pound pressure differential and provision of duct relief valves so that this differential is not exceeded during the LOCA pressure transient.

6.2.2.3.3 Heat Removal Rate

The Reactor Building Spray System utilizes 165 spray nozzles on each loop. The spray nozzles are Spray Engineering Company (SPRACO) Model 1713A and have a hollow cone spray pattern with an average droplet size of 230 microns at a differential pressure of 40 psi across the nozzles.

At a discharge flow rate of 2500 gpm, each subsystem absorbs 2×10^8 BTU/hr at a Reactor Building atmosphere temperature of 260° F. The spray droplets in this analysis reach thermal equilibrium with the Reactor Building atmospheres in less than 0.5 seconds.

The Reactor Building cooling units reject heat to the Service Water System following a LOCA. Four (4) Reactor Building cooling units are furnished, 2 piped and wired to the A loop and A channel, respectively, and the other 2 to the B loop and B channel, respectively. The system design anticipates simultaneous use of one Reactor Building cooling unit from each loop. The design heat removal rate for each unit following a LOCA is as follows: 125×10^6 BTU/hr with saturated air entering the cooling unit at 283° F, 69.39 psia, density of 0.182 lb/ft^3, with 2000 gpm of cooling service water entering at 95°F. In order to allow for degraded performance, containment pressure and temperature analysis for LOCA transients use the more conservative performance curve corresponding to a tubeside fouling factor of 0.0014, as shown on Figure 6.2-15. Analysis of MSLB transients use the design performance curve on Figure 6.2-15 times 60%.

6.2.2.4 Tests and Inspections

6.2.2.4.1 Reactor Building Spray System

In addition to the checkout tests performed prior to initial plant startup and following maintenance, system and component tests are performed periodically in accordance with the ASME Code, prescribed under 10CFR50.55a, to verify continued operability of the Reactor Building Spray System. Also, those elements of the Reactor Building Spray System that perform a containment isolation function must be leak tested periodically in accordance with the requirements of Appendix J to 10CFR50.

Prior to plant startup, flow tests were performed to verify that the various orifices are properly sized to provide the correct mixture of sodium hydroxide solution and RWST water during operation of the Reactor Building Spray System.

6.2.2.4.1.1 System Actuation Tests

Reactor Building Spray System actuation tests verify that the system will operate properly and as designed in the event of an accident. These tests are performed as a part of an overall test of the ESF actuation system. This procedure involves testing of analog and logic circuitry and the actuation of the ESF components (except those whose actuation is not acceptable while the plant is in operation).

The procedures followed in testing actuation of the Reactor Building Spray System components prevent introduction of spray into the Reactor Building or introduction of sodium hydroxide solution into the pump suction lines. Actuation of the header isolation valve and the spray pump in a spray subsystem are tested separately. By following this procedure during testing, pump operation with an open header isolation valve will not occur.

Actuation of the valves in the line from the sodium hydroxide storage tank is blocked during testing when the plant is operating. These valves are tested only during shutdown and then only with the manual shutoff valve in the sodium hydroxide storage tank outlet line closed.

The test line is opened (only to the subsystem being tested) for testing of the pump. This allows the pump to be operated without spray flow into the Reactor Building. In conjunction with testing the actuation of the pump, an evaluation of the pump performance is made to ensure that performance is satisfactory. The opening signal to the valve (normally open) in the suction line from the RWST is tested simultaneously with the actuation of the Reactor Building spray pumps by a simulated High-3 Reactor Building pressure signal. The RWST discharge valves are not closed except during testing of the valves themselves or testing of the sump isolation valves. Testing pump actuation with the RWST discharge valves closed is not considered necessary.

Testing is performed on one spray subsystem at a time. The other subsystem remains in its normal condition for plant operation.

6.2.2.4.1.2 Component Tests

Sump isolation valves are tested by manual operator action with the shutoff valves in the suction lines from the RWST closed. The sump isolation valves are tested in one line at a time. One valve in the line is actuated open and closed, followed by actuation of the other valve in that line. One valve in the line is fully closed at all times. The response of the valves is monitored and evaluated to verify proper operation. The header isolation valves and RWST discharge valves are tested with the Reactor Building spray pumps off.

When Reactor Building Spray Nozzles are required to be verified to be unobstructed, an evaluation, based on the specific situation, will determine the appropriate method (e.g., visual inspection, air or smoke or equivalent flow test, or by draining and flushing the filled portions of the system inside containment) to verify no nozzle obstruction.

6.2.2.4.1.3 Leak Tests of Containment Isolation Elements

Containment isolation is provided on each pump discharge line by a check valve located inside the Reactor Building and a motor operated gate valve located outside. Isolation is provided on each suction line from the Reactor Building sump by a motor operated gate valve located outside the Reactor Building combined with a concentric guard pipe and protective chamber enclosing the line from the sump to and including the gate valve. Test connections are provided for leak testing these isolation elements.

To leak test the check valves, it is necessary to replace the system balance orifice in the pump discharge line, located on the spray header side of the check valve, with a blank orifice plate. The orifice blank is provided with the orifice as a one piece unit. This provides a direct visual means of verifying that the orifice blank has been removed and the orifice replaced.

6.2.2.4.2 Reactor Building Cooling System

Various components of the Reactor Building cooling unit plenums have been tested and qualified for emergency conditions as reported in AAF-TR-7101 (Reference 16), approved by the USAEC, DRL in November, 1972. The components tested included moisture separators, cooling coils, HEPA filter banks, and plenum housing relief valves. The fan and motor assembly has been tested and qualified by the Joy Manufacturing Company in a simulated environmental test in accordance with the procedure outlined in IEEE-334 (Reference 17).

6.2.2.4.2.1 Preoperational and Periodic Tests

Prior to plant startup, check and balance tests are performed on the “air-side” and “water-side” of the Reactor Building Cooling System to adjust and verify that system components can develop the required design air and water flow rates. In addition to the tests performed prior to initial plant startup, system and component tests are performed periodically to verify continued operability of the Reactor Building cooling units in both normal and emergency modes.

6.2.2.4.2.2 System Actuation Tests

Reactor Building Cooling System actuation tests verify that the operating components of the system shift to the emergency mode. Actuation tests are performed to verify the following “air-side” and “water-side” functions:

1. “Air-Side” Actuation Tests

   a. Tripping of the Reactor Building cooling unit while operating at normal speed upon receipt of safety injection or loss of offsite power signals.

   b. Automatic start at low speed in accordance with the ESF actuation system.

   c. Closing of the bypass damper following receipt of safety injection signal.

2. "Water-Side" Actuation Tests

   a. Closing of the industrial cooling supply and return valves upon receipt of safety injection or loss of offsite power signals.

   b. Automatic starting of the service water pumps and service water booster pumps in accordance with the ESF actuation system.

   c. Automatic opening of the service water supply XVG-3106, 3108 and return XVB-3107 valves as the service water booster pumps start.

   d. Automatic opening of one of the service water Reactor Building cooling unit discharge XVG-3109 valves and automatic closure of the other XVG-3109 Reactor Building cooling unit discharge valve.

"Air-side" and "water-side" testing is performed on one of the 2 redundant subsystems at a time. The other subsystem continues normal operation during the tests. The manual shutoff valve downstream of the service water booster pumps is closed prior to the tests to prevent unnecessary contamination of the cooling coils with service water.

6.2.2.4.2.3 Component Inspections and Tests

The cooling plenum structure, cooling coils, fans, motors, and filters are inspected during refueling periods for signs of corrosion, metal fatigue, leakage, deterioration of gaskets or painted surfaces, loosening of instrumentation, and for adequate lubrication. The filter plenums are tested during each refueling period with dioctyl phthalate (DOP) in accordance with the requirements of ANSI N510-1975 (Reference 20).

6.2.2.5 Instrumentation Requirements

6.2.2.5.1 Reactor Building Spray System

Reactor Building Spray System instrumentation provides for system performance and status monitoring during normal plant operation, during system tests, and during system operation following a LOCA. The Spray System instrumentation does not have an active function in the actuation or operation of the system. The data displayed and controls located in the control room are adequate for assessing malfunctions and accidents and performing necessary actions for recovery.

6.2.2.5.1.1 Flow Instrumentation

Flow instrumentation loops utilize orifices and electronic transmitters for measuring the flow rate in the discharge of each pump. Each transmitter supplies a signal to a flow indicator on the main control board (in the control room) and to a bistable mounted in the instrumentation panel in the Control Building relay room. The bistable has adjustable setpoints for the high and low flow alarm inputs to the main control board annunciator system. Flow alarms are defeated until the associated pump breaker has been closed for a time interval greater than the setpoint of a time

delay relay. This alarm alerts the operator to an abnormality in the Reactor Building Spray System. Flow rate is also displayed locally at the transmitter and is monitored by the computer.

6.2.2.5.1.2 Level Instrumentation

Redundant liquid level measuring loops are provided on the sodium hydroxide storage tank. In each of the 2 measuring loops an electronic pressure differential transmitter is used to detect the fluid level in the tank. Fluid level is displayed on the main control board and is monitored by the computer. The level signal is also supplied to a bistable mounted on the instrumentation panel in the Control Building relay room. The bistable has adjustable setpoints for Hi and Lo alarm inputs to the main control board annunciator system. A site glass also provides visible indication of level in the sodium hydroxide storage tank. The site glass is isolated and drained after each reading and remains valved out until another reading is required.

An empty alarm is not used on the sodium hydroxide storage tank. Should the tank be emptied before the RWST is emptied, the liquid interface recedes into the tank discharge lines but the lines to not completely empty because of the pressure maintained at the junction with the RWST lines by the head of liquid in the RWST. Introduction of air into the pumps from vortex effects in the sodium hydroxide storage tank has no significant effect on pump operation because of the low flow velocity in the tank outlet line and the fact that the flow from the sodium hydroxide storage tank comprises only about 2% of the total pump flow.

Level instrumentation in the Reactor Building recirculation sumps permits verification that adequate water has been collected in the bottom of the Reactor Building to maintain sufficient flow and NPSH for the spray pumps in the recirculation mode.

The RWST is not a part of the Reactor Building Spray System but has level instrumentation relevant to the Reactor Building Spray System. An alarm is sounded if the water level drops to a “lo” level during startup or normal plant operations. Level instrumentation also initiates alarms in the Control Room on “Hi”, “lo-lo” and “empty” RWST level. Upon receipt of the RWST “lo-lo” level signal in conjunction with the safety injection signal, the Reactor Building sump isolation valves open automatically and the operator closes the valves in the line from the RWST. The operator will not terminate the Reactor Building Spray System operation until after the required operating period of 2 hours for a design basis LOCA.

6.2.2.5.1.3 Pressure Instrumentation

Local pressure gages are located in the suction lines and the discharge lines of each spray pump. A pressure gage is also located on the nitrogen gas supply line to the sodium hydroxide storage tank. The gages are used for system and component evaluation during testing. The latter gages are also used for monitoring and controlling the nitrogen cover gas pressure in the sodium hydroxide storage tank.

An electronic pressure transmitter is located on the discharge of each spray pump. These transmitters supply a signal to a pressure indicator on the main control board. Pressure data are also monitored by the computer.

Orifices are located in the individual lines from the sodium hydroxide storage tank. The purpose of these orifices is to create a specific flow impedance in the sodium hydroxide lines from the tank to the junctions with the lines from the RWST. However, test connections are provided to which test gages can be attached for measurement of flow through these lines.

Flow tests, performed prior to plant startup define the flow characteristics of the Reactor Building Spray System from the RWST and sodium hydroxide storage tank through the line junctions. These test data are utilized to verify that the system delivers the proper flow of sodium hydroxide solution or to resize the orifices to obtain correct system characteristics.

6.2.2.5.1.4 Temperature Instrumentation

A temperature loop provides local indication of the temperature of the liquid in the sodium hydroxide storage tank. Temperature loops (2) provide local indication of the temperature of the liquid at the spray pump suctions.

6.2.2.5.1.5 Valve Position Indication

Valve position indication for all 10 motor operated valves in this system is provided on the main control board by status lights.

6.2.2.5.1.6 Control

Actuation of the Reactor Building Spray System results from a safety injection and spray actuation signals or from manual action at the main control board. Four (4) manual spray actuation switches are provided. Manual actuation of the Spray System requires simultaneous operation of one of the pairs of the 4 switches. The safety injection signal and spray actuation signals are generated by the ESF Actuation System. Upon receipt of a phase “A” containment isolation signal, the valves in the discharge headers (XVG-3003A and B) and in the sodium hydroxide storage tank discharge lines (XVG-3002A and B) open. The spray actuation signals result from the Reactor Building “Hi-3” pressure instrumentation (2 out of 4 instrument channels tripped). A separate actuation signal is supplied to each spray subsystem. Upon receipt of this signal, the spray pump starts and the valve (XVG-3001A or B) in the suction line from the RWST is opened (if closed). The spray pump and each valve have individual switches on the main control board for manual operation of each component. Switches are also provided on the main control board for normal operation of the valves (XVG-3004A and B, and XVG-3005A and B) in the suction lines from the Reactor Building sumps. The spray pumps are automatically aligned to the Reactor Building sumps in response to signals from the RWST level instrumentation at the “lo-lo” level. The pumps can be restarted individually by switches located on the main control board. The operator will not terminate Reactor Building Spray System operation prior to the required 2 hour operating period.

Operator action from the control room is required to accomplish the following:

1. Shutdown of the Reactor Building Spray System.

2. Manual activation of a Reactor Building spray subsystem.
3. Reactor Building Spray System operation in the recirculation mode.

6.2.2.5.2 Reactor Building Cooling System

Reactor Building Cooling System instrumentation provides for performance and status monitoring of the system during normal operation, during system tests and, for certain components, during system operation following a LOCA. Some instrumentation components provide for control and interlock functions in the operation of the system. Instrumentation relevant to the "waterside" of the Reactor Building cooling system is further described in Sections 9.2.1.5 and 9.4.7.2.5.

6.2.2.5.2.1 Flow Instrumentation

Flow rate in the supply and return service water piping serving the plenum coils is displayed and alarms are provided in the control room. Main control board indication of these flow signals permits verification that adequate cooling water flow is established in the Reactor Building cooling unit coils for post accident Reactor Building heat removal. Refer to Section 9.2.1.5 for further information on this service water flow instrumentation.

6.2.2.5.2.2 Temperature Instrumentation

Redundant resistance temperature detectors are located inside the Reactor Building to measure Reactor Building ambient temperature. Each detector supplies a signal to a temperature indicator on the main control board and one detector, through an isolation device, supplies a signal to an indicator on the control room evacuation panel.

A temperature switch is located in the discharge duct of each Reactor Building cooling unit and provides a control room alarm upon occurrence of high discharge temperature during normal operation.

6.2.2.5.2.3 Pressure Instrumentation

A differential pressure switch and a direct reading differential pressure gage are installed across the moisture separator and across the HEPA filter bank of each Reactor Building cooling unit.

The pressure switches provide control room annunciation of high filter pressure drop.

The gages are used for component evaluation and inspection.

6.2.2.5.2.4 Vibration Instrumentation

A velomitor is mounted on each Reactor Building cooling unit fan. These switches provide signals to trip the fan motors from high speed and to annunciate the condition in the control room if high fan vibration exists for a period greater than approximately 10 seconds. The velomitor

signal is not a part of the fan control circuit for emergency (slow) speed operation and, therefore, has no effect upon this mode of fan operation.

6.2.2.5.2.5 Smoke Detection Instrumentation

An ionization type smoke detector is located in the discharge duct of each Reactor Building cooling unit. Each detector provides a control room alarm upon detection of smoke in the duct. Note that these duct detectors are maintained by the plant, but are not credited because other means exist to detect a fire in the Reactor Building. Their purpose is to aid plant operators in their decision making process.

6.2.2.5.2.6 Motor Current Instrumentation

Current transformers, located at the motor controllers, supply signals to ammeters on the main control board for indication of fan motor current. One ammeter is provided for each motor (high speed and slow speed) of each of the 4 cooling units (a total of 8 ammeters). Thus, fan motor current is continuously indicated for all operating modes and provides information on cooling unit status.

6.2.2.5.2.7 Damper Position Indication

Position indication for each HEPA filter bypass damper is provided on the main control board by status lights on the damper control switch assembly.

Additionally, the status of each damper is independently indicated by means of ESF monitor lights on the main control board.

6.2.2.5.2.8 Special Instrumentation

The main control board ESF monitor lights (see Section 7.5 for more detailed explanation) provide an easily recognizable indication of the status of essential components and equipment. Included among the monitor lights for this system are status indication (actuated or not actuated) of the Reactor Building cooling unit slow speed fan motors and of the HEPA filter bypass dampers. See Section 9.2.1.5 for a description of similar status monitoring of the Service Water System components required for Reactor Building heat removal.

An audible and visual alarm is annunciated on the main control board if manual action by the operator deliberately bypasses the operation of the Reactor Building Cooling System.

Also, an alarm annunciation of motor trip is provided on the main control board for each Reactor Building cooling unit fan.

6.2.2.5.2.9 Control

Actuation of the Reactor Building Cooling System results from a safety injection signal, a loss of offsite power signal, or manual action in the control room. Automatic actuation of the system

follows the sequence outlined in Section 6.2.2.2.2.2. A separate actuation signal is supplied to each subsystem. Control switches, located at the main control board, allow the operators to manually operate each component required for heat removal.

For each Reactor Building cooling unit, main control board switches are provided for the following components:

1. High speed fan motor.
2. Slow speed fan motor.
3. HEPA filter bypass damper.

Manual actuation of the Reactor Building Cooling System (air-side) is accomplished with these switches.

For automatic initiation of the system (air-side) operation, the position of main control board selector switches determines which 1 of the 2 A and which 1 of the 2 B power train units starts in response to the ESF loading sequence signal for that train. One (1) two-position selector switch per electrical power train is utilized for this purpose.

Actuation of the water-side of the Reactor Building cooling units is described in Sections 9.2.1.5 and 9.4.7.2.5.

Operator action from the control room is required to accomplish the following:

1. Shutdown of the Reactor Building Cooling System.
2. Manual actuation of a Reactor Building cooling subsystem.

6.2.3 Reactor Building Air Purification and Cleanup System

The Reactor Building Spray System has 2 functions. One is to remove heat from the Reactor Building atmosphere after a LOCA and the other is to remove fission products from the post LOCA atmosphere to reduce the dose to personnel offsite. The heat removal function is described and evaluated in Section 6.2.2. Additionally, the Reactor Building Cooling System HEPA filters aid in Reactor Building air purification. These filters are discussed in Section 6.5.

6.2.3.1 Design Bases

The Reactor Building Spray System is designed to reduce the concentration of radioactive iodine in the post LOCA Reactor Building atmosphere. In accordance with Regulatory Guide 1.183, it is assumed that of the radioiodine activity released from the core, 95% is in the form of cesium iodide (Csl), 4.85% in the form of elemental iodine and 0.15% in the form of organic iodine.

6.2.3.2 System Design (For Fission Product Removal)

The design of the Reactor Building Spray System is described in Section 6.2.2.2.1 for the overall system. The system diagram is included as Figure 6.2 46. This section discusses the design features related solely to the fission product removal function of the system.

6.2.3.2.1 System Design Features

The sodium hydroxide (NaOH) storage tank is designed and located to permit gravity draining into the spray pump suction line from the RWST. For the design case (one spray subsystem, one RHR pump, and one charging pump operating) it empties at approximately the same time as does the RWST. Orifices in RWST suction lines and the NaOH lines provide sufficient impedance to the system to maintain NaOH flow within the limits necessary for satisfactory spray pH level.

The 3300 gallon nominal capacity tank (3050 gallon minimum required usable volume) is 45-1/2 inches in diameter (OD), 40 feet-10 inches high, and is filled with NaOH solution at a minimum concentration of 20% by weight and a maximum concentration of 22% by weight. During injection, NaOH drains into each pump suction line at a junction at the 399' 6" elevation level at a nominal rate of 50 gpm.

A cover gas of nitrogen is maintained in the vapor space over the liquid to preclude precipitation or tank corrosion that could occur with air present. The tank is equipped with 2 pressure relief valves set to limit nitrogen overpressure to 3 psig. Redundant vacuum relief valves are sized to relieve vacuum in the tank as it is drained during spray operation. An orifice in the nitrogen supply line limits the flow of nitrogen to the relief capacity of one relief valve. This prevents any inadvertent overpressurization of the tank during pressurization operations.

A common discharge line from the NaOH storage tank is subsequently branched to provide flow to each pump suction line. In addition, nitrogen supply, vent, demineralized water supply, and liquid sample connections are provided on the tank. Redundant instrumentation is provided for measuring the liquid level and alarms in the control room. A temperature instrument is also provided.

The NaOH storage tank is provided with a recirculation loop attached at the fill and drain tank nozzles. The recirculation loop is provided with a recirculation pump and associated valves and instrumentation. The recirculation loop was added after initial plant operation under MRF 20168 to address concerns with NaOH tank stratification particularly when adding water to dilute the more dense NaOH solution and to provide a consistent NaOH concentration throughout the tank. To address industrial safety concerns related to handling NaOH, a feed pump and feed tank with a mixer are also provided, tying in to the recirculation loop. The feed is isolated from the recirculation loop by a check valve. The recirculation loop is normally isolated by locked closed valves as shown in Figure 6.2-46. The recirculation loop is non-safety related, but is seismically supported.

The NaOH storage tank is located outside in the Auxiliary Building tank pit at elevation 412'. For a concentration range between 20% and 22%, the maximum temperature at which freezing or separation of solids occurs is - 13°F. Therefore, a heat tracing system is not required.

The Reactor Building Spray System includes a total of 330 spray nozzles. These nozzles are ramp type, hollow cone nozzles. With a 40 psi pressure drop across the nozzle, the drop size distribution is a log normal distribution with a number mean diameter of 230 microns. The mass median diameter is approximately 680 microns. For conservatism, a mass mean diameter of 1300 microns is used in calculating iodine removal effectiveness (see Section 6.2.3.3.1). The spray nozzles are located on 6 rings as described in Section 6.2.2.2.1.1. A plan view of the spray nozzle locations is shown in Figure 6.2 47. The arrangement of the spray rings within the Reactor Building is such that essentially all of the free volume above the operating floor, elevation 463', is exposed to the spray. Below the operating floor elevation, areas outside the secondary shield walls are shielded from the spray. However, the atmosphere in this area is mixed with the rest of the volume inside the secondary shield walls. The volume inside the secondary shield walls with the exception of the pressurizer compartment, is open to the spray.

6.2.3.2.2 System Operation

The operation of the Reactor Building Spray System is presented in Section 6.2.2.2.1.2.

6.2.3.3 Design Evaluation

6.2.3.3.1 Fission Product Removal Effectiveness Calculations

The fission product removal capabilities of the Reactor Building Spray System under post accident conditions have been the subject of much research of government laboratories as well as NSSS vendors.

The effectiveness of this system is estimated by considering the chemical and physical processes that could occur under postulated accident conditions. Iodine is the primary fission product to be considered for removal by the Reactor Building Spray System, post accident. The principal forms of iodine that are of concern in the post accident environment are: elemental, aerosol particulates, and organic iodides.

The removal of elemental iodine from the Reactor Building atmosphere is considered a first order removal process which is mathematically represented by time dependent removal coefficients (λ) due to the action of the spray system (λ_S) and by wall deposition (λ_W). These removal coefficients are summed to obtain the total removal coefficient for elemental iodine.

Experimental results, References 33, 34, and 35 have shown that an important factor determining effectiveness of sprays in removing elemental iodine vapor is the concentration of iodine in the spray solution. Fresh sprays having no dissolved iodine were observed to be quite effective in the scrubbing of elemental iodine even at a pH as low as 5, References 34 and 35. Sump solutions with dissolved iodine that recirculate post accident may revolatilize iodine if the solution is acidic, Reference 36. Section 6.2.2.3.1.4 details the spray solution pH during the conditions of injection

and sump recirculation under the extremes of system operating conditions. In all configurations analyzed, the spray/sump solution pH remains greater than 7.

Chemical additives in the spray solution have no significant effect upon aerosol particle removal since this process is principally mechanical.

1. Elemental Iodine

During injection, the removal of elemental iodine by wall deposition is calculated by using the following equation:

$$\lambda_w = K_W A/V$$

where:

K_W	=	mass transfer coefficient = 4.9 m/hr.
A	=	wetted surface area = 3457 m^2.
V	=	Reactor Building net free volume = 1.84 x 10^6 ft^3.
λ_w	=	removal coefficient by wall deposition = 0.325 hr^{-1}.

Based upon the well-mixed droplet model, the effectiveness of the spray in removing elemental iodine vapor is chiefly determined by the rate at which fresh solution area is introduced into the atmosphere. This can be estimated by the relationship (6F/VD) where F is the volume flow rate of the spray, V is the building net free volume, and D is the mass mean diameter of the spray drops. The first order spray removal coefficient is calculated using the following relationship:

$$\lambda_s = 6K_gTF/VD$$

where:

K_g	=	gas-phase mass transfer coefficient = 180 m/hr.
T	=	fall time of the drops = ratio of the average fall height (h) to the terminal velocity (U) where h = 114 ft and U = 410 cm/sec.
F	=	Flow rate = 2500 gpm.
V	=	Reactor Building volume - 1.84 x 10^6 ft^3.
D	=	drop diameter = 1300μ
λ_s	=	20.0hr^{-1}
λ_s	=	$\lambda_s + \lambda_w = 20.0 + 0.325 = 20.325 hr^{-1}$

2. Organic Iodides

It is conservatively assumed that organic iodides are not removed by the action of the sprays or wall deposition.

3. Particulate Iodine

The removal coefficient for particulate iodine by sprays is given by the following equation:

$\lambda_p = 3hFE/2VD$

where:

h	=	fall height of the droplets = 114 ft.
F	=	spray flow rate = 2500 gpm.
V	=	Reactor Building volume = 1.84×10^6 ft^3.
E/D	=	ratio of the dimensionless collection efficiency, (E), to the drop diameter, (D). E/D is assumed equal to 10 m^{-1} for a period of time until the aerosol mass has been depleted by a factor of 50. Thereafter, E/D is reduced by a factor of 10 to 1 m^{-1} (i.e. 98% of the suspended mass is 10 times more readily removed than the remaining 2%).
λ_p	=	5.68 hr^{-1} (0 - 98% removal).
λ_p	=	0.568 hr^{-1}(98 - 100% removal).

6.2.3.4 Tests and Inspections

Tests and inspections of the Reactor Building Spray System are described in Section 6.2.2.4.1.

6.2.3.5 Instrumentation Requirements

Instrumentation requirements of the Reactor Building Spray Systems are described in Section 6.2.2.5.1.

6.2.3.6 Materials

Spray system materials are compatible with the reactor coolant and the alkaline (NaOH) solution. The major components of the system are constructed of stainless steel, except the sodium hydroxide storage tank which is of carbon steel. Minor parts, such as pump seals, utilize other corrosion resistant materials.

6.2.4 Containment Isolation System

The objective of the containment isolation system is to allow the passage of fluids through the containment boundary under normal and accident conditions, while preserving the integrity of the containment boundary, when required to prevent or limit the escape of fission products as a result of a postulated LOCA.

The containment isolation system is not an independent system. Rather, the system is comprised of specific provisions included in each piping system that penetrates the Reactor Building. Actuation of containment isolation is accomplished through the Engineered Safety Features Actuation System (ESFAS). A detailed discussion of the ESFAS system is provided in Section 7.3.

6.2.4.1 Design Basis

In the unlikely event of a LOCA, the containment isolation system is designed to limit leakage of radioactive materials through lines penetrating the Reactor Building so that the site boundary dose guidelines specified in 10 CFR 50.67 are not exceeded.

Lines for which isolation is required are provided with 2 barriers, such that no single failure can prevent isolation. Each of these barriers is adequate to limit leakage of radioactivity within acceptable values over the entire range of normal and accident conditions. The selection of fast action automatically operated valves that receive isolation signals is based upon the safety analysis requirements described in Chapter 15.

An “isolation barrier” is either an isolation valve, blind flange, or a closed system. A closed system is defined as a fluid system which is not part of the Reactor Coolant System and which does not communicate with the Reactor Building atmosphere.

Fluid systems, including instrument lines, penetrating the Reactor Building satisfy the following specific design bases:

1. The design of isolation barriers for lines penetrating the Reactor Building follows the requirements of General Design Criteria 54 through 57 of 10CFR50, Appendix A.
2. The containment isolation system is protected against the effects of missiles and postulated pipe ruptures. See Sections 3.5 and 3.6.
3. The containment isolation system is designed to Safety Class 2a, Seismic Category 1 requirements. Regulatory Guides 1.26 and 1.29 are discussed in Appendix 3A.
4. The containment isolation system is designed with redundancy in accordance with General Design Criterion 54 so that no single active failure can result in loss of containment integrity.
5. The containment isolation system is designed to withstand accident environmental conditions (see Section 3.11).

6. Provisions are made for periodically testing the operability and leak tightness of the containment isolation valves to the extent necessary to ensure that the system satisfies performance requirements in the event of an accident.

6.2.4.2 System Design

A list of Reactor Building penetrations showing the means of containment isolation is included as Table 6.2-53. Containment isolation valves are listed by penetration number in Table 6.2-54. Each listing indicates valve number, size, methods of actuation and positions under various plant conditions. Figure 6.2-52 schematically shows the various valve arrangements used to isolate the fluid system penetrations.

6.2.4.2.1 Lines Penetrating the Reactor Building that Connect to the Reactor Coolant Pressure Boundary (General Design Criterion 55)

This category includes the process lines passing through penetrations numbered 221, 222, 223, 226, 227, 229, 314, 316, 318, 322, 325, 405, 408, 409, 410, 412, 415 and 426. Of these, 221, 222, 227, 229, 322, 325, 408, 409, 412, 415 and 426 have one or more check valves in parallel as the inside isolation valves and one or more power-operated valves in parallel as the outside isolation valves. Penetrations 223, 314, 318 and 405 have one or more power-operated valves in parallel as the inside isolation valves and one power-operated valve as the outside isolation valve.

Penetration 410 has a power-operated valve and check valve in parallel as the inside isolation device and power-operated valve as the outside isolation device. These arrangements all comply with the literal requirements of General Design Criterion 55.

Penetrations 226 and 316 do not have outside isolation valves. The closed Residual Heat Removal (RHR) System boundary is used as the outside containment device. These lines connect to the safety injection recirculation loops which are filled with sump water and at least one of which is in operation following an accident. Should a leak occur in the short length of pipe inside the Reactor Building between the valve and Reactor Building wall, the Reactor Building atmosphere would pass only as far as the fluid filled system containing sump water. This would prevent gas release to the outside. The design basis for these penetrations is that isolation valves outside the Reactor Building on the RHR suction lines are unnecessary and that inclusion of any such additional valves does not enhance plant safety.

The power-operated valves for penetrations 223, 314, 318, 405, 409, and 410 are automatically closed upon receipt of either a safety injection signal or containment isolation, Phase A signal, as noted in Table 6.2-54. The power-operated valves for penetration 426 are automatically opened by the safety injection signal to permit boron injection.

Valves in lines required to perform a safety function following an accident must be opened or must remain open for the Engineered Safety Features (ESF) Systems to operate. Automatic closing of these valves would defeat their intended purpose. Therefore, these valves are designed for remote manual operation from the control room. Lines in this category include low pressure

safety injection lines and high pressure safety injection lines. Penetrations in this category are 222, 227, 322, 325, 412, and 415.

The seal injection lines to the reactor coolant pumps pass through penetrations 221, 229, and 408. Due to the sensitive nature of the pump seals, it is highly desirable to provide seal cooling flow at all times. Since the charging pumps are used for safety injection, the high pressure in-flow through the seal injection lines eliminates any need for automatic closure of the valves in these lines. Remote manual closure from the control room is available.

6.2.4.2.2 Lines Penetrating the Reactor Building That are Open to the Reactor Building Atmosphere (General Design Criterion 56)

This category includes the process lines passing through penetrations numbered 101, 103, 105A, 105B, 107, 201, 210, 211, 212, 216, 217, 231, 301A, 301B, 302, 303, 310, 311, 313, 317, 319, 320, 321, 324, 327, 328, 329, 401, 402, 404, 406B, 407A, 407B, 417D, 418, 419, 420, 421, 422, 423, 424, 425, 427, 500, 505, 600, 602, and 703. Of these, 101, 103, 105A, 105B, 302, 303, 311, 317, 319, 320, 321, 401, 402, 407A, 407B, 417D, 418, 420, 422, 423, 424, and 427 have one power-operated valve outside and one power-operated or check valve inside. Penetration 301A has 2 power operated valves in parallel as the inside isolation and one power operated valve as the outside isolation. Penetration 301B has one power operated valve as the inside isolation and 2 power operated valves as the outside isolation. Penetrations 231, 310, 313, 324, 404, 419, and 421 have a locked closed manual valve outside and check valve or a locked closed manual valve inside. The process pipes through penetrations 201, 210, 211, 212, 216, 505, 600, and 602 are sealed with blind flanges inside and outside during operation. These modes of isolation are in literal compliance with General Design Criterion 56, considering that a blind flange is the equivalent of a locked closed valve.

Penetration 107, the fuel transfer tube, is sealed with a blind flange on the inside end. This flange has a double O-ring seal to provide a double barrier. Although there is a manual gate valve on the outside end of the tube, it is not considered a containment isolation barrier since the blind flange, when in place, is the containment boundary.

Penetrations 217, 406B, 500, and 703 are for the Reactor Building pressure sensing lines. Reactor Building pressure is sensed by 4 physically separated differential pressure transmitters mounted on Seismic Category 1 supports outside the Reactor Building. These devices are connected to the 1/2 inch stainless steel Reactor Building penetration by a length of 1/4 inch outside diameter, high pressure, stainless steel tubing. Bellows are connected to the ends of the tubes inside the Reactor Building. The capillary tubing between the bellows and the transmitter is fluid filled. The distance from penetration to transmitter is minimized and separation is maintained. This arrangement, together with the pressure sensors outside the Reactor Building, forms a double barrier. For a discussion of Regulatory Guide 1.11, see Appendix 3A.

The lines from the Reactor Building recirculation sumps to the suctions of the redundant, low head safety injection recirculation (residual heat removal) pumps and Reactor Building spray pumps are each provided with a single motor-operated gate valve outside the Reactor Building. These valves are enclosed in containers which are leaktight at the Reactor Building design

pressure. Piping from the sump to the valve containers is enclosed in a concentric guard pipe, also leaktight at the Reactor Building design conditions. The structural configuration is such that neither a valve contained nor the guard pipe is connected directly to the sump or to the Reactor Building atmosphere.

At the beginning of the safety injection recirculation phase the sump is full of water, the sump line valves are opened, and the line from the refueling water storage tank is closed. Since the sump is always submerged during recirculation following an accident and no Reactor Building atmosphere can impinge upon the valve, this valve is not a containment isolation valve in the usual sense. The valve does provide a barrier outside the Reactor Building to prevent loss of sump water should a leak develop in a recirculation loop. (This valve is capable of remote manual closure from the control room to accomplish this.) Should a leak develop in the valve body or in the pipe between the sump and the valve, the sump fluid is contained by the leaktight container and guard pipe arrangement. Since the sump line connection to the sump is always submerged during the recirculation phase, there is no need for a valve inside the Reactor Building to prevent escape of the Reactor Building atmosphere.

No single failure of either an active or passive component of this system will prevent recirculation of core cooling water nor will such a failure adversely affect the integrity of the Reactor Building. This arrangement satisfies safety requirements and no additional valves are necessary for containment isolation with respect to penetrations 327, 328, 329, and 425.

The power operated valves associated with penetrations 311, 317, 319, 320, 321, 407A, 407B, 417D, 418, 420, 422, 423, 424, and 427 are automatically closed by the containment isolation, Phase A signal. The hydrogen analyzer isolation valves associated with penetrations 105A, 105B, 301A, and 301B do not receive a closure signal because these valves are normally closed and will be opened post LOCA. The portion of penetration 301B shared with a Reactor Building pressure transmitter does isolate on a Phase A signal. The power operated valves associated with penetrations 101, 103, 302, and 402 are automatically closed by a containment ventilation isolation signal or high radiation in the Reactor Building purge exhaust vent (A train valves) or containment atmosphere high radiation (B train valves). The valves on penetrations 303 and 401, the Reactor Building spray supply lines, are automatically opened by a containment Phase A isolation signal.

6.2.4.2.3 Lines Penetrating Reactor Building That Do Not Connect With Either the Reactor Coolant Pressure Boundary or the Reactor Building Atmosphere (General Design Criterion 57)

The category includes the process lines passing through penetrations numbered 102, 202, 203, 204, 205, 206, 207, 213, 219, 220, 224, 225, 230A, 230B, 230C, 304, 305, 306, 308, 312, 323, 326, 330, 403, 411, 417A, 417B, 417C, and 428. Of these 102, 204, 304, 305, 312, 323, 330, and 403 have automatically actuated power operated valves outside the Reactor Building. These lines are in literal compliance with General Design Criterion 57.

6.2.4.3 Design Evaluation

The process piping through the penetrations and the isolation valves are designated as Safety Class 2a. They are designed in accordance with the ASME Code, Section III, Class 2.

Where power-operated valves are supplied inside and outside the Reactor Building, the inside valve and the outside valve are actuated by different trains of the actuation system. The train that actuates any isolation valve is indicated in the “Signal” column of Table 6.2-54.

Valves which may be required to operate in the post LOCA Reactor Building atmosphere to serve their safety function are qualified as described in Section 3.11.

The containment isolation system design complies with the recommendations of SRP 6.2.4; i.e., that there be diversity in the parameters sensed for the initiation of containment isolation. The containment isolation signals are given in Table 6.2-54.

Careful reconsideration as required by NUREG-0578, item 2.1.4, to the definition of essential and non-essential systems has been given. The basis of selection is that the essential systems are those which are required immediately to mitigate the consequences of an accident. All other systems are considered non-essential. The systems which penetrate containment and their classification are listed in Tables 6.2-53 and 6.2-54a. During the re-evaluation none of the systems were changed from nonessential to essential.

All non-essential systems, except those which have a blind flange or a locked closed manual valve, are automatically isolated by the containment isolation signals.

The design of control systems for automatic containment isolation valves is such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves, with the exception of the letdown orifice isolation valves if the transfer switch on the Control Room Evacuation Panel is set for local operation and the control switch is in the open position. Reopening of containment isolation valves requires deliberate operator action. System operating procedures detail specific valves to operate during post accident recovery operations and valve operations for complete Safety Injection - Containment Isolation Recovery operations.

6.2.4.4 Test and Inspection

Leakage tests and containment isolation valve operability tests are discussed in Section 6.2.6.3. An isolation valve seal system is not employed.

6.2.4.5 Materials

The materials used in the components of the containment isolation system are selected so that the system can perform its engineered safety function throughout the life of the plant under all anticipated environmental situations. Criteria considered are as follows:

1. Materials selected for components of the containment isolation system inside the Reactor Building will withstand an integrated radiation dose of 10^8 rads without significant degradation of material properties.
2. All materials used in the containment isolation system that come in contact with the Reactor Building spray solution (alkaline solution of sodium hydroxide and boric acid) are resistant to corrosion by this solution. Nuclear steam supply systems that are normally wetted by borated water are made of austenitic stainless steel. Other containment isolation valves inside the Reactor Building are of carbon steel.
3. Materials used for containment isolation system components which contain zinc or aluminum are kept to a minimum.

6.2.4.6 Special Instrumentation

The main control board ESF monitor lights (see Section 7.5 for more detailed explanation) provide an easily recognizable indication of the status of essential components and equipment. Included among the monitor lights are status (position) indication of the containment isolation valves.

6.2.5 Combustible Gas Control in Reactor Building

Following a design basis accident, hydrogen gas may be generated inside the Reactor Building by reactions such as zirconium metal with water, corrosion of materials of construction, and core and sump water radiolysis. The following section is presented to describe the basis for the sizing of the combustible gas control system. To ensure that the hydrogen recombiners and an alternate Reactor Building purge system are provided.

To minimize hydrogen generation as a result of corrosion of containment metals, the use of exposed zinc and aluminum inside the Reactor Building is tracked and logged. In addition, the amount of hydrogen generated in the post accident environment is limited by maintaining a Reactor Building spray pH of 10.5 or less and a recirculation solution pH of less than 9.0.

6.2.5.1 Design Bases

6.2.5.1.1 Electric Hydrogen Recombiners

1. The recombiners are designed to sustain all normal loads as well as accident loads including safe shutdown earthquake and pressure transients from a design basis loss of coolant accident.
2. The recombiners are designed for a lifetime of 40 years, consistent with that of the plant. (Aging management will extend recombiner life for the duration of the plant life.)
3. All materials used in the recombiners are selected to be compatible with the environmental conditions inside the Reactor Building during normal operation or during accident conditions.

4. Process capacity is such that the Reactor Building hydrogen concentration will not exceed 4 volume percent based on the NRC TID-14844 release model as indicated in Regulatory Guide 1.7.
5. Each recombiner is provided with a separate power panel and control panel. Each recombiner is powered from a separate ESF bus.

6.2.5.1.2 Alternate Reactor Building Purge System

Supply and exhaust flow lines connected to pressure blowers are provided as a backup system to purge the Reactor Building for combustible gas control and to aid in cleanup of the Reactor Building atmosphere.

6.2.5.1.3 Hydrogen Concentration Monitor

The following design bases apply to the equipment provided to monitor hydrogen in the Reactor Building.

1. Redundant hydrogen concentration analyzers are provided to confirm that the electric hydrogen recombiners are functioning property following an accident. The analyzers are not required to initiate operation of the electric hydrogen recombiners since the recombiners will be started 24 hours after a LOCA and the ability of these recombiners to remove hydrogen from the Reactor Building atmosphere has been accepted by the NRC (Reference 22). During normal plant operating conditions, one hydrogen analyzer is in standby. The redundant hydrogen analyzers will be started after a LOCA.
2. Dedicated sampling points for each monitor, capable of withstanding the SSE without loss of function, are provided.
3. The system is capable of remaining operable under both positive and negative pressure assuming a single failure.
4. The hydrogen monitoring system is class 1E and seismic Category 1.
5. Semi-automatic sampling capability to permit laboratory analysis as backup to the hydrogen analyzer is provided. This system is also capable of determining noble gases and iodine concentrations.
6. During a loss of coolant accident, Reactor Building hydrogen concentration is monitored and hydrogen recombiners are placed in service to minimize hydrogen buildup in the Reactor Building. Adequate shielding is provided to prevent personnel overexposure during hydrogen recombiner operation at local panels.

6.2.5.2 System Design

The system is designed for control of combustible H_2 concentrations in the Reactor Building following a loss of coolant accident. This system consists of a sampling system that provides Reactor Building atmosphere samples with electric hydrogen recombiners as the primary means

of reducing H_2 Reactor Building concentrations and a purge system which is used as a backup system to the recombiners.

6.2.5.2.1 Electric Hydrogen Recombiners

Redundant electrical recombiners, as shown on Figure 6.2-53 are located inside the Reactor Building. The recombiner units are located in the Reactor Building such that they process a flow of Reactor Building air containing hydrogen at a concentration which is generally typical of the average concentration throughout the Reactor Building. Since the recombiner units are located in the Reactor Building, dedicated containment penetrations for hydrogen control are not required. In addition, the capability to install a recombiner unit outside the Reactor Building is not required.

To meet the requirements for redundancy and independence, 2 recombiners are provided, and each recombiner is provided with a separate power panel and control panel, and each is powered from a separate class 1E bus.

Reactor Building atmosphere is circulated through the recombiner by natural circulation where hydrogen is removed by heating to a temperature sufficient to cause recombination with the Reactor Building oxygen.

The recombiner consists of a thermally insulated vertical metal duct with electric resistance metal sheathed heaters provided to heat a continuous flow of Reactor Building air (containing hydrogen) up to a temperature which is sufficient to cause a reaction between hydrogen and oxygen. The recombiner is provided with an outer enclosure to keep out Reactor Building spray water. The recombiner consists of an inlet preheater section, a heater-recombination section, and a discharge mixing chamber that lowers the exist temperature of the air.

The unit is manufactured with corrosion resistant, high temperature materials except for the base which is carbon steel. The electric hydrogen recombiner uses commercial type electric resistance heaters sheathed with Incoloy-800 which is an excellent corrosion resistant material for this service.

Air drawn into the recombiner by natural convection and passes first through the preheater section. This section consists of a shroud placed around the center heater section to take advantage of heat conduction through the walls to preheat the incoming air. This accomplishes the dual functions of reducing heat losses from the recombiner and of preheating the air.

The warmed air passes through a flow orifice and then enters the electric heater section where it is heated to approximately 1150° F to 1400° F causing recombination to occur. Tests have verified that the recombination is not a catalytic surface effect associated with the heaters but occurs due to the increased temperature of the process gases. Since the phenomenon is not a catalytic effect, saturating of the unit by fission products will not occur. The heater section consists of 5 assemblies of electric heaters stacked vertically. Each assembly contains individual heating elements. Table 6.2-55 gives the recombiner design parameters.

The recombiner, power supply panel, and control panel are shown schematically in Figure 6.2-54. The power panel for the recombiner contains an isolation transformer plus a semiconductor controlled rectifier controller to regulate power into the recombiner. This equipment is not exposed to the post LOCA environment. To control the recombination process, the correct power input which will bring the recombiner above the threshold temperature for recombination will be set on the controller. The correct power required for recombination depends upon Reactor Building atmosphere conditions and will be determined when a recombiner operation is required. For equipment test and periodic checkout, a thermocouple readout instrument is also provided in the control panel for monitoring temperatures in the recombiner.

Reference 22 provides a description of the testing of a full scale prototype electric hydrogen recombiner.

6.2.5.2.2 Alternate Reactor Building Purge System

The alternate purge lines, which serve as backup to the hydrogen recombiners may be used in the unlikely event of failure of both hydrogen recombiners to operate following a LOCA. For this case, the supply pressure blower is operated to pressurize the Reactor Building to 3 psig with a clean supply of outside air (at approximately 600 scfm). This procedure is initiated when the H_2 concentration approaches 3 volume percent after a loss of coolant accident (approximately 2 1/2 days) and reduces the H_2 concentration to approximately 2.5 volume percent. As the H_2 concentration again approaches 3 volume percent, the backup purge isolation valves are opened and the Reactor Building atmosphere is released and throttled at a rate of 100 scfm through the charcoal and HEPA filters of the purge exhaust plenum while pressure returns to 0 psig. This operation is repeated each time H_2 concentration approaches 3 volume percent subsequent to initial accumulation. The alternate purge lines contain the required safety-related isolation valves as specified by Regulatory Guide 1.7. These components are designed for remote-manual operation from the control room, as required following a LOCA.

6.2.5.2.3 Hydrogen Concentration Monitor

Figure 6.2-58 schematically shows the provisions for monitoring the Reactor Building atmosphere.

The capability for obtaining samples near each electric hydrogen recombiner and near the Reactor Building cooling units at approximately 530 foot elevation is provided. The redundant analyzers are operated post accident to continuously monitor the Reactor Building atmosphere. The plant operator can operate each analyzer from the control room. Two (2) sampling panels are provided for taking samples from connections in each hydrogen analyzer system. Each redundant sampling system and its associated control panel are accessible following an accident.

Seismic and environmental qualifications of the containment isolation valves for the sample lines and the hydrogen analyzers are discussed in Sections 3.10 and 3.11, respectively. The hydrogen analyzers are located outside the Reactor Building and are not subjected to extreme environmental conditions.

6.2.5.3 Design Evaluation

6.2.5.3.1 Electric Hydrogen Recombiners

Prediction of hydrogen generation following a LOCA (refer to Figures 15.4-71 through 15.4-73), shows that although hydrogen production rate decreases with time after the accident, total hydrogen accumulation could exceed 4 volume percent. The hydrogen recombiners limit hydrogen accumulation. Figure 15.4-71 shows the rate of hydrogen production from various sources with no recombiner operating after a LOCA. Figure 15.4-72 depicts the corresponding hydrogen accumulation in the containment.

For the purpose of showing that the electric recombiner is capable of maintaining safe hydrogen concentrations, an analysis was performed using the Regulatory Guide 1.7 model. The results for the Reactor Building volume are shown in Figure 15.4-73. The model is based upon assuming a fission product activity release specified in TID-14844 and the values for post accident hydrogen generation specified in Regulatory Guide 1.7. The results, using no recombiner, are also shown on this figure.

Each electric recombiner is capable of continually processing a minimum of 100 scfm of Reactor Building atmosphere. The hydrogen contained in the processed atmosphere is converted to steam, which then exists to the Reactor Building atmosphere, thus reducing the overall Reactor Building hydrogen concentration. The hydrogen concentration in the Reactor Building was calculated for the models described above based on a recombiner capability of processing 100 scfm of Reactor Building atmosphere. This calculation shows that the maximum hydrogen concentration will be much less than 4 volume percent if the recombiner is started one day following the accident. Therefore one of these recombiners meets the design criterion of maintaining a safe hydrogen concentration with considerable margin, and the second unit provides the redundance of a system of equal capability on a redundant power supply.

The peak hydrogen concentration occurs at the time when the amount of hydrogen being generated is equal to the amount of hydrogen being processed. Once this peak has been reached, the recombiner will be processing hydrogen at a faster rate than it is being produced. This will result in an overall reduction of the hydrogen concentration inside the Reactor Building. Thus, once the peak has been reached, the electric recombiner provides a continually increasing margin between the Reactor Building hydrogen concentration and the 4 volume percent limit.

The recombiner is designed to sustain all normal loads as well as accident loads such as seismic loads and temperature and pressure transients from a LOCA.

The Westinghouse electrical hydrogen recombiner, as described in topical report WCAP 7709-L (Proprietary) with Supplements 1 to 4 and in WCAP 7820 (non-proprietary) is considered by the Virgil C. Summer Nuclear Station to be the principal component used for combustible gas control. Whereas, bypass and inoperable status monitoring may be needed to provide information that certain protection equipment and systems that are normally operating are actually inoperative, such monitoring is not necessary for the electrical hydrogen recombiner because it is normally not operating and is not armed for automatic actuation. As described in WCAP 7709, the system is

operated only during periodic testing and after the postulated Loss-of-Coolant Accident. Operation is initiated by operator action from the control station. Following an accident, the elapsed time prior to the needed start of the equipment is in terms of hours or days, and this elapsed time is evaluated in WCAP 7709. The design and environmental and seismic qualification of the Westinghouse electrical hydrogen recombiner was found acceptable for the prototype and production models by NRC, as reported in NRC's letter of May 1, 1975, from D. B. Vassallo to C. Eicheldinger, Manager of Westinghouse Nuclear Safety Department.

For further information on hydrogen production and accumulation see Section 15.4.1.2.

6.2.5.3.2 Alternate Reactor Building Purge System

If required, purging of the Reactor Building atmosphere following a LOCA is limited to a flow rate of 100 scfm by the alternate purge system. This flow rate is consistent with the minimum rated capacity of 100 scfm for one hydrogen recombiner.

6.2.5.3.3 Reactor Building Atmospheric Sampling System

Redundant sample systems have been designed to collect samples of the containment atmosphere. These samples are then analyzed in the radiochemistry laboratory for hydrogen, noble gases, and iodine. Radiation exposure and shielding considerations are discussed in FSAR Appendix 12A. Heat tracing is provided to prevent condensation of water vapor within the system.

6.2.5.4 Tests and Inspections

6.2.5.4.1 Electric Hydrogen Recombiners

The electric hydrogen recombiners have undergone extensive testing in the Westinghouse development program. These tests encompassed the initial analytical studies, laboratory proof-of-principal tests, and full scale prototype testing. The full scale prototype tests included the effects of:

1. Varying hydrogen concentrations.
2. Alkaline spray atmosphere.
3. Steam effects.
4. Convection currents.
5. Seismic.

A detailed discussion of these tests is given in Reference 22. Post operational tests and inspections will be performed in accordance with Technical Specification requirements. Inspections will be performed to assure the capability of the recombiner to perform its function. Testing will be performed to verify operation of the control system to verify functional performance of the heaters to the required temperature level.

Seismic and environmental qualifications are discussed in Sections 3.10 and 3.11.

6.2.5.4.2 Alternate Reactor Building Purge System

The active components of the alternate purge lines, which are the containment isolation valves, are periodically tested in accordance with the requirements of Section 6.2.6, Containment Leakage Testing.

6.2.5.4.3 Sample Panels

The sample panels will be used on a periodic basis to maintain operator proficiency with system operation.

6.2.5.5 Instrumentation Requirements

6.2.5.5.1 Electric Hydrogen Recombiners

The recombiners do not require any instrumentation inside the Reactor Building for proper operation after a LOCA. The recombiners will be started manually after a LOCA. The sampling system will be used in obtaining Reactor Building atmosphere samples to verify proper operation of the recombiners or to indicate when the purge system should be actuated. This sample can be taken from any of 3 well ventilated locations within the Reactor Building.

6.2.5.5.2 Alternate Reactor Building Purge System

The powered components of the alternate Reactor Building purge line are designed for remote manual operation from the control room, as required following a LOCA.

6.2.5.5.3 Hydrogen Concentration Monitors

Manual action is required to start the redundant hydrogen analyzers. Since these analyzers provide only confirmation of proper operation of the redundant electric hydrogen recombiners, no automatic action is required.

The hydrogen analyzers have 0-10% and 0-20% range of H_2 in air (by volume) and an accuracy of ± 2% of range. This provides adequate confirmation of electric hydrogen recombiner operation. Hydrogen concentration in the Reactor Building is indicated in the control room.

6.2.5.5.4 Reactor Building Atmospheric Sampling System

Manual action is required to align the sampling system valves with the hydrogen analyzer supply and return lines. Once in service, the operational sequence is controlled remotely. The system is purged with nitrogen to containment following sampling completion. Following purge, the system is returned to the non-sampling mode manually, if required.

6.2.5.6 Materials

6.2.5.6.1 Electric Hydrogen Recombiners

The materials of construction for the electric recombiner are selected for their compatibility with the post LOCA environment.

The major structural components are manufactured from 300-Series stainless steel except for the base which is carbon steel. Incoloy-800 is used for the heater sheaths and Inconel-600 for other parts, such as the heat duct, which operate at high temperature.

There are no radiolytic or pyrolytic decomposition products from these materials. The carbon steel base of the recombiner unit is coated with a paint that satisfies the requirements of ANSI 101.2 (1972), “Protective Coating (Paints) for Light Water Nuclear Reactor Containment Facilities.”

6.2.6 Containment Leakage Testing

The Virgil C. Summer Nuclear Station containment and associated systems are designed to permit leakage testing in accordance with 10CFR50, Appendix J.

6.2.6.1 Containment Integrated Leakage Rate Test

The containment integrated leakage rate test is a Type A test as defined by 10CFR50, Appendix J. Integrated leakage rate testing is performed in accordance with a detailed, written, and approved procedure prepared in accordance with 10CFR50, Appendix J, which satisfies the requirements of General Design Criteria 52, 53, and 54 (see Chapter 14).

6.2.6.1.1 Preoperational Type B and C Testing

Preoperational Type B and C leak testing is employed to detect leaks which may affect the integrity of the containment and the results of the initial integrated leakage rate test. These tests are performed at a pressure of not less than 45.8 psig.

The following areas are subjected to preoperational Type B or C tests, as applicable:

1. Containment penetrations (mechanical and electrical).
2. Equipment and personnel access hatches.
3. Fuel transfer tube.
4. Isolation valves in lines penetrating the containment boundary.

Any leaks detected are repaired as required.

6.2.6.1.2 Preoperational Testing - Integrated

An initial integrated leakage rate test of the Reactor Building is performed in accordance with 10CFR50, Appendix J, following completion of building construction, installation of all systems penetrating the containment boundary and after completion of Reactor Building inspection and structural integrity testing. This initial test is performed at the calculated peak containment internal pressure, P_a (47.1 psig). The absolute pressure-temperature method of measuring leakage from the Reactor Building, as described in ANSI N45.4-1972, Appendix B is employed during both of these leakage rate tests. The objectives of the tests are as follows:

1. To establish the measured integrated leakage rate, $L_{am.}$
2. To obtain a leakage rate history and leakage characteristic of the containment system.

The leakage rate is determined by measuring the leakage from the Reactor Building over a period of at least 24 hours after Reactor Building temperature and pressure have been stable for a minimum of 4 hours. To ensure equal temperature distribution, throughout the building interior, fans are provided to circulate the air in the Reactor Building during the test. Verification of the leakage rate is obtained by supplemental testing as described in ANSI N45.4-1972, Appendix B. By measuring leakage from the Reactor Building while a known leakage rate is superimposed on the normal building leakage rate, the difference between the total leakage and the superimposed known leakage results in the actual leakage rate. This leakage rate (difference) is compared with the original leakage rate as a check of its accuracy.

High accuracy instrumentation is provided to assure that building atmospheric temperature, pressure, and dewpoints are measured accurately.

Acceptance Criteria for this test are as follows:

1. The total measured containment leakage rate, L_{am}, at pressure, P_a, may not exceed O.75 L_a, the containment design basis leakage rate. L_a is 0.2% by weight of the contained atmosphere in 24 hours. If local leakage measurements are taken following repairs made to satisfy acceptance criteria, these measurements shall be taken at a test pressure, P_a.

In the event of failure of preoperational integrated testing to satisfy the acceptance outlined above, repairs and/or adjustments to equipment shall be made and a Type A test plus a supplemental test shall be performed. All repairs, adjustments to equipment, and test results shall be reported to the NRC as required by Section III.A.1.a of Appendix J to 10CFR50.

6.2.6.1.3 Periodic Testing - Integrated

Prior to December 1, 1996, Integrated Leakage Rate Testing was conducted in accordance with 10CFR50 Appendix J, Option A and ANSI N45.4 - 1972. Commencing with the implementation of Technical Specification Amendment 135, Integrated Leakage Rate Testing will be conducted in accordance with 10CFR50 Appendix J, Option B as delineated in the Containment Leakage Rate Testing Program (CLRTP).

The performance of Type A tests shall be limited to periods when the plant is nonoperational and secured in the shutdown condition under the administrative control and in accordance with the safety procedure defined in the license.

6.2.6.1.4 Special Conditions During Testing

All containment penetrations except those in systems which are required to remain filled during and following a LOCA (i.e., Residual Heat Removal, Reactor Building Spray and Safety Injection Systems) will be tested in accordance with the Type A test requirements as described in the CLRTP.

6.2.6.1.5 Leakage Rate Test System Description

ECR 50504 removes existing leak rate components and installs a spool piece to provide a tie-in for vendor supplied equipment. The as-built system is a combination of vendor supplied and permanent plant components. The schematic system diagram is shown by Figure 6.2-59 and locations of temperature and humidity elements are shown by Figure 6.2-60.

The leakage rate test system consists of the applicable components, valves, instrumentation, controls, and associated piping required to accomplish the following:

1. Pressurize the Reactor Building with dry, compressed air.
2. Control the pressurization and blowdown of the Reactor Building.
3. Remove moisture and other impurities from the compressed air.
4. Protect against overpressurization.
5. Measure pressure, temperature and humidity of the Reactor Building atmosphere.
6. Superimpose a known leakage rate on the measured containment leakage rate.

Instruments to monitor the pressure, temperature and dewpoint temperature of the contained air are mounted on a test panel located outside the Reactor Building. Sensors for these instruments are mounted in selected locations within the Reactor Building. Two (2) flow meters are also mounted on the test panel. These flow meters are used to superimpose a known leakage rate on the previously measured Reactor Building leakage rate. Additional temporary instrumentation may be installed to enhance the measurement of test parameters.

Two (2) 8 inch Reactor Building blowdown lines are provided for depressurization upon completion of the leakage rate tests. Associated piping, valves, instrumentation and controls are also provided.

Permanent components of the system are rated at 150 psig and 250° F. Piping penetrations and blind flanges are fabricated in accordance with the ASME Code, Section III (Reference 23), Class 2.

6.2.6.2 Containment Penetration Leakage Rate Test

Components which penetrate and seal the containment boundary with seals, gaskets or sealant compounds which are resilient; or piping penetrations fitted with an expansion bellows as the only barrier to leakage from containment are leak tested (Type B test) at periodic intervals in accordance the CLRTP during the lifetime of the plant to ensure their continuing integrity.

6.2.6.2.1 Applicability

This section discusses the various types of penetrations used in the Virgil C. Summer Nuclear Station and identifies which types are leakage tested and which do not require leakage testing.

6.2.6.2.1.1 Piping Penetrations and Spares

Table 6.2-53 is a listing of piping penetrations and spares. There are basically 4 types of penetration: spares, cold penetrations, hot penetrations, and specialty penetrations.

Spare penetrations are sealed by welding pipe caps to each end of the penetration sleeve. Since no resilient or flexible seals are used, these penetrations do not require Type B leakage tests.

Cold penetrations are sealed by a flat plate, of 1/2 inch or greater thickness, welded to both the sleeve and the process pipe at each end of the penetration sleeve. Since no resilient or flexible seals are used, these penetrations do not require Type B leakage tests.

Hot penetrations are sealed on the inside of containment by a flat plate in a manner similar to cold penetrations. On the outside, they are sealed by a single bellows, one end of which is attached to the penetration sleeve and the other to the process pipe. Since the containment barrier does not utilize a resilient or flexible seal, these penetrations do not require Type B leakage tests.

The specialty penetrations are No. 107, the fuel transfer tube; No. 309, is used to house an abandoned radiation detector and check source assembly originally assigned to RM-G7. Figure 6.2-60a illustrates details of this penetration. Nos. 327, 328, 329, and 425 are used for the recirculation sump line penetrations. The fuel transfer tube is sealed inside containment by a flat plate welded to both the penetration sleeve and to the fuel transfer tube. The fuel transfer tube closure design provides a double barrier and, therefore, constitutes the containment boundary and is tested. This penetration has a bellows seal in the refueling cavity, this bellows seal retains water within the cavity and is not a containment isolation seal. Similarly, a bellows seal is used in the transfer canal to retain water. Since no resilient or flexible seal is used for containment, this bellows seal does not require a Type B leakage test. The lines from the recirculation sumps are sealed by a 1/2 inch thick flat plate welded to both the penetration sleeve and the process pipe. Since no resilient or flexible seal is used for containment isolation, no Type B leakage test is required. The outer end of the sleeve is attached to sump isolation valve containers which are leakage tested. The pipe to containment liner seal is leakage tested with the container.

For the reasons listed above, no piping penetrations are required to be subjected to Type B leakage tests. However, all piping penetrations, including those with a single bellows, have a design

capability for Type B leakage testing. Other spare penetrations are as identified in Section 3.8.1.1.2.2.

6.2.6.2.1.2 Electrical Penetrations

The electrical penetrations are of the header plate type. The seal between the individual wires and the header plate is glass. This seal is neither resilient nor flexible. Therefore, no Type B leakage test is required. The header plate is bolted to the nozzle. The seal is formed by double O-ring gaskets. This type of seal is subjected to Type B leakage tests.

6.2.6.2.1.3 Personnel Airlocks and Equipment Hatch

There are 2 personnel airlocks and one equipment hatch that penetrate the containment boundary. There is a 16 foot diameter equipment hatch, a 9 foot diameter personnel airlock, and a 5 foot diameter personnel emergency airlock. In the case of these penetrations, the barrel is solidly welded to the Reactor Building liner. The cover door on the equipment hatch is sealed to the barrel assembly with a double O-ring seal. Both the inside and outside doors of both personnel airlocks are sealed with double O-ring seals. The personnel airlocks also have operating shafts which penetrate the inner and outer barriers of these penetrations. These barrier penetrations are also sealed with double O-ring seals. The double O-ring seals are subjected to Type B leakage tests.

The personnel airlock and emergency airlock are shown by Figures 3.8-19 through 3.8-20b. All mechanical and electrical penetrations through the atmosphere and containment bulkheads of each airlock are shown by these figures.

Each airlock design provides test connections on the atmosphere side of the atmosphere bulkhead for use in leak testing the entire airlock interspace at design pressure, P_a.

Clamps have been provided for the containment bulkhead door of each airlock. These clamps are installed from within the airlock and must be in place when testing the airlock interspace to P_a as defined in the CLRTP. The clamps are installed by sliding them from the stored position into the clamping position. For testing the personnel and emergency airlocks at P_a, test clamp bolts will be torqued in accordance with the manufacturer’s recommendations as specified in surveillance procedures.

Sufficient clamps have been provided around the door perimeter to assure uniform door sealing. The design has accounted for the bolt forces generated from torquing as well as the design pressure, P_a, multiplied by 1.15.

For local leak testing, a test panel is located on the atmosphere side of the atmosphere bulkhead of each airlock. Separate test connections are provided on each test panel for individual pressurization between the double seals for all handwheel shafts and between the double seals for each door.

Handwheel shaft seals are pressurized and leak tested at a pressure greater than or equal to 8 psig, for at least 3 minutes.

Double door seals are pressurized and leak tested at a pressure greater than or equal to 8 psig, for at least 3 minutes.

The door seals for each airlock have been designed for leak testing between the double seals at a maximum pressure of 10 psig when using only the normal door latching mechanism.

Testing the airlocks at a minimum of 8 psig will verify proper latching of the doors and seating of the double seals, as well as indicating any seal degradation detrimental to leak tightness.

6.2.6.2.2 Procedures

This section discusses the procedures for conducting Type B leakage tests, including test pressure and acceptance criteria.

6.2.6.2.2.1 Piping Penetrations and Spares

As discussed in Section 6.2.6.2.1.1, the only pressure testing of the piping penetrations is testing of the sump isolation valve containers and the process piping that is isolated by gasketed, blind flanges.

The sump isolation valve containers are tested by pressurizing the containers and guard pipes with compressed air through a test connection outside the Reactor Building and monitoring pressure decay.

The blind flange that seals the fuel transfer tube has a double gasketed seal. The collar on the transfer tube that mates with the flange is drilled with passageways that allow pressurization between the gaskets. Because of the small volume between the gaskets, the pressure decay method is impracticable. The test is performed by measuring makeup flow into the test connection.

The leakage rate test system piping is sealed inside and outside the Reactor Building with blind flanges. The gaskets on these flanges are tested by pressurizing the piping between the flanges through test connections on the piping and measuring makeup flow into the test connection.

6.2.6.2.2.2 Electrical Penetrations

As discussed in Section 6.2.6.2.1.2, only the O-ring seals in the mechanical joints on some of the electrical penetrations are subjected to Type B leakage testing. These seals are tested by pressurizing the space between the O-rings and either performing a pressure drop test or by measuring the makeup flow into the test connection.

6.2.6.2.2.3 Personnel Airlock and Equipment Hatch

Type B leakage tests are performed on these 3 penetrations by pressurizing the space between the double resilient seals and measuring the makeup flow into the test connection.

6.2.6.2.3 Test Pressure

Type B leakage tests are conducted using a pressure not less than P_a as defined in the CLRTP.

6.2.6.2.4 Acceptance Criteria

The combined leakage rate for all penetrations and valves subjected to Type B and C tests shall be in accordance with the CLRTP.

6.2.6.3 Containment Isolation Valve Leakage Rate Test

Periodic tests (Type C tests) are conducted in accordance with the CLRTP, to determine the operability and leakage rate characteristics of valves serving an isolation function in the testable fluid systems lines penetrating the Reactor Building.

The Engineered Safety Features Actuation System test circuitry provides the means for testing isolation valve operability.

6.2.6.3.1 Applicability

A list of all piping penetrations is included as Table 6.2-53. A column of this table indicates which penetrations are subjected to Type B leakage tests. Table 6.2-53a indicates containment isolation valves subject to Type C leakage tests. The containment isolation valves associated with the secondary isolation side are not tested.

The boundary or barrier against leakage of containment atmosphere to the environment is the inside of the steam generator tubes, the outside of the steam generator shell, and the outside of all lines connected to the steam generator shell side. After a loss of coolant accident, these components form the actual barrier against release of the containment atmosphere to the environment.

Lines which emanate from the steam generator shell side will not be damaged during a loss of coolant accident. The design of these components is at least equivalent to, or better than, the Reactor Building liner with respect to quality assurance, pressure, temperature, testing, missile protection, etc. Thus, after a loss of coolant accident, components will be available and can be relied upon to limit release of radioactivity in the same manner as the Reactor Building liner.

In the event that the plant has been operating with steam generator tube leaks at the time of a loss of coolant accident, the barrier against release is as previously described. For large breaks, when an orderly shutdown cannot be executed, a plant trip will occur and the Emergency Core Cooling System will be started. Reactor Coolant System pressure will decrease at a rate dependent upon

break size. Some time after the incident, containment atmosphere will enter the steam generator tube bundle through the pipe break. During this initial period (approximately 1/2 to 6 hours after the incident) the steam generator shell side is pressurized. Also, after the short term, the barrier is maintained by a head of water above the tube bundle.

Before, during, and after the initial relief of steam through the safety valves, radioactivity leakage is restricted by the barrier at the steam generator tubes, shell, steam lines, blowdown lines, and sample lines inside the Reactor Building.

In general, test connections are provided to permit pressurization of piping inside the inside isolation valve and a test vent is provided outside of the outside isolation valve to measure leakage through the valves. The test is conducted by connecting the pressure source to a test connection, aligning the valves so that there is only one closed valve between the test connection and test vent and measuring the leakage flow. In those cases where the inside isolation valve is a check valve, a second test connection is provided between the isolation valves to permit pressurizing the outside isolation valve. Where required, the test connection is attached to a blind flange which is attached to the piping inside the Reactor Building (e.g., Reactor Building purge valves).

The selection of the number and location of test connections and vents for each isolation valve to be subjected to Type C leakage testing is based upon satisfying the requirement that the test pressure be applied in the same direction as the pressure existing when the valve is performing its safety function, unless it can be determined that the results for a pressure applied in a different direction will provide equivalent or more conservative results. These valves are listed in Table 6.2-53a. The test media for XVG-08889-SI is directed between the disc. This method is identified per ANS 56.8 as an equivalent and conservative method of leak rate testing.

As previously discussed, test connections and vents have been incorporated into the design of piping penetrations that contain isolation valves. These connections, which permit testing of those isolation valves subject to Type C leakage testing, are shown schematically on the appropriate system flow diagrams. Leakage testing will be performed in such a manner that measurement of leakage past the valve seat will be from inside to outside containment except as listed in Table 6.2-53a.

6.2.6.3.2 Test Pressure

Type C leakage tests are conducted at a pressure not less than P_a as defined in the CLRTP.

6.2.6.3.3 Acceptance Criteria

See Section 6.2.6.2.4.

6.2.6.4 Scheduling and Reporting of Periodic Tests

6.2.6.4.1 Test Frequencies

6.2.6.4.1.1 Type A Tests

Test frequency shall be as established by the CLRTP.

6.2.6.4.1.2 Type B Tests

Test frequency shall be as established by the CLRTP.

6.2.6.4.1.3 Type C Tests

Test frequency shall be as established by the CLRTP.

6.2.6.4.2 Reports

The preoperational test summary technical report was submitted to the NRC approximately 3 months after the performance of the Type A test.

The report of the preoperational test included a schematic arrangement of the leakage rate measurement system, the instrumentation used and the test program selected as applicable to the preoperational test and subsequent periodic tests. The report contained an analysis and interpretation of the leakage rate test data for the Type A test results to the extent necessary for demonstration of the acceptability of the containment leakage rate in satisfying the acceptance criteria.

Periodic test results are documented and available for review in accordance with the CLRTP.

6.2.6.5 Special Testing Requirements

Leakage rate testing subsequent to containment modification is performed in accordance with the CLRTP.

Virgil C. Summer Nuclear Station does not utilize a subatmospheric containment, secondary containment, or pressure seal system.

6.2.7 References

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Table 6.2-1
General Containment Design and Evaluation Parameters

General Design Information		
Maximum Internal Design Pressure, psig		57
Maximum External Design Pressure, psig		3.5 psig
Design temperature, °F		283(1)
Free Volume, ft^3		1.84×10^6
Design Leak Rate, max. allowable, %/day		0.2
Engineered Safety Features	Full Capacity	Value Used for Analysis
Passive Safety Injection		
Number of Accumulators	3	2 or 3
Pressure Setpoint, Psig	600	600
Active Safety Injection		
Residual Heat Removal Flow Rate, lb/sec	990.4	460.2 or 990.4
Reactor Building Spray System		
Number of Lines	2	1 or 2
Number of Pumps	2	1 or 2
Number of Headers	6	3 or 6
Design Flow, gpm	5,000	2,500 to 5,000
Reactor Building Cooling Units		
Number	4	1 or 2
Air Side Flow Rate, cfm/unit	60,270(3)	54,200(3)
Heat Removal Rate at 283°F, Btu/hr/unit	125×10^6	90.7×10^6(2)
Residual Heat Removal System Heat Exchangers		
Number	2	1
UA, BTU/hr-°F/unit	1.519×10^6(4)	1.519×10^6(4)

Table 6.2-1 (CONTINUED)
General Containment Design and Evaluation Parameters

Flow Rate		
Shell Side, gpm	5,600	5,600
Tube Side, gpm	3,750	3,750

(1) Peak reactor building temperature is 373.7 °F as described in Section 6.2.1.1.1

(2) Maximum analysis value assumed was an energy removal rate of 90.7 x 10^6 Btu/Hr, at 283°F.

(3) This parameter is used only in the Chapter 15 Radiological Consequence Analysis for particulate iodine removal post-LOCA. This parameter is not used in the Chapter 6 pressure/temperature analyses.

(4) Based on the maximum component cooling water shell-side inlet temperature of 120° F (Reference 47).

Table 6.2-1a
Main Steam Line Breaks Analyzed

Double Ended Ruptures[1] (No Entrainment) to Assess Impact of Single Failures

Area/Power	Failures Assumed[2]
1.4 ft^2/ 102%	MSIV[3]
1.4 ft^2/ 102%	FWIV[4]
1.4 ft^2/ 102%	EFW FCV[5]
1.4 ft^2/ 102%	Diesel[6]
1.4 ft^2/ 102%	CH-A[7]

Double Ended Ruptures (with Entrainment) to Assess Impact of Power Level

Area/Power	Failures Assumed[2]
1.4 ft^2/ 75%	CH-A
1.4 ft^2/ 50%	CH-A
1.4 ft^2/ 25%	CH-A
1.4 ft^2/ 25%	FWIV[4]
1.4 ft^2/ 0%	CH-A

Double Ended Ruptures (No Entrainment) to Assess Impact of Break Size

Area/Power	Failures Assumed[2]
1.2 ft^2/ 102%	FWIV, MSIV, EFW FCV, Diesel
1.2 ft^2/ 102%	FWIV, MSIV, EFW FCV, Diesel

Small Double Ended Ruptures (With Entrainment)

Area/Power	Failures Assumed[2]
1.1 ft^2/ 75%	FWIV, MSIV, EFW FCV, Diesel
0.8 ft^2/ 50%	FWIV, MSIV, EFW FCV, Diesel
0.6 ft^2/ 25%	FWIV, MSIV, EFW FCV, Diesel
0.2 ft^2/ 0%	FWIV, MSIV, EFW FCV, Diesel

Table 6.2-1a (continued)
Main Steam Line Breaks Analyzed

Small Double Ended Ruptures (No Entrainment)

Area/Power	Failures Assumed(2)
1.0 ft^2/ 75%	FWIV, MSIV, EFW FCV, Diesel
0.7 ft^2/ 50%	FWIV, MSIV, EFW FCV, Diesel
0.5 ft^2/ 25%	FWIV, MSIV, EFW FCV, Diesel
0.1 ft^2/ 0%	FWIV, MSIV, EFW FCV, Diesel

Split Ruptures (No Entrainment)

Area/Power	Failures Assumed(2)
0.878 ft^2/ 102%	
0.871 ft^2/ 75%	FWIV, EFW FCV, Diesel
0.863 ft^2/ 50%	FWIV, EFW FCV, Diesel
0.849 ft^2/ 25%	FWIV, EFW FCV, Diesel
0.772 ft^2/ 0%	FWIV, EFW FCV, Diesel

(1) Effective break area for broken loop is 1.4 ft^2.
(2) Failure of one Chg/SI pump is assumed in all analyses.
(3) MSIV = Main steam isolation valve fails to close.
(4) FWIV = Main feedwater isolation valve fails to close.
(5) EFW FCV = EFW control valve which terminates flow to the faulted SG fails to close.
(6) Diesel = One emergency diesel fails to start.
(7) CH-A = Failure of Electrical Channel A.

Table 6.2-2
Initial Conditions Used in Reactor Building
MSLB Peak Pressure Analysis

Reactor Coolant System	
Power Level, MWt (Includes +2% Allowance for Instrument Error and Deadband)	2958
Vessel Average Temperature, °F (Includes +5.3° F Allowance for Instrument Error and Deadband)	592.7
Mass of Reactor Coolant, lbm	421.3×10^3
Reactor Coolant Energy,(1) BTU	251.3×10^6
Reactor Coolant Pressure, psia	2300
Reactor Building	
Pressure, psig(2)	1.5
Temperature, °F	120
Relative humidity, %	30
Service Water Temperature °F	95
Refueling Water Temperature, °F	95
Stored Water Quantity Assumed in Analysis	
Refueling Water Storage Tank, gal	404,000
Accumulators, lbm	188,130

(1) Energy relative to 32 °F.
(2) Peak pressure analysis; peak temperature analysis uses pressure of 0.0 psig.

Table 6.2-3
Comparative Results, Peak Pressure, and Temperature
For a Spectrum of Accidents

LARGE MSLBs

BREAK SIZE FT^2 /% POWER	1.4 / 102% (CASE IG)	1.4 / 102% (CASE IH)	1.4 / 102% (CASE II)	1.4 / 102% (CASE IJ)	1.4 / 102% (CASE IK)	1.4 / 75% (CASE 2E)	1.4 / 50% (CASE 3E)	1.4 / 25% (CASE 4E)	1.4 / 25% (CASE 4G)	1.4 / 0% (CASE 5F)
RB SPRAY	2	2	2	1	1	1	1	1	2	1
RBCU'S	2	2	2	1	1	1	1	1	2	1
OTHER FAILURES	FWIV SI PUMP	MISV SI PUMP	EFW FCV SI PUMP	DIESEL	CH-A	CH-A	CH-A	CH-A	FWIV SI PUMP	CH-A
PEAK PRESSURE (PSIG)	50.4	48.1	47.9	48.2	49.3	49.6	50.9	53	52.6	51.7
TIME TO PEAK PRESSURE (SEC)	204	177	185	173	1,800	1,800	1,800	1,800	193	1,900
PEAK TEMPERATURE ($^{\circ}F$)	360.8	372.7	360.9	361	352.1	283.7	275.4	278.1	277.8	276.4
TIME TO PEAK TEMPERATURE (SEC)	31	19	31	30	53	4	1,800	1,800	193	1,900

Table 6.2-3 (Continued)
Small MSLB'S Without Entrainment

BREAK SIZE FT2 /% POWER	1.2/102% (CASE IB)	1.1/102% (CASE IC)	1.0/75% (CASE 2C)	0.7/50% (CASE 3C)	0.5/25% (CASE 4C)	0.1/0% (CASE 5C)
RB SPRAY	1	1	1	1	1	1
RBCU'S	1	1	1	1	1	1
OTHER FAILURES	(Note 1)	(Note 1)	(Note 1)	(Note 1)	(Note 1)	(Note 1)
PEAK PRESSURE (PSIG)	51.6	50.3	50.2	51.8	49.7	13.7
TIME TO PEAK PRESSURE (SEC)	1,200	1,200	1,200	1,200	1,200	1,200
PEAK TEMPERATURE (°F)	350.5	347.2	341.1	322	303.8	251.6
TIME TO PEAK TEMPERATURE (SEC)	49	53	53	58	67	480

(1) Multiple failures assumed: MSIV, FWIV, EFW FCV, and Diesel.

Table 6.2-3 (Continued)
Small MSLB'S With Entrainment

BREAK SIZE FT^2/% POWER	1.1/75% (CASE 2B)	0.8/50% CASE 3B)	0.6/25% (CASE 4B)	0.2/0% (CASE 5B)
RB SPRAY	1	1	1	1
RBCU'S	1	1	1	1
OTHER FAILURES	(Note 1)	(Note 1)	(Note 1)	(Note 1)
PEAK PRESSURE (PSIG)	51.3	48.7	49.9	25.9
TIME TO PEAK PRESSURE (SEC)	1,200	1,200	1,200	1,200
PEAK TEMPERATURE (°F)	276	272.4	274.1	232.8
TIME TO PEAK TEMPERATURE (SEC)	1,200	1,200	1,200	1,200

(1) Multiple failures assumed: MSIV, FWIV, EFW FCV, and Diesel.

Table 6.2-3 (Continued)
Split MSLB's Without Entrainment

BREAK SIZE FT^2/% POWER	0.878/102% (CASE IB)	0.871/75% (CASE 2B)	0.863/50% (CASE 3B)	0.849/25% (CASE 4B)	0.772/0% (CASE 5B)
RB SPRAY	1	1	1	1	1
RBCU'S	1	1	1	1	1
OTHER FAILURES	(Note 1)	(Note 1)	(Note 1)	(Note 1)	(Note 1)
PEAK PRESSURE (PSIG)	35	35	38.1	37.8	35.7
TIME TO PEAK PRESSURE (SEC)	230	280	320	245	400.0
PEAK TEMPERATURE (°F)	331.9	329.5	327.9	325.9	318.1
TIME TO PEAK TEMPERATURE (SEC)	67	67	67	67	67

(1) Multiple failures assumed: MSIV, FWIV, EFW FCV, and Diesel.

Table 6.2-3 (Continued)
Comparative Results, Peak Pressure and Temperature For a Spectrum of Accidents

Large LOCA

BREAK SIZE FT^2/% POWER	DEPS[1]/102	DEPS/102	DEHL[2]/102
R B SPRAY	1	1	N/A
RBCU'S	1	1	N/A
SAFETY INJECTION	MIN	MAX	N/A
PEAK PRESSURE (PSIG)[3]	44.39	44.22	45.65
PEAK TEMPERATURE (°F)	267	266	268

(1) DEPS = Double-Ended Pump Suction
(2) DEHL = Double-Ended Hot Leg
(3) Includes a PAD5 penalty of 0.12 psig

Table 6.2-4
Long Term Values of Reactor Building Parameters For Loss of Coolant Accident and Main Steam Line Break

	Design Basis [1] Accident Main Steam Line Break	LOCA [1] DEPS with Minimum Safety Injection
Reactor Building Pressure, psig	38.3	2.1
Reactor Building Vapor Temperature, °F	257	111.1
Reactor Building Sump Temperature, °F	270	136.2

(1) Long-term MSLB = 1800 Seconds
Long-term LOCA = 1440 Hours

Table 6.2-5
Chronology of Events For the Design Basis Accident
Main Stream Line Break[1]

	Time (Sec.)
1. Break occurs, which blows down all three steam generators, coincident with Electrical Channel A Failure [2]	0.0
2. Reactor building pressure reaches the safety injection setpoint.	1.0
3. Feedwater pumps tripped (not assumed in analysis)	N/A
4. Main steam isolation valves close (blowdown limited to one steam generator)	7.0
5. Reactor building spray initiated	53.1
6. Reactor building cooling units fully operational	86.5
7. Peak pressure of 53.0 psig is reached	1800
8. Emergency feedwater flow manually terminated	1800
9. End of Analysis for DBA	1800.0

(1) 1.4 ft^2 DE Rupture from 25% power.
(2) Electrical Channel A Failure results in loss of power to the feedwater control and isolation valves, main steam isolation valves, prevents startup of an emergency diesel generator, and prevents automatic isolation of emergency feedwater to the faulted SG.

Table 6.2-6A
Double-Ended Pump Suction Break With Minimum
Safeguards Sequence of Events

TIME (SEC)	EVENT DESCRIPTION
0.00	Break Occurs and Loss of Offsite Power is assumed
2.47	Low Pressurizer Pressure Reactor Trip – 1925 psia reached
2.65	Turbine Throttle Valve Closed Isolating SG Steam Flow
3.40	Low Pressurizer Pressure SI Setpoint - 1730 psia reached
11.00	Broken Loop Accumulator Begins Injecting Water
11.20	Intact Loop Accumulator Begins Injecting Water
13.40	Main Feedwater Isolated
18.80	End of Blowdown Phase
30.40	Safety Injection Begins
41.13	Intact Loop Accumulator Water Injection Ends
42.13	Broken Loop Accumulator Water Injection Ends
221.23	End of Reflood Phase
1275.27	Broken loop SG equilibration (corresponds to PBL)
1399.20	Intact loop SG equilibration (corresponds to PUL)
2500.00	Cold Leg Recirculation Begins
1.0E+07	Transient Modeling Terminated

Table 6.2-6B
Double-Ended Hot-Leg Break With Maximum Safeguards
Sequence of Events

TIME (SEC)	EVENT DESCRIPTION
0.00	Break Occurs and Loss of Offsite Power is assumed
2.47	Low Pressurizer Pressure Reactor Trip – 1925 psia reached
2.65	Turbine Throttle Valve Closed Isolating SG Steam Flow
3.40	Low Pressurizer Pressure SI Setpoint - 1730 psia reached
10.40	Safety Injection Begins
11.00	Broken Loop Accumulator Begins Injecting Water
11.20	Intact Loop Accumulator Begins Injecting Water
13.40	Main Feedwater Isolated
18.60	End of Blowdown Phase
42.05	Intact Loop Accumulator Water Injection Ends
43.05	Broken Loop Accumulator Water Injection Ends
201.55	End of Reflood Phase
1085.63	Broken loop SG equilibration (corresponds to PBL)
1276.17	Intact loop SG equilibration (corresponds to PUL)
1460.00	Cold Leg Recirculation Begins
1.0E+7	Transient Modeling Terminated

Table 6.2-6C
Double-Ended Hot-Leg Break Sequence of Events

TIME (SEC)	EVENT DESCRIPTION
0.00	Break Occurs and Loss of Offsite Power is assumed
2.10	Low Pressurizer Pressure Reactor Trip – 1925 psia reached
2.24	Turbine Throttle Valve Closed Isolating SG Steam Flow
3.00	Low Pressurizer Pressure SI Setpoint - 1730 psia reached
10.80	Broken Loop Accumulator Begins Injecting Water
11.00	Intact Loop Accumulator Begins Injecting Water
19.00	End of Blowdown Phase

Table 6.2-7
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Reactor Building Concrete and steel						
Reactor Building Shell	Concrete	4			57,397(5)	0
Reactor Building Dome	Concrete	3			20,241	0
Floor Slab (el.412')	Concrete	4			8,868	8,868
Floor Slab (el.436')	Concrete	2			5,019	5,019
Floor Slab (el.463')	Concrete	2			6,675	6,675
Decking under Floor Slabs at el. 436' and el.463'	Carbon Steel	1/8 in	44,315	Ambient	8,696	8,696
Secondary Shield Walls between el. 412' and 436'	Concrete	3.66			6,168	11,919
Secondary Shield Walls between el. 436' and 463'	Concrete	3.66			7,523	14,492
Secondary Shield Walls above el. 463’	Concrete	3.66			8,613	17,126
Misc. Walls and Shield Slabs between el. 412' and 436'	Concrete	2			2,581	5,162
Misc. Walls between el. 436' and el. 463'	Concrete	2			737	1,473
Misc. Walls above el. 463'	Concrete	2			808	1,616
Primary Shield Wall and Fuel Transfer Canal Walls between el. 412' and el. 436'	Concrete	8			2,729	5,457
Primary Shield Wall and Fuel Transfer Canal Walls at el. 436'	Concrete	4.5			2,348	4,695
Secondary Shield Slab	Concrete	2			1,280	2,560
Reactor Building Liner	Carbon Steel	0.26 in	954,450[6]	Ambient	77,638	77,638
Liner Anchors	Carbon Steel	0.25 in	390,600[6]	Ambient	36,943	0
Fuel Transfer Canal Liners	Stainless Steel	0.266 in	131,250[6]	Ambient	11,497	11,497

Table 6.2-7 (continued)
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Reactor Building Concrete and steel (Continued)						
Column Steel	Carbon Steel	1.55 in	212,000	Ambient	3,350	6,616
Framing Steel, Platforms, Stairs, Restraints	Carbon Steel	0.5 in	969,000	Ambient	47,281	88,887
Special Steel Around Reactor in Primary Wall	Carbon Steel	1.9	305,000	Ambient	3,930	4,249
Brackets	Carbon Steel	0.936 in	128,000	Ambient	3,349	3,339
Airlocks and Hatch	Carbon Steel	0.87	45,000	Ambient	1,266	1,266
Piping, Piping Supports and Equipment						
Spent Fuel Cooling System						
Sch 40 Pipe, 2 in	Stainless Steel	0.013	110	Ambient	19	19
Sch 40 Pipe, 3 in	Stainless Steel	0.018	834	Ambient	101	101
Leak Test Canal System						
Sch 40 Pipe, 1/2 in	Stainless Steel	0.009	26	Ambient	7	7
OD Tubing, 1/2 in	Stainless Steel	0.005	24	Ambient	10	10
R.B. Spray System						
Sch 40 Pipe, 3/4 in	Stainless Steel	0.009	11	Ambient	3	3
Sch 40 Pipe, 1 in	Stainless Steel	0.011	544	Ambient	113	113
Sch 40 Pipe, 2 in	Stainless Steel	0.013	37	Ambient	6	6
Sch 40 Pipe, 3 in	Stainless Steel	0.018	2,274	Ambient	275	275
Sch 40 Pipe, 6 in	Stainless Steel	0.024	23,333	Ambient	2,133	2,133

Table 6.2-7 (continued)
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Piping, Piping Supports and Equipment (Continued)						
Sch 40 Pipe, 10 in	Stainless Steel	0.030	8,096	Ambient	563	563
Safety Injection System						
Sch 140 Pipe, 12 in	Stainless Steel	0.094	23.043	Ambient	551	551
Sch 40 Pipe, 12 in	Stainless Steel	0.034	1,338	Ambient	83	83
Sch 150 Pipe, 3 in	Stainless Steel	0.036	501	Ambient	32	32
Sch 160 Pipe, 2 in	Stainless Steel	0.029	4,690	Ambient	392	392
Sch 40 Pipe, 2 in	Stainless Steel	0.013	110	Ambient	19	19
Sch 160 Pipe, 1 in	Stainless Steel	0.021	924	Ambient	112	112
Sch 40 Pipe, 1 in	Stainless Steel	0.011	285	Ambient	58	58
Sch 160 Pipe, 3/4 in	Stainless Steel	0.018	620	Ambient	89	89
Sch 40 Pipe, 1 in	Carbon Steel	0.011	445	Ambient	91	91
Nuclear Utility System						
Sch Std Pipe, 1/2 in	Carbon Steel	0.009	204	Ambient	53	53
Sch 40 Pipe, 1/2 in	Stainless Steel	0.009	247	Ambient	64	64
Sch Std Pipe, 3/4 in	Carbon Steel	0.009	90	Ambient	22	22
Sch 40 Pipe, 3/4 in	Stainless Steel	0.009	79	Ambient	19	19
Sch Std Pipe, 1 in	Carbon Steel	0.011	1,595	Ambient	327	327
Sch 40 Pipe, 1 in	Stainless Steel	0.011	487	Ambient	100	100
Sch Std Pipe, 1-1/2 in	Carbon Steel	0,012	49	Ambient	9	9

Table 6.2-7 (continued)
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Piping, Piping Supports and Equipment (Continued)						
Sch Std Pipe, 2 in	Carbon Steel	0.013	877	Ambient	149	149
Sch 40 Pipe, 2-1/2 in	Carbon Steel	0.017	1,448	Ambient	188	188
Sch 40 Pipe, 4 in	Carbon Steel	0.020	2,482	Ambient	271	271
Sch 40 Pipe, 6 in	Carbon Steel	0.024	95	Ambient	9	9
Nuclear Sampling System						
OD Tubing, 3/8 in	Stainless Steel	0.005	105	Ambient	48	48
Sch 40 Pipe, 3/4 in	Stainless Steel	0.009	23	Ambient	6	6
Reactor Building Leak Rate Test System						
Sch 40 Pipe, 8 in	Carbon Steel	0.027	143	Ambient	11	11
ECCS Check Valve Testing System						
Sch 160 Pipe, 3/4 in	Stainless Steel	0.018	1,027	Ambient	147	147
Nuclear Drains System						
Sch 40 Pipe, 3 in	Stainless Steel	0.018	303	Ambient	37	37
Sch 40 Pipe, 2 in	Stainless Steel	0.013	913	Ambient	155	155
Sch 40 Pipe, 1/2 in	Stainless Steel	0.009	17	Ambient	4	4
Post Accident Hydrogen Removal System						
Sch 40 Pipe, 3 in	Stainless Steel	0.018	2,426	Ambient	293	293
Floor & Equipment Drains						
Sch 10 Pipe, 8 in	Stainless Steel	0.013	630	Ambient	106	106
Sch 10 Pipe, 6 in	Stainless Steel	0.011	2,685	Ambient	501	501

Table 6.2-7 (continued)
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Piping, Piping Supports and Equipment (Continued)						
Sch 10 Pipe, 4 in	Stainless Steel	0.010	7,349	Ambient	1,544	1,544
Sch 10 Pipe, 2-1/2 in	Stainless Steel	0.010	1,077	Ambient	230	230
Sch 10 Pipe, 2 in	Stainless Steel	0.009	92	Ambient	22	22
Sch 10 Pipe, 1 in	Stainless Steel	0.009	1	Ambient	1	1
Hanger Components and Supplementary Steel for Hanger Components	Carbon Steel	0.019	135,507	Ambient	14,555	14,555
Polar Crane	Carbon Steel	0.198	205,000	Ambient	2,113	22,500
Reactor Cavity Manipulator Crane	Carbon Steel	0.556	74,104	Ambient	3,000	3,000
Loop B Auxiliary Crane [9]	Carbon Steel	0.043	32,393	Ambient	2,474	2,474
Fuel Transfer Control Panel	Carbon Steel	0.292	4,865	Ambient	34	34
Service Water System [7]						
Sch Std Pipe, 16 in	Carbon Steel	0.034	19,400	95	1,298	1,298
Sch 40 Pipe, 10 in	Carbon Steel	0.030	10,930	95	760	760
Sch Std Pipe, 1 in	Carbon Steel	0.011	40	95	24	24
Sch 40 Pipe, 3/4 in	Carbon Steel	0.009	9	95	8	8
Reactor Makeup Water						
Sch 40 Pipe, 3 in	Stainless Steel	0.018	834	120	101	101
Sch 40 Pipe, 3/4 in	Stainless Steel	0.009	418	120	103	103
Integrated Head Assembly [9]	Stainless Steel		15,598			709
(IHA)	Carbon Steel		73,104			1,953

Table 6.2-7 (continued)
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Piping, Piping Supports and Equipment (Continued)						
Reactor Coolant System						
OD Tubing, 3/8 in	Stainless Steel	0.005	2	120	1	1
Sch 40 Pipe, 3/4 in	Stainless Steel	0.009	6	120	1	1
Sch 40 Pipe, 1 in	Stainless Steel	0.011	84	120	17	17
Sch 40 Pipe, 3 in	Stainless Steel	0.018	834	120	101	101
Sch 40 Pipe, 4 in	Stainless Steel	0.020	2,644	120	289	289
Sch 40 Pipe, 6 in	Stainless Steel	0.024	2,466	120	225	225
Sch 160 Pipe, 6 in	Stainless Steel	0.059	277	120	9	9
Sch 40 Pipe, 12 in	Stainless Steel	0.034	4,550	120	284	284
Chemical and Volume Control System[7]						
Sch 160 Pipe, 3/4 in	Stainless Steel	0.018	39	130	6	6
Sch 160 Pipe, 1-1/2 in	Stainless Steel	0.023	1,118	130	115	115
Sch Pipe, 3 in	Stainless Steel	0.037	1,862	130	119	119
Component Cooling System[7]						
Sch 40 Pipe, 1 in	Carbon Steel	0.011	319	135	65	65
Sch 40 Pipe, 3/4 in	Carbon Steel	0.009	17	135	4	4
Sch 40 Pipe, 1-1/2 in	Carbon Steel	0.012	734	135	135	135
Sch 40 Pipe, 2 in	Carbon Steel	0.013	37	135	6	6
Sch 40 Pipe, 3 in	Carbon Steel	0.018	2,880	135	348	348
Sch 40 Pipe, 4 in	Carbon Steel	0.020	1,187	135	130	130

Table 6.2-7 (continued)
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Piping, Piping Supports and Equipment (Continued)						
Sch 40 Pipe, 6 in	Carbon Steel	0.024	13,279	135	1,214	1,214
Sch 40 Pipe, 8 In	Carbon Steel	0.027	2,998	135	237	237
Sch 160 Pipe, 1-1/2 in	Carbon Steel	0.023	1,166	135	120	120
Sch Std Pipe, 1/2 in	Carbon Steel	0.009	298	135	77	77
Sch Std Pipe, 1 in	Carbon Steel	0.011	151	135	31	31
Waste Disposal System[7]						
OD Tubing, 3/8 in	Stainless Steel	0.005	2	160	1	1
Sch 40 Pipe, 3/4 in	Stainless Steel	0.009	102	160	25	25
Sch 40 Pipe, 1/2 in	Stainless Steel	0.009	204	160	53	53
Sch 40 Pipe, 1 in	Stainless Steel	0.011	84	160	17	17
Sch 40 Pipe, 1-1/2 in	Stainless Steel	0.012	571	160	105	105
Sch 40 Pipe, 2 in	Stainless Steel	0.013	475	160	81	81
Sch 160 Pipe, 2 in	Stainless Steel	0.028	893	160	75	75
Sch 40 Pipe, 3 in	Stainless Steel	0.018	1,364	160	165	165
Sch 160 Pipe, 3 in	Stainless Steel	0.037	1,002	160	65	65
Sch 40 Pipe, 4 in	Stainless Steel	0.044	216	160	24	24
Feedwater System[7]						
Sch 80 Pipe, 1 in	Carbon Steel	0.015	11	200	2	2
Reactor Coolant System						
Sch 160 Pipe, 3/4 in.[8]	Stainless Steel	0.018	203	653	29	29

Table 6.2-7 (continued)
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Piping, Piping Supports and Equipment (Continued)						
Reactor Coolant Drain Tank	Stainless Steel	0.043	2,000	120	93	93
Reactor Coolant Drain Tank Heat Exchanger[8]	Stainless Steel	0.030	1,325	250	87	87
Reactor Coolant Drain Tank Pump[7]	Stainless Steel	0.05	720	200	30	30
Accumulator[8]	Stainless Steel	0.117	168,000	300	2,878	2,878
Reactor Coolant Pumps Relief Tank[8]	Stainless Steel	0.071	23,000	340	650	650
CRDM[8]	Stainless Steel	0.152	36,720	400	1,383	1,383
Reactor Coolant Pump Handling Fixture	Carbon Steel	0.029	8.000	Ambient	547	547
Reactor Vessel Internals Lifting Device	Stainless Steel	0.077	15,000	Ambient	398	398
Upper Internals Storage Stand	Stainless Steel	0.053	2,435	Ambient	93	93
Lower Internals Storage Stand	Stainless Steel	0.063	2,176	Ambient	70	70
Reactor Coolant Pump Tierods and Steam Generator Upper/Lower Supports	Carbon Steel	0.029	50,976	Ambient	3,510	3,510
Reactor Coolant Piping Crossover Supports	Carbon Steel	0.049	7,800	Ambient	330	330
Incore Instrument Tubing I	Stainless Steel	0.025	7,900	Ambient	921	921
Incore Instrument Tubing II	Stainless Steel	0.017	1,152	Ambient	176	176
Misc. Supports, Fittings, Special Tools		0.083	104,565	Ambient	2,568	2,568
HVAC Ductwork and Units						
Ring Duct	Carbon Steel	0.011	39,105	Ambient	6,952	6,952
Vertical Risers	Carbon Steel	0.014	62,906	Ambient	9,150	9,150
HVAC Ductwork and Units (Continued)						

Table 6.2-7 (continued)
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Duct Reinforcing Angles	Carbon Steel	0.015	9,772	Ambient	1,357	1,357
Risers, Duct Reinforcing Angles	Carbon Steel	0.024	75,360	Ambient	6,384	6,384
Duct Supports	Carbon Steel	0.015	17,640	Ambient	2,394	2,394
Riser Supports	Carbon Steel	0.024	14,130	Ambient	1,197	1,197
Reactor Building Cooling Unit to Ring Duct Connectors	Carbon Steel	0.014	15,400	Ambient	2,240	2,240
Reactor Building Cleanup Units	Carbon Steel	0.006	26,000	Ambient	830	830
Reactor Building Cooling Units	Carbon Steel	0.069	392,000	Ambient	11,640	11,640
Reactor Compartment Cooling System	Carbon Steel	0.062	2,400	Ambient	79	79
Refueling Water Surface System Fans	Carbon Steel	0.047	1,110	Ambient	48	48
Reactor Building Charcoal Cleanup Fans	Carbon Steel	0.016	1,200	Ambient	149	149
Secondary Compartment Cooling System	Carbon Steel	0.017	4,500	Ambient	545	545
Duct Support and Support Angles: Floor El. 412'	Carbon Steel	0.005	1,678	Ambient	635	635
Floor El. 463'	Carbon Steel	0.005	49,500	Ambient	18,710	18,710
Electrical						
Cable Trays	Carbon Steel	0.009	46,186	Ambient	10,473	10,473
Cable Tray Supports	Carbon Steel	0.042	100,842	Ambient	4,900	4,900
Conduits	Carbon Steel	0.018	37,220	Ambient	4,220	4,220
Conduit Supports	Carbon Steel	0.007	7,080	Ambient	2,064	2,064
Penetrations Type 1	Carbon Steel	0.009	7,285	Ambient	1,652	1,652
Electrical (Continued)						

Table 6.2-7 (continued)
Passive Heat Sinks

Description	Material of Each Layer	Thickness of Layer [1] (ft)	Steel Weight[2] (lbm)	Steel Temp (°F)	Area[3] (ft^2)	Exposure[4] (ft^2)
Penetrations Type 2	Carbon Steel	0.056	50,407	Ambient	1,837	1,837
Misc. Panels	Carbon Steel	0.007	909	Ambient	265	265

(1) Material thickness, where not indicated specifically, is in feet.
(2) A 5 percent (plus), margin (for ECCS analysis) is included in the calculated weights of reactor building liner, liner anchors and fuel transfer canal liner.
(3) The Area column shows a conservatively high surface area (for ECCS analysis) for one side (plus ends if significant) of the heat sink.
(4) The Exposure column indicates if both sides are exposed to the reactor building atmosphere (or one side to the outside).
(5) Carbon Steel plate (1/4 in.) lines interior surface. Theoretically, zero surface are is exposed directly to reactor building atmosphere.
(6) Uncertainty margin of 5 percent included.
(7) Heat sink modeled at ambient temperature of 120°F, weighted average temperature
(8) Not used for peak pressure analysis, only for ECCS analysis.
(9) Conservatively not used for peak pressure analysis.
(10) IHA Carbon and Stainless Steel Summaries - See DC00020-002, Table 12.

Table 6.2-8
Passive Heat Sink Models Used in Peak Pressure Analysis

Reactor Building Cylinder

a. Surface = 57,397.0 ft^2

b. Materials

First region - carbon steel, 0.0217 ft

Second region - air/steel, 0.00521 ft

Third region - concrete, 0.25 ft

Fourth region - concrete, 0.75 ft

Reactor Building Dome

a. Surface = 20,241 ft^2

b. Materials

First region - carbon steel, 0.0217 ft

Second region - air/steel, 0.00521 ft

Third region - concrete, 0.25 ft

Fourth region - concrete, 0.75 ft

Reactor Building Material

a. Surface = 12,463 ft^2

b. Material

First region - concrete, 0.33 ft

Second region - concrete, 1.67 ft

Internal Concrete

a. Surface = 76,839 ft^2

b. Material

First region - concrete, 0.25 ft

Second region - concrete, 0.75 ft

Table 6.2-8 (continued)
Passive Heat Sink Models Used in Peak Pressure Analysis

Carbon Steel, 0.02 ft < thickness < 0.03 ft

a. Surface = 29,885.0 ft^2

b. Material, carbon steel, average thickness, 0.0266 ft

Carbon Steel, thickness < 0.025 ft

a. Surface = 68,946.0 ft^2

b. Material, carbon steel, average thickness, 0.0132 ft

Stainless Steel, thickness > 0.025 ft

a. Surface - 17, 051.0 ft^2

b. Material, stainless steel, average thickness, 0.033 ft

Stainless Steel, thickness < 0.025 ft

a. Surface = 4919.4 ft^2

b. Material, stainless steel, average thickness, 0.0138 ft

Carbon Steel, thickness > 0.03 ft

a. Surface = 121,616.0 ft^2

b. Material, carbon steel, average thickness, 0.0415 ft

Table 6.2-9
Reactor Building Design Evaluation Parameters
Passive Heat Sink Material Properties

Material	Thermal Conductivity (BTU/hr/ft/°F)	Volumetric Heat Capacity (BTU/ft^3/°F)
Concrete	0.8	28.0
Stainless Steel	9.4	53.7
Carbon Steel	28.0	53.9
Air/steel	0.72	1.31

Table 6.2-11
Reactor Building Subcompartment Calculated and Design Pressures

Compartment	Peak Calculated Differential Pressure (psid)	Design Differential Pressure (psid)
Pressurizer		
Spray Line Break	26.0	41.4
Surge Line Break	30.6	51.3
Steam Generator		
Lower Compartment	See Section 6.2.1.3.9.2	
Reactor Cavity	See Section 6.2.1.3.9.3	

Table 6.2-11a
Summary of Initial Steam Generator Compartment Models

Model	Nodal Arrangement Figure No.	Model Description/Results Listed in Table No.	Results Illustrated by Figure No.
16 Node Model, Loop A Steam Generator Compartment Cold Leg Break	6.2-22a	6.2-12, 6.2-12a	6.2-22b
17 Node Model, Loop A Steam Generator Compartment Hot Leg Break	6.2-22c	6.2-12b, 6.2-12c	6.2-22d
12 Node Model, Loop B Steam Generator Compartment Cold Leg Break	6.2-22e	6.2-13, 6.2-13a	6.2-22f
13 Node Model, Loop B Steam Generator Compartment Hot Leg Break	6.2-22g	6.2-13b, 6.2-13c	6.2-22h
14 Node Model, Loop C Steam Generator Compartment Hot and Cold Leg Breaks	6.2-22i	6.2-14, 6.2-14a	6.2-22j, 6.2-22k

Table 6.2-12
16 Node Loop A Steam Generator Compartment Model
Cold Leg Break, Volume Description

Control Volume No	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. press[1] (psi)	Design Diff. press.[2] (psi)	Design Margin (%)
						Temp (°F)	Pressure (psia)	Quality			
1	Lower 1/2 Compartment below Steam Generator	14.0	6,768.	615.	412.5	212	14.696	0.573	21.5	41.2	92
2	Lower 1/2 Compartment below Reactor Coolant Pump	14.0	4,641.	413.	412.5	212	14.696	0.573	21.4	41.2	93
3	Between Steam Generator and Secondary Shield Wall	9.5	2,084.	317.	426.5	212	14.696	0.573	21.6	41.2	91
4	Between Steam Generator, Reactor Coolant Pump and Primary Shield Wall	9.5	2,195.	326.	426.5	212	14.696	0.573	21.8	41.2	89
5	Between Steam Generator, Reactor Coolant Pump and Secondary Shield Wall	9.5	1,380.	332.	426.5	212	14.696	0.573	21.6	41.2	91
6	Between Reactor Coolant Pump, Cold Leg and Secondary Shield Wall	9.5	1,134.	314.	426.5	212	14.696	0.573	24.7	41.2	67
7	Between Reactor Coolant Pump and Secondary Shield Wall	9.5	314.	90.	426.5	212	14.696	0.573	21.6	41.2	91
8	Compartment above Elevation 436'	23.5	16,686.	758.	436.0	212	14.696	0.573	21.5	41.2	92
9	Around Steam Generator above Elevation 459.5’	15.9	4,826.	392.	459.5	212	14.696	0.573	5.8	16.9	191
10	Steam Generator B Compartment below Elevation 459.5'	47.0	34,094.	863.	412.5	212	14.696	0.573	NA [3]		
11	Steam Generator B Compartment above Elevation 459.5'	15.9	4,347.	413.	459.5	212	14.696	0.573	NA		

Table 6.2-12 (continued)
16 Node Loop A Steam Generator Compartment Model
Cold Leg Break, Volume Description

Control Volume No	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions: Temp (°F)	Initial Conditions: Pressure (psia)	Initial Conditions: Quality	Calc. Peak Diff. press[1] (psi)	Design Diff. press.[2] (psi)	Design Margin (%)
12	Pressurizer Surge Tank Compartment	22.5	6,200.	100.	412.5	212	14.696	0.573	NA		
13	Gallery between Steam Generators A and C	11.5	6,900.	200.	412.0	212	14.696	0.573	NA		
14	Steam Generator C Compartment below Elevation 459.5'	47.0	34,992.	859.	412.5	212	14.696	0.573	NA		
15	Steam Generator C Compartment above Elevation 459.5'	15.9	5,461.	315.	459.5	212	14.696	0.573	NA		
16	Containment	200.	1.74+6	1.3+4	412.0	212	14.696	0.545	NA		

(1) With respect to containment.
(2) Values to be multiplied by dynamic load factor of 1.1 for purposes of structural design.
(3) NA, not applicable.

Table 6.2-12a
16 Node Loop A Steam Generator Compartment Model
Cold Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area [2]	Inertia (ft^{-1})	Head Loss, K [1]							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
1	1	2	Inertial[2]	419.5	276.	0.05	0.01	-	-	0.04	0.05	-	0.04	0.05
2	1	3	Inertial	426.5	245.	0.05	0.01	-	-	-	0.01	-	-	0.01
3	2	4	HEM[3]	426.5	108.	0.11	0.01	-	-	0.30	0.31	-	0.47	0.48
4	2	5	Inertial	426.5	28.	0.42	0.01	-	-	-	0.01	-	-	0.01
5	1	4	HEM	426.5	150.	0.08	0.01	-	-	0.31	0.32	-	0.49	0.50
6	1	5	Inertial	426.5	109.	0.11	0.01	-	-	-	0.01	-	-	0.01
7	2	6	HEM	426.5	127.	0.12	0.02	-	-	0.28	0.30	-	0.39	0.41
8	2	7	HEM	426.5	31.	0.31	0.01	-	0.20	-	0.21	0.20	-	0.21
9	1	16	HEM	415.9	26.8	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
10	1	12	HEM	419.5	91.	0.04	-	1.20	1.00	0.33	2.53	0.44	0.50	2.14
11	1	13	HEM	419.5	79.	0.12	-	-	0.25	0.50	0.75	1.00	0.29	1.29
12	2	10	HEM	419.5	105.	0.18	0.03	0.30	1.00	0.50	1.83	1.00	0.50	1.83
13	10	16	HEM	419.5	107.	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
14	10	16	HEM	418.0	44.	0.36	0.06	3.60	1.00	0.50	5.16	1.00	0.50	5.16
15	10	16	HEM	459.5	157.	0.07	0.01	-	1.00	0.50	1.51	1.00	0.50	1.51
16	10	11	HEM	459.5	193.	0.07	0.01	-	0.13	0.52	0.66	0.13	0.52	0.66

Table 6.2-12a (continued)
16 Node Loop A Steam Generator Compartment Model
Cold Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area [2]	Inertia (ft^{-1})	Head Loss, K [1]							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
17	11	16	HEM	475.4	246.	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
18	5	7	HEM	431.25	50.	0.16	0.01	-	0.24	0.31	0.56	0.24	0.31	0.56
19	6	7	HEM	431.25	31.	0.30	0.01	-	1.70	0.25	1.96	1.70	0.31	2.02
20	6	4	HEM	431.25	75.	0.10	0.01	-	0.36	0.24	0.61	0.26	0.31	0.58
21	4	5	HEM	431.25	51.	0.28	0.01	-	0.42	0.31	0.74	0.29	0.46	0.76
22	3	5	HEM	431.25	49.	0.38	0.01	-	0.24	0.31	0.56	0.22	0.43	0.66
23	3	4	HEM	431.25	51.	0.14	0.01	-	0.28	0.29	0.58	0.24	0.41	0.66
24	6	10	HEM	431.25	70.	0.18	0.03	0.30	1.00	0.50	1.83	1.00	0.50	1.83
25	3	8	HEM	436.0	102.	0.09	0.01	-	0.22	0.20	0.43	0.20	0.22	0.43
26	4	8	HEM	436.0	160.	0.08	0.01	-	0.07	0.07	0.15	0.07	0.07	0.15
27	5	8	HEM	436.0	77.	0.12	0.01	-	0.23	0.21	0.45	0.21	0.23	0.45
28	6	8	HEM	436.0	118.	0.14	-	-	0.01	-	0.01	0.01	-	0.01
29	7	8	Inertial	436.0	28.	0.49	0.02	-	0.035	0.035	0.09	0.035	0.035	0.09
30	8	16	HEM	459.5	185.	0.06	0.01	-	1.00	0.50	1.51	0.50	1.00	1.51
31	8	9	HEM	459.5	160.	0.05	0.01	-	0.41	0.28	0.70	0.28	0.41	0.70
32	9	16	HEM	475.4	269.	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
33	12	13	HEM	417.5	108.	0.12	-	1.20	0.20	0.38	1.78	0.57	0.23	2.00

Table 6.2-12a (continued)
16 Node Loop A Steam Generator Compartment Model
Cold Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area [2]	Inertia (ft^{-1})	Head Loss, K [1]							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
34	13	14	HEM	417.8	162.	0.90	0.02	-	0.21	0.22	0.37	0.27	-	0.51
35	13	16	HEM	415.9	27.	0.75	-	0.80	0.71	0.19	1.70	0.71	0.19	1.70
36	13	16	HEM	420.0	33.	0.25	-	1.20	1.00	0.50	2.70	1.00	0.50	2.70
37	14	16	HEM	415.9	81.	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
38	14	16	HEM	418.0	54.	0.17	-	1.80	0.59	0.50	2.89	0.59	0.50	2.89
39	14	16	HEM	459.4	128.	0.05	-	-	1.00	0.50	1.50	1.00	0.50	1.50
40	14	15	HEM	459.5	225.	0.05	0.02	-	0.08	0.64	0.74	0.08	0.64	0.74
41	15	16	HEM	475.4	318.	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
42	0	4	Inertial	430.75	Fill syst.									
43	0	6	Inertial	430.75	Fill syst.									

(1) With respect to minimum flow area.
(2) No choking allowed.
(3) Homogeneous equilibrium model.

Table 6.2-12b
17 Node Loop A Steam Generator Compartment Model
Hot Leg Break, Volume Description

Control Volume No	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Clac. Peak Diff. press[1] (psi)	Design Diff. press [2] (psi)	Design Margin (%)
						Temp ($^{\circ}F$)	Pressure (psia)	Quality			
1	Lower 1/2 Compartment below Steam Generator	14.0	6,768.	615.	412.5	212	14.696	0.573	19.4	41.2	112
2	Lower 1/2 Compartment below Reactor Coolant Pump	14.0	4,641.	413.	412.5	212	14.696	0.573	19.4	41.2	112
3	Between Steam Generator and Secondary Shield Wall	9.5	1,044.	208.	426.5	212	14.696	0.573	19.5	41.2	111
4	Between Steam Generator, Reactor Coolant Pump and Primary Shield Wall	9.5	1,853.	374.	426.5	212	14.696	0.573	20.5	41.2	101
5	Between Steam Generator, Reactor Coolant Pump and Secondary Shield Wall	9.5	1,380.	332.	426.5	212	14.696	0.573	19.9	41.2	107
6	Between Reactor Coolant Pump, Cold Leg and Secondary Shield Wall	9.5	1,134.	314.	426.5	212	14.696	0.573	19.0	41.2	116
7	Between Reactor Coolant Pump and Secondary Shield Wall	9.5	314.	90.	426.5	212	14.696	0.573	19.5	41.2	111
8	Compartment above Elevation 436'	23.5	16,686.	758.	436.0	212	14.696	0.573	19.7	41.2	109
9	Around Steam Generator above Elevation 459.5'	15.9	4,826.	392.	459.5	212	14.696	0.573	4.7	16.9	260
10	Steam Generator B Compartment below Elevation 459.5'	47.0	34,094.	863.	412.5	212	14.696	0.573	NA[3]		

Table 6.2-12b (continued)
17 Node Loop A Steam Generator Compartment Model
Hot Leg Break, Volume Description

Control Volume No	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Clac. Peak Diff. press(1 (psi)	Design Diff. press (2) (psi)	Design Margin (%)
						Temp ($^{\circ}F$)	Pressure (psia)	Quality			
11	Steam Generator B Compartment above Elevation 459.5'	15.9	4,347.	413.	459.5	212	14.696	0.573	NA		
12	Pressurizer Surge Tank Compartment	22.5	6,200.	100.	412.5	212	14.696	0.573	NA		
13	Gallery between Steam Generators A and C	11.5	6,900.	200.	412.0	212	14.696	0.573	NA		
14	Steam Generator C Compartment below Elevation 459.5'	47.0	34,922.	859.	412.5	212	14.696	0.573	NA		
15	Steam Generator C Compartment above Elevation 459.5'	15.9	5,461.	315.	459.5	212	14.696	0.573	NA		
16	Containment	200.	1.74+7	1.3+4	412.0	212	14.696	0.573	NA		
17	Between Steam Generator Hot Leg and Primary Shield Wall	9.5	1,205.	218.	426.5	212	14.696	0.545	37.5	41.2	10

(1) With respect to containment.
(2) Values to be multiplied by dynamic load factor of 1.1 for purposes of structural design.
(3) NA, not applicable.

Table 6.2-12c
17 Node Loop A Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K [1]							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
1	1	2	Inertial [2]	419.5	276.	0.05	0.01	-	-	0.04	0.05	-	0.04	0.05
2	1	3	Inertial	426.5	114.	0.01	0.01	-	-	-	0.01	-	-	0.01
3	2	4	HEM [3]	426.5	108.	0.11	0.01	-	-	0.30	0.31	-	0.47	0.48
4	2	5	Inertial	426.5	28.	0.42	0.01	-	-	-	0.01	-	-	0.01
5	1	4	HEM	426.5	117.	0.10	0.01	-	-	0.34	0.35	-	0.59	0.60
6	1	5	Inertial	426.5	109.	0.11	0.01	-	-	-	0.01	-	-	0.01
7	2	6	HEM	426.5	127.	0.12	0.02	-	-	0.28	0.30	-	0.39	0.41
8	2	7	HEM	426.5	31.	0.31	0.01	-	0.20	-	0.21	0.20	-	0.21
9	1	16	HEM	415.9	27.	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
10	1	12	HEM	419.5	91.	0.04	-	1.20	1.00	0.33	2.53	0.44	0.50	2.14
11	1	13	HEM	419.5	79.	0.12	-	-	0.25	0.50	0.75	1.00	0.29	1.29
12	2	10	HEM	419.5	105.	0.18	0.03	0.30	1.00	0.50	1.83	1.00	0.50	1.83
13	10	16	HEM	415.9	107.	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
14	10	16	HEM	418.0	44.	0.36	0.06	3.60	1.00	0.50	5.16	1.00	0.50	5.16
15	10	16	HEM	459.5	157.	0.07	0.01	-	1.00	0.50	1.51	1.00	0.50	1.51
16	10	11	HEM	459.5	193.	0.07	0.01	-	0.13	0.52	0.66	0.13	0.52	0.66

Table 6.2-12c (continued)
17 Node Loop A Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K (1)							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
17	11	16	HEM	457.4	246.	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
18	5	7	HEM	431.25	50.	0.16	0.01	-	0.24	0.31	0.56	0.24	0.31	0.56
19	6	7	HEM	431.25	31.	0.30	0.01	-	1.70	0.25	1.96	1.70	0.31	2.02
20	6	4	HEM	431.25	75.	0.10	0.01	-	0.36	0.24	0.61	0.26	0.31	0.58
21	4	5	HEM	431.25	51.	0.28	0.01	-	0.43	0.27	0.71	0.29	0.38	0.68
22	3	5	HEM	431.25	54.	0.28	0.01	-	0.28	0.14	0.43	0.22	0.14	0.37
23	4	17	HEM	431.25	51.	0.19	0.01	-	0.30	0.28	0.59	0.24	0.40	0.65
24	6	10	HEM	432.25	70.	0.18	0.03	0.30	1.00	0.50	1.83	1.00	0.50	1.83
25	3	8	HEM	436.0	66.	0.17	0.01	-	0.13	0.12	0.26	0.12	0.13	0.26
26	4	8	HEM	436.0	159.	0.09	0.01	-	0.04	0.04	0.09	0.04	0.04	0.09
27	5	8	HEM	436.0	77.	0.12	0.01	-	0.23	0.21	0.45	0.21	0.23	0.45
28	6	8	HEM	436.0	118.	0.14	0.01	-	0.01	-	0.02	0.01	-	0.02
29	7	8	Inertial	436.0	28.	0.49	0.02	-	0.035	0.035	0.09	0.035	0.035	0.09
30	8	16	HEM	459.5	185.	0.06	0.01	-	1.00	0.50	1.51	0.50	1.00	1.51
31	8	9	HEM	459.5	160.	0.05	0.01	-	0.41	0.28	0.70	0.28	0.41	0.70
32	9	16	HEM	475.4	269.	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
33	12	13	HEM	417.5	108.	0.12	-	1.20	0.20	0.38	1.78	0.57	0.23	2.00

Table 6.2-12c (continued)
17 Node Loop A Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K (1)							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
34	13	14	HEM	417.8	162.	0.10	0.02	-	0.21	0.22	0.45	0.27	-	0.29
35	13	16	HEM	415.9	27.	0.75	-	0.80	0.71	0.19	1.70	0.71	0.19	1.70
36	13	16	HEM	420.0	33.	0.25	-	1.20	1.00	0.50	2.70	1.00	0.50	2.70
37	14	16	HEM	415.9	81.	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
38	14	16	HEM	418.0	54.	0.17	-	1.80	0.59	0.50	2.89	0.59	0.50	2.89
39	14	16	HEM	459.4	128.	0.05	-	-	1.00	0.50	1.50	1.00	0.50	1.50
40	14	15	HEM	459.5	225.5	0.05	0.02	-	0.08	0.64	0.74	0.08	0.64	0.74
41	15	16	HEM	475.4	318.	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
42	3	17	HEM	431.25	54.	0.21	0.01	-	0.19	0.19	0.39	0.19	0.19	0.39
43	17	8	HEM	436.0	51.	0.14	0.01	-	0.19	0.13	0.33	0.23	0.33	0.57
44	1	17	HEM	426.5	159.	0.08	0.01	-	-	-	0.01	-	-	0.01
45	0	4	Inertial	430.75	Fill syst.									
46	0	17	Inertial	430.75	Fill syst.									

(1) With respect to minimum flow area.
(2) No choking allowed.
(3) Homogeneous equilibrium model.

Table 6.2-13
12 Node Loop B Steam Generator Compartment Model
Cold Leg Break, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press (1) (psi)	Design Diff. Press (2) (psi)	Design Margin (%)
						Temp. (°F)	Pressure (psia)	Quality			
1	Lower 1/2 Compartment below Reactor Coolant Pump	14.0	3,869.	364.	412.5	212	14.696	0.573	22.8	41.2	81
2	Lower 1/2 Compartment below Steam Generator	14.0	6.708.	510.	412.5	212	14.696	0.573	22.8	41.2	81
3	Between Reactor Coolant Pump and Secondary Shield Wall	9.5	369.	132.	426.5	212	14.696	0.573	22.9	41.2	80
4	Between Reactor Coolant Pump, Cold Leg and Secondary Shield Wall	9.5	1,003.	332.	426.5	212	14.696	0.573	40.0	41.2	3
5	Between Reactor Coolant Pump, Steam Generator and Primary Shield Wall	9.5	1,722.	744.	426.5	212	14.696	0.573	23.4	41.2	76
6	Between Reactor Coolant Pump, Steam Generator and Secondary Shield Wall	9.5	1,430.	371.	426.5	212	14.696	0.573	22.8	41.2	81
7	Between Steam Generator and Secondary Shield Wall	9.5	2,326.	460.	426.5	212	14.696	0.573	22.7	41.2	81
8	Compartment above Elevation 436’	23.5	16,663.	863.	436.0	212	14.696	0.573	22.5	41.2	83
9	Around Steam Generator above Elevation 459.5’	15.9	4,347.	413.	459.5	212	14.696	0.573	11.5	16.9	47
10	Steam Generator A Compartment below Elevation 459.5’	47.0	35,254.	858.	412.5	212	14.696	0.573	NA (3)		

Table 6.2-13 (continued)
12 Node Loop B Steam Generator Compartment Model
Cold Leg Break, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press (1) (psi)	Design Diff. Press (2) (psi)	Design Margin (%)
						Temp. (°F)	Pressure (psia)	Quality			
11	Steam Generator A Compartment above Elevation 459.5’	15.9	4,826.	458.	459.5	212	14.696	0.573	NA		
12	Containment	200.	1,84+6	1.3+4	412.0	212	14.696	0.545	NA		

(1) With respect to containment.
(2) Values to be multiplied by dynamic load factor of 1.1 for purposes of structural design.
(3) NA - not applicable.

Table 6.2-13a
12 Node Loop B Steam Generator Compartment Model
Cold Leg Break, Flow Path Data

									Head Loss, K [1]					
									Forward Flow			Reverse Flow		
Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
1	1	2	Inertial [2]	419.5	235.8	0.05	0.01	-	0.02	0.02	0.05	0.02	0.02	0.05
2	1	3	HEM [3]	426.5	28.4	0.31	0.01	-	-	0.41	0.42	0.81	-	0.82
3	1	4	HEM	426.5	47.7	0.17	0.01	-	-	0.36	0.37	0.69	-	0.70
4	1	5	HEM	426.5	99.6	0.10	0.01	-	0.02	0.28	0.31	0.40	0.02	0.43
5	1	6	HEM	426.5	22.7	0.27	0.01	-	0.19	0.23	0.43	0.21	0.21	0.43
6	1	12	HEM	415.9	40.2	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
7	1	12	HEM	418.0	43.9	0.36	0.06	3.6	1.0	0.5	5.16	1.0	0.5	5.16
8	2	5	Inertial	426.5	83.6	0.14	0.01	-	-	-	0.01	-	-	0.01
9	2	6	Inertial	426.5	90.8	0.11	0.01	-	-	0.06	0.07	-	0.06	0.07
10	2	7	Inertial	426.5	277.8	0.04	0.01	-	-	-	0.01	-	-	0.01
11	2	10	HEM	419.5	104.5	0.18	0.03	0.30	1.0	0.5	1.83	1.0	0.5	1.83
12	2	12	HEM	415.9	67.0	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
13	3	4	HEM	431.25	30.9	0.33	0.01	-	0.30	0.24	0.55	0.30	0.24	0.55
14	3	6	HEM	431.25	58.3	0.17	0.01	-	0.15	-	0.16	-	0.15	0.16
15	3	8	HEM	436.0	32.0	0.39	0.01	-	0.05	0.05	0.11	0.05	0.05	0.11
16	4	5	HEM	431.25	61.1	0.17	0.01	-	0.33	0.25	0.59	0.33	0.25	0.59

Table 6.2-13a (continued)
12 Node Loop B Steam Generator Compartment Model
Cold Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction fL/D	Bends	Head Loss, K (1)					
									Forward Flow			Reverse Flow		
									Expansion	Contraction	Total	Expansion	Contraction	Total
17	4	8	HEM	436.0	101.7	0.14	0.01	-	0.02	0.02	0.05	0.02	0.02	0.05
18	5	6	HEM	431.25	50.4	0.19	0.01	-	0.28	0.23	0.52	0.28	0.23	0.52
19	5	7	HEM	431.25	119.1	0.09	0.01	-	0.09	0.09	0.19	0.09	0.09	0.19
20	5	8	HEM	436.0	134.2	0.09	0.01	-	0.06	0.12	0.19	0.12	0.06	0.19
21	6	7	HEM	431.25	79.8	0.16	0.01	-	0.08	0.08	0.17	0.08	0.08	0.17
22	6	8	HEM	436.0	80.0	0.14	0.01	-	0.12	0.19	0.32	0.91	0.12	0.32
23	7	8	HEM	436.0	181.3	0.08	0.01	-	0.03	0.12	0.16	0.3	0.12	0.16
24	7	10	HEM	431.25	70.2	0.18	0.03	0.3	1.00	0.5	1.83	1.00	0.5	1.83
25	8	9	HEM	459.5	193.0	0.07	0.01	-	0.13	0.52	0.66	0.13	0.52	0.66
26	8	12	HEM	459.5	157.0	0.07	0.01	-	1.00	0.5	1.51	1.00	0.5	1.51
27	9	12	HEM	475.4	245.9	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
28	10	11	HEM	459.5	160.2	0.07	0.01	-	0.13	0.52	0.66	0.13	0.52	0.66
29	10	12	HEM	415.9	26.8	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
30	10	12	HEM	459.5	184.6	0.07	0.01	-	1.00	0.5	1.51	1.00	0.5	1.51
31	11	12	HEM	475.4	269.1	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
32	0	4	NA (4)	430.75	Fill syst.									
33	0	5	NA	430.75	Fill syst.									

Table 6.2-13a (continued)
12 Node Loop B Steam Generator Compartment Model
Cold Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction fL/D	Bends	Head Loss, K (1)					
									Forward Flow			Reverse Flow		
									Expansion	Contraction	Total	Expansion	Contraction	Total

(1) With respect to minimum flow area.
(2) No choking allowed.
(3) Homogeneous equilibrium model.
(4) NA, not applicable.

Table 6.2-13b
13 Node Loop B Steam Generator Compartment Model
Hot Leg Break, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press [1] (psi)	Design Diff. Press [2] (psi)	Design Margin (%)
						Temp. (°F)	Pressure (psia)	Quality			
1	Lower 1/2 Compartment below Reactor Coolant Pump	14.0	3,869.	364.	412.5	212	14.696	0.573	19.9	41.2	107
2	Lower 1/2 Compartment below Steam Generator	14.0	6.708.	510.	412.5	212	14.696	0.573	19.9	41.2	107
3	Between Reactor Coolant Pump and Secondary Shield Wall	9.5	369.	132.	426.5	212	14.696	0.573	20.3	41.2	103
4	Between Reactor Coolant Pump, Cold Leg and Secondary Shield Wall	9.5	1,003.	332.	426.5	212	14.696	0.573	20.1	41.2	105
5	Between Reactor Coolant Pump, Steam Generator and Primary Shield Wall	9.5	1,722.	744.	426.5	212	14.696	0.573	26.6	41.2	55
6	Between Reactor Coolant Pump, Steam Generator and Secondary Shield Wall	9.5	1,430.	371.	426.5	212	14.696	0.573	20.3	41.2	103
7	Between Steam Generator, Hot Leg and Secondary Shield Wall	9.5	1,326.	276.	426.5	212	14.696	0.573	26.0	41.2	58
8	Compartment above Elevation 436’	23.5	16,663.	863.	436.0	212	14.696	0.573	20.2	41.2	104

Table 6.2-13b (continued)
13 Node Loop B Steam Generator Compartment Model
Hot Leg Break, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press (1) (psi)	Design Diff. Press (2) (psi)	Design Margin (%)
						Temp. (°F)	Pressure (psia)	Quality			
9	Around Steam Generator above Elevation 459.5’	15.9	4,347.	413.	459.5	212	14.696	0.573	9.6	16.9	76
10	Steam Generator A Compartment below Elevation 459.5’	47.0	32,254.	858.	412.5	212	14.696	0.573	NA (3)		
11	Steam Generator A Compartment above Elevation 459.5’	15.9	4,826.	458.	459.5	212	14.696	0.573	NA		
12	Containment	200.	1,74+6	1.3+4	412.0	212	14.696	0.545	NA		
13	Between Steam Generator and Secondary Shield Wall	9.5	930.	184.	426.5	212	14.696	0.573	20.1	41.2	105

(1) With respect to containment.
(2) Values to be multiplied by dynamic load factor of 1.1 for purposes of structural design.
(3) NA - not applicable.

Table 6.2-13c
13 Node Loop B Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction fL/D	Bends	Head Loss, K [1] Forward Flow Expansion	Forward Flow Contraction	Forward Flow Total	Reverse Flow Expansion	Reverse Flow Contraction	Reverse Flow Total
1	1	2	Inertial[2]	419.5	235.8	0.05	0.01	-	0.02	0.02	0.05	0.02	0.02	0.05
2	1	3	HEM[3]	426.5	28.4	0.31	0.01	-	-	0.41	0.42	0.81	-	0.82
3	1	4	HEM	426.5	47.7	0.17	0.01	-	-	0.36	0.37	0.69	-	0.70
4	1	5	HEM	426.5	99.6	0.10	0.01	-	0.02	0.28	0.31	0.42	0.02	0.43
5	1	6	HEM	426.5	22.7	0.27	0.01	-	0.19	0.23	0.43	0.21	0.21	0.43
6	1	12	HEM	415.9	40.2	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
7	1	12	HEM	418.0	43.9	0.36	0.06	3.6	1.0	0.5	5.16	1.0	0.5	5.16
8	2	5	HEM	426.5	83.6	0.14	0.01	-	-	0.37	0.38	0.69	-	0.70
9	2	6	HEM	426.5	90.8	0.11	0.01	-	0.06	0.36	0.43	0.67	0.06	0.74
10	2	7	HEM	426.5	166.7	0.04	0.01	-	-	0.18	0.19	0.18	-	0.19
11	2	10	HEM	419.5	104.5	0.18	0.03	0.3	1.0	0.5	1.83	1.0	0.5	1.83
12	2	12	HEM	415.9	67.0	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
13	3	4	HEM	431.25	30.9	0.33	0.01	-	0.30	0.24	0.55	0.30	0.24	0.55
14	3	6	HEM	431.25	58.3	0.17	0.01	-	0.15	-	0.16	-	0.15	0.16
15	3	8	HEM	436.0	32.0	0.39	0.01	-	0.05	0.05	0.11	0.05	0.05	0.11
16	4	5	HEM	431.25	61.1	0.17	0.01	-	0.33	0.25	0.59	0.33	0.25	0.59

Table 6.2-13c (continued)
13 Node Loop B Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction fL/D	Bends	Head Loss, K (1)					
									Forward Flow			Reverse Flow		
									Expansion	Contraction	Total	Expansion	Contraction	Total
17	4	8	HEM	436.0	101.7	0.14	0.01	-	0.02	0.02	0.05	0.02	0.02	0.05
18	5	6	HEM	431.25	50.4	0.19	0.01	-	0.28	0.23	0.52	0.28	0.23	0.52
19	5	7	HEM	431.25	119.1	0.09	0.01	-	0.09	0.09	0.19	0.09	0.09	0.19
20	5	8	HEM	436.0	134.2	0.09	0.01	-	0.06	0.12	0.19	0.12	0.06	0.19
21	6	13	HEM	431.25	79.8	0.16	0.01	-	0.08	0.08	0.17	0.08	0.08	0.17
22	6	8	HEM	436.0	80.0	0.14	0.01	-	0.12	0.19	0.32	0.19	0.12	0.32
23	7	8	HEM	436.0	108.8	0.15	0.01	-	0.03	0.12	0.16	0.03	0.12	0.16
24	7	10	HEM	431.25	70.2	0.18	0.03	0.30	1.00	0.5	1.83	1.00	0.5	1.83
25	8	9	HEM	459.5	193.0	0.07	0.01	-	0.13	0.52	0.66	0.13	0.52	0.66
26	8	12	HEM	459.5	157.0	0.07	0.01	-	1.00	0.5	1.51	1.00	0.5	1.51
27	9	12	HEM	475.4	245.9	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
28	10	11	HEM	459.5	160.2	0.07	0.01	-	0.13	0.52	0.66	0.13	0.52	0.66
29	10	12	HEM	415.9	26.8	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
30	10	12	HEM	459.5	184.6	0.07	0.01	-	1.00	0.50	1.51	1.00	0.5	1.51
31	11	12	HEM	475.4	269.1	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
32	2	13	HEM	426.5	111.1	0.04	0.01	-	-	0.18	0.19	0.18	-	0.19
33	07	13	HEM	431.25	77.6	0.19	0.01	-	-	0.09	0.10	0.09	-	0.10

Table 6.2-13c (continued)
13 Node Loop B Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction fL/D	Bends	Head Loss, K (1)					
									Forward Flow			Reverse Flow		
									Expansion	Contraction	Total	Expansion	Contraction	Total
34	8	13	HEM	436.0	72.5	0.23	0.01	-	0.03	0.12	0.16	0.03	0.12	0.16
35	0	5	NA (4)	Fill syst.										
36	0	7	NA	Fill syst.										

(1) With respect to minimum flow area.
(2) No choking allowed.
(3) Homogeneous equilibrium model.
(4) NA, not applicable.

Table 6.2-14
14 Node Loop C Steam Generator Compartment Model
Hot and Cold Leg Breaks, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Flow Area (ft^2)	Volume Elevation (ft)	Bottom Temp. (°F)	Pressure (psia)	Quality	Calc. Peak Diff. Press.[1] Cold Leg (psi)	Calc. Peak Diff. Press.[1] Hot Leg (psi)	Design Press [2] (psi)	Design Margin (%)
1	Lower 1/2 Compartment below Reactor Coolant Pump	14.0	5,519.	442.	412.5	212	14.696	0.573	23.2	20.2	41.2	78
2	Lower 1/2 Compartment below Steam Generator	14.0	6,232.	462.	412.5	212	14.696	0.573	23.3	20.2	41.2	77
3	Between Reactor Coolant Pump, primary Shield and Steam Generator	9.5	1,528.	586.	426.5	212	14.696	0.573	26.3	26.3	41.2	57
4	Between Cold Leg, Reactor Coolant Pump and Secondary Shield	9.5	609.	203.	426.5	212	14.696	0.573	47.9	20.1	41.2	-14[4]
5	Between Reactor Coolant Pump, Steam Generator and Secondary Shield	9.5	2,640.	300.	426.5	212	14.696	0.573	23.2	20.1	41.2	78
6	Between Steam Generator and Secondary Shield	9.5	1,022.	163.	426.5	212	14.696	0.573	23.3	20.2	41.2	77
7	Between Steam Generator, Hot Leg and Secondary Shield Wall	9.5	864.	158.	426.5	212	14.696	0.573	23.4	43.4	41.2	-5[4]

Table 6.2-14 (continued)
14 Node Loop C Steam Generator Compartment Model
Hot and Cold Leg Breaks, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Flow Area (ft^2)	Volume Elevation (ft)	Bottom Temp. (°F)	Pressure (psia)	Quality	Calc. Peak Diff. Press.(1) Cold Leg (psi)	Calc. Peak Diff. Press.(1) Hot Leg (psi)	Design Press (2) (psi)	Design Margin (%)
8	Compartment above Elevation 436’	23.5	16,470.	730.	436.0	212	14.696	0.573	22.9	20.4	41.2	80
9	Around Steam Generator above Elevation 459.5’	15.9	5,461.	315.	459.5	212	14.696	0.573	6.4	6.0	16.9	164
10	Gallery between Loops A and C	11.5	6,900.	200.	412.0	212	14.696	0.573	8.9	7.5	41.2	363
11	Pressurizer Relief Tank Compartment	22.5	6,200.	100.	412.5	212	14.696	0.573	NA (3)			
12	Steam Generator A Compartment below Elevation 459.5'	47.0	35,254.	858.	412.5	212	14.696	0.573	NA			
13	Steam Generator A Compartment above Elevation 459.5'	15.9	4,826.	260.	459.5	212	14.696	0.573	NA			
14	Containment	200.	1.74+6	12,500.	412.0	212	14.696	0.573	NA			

(1) With respect to containment.
(2) Values to be multiplied by dynamic load factor of 1.1 for purposes of structural design.
(3) NA - not applicable.
(4) For discussion of results, see Section 6.2.1.3.9.2.3.

Table 6.2-14a
14 Node Loop C Steam Generator Compartment Model
Hot and Cold Leg Breaks, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction fL/D	Bends	Head Loss, K [1]					
									Forward Flow			Reverse Flow		
									Expansion	Contraction	Total	Expansion	Contraction	Total
1	1	2	Inertial[2]	419.5	304.00	0.05	0.01	-	-	-	0.01	-	-	0.01
2	1	10	HEM [3]	417.8	161.8	0.09	0.02	-	0.21	0.22	0.45	0.27	-	0.29
3	1	14	HEM	415.9	26.8	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
4	2	14	HEM	415.9	53.6	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
5	2	14	HEM	418.0	53.8	0.17	-	1.8	0.59	0.5	2.89	0.59	0.5	2.89
6	3	1	HEM	426.5	63.0	0.08	0.01	-	0.72	-	0.73	-	0.06	0.07
7	3	2	HEM	426.5	116.4	0.05	0.01	-	0.56	-	0.57	-	0.37	0.38
8	3	4	HEM	431.25	44.3	0.28	0.02	-	1.86	1.13	3.01	0.41	-	0.43
9	3	5	HEM	431.25	54.8	0.25	0.02	-	0.50	0.28	0.8	0.33	0.33	0.68
10	3	7	HEM	431.25	74.8	0.14	0.03	-	0.04	0.20	0.27	0.15	0.11	0.29
11	3	8	HEM	436.0	108.8	0.06	0.01	-	0.09	0.19	0.29	0.01	0.15	0.17
12	4	1	HEM	426.5	64.4	0.08	0.02	-	0.71	-	0.73	0.10	-	0.11
13	4	5	HEM	431.25	40.0	0.20	0.02	-	0.22	0.24	0.48	0.22	0.24	0.48
14	4	8	HEM	436.0	60.5	0.12	0.02	-	-	0.03	0.05	-	0.03	0.05
15	5	1	HEM	426.5	144.4	0.03	0.01	-	0.12	0.15	0.28	0.09	0.17	0.27
16	5	5	HEM	426.5	80.7	0.03	0.02	-	0.06	0.12	0.20	0.06	0.12	0.20
17	5	6	HEM	431.25	81.0	0.15	0.03	-	-	0.23	0.26	0.21	-	0.24
18	5	8	HEM	436.0	209.6	0.04	0.01	-	0.06	0.12	0.19	0.06	0.12	0.19
19	6	2	Inertial	426.5	119.2	0.05	0.01	-	-	-	0.01	-	-	0.01

Table 6.2-14a (continued)
14 Node Loop C Steam Generator Compartment Model
Hot and Cold Leg Breaks, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction fL/D	Bends	Head Loss, K [1]					
									Forward Flow			Reverse Flow		
									Expansion	Contraction	Total	Expansion	Contraction	Total
20	6	7	HEM	431.25	71.6	0.16	0.02	-	0.0	0.18	0.20	0.13	0.03	0.18
21	6	8	HEM	436.0	53.7	0.09	0.01	-	0.19	0.25	0.45	0.05	0.21	0.27
22	7	2	HEM	426.5	110.8	0.12	0.02	-	0.58	-	0.60	-	-	0.02
23	7	8	HEM	436.0	59.0	0.10	0.02	-	0.05	0.11	0.18	0.05	0.11	0.18
24	8	9	HEM	459.5	225.5	0.05	0.02	-	0.08	0.64	0.74	0.08	0.64	0.74
25	8	14	HEM	459.5	128.4	0.05	-	-	1.00	0.50	1.50	1.00	0.50	1.50
26	9	14	HEM	475.4	317.6	0.02	0.01	-	1.00	-	1.01	1.00	-	1.01
27	10	11	HEM	417.5	107.7	0.12	-	1.2	0.57	0.23	2.0	0.20	0.38	1.78
28	11	12	HEM	419.5	90.9	0.04	-	1.2	1.00	0.33	2.53	0.44	0.50	2.14
29	10	14	HEM	415.9	26.8	0.75	-	0.80	0.71	0.19	1.7	0.71	0.19	1.7
30	10	14	HEM	420.0	33.0	0.24	-	1.2	1.00	0.50	2.7	1.00	0.50	2.7
31	10	12	HEM	419.5	78.8	0.12	-	-	1.00	0.29	1.29	0.25	0.50	0.75
32	12	13	HEM	459.5	160.2	0.12	0.02	-	0.16	0.70	0.88	0.16	0.70	0.88
33	12	14	HEM	423.2	178.7	0.11	-	-	1.00	0.50	1.50	1.00	0.50	1.50
34	12	14	HEM	415.9	26.8	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
35	12	14	HEM	459.5	184.6	0.04	-	-	1.00	0.38	1.38	1.00	0.38	1.38
36	13	14	HEM	475.4	269.1	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
37	0	3	NA [4]	430.75	0.5	Fill system; hot and cold leg breaks								
38	0	4	NA	430.75	0.5	Fill system; cold leg break								
39	0	7	NA	430.75	0.5	Fill system; hot leg break								

Table 6.2-14a (continued)
14 Node Loop C Steam Generator Compartment Model
Hot and Cold Leg Breaks, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Friction fL/D	Bends	Head Loss, K (1)					
									Forward Flow			Reverse Flow		
									Expansion	Contraction	Total	Expansion	Contraction	Total

(1) With respect to minimum flow area.
(2) No choking allowed.
(3) Homogeneous equilibrium model.
(4) NA, not applicable.

Table 6.2-15
Summary of Loop C Generator Compartment Models

Model	Model Arrangement Figure No.	Model Description/Results Listed in Table No.	Results Illustrated by Fig. No.	Forces and Moments Data	
				Fig. No.	Table No.
20 Node Model, Loop C Steam Generator Compartment, Cold Leg Break, Reactor Coolant Pump Loading	6.2-23	6.2-15a 6.2-15b	6.2-23a 6.2-23b 6.2-23c	6.2-24	6.2-15c
25 Node Model, Loop C Steam Generator Compartment, Hot Leg Break, Steam Generator Loading	6.2-25	6.2-15d 6.2-15e	6.2-25a 6.2-25b 6.2-25c	6.2-26	6.2-15f

Table 6.2-15a
20 Node Loop C Steam Generator Compartment Model
Cold Leg Break, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press.[1] (psi)	Design Diff. Press [2] (psi)	Design Margin (psi)
						Temp. (°F)	Pressure (psia)	Quality			
1	Lower 1/2 Compartment below Reactor Coolant Pump	14.0	5,519.	442.	412.5	212	14.696	0.573	23.0	41.2	79
2	Lower 1/2 Compartment below Steam Generator	14.0	6,232.	462.	412.5	212	14.696	0.573	23.0	41.2	79
3	Between Reactor Coolant Pump, Primary Shield and Steam Generator	9.5	1,528.	586.	426.5	212	14.696	0.573	26.5	41.2	55
4	Between Cold Legs, Reactor Coolant Pump and Secondary Shield	9.5	609.	203.	426.5	212	14.696	0.573	47.9	41.2	-14[4]
5	Between Reactor Coolant Pump, Steam Generator and Secondary Shield	9.5	2,640.	300.	426.5	212	14.696	0.573	23.0	41.2	79
6	Between Steam Generator and Secondary Shield	9.5	1,022.	163.	426.5	212	14.696	0.573	23.1	41.2	78
7	Between Steam Generator, Hot Leg and Secondary Shield	9.5	864.	158.	426.5	212	14.696	0.573	23.2	41.2	78
8	Between Reactor Coolant Pump, Steam Generator and Primary Shield above Elevation 436’	15.0	2,300.	277.	436.0	212	14.696	0.573	22.8	41.2	81
9	Around Steam Generator above Elevation 459.5’	15.9	5,461.	315.	459.5	212	14.696	0.573	6.4	16.9	164
10	Gallery between Loops A and C	11.5	6,900.	200.	412.0	212	14.696	0.573	8.9	41.2	463
11	Pressurizer Relief Tank Compartment	22.5	6,200.	100.	412.5	212	14.696	0.573	NA [3]		

Table 6.2-15a (continued)
20 Node Loop C Steam Generator Compartment Model
Cold Leg Break, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions: Temp. (°F)	Initial Conditions: Pressure (psia)	Initial Conditions: Quality	Calc. Peak Diff. Press.(1) (psi)	Design Diff. Press (2) (psi)	Design Margin (psi)
12	Steam Generator A Compartment below Elevation 459.5'	47.0	35,254.	858.	412.5	212	14.696	0.573	NA		
13	Steam Generator A Compartment above Elevation 459.5'	15.9	4,826.	260.	459.5	212	14.696	0.573	NA		
14	Containment	200.	1.74+6	12,500.	412.0	212	14.696	0.573	NA		
15	Between Reactor Coolant Pump and Secondary Shield above Elevation 436’	15.	966.	126.	436.0	212	14.696	0.573	22.8	41.2	81
16	Between Reactor Coolant Pump, Steam Generator and Secondary Shield above Elevation 436’	15.	4,161.	382.	436.0	212	14.696	0.573	22.8	41.2	81
17	Between Steam Generator and Secondary Shield above Elevation 436’	15.	1,431.	191.	436.0	212	14.696	0.573	22.8	41.2	81
18	Between Steam Generator and Primary Shield above Elevation 436’	15.	1,144.	176.	436.0	212	14.696	0.573	22.8	41.2	81
19	Between Steam Generator and Secondary Shield above Elevation 451’	8.5	1,457.	237.	451.0	212	14.696	0.573	22.8	41.2	81
20	Above Reactor Coolant Pump	8.5	4,208.		451.0	212	14.696	0.573	22.8	41.2	81

(1) With respect to containment.
(2) Values to be multiplied by dynamic load factor of 1.1 for purposes of structural design.
(3) NA - not applicable.
(4) For discussion of results, see Section 6.2.1.3.9.2.3.

Table 6.2-15b
20 Node Loop C Steam Generator Compartment Model
Cold Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K [1]							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
1	1	2	Inertial [2]	419.5	304.0	0.05	0.01	-	-	-	0.01	-	-	0.01
2	1	10	HEM [3]	417.8	161.8	0.09	0.02	-	0.21	0.22	0.45	0.27	-	0.29
3	1	14	HEM	415.9	26.8	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
4	2	14	HEM	415.9	53.6	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
5	2	14	HEM	418.0	53.8	0.17	-	1.8	0.59	0.50	2.89	0.59	0.50	2.89
6	3	1	HEM	426.5	63.0	0.08	0.01	-	0.72	-	0.73	-	0.06	0.07
7	3	2	HEM	426.5	116.4	0.05	0.01	-	0.56	-	0.57	-	0.37	0.38
8	3	4	HEM	431.25	44.3	0.28	0.02	-	1.86	1.13	3.01	0.41	-	0.43
9	3	5	HEM	431.25	54.8	0.25	0.02	-	0.50	0.28	0.80	0.33	0.33	0.68
10	3	7	HEM	431.25	74.8	0.14	0.03	-	0.04	0.20	0.27	0.15	0.11	0.29
11	3	8	HEM	436.0	108.8	0.07	0.02	-	0.08	0.19	0.29	0.14	0.01	0.17
12	4	1	HEM	426.5	64.4	0.08	0.02	-	0.71	-	0.73	0.10	-	0.12
13	4	5	HEM	431.25	40.0	0.20	0.02	-	0.22	0.24	0.48	0.22	0.24	0.48
14	4	15	HEM	436.0	60.5	0.16	0.02	-	-	0.03	0.05	-	0.03	0.05
15	5	1	HEM	426.5	144.4	0.03	0.01	-	0.12	0.15	0.28	0.09	0.17	0.27
16	5	2	HEM	426.5	80.7	0.15	0.02	-	0.06	0.12	0.20	0.06	0.12	0.20
17	5	6	HEM	431.25	81.0	0.04	0.03	-	-	0.23	0.26	0.22	-	0.25
18	5	16	HEM	436.0	209.6	0.04	0.01	-	0.06	0.12	0.19	0.06	0.12	0.19
19	6	2	Inertial	426.5	119.2	0.05	0.01	-	-	-	0.01	-	-	0.01

Table 6.2-15b (continued)
20 Node Loop C Steam Generator Compartment Model
Cold Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K [1]							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
20	6	7	HEM	431.25	71.6	0.16	0.02	-	-	0.18	0.20	0.13	0.03	0.18
21	6	17	HEM	436.0	53.7	0.11	0.01	-	0.19	0.25	0.45	0.05	0.21	0.27
22	7	2	HEM	426.5	110.8	0.12	0.02	-	0.58	-	0.60	-	-	0.02
23	7	18	HEM	436.0	59.0	0.14	0.02	-	0.05	0.11	0.18	0.05	0.11	0.18
24	19	9	HEM	459.5	140.8	0.07	0.02	-	0.32	0.09	0.43	0.32	0.09	0.43
25	20	14	HEM	459.5	128.4	0.04	0.01	-	1.00	0.37	1.50	1.00	0.37	1.50
26	9	14	HEM	475.4	317.6	0.02	0.01	-	1.00	-	1.01	1.00	-	1.01
27	10	11	HEM	417.5	107.7	0.12	-	1.2	0.57	0.23	2.0	0.20	0.38	1.78
28	11	12	HEM	419.5	90.9	0.04	-	1.2	1.00	0.33	2.53	0.44	0.50	2.14
29	10	14	HEM	415.9	26.8	0.75	-	0.8	0.71	0.19	1.7	0.71	0.19	1.7
30	10	14	HEM	420.0	33.0	0.24	-	1.2	1.00	0.50	2.7	1.00	0.50	2.7
31	10	12	HEM	419.5	78.8	0.12	-	-	1.00	0.29	1.29	0.25	0.50	0.75
32	12	13	HEM	459.5	160.2	0.12	0.02	-	0.16	0.70	0.88	0.16	0.70	0.88
33	12	14	HEM	423.2	178.7	0.11	-	-	1.00	0.50	1.50	1.00	0.50	1.50
34	12	14	HEM	415.9	26.8	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
35	12	14	HEM	459.5	184.6	0.04	-	-	1.00	0.38	1.38	1.00	0.38	1.38
36	13	14	HEM	475.4	269.1	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
37	8	15	HEM	443.5	45.0	0.16	-	-	0.25	0.30	0.55	0.41	0.25	0.66
38	8	16	HEM	443.5	112.5	0.15	0.01	-	0.39	0.21	0.61	0.18	0.31	0.50
39	8	18	HEM	443.5	135.0	0.08	0.02	-	0.01	0.15	0.18	0.09	0.05	0.16

Table 6.2-15b (continued)
20 Node Loop C Steam Generator Compartment Model
Cold Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K (1)							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
40	8	20	Inertial	451.0	153.3	0.08	0.02	-	-	-	0.02	-	-	0.02
41	15	16	HEM	443.5	82.5	0.13	0.01	-	0.10	0.16	0.27	0.10	0.16	0.27
42	15	20	Inertial	451.0	64.4	0.17	0.02	-	0.04	-	0.06	0.04	-	0.06
43	16	17	HEM	443.5	150.0	0.18	0.02	-	-	0.19	0.21	0.14	-	0.16
44	16	20	Inertial	451.0	209.6	0.06	0.02	-	0.0	-	0.02	-	-	0.02
45	17	18	HEM	443.5	82.5	0.11	0.02	-	0.10	0.27	0.39	0.29	0.16	0.47
46	17	19	Inertial	451.0	95.4	0.10	0.02	-	-	-	0.02	-	-	0.02
47	18	19	Inertial	451.0	76.0	0.13	0.02	-	-	-	0.02	-	-	0.02
48	19	20	HEM	455.2	85.0	0.11	0.02	-	0.14	-	0.16	-	0.19	0.21
49	19	20	HEM	455.2	76.5	0.14	0.02	-	0.19	-	0.21	-	0.21	0.23
50	20	9	HEM	459.5	84.7	0.07	0.02	-	0.55	0.41	0.98	0.55	0.41	0.98
51	0	3	NA(4)	430.75	0.5	Fill syst.								
52	0	4	NA(4)	430.75	0.5	Fill syst.								

(1) With respect to minimum flow area.
(2) No choking allowed.
(3) Homogeneous equilibrium model.
(4) NA, not applicable.

Table 6.2-15c
20 Node Loop C Steam Generator Compartment Model
Forces and Moments on Reactor Coolant Pump

Time (Sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)	Node	A_x (ft^2)	A_y (ft^2)	A_z (ft^2)	AM_x (ft^3)	AM_y (ft^3)
0	0	0	0	0	0	1	0.0	0.0	0.0	0.0	0.0
2.50-3	-9.49+4	-6.26+4	2.86+4	-3.38+5	5.13+5	2	0.0	0.0	0.0	0.0	0.0
5.10-3	-2.19+5	-1.46+5	6.60+4	-7.48+5	1.12+6	3	3.133+1	-3.603+1	7.560+0	-1.982+2	-1.723+2
7.50-3	-2.94+5	-1.98+5	8.78+4	-9.14+5	1.37+6	4	-6.957+1	-2.286+1	1.412+1	-1.257+2	3.826+2
1.00-2	-3.22+5	-2.17+5	9.40+4	-8.28+5	1.25+6	5	3.824+1	5.889+1	1.412+1	3.239+2	-2.103+2
1.48-2	-3.16+5	-2.01+5	8.26+4	-3.09+5	6.23+5	6	0.0	0.0	0.0	0.0	0.0
2.96-2	-1.62+5	-7.95+4	5.23+4	-3.29+5	8.14+5	7	0.0	0.0	0.0	0.0	0.0
3.52-2	-1.05+5	-3.64+4	5.01+4	-5.72+5	1.15+6	8	3.838+1	-4.913+1	0.0	3.685+2	2.879+2
4.00-2	-8.26+4	-1.29+4	5.00+4	-6.79+5	1.26+6	9	0.0	0.0	0.0	0.0	0.0
5.00-2	-1.18+5	-3.20+4	4.81+4	-5.84+5	9.83+5	10	0.0	0.0	0.0	0.0	0.0
6.00-2	-2.54+5	-1.43+5	6.48+4	-4.64+5	7.86+5	11	0.0	0.0	0.0	0.0	0.0
7.00-2	-3.20+5	-2.03+5	7.88+4	-3.04+5	7.84+5	12	0.0	0.0	0.0	0.0	0.0
8.00-2	-2.85+5	-1.73+5	8.49+4	-5.62+5	1.25+6	13	0.0	0.0	0.0	0.0	0.0
9.00-2	-2.40+5	-1.20+5	8.60+4	-1.00+6	1.73+6	14	0.0	0.0	0.0	0.0	0.0
1.00-1	-2.44+5	-9.97+4	8.25+4	-1.11+6	1.12+6	15	-9.053+1	-3.117+1	0.0	2.338+2	-6.790+2
1.50-1	-2.64+5	-1.16+5	7.19+4	-7.92+5	1.54+6	16	5.215+1	8.030+1	0.0	-6.023+2	3.911+2
2.00-1	-2.58+5	-1.20+5	6.54+4	-5.87+5	1.42+6	17	0.0	0.0	0.0	0.0	0.0
3.00-1	-2.33+5	-1.04+5	5.60+4	-5.34+5	1.24+6	18	0.0	0.0	0.0	0.0	0.0
4.00-1	-2.10+5	-9.11+4	4.93+4	-4.90+5	1.12+6	19	0.0	0.0	0.0	0.0	0.0

Table 6.2-15c (continued)
20 Node Loop C Steam Generator Compartment Model
Forces and Moments on Reactor Coolant Pump

Time (Sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)	Node	A_x (ft^2)	A_y (ft^2)	A_z (ft^2)	AM_x (ft^3)	AM_y (ft^3)
5.00-1	-1.95+5	-8.55+4	4.74+4	-4.50+5	1.03+6	20	0.0	0.0	-3.58+1	0.0	0.0
1.00	-1.69+5	-7.32+4	4.03+4	-3.89+5	8.96+5						

Maximum Forces and Moments and Corresponding Times

Max. F_x = -3.240+5 at time = 0.0116

Max F_y = -2.177+5 at time = 0.0104

Max. F_z = 9.403+4 at time = 0.0099

Max. M_x = -1.124+6 at time = 0.0970

Max. M_y = 1.795+6 at time = 0.0940

Table 6.2-15d
25 Node Loop C Steam Generator Compartment Model
Hot Leg Break, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press.[1] (psi)	Design Diff. Press [2] (psi)	Design Margin (psi)
						Temp. (°F)	Pressure (psia)	Quality			
1	Lower 1/2 Compartment below Reactor Coolant Pump	14.0	5,519.	442.	412.5	212	14.696	0.573	20.5	41.2	101
2	Lower 1/2 Compartment below Steam Generator	14.0	6,232.	462.	412.5	212	14.696	0.573	20.4	41.2	102
3	Between Reactor Coolant Pump, Primary Shield and Steam Generator	9.5	1,528.	586.	426.5	212	14.696	0.573	27.2	41.2	51
4	Between Cold Leg, Reactor Coolant Pump and Secondary Shield	9.5	609.	203.	426.5	212	14.696	0.573	20.3	41.2	103
5	Between Reactor Coolant Pump, Steam Generator and Secondary Shield	9.5	2,640.	300.	426.5	212	14.696	0.573	20.5	41.2	101
6	Between Steam Generator and Secondary Shield	9.5	1,022.	163.	426.5	212	14.696	0.573	20.8	41.2	98
7	Between Steam Generator, Hot Leg and Secondary Shield	9.5	864.	158.	426.5	212	14.696	0.573	45.9	41.2	-10 [4]
8	Between Reactor Coolant Pump, Steam Generator and Primary Shield above Elevation 436’	15.0	2,300.	277.	436.0	212	14.696	0.573	21.6	41.2	91
9	Around Steam Generator between Elevations 475.4’ and 513.5’	38.1	4,314.	259.	475.4	212	14.696	0.573	0.9	12.1	1244
10	Gallery between Loops A and C	11.5	6,900.	200.	412.0	212	14.696	0.573	11.2	41.2	268
11	Pressurizer Relief Tank Compartment	22.5	6,200.	100.	412.5	212	14.696	0.573	NA [3]		

Table 6.2-15d (continued)
25 Node Loop C Steam Generator Compartment Model
Hot Leg Break, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press.(1) (psi)	Design Diff. Press (2) (psi)	Design Margin (psi)
						Temp. (°F)	Pressure (psia)	Quality			
12	Steam Generator A Compartment below Elevation 459.5'	47.0	35,254.	858.	412.5	212	14.696	0.573	NA		
13	Steam Generator A Compartment above Elevation 459.5'	15.9	4,826.	260.	459.5	212	14.696	0.573	NA		
14	Containment	200.	1.74+6	12,500.	412.0	212	14.696	0.573	NA		
15	Between Reactor Coolant Pump and Secondary Shield above Elevation 436’	15.	966.	126.	436.0	212	14.696	0.573	20.8	41.2	98
16	Between Reactor Coolant Pump, Steam Generator and Secondary Shield above Elevation 436’	15.	4,161.	382.	436.0	212	14.696	0.573	21.0	41.2	96
17	Between Steam Generator and Secondary Shield above Elevation 436’	15.	1,431.	191.	436.0	212	14.696	0.573	20.4	41.2	102
18	Between Steam Generator and Primary Shield above Elevation 436’	15.	1,144.	176.	436.0	212	14.696	0.573	20.5	41.2	101
19	Between Steam Generator and Secondary Shield above Elevation 451’	8.5	1,457.	237.	451.0	212	14.696	0.573	20.5	41.2	101
20	Above Reactor Coolant Pump	8.5	4,208.	495.	451.0	212	14.696	0.573	20.4	41.2	102
21	Around Steam Generator between Elevations 459.5' and 475.4'	15.9	378.	87.	459.5	212	14.696	0.573	10.4	16.9	63
22	Around Steam Generator between Elevations 459.5' and 475.4'	15.9	1,277.	166.	459.5	212	14.696	0.573	10.3	16.9	64

Table 6.2-15d (continued)
25 Node Loop C Steam Generator Compartment Model
Hot Leg Break, Volume Description

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions: Temp. (°F)	Initial Conditions: Pressure (psia)	Initial Conditions: Quality	Calc. Peak Diff. Press.(1) (psi)	Design Diff. Press (2) (psi)	Design Margin (psi)
23	Around Steam Generator between Elevations 459.5' and 475.4'	15.9	2,094.	236.	459.5	212	14.696	0.573	10.4	16.9	63
24	Around Steam Generator between Elevations 459.5' and 475.4’	15.9	1,687.	162.	459.5	212	14.696	0.573	10.2	16.9	66
25	Around Steam Generator between Elevations 475.4' and 513.5'	38.1	5,156.	313.	475.4	212	14.696	0.573	10.1	12.1	1,000

(1) With respect to containment.
(2) Values to be multiplied by dynamic load factor of 1.1 for purposes of structural design.
(3) NA - not applicable.
(4) For discussion of results, see Section 6.2.1.3.9.2.3.

Table 6.2-15e
25 Node Loop C Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K [1]							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
1	1	2	Inertial [2]	419.5	304.0	0.05	0.01	-	-	-	0.01	-	-	0.01
2	1	10	HEM [3]	417.8	161.8	0.09	0.02	-	0.21	0.22	0.45	0.27	-	0.29
3	1	14	HEM	415.9	26.8	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
4	2	14	HEM	415.9	53.6	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
5	2	14	HEM	418.0	53.8	0.17	-	1.8	0.59	0.50	2.89	0.59	0.50	2.89
6	3	1	HEM	426.5	63.0	0.08	0.01	-	0.72	-	0.73	-	0.06	0.07
7	3	2	HEM	426.5	116.4	0.05	0.01	-	0.56	-	0.57	-	0.37	0.38
8	3	4	HEM	431.25	44.3	0.28	0.02	-	1.86	1.13	3.01	0.41	-	0.43
9	3	5	HEM	431.25	54.8	0.25	0.02	-	0.50	0.28	0.80	0.33	0.33	0.68
10	3	7	HEM	431.25	74.8	0.14	0.03	-	0.04	0.20	0.27	0.15	0.11	0.29
11	3	8	HEM	436.0	108.8	0.07	0.02	-	0.08	0.19	0.29	0.14	0.01	0.17
12	4	1	HEM	426.5	64.4	0.08	0.02	-	0.71	-	0.73	0.10	-	0.12
13	4	5	HEM	431.25	40.0	0.20	0.02	-	0.22	0.24	0.48	0.22	0.24	0.48
14	4	15	HEM	436.0	60.5	0.16	0.02	-	-	0.03	0.05	-	0.03	0.05
15	5	1	HEM	426.5	144.4	0.03	0.01	-	0.12	0.15	0.28	0.09	0.17	0.27
16	5	2	HEM	426.5	80.7	0.15	0.02	-	0.06	0.12	0.20	0.06	0.12	0.20
17	5	6	HEM	431.25	81.0	0.04	0.03	-	-	0.23	0.26	0.22	-	0.25
18	5	16	HEM	436.0	209.6	0.04	0.01	-	0.06	0.12	0.19	0.06	0.12	0.19
19	6	2	Inertial	426.5	119.2	0.05	0.01	-	-	-	0.01	-	-	0.01

Table 6.2-15e (continued)
25 Node Loop C Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K [1]							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
20	6	7	HEM	431.25	71.6	0.16	0.02	-	0.0	0.18	0.20	0.13	0.03	0.18
21	6	17	HEM	436.0	53.7	0.11	0.01	-	0.19	0.25	0.45	0.05	0.21	0.27
22	7	2	HEM	426.5	110.8	0.12	0.02	-	0.58	-	0.60	-	-	0.02
23	7	18	HEM	436.0	59.0	0.14	0.02	-	0.05	0.11	0.18	0.05	0.11	0.18
24	20	21	HEM	459.5	12.0	0.20	0.01	-	0.55	0.43	0.99	0.86	0.33	1.20
25	20	14	HEM	459.5	128.4	0.04	0.01	-	1.00	0.37	1.38	1.00	0.37	1.38
26	20	22	HEM	459.5	60.9	0.10	0.01	-	0.17	0.28	0.46	0.40	0.17	0.58
27	10	11	HEM	417.5	107.7	0.12	-	1.2	0.57	0.23	2.0	0.20	0.38	1.78
28	11	12	HEM	419.5	90.9	0.04	-	1.2	1.00	0.33	2.53	0.44	0.50	2.14
29	10	14	HEM	415.9	26.8	0.75	-	0.8	0.71	0.19	1.7	0.71	0.19	1.7
30	10	14	HEM	420.0	33.0	0.24	-	1.2	1.00	0.5	2.7	1.00	0.50	2.7
31	10	12	HEM	419.5	78.8	0.12	-	-	1.00	0.29	1.29	0.25	0.50	0.75
32	12	13	HEM	459.5	160.2	0.12	0.02	-	0.16	0.70	0.88	0.16	0.70	0.88
33	12	14	HEM	423.2	178.7	0.11	-	-	1.00	0.50	1.50	1.00	0.50	1.50
34	12	14	HEM	415.9	26.8	0.28	-	0.68	0.51	0.38	1.57	0.51	0.38	1.57
35	12	14	HEM	459.5	184.6	0.04	-	-	1.00	0.38	1.38	1.00	0.38	1.38
36	13	14	HEM	475.4	269.1	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
37	8	15	HEM	443.5	45.0	0.16	-	-	0.25	0.30	0.55	0.41	0.25	0.66
38	8	16	HEM	443.5	112.5	0.15	0.01	-	0.39	0.21	0.61	0.18	0.31	0.50
39	8	18	HEM	443.5	135.0	0.08	0.02	-	0.01	0.15	0.18	0.09	0.05	0.16
40	8	20	Inertial	451.0	153.3	0.08	0.02	-	-	-	0.02	-	-	0.02

Table 6.2-15e (continued)
25 Node Loop C Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K [1]							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
41	15	16	HEM	443.5	82.5	0.13	0.01	-	0.10	0.16	0.27	0.10	0.16	0.27
42	15	20	Inertial	451.0	64.4	0.17	0.02	-	0.04	-	0.06	0.04	-	0.06
43	16	17	HEM	443.5	150.0	0.18	0.02	-	-	0.19	0.21	0.14	-	0.16
44	16	20	Inertial	451.0	209.6	0.06	0.02	-	0.0	-	0.02	-	-	0.02
45	17	18	HEM	443.5	82.5	0.11	0.02	-	0.10	0.27	0.39	0.29	0.16	0.47
46	17	19	Inertial	451.0	95.4	0.10	0.02	-	-	-	0.02	-	-	0.02
47	18	19	Inertial	451.0	76.0	0.13	0.02	-	-	-	0.02	-	-	0.02
48	19	20	HEM	455.2	85.0	0.11	0.02	-	0.14	-	0.16	-	0.19	0.21
49	19	20	HEM	455.2	76.5	0.14	0.02	-	0.19	-	0.21	-	0.21	0.23
50	19	23	HEM	459.5	85.4	0.06	0.01	-	0.25	0.33	0.59	0.55	0.22	0.78
51	20	23	HEM	459.5	11.8	0.10	0.01	-	0.17	0.28	0.46	0.40	0.17	0.58
52	19	24	HEM	459.5	55.4	0.06	0.01	-	0.39	0.37	0.77	0.68	0.28	0.97
53	21	22	HEM	467.5	34.6	0.31	0.01	-	0.32	0.25	0.58	0.32	0.25	0.58
54	21	24	HEM	467.5	33.7	0.30	0.01	-	0.40	0.08	0.49	0.08	0.28	0.37
55	22	23	HEM	467.5	121.2	0.12	0.01	-	0.04	0.21	0.26	0.24	0.04	0.29
56	23	24	Inertial	467.5	75.4	0.16	0.01	-	0.02	0.02	0.05	0.02	0.02	0.05
57	21	14	HEM	475.4	18.3	0.48	0.01	-	1.00	-	1.01	1.00	-	1.01
58	22	14	HEM	475.4	78.7	0.10	0.01	-	1.00	-	1.01	1.00	-	1.01
59	23	25	HEM	475.4	114.5	0.24	0.01	-	-	0.09	0.10	0.09	-	0.10
60	24	9	HEM	475.4	87.4	0.31	0.01	-	0.01	0.12	0.14	0.12	0.01	0.14
61	25	14	HEM	513.5	114.5	0.22	0.01	-	1.00	-	1.01	1.00	-	1.01

Table 6.2-15e (continued)
25 Node Loop C Steam Generator Compartment Model
Hot Leg Break, Flow Path Data

Junction No.	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K (1)							
									Forward Flow			Reverse Flow		
							Friction fL/D	Bends	Expansion	Contraction	Total	Expansion	Contraction	Total
62	25	14	HEM	494.5	275.5	0.03	0.01	-	1.00	-	1.01	1.00	-	1.01
63	25	9	Inertial	494.5	122.0	0.12	0.01	-	0.02	0.02	0.05	0.02	0.02	0.05
64	9	14	HEM	513.5	87.4	0.22	0.01	-	1.00	-	1.01	1.00	-	1.01
65	9	14	HEM	494.5	152.0	0.07	0.01	-	1.00	-	1.01	1,00	-	1.01
66	0	3	NA(4)	430.75	0.5	Fill syst.								
67	0	7	NA	430.75	0.5	Fill syst.								

(1) With respect to minimum flow area.
(2) No choking allowed.
(3) Homogeneous equilibrium model.
(4) NA, not applicable.

Table 6.2-15f
25 Node Loop C Steam Generator Compartment Model
Forces and Moments on Steam Generator

Time (Sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)	Node	A_x (ft^2)	A_y (ft^2)	A_z ($ft^{2)}$	AM_x(ft^3)	AM_y (ft^3)
0	0	0	0	0	0	1	0.0	0.0	0.0	0.0	0.0
2.50-3	3.49+4	-7.71+4	9.36+4	-1.40+5	-6.37+4	2	0.0	0.0	0.0	0.0	0.0
5.10-3	8.83+5	-1.90+5	2.21+5	-2.28+5	-1.12+5	3	-2.552+1	-2.338+1	2.602+1	-4.676+1	5.104+1
7.50-3	1.32+5	-2.69+5	2.91+5	-5.53+4	-5.07+4	4	0.0	0.0	0.0	0.0	0.0
1.00-2	1.70+5	-3.23+5	3.15+5	3.75+5	1.41+5	5	-2.464+1	2.338+1	2.781+1	4.676+1	4.928+1
1.48-2	1.96+5	-3.54+5	2.98+5	1.27+6	6.90+5	6	1.935+1	2.306+1	2.393+1	4.612+1	-3.870+1
2.96-2	-2.24+4	-3.03+4	2.66+5	-3.38+5	5.85+5	7	3.081+1	-2.306+1	2.991+1	-4.612+1	-6.162+1
3.52-2	-7.36+4	5.41+4	2.95+5	-9.72+5	1.60+5	8	-8.322+1	-8.769+1	0.0	6.577+2	-6.241+2
4.00-2	-7.52+4	8.98+4	3.28+5	-1.22+6	1.16+5	9	1.380+2	-2.830+2	0.0	1.449+4	7.069+3
5.00-2	1.43+4	6.85+4	3.76+5	-8.36+5	1.55+6	10	0.0	0.0	0.0	0.0	0.0
6.00-2	1.25+5	-9.64+4	3.86+5	8.74+5	3.80+6	11	0.0	0.0	0.0	0.0	0.0
7.00-2	1.40+5	-2.33+5	4.16+5	2.38+6	4.32+6	12	0.0	0.0	0.0	0.0	0.0
8.00-2	6.28+4	-1.47+5	4.47+5	1.74+6	3.13+6	13	0.0	0.0	0.0	0.0	0.0
9.00-2	-1.32+4	1.61+4	4.56+5	-1.11+5	1.70+6	14	-3.165+2	5.867+1	-1.791+2	-3.004+3	-1.621+4
1.00-1	-7.26+3	3.12+4	4.57+5	-9.05+5	1.39+6	15	0.0	0.0	0.0	0.0	0.0
1.50-1	1.85+4	-9.15+3	4.58+5	7.40+5	1.64+6	16	-9.241+1	8.769+1	0.0	-6.577+2	-6.931+2
2.00-1	4.44+4	-1.20+4	4.59+5	3.43+5	2.21+6	17	7.257+1	8.648+1	0.0	-6.486+2	5.443+2
3.00-1	4.84+4	-2.76+4	4.13+5	3.04+5	2.07+6	18	1.031+2	-8.648+1	0.0	6.486+2	7.729+2
4.00-1	3.84+4	-3.17+4	3.55+5	2.91+5	1.68+6	19	9.952+1	0.0	0.0	0.0	1.916+3

Table 6.2-15f (continued)
25 Node Loop C Steam Generator Compartment Model
Forces and Moments on Steam Generator

Time (Sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)	Node	A_x (ft^2)	A_y (ft^2)	A_z ($ft^{2)}$	AM_x(ft^3)	AM_y (ft^3)
5.00-1	3.37+4	-2.96+4	3.05+5	2.37+5	1.48+6	20	0.0	0.0	-3.58+1	0.0	-1.916+3
1.00	2.65+4	-2.28+4	1.62+5	1.74+5	1.24+6	21	-8.394+1	-4.095+1	1.741+1	1.288+3	-2.641+3
						22	-9.262+1	7.368+1	1.860+1	-2.318+3	-2.695+3
						23	9.956+1	1.252+2	1.600+1	-3.938+3	2.914+3
						24	7.700+1	-1.579+2	2.000+1	4.968+3	2.422+3
						25	1.785+2	2.244+2	0.0	-1.149+4	9.139+3

Maximum Forces and Moments and Corresponding Times

Max. F_x = 1.992+5 at time = 0.0136

Max F_y = -3.594+5 at time = 0.0136

Max. F_z = 4.602+5 at time = 0.1680

Max. M_x = 2.446+6 at time = 0.0720

Max. M_y = 4.381+6 at time = 0.0680

Table 6.2-16
Reactor Cavity Model Cross References

	22 Node Model	31 Node Model	33 Node Model
Penetration Nodes	Figure 6.2-30	Figure 6.2-30	Figure 6.2-30a
Reactor Vessel Annulus Nodes	Figure 6.2-31	Figure 6.2-31a	Figure 6.2-31a
Overall Model Schematic	Figure 6.2-32	Figure 6.2-32a	Figure 6.2-32a
Control Volumes	Table 6.2-16a	Table 6.2-16b	Table 6.2-16c
Flow Paths	Table 6.2-17	Table 6.2-17a	Table 6.2-17b
Force/Moment Areas	Table 6.2-188	Table 6.2-18a	Table 6.2-18b

Table 6.2-16a
22 Node Reactor Cavity Model Control Volumes

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press.(1) (psi)	Design Diff. Press (2) (psi)	Design Margin (psi)
						Temp. (°F)	Pressure (psia)	Quality			
1	Reactor Vessel Annulus -	2.56	14.4	6.5	434.67	212	14.7	0.573	5.4	22.4	310
2	See Figure 6.2-31								18.3	43.4	140
3									5.4	22.4	310
4	Reactor Vessel Annulus -	3.92	23.3	7.3	430.75	212	14.7	0.573	5.3	22.4	320
5	See Figure 6.2-31								18.7	105.0	460
6									5.3	22.4	320
7	Reactor Vessel Annulus -	4.08	24.2	7.3	426.67	212	14.7	0.573	4.2	22.4	430
8	See Figure 6.2-31								15.1	105.0	590
9									4.2	22.4	430
10	Reactor Vessel Annulus -	7.42	35.8	7.0	419.25	212	14.7	0.573	4.2	30.0	610
11	See Figure 6.2-31								8.0	198.0	2370
12									4.2	30.0	610
13	Reactor Vessel Annulus -	7.42	35.8	7.0	411.83	212	14.7	0.573	3.7	30.0	710
14	See Figure 6.2-31								4.0	48.0	1100
15									3.7	30.0	710
16	Under Reactor Vessel	24.16	5528.	270.	386.67	212	14.7	0.573	0.9	30.0	3230
17	Instrument Chase 1	8.5	4439.	130.5	387.5	212	14.7	0.573	0.8	-	-
18	Instrument Chase 2	32.	3472.	108.5	396.	212	14.7	0.573	0.3	-	-

Table 6.2-16a (continued)
22 Node Reactor Cavity Model Control Volumes

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press.(1) (psi)	Design Diff. Press (2) (psi)	Design Margin (psi)
						Temp. (°F)	Pressure (psia)	Quality			
19	Penetration - Break Node - See Figure 6.2-30	7.57	163.4	61.9	427.76	212	14.7	0.573	237.7	483.0	100
20	Penetration - Pipe Sleeve - See Figure 6.2-30	5.83	46.0	15.5	427.83	212	14.7	0.573	207.2	280.	30
21	Penetration - Inspection Port - See Figure 6.2-30	1.88	25.9	13.8	435.33	212	14.7	0.573	146.1	483.0	230
22	Containment	200	1.82+6	9100.	412.	212	14.7	0.545			

(1) With respect to containment.
(2) Values to be multiplied by dynamic load factor of 1.5 for purposes of structural design.

Table 6.2-16b
31 Node Reactor Cavity Model Control Volumes

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press.(1) (psi)	Design Diff. Press (2) (psi)	Design Margin (%)
						Temp. (°F)	Pressure (psia)	Quality			
1	Reactor Vessel Annulus -	2.56	8.4	4.1	434.67	212	14.7	0.573	4.9	22.4	360
3	See Figure 6.2-31a								16.0	43.4	170
5									6.3	22.4	250
2	Reactor Vessel Annulus -	2.56	6.0	3.2	434.67	212	14.7	0.573	7.7	22.4	190
4	See Figure 6.2-31a								15.9	77.0	380
6									4.9	22.4	360
7	Reactor Vessel Annulus -	3.92	13.6	4.8	430.75	212	14.7	0.573	4.8	22.4	370
9	See Figure 6.2-31a								16.4	105.0	540
11									6.2	22.4	260
8	Reactor Vessel Annulus -	3.92	9.7	3.9	430.75	212	14.7	0.573	7.6	23.1	200
10	See Figure 6.2-31a								16.8	77.0	360
12									4.9	22.4	360
13	Reactor Vessel Annulus -	4.08	14.1	4.9	426.67	212	14.7	0.573	4.2	22.4	430
15	See Figure 6.2-31a								14.1	105.0	640
17									4.3	22.4	420
14	Reactor Vessel Annulus -	4.08	10.1	3.9	426.67	212	14.7	0.573	4.2	23.1	450
16	See Figure 6.2-31a								13.9	77.0	450
18									4.2	22.4	430

Table 6.2-16b (continued)
31 Node Reactor Cavity Model Control Volumes

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press.(1) (psi)	Design Diff. Press (2) (psi)	Design Margin (%)
						Temp. (°F)	Pressure (psia)	Quality			
19	Reactor Vessel Annulus -	7.42	35.8	4.8	419.25	212	14.7	0.573	4.1	30.0	630
20	See Figure 6.2-31a								6.8	198.0	2810
21									4.1	30.0	630
22	Reactor Vessel Annulus -	7.42	35.8	4.8	411.83	212	14.7	0.573	3.7	30.0	710
23	See Figure 6.2-31a								3.8	48.0	1160
24									3.7	30.0	710
25	Under Reactor Vessel	24.16	5528.	270.	387.67	212	14.7	0.573	0.9	30.0	3230
26	Instrument Chase 1	8.5	4439.	130.5	387.5	212	14.7	0.573	0.8	-	-
27	Instrument Chase 2	32.	3472.	108.5	396.	212	14.7	0.573	0.3	-	-
28	Penetration - Break Node - See Figure 6.2-30	7.57	163.4	61.9	427.76	212	14.7	0.573	237.7	483.0	100
29	Penetration - Pipe Sleeve - See Figure 6.2-30	5.83	46.0	15.5	427.83	212	14.7	0.573	207.2	280.	30
30	Penetration - Inspection Port - See Figure 6.2-30	1.88	25.9	13.8	435.33	212	14.7	0.573	146.1	483.0	230
31	Containment	200.	1.82+6	9100.	412.	212	14.7	0.573	-	-	-

(1) With respect to containment.
(2) Values to be multiplied by dynamic load factor of 1.5 for purposes of structural design.

Table 6.2-16c
33 Node Reactor Cavity Model Control Volumes

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press.[1] (psi)	Design Diff. Press [2] (psi)	Design Margin (%)
						Temp. (°F)	Pressure (psia)	Quality			
1	Reactor Vessel Annulus -	2.56	8.4	4.1	434.67	212	14.7	0.573	4.9	22.4	350
3	See Figure 6.2-31a								16.1	43.4	170
5									6.3	22.4	250
2	Reactor Vessel Annulus -	2.56	6.0	3.2	434.67	212	14.7	0.573	7.7	22.4	190
4	See Figure 6.2-31a								16.0	77.0	380
6									5.0	22.4	350
7	Reactor Vessel Annulus -	3.92	13.6	4.8	430.75	212	14.7	0.573	4.9	22.4	360
9	See Figure 6.2-31a								16.5	105.0	530
11									6.2	22.4	260
8	Reactor Vessel Annulus -	3.92	9.7	3.9	430.75	212	14.7	0.573	7.7	23.1	250
10	See Figure 6.2-31a								16.7	77.0	360
12									4.9	22.4	350
13	Reactor Vessel Annulus -	4.08	14.1	4.9	426.67	212	14.7	0.573	4.2	22.4	430
15	See Figure 6.2-31a								14.3	105.0	630
17									4.4	22.4	410
14	Reactor Vessel Annulus -	4.08	10.1	3.9	426.67	212	14.7	0.573	4.3	23.1	440
16	See Figure 6.2-31a								14.1	77.0	440
18									4.2	22.4	430

Table 6.2-16c (continued)
33 Node Reactor Cavity Model Control Volumes

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions			Calc. Peak Diff. Press.[1] (psi)	Design Diff. Press [2] (psi)	Design Margin (%)
						Temp. (°F)	Pressure (psia)	Quality			
19	Reactor Vessel Annulus -	7.42	35.8	7.0	419.25	212	14.7	0.573	4.2	30.0	610
20	See Figure 6.2-31a								6.5	198.0	2930
21									4.2	30.0	610
22	Reactor Vessel Annulus -	7.42	35.8	7.0	411.83	212	14.7	0.573	3.7	30.0	700
23	See Figure 6.2-31a								3.8	48.0	1360
24									3.7	30.0	710
25	Under Reactor Vessel	24.16	5528.	270.	386.67	212	14.7	0.573	0.9	30.0	3270
26	Instrument Chase 1	8.5	4439.	130.5	387.5	212	14.7	0.573	0.8	-	-
27	Instrument Chase 2	32.	3472.	108.5	396.	212	14.7	0.573	0.3	-	-
28	Penetration - Break Node 1- See Figure 6.2-30a	2.99	63.7	45.3	427.76	212	14.7	0.573	242.3 [2][3] 195.2 [2][4]	483.0 195.2	100 0
29	Penetration - Break Node 2 - See Figure 6.2-30a	4.58	99.7	45.3	430.75	212	14.7	0.573	236.3 [2][3] 188.5 [2][4]	483.0 188.5	100 0
30	Penetration - Pipe Sleeve 1 - See Figure 6.2-30a	2.92	23.0	7.8	427.83	212	14.7	0.573	211.7	280.	30
31	Penetration - Pipe Sleeve 2 - See Figure 6.2-30a	2.92	23.0	7.8	430.75	212	14.7	0.573	206.5	280.	30
32	Penetration - Inspection Port - See Figure 6.2-30a	1.88	25.9	13.8	435.33	212	14.7	0.545	145.2[2][3] 109.2[2][4]	483.0 109.2	230 0
33	Containment	200.	1.82+6	9100.	412.	212	14.7	0.573	-	-	-

Table 6.2-16c (continued)
33 Node Reactor Cavity Model Control Volumes

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elev. (ft)	Initial Conditions: Temp. (°F)	Initial Conditions: Pressure (psia)	Initial Conditions: Quality	Calc. Peak Diff. Press.(1) (psi)	Design Diff. Press (2) (psi)	Design Margin (%)

(1) With respect to containment.
(2) The following notes 3 and 4 are applicable to the design of the reactor baffle system.
(3) These values are for 150 sq. inch break and apply to original design of the baffles before the design details were changed in 1978 to accommodate a revised construction sequence. These loads were increased by a dynamic load factor of 1.5 for structural design.
(4) For Nodes 28, 29 and 32 the peak differential pressures were also evaluated for a break size of 100 sq. inches in 1978 and 127 sq. inches in 1988. The 127 sq. inch break values were obtained by interpolation of the pressure/temperature analyses for the 100 sq. inch and 150 sq. inch breaks. The calculated peak and design differential pressures (with respect to annulus) shown are for the 127 sq. inch break which is the maximum expected break size that can occur. These values were increased by a dynamic load factor of 1.2 for structural design.0

Table 6.2-17
22 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K[1]				
								Friction fL/D	Bends	Expansion	Contraction	Total
1	Reactor Vessel Annulus -	1	2	Inertia	435.95	0.85	200	0.62	0.0	0.0	0.0	0.62
2	See Figure 6.2-31	2	3									
3		3	1									
4	Reactor Vessel Annulus -	1	22	HEM[2]	437.23	0.72	0.69	0.001	1.2	1.0	0.0	2.2
5	See Figure 6.2-31	2	22									
6		3	22									
7	Reactor Vessel Annulus -	1	4	HEM	434.67	5.8	0.56	0.092	0.0	0.0	0.0	0.092
8	See Figure 6.2-31	2	5									
9		3	6									
10	Reactor Vessel Annulus -	4	5	HEM	432.71	0.60	19.5	0.20	0.0	1.0	0.69	1.9
11	See Figure 6.2-31	5	6									
12		6	4									
13	Reactor Vessel Annulus -	4	7	HEM	430.75	2.4	1.4	0.11	0.0	0.36	0.26	0.73
14	See Figure 6.2-31	5	8									
15		6	9									
16	Reactor Vessel Annulus -	7	8	HEM	428.71	0.65	17.6	0.20	0.0	1.09	0.70	2.0
17	See Figure 6.2-31	8	9									
18		9	7									

Table 6.2-17 (continued)
22 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K[1]				
								Friction fL/D	Bends	Expansion	Contraction	Total
19	Reactor Vessel Annulus -	7	10	HEM	426.67	4.8	1.1	0.079	0.0	0.0	0.0	0.079
20	See Figure 6.2-31	8	11									
21		9	12									
22	Reactor Vessel Annulus -	10	11	Inertia	422.96	2.2	7.3	0.53	0.0	0.0	0.0	0.053
23	See Figure 6.2-31	11	12									
24		12	10									
25	Reactor Vessel Annulus -	10	13	Inertia	419.25	4.8	1.5	0.25	0.0	0.0	0.0	0.25
26	See Figure 6.2-31	11	14									
27		12	15									
28	Reactor Vessel Annulus -	13	14	Inertia	415.54	2.2	73	0.53	0.0	0.0	0.0	0.53
29	See Figure 6.2-31	14	15									
30		15	13									
31	Reactor Vessel Annulus -	13	16	HEM	411.83	4.8	0.85	0.12	0.0	1.0	0.0	1.12
32	See Figure 6.2-31	14	16									
33		15	16									
34	Instrument Chase	16	17	HEM	391.83	130.5	0.21	0.02	1.2	0.0	0.05	1.27
35	Instrument Chase	17	18	HEM	396.0	81.4	0.31	0.03	(3)	(3)	0.02	0.35
36	Instrument Chase	18	22	HEM	420.0	29.0	0.089	0.0	0.0	1.0	0.5	1.5
37	Instrument Chase	18	22	HEM	420.0	41.2	0.27	0.0	0.0	1.0	0.5	1.5

Table 6.2-17 (continued)
22 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K[(1)]				
								Friction fL/D	Bends	Expansion	Contraction	Total
38	From Break Node - See Figure 6.2-30	19	20	HEM	430.75	11.7	0.21	0.02	0.0	0.0	0.28	0.30
39	From Break Node - See Figure 6.2-30	19	21	HEM	435.33	13.8	0.23	0.01	0.0	0.04	0.22	0.27
40	From Break Node -	19	5	HEM	430.75	0.43	2.8	0.16	0.0	0.13	0.5	0.79
41	See Figure 6.2-30											
42	From Break Node -	19	8	HEM	430.75	0.25	1.6	0.16	0.0	0.13	0.5	0.79
43	See Figure 6.2-30											
44	Penetration to Contain.	20	22	HEM	430.75	11.7	0.14	0.02	0.0	1.0	0.0	1.02
45	Penetration to Contain.	21	22	HEM	437.21	13.8	0.07	0.01	0.0	1.0	0.0	1.01
46	From Reactor Vessel Annulus	4	22	HEM	430.75	0.73	3.1	0.17	0.0	1.0	0.05	1.67
47	to Contain. through Penetr.											
48	From Reactor Vessel Annulus	5	22	HEM	430.75	0.30	3.5	0.17	0.0	1.0	0.05	1.67
49	to Contain. through Penetr.											
50	From Reactor Vessel Annulus	6	22	HEM	430.75	0.73	3.1	0.17	0.0	1.0	0.05	1.67
51	to Contain. through Penetr.											
52	From Reactor Vessel Annulus	7	22	HEM	430.75	0.42	1.8	0.17	0.0	1.0	0.5	1.67
53	to Contain. through Penetr.											
54	From Reactor Vessel Annulus	8	22	HEM	430.75	0.17	2.0	0.17	0.0	1.0	0.5	1.67
55	to Contain. through Penetr.											

Table 6.2-17 (continued)
22 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K(1)				
								Friction fL/D	Bends	Expansion	Contraction	Total
56	From Reactor Vessel Annulus	9	22	HEM	430.75	0.42	1.8	0.17	0.0	1.0	0.5	1.67
57	to Contain. through Penetr.											
58	Break Path	19	0	None								

(1) With respect to the minimum area.
(2) Homogeneous equilibrium model.
(3) K grating = 0.30.

Table 6.2-17a
31 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K[1]				
								Friction fL/D	Bends	Expansion	Contraction	Total
1	Reactor Vessel	1	2	Inertia	435.95	0.85	10.0	0.31	0.0	0.0	0.0	0.31
2	Annulus - See	2	3									
3	Figure 6.2-31a	3	4									
4		4	5									
5		5	6									
6		6	1									
7	Reactor Vessel	1	31	HEM[2]	437.23	0.42	1.2	0.001	1.2	1.0	0.0	2.2
8	Annulus - See	3	31									
9	Figure 6.2-31a	5	31									
10	Reactor Vessel	2	31	HEM	437.23	0.30	1.7	0.001	1.2	0.0	0.0	2.2
11	Annulus - See	4	31									
12	Figure 6.2-31a	6	31									
13	Reactor Vessel	1	7	HEM	434.67	3.4	0.96	0.092	0.0	0.0	0.0	0.092
14	Annulus - See	3	9									
15	Figure 6.2-31a	5	11									
16	Reactor Vessel	2	8	HEM	434.67	2.4	1.3	0.092	0.0	0.0	0.0	0.092
17	Annulus - See	4	10									
18	Figure 6.2-31a	6	12									

Table 6.2-17a (continued)
31 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K[(1)]				
								Friction fL/D	Bends	Expansion	Contraction	Total
19	Reactor Vessel	7	8	HEM	432.71	0.48	10.6	0.10	0.0	0.42	0.28	0.80
20	Annulus - See	9	10									
21	Figure 6.2-31a	11	12									
22	Reactor Vessel	8	9	HEM	432.71	0.60	8.9	0.11	0.0	0.34	0.25	0.70
23	Annulus - See	10	11									
24	Figure 6.2-31a	12	7									
25	Reactor Vessel	7	13	HEM	430.75	1.68	2.1	0.11	0.0	0.25	0.22	0.58
26	Annulus - See	9	15									
27	Figure 6.2-31a	11	17									
28	Reactor Vessel	8	14	HEM	430.75	0.69	4.3	0.11	0.0	0.52	0.32	0.95
29	Annulus - See	10	16									
30	Figure 6.2-31a	12	18									
31	Reactor Vessel	13	14	HEM	428.71	0.54	9.2	0.10	0.0	0.53	0.32	0.95
32	Annulus - See	15	16									
33	Figure 6.2-31a	17	18									
34	Reactor Vessel	14	15	HEM	428.71	0.65	8.4	0.11	0.0	0.32	0.24	0.67
35	Annulus - See	16	17									
36	Figure 6.2-31a	18	13									
37	Reactor Vessel	13	19	HEM	426.67	2.8	1.4	0.079	0.0	0.0	0.0	0.079

Table 6.2-17a (continued)
31 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K[(1)]				
								Friction fL/D	Bends	Expansion	Contraction	Total
38	Annulus - See	15	20									
39	Figure 6.2-31a	17	21									
40	Reactor Vessel	14	19	HEM	426.67	2.0	1.6	0.079	0.0	0.0	0.0	0.079
41	Annulus - See	16	20									
42	Figure 6.2-31a	18	21									
43	Reactor Vessel	19	20	Inertia	422.96	2.2	7.3	0.53	0.0	0.0	0.0	0.53
44	Annulus - See	20	21									
45	Figure 6.2-31a	21	19									
46	Reactor Vessel	19	22	Inertia	419.25	4.8	1.5	0.25	0.0	0.0	0.0	0.25
47	Annulus - See	20	23									
48	Figure 6.2-31a	21	24									
49	Reactor Vessel	22	23	Inertia	415.54	2.2	7.3	0.53	0.0	0.0	0.0	0.53
50	Annulus - See	23	24									
51	Figure 6.2-31a	24	22									
52	Reactor Vessel	22	25	HEM	411.83	4.8	0.85	0.12	0.0	1.0	0.0	1.12
53	Annulus - See	23	25									
54	Figure 6.2-31 a	24	25									
55	Instrument Chase	25	26	HEM	391.83	130.5	0.21	0.02	1.0	0.0	0.05	1.27
56	Instrument Chase	26	27	HEM	396.	81.4	0.31	0.03	(3)	(3)	0.02	0.35

Table 6.2-17a (continued)
31 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K[(1)]				
								Friction fL/D	Bends	Expansion	Contraction	Total
57	Instrument Chase	27	31	HEM	420.0	29.0	0.089	0.0	0.0	1.0	0.5	1.5
58	Instrument Chase	27	31	HEM	420.0	41.2	0.27	0.0	0.0	0.01	0.5	1.5
59	From Reactor Vessel Annulus	7	31	HEM	430.75	0.73	3.1	0.17	0.0	1.0	0.5	1.67
60	to Contain. through Penetr.	8	31									
61	From Reactor Vessel Annulus	9	31	HEM	430.75	0.30	3.5	0.17	0.0	1.0	0.5	1.67
62	to Contain. through Penetr.	10	31									
63	From Reactor Vessel Annulus	11	31	HEM	430.75	0.73	3.1	0.17	0.0	1.0	0.5	1.67
64	to Contain. through Penetr.	12	31									
65	From Reactor Vessel Annulus	13	31	HEM	430.75	0.42	1.8	0.17	0.0	1.0	0.5	1.67
66	to Contain. through Penetr.	14	31									
67	From Reactor Vessel Annulus	15	31	HEM	430.75	0.17	2.0	0.17	0.0	1.0	0.5	1.67
68	to Contain. through Penetr.	16	31									
69	From Reactor Vessel Annulus	17	31	HEM	430.75	0.42	1.8	0.17	0.0	1.0	0.5	1.67
70	to Contain. through Penetr.	18	31									
71	From Break Node - See Figure 6.2-30	28	29	HEM	430.75	11.7	0.21	0.02	0.0	0.0	0.28	0.30
72	From Break Node - See Figure 6.2-30	28	30	HEM	435.33	13.8	0.23	0.01	0.0	0.04	0.22	0.27
73	From Break Node - See	28	9	HEM	430.75	0.43	2.8	0.16	0.0	0.13	0.5	0.79
74	Figure 6.2-30	28	10									

Table 6.2-17a (continued)
31 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K(1)				
								Friction fL/D	Bends	Expansion	Contraction	Total
75	From Break Node - See	28	15	HEM	430.75	0.25	1.6	0.16	0.0	0.13	0.5	0.79
76	Figure 6.2-30	28	16									
77	Penetration to Contain.	29	31	HEM	430.75	11.7	0.14	0.02	1.0	0.0	0.0	1.02
78	Penetration to Contain.	30	31	HEM	437.21	13.8	0.07	0.01	1.0	0.0	0.0	1.01
79	Break Path	28	0	None								

(1) With respect to the minimum area.
(2) Homogeneous equilibrium model.
(3) K grating = 0.30.

Table 6.2-17b
33 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K[1]				
								Friction fL/D	Bends	Expansion	Contraction	Total
1 through 70	Same as 31 Node Model - See Figure 6.2-17 - Except Containment is Node 33											
71	From Break Node -	28	15	HEM[2]	429.26	0.25	1.6	0.16	0.0	0.13	0.5	0.79
72	See Figure 6.2-30a	28	16									
73	From Break Node -	29	9	HEM	433.04	0.43	2.8	0.16	0.0	0.13	0.5	0.79
74	See Figure 6.2-30a	29	10									
75	From Break Node - See Figure 6.2-30a	28	29	HEM	430.75	13.3	0.34	0.01	0.0	0.28	0.23	0.52
76	From Break Node - See Figure 6.2-30a	28	30	HEM	429.26	5.85	0.38	0.04	0.0	0.0	0.32	0.36
77	From Break Node - SeeFigure 6.2-30a	29	31	HEM	432.25	5.85	0.38	0.04	0.0	0.0	0.32	0.36
78	From Break Node - See Figure 6.2-30a	29	32	HEM	435.33	13.8	0.15	0.01	0.0	0.0	0.22	0.23
79	Penetration to Contain.	30	33	HEM	429.26	5.85	0.28	0.02	0.0	1.0	0.0	1.02
80	Penetration to Contain.	31	33	HEM	432.25	5.85	0.28	0.02	0.0	1.0	0.0	1.02
81	Penetration to Contain.	32	33	HEM	437.21	13.8	0.07	0.01	0.0	1.0	0.0	1.01
82	Break Path	28	0	None								
83	Break Path	29	0	None								

Table 6.2-17b (continued)
33 Node Reactor Cavity Model Junctions

Junction No.	Description	Control Volume 1	Control Volume 2	Choking Model	Elevation (ft)	Flow Area (ft^2)	Inertia (ft^{-1})	Head Loss, K(1)				
								Friction fL/D	Bends	Expansion	Contraction	Total

(1) With respect to minimum area.
(2) Homogeneous equilibrium area.

Table 6.2-18
22 Node Reactor Cavity Model Force/Moment Areas

Control Volume No.	Description	A_x (ft^2)(1)	A_y (ft^2)	A_z (ft^2) (2)	M_x(ft^3) (3)	M_y(ft^3)
1	Reactor Vessel Annulus	-21.48	-25.59	15.34	217.71	-170.95
2	See Figure 6.2-31	32.89	-5.80	15.34	39.14	273.93
3		-11.41	31.39	15.34	-256.85	-102.98
4		-26.28	-28.88	-12.08	56.61	-51.51
5		39.49	-7.92	-12.08	15.52	77.40
6		-13.21	36.80	-12.08	-72.13	-25.89
7		-27.57	-30.44	13.04	-57.14	52.78
8		41.47	-8.27	13.04	-16.34	-78.58
9		-13.90	38.71	13.04	73.48	25.80
10		-59.80	-71.23	0.	-554.9	465.8
11		91.58	-16.16	0.	-125.9	-713.4
12		-31.78	87.39	0.	680.8	247.6
13		-59.80	-71.23	0.	-1083.	910.
14		91.58	-16.16	0.	-246.	-1393.
15		-31.78	87.39	0.	1329.	483.
16	Under Reactor Vessel	0.	0.	164.42	0.	0.
17	Instrument Chase - 1	0.	0.	0.	0.	0.
18	Instrument Chase - 2	0.	0.	0.	0.	0.
19	Penetration - Break Node - See Figure 6.2-30	14.93	0.	0.	0.	3.02

Table 6.2-18 (continued)
22 Node Reactor Cavity Model Force/Moment Areas

Control Volume No.	Description	A_x (ft^2)(1)	A_y (ft^2)	A_z (ft^2) (2)	M_x(ft^3) (3)	M_y(ft^3)
20	Penetration - Pipe Sleeve - See Figure 6.2-30	0.	0.	0.	0.	0.
21	Penetration - Inspection Port See Figure 6.2-30	0.	0.	0.	0.	0.
22	Containment	-14.93	0.	0.	0.	-3.02

(1) Net area for force calculation.
(2) F_Z calculations use nodal pressure minus containment pressure.
(3) Net area times moment arm for moment calculations.

Table 6.2-18a
31 Node Reactor Cavity Model Force/Moment Areas

Control Volume No.	Description	A_x (ft^2)(1)	A_y (ft^2)	A_z (ft^2) (2)	M_x(ft^3) (3)	M_y(ft^3)
1	Reactor Vessel Annulus	-20.05	-9.35	7.67	73.84	-158.31
2	See Figure 6.2-31a	-1.43	-16.24	7.67	143.87	-12.64
3		18.12	-12.68	7.67	100.14	143.08
4		14.77	6.88	7.67	-61.00	130.85
5		1.93	22.04	7.67	-174.03	15.24
6		-13.34	9.35	7.67	-82.82	-118.22
7		-24.75	-11.54	-6.04	22.62	-48.51
8		-1.53	-17.34	-6.04	33.99	-3.00
9		22.58	-15.80	-6.04	30.97	44.26
10		16.91	7.88	-6.04	-15.45	33.14
11		2.27	25.95	-6.04	-50.86	4.45
12		-15.48	10.85	-6.04	-21.27	-30.34
13		-25.96	-12.11	6.52	-23.23	49.80
14		-1.61	-18.33	6.52	-33.91	2.98
15		23.67	-16.57	6.52	-31.80	-45.53
16		17.80	8.30	6.52	15.46	-33.15
17		2.39	27.29	6.52	52.19	-4.57
18		-16.29	11.42	6.52	21.29	30.37
19		-59.80	-71.23	0.	-554.9	465.8
20		91.58	-16.16	0.	-125.9	-713.4

Table 6.2-18a (continued)
31 Node Reactor Cavity Model Force/Moment Areas

Control Volume No.	Description	A_x (ft^2)(1)	A_y (ft^2)	A_z (ft^2) (2)	M_x(ft^3) (3)	M_y(ft^3)
21		-31.78	87.39	0.	680.8	247.6
22		-59.80	-71.23	0.	-1083.	910.
23		91.58	-16.16	0.	-246.	-1393.
24		-31.78	87.39	0.	1329.	483.
25	Under Reactor Vessel	0.	0.	164.42	0.	0.
26	Instrument Chase - 1	0.	0.	0.	0.	0.
27	Instrument Chase - 2	0.	0.	0.	0.	0.
28	Penetration - Break Node See Figure 6.2-30	14.93	0.	0.	0.	3.02
29	Penetration - Pipe Sleeve See Figure 6.2-30	0.	0.	0.	0.	0.
30	Penetration - Inspection Port See Figure 6.2-30	0.	0.	0.	0.	0.
31	Containment	-14.93	0.	0.	0.	-3.02

(1) Net area for force calculation.
(2) F_z calculations use nodal pressure minus containment pressure.
(3) Net area times moment arm for moment calculations.

Table 6.2-18b
33 Node Reactor Cavity Model Force/Moment Areas

Control Volume No.	Description	A_x (ft^2)(1)	A_y (ft^2)	A_z (ft^2) (2)	M_x(ft^3) (3)	M_y(ft^3)
1 through 24	Reactor Vessel Annulus - Same as 31 Node Model See Table 6.2-16a					
25	Under Reactor Vessel	0.	0.	164.42	0.	0.
26	Instrument Chase - 1	0.	0.	0.	0.	0.
27	Instrument Chase - 2	0.	0.	0.	0.	0.
28	Penetration - Break Node 1 - See Figure 6.2-30a	6.81	0.	15.45	0.	-7.70
29	Penetration - Break Node 2 - See Figure 6.2-30a	8.12	0.	-15.45	0.	10.72
30	Penetration - Pipe Sleeve 1 - See Figure 6.2-30a	0.	0.	0.	0.	0.
31	Penetration - Pipe Sleeve 2 - See Figure 6.2-30a	0.	0.	0.	0.	0.
32	Penetration - Inspection Port - See Figure 6.2-30a	0.	0.	0.	0.	0.
33	Containment	-14.93	0.	0.	0.	-3.02

(1) Net area for force calculation.
(2) F_z calculations use nodal pressure minus containment pressure.
(3) Net area times moment arm for moment calculations.

Table 6.2-18c
Reactor Cavity Model Results Cross Reference

	22 Node Model	31 Node Model	33 Node Model
Peak Differential Pressure	Table 6.2-16a	Table 6.2-16 b	Table 6.2-16 c
Transient Differential Pressure for Selected Nodes	Figures 6.2-33 6.2-33a	Figures 6.2-33b 6.2-33c	Figures 6.2-33d 6.2-33e
Forces and Moments	Table 6.2-18 d	Table 6.2-18 e	Table 6.2-18 f; Figures 6.2-34, 6.2-34a, 6.2-34b 6.2-35, 6.2-35 a

Table 6.2-18d
22 Node Reactor Cavity Model Forces and Moments

Time (sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)
0.0	0.0	0.0	0.0	0.0	0.0
0.0051	1.252+5	-5.636+3	1.328+2	2.598+3	3.774+4
0.01	2.785+5	-1.851+4	9.343+3	4.779+3	9.869+4
0.0148	4.335+5	-3.352+4	1.800+4	-2.219+4	-1.030+4
0.02	5.802+5	-4.879+4	2.382+4	-6.805+4	-2.386+5
0.0296	6.755+5	-5.823+4	3.557+4	-8.64+4(1)	-3.098+5
0.0256	7.108+5	-5.993+4 (1)	4.054+4	-8.327+4	-2.821+5
0.032	7.236+5	-5.963+4	4.204+4	-8.122+4	-2.693+5
0.04	7.436+5(1)	-5.592+4	5.016+4	-7.764+4	-2.443+5
0.05	7.227+5	-4.764+4	5.948+4	-2.425+4	5.758+4
0.06	7.034+5	-4.161+4	6.548+4	5.131+4	4.884+5
0.067	7.056+5	-4.082+4	6.753+4	6.777+4	5.811+5 (1)
0.07	7.094+5	-4.110+4	6.838+4	6.615+4	5.724+5
0.08	7.23+5	-4.258+4	7.033+4	4.719+4	4.679+5
0.09	7.253+5	-4.236+4	7.159+4	3.905+4	4.210+5
0.10	7.166+5	-4.04+4	7.27+4	4.73+4	4.655+5
0.11	7.074+5	-3.849+4	7.36+4	5.774+4	5.23+5

Table 6.2-18d (continued)
22 Node Reactor Cavity Model Forces and Moments

Time (sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)
0.12	7.048+5	-3.78+4	7.43+4	6.027+4	5.35+5
0.13	7.074+5	-3.815+4	7.491+4	5.506+4	5.083+5
0.14	7.101+5	-3.855+4	7.557+4	5.059+4	4.818+5
0.15	7.108+5	-3.86+4	7.626+4	4.917+4	4.739+5
0.16	7.102+5	-3.842+4	7.677+4	4.974+4	4.766+5
0.167	7.098+5	-3.829+4	7.689+4 (1)	5.026+4	4.794+5
0.18	7.097+5	-3.822+4	7.638+4	5.024+4	4.795+5
0.19	7.103+5	-3.827+4	7.527+4	4.974+4	4.767+5
0.20	7.108+5	-3.832+4	7.361+4	4.948+4	4.754+5

(1) Maximum absolute value.

Table 6.2-18e
31 Node Reactor Cavity Model Forces and Moments

Time (sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)
0.0	0.0	0.0	0.0	0.0	0.0
0.0051	1.194+5	-2.882+3	-1.201+2	-8.95+2	3.119+4
0.01	2.734+5	-1.187+4	7.719+3	-1.731+4	6.836+4
0.0152	4.329+5	-2.448+4	1.663+4	-5.663+4	-8.696+4
0.02	5.492+5	-3.386+4	2.168+4	-8.78+4	-2.779+5
0.0296	6.4+5	-3.852+4	3.667+4	-5.224+4	-1.84+5
0.04	6.76+5	-3.167+4	4.637+4	-3.138+4	-6.723+4
0.05	6.899+5	-3.046+4	5.484+4	-7.078+3	1.035+5
0.06	6.917+5	-3.367+4	6.059+4	6.952+4	3.651+5
0.07	6.959+5	-3.751+4	6.422+4	1.005+5 (1)	4.269+5
0.077	6.974+5 (1)	-3.898+4	6.622+4	8.824+4	4.153+5
0.082	6.968+5	-3.930+4 (1)	6.721+4	7.552+4	4.084+5
0.09	6.934+5	-3.834+4	6.861+4	6.864+4	4.164+5
0.10	6.874+5	-3.583+4	6.978+4	8.091+4	4.486+5
0.11	6.835+5	-3.446+4	7.063+4	8.913+4	4.737+5
0.115	6.83+5	-3.465+4	7.098+4	8.50+4	4.778+5 (1)
0.13	6.854+5	-3.608+4	7.209+4	7.159+4	4.551+5

Table 6.2-18e (continued)
31 Node Reactor Cavity Model Forces and Moments

Time (sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)
0.14	6.869+5	-3.657+4	7.290+4	6.757+4	4.414+5
0.15	6.87+5	-3.653+4	7.365+4	6.613+4	4.396+5
0.16	6.866+5	-3.625+4	7.416+4	6.642+4	4.424+5
0.166	6.864+5	-3.611+4	7.426+4 (1)	6.648+4	4.431+5
0.18	6.866+5	-3.601+4	7.37+4	6.60+4	4.415+5
0.19	6.87+5	-3.604+4	7.258+4	6.572+4	4.395+5
0.20	6.874+5	-3.606+4	7.092+4	6.594+4	4.399+5

(1) Maximum absolute value.

Table 6.2-18f
33 Node Reactor Cavity Model Forces and Moments

Time (sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)
0.0	0.0	0.0	0.0	0.0	0.0
0.0051	1.255+5	-3.274+3	4.615+4	-2.510+3	-4.645+3
0.01	2.803+5	-1.264+4	8.109+4	-2.483+4	-3.587+4
0.0152	4.418+5	-2.563+4	7.694+4	-6.682+4	-2.205+5
0.020	5.565+5	-3.476+4	6.092+4	-9.087+4	-3.438+5
0.0296	6.403+5	-3.781+4	4.712+4	-4.364+4	-1.23+5
0.04	6.823+5	-3.114+4	6.923+4	-3.485+4	-8.853+4
0.05	6.988+5	-3.088+4	7.566+4	-9.219+3	4.629+4
0.06	6.982+5	-3.479+4	7.401+4	7.053+4	3.483+5
0.069	6.99+5	-3.808+4	7.738+4	1.005+5 (1)	4.360+5
0.078	7.00+5 (1)	-3.950+4	8.179+4	8.584+4	4.211+5
0.081	6.999+5	-3.960+4 (1)	8.256+4	7.889+4	4.127+5
0.10	6.921+5	-3.614+4	8.348+4	8.241+4	4.365+5
0.11	6.877+5	-3.500+4	8.456+4	8.717+4	4.649+5
0.115	6.869+5	-3.516+4	8.510+4	8.386+4	4.69+5 (1)
0.12	6.871+5	-3.556+4	8.552+4	7.956+4	4.652+5
0.13	6.889+5	-3.646+4	8.611+4	7.247+4	4.475+5

Table 6.2-18f (continued)
33 Node Reactor Cavity Model Forces and Moments

Time (sec)	F_x (lbf)	F_y (lbf)	F_z (lbf)	M_x (ft-lbf)	M_y (ft-lbf)
0.14	6.905+5	-3.694+4	8.678+4	6.797+4	4.344+5
0.15	6.908+5	-3.692+4	8.756+4	6.608+4	4.302+5
0.16	6.905+5	-3.665+4	8.807+4	6.610+4	4.311+5
0.165	6.903+5	-3.653+4	8.815+4 (1)	6.622+4	4.320+5
0.17	6.902+5	-3.645+4	8.809+4	6.621+4	4.325+5
0.18	6.903+5	-3.640+4	8.755+4	6.59+4	4.318+5
0.19	6.907+5	-3.642+4	8.642+4	6.560+4	4.301+5
0.20	6.911+5	-3.645+4	8.475+4	6.577+4	4.301+5

(1) Maximum absolute value.

Table 6.2-18g
Reactor Cavity Nodilization Study Peak Forces and Moments

	22 Node Model	31 Node Model	33 Node Model
F_x (lbf) (1)	7.436+5	6.974+5	7.00+5
F_z (lbf)	7.689+4	7.426+4	8.82+4
M_y (ft-lbf) (1)	5.811+5	4.778+5	4.69+5

(1) F_i, force in the i direction.
M_y, Moment around the y axis.

Table 6.2-19A
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
0.00	0.0	0.0	0.0	0.0
0.001	4490.38	2508.02	4340.02	2420.02
0.10	38063.53	21120.47	19000.96	10535.08
0.20	43598.25	24303.31	24167.46	13380.86
0.30	43500.59	24389.84	24686.48	13681.64
0.40	44121.98	24919.71	24049.92	13345.42
0.50	44511.53	25357.64	23145.04	12854.76
0.60	43496.67	25018.53	22382.60	12437.99
0.70	41835.05	24298.77	21761.16	12094.83
0.80	41899.51	24560.32	21228.76	11801.77
0.90	42189.99	24940.95	20828.35	11582.17
1.00	42243.16	25169.27	20501.04	11401.62
1.10	42042.40	25232.83	20244.61	11259.46
1.20	41664.71	25182.64	20094.67	11176.29
1.30	41214.41	25083.20	20002.03	11124.81
1.40	40737.13	24965.59	19888.42	11060.87
1.50	40209.09	24822.89	19757.94	10986.91
1.60	39588.37	24623.59	19677.62	10941.08
1.70	38836.63	24353.39	19640.82	10919.87
1.80	38049.31	24078.44	19567.89	10878.23
1.90	36836.83	23557.52	19425.38	10797.29
2.00	35317.53	22849.83	19272.45	10710.71
2.10	33682.01	22073.52	19131.99	10631.64
2.20	32212.87	21417.45	18932.31	10519.47
2.30	30708.22	20731.78	18640.28	10355.44
2.40	29057.87	19932.58	18207.88	10112.85
2.50	27286.94	19030.67	17735.51	9849.43

Table 6.2-19A (continued)
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
2.60	25556.73	18132.50	17379.20	9650.98
2.70	23843.10	17204.74	16988.71	9432.99
2.80	22052.80	16166.31	16586.50	9208.69
2.90	19880.08	14783.91	16200.09	8993.79
3.00	18250.32	13753.65	15889.26	8821.67
3.10	17045.54	12981.76	15550.56	8633.81
3.20	16040.88	12318.61	15213.53	8447.19
3.30	15229.90	11781.50	14884.87	8265.12
3.40	14536.64	11319.17	14613.69	8115.26
3.50	13955.20	10933.53	14363.85	7977.76
3.60	13452.15	10599.18	14173.83	7873.82
3.70	13024.98	10316.17	15316.14	8516.32
3.80	12610.95	10034.79	15503.25	8617.92
3.90	12240.71	9782.47	15271.86	8488.16

Table 6.2-19A (continued)
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
THE FOLLOWING DATA UNTIL THE END OF TABLE DENOTES Max SI				
4.00	11935.57	9573.65	14977.91	8325.04
4.20	11526.83	9273.85	14771.79	8212.47
4.40	11344.12	9110.14	14687.26	8166.45
4.60	11354.82	9041.71	14621.02	8131.73
4.80	11571.69	9064.62	14494.84	8063.21
5.00	11973.47	9172.94	14329.52	7972.24
5.20	12533.95	9364.23	14165.60	7881.50
5.40	13208.65	9623.21	14020.39	7800.84
5.60	13884.52	9887.82	13865.79	7714.90
5.80	15734.22	10983.93	13716.09	7631.32
6.00	14441.77	10422.09	13560.73	7544.38
6.20	13172.10	9832.08	13241.04	7365.30
6.40	13232.85	9805.21	13116.31	7297.20
6.60	13652.73	9951.58	12908.91	7182.27
6.80	14047.70	10090.06	12666.32	7047.26
7.00	14362.34	10192.02	12459.12	6932.25
7.20	14594.56	10248.87	12229.30	6804.66
7.40	14740.82	10257.84	12001.74	6678.38
7.60	14834.72	10242.82	11784.06	6557.56
7.80	14878.94	10203.73	11554.07	6429.64
8.00	14824.71	10115.96	11350.36	6316.46
8.20	14605.63	9953.67	11126.62	6191.42
8.40	14363.63	9781.08	10909.46	6069.90
8.60	14111.95	9588.59	10700.25	5952.49
8.80	13729.77	9313.19	10495.99	5837.31
9.00	13152.15	8923.95	10314.16	5733.98
9.20	12366.03	8410.59	10144.28	5636.36

Table 6.2-19A (continued)
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine -

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
9.40	11174.22	7647.30	10051.18	5580.70
9.60	9863.16	6856.84	10029.32	5562.06
9.80	9156.55	6473.79	9896.50	5476.30
10.00	8869.03	6336.75	9804.70	5412.87
10.20	8555.61	6184.74	9692.83	5338.78
10.40	8221.66	6009.27	9595.51	5273.78
10.60	7965.11	5859.47	9476.72	5197.74
10.80	7666.63	5670.37	9321.64	5103.29
11.00	7340.35	5478.32	9249.02	5057.18
11.20	7063.17	5315.91	9084.84	4958.15
11.40	6813.42	5169.97	9084.69	4928.66
11.60	6537.66	5017.17	8857.13	4759.10
11.80	6232.37	4891.66	9045.91	4782.73
12.00	5819.98	4750.81	8756.42	4543.67
12.20	5322.37	4604.37	8599.38	4367.29
12.40	4752.12	4448.01	8419.39	4197.96
12.60	4191.02	4317.36	7361.36	3586.78
12.80	3667.76	4186.92	7784.52	3685.44
13.00	3289.34	4005.41	6754.60	3149.15
13.20	2899.29	3583.87	6275.28	2855.65
13.40	2627.05	3263.05	6378.07	2818.64
13.60	2376.51	2962.64	5759.51	2494.09
13.80	2175.43	2719.60	5256.76	2222.98
14.00	1988.85	2492.27	5109.59	2089.31
14.20	1809.87	2273.15	5467.11	2165.62
14.40	1631.78	2053.53	6282.93	2401.49
14.60	1463.28	1844.95	5998.17	2223.49
14.80	1309.25	1654.00	5545.56	2008.01

Table 6.2-19A (continued)
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine -

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
15.00	1205.01	1526.81	5288.71	1872.45
15.20	1039.96	1319.85	4854.42	1673.98
15.40	907.32	1152.53	4228.43	1418.43
15.60	783.54	996.13	3890.34	1263.42
15.80	678.47	863.23	3335.58	1047.21
16.00	587.46	747.76	2642.85	802.78
16.20	551.63	702.76	1733.04	512.51
16.40	501.06	638.68	598.28	174.59
16.60	449.72	573.40	0.00	0.00
16.80	399.89	510.10	0.00	0.00
17.00	346.37	442.06	0.00	0.00
17.20	308.81	394.32	0.00	0.00
17.40	262.62	335.49	0.00	0.00
17.60	205.26	262.40	0.00	0.00
17.80	164.40	210.32	0.00	0.00
18.00	135.80	173.89	0.00	0.00
18.20	108.09	138.55	0.00	0.00
18.40	68.58	88.03	0.00	0.00
18.60	15.01	19.34	0.00	0.00
18.80	0.00	0.00	0.00	0.00

* M&E exiting the SG side of the break
** M&E exiting the pump side of the break

Table 6.2-19B
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
0.00	0.0	0.0	0.0	0.0
0.001	4490.38	2508.02	4340.02	2420.02
0.10	38063.53	21120.47	19000.96	10535.08
0.20	43598.25	24303.31	24167.46	13380.86
0.30	43500.59	24389.84	24686.48	13681.64
0.40	44121.98	24919.71	24049.92	13345.42
0.50	44511.53	25357.64	23145.04	12854.76
0.60	43496.67	25018.53	22382.60	12437.99
0.70	41835.05	24298.77	21761.16	12094.83
0.80	41899.51	24560.32	21228.76	11801.77
0.90	42189.99	24940.95	20828.35	11582.17
1.00	42243.16	25169.27	20501.04	11401.62
1.10	42042.40	25232.83	20244.61	11259.46
1.20	41664.71	25182.64	20094.67	11176.29
1.30	41214.41	25083.20	20002.03	11124.81
1.40	40737.13	24965.59	19888.42	11060.87
1.50	40209.09	24822.89	19757.94	10986.91
1.60	39588.37	24623.59	19677.62	10941.08
1.70	38836.63	24353.39	19640.82	10919.87
1.80	38049.31	24078.44	19567.89	10878.23
1.90	36836.83	23557.52	19425.38	10797.29
2.00	35317.53	22849.83	19272.45	10710.71
2.10	33682.01	22073.52	19131.99	10631.64
2.20	32212.87	21417.45	18932.31	10519.47
2.30	30708.22	20731.78	18640.28	10355.44
2.40	29057.87	19932.58	18207.88	10112.85
2.50	27286.94	19030.67	17735.51	9849.43

Table 6.2-19B (continued)
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
2.60	25556.73	18132.50	17379.20	9650.98
2.70	23843.10	17204.74	16988.71	9432.99
2.80	22052.80	16166.31	16586.50	9208.69
2.90	19880.08	14783.91	16200.09	8993.79
3.00	18250.32	13753.65	15889.26	8821.67
3.10	17045.54	12981.76	15550.56	8633.81
3.20	16040.88	12318.61	15213.53	8447.19
3.30	15229.90	11781.50	14884.87	8265.12
3.40	14536.64	11319.17	14613.69	8115.26
3.50	13955.20	10933.53	14363.85	7977.76
3.60	13452.15	10599.18	14173.83	7873.82
3.70	13024.98	10316.17	15316.14	8516.32
3.80	12610.95	10034.79	15503.25	8617.92
3.90	12240.71	9782.47	15271.86	8488.16
4.00	11935.57	9573.65	14977.91	8325.04
4.20	11526.83	9273.85	14771.79	8212.47
4.40	11344.12	9110.14	14687.26	8166.45
4.60	11354.82	9041.71	14621.02	8131.73
4.80	11571.69	9064.62	14494.84	8063.21
5.00	11973.47	9172.94	14329.52	7972.24
5.20	12533.95	9364.23	14165.60	7881.50
5.40	13208.65	9623.21	14020.39	7800.84
5.60	13884.52	9887.82	13865.79	7714.90
5.80	15734.22	10983.93	13716.09	7631.32
6.00	14441.77	10422.09	13560.73	7544.38
6.20	13172.10	9832.08	13241.04	7365.30
6.40	13232.85	9805.21	13116.31	7297.20
6.60	13652.73	9951.58	12908.91	7182.27

Table 6.2-19B (continued)
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
6.80	14047.70	10090.06	12666.32	7047.26
7.00	14362.34	10192.02	12459.12	6932.25
7.20	14594.56	10248.87	12229.30	6804.66
7.40	14740.82	10257.84	12001.74	6678.38
7.60	14834.72	10242.82	11784.06	6557.56
7.80	14878.94	10203.73	11554.07	6429.64
8.00	14824.71	10115.96	11350.36	6316.46
8.20	14605.63	9953.67	11126.62	6191.42
8.40	14363.63	9781.08	10909.46	6069.90
8.60	14111.95	9588.59	10700.25	5952.49
8.80	13729.77	9313.19	10495.99	5837.31
9.00	13152.15	8923.95	10314.16	5733.98
9.20	12366.03	8410.59	10144.28	5636.36
9.40	11174.22	7647.30	10051.18	5580.70
9.60	9863.16	6856.84	10029.32	5562.06
9.80	9156.55	6473.79	9896.50	5476.30
10.00	8869.03	6336.75	9804.70	5412.87
10.20	8555.61	6184.74	9692.83	5338.78
10.40	8221.66	6009.27	9595.51	5273.78
10.60	7965.10	5859.41	9490.73	5200.53
10.80	7659.14	5664.93	9355.53	5104.17
11.00	7312.35	5461.31	9270.98	5045.07
11.20	7047.83	5307.02	9136.04	4956.51
11.40	6802.40	5159.90	9096.31	4904.16
11.60	6534.84	5011.28	8920.82	4761.46
11.80	6235.05	4888.54	9029.24	4744.14
12.00	5818.50	4746.20	8873.31	4579.95
12.20	5313.85	4596.74	8360.03	4229.90

Table 6.2-19B (continued)
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
12.40	4755.24	4450.53	8692.05	4307.55
12.60	4174.74	4304.13	7405.01	3610.73
12.80	3669.59	4192.38	7276.56	3440.39
13.00	3281.18	3994.29	7702.69	3569.41
13.20	2885.52	3567.59	6102.89	2791.73
13.40	2634.87	3272.99	5950.15	2639.86
13.60	2372.61	2957.52	5149.71	2222.39
13.80	2168.82	2711.56	5391.46	2268.09
14.00	1979.28	2480.53	5146.31	2107.52
14.20	1802.18	2263.57	5305.88	2107.07
14.40	1628.06	2049.08	6646.24	2533.52
14.60	1457.64	1838.03	6035.08	2222.72
14.80	1303.41	1646.61	5508.42	1982.44
15.00	1195.92	1515.47	5251.82	1848.53
15.20	1034.05	1312.38	4847.54	1662.92
15.40	899.74	1142.94	4409.06	1467.22
15.60	778.04	989.17	3906.01	1256.15
15.80	690.51	878.69	3304.59	1024.51
16.00	606.90	772.88	2526.60	755.89
16.20	563.26	717.51	1507.85	438.45
16.40	518.11	660.35	127.56	36.70
16.60	458.35	584.40	0.0	0.0
16.80	403.69	514.96	0.0	0.0
17.00	363.39	463.81	0.0	0.0
17.20	321.31	410.25	0.0	0.0
17.40	261.44	333.97	0.0	0.0
17.60	212.44	271.58	0.0	0.0
17.80	171.44	219.33	0.0	0.0

Table 6.2-19B (continued)
Blowdown Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME Seconds	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec	FLOW Lbm/Sec	ENERGY Thousand Btu/Sec
18.00	145.88	186.78	0.0	0.0
18.20	107.70	138.02	0.0	0.0
18.40	55.11	70.77	0.0	0.0
18.60	0.00	0.00	0.0	0.0

* M&E exiting the SG side of the break
** M&E exiting the pump side of the break

Table 6.2-20
Blowdown Mass and Energy Releases Double-Ended
Hot Leg Guillotine

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (Thousand Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
0.00	0.0	0.0	0.0	0.0
0.001	1962.74	1286.36	1962.63	1286.28
0.002	4090.93	2687.15	4018.10	2625.86
0.003	7244.43	4763.14	9332.79	6098.68
0.004	10277.19	6752.24	13661.08	8926.43
0.005	12829.29	8413.34	17521.21	11447.70
0.006	14452.62	9457.97	20759.46	13562.09
0.007	16122.50	10536.64	23672.24	15463.16
0.008	19904.84	13008.64	26237.28	17136.40
0.10	42489.29	28258.65	28317.16	18466.91
0.20	36559.05	24457.46	24553.97	15897.56
0.30	36892.94	24679.97	22039.10	14074.71
0.40	35964.89	24078.14	20735.89	13024.72
0.50	35286.64	23658.89	19985.85	12353.79
0.60	34746.62	23347.61	19464.92	11865.58
0.70	34065.76	22958.32	19026.69	11458.87
0.80	33147.53	22419.34	18719.30	11160.75
0.90	32337.50	21968.53	18462.16	10913.17
1.00	31746.07	21684.62	18233.43	10701.26
1.10	31207.86	21417.11	18051.25	10530.13
1.20	30582.01	21062.05	17912.16	10393.64
1.30	29906.17	20664.22	17800.47	10280.75
1.40	29202.20	20247.20	17732.39	10198.98
1.50	28506.26	19840.72	17698.20	10140.82
1.60	27814.14	19439.72	17688.50	10100.75
1.70	27067.74	18999.22	17693.91	10072.27
1.80	26267.82	18515.41	17706.32	10050.50
1.90	25492.35	18045.45	17721.30	10032.85
2.00	24752.81	17599.02	17736.99	10017.72
2.10	24045.94	17167.26	17749.04	10003.16
2.20	23372.64	16749.18	17755.46	9987.87
2.30	22724.08	16334.87	17753.64	9970.13
2.40	22115.96	15934.17	17739.69	9947.78
2.50	21566.83	15564.97	17715.74	9921.85
2.60	21074.32	15220.50	17678.46	9890.53
2.70	20653.58	14913.80	17626.72	9853.09

Table 6.2-20 (continued)
Blowdown Mass and Energy Releases Double-Ended
Hot Leg Guillotine

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (Thousand Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
2.80	20295.21	14637.77	17560.53	9809.30
2.90	19976.14	14377.27	17475.96	9757.00
3.00	19718.80	14149.88	17374.13	9696.74
3.10	19507.22	13946.72	17253.52	9627.61
3.20	19339.53	13768.74	17116.50	9550.91
3.30	19210.01	13613.26	16962.45	9466.24
3.40	19117.22	13480.96	16792.33	9374.09
3.50	19053.52	13364.86	16605.22	9273.91
3.60	19094.95	13301.61	16398.28	9164.05
3.70	19229.90	13291.46	16178.79	9048.59
3.80	19412.80	13310.84	15961.70	8935.72
3.90	19600.59	13326.54	15753.38	8829.30
4.00	19780.57	13336.88	15533.51	8716.99
4.20	20143.57	13361.35	15004.26	8442.94
4.40	20474.19	13391.31	14475.38	8170.83
4.60	20798.14	13438.43	13991.81	7926.63
4.80	21179.05	13531.61	13504.52	7679.94
5.00	21694.65	13697.42	13031.49	7439.58
5.20	16767.93	11580.36	12602.17	7222.50
5.40	16434.36	11283.10	12184.11	7009.70
5.60	16608.98	11277.94	11821.43	6825.77
5.80	16750.95	11319.34	11510.91	6669.25
6.00	16900.03	11311.04	11229.43	6525.76
6.20	17103.60	11351.82	10977.71	6396.52
6.40	17256.49	11388.23	10754.12	6281.04
6.60	17334.17	11368.39	10546.64	6172.79
6.80	17149.71	11210.29	10352.14	6070.63
7.00	17381.89	11272.07	10169.66	5974.24
7.20	17621.05	11346.34	9991.92	5880.10

Table 6.2-20 (continued)
Blowdown Mass and Energy Releases Double-Ended
Hot Leg Guillotine

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (Thousand Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
7.40	17886.58	11441.81	9814.81	5785.78
7.60	18255.00	11584.09	9620.42	5681.41
7.80	18910.03	11908.82	9416.27	5572.67
8.00	18728.39	11753.08	9197.77	5457.40
8.20	18195.71	11385.38	8966.99	5336.93
8.40	15321.99	9826.18	8717.06	5207.60
8.60	14873.70	9557.10	8473.94	5084.35
8.80	14827.00	9506.86	8229.46	4962.51
9.00	14769.08	9455.53	8007.08	4853.67
9.20	14661.56	9376.90	7771.26	4735.62
9.40	14483.64	9261.54	7545.51	4622.34
9.60	14157.25	9067.60	7311.60	4504.88
9.80	13664.65	8786.13	7074.58	4387.08
10.00	13135.12	8489.01	6835.83	4270.24
10.20	12685.91	8240.55	6594.76	4153.22
10.30	12680.07	8237.39	6591.53	4151.68
10.40	12296.41	8032.34	6360.45	4040.85
10.60	11903.02	7831.47	6130.73	3930.65
10.80	11478.27	7623.56	5905.29	3822.75
11.00	11032.92	7414.81	5688.63	3718.87
11.20	10170.73	7136.35	5474.71	3616.44
11.40	9473.09	6934.13	5248.76	3506.56
11.60	8801.95	6698.57	4989.21	3379.05
11.80	7817.40	6269.81	4679.02	3231.04
12.00	6755.00	5800.16	4319.36	3068.33
12.20	5912.66	5456.75	3923.37	2898.21
12.40	5234.57	5173.46	3525.23	2734.86
12.60	4707.04	4891.41	3156.53	2586.12

Table 6.2-20 (continued)
Blowdown Mass and Energy Releases Double-Ended
Hot Leg Guillotine

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (Thousand Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
12.80	4330.28	4592.68	2828.56	2451.14
13.00	4061.14	4280.79	2569.67	2337.38
13.20	3861.23	4020.52	2354.32	2239.75
13.40	3620.34	3779.66	2172.65	2150.97
13.60	3318.79	3535.71	2031.47	2084.88
13.80	2973.74	3287.26	1897.32	2016.18
14.00	2627.37	3033.27	1758.21	1947.27
14.20	2298.02	2785.55	1619.47	1877.67
14.40	2069.03	2555.41	1469.18	1774.90
14.60	1943.02	2405.66	1348.37	1653.70
14.80	1822.11	2253.22	1252.49	1546.18
15.00	1709.53	2112.08	1181.47	1462.90
15.20	1592.28	1966.96	1190.73	1475.93
15.40	1515.40	1865.16	1095.06	1362.52
15.60	1422.49	1751.31	1026.48	1279.50
15.80	1325.63	1646.12	943.31	1177.59
16.00	1244.73	1548.59	847.12	1059.39
16.20	1179.26	1465.89	792.05	992.62
16.40	1276.72	1588.63	771.53	968.16
16.60	1179.64	1468.04	782.75	983.13
16.80	1083.78	1347.51	818.64	1028.25
17.00	964.23	1211.48	838.69	1053.07
17.20	790.59	1000.93	809.51	1015.93
17.40	627.35	796.02	680.43	853.46
17.60	476.09	606.25	618.71	779.59
17.80	352.45	448.40	629.00	793.06
18.00	260.15	331.87	527.47	663.58
18.20	193.69	247.24	374.36	472.60
18.40	109.48	139.99	345.41	436.83
18.60	89.55	114.79	176.79	224.33
18.80	0.00	0.00	72.14	92.36

Table 6.2-20 (continued)
Blowdown Mass and Energy Releases Double-Ended
Hot Leg Guillotine

BREAK PATH No. 1*			BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (Thousand Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
19.00	0.00	0.00	0.00	0.00

* M&E exiting from the Reactor Vessel (RV) side of the break
** M&E exiting from the SG side of the break

Table 6.2-21
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

BREAK PATH No. 1*			BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
18.80	0.00	0.00	0.00	0.00
19.25	0.00	0.00	0.00	0.00
19.35	0.00	0.00	0.00	0.00
19.55	0.00	0.00	0.00	0.00
19.65	0.00	0.00	0.00	0.00
19.79	78.26	92.44	0.00	0.00
19.80	70.43	83.19	0.00	0.00
19.91	51.41	60.71	0.00	0.00
20.01	56.36	66.56	0.00	0.00
20.11	62.71	74.07	0.00	0.00
20.21	68.87	81.34	0.00	0.00
20.31	74.74	88.27	0.00	0.00
20.41	80.31	94.86	0.00	0.00
20.51	85.62	101.14	0.00	0.00
20.61	90.70	107.14	0.00	0.00
20.71	95.57	112.89	0.00	0.00
20.81	100.24	118.42	0.00	0.00
20.91	104.74	123.74	0.00	0.00
21.01	109.09	128.87	0.00	0.00
21.11	113.29	133.84	0.00	0.00
21.21	117.36	138.66	0.00	0.00
21.31	121.31	143.33	0.00	0.00
21.41	125.15	147.87	0.00	0.00
21.51	128.88	152.28	0.00	0.00
21.61	132.51	156.58	0.00	0.00
21.71	136.06	160.78	0.00	0.00
21.81	139.52	164.87	0.00	0.00
22.68	303.38	359.22	2757.66	326.98
22.82	450.74	534.95	4302.92	529.31
23.88	547.75	651.25	5185.21	676.25
24.88	532.26	632.67	5051.62	662.85
25.88	515.71	612.83	4905.04	647.32
26.88	499.56	593.48	4759.38	631.68
27.88	484.14	575.02	4618.27	616.44
28.88	469.55	557.56	4482.82	601.77
29.88	455.77	541.07	4353.24	587.72

Table 6.2-21 (continued)
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
30.73	467.72	555.25	4504.35	587.24
30.93	463.32	550.06	4449.36	585.29
31.93	450.25	534.46	4318.51	573.73
32.93	439.18	521.23	4212.89	562.02
33.93	428.66	508.65	4111.43	550.77
34.93	418.48	496.49	4012.28	539.86
35.93	408.77	484.89	3916.83	529.35
36.43	404.08	479.30	3870.45	524.24
36.93	399.50	473.83	3824.93	519.23
37.93	390.65	463.26	3736.33	509.49
38.93	382.18	453.15	3650.81	500.08
39.93	374.06	443.46	3568.16	490.98
40.93	366.26	434.16	3488.20	482.18
41.93	205.15	242.61	1471.37	268.32
42.93	321.85	381.23	266.48	164.93
43.43	322.43	381.95	266.50	165.30
43.93	319.20	378.11	265.25	163.52
44.93	312.40	370.01	262.64	159.79
45.93	305.70	362.04	260.07	156.13
46.93	298.93	353.98	257.47	152.44
47.93	292.66	346.52	255.08	149.04
48.93	286.64	339.36	252.79	145.80
49.93	280.76	332.37	250.55	142.64
50.93	275.01	325.54	248.37	139.57
51.33	272.75	322.86	247.51	138.37
51.93	269.40	318.87	246.25	136.59
52.93	263.91	312.35	244.18	133.69
53.93	258.56	305.99	242.16	130.87
54.93	253.32	299.78	240.20	128.12
55.93	248.21	293.71	238.28	125.46
56.93	243.22	287.78	236.42	122.87
57.93	238.35	282.00	234.61	120.36
58.93	233.60	276.36	232.85	117.92
59.93	228.97	270.86	231.14	115.55
60.93	224.44	265.49	229.47	113.25
61.93	220.02	260.25	227.85	111.02
62.93	215.72	255.14	226.28	108.86

Table 6.2-21 (continued)
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
63.93	211.52	250.17	224.75	106.76
64.93	207.44	245.32	223.27	104.73
65.93	203.46	240.61	221.83	102.76
66.93	199.59	236.02	220.44	100.86
67.93	195.83	231.56	219.09	99.02
68.93	192.17	227.23	217.78	97.24
69.93	188.62	223.01	216.52	95.52
70.73	185.85	219.73	215.54	94.19
70.93	185.17	218.93	215.30	93.86
71.93	181.82	214.96	214.11	92.26
72.93	178.57	211.11	212.97	90.72
73.93	175.42	207.38	211.87	89.23
74.93	172.37	203.77	210.81	87.79
75.93	169.42	200.27	209.79	86.41
76.93	166.56	196.89	208.80	85.08
77.93	163.83	193.66	207.83	83.82
78.93	161.20	190.54	206.90	82.60
79.93	158.66	187.53	206.00	81.44
81.93	153.81	181.79	204.30	79.23
83.93	149.30	176.45	202.74	77.20
85.93	145.10	171.49	201.29	75.33
87.93	141.22	166.89	199.97	73.61
89.93	137.64	162.65	198.75	72.04
91.93	134.34	158.75	197.64	70.60
93.93	131.31	155.17	196.62	69.29
95.93	128.54	151.89	195.70	68.10
96.33	128.02	151.27	195.52	67.87
97.93	126.02	148.90	194.86	67.01
99.93	123.72	146.18	194.10	66.03
101.93	121.62	143.70	193.40	65.14
103.93	119.73	141.46	192.78	64.34
105.93	118.02	139.44	192.22	63.61
107.93	116.48	137.62	191.71	62.96
109.93	115.11	136.00	191.26	62.38
111.93	113.89	134.56	190.85	61.86
113.93	112.81	133.28	190.49	61.39
115.93	111.86	132.15	190.17	60.98

Table 6.2-21 (continued)
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
117.93	111.02	131.17	189.88	60.61
119.93	110.30	130.31	189.63	60.29
121.93	109.67	129.56	189.41	60.01
123.93	109.13	128.93	189.22	59.76
125.93	108.68	128.39	189.05	59.54
127.13	108.44	128.11	188.96	59.43
127.93	108.30	127.94	188.90	59.36
129.93	107.98	127.57	188.78	59.20
131.93	107.73	127.28	188.67	59.06
133.93	107.54	127.05	188.58	58.94
135.93	107.40	126.88	188.51	58.85
137.93	107.30	126.76	188.44	58.77
139.93	107.24	126.70	188.40	58.71
141.93	107.23	126.68	188.36	58.66
143.93	107.24	126.70	188.33	58.63
145.93	107.29	126.75	188.31	58.60
147.93	107.36	126.84	188.30	58.59
149.93	107.46	126.95	188.30	58.59
151.93	107.56	127.08	188.30	58.59
153.93	107.69	127.22	188.31	58.60
155.93	107.83	127.39	188.32	58.61
157.93	107.98	127.57	188.34	58.63
159.93	108.16	127.78	188.36	58.66
160.73	108.23	127.86	188.37	58.67
161.93	108.34	127.99	188.38	58.69
163.93	108.54	128.22	188.41	58.73
165.93	108.74	128.47	188.44	58.77
167.93	108.96	128.72	188.48	58.81
169.93	109.18	128.98	188.51	58.86
171.93	109.41	129.26	188.55	58.91
173.93	109.64	129.53	188.59	58.96
175.93	109.88	129.82	188.64	59.02
177.93	110.13	130.11	188.68	59.08
179.93	110.38	130.41	188.73	59.14
181.93	110.64	130.71	188.78	59.20
183.93	110.89	131.01	188.83	59.26
185.93	111.15	131.32	188.88	59.33

Table 6.2-21 (continued)
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

BREAK PATH No. 1*			BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
187.93	111.42	131.63	188.93	59.39
189.93	111.68	131.94	188.98	59.46
191.93	111.95	132.26	189.03	59.53
193.93	112.22	132.58	189.09	59.60
195.83	112.47	132.88	189.14	59.66
195.93	112.49	132.89	189.14	59.67
197.93	112.76	133.22	189.20	59.74
199.93	113.03	133.54	189.26	59.81
201.93	113.29	133.85	189.31	59.88
203.93	113.55	134.15	189.36	59.95
205.93	113.81	134.46	189.42	60.02
207.93	114.07	134.77	189.47	60.09
209.93	114.34	135.09	189.53	60.16
211.93	114.61	135.41	189.59	60.23
213.93	114.88	135.73	189.64	60.31
215.93	115.15	136.05	189.70	60.39
217.93	115.45	136.40	189.77	60.47
219.93	116.23	137.32	190.21	60.80
221.23	116.59	137.74	190.67	61.00

* M&E exiting the SG side of the break
** M&E exiting the pump side of the break

Table 6.2-22
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

BREAK PATH No. 1*			BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
18.60	0.00	0.00	0.00	0.00
19.00	0.00	0.00	296.63	18.70
19.10	0.00	0.00	296.63	18.70
19.20	0.00	0.00	296.63	18.70
19.30	0.00	0.00	296.63	18.70
19.35	0.00	0.00	296.63	18.70
19.61	55.04	65.01	296.63	18.70
19.71	59.50	70.27	296.63	18.70
19.81	66.12	78.09	296.63	18.70
19.91	72.59	85.73	296.63	18.70
20.01	78.76	93.02	296.63	18.70
20.11	84.63	99.96	296.63	18.70
20.21	90.22	106.57	296.63	18.70
20.24	91.58	108.17	296.63	18.70
20.31	95.56	112.88	296.63	18.70
20.41	100.68	118.94	296.63	18.70
20.51	105.60	124.75	296.63	18.70
20.61	110.34	130.36	296.63	18.70
20.71	114.91	135.77	296.63	18.70
20.81	119.34	141.00	296.63	18.70
20.91	123.62	146.07	296.63	18.70
21.01	127.78	150.99	296.63	18.70
21.11	131.82	155.77	296.63	18.70
21.21	135.76	160.42	296.63	18.70
21.31	139.59	164.95	296.63	18.70
21.41	143.32	169.37	296.63	18.70
21.51	146.97	173.69	296.63	18.70
21.61	150.53	177.91	296.63	18.70
22.65	603.26	717.66	5737.31	693.91
23.25	611.25	727.47	5768.91	720.08
23.65	605.64	720.75	5723.32	715.84
24.65	589.34	701.17	5587.65	701.27
25.65	572.41	680.84	5443.31	685.42
26.65	556.02	661.17	5301.25	669.68
26.75	554.42	659.25	5287.30	668.13

Table 6.2-22 (continued)
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
27.65	540.43	642.47	5164.25	654.46
28.65	525.70	624.80	5033.11	639.87
29.65	511.79	608.13	4907.89	625.93
30.65	498.66	592.41	4788.39	612.64
31.55	487.47	579.00	4685.45	601.19
31.65	486.26	577.55	4674.27	599.95
32.65	474.52	563.50	4565.17	587.83
33.65	463.39	550.18	4460.74	576.23
34.65	452.81	537.52	4360.64	565.12
35.65	442.74	525.49	4264.55	554.46
36.65	433.15	514.02	4172.18	544.21
37.25	427.60	507.39	4118.43	538.25
37.65	423.99	503.07	4083.26	534.35
38.65	415.22	492.60	3997.55	524.85
39.65	406.82	482.57	3914.83	515.67
40.65	398.76	472.94	3834.90	506.81
41.65	391.01	463.69	3757.57	498.22
42.65	228.69	270.53	1857.68	297.14
43.65	172.89	204.38	563.88	135.31
44.15	172.67	204.12	564.31	135.21
44.65	172.45	203.86	564.77	135.13
45.65	172.03	203.36	565.72	134.97
46.65	171.61	202.86	566.70	134.81
47.65	171.19	202.37	567.68	134.66
48.65	170.77	201.87	568.65	134.51
49.65	170.36	201.38	569.62	134.35
50.65	169.95	200.90	570.58	134.20
51.65	169.54	200.41	571.53	134.05
52.65	169.13	199.93	572.47	133.89
53.65	168.72	199.44	573.41	133.74
54.65	168.32	198.96	574.34	133.59
55.65	167.91	198.49	575.27	133.43
56.65	167.51	198.01	576.20	133.28
57.65	167.11	197.54	577.11	133.13
58.65	166.71	197.07	578.03	132.97
59.65	166.32	196.60	578.94	132.82
60.65	165.92	196.13	579.85	132.67

Table 6.2-22 (continued)
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
61.65	165.52	195.66	580.76	132.52
62.65	165.13	195.19	581.67	132.36
63.65	164.73	194.72	582.58	132.21
64.65	164.34	194.26	583.48	132.06
64.85	164.26	194.16	583.66	132.03
65.65	163.95	193.79	584.39	131.91
66.65	163.56	193.33	585.29	131.76
67.65	163.16	192.86	586.19	131.61
68.65	162.77	192.40	587.09	131.46
69.65	162.39	191.94	587.99	131.32
70.65	162.00	191.48	588.89	131.17
71.65	161.61	191.02	589.79	131.02
72.65	161.22	190.57	590.68	130.87
73.65	160.84	190.11	591.58	130.73
74.65	160.45	189.65	592.48	130.58
75.65	160.07	189.20	593.37	130.44
76.65	159.69	188.74	594.27	130.30
77.65	159.30	188.29	595.17	130.15
78.65	158.92	187.84	596.06	130.01
79.65	158.54	187.39	596.96	129.87
81.65	157.77	186.48	598.76	129.59
83.65	157.00	185.57	600.56	129.31
85.65	156.23	184.66	602.36	129.02
87.15	155.66	183.98	603.71	128.81
87.65	155.47	183.75	604.15	128.74
89.65	154.70	182.84	605.93	128.46
91.65	153.93	181.93	607.70	128.17
93.65	153.16	181.02	609.46	127.89
95.65	152.39	180.11	611.21	127.60
97.65	151.62	179.20	612.95	127.31
99.65	150.85	178.28	614.68	127.02
101.65	150.07	177.37	616.41	126.73
103.65	149.30	176.44	618.14	126.44
105.65	148.52	175.52	619.86	126.15
107.65	147.74	174.60	621.57	125.85
109.65	146.95	173.67	623.28	125.56
111.55	146.21	172.79	624.89	125.28

Table 6.2-22 (continued)
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

BREAK PATH No. 1*			BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
111.65	146.17	172.75	624.98	125.27
113.65	145.39	171.82	626.67	124.97
115.65	144.60	170.89	628.36	124.67
117.65	143.82	169.96	630.05	124.38
119.65	143.03	169.03	631.72	124.08
121.65	142.24	168.10	633.40	123.78
123.65	141.46	167.17	635.06	123.49
125.65	140.67	166.23	636.73	123.19
127.65	139.88	165.30	638.39	122.89
129.65	139.09	164.36	640.04	122.60
131.65	138.30	163.43	641.69	122.30
133.65	137.50	162.49	643.33	122.00
135.65	136.71	161.55	644.97	121.71
137.65	135.92	160.61	646.60	121.41
138.35	135.64	160.28	647.18	121.31
139.65	135.12	159.67	648.23	121.11
141.65	134.33	158.73	649.86	120.82
143.65	133.53	157.79	651.48	120.52
145.65	132.73	156.85	653.10	120.23
147.65	131.94	155.90	654.72	119.93
149.65	131.14	154.96	656.33	119.64
151.65	130.33	154.00	657.94	119.34
153.65	129.52	153.05	659.56	119.05
155.65	128.79	152.18	661.45	118.94
157.65	128.26	151.55	662.50	118.90
159.65	127.72	150.92	663.54	118.86
161.65	127.19	150.29	664.58	118.82
163.65	126.66	149.66	665.62	118.77
165.65	126.14	149.04	666.65	118.72
167.65	125.61	148.42	667.67	118.67
168.25	125.46	148.24	667.98	118.65
169.65	125.09	147.80	668.69	118.62
171.65	124.57	147.19	669.71	118.56
173.65	124.05	146.58	670.72	118.50
175.65	123.54	145.97	671.73	118.43
177.65	123.03	145.36	672.73	118.37
179.65	122.52	144.76	673.73	118.30

Table 6.2-22 (continued)
Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

BREAK PATH No. 1*			BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND Btu/Sec)	TIME (SEC)	FLOW (LBM/SEC)
181.65	122.01	144.16	674.72	118.22
183.65	121.51	143.56	675.71	118.15
185.65	121.00	142.97	676.70	118.07
187.65	120.51	142.38	677.68	117.99
189.65	120.01	141.79	678.65	117.91
191.65	119.51	141.21	679.63	117.82
193.65	119.02	140.63	680.59	117.73
195.65	118.53	140.05	681.56	117.64
197.65	118.05	139.47	682.52	117.55
199.65	117.56	138.90	683.47	117.46
201.55	117.10	138.36	684.38	117.36

* M&E exiting the SG side of the break
** M&E exiting the pump side of the break

Table 6.2-23
Double-Ended Pump Suction Break - Minimum Safeguards
Principle Parameters During Reflood

TIME (SEC)	TEMP (°F)	FLOODING RATE (IN/SEC)	CARRYOVER FRACTION	CORE HEIGHT (FT)	DOWNCOMER HEIGHT (FT)	FLOW FRACTION	TOTAL	INJECTION (LBM/SEC)	SPILL	ENTHALPY (BTU/LBM)
18.8	192.7	0.000	0.000	0.00	0.00	0.333	0.0	0.0	0.0	0.00
19.6	189.1	29.368	0.000	0.82	2.44	0.000	9351.8	9351.8	0.0	89.75
19.7	188.1	32.087	0.000	1.08	2.45	0.000	9297.7	9297.7	0.0	89.75
20.6	186.9	3.192	0.320	1.51	6.41	0.402	8744.8	8744.8	0.0	89.75
21.6	186.7	3.004	0.459	1.67	10.88	0.437	8310.6	8310.6	0.0	89.75
23.9	186.2	5.549	0.642	2.02	15.62	0.692	6349.7	6349.7	0.0	89.75
24.9	185.9	5.151	0.676	2.17	15.62	0.690	6097.0	6097.0	0.0	89.75
27.9	185.8	4.494	0.717	2.53	15.62	0.680	5492.7	5492.7	0.0	89.75
29.9	186.1	4.216	0.728	2.73	15.62	0.673	5160.6	5160.6	0.0	89.75
30.7	186.2	4.267	0.732	2.81	15.62	0.685	5320.7	4976.1	0.0	88.02
32.9	186.8	4.033	0.737	3.01	15.62	0.669	4976.6	4619.1	0.0	87.83
38.9	188.9	3.584	0.744	3.50	15.62	0.650	4313.0	3931.1	0.0	87.39
41.9	190.2	2.457	0.733	3.71	15.62	0.517	1863.8	1429.4	0.0	83.53
42.9	190.7	3.186	0.744	3.77	15.48	0.619	402.2	0.0	0.0	63.05
46.9	193.0	2.971	0.743	4.04	14.58	0.614	407.1	0.0	0.0	63.05
54.9	198.9	2.582	0.740	4.51	13.17	0.601	417.6	0.0	0.0	63.05
64.9	207.8	2.196	0.736	5.03	11.99	0.582	426.7	0.0	0.0	63.05
75.9	218.4	1.879	0.732	5.53	11.27	0.559	433.1	0.0	0.0	63.05
87.9	228.8	1.645	0.729	6.00	10.96	0.535	436.3	0.0	0.0	63.05
103.9	239.7	1.466	0.727	6.56	11.02	0.510	438.4	0.0	0.0	63.05
117.9	247.6	1.390	0.728	7.01	11.33	0.498	439.2	0.0	0.0	63.05
133.9	255.3	1.354	0.732	7.51	11.81	0.493	439.6	0.0	0.0	63.05

Table 6.2-23 (continued)
Double-Ended Pump Suction Break - Minimum Safeguards
Principle Parameters During Reflood

TIME (SEC)	TEMP (°F)	FLOODING RATE (IN/SEC)	CARRYOVER FRACTION	CORE HEIGHT (FT)	DOWNCOMER HEIGHT (FT)	FLOW FRACTION	TOTAL	INJECTION (LBM/SEC)	SPILL	ENTHALPY (BTU/LBM)
151.9	262.8	1.343	0.737	8.04	12.40	0.494	439.7	0.0	0.0	63.05
157.9	265.0	1.342	0.739	8.22	12.61	0.495	439.6	0.0	0.0	63.05
167.9	268.6	1.343	0.742	8.51	12.95	0.497	439.6	0.0	0.0	63.05
185.9	274.3	1.348	0.748	9.02	13.56	0.501	439.5	0.0	0.0	63.05
203.9	279.3	1.354	0.755	9.53	14.17	0.505	439.4	0.0	0.0	63.05
221.2	283.5	1.365	0.761	10.00	14.73	0.510	439.2	0.0	0.0	63.05

Table 6.2-24
Double-Ended Pump Suction Break - Minimum Safeguards
Principle Parameters During Reflood

TIME (SEC)	FLOODING TEMP (°F)	FLOODING RATE (IN/SEC)	CARRYOVER FRACTION	CORE HEIGHT (FT)	DOWNCOMER HEIGHT (FT)	FLOW FRACTION	INJECTION TOTAL (LBM/SEC)	INJECTION ACCUM (LBM/SEC)	SPILL (LBM/SEC)	ENTHALPY (BTU/LBM)
18.6	190.8	0.000	0.000	0.00	0.00	0.333	0.0	0.0	0.0	0.00
19.2	187.9	27.647	0.000	0.64	2.27	0.000	10481.9	9589.8	0.0	87.48
19.4	186.4	32.261	0.000	1.01	2.38	0.000	10367.5	9475.4	0.0	87.45
20.2	184.9	3.350	0.309	1.50	6.24	0.400	9849.8	8957.9	0.0	87.33
21.3	184.7	3.107	0.465	1.67	11.50	0.439	9358.5	8466.8	0.0	87.21
22.7	184.3	6.459	0.597	1.89	15.61	0.716	7398.8	6664.5	0.0	87.10
23.3	184.0	6.098	0.639	2.01	15.62	0.706	7067.8	6348.5	0.0	87.03
23.7	183.8	5.884	0.657	2.08	15.62	0.706	6952.8	6229.9	0.0	86.97
26.8	183.3	5.012	0.716	2.50	15.62	0.699	6279.9	5529.6	0.0	86.56
31.6	183.8	4.368	0.739	3.01	15.62	0.685	5524.4	4743.6	0.0	85.98
37.3	185.7	3.892	0.746	3.51	15.62	0.668	4849.5	4043.5	0.0	85.31
43.7	188.4	2.232	0.730	3.98	15.62	0.482	888.2	0.0	0.0	63.05
44.2	188.6	2.229	0.730	4.00	15.62	0.482	888.2	0.0	0.0	63.05
54.7	195.2	2.165	0.732	4.52	15.62	0.482	888.2	0.0	0.0	63.04
64.9	203.5	2.105	0.734	5.00	15.62	0.482	888.1	0.0	0.0	63.04
76.7	214.5	2.038	0.737	5.54	15.62	0.483	888.2	0.0	0.0	63.04
87.2	224.6	1.978	0.739	6.00	15.62	0.483	888.2	0.0	0.0	63.05

Table 6.2-24 (continued)
Double-Ended Pump Suction Break - Minimum Safeguards
Principle Parameters During Reflood

TIME (SEC)	FLOODING TEMP (°F)	FLOODING RATE (IN/SEC)	CARRYOVER FRACTION	CORE HEIGHT (FT)	DOWNCOMER HEIGHT (FT)	FLOW FRACTION	TOTAL	INJECTION ACCUM	SPILL	ENTHALPY (BTU/LBM)
							(LBM/SEC)			
99.7	235.2	1.909	0.742	6.53	15.62	0.483	888.2	0.0	0.0	63.05
111.6	243.8	1.843	0.745	7.00	15.62	0.483	888.2	0.0	0.0	63.04
125.7	252.5	1.767	0.748	7.54	15.62	0.483	888.3	0.0	0.0	63.04
138.4	259.2	1.700	0.750	8.00	15.62	0.483	888.3	0.0	0.0	63.05
153.7	266.0	1.619	0.752	8.53	15.62	0.483	888.4	0.0	0.0	63.05
168.3	271.6	1.557	0.755	9.00	15.62	0.484	888.4	0.0	0.0	63.05
185.7	277.2	1.487	0.759	9.54	15.62	0.487	888.4	0.0	0.0	63.05
201.6	281.6	1.426	0.762	10.00	15.62	0.490	888.3	0.0	0.0	63.05

Table 6.2-25
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
221.30	141.02	177.89	300.46	91.54
226.30	140.61	177.37	300.87	91.49
231.30	140.20	176.86	301.28	91.44
236.30	139.78	176.34	301.69	91.39
241.30	139.37	175.82	302.10	91.33
246.30	138.96	175.30	302.52	91.28
251.30	138.55	174.78	302.93	91.23
256.30	138.14	174.26	303.34	91.17
261.30	137.72	173.74	303.75	91.12
266.30	137.31	173.22	304.17	91.07
271.30	136.90	172.69	304.58	91.01
276.30	136.48	172.17	304.99	90.96
281.30	136.07	171.65	305.41	90.90
286.30	135.65	171.12	305.82	90.85
291.30	135.24	170.60	306.24	90.79
296.30	134.82	170.08	306.66	90.74
301.30	134.40	169.55	307.07	90.68
306.30	133.99	169.02	307.49	90.63
311.30	133.57	168.50	307.91	90.57
316.30	133.15	167.97	308.33	90.51
321.30	132.73	167.44	308.74	90.46
326.30	132.31	166.91	309.16	90.40
331.30	131.89	166.38	309.58	90.34
336.30	131.48	165.86	310.00	90.28
341.30	131.05	165.32	310.42	90.23
346.30	130.63	164.79	310.84	90.17
351.30	130.21	164.26	311.26	90.11
356.30	129.79	163.73	311.69	90.05
361.30	129.37	163.20	312.11	89.99
366.30	128.95	162.66	312.53	89.93
371.30	128.52	162.13	312.95	89.88
376.30	128.10	161.60	313.38	89.82
381.30	126.37	159.41	315.11	90.11
386.30	125.95	158.89	315.52	90.05
391.30	125.53	158.36	315.94	89.99

Table 6.2-25 (continued)
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
396.30	125.12	157.83	316.36	89.93
401.30	124.73	157.35	316.75	89.86
406.30	124.44	156.97	317.04	89.77
411.30	124.14	156.60	317.34	89.68
416.30	123.85	156.23	317.63	89.58
421.30	123.55	155.86	317.93	89.49
426.30	121.99	153.88	319.49	89.75
431.30	121.70	153.52	319.78	89.65
436.30	121.41	153.15	320.07	89.56
441.30	121.12	152.79	320.36	89.46
446.30	120.83	152.42	320.65	89.37
451.30	120.54	152.05	320.94	89.27
456.30	119.00	150.11	322.48	89.52
461.30	118.71	149.76	322.76	89.42
466.30	118.43	149.40	323.05	89.32
471.30	118.14	149.03	323.34	89.23
476.30	117.86	148.67	323.62	89.13
481.30	116.34	146.76	325.14	89.36
486.30	116.06	146.41	325.42	89.26
491.30	115.78	146.06	325.70	89.16
496.30	116.71	147.24	324.76	88.73
501.30	116.43	146.87	325.05	88.63
506.30	116.14	146.51	325.34	88.52
511.30	115.85	146.14	325.63	88.42
516.30	115.56	145.77	325.92	88.32
521.30	115.26	145.41	326.21	88.22
526.30	116.16	146.54	325.31	87.79
531.30	115.86	146.16	325.61	87.69
536.30	115.56	145.78	325.91	87.59
541.30	115.26	145.40	326.21	87.49
546.30	114.96	145.02	326.52	87.39
551.30	114.66	144.64	326.82	87.29
556.30	115.52	145.73	325.96	86.87
561.30	115.21	145.34	326.27	86.77
566.30	114.90	144.94	326.58	86.67
571.30	114.58	144.55	326.89	86.57
576.30	114.27	144.15	327.21	86.47

Table 6.2-25 (continued)
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
581.30	115.10	145.20	326.38	86.05
586.30	114.78	144.79	326.70	85.95
591.30	114.45	144.38	327.02	85.85
596.30	114.13	143.97	327.35	85.75
601.30	113.81	143.58	327.66	85.65
606.30	114.65	144.63	326.83	88.77
611.30	114.36	144.26	327.12	88.65
616.30	114.07	143.89	327.41	88.53
621.30	113.77	143.52	327.71	88.41
626.30	113.47	143.15	328.00	88.28
631.30	114.27	144.16	327.20	87.86
636.30	113.97	143.77	327.51	87.73
641.30	113.66	143.38	327.82	87.61
646.30	113.35	142.99	328.13	87.49
651.30	114.11	143.96	327.36	87.07
656.30	113.79	143.55	327.68	86.95
661.30	113.47	143.14	328.01	86.83
666.30	113.15	142.73	328.33	86.71
671.30	113.88	143.65	327.60	86.30
676.30	113.54	143.23	327.94	86.18
681.30	113.20	142.80	328.28	86.06
686.30	112.86	142.37	328.62	85.94
691.30	113.55	143.24	327.93	85.54
696.30	113.20	142.80	328.28	85.43
701.30	112.84	142.35	328.64	85.31
706.30	112.48	141.90	328.99	85.19
711.30	113.13	142.72	328.34	84.80
716.30	112.76	142.25	328.72	84.69
721.30	112.39	141.77	329.09	84.57
726.30	113.00	142.55	328.48	84.19
731.30	112.61	142.06	328.87	84.08
736.30	112.22	141.56	329.26	87.29
741.30	112.79	142.29	328.68	86.90
746.30	112.38	141.77	329.09	86.77
751.30	111.97	141.25	329.50	86.65
756.30	112.51	141.93	328.97	86.26
761.30	112.08	141.39	329.40	86.14

Table 6.2-25 (continued)
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
766.30	111.65	140.84	329.83	86.02
771.30	112.14	141.46	329.34	85.64
776.30	111.69	140.89	329.79	85.52
781.30	112.14	141.47	329.33	85.15
786.30	111.67	140.87	329.81	85.04
791.30	112.09	141.41	329.38	84.68
796.30	111.60	140.78	329.88	84.57
801.30	111.99	141.27	329.49	84.22
806.30	111.49	140.65	329.98	84.11
811.30	111.86	141.11	329.62	83.76
816.30	111.34	140.45	330.14	83.66
821.30	111.66	140.86	329.82	83.32
826.30	111.11	140.16	330.37	83.22
831.30	111.39	140.51	330.09	82.90
836.30	110.81	139.79	330.67	85.95
841.30	111.04	140.07	330.44	85.61
846.30	111.23	140.31	330.25	85.29
851.30	110.59	139.51	330.88	85.19
856.30	110.73	139.69	330.75	84.88
861.30	110.83	139.81	330.65	84.58
866.30	110.89	139.88	330.59	84.28
871.30	110.90	139.90	330.57	84.00
876.30	110.87	139.86	330.61	83.73
881.30	110.79	139.77	330.68	83.48
886.30	110.67	139.61	330.81	83.23
891.30	110.49	139.38	330.99	83.00
896.30	110.25	139.08	331.22	82.78
901.30	110.63	139.56	330.85	82.39
906.30	110.24	139.07	331.23	85.22

Table 6.2-25 (continued)
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
911.30	110.43	139.31	331.05	84.86
916.30	109.87	138.60	331.61	84.71
921.30	109.83	138.56	331.64	84.41
1275.17	109.83	138.56	331.64	84.41
1275.27	71.88	89.53	369.60	90.76
1276.30	71.86	89.51	369.61	90.90
1399.20	71.86	89.51	369.61	90.90
1399.30	69.21	79.63	372.27	30.04
2500.00	60.71	69.86	380.77	31.57
2500.10	60.71	69.86	291.16	51.64
3599.00	55.10	63.40	296.77	52.65
3599.10	55.10	63.40	296.77	52.65
3600.00	55.09	63.39	296.77	52.65
3600.10	42.81	49.26	309.06	42.07
3601.00	42.81	49.26	309.06	42.07
3601.10	42.64	49.06	309.75	40.92
4500.00	39.50	45.45	312.89	41.34
4500.10	39.46	45.40	313.27	41.08
7200.00	34.15	39.30	318.58	41.77
7200.10	34.02	39.14	319.36	40.60
10000.00	30.86	35.51	322.52	41.00
11000.00	30.22	34.77	323.16	41.08
11000.10	30.13	34.67	324.00	40.21
18000.00	26.36	30.33	327.77	40.68
18000.10	26.23	30.18	328.72	39.16
28800.00	23.54	27.08	331.41	39.48
28800.10	23.43	26.96	326.97	37.38
100000.00	16.29	18.75	334.11	38.20
180000.00	13.63	15.69	336.77	38.50
180000.10	13.50	15.53	337.53	35.14
1000000.00	6.91	7.96	344.12	35.83
1000000.00	6.86	7.89	345.08	33.17

Table 6.2-25 (continued)
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MIN SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
10000000.00	2.15	2.47	349.79	33.63

* M&E exiting the SG side of the break
** M&E exiting the pump side of the break

Table 6.2-26
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
201.60	132.59	167.07	757.76	122.55
206.60	132.22	166.60	758.13	122.48
211.60	131.85	166.13	758.50	122.42
216.60	132.86	167.40	757.49	121.97
221.60	132.48	166.93	757.87	121.90
226.60	132.10	166.45	758.25	121.83
231.60	131.72	165.97	758.63	121.76
236.60	132.71	167.22	757.64	121.32
241.60	132.33	166.74	758.02	121.25
246.60	131.94	166.25	758.41	121.18
251.60	131.56	165.77	758.79	121.11
256.60	131.17	165.28	759.18	121.05
261.60	132.14	166.50	758.21	120.60
266.60	131.75	166.01	758.60	120.54
271.60	131.35	165.51	758.99	120.47
276.60	130.96	165.02	759.39	120.40
281.60	130.57	164.52	759.78	120.33
286.60	131.51	165.71	758.84	119.90
291.60	131.11	165.21	759.24	119.83
296.60	130.71	164.70	759.64	119.76
301.60	130.31	164.20	760.04	119.69
306.60	129.91	163.69	760.44	119.63
311.60	130.83	164.85	759.52	119.19
316.60	130.42	164.33	759.93	119.13
321.60	130.01	163.82	760.34	119.06
326.60	129.60	163.30	760.75	118.99
331.60	129.19	162.78	761.16	118.92
336.60	130.08	163.91	760.27	118.50
341.60	129.66	163.38	760.69	118.43
346.60	129.24	162.85	761.10	118.37
351.60	128.83	162.33	761.52	118.30
356.60	129.69	163.42	760.66	117.88
361.60	129.27	162.88	761.08	117.81
366.60	128.84	162.34	761.51	117.75
371.60	128.41	161.80	761.94	117.68

Table 6.2-26 (continued)
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
376.60	129.25	162.87	761.10	117.26
381.60	128.82	162.32	761.53	117.20
386.60	128.38	161.76	761.97	117.13
391.60	127.94	161.21	762.41	117.07
396.60	127.51	160.66	762.84	117.00
401.60	128.36	161.73	761.99	116.58
406.60	128.04	161.33	762.31	116.49
411.60	127.71	160.92	762.64	116.40
416.60	127.39	160.52	762.96	116.31
421.60	127.07	160.11	763.28	116.21
426.60	127.97	161.25	762.38	115.78
431.60	127.64	160.83	762.71	115.69
436.60	127.31	160.41	763.04	119.21
441.60	126.97	159.99	763.38	119.10
446.60	127.85	161.09	762.50	118.67
451.60	127.50	160.66	762.85	118.56
456.60	127.16	160.22	763.19	118.46
461.60	126.81	159.79	763.54	118.35
466.60	126.46	159.35	763.89	118.25
471.60	127.30	160.41	763.05	117.82
476.60	126.94	159.95	763.41	117.71
481.60	126.58	159.50	763.76	117.61
486.60	126.22	159.05	764.12	117.50
491.60	127.03	160.07	763.32	117.08
496.60	126.66	159.60	763.69	116.98
501.60	126.29	159.13	764.06	116.88
506.60	125.91	158.66	764.44	116.77
511.60	126.69	159.63	763.66	116.36
516.60	126.30	159.15	764.05	116.26
521.60	125.91	158.66	764.43	116.16
526.60	125.53	158.17	764.82	116.06
531.60	126.27	159.10	764.08	115.65
536.60	125.87	158.60	764.48	115.55
541.60	125.46	158.09	764.89	115.45
546.60	126.17	158.98	764.18	115.04
551.60	125.76	158.46	764.59	114.95
556.60	125.34	157.93	765.01	114.85

Table 6.2-26 (continued)
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
561.60	124.92	157.40	765.43	114.76
566.60	125.59	158.25	764.76	114.36
571.60	125.15	157.70	765.19	114.27
576.60	124.72	157.15	765.63	114.18
581.60	125.35	157.95	765.00	113.79
586.60	124.90	157.38	765.45	113.70
591.60	124.45	156.81	765.90	113.61
596.60	125.05	157.57	765.30	113.23
601.60	124.59	156.99	765.76	113.14
606.60	125.21	157.77	765.14	116.10
611.60	124.77	157.21	765.58	115.99
616.60	124.32	156.65	766.03	115.88
621.60	124.90	157.37	765.45	115.49
626.60	124.44	156.79	765.91	115.39
631.60	123.97	156.21	766.38	115.28
636.60	124.50	156.88	765.85	114.90
641.60	124.02	156.27	766.33	114.80
646.60	124.52	156.90	765.83	114.42
651.60	124.01	156.26	766.34	114.32
656.60	124.48	156.85	765.87	113.96
661.60	123.95	156.18	766.40	113.86
666.60	124.38	156.72	765.97	113.51
671.60	123.83	156.03	766.52	113.42
676.60	124.22	156.52	766.13	113.07
681.60	123.64	155.80	766.71	112.99
686.60	123.99	156.23	766.36	112.65
691.60	123.39	155.48	766.96	112.57
696.60	123.69	155.86	766.66	112.24
701.60	123.96	156.20	766.38	111.92
706.60	123.32	155.38	767.03	111.86
711.60	123.54	155.67	766.81	114.72
716.60	123.73	155.91	766.62	114.40
721.60	123.03	155.02	767.32	114.33
726.60	123.16	155.19	767.19	114.02
731.60	123.26	155.31	767.09	113.73
736.60	123.32	155.39	767.03	113.44
741.60	123.34	155.42	767.01	113.16

Table 6.2-26 (continued)
Post-Reflood Mass and Energy Releases Double-Ended
Pump Suction Guillotine - MAX SI

	BREAK PATH No. 1*		BREAK PATH No. 2**	
TIME (SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU-SEC)	FLOW (LBM/SEC)	ENERGY (THOUSAND BTU/SEC)
746.60	123.32	155.39	767.03	112.90
751.60	123.25	155.30	767.10	112.65
756.60	123.14	155.16	767.21	112.40
761.60	122.98	154.96	767.37	112.17
766.60	122.77	154.69	767.58	111.96
1085.53	122.77	154.69	767.58	111.96
1085.63	71.87	89.70	818.48	121.91
1086.60	71.86	89.69	818.49	121.79
1276.17	71.86	89.69	818.49	121.79
1276.27	68.30	78.58	822.05	55.13
1460.00	65.92	75.85	824.43	55.55
1460.10	65.92	75.85	912.47	144.37
3599.00	52.60	60.52	925.79	146.78
3599.10	52.60	60.52	925.79	146.78
3600.00	52.59	60.51	925.80	146.78
3600.10	43.33	49.85	935.06	138.53
3601.00	43.32	49.85	935.07	138.53
3601.10	43.06	49.55	937.45	133.23
4500.00	39.89	45.90	940.62	133.68
4500.10	39.61	45.58	943.30	127.34
7200.00	34.28	39.45	948.63	128.06
7200.10	33.82	38.92	953.72	115.51
10000.00	30.68	35.30	956.86	115.90
11000.00	30.04	34.57	957.50	115.97
11000.10	29.75	34.24	960.78	106.77
18000.00	26.03	29.95	964.50	107.18
18000.10	25.86	29.75	966.69	100.66
28800.00	23.20	26.70	969.35	100.94
28800.10	23.16	26.65	796.99	81.40
100000.00	16.10	18.53	804.05	82.12
180000.00	13.47	15.50	806.68	82.39
180000.10	13.38	15.40	808.31	76.90
1000000.00	6.85	7.89	814.84	77.52
1000000.00	6.83	7.86	815.79	75.01
10000000.00	2.14	2.46	820.48	75.44

* M&E exiting the SG side of the break
** M&E exiting the pump side of the break

Table 6.2-27
Double-Ended Pump Suction Break With
Minimum Safeguards Mass Balance

		Time (Sec)						
		0.00	18.80	18.80	221.23	1275.27	1399.20	3600.00
		Mass (Thousand Lbm)						
Initial	In RCS & Accumulators	614.23	614.23	614.23	614.23	614.23	614.23	614.23
Added Mass	Pumped Injection	0.00	0.00	0.00	82.33	547.63	602.35	1475.38
	Total Added	0.00	0.00	0.00	82.33	547.63	602.35	1475.38
							1216.58	2089.61
	Total Available	614.23	614.23	614.23	696.56	1161.87	118.34	118.34
	Reactor Coolant	421.58	61.32	69.07	118.34	118.34	118.34	118.34
Distribution	Accumulator	192.65	133.30	125.55	0.00	0.00	0.00	0.00
	Total Contents	614.23	194.62	194.62	118.34	118.34	118.34	118.34
	Break Flow	0.00	419.61	419.61	569.42	1034.72	1089.44	1962.47
Effluent	ECCS Spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total Effluent	0.00	419.61	419.61	569.42	1034.72	1089.44	1962.47
	Total Accountable	614.23	614.24	614.24	687.76	1153.06	1207.78	2080.81

Table 6.2-28
Double-Ended Pump Suction Break With
Maximum Safeguards Mass Balance

		Time (Sec)						
		0.0	18.60	18.60	201.55	1085.63	1276.17	3600.00
		Mass (Thousand lbm)						
Initial	In RCS & Accumulators	614.23	614.23	614.23	614.23	614.23	614.23	614.23
Added Mass	Pumped Injection	0.00	3.055	3.055	163.32	950.41	1120.06	3377.49
	Total Added	0.00	3.055	3.055	163.32	950.41	1120.06	3377.49
Total Available		614.23	617.29	617.29	777.55	1564.64	1734.29	3991.72
	Reactor Coolant	421.58	62.25	69.42	120.39	120.39	120.39	120.39
Distribution	Accumulator	192.65	135.40	128.23	0.00	0.00	0.00	0.00
	Total Contents	614.23	197.65	197.65	120.39	120.39	120.39	120.39
	Break Flow	0.00	419.64	419.64	658.35	1435.44	1605.09	3862.51
Effluent	ECCS Spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total Effluent	0.00	419.64	419.64	648.35	1435.44	1605.09	3862.51
Total Accountable		614.23	617.29	617.29	768.74	1555.83	1725.48	3982.90

Table 6.2-29
Double-Ended Hot-Leg Break Mass Balance

		Time (Sec)		
		0.00	19.00	19.00
		Mass (Thousand Lbm)		
Initial	In RCS & Accumulators	614.23	614.23	614.23
Added Mass	Pumped Injection	0.00	0.00	0.00
	Total Added	0.00	0.00	0.00
	Total Available	614.23	614.23	614.23
Distribution	Reactor Coolant	421.58	84.65	97.59
	Accumulator	192.65	128.98	116.04
	Total Contents	614.23	213.63	213.63
	Break Flow	0.00	400.61	400.61
Effluent	ECCS Spill	0.00	0.00	0.00
	Total Effluent	0.00	400.61	400.61
	Total Accountable	**614.23**	**614.24**	**614.24**

Table 6.2-30
Double-Ended Pump Suction Break With Minimum Safeguards Energy Balance

		TIME (SEC)						
		0.00	18.80	18.80	221.23	1275.27	1399.20	3600.0
		ENERGY (MILLION BTU)						
Initial Energy	In RCS, Accumulators & Steam Generator	691.35	691.35	691.35	691.35	691.35	691.35	691.35
	Pump Injection	0.00	0.00	0.00	5.19	34.53	37.97	121.30
Added Energy	Decay Heat	0.00	4.98	4.98	25.23	97.34	104.51	212.16
	Heat From Secondary	0.00	-0.27	-0.27	-0.27	3.64	3.67	3.67
	Total Added	0.00	4.71	4.71	30.15	135.51	146.15	337.13
Total Available		691.35	696.07	696.07	721.50	826.86	837.51	1028.48
	Reactor Coolant	251.52	12.20	12.89	31.60	31.60	31.60	31.60
	Accumulator	17.26	11.94	11.24	0.00	0.00	0.00	0.00
	Core Stored	18.33	9.79	9.79	4.10	3.80	3.74	2.71
	Primary Metal	132.47	125.97	125.97	104.95	62.99	60.25	44.09
Distribution	Secondary Metal	35.77	34.82	34.82	31.99	19.64	18.53	13.63
	Steam Generator	236.02	239.70	239.70	216.90	130.51	123.36	91.07
	Total Contents	691.35	434.40	434.40	389.54	248.54	237.48	183.10
	Break Flow	0.00	261.20	261.20	325.06	571.41	592.89	839.74
Effluent	ECCS Spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total Effluent	0.00	261.20	261.20	325.06	571.41	592.89	839.74
Total Accountable		691.35	695.60	695.60	714.60	819.95	830.38	1022.83

Energy released to the containment atmosphere from the inactive metal sources in the RCS would be 305.346 Btu/sec beginning at the end of the blowdown period and ending at 86,418.81 seconds.

Table 6.2-31
Double-Ended Pump Suction Break With Maximum Safeguards Energy Balance

		TIME (SEC)						
		0.00	18.60	18.60	201.55	1085.63	1276.17	3600.0
		ENERGY (MILLION BTU)						
Initial Energy	In RCS, Accumulators & Steam Generator	691.35	691.35	691.35	691.35	691.35	691.35	691.35
	Pump Injection	0.00	0.1926	0.1926	10.293	59.923	70.613	391.12
Added Energy	Decay Heat	0.00	4.95	4.95	23.53	85.97	97.37	211.81
	Heat From Secondary	0.00	-0.27	-0.27	-0.27	7.71	7.76	7.76
	Total Added	0.00	4.87	4.87	33.55	153.60	175.74	610.69
	Total Available	691.35	696.22	696.22	724.90	844.95	867.09	1302.04
Distribution	Reactor Coolant	251.52	12.23	12.88	32.08	32.08	32.08	32.08
	Accumulator	17.26	12.13	11.48	0.00	0.00	0.00	0.00
	Core Stored	18.33	9.76	9.76	4.10	3.60	3.53	2.71
	Primary Metal	132.47	125.98	125.98	103.85	63.93	59.75	46.72
	Secondary Metal	35.77	34.82	34.82	31.66	20.51	18.78	14.81
	Steam Generator	236.02	239.70	239.70	214.27	140.71	129.43	103.32
	Total Contents	691.35	434.61	434.61	385.97	260.83	243.59	199.65

Table 6.2-31 (continued)
Double-Ended Pump Suction Break With
Maximum Safeguards Energy Balance

		TIME (SEC)						
		0.00	18.60	18.60	201.55	1085.63	1276.17	3600.0
		ENERGY (MILLION BTU)						
Effluent	Break Flow	0.00	261.15	261.15	332.07	577.24	613.85	1095.66
	ECCS Spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total Effluent	0.00	261.15	261.15	332.07	577.24	613.85	1095.66
Total Accountable		691.35	695.77	695.77	718.03	838.08	857.44	1295.30

Energy released to the containment atmosphere from the inactive metal sources in the RCS would be 305.346 Btu/sec beginning at the end of the blowdown period and ending at 86,418.81 seconds.

Table 6.2-32
Double-Ended Hot-Leg Break Energy Balance

		Time (Sec)		
		0.00	19.00	19.00
			Energy (Million BTU)	
Initial Energy	In RCS, Accumulators & Steam Generator	691.35	691.35	691.35
	Pump Injection	0.00	0.00	0.00
	Decay Heat	0.00	5.48	5.48
Added Energy	Heat From Secondary	0.00	-9.10	-9.10
	Total Added	0.00	-3.62	-3.62
	Total Available	691.35	687.74	687.74
	Reactor Coolant	251.52	18.00	19.17
	Accumulator	17.26	11.55	10.39
	Core Stored	18.33	7.63	7.63
Distribution	Primary Metal	132.47	124.08	124.08
	Secondary Metal	35.77	34.39	34.39
	Steam Generator	236.02	224.84	224.84
	Total Contents	691.35	420.49	420.49
	Break Flow	0.00	266.77	266.77
Effluent	ECCS Spill	0.00	0.00	0.00
	Total Effluent	0.00	266.77	266.77
	Total Accountable	691.35	687.26	687.26

Table 6.2-33
System Parameters LOCA Initial Conditions

PARAMETERS	VALUE
Core Thermal Power (MWt) (with 2% calorimetric included)	2958
Reactor Coolant System Total Flowrate (lbm/sec)	28656.4
Vessel Outlet Temperature (°F)	628.2
Core Inlet Temperature (°F)	559.2
Vessel Average Temperature (°F)	593.7
Initial Steam Generator Steam Pressure (psia)	1010
Steam Generator Design	Δ75
Steam Generator Tube Plugging (percent)	0
Initial Steam Generator Secondary Side Mass (lbm)	139035
Assumed Maximum Containment Backpressure (psia)	71.7
Accumulator	
Water Volume (ft^3) per accumulator (includes line volume)	1034.3
N_2 Cover Gas Pressure (psia)	628
Temperature (°F)	120
Safety Injection Delay, total (sec) (from SI Signal)	27
RWST Temperature (°F)	95

Note:
Core Thermal Power, RCS Total Flowrate, RCS Coolant Temperatures, and Steam Generator Secondary Side Mass include appropriate uncertainty and/or allowance.

Table 6.2-34
LOCA M&E Release Analysis Core Decay Heat Fraction

Time (sec)	Decay Heat (P/P_o)
10	0.053876
15	0.050401
20	0.048018
40	0.042401
60	0.039244
80	0.037065
100	0.035466
150	0.032724
200	0.030936
400	0.027078
600	0.024931
800	0.023389
1000	0.022156
1500	0.019921
2000	0.018315
4000	0.014781
6000	0.013040
8000	0.012000
10000	0.011262
15000	0.010097
20000	0.009350
40000	0.007778
60000	0.006958
80000	0.006424
100000	0.006021

Table 6.2-34 (continued)
LOCA M&E Release Analysis Core Decay Heat Fraction

Time (sec)	Decay Heat (P/P_o)
150000	0.005323
200000	0.004847
400000	0.003770
600000	0.003201
800000	0.002834
1000000	0.002580
2000000	0.001909
4000000	0.001355
6000000	0.001091
8000000	0.000927
10000000	0.000808

Table 6.2-41
Blowdown Table (Without Margin) for Reactor Cavity Pressure Response Analysis, 150 Square Inch Break Area, Cold Leg Break

Time (sec)	Mass Flow (10^3 lbm/sec)	Enthalpy (Btu/lbm)
0.0	0.00	557.61
0.001	8.83	557.61
0.002	12.46	557.40
0.003	12.86	557.52
0.010	20.53	556.35
0.017	24.70	555.57
0.022	23.82	554.11
0.036	26.72	553.97
0.042	26.23	553.43
0.049	26.99	553.61

Table 6.2-42
Blowdown Table For Steam Generator Compartment Differential Pressure Analysis Cold Leg Double Ended Guillotine Break

Time (sec)	Mass Flow (10^3 lbm/sec)	Enthalpy (Btu/lbm)
0.	10.022	553.81
0.001	40.519	549.06
0.004	60.438	548.88
0.010	51.753	547.88
0.015	51.461	548.64
0.025	54.794	548.97
0.030	56.260	549.08
0.035	57.373	549.14
0.040	58.238	549.26
0.045	58.870	549.42
0.050	59.569	549.76
0.055	69.678	554.68
0.058	79.314	550.76
0.060	81.633	551.21
0.062	80.386	550.82
0.065	81.351	550.81
0.070	83.484	550.83
0.075	84.880	550.82
0.080	87.451	551.00
0.085	88.606	550.95
0.090	89.752	550.96
0.095	89.695	550.83
0.100	90.318	550.85
0.125	92.418	550.87
0.150	94.527	551.23

Table 6.2-42 (continued)
Blowdown Table For Steam Generator Compartment Differential
Pressure Analysis Cold Leg Double Ended Guillotine Break

Time (sec)	Mass Flow (10^3 lbm/sec)	Enthalpy (Btu/lbm)
0.175	95.191	551.17
0.200	95.876	551.15
0.250	96.582	551.24
0.300	96.209	551.18
0.350	94.955	551.09
0.400	93.945	551.14
0.450	92.873	551.14
0.500	91.364	551.21
0.600	89.085	551.63
0.750	87.717	552.71
0.900	85.512	554.42
1.000	82.637	555.98
1.100	80.511	557.86

Table 6.2-43
Blowdown Table For Steam Generator Compartment Differential Pressure Analysis Hot Leg Double Ended Guillotine Break

Time (sec)	Mass Flow (10^3 lbm/sec)	Enthalpy (Btu/lbm)
0.	10.022	647.51
0.001	54.859	645.59
0.003	80.761	645.01
0.008	63.883	647.45
0.010	65.471	648.08
0.015	66.879	649.87
0.020	68.935	650.91
0.030	70.920	652.36
0.039	71.408	653.24
0.050	71.948	655.22
0.060	75.985	656.17
0.070	80.768	654.92
0.080	83.236	653.78
0.085	83.747	653.39
0.089	83.859	653.15
0.100	83.421	652.72
0.125	80.990	651.45
0.150	76.694	650.73
0.175	74.661	649.64
0.200	73.906	647.85
0.250	71.393	644.44
0.300	69.196	641.27
0.350	67.446	638.54
0.400	66.152	636.18
0.450	65.167	634.16

Table 6.2-43 (continued)
Blowdown Table For Steam Generator Compartment Differential
Pressure Analysis Hot Leg Double Ended Guillotine Break

Time (sec)	Mass Flow (10^3 lbm/sec)	Enthalpy (Btu/lbm)
0.500	64.153	632.66
0.600	61.847	630.68
0.700	59.740	630.19
0.800	59.165	631.82
0.900	57.600	634.08
1.000	55.551	636.03
1.100	53.998	638.07

Table 6.2-44
Double Ended Pressurizer Surge Line Guillotine Break
Short Term Mass and Energy Release Rates Into Pressurizer Cavity

Time (seconds)	Mass Flow (10^3 lbm/sec)	Enthalpy (Btu/lbm)
0.00	21.76	668.6
0.02	22.52	662.9
0.04	23.40	670.3
0.05	23.71	671.2
0.06	23.91	659.0
0.08	24.16	633.5
0.10	24.27	599.5
0.12	23.78	579.0
0.14	23.02	570.4
0.16	20.87	611.0
0.18	18.40	677.5
0.20	18.11	674.3
0.22	18.08	674.3
0.24	18.06	674.5
0.26	18.04	674.3
0.28	18.01	675.0
0.30	17.99	675.2
0.35	17.93	675.4
0.40	17.87	676.3
0.45	17.83	675.5
0.50	17.77	675.7
0.55	17.72	676.2
0.60	17.70	675.1
0.65	17.69	674.2
0.70	17.66	673.2

Table 6.2-44 (continued)
Double Ended Pressurizer Surge Line Guillotine Break
Short Term Mass and Energy Release Rates Into Pressurizer Cavity

Time (seconds)	Mass Flow (10^3 lbm/sec)	Enthalpy (Btu/lbm)
0.75	17.62	673.6
0.80	17.58	673.6
0.85	17.56	672.6
0.90	17.52	673.0
1.00	17.37	676.2

Table 6.2-45
Blowdown Table For Pressurizer Spray Line Break

Time (seconds)	Mass Flow (10^3 lbm/sec)	Enthalpy (Btu/lbm)
0.00000	5.350	611.05
0.05003	5.350	611.05
0.10011	5.478	609.82
0.15001	5.214	612.01
0.20062	5.199	612.03
0.25024	5.207	611.80
0.30016	5.108	612.62
0.35000	5.134	612.22
0.40023	5.115	612.26
0.45080	5.137	611.88
0.50011	5.158	611.52
0.55038	5.138	611.56
0.60015	5.145	611.34
0.65025	5.138	611.25
0.70026	5.134	611.14
0.75041	5.132	611.02
0.80005	5.115	611.05
0.85031	5110	610.95
0.90033	5.099	610.93
0.95038	5.084	610.93
1.00004	5.079	610.86
1.05002	5.059	610.93
1.10003	5.048	610.90
1.15004	5.037	610.89
1.20016	5.022	610.95

Table 6.2-45 (continued)
Blowdown Table For Pressurizer Spray Line Break

Time (seconds)	Mass Flow (10^3 lbm/sec)	Enthalpy (Btu/lbm)
1.25006	5.012	610.91
1.30023	4.997	610.94
1.35011	4.983	610.97
1.40013	4.974	610.95
1.45020	4.959	611.00
1.50020	4.947	611.02
1.55112	4.936	611.02
1.60021	4.921	611.07
1.65033	4.909	611.09
1.70032	4.898	611.11
1.75012	4.884	611.17
1.80021	4.872	611.20
1.85040	4.860	611.24
1.90010	4.844	611.30
1.95032	4.832	611.34
2.00001	4.820	611.40
4.0	4.820	611.40

Table 6.2-46a
Deleted per RN 01-073

Table 6.2-46b
Steam Line Break Mass & Energy Release Inside Containment
System Nominal Parameters(1)

NSSS Power, Mwt	2912
Core Power Mwt	2900
Reactor Coolant Pump Heat, Mwt	12
Reactor Coolant Flow, Total, gpm	277800
Pressurizer Pressure, psia	2250
Reactor Coolant Temperature, °F	
Core Outlet	627.7
Vessel Outlet	621.9
Core Average	592.8
Vessel Average	587.4
Vessel/Core Inlet	552.9
Steam Generator	
Steam Temperature, °F	540.4
Steam Pressure, psia	966

(1) Parameters for the partial power cases are adjusted accordingly

Table 6.2-46c
Steam Line Break Mass & Energy Release Inside Containment
Analysis Initial Condition Assumptions

PARAMETER Power Level (%)	102	75	50	25	0
RCS Average Temperature (°F)	591.4	583.2	575.6	568.0	557.0
RCS Flowrate (gpm)	277800	277800	277800	277800	277800
RCS Pressure (psia)	2250	2250	2250	2250	2250
Pressurizer Water Volume (ft^3)	861.5	739.5	626.5	513.5	409.6
Feedwater Enthalpy (btu/lbm)	419.4	385.6	349.3	297.2	220.8
Faulted SG Water Level (% span)	65	65	65	65	65
Intact SG Water Level (% span)	55	55	55	55	55

Table 6.2-46d
Steam Line Break Mass & Energy Release Inside Containment
Safety System Assumptions

Parameter	Value
Trip Setpoints	
Low Pressurizer Pressure Reactor Trip (psia)	1775
Low Pressurizer Pressure Safety Injection (psia)	1715
Low Steam Line Pressure (psia)	430
Overpower ΔT	1.143
Time Constants	
Steam Line Pressure Lead Time Constant (sec)	50.0
Steam Line Pressure Lag Time Constant (sec)	5.0
Time Delays (sec)	
Low Pressurizer Pressure Reactor Trip Delay	2.0
Low Steam Line Pressure Reactor Trip Delay	2.0
Overpower ΔT Reactor Trip Delay	8.5
High-1 Containment Pressure Reactor Trip Delay	3.0
Steam Line Isolation Valve Closure	10.0
Feedwater Isolation Delay	10.0
SI System Reactor Trip Delay	3.0
SI Start Up Time (with offsite power)	27.0
Auxiliary Feedwater Delay	0.0

Table 6.2-47a
Steam Line Break Mass & Energy Release Inside Containment
Case Analyzed

Break Type/Case	Power (%)	Break Size (ft^2)	Failure(s)	Entrainment	Reactor Trip (sec)	FW Isolation (sec)	SL Isolation (sec)
DER/1G	102	1.4	FWIV, SIS	No	LSP (3.6)	LSP (10.6)	LSP (10.6)
DER/1B	102	1.2	FWIV, SIS, EFW	No	LSP (4.6)	LSP (11.6)	LSP (11.6)
DER/1C	102	1.1	FWIV, SIS, EFW	No	LSP (5.0)	LSP (12.0)	LSP (12.0)
DER/1H	102	1.4	SIS	No	LSP (3.6)	LSP (10.6)	LSP (10.6)
DER/1I	102	1.4	SIS, EFW	No	LSP (3.6)	LSP (10.6)	LSP (10.6)
DER/1J	102	1.4	DIESEL	No	LSP (3.6)	LSP (10.6)	LSP (10.6)
DER/1K	102	1.4	CH-A	No	LSP (3.6)	LOP (8.5)	LOP (7.0)
SPLIT/1	102	0.878	FWIV, SIS, EFW	No	Hi-1 (15.0)	Hi-1 (22.0)	Hi-2 (22.0)
DER/2E	75	1.4	CH-A	Yes	LSP (3.7)	LOP (8.5)	LOP (7.0)
DER/2B	75	1.1	FWIV, SIS, EFW	Yes	LSP (4.4)	LSP (11.4)	LSP (11.4)
DER/2C	75	1.0	FWIV, SIS, EFW	No	LSP (4.6)	LSP (11.6)	LSP (11.6)
SPLIT/2	75	0.871	FWIV, SIS, EFW	No	Hi-1 (14.7)	Hi-1 (21.7)	Hi-2 (21.7)
DER/3E	50	1.4	CH-A	Yes	LSP (3.8)	LOP (8.5)	LOP (7.0)
DER/3B	50	0.8	FWIV, SIS, EFW	Yes	LSP (4.6)	LSP (11.6)	LSP (11.6)
DER/3C	50	0.7	FWIV, SIS, EFW	No	LSP (4.9)	LSP (11.9)	LSP (11.9)
SPLIT/3	50	0.863	FWIV, SIS, EFW	No	Hi-1 (14.5)	Hi-1 (21.5)	Hi-2 (21.5)
DER/4E	25	1.4	CH-A	Yes	LSP (3.8)	LOP (8.5)	LOP (7.0)
DER/4G	25	1.4	FWIV, SIS	Yes	LSP (3.8)	LSP (10.9)	LSP (10.9)
DER/4B	25	0.6	FWIV, SIS, EFW	Yes	LSP (4.5)	LSP (11.5)	LSP (11.5)
DER/4C	25	0.5	FWIV, SIS, EFW	No	LSP (4.8)	LSP (11.8)	LSP (11.5)
SPLIT/4	25	0.849	FWIV, SIS, EFW	No	Hi-1 (14.3)	Hi-1 (21.3)	Hi-2 (21.3)

Table 6.2-47a (continued)
Steam Line Break Mass & Energy Release Inside Containment
Case Analyzed

Break Type/Case	Power (%)	Break Size (ft^2)	Failure(s)	Entrainment	Reactor Trip (sec)	FW Isolation (sec)	SL Isolation (sec)
DER/5F	0	1.4	CH-A	Yes	LSP (3.8)	LOP (8.5)	LOP (7.0)
DER/5B	0	0.2	FWIV, SIS, EFW	Yes	LSP (4.4)	LSP (11.4)	LSP (11.4)
DER/5C	0	0.1	FWIV, SIS, EFW	No	LSP (4.6)	LSP (11.6)	LSP (11.6)
SPLIT/5	0	0.772	FWIV, SIS, EFW	No	Hi-1 (15.4)	Hi-1-(22-4)	Hi-2 (22.4)

CH-A - Failure of Electrical Channel A
DER - Double-ended rupture
FWIV - Feedwater Isolation Valve Failure
EFW - Emergency Feedwater Runout Control Failure
SIS - Failure of 1 Train of the Safety Injection System
LSP - Low Steam Line Pressure Setpoint
Hi-1 - High-1 Containment Pressure Setpoint
Hi-2 - High-2 Containment Pressure Setpoint
LOP - Loss of Power

Table 6.2-47b
Containment Pressure Engineered Safety Features Actuation
Times For Steam Line Breaks Inside Containment

		Hi-1		Hi-2	Hi-3
Reactor building pressure setpoint value used in analysis.		4.2 psig		6.95 psig	12.65 psig
Time after break to reach setpoint		t_1		t_2	t_3
Signal processing delay and response time		1.5 seconds		1.5 seconds	1.5 seconds
	Feedwater Isolation	Diesel	Fan Coolers		
Feedwater isolation valve closure time	8.5 seconds				
Main steam valve closure				8.5 seconds	
Diesel start time		10 sec.	10 sec.		
R.B. fan coolers start time, water side switchover, diesel loading sequence time			66.5 sec.		
R.B. spray pump start and header fill time					37 seconds
	$\bar{t}_1\overline{+10.0}$	$\bar{t}_1\overline{+11.5}$	$\bar{t}_1\overline{+76.5}$	$\bar{t}_2\overline{+10.0}$	$t_3+38.5$

Hi-1 - Diesel Start, Feedwater Isolation Signal, Fan Cooler Actuation Signal
Hi-2 - Main Steam Isolation Signal
Hi-3 - Reactor Building Spray Actuation Signal

Table 6.2-47b (continued)
Containment Pressure Engineered Safety Features Actuation Times
For Steam Line Breaks (Values Used For Analysis)

Break Type/Case	Power (%)	Break Size (ft^2)	t_1 (sec)	t_2 (sec)	t_3 (sec)	Main Feedwater Isolation (sec)	Main Steam Isolation (sec)	Fan Cooler Actuation (sec)	Spray Actuation (sec)
DER/1G	102	1.4	0.5	1	2.5	(1, 2)	(1, 2)	86.5	53.1
DER/1B	102	1.2	3	4.5	8.5	(1, 2)	(1, 2)	86.5	53.1
DER/1C	102	1.1	3	5	9	(1, 2)	(1, 2)	86.5	53.1
DER/1H	102	1.4	1	1.5	3	(1, 2)	(1, 2)	86.5	53.1
DER/1I	102	1.4	0.5	1	2.5	(1, 2)	(1, 2)	86.5	53.1
DER/1J	102	1.4	0.5	1	2.5	(1, 2)	(1, 2)	86.5	53.1
DER/1K	102	1.4	0.5	1	2.5	(1, 2)	(1, 2)	86.5	53.1
SPLIT/1	102	0.878	6.8	12	24	22	22	86.5	67.1
DER/2E	75	1.4	0.5	1	2.5	(1, 2)	(1, 2)	86.5	53.1
DER/2B	75	1.1	2	4	8	(1, 2)	(1, 2)	86.5	53.1
DER/2C	75	1.0	3	5.5	10	(1, 2)	(1, 2)	86.5	53.1
SPLIT/2	75	0.871	6.6	11.6	24	21.7	21.7	86.5	67.1
DER/3E	50	1.4	0.5	1	2.5	(1, 2)	(1, 2)	86.5	53.1
DER/3B	50	0.8	2.5	5	14	(1, 2)	(1, 2)	86.5	57.1
DER/3C	50	0.7	4.5	7.5	15	(1, 2)	(1, 2)	86.5	58.1
SPLIT/3	50	0.863	6.6	11.4	23	21.5	21.5	86.5	66.1
DER/4E	25	1.4	0.5	1	2.5	(1, 2)	(1, 2)	86.5	53.1
DER/4G	25	1.4	0.5	1	2.5	(1, 2)	(1, 2)	86.5	53.1

Table 6.2-47b (continued) (continued)
Containment Pressure Engineered Safety Features Actuation Times
For Steam Line Breaks (Values Used For Analysis)

Break Type/Case	Power (%)	Break Size (ft^2)	t_1 (sec)	t_2 (sec)	t_3 (sec)	Main Feedwater Isolation (sec)	Main Steam Isolation (sec)	Fan Cooler Actuation (sec)	Spray Actuation (sec)
DER/4B	25	0.6	3.5	6.5		(1, 2)	(1, 2)	86.5	65.1
DER/4C	25	0.5	6	11	24	(1, 2)	(1, 2)	86.5	67.1
SPLIT/4	25	0.849	6.4	11.2	23	21.3	21.3	86.5	66.1
DER/5F	0	1.4	0.5	1	2.5	(1, 2)	(1, 2)	86.5	53.1
DER/5B	0	0.2	10	28	120	(1, 2)	(1, 2)	86.5	163.1
DER/5C	0	0.1	39	87	441	(1, 2)	(1, 2)	115.5	484.1
SPLIT/5	0	0.772	7	12.4	26	22.4	22.4	86.5	69.1

(1) Main steam and feedwater isolation is initiated by other variable than containment pressure
(2) Analysis values are defined in Table 6.2-47a

Table 6.2-48a
SLB M&E Inside Containment Case 4E: 25% Power 1.4 Ft^2
DER Failure: Electrical CH-A

Time (sec)	Break Flow Rate (lbm/sec)	Break Energy (10^6 btu/sec)	Integrated Mass Release (10^3 lbm)	Integrated Energy Release (10^6 btus)
0.0	0.0	0.0	0.0	0.0
0.2	9,441.0	11.23	1.888	2.245
0.4	9,207.0	10.96	3.73	4.437
0.6	9,052.0	10.78	5.54	6.592
0.8	8,903.0	10.61	7.321	8.713
1	8,758.0	10.44	9.072	10.80
2	8,125.0	9.704	17.44	20.79
3	16,729.0	12.14	29.66	31.58
4	18,151.0	12.35	47.31	43.87
5	17,156.0	11.83	64.86	55.91
6	16,214.0	11.33	81.45	67.43
7	14,980.0	10.74	96.93	78.40
7.2	4,711.0	3.373	97.87	79.08
8	4,397.0	3.217	101.5	81.70
9	4,009.0	3.048	105.6	84.81
10	3,691.0	2.917	109.5	87.77
15	2,562.0	2.366	124.7	100.9
20	1,540.0	1.831	134.9	111.3
30	1,205.0	1.451	148.3	127.4
40	1,064.0	1.281	159.5	140.9
61.5	1,002.0	1.206	181.4	167.3
80	987.6	1.189	199.8	189.4
100	980.0	1.180	219.4	213.1
120	982.1	1.182	239.0	236.7
140	979.7	1.179	258.7	260.3
160	976.0	1.175	278.2	283.8
180	299.1	0.3558	291.0	299.2
200	297.1	0.3525	297.2	306.5

Table 6.2-48a (continued)
SLB M&E Inside Containment Case 4E: 25% Power 1.4 Ft^2
DER Failure: Electrical CH-A

Time (sec)	Break Flow Rate (lbm/sec)	Break Energy (10^6 btu/sec)	Integrated Mass Release (10^3 lbm)	Integrated Energy Release (10^6 btus)
220	458.4	0.5478	303.6	314.2
240	236.6	0.2812	309.1	320.7
260	186.6	0.2205	313.8	326.3
280	143.9	0.1690	317.3	330.3
300	141.0	0.1653	320.1	333.7
340	137.5	0.1612	325.6	340.1
1800	137.5	0.1612	526.4	575.5
1802	138.0	0.1619	526.7	575.9
1828	0.0	0.0	527.5	576.8

Steamline isolation: 7.0 sec Feedline isolation: 8.5 sec

Table 6.2-48b
SLB M&E Inside Containment Case 1H: 102% Power 1.4 Ft^2
DER Failure: 1 Train SI

Time (sec)	Break Flow Rate (lbm/sec)	Break Energy (10^6 btu/sec)	Integrated Mass Release (10^3 lbm)	Integrated Energy Release (10^6 btus)
0.0	0.0	0.0	0.0	0.0
0.2	8,622.0	10.28	1.724	2.057
0.4	8,400.0	10.02	3.404	4.062
0.6	8,255.0	9.856	5.055	6.033
0.8	8,117.0	9.695	6.679	7.972
1	7,985.0	9.541	8.276	9.880
2	7,399.0	8.856	15.90	19.00
3	6,908.0	8.28	23.00	27.50
4	6,635.0	7.958	29.70	35.54
5	6,521.0	7.824	36.26	43.42
6	6,416.0	7.699	42.72	51.16
7	6,320.0	7.587	49.08	58.79
8	6,228.0	7.478	55.34	66.32
9	6,132.0	7.365	61.52	73.73
10	6,022.0	7.234	67.58	81.02
10.6	5,944.0	7.142	71.17	85.32
10.8	2,074.0	2.491	71.58	85.32
11	2,067.0	2.482	71.99	86.31
15	1,859.0	2.236	79.85	95.75
20	1,594.0	1.919	88.43	106.1
30	1,264.0	1.522	102.5	123.0
40	1,101.0	1.326	114.2	137.1
61.5	1,002.0	1.206	136.4	163.9
80	978.3	1.178	154.7	185.8
100	964.8	1.161	174.1	209.2
110	959.7	1.155	183.7	220.8
120	981.2	1.181	193.5	232.5
140	981.5	1.181	213.1	256.2

Table 6.2-48b (continued)
SLB M&E Inside Containment Case 1H: 102% Power 1.4 Ft^2
DER Failure: 1 Train SI

Time (sec)	Break Flow Rate (lbm/sec)	Break Energy (10^6 btu/sec)	Integrated Mass Release (10^3 lbm)	Integrated Energy Release (10^6 btus)
160	962.5	1.158	232.7	279.7
180	250.6	0.2964	244.8	294.3
200	29.23	0.337	246.7	296.5
206	0.0	0.0	246.8	296.6
252	48.42	0.0562	247.8	297.7
506	0.0	0.0	254.9	306.0
752	51.17	0.0594	261.5	313.6
1000	0.0	0.0	268.4	321.6
1250	49.56	0.0575	275.2	329.5
1502	0.0	0.0	282.4	337.7
1754	51.92	0.0603	289.1	345.5
1800	0.0	0.0	290.3	346.9
1808	13.43	0.0155	290.7	347.3
1810	0.0	0.0	290.7	347.3
	Steamline isolation: 10.6 sec		Feedline isolation: 10.6 sec	

Table 6.2-49
Reactor Building Spray System Component Data

Reactor Building Spray Pumps	
Number	2
Rated Capacity, gpm	2500
Rated Head, ft	450
Material	Stainless steel (wetted parts) or equivalent corrosion resistant material
Design Pressure, psig	300
Design Temperature, °F	250
Code	ASME III, Class 2
Safety Class	2a
Sodium Hydroxide Storage Tank	
Number	1
Nominal Capacity, gal (minimum required usable volume)	3300 (3050)
Material	Carbon steel
Design Pressure, ft	Static Head + 3 psig
Code	ASME III, Class 3
Safety Class	2b
Valves Exposed to Recirculated Coolant and Valves in the Refueling Water Storage Tank Discharge Line	
Material	Stainless steel
Code	ASME III, Class 2
Safety Class	2a
Valves in the Sodium Hydroxide Storage Tank Discharge Line	
Material	Stainless steel

Table 6.2-49 (continued)
Reactor Building Spray System Component Data

Code	ASME III, Class 3
Safety Class	2b

Piping in Sodium Hydroxide Storage Tank Discharge Line

Material	Stainless steel
Code	ASME III, Class 3
Safety Class	2b

Other Piping, exposed to water recirculated from the Reactor Building Sump and water from the RWST

Material	Stainless steel
Code	ASME III, Class 2
Safety Class	2a

Spray Nozzles

Number	330
Material	Stainless steel
Type	Hollow cone
Flow, gpm/nozzle	15.2
Pressure Drop, psi	40

Table 6.2-50
Single Failure Analysis - Reactor Building Spray System

	Component	Malfunction	Comments
1.	Reactor building spray pump	Fails to start.	Since each of the two subsystems of the reactor building spray system is equally sized, the remaining subsystem provides heat removal capability at a reduced rate. In combination with the reactor building emergency cooling system, heat removal capability in excess of the requirements is provided. Elemental iodine removal is adequate with one subsystem operating.
2.	Reactor building isolation valve.	Fails to open.	(Same as above.)
3.	Check valve in suction line.	Fails to open.	(Same as above.)
4.	Sodium hydroxide tank discharge valve.	Fails to open.	The redundant discharge valve admits adequate sodium hydroxide to the other subsystem to provide the required iodine removal.

Table 6.2-51
Reactor Building Spray System Header Locations and Sizes

Subsystem A

Header	Ring Diameter (ft)	Pipe Size (in)	Elevation (ft-in)
Outer header	98	6	578-10
Middle header	58	6	590-4
Inner header	16	3	595-7

Subsystem B

Header	Ring Diameter (ft)	Pipe Size (in)	Elevation (ft-in)
Outer header	102	6	577-0
Middle header	62	6	589-6
Inner header	20	3	595-0

Table 6.2-52
Single Failure Analysis - Reactor Building
Heat Removal and Filtering System

	Component	Malfunction	Comments
1.	Air Handling Unit Fan Motor	Fails to start or fails to start at low speed.	Cooling continues from the remaining operating unit with supplemental cooling from the spray system.
2.	Cooling Coils	Rupture	The coils are designed for hydrostatic testing at 200 psig which is in excess of the design service water pressure. However, if rupture occurs, cooling continues as noted under item 1 above.
3.	Plenum and Ductwork	Rupture	The plenums and connected ductwork are designed to withstand the post accident pressure transient and the systems are sufficiently separated so that the effects of a pipe break or missile are confined to a single unit. Thus, rupture of a portion of the system or a single component does not prevent continued cooling as noted under item 1 above.
4.	Cooling Water Piping	Rupture	The piping for two of the units is physically separated from that of the remaining two units and is designed as Seismic Category I. Thus, rupture of a portion of the system does not affect all units and does not prevent cooling as noted under item 1 above.
5.	Water Control Valves	Fail to operate.	The valves are used for switching from the normal cooling water supply to the service water supply during a post accident period. The valves are redundant and are periodically tested. Failure of a single valve does not prevent cooling as noted under item 1 above.
6.	HEPA Filter Bypass Duct	Fails to operate.	Failure of the dampers in the normal position results in loss of filtering ability but not in loss of cooling for the affected units.

Table 6.2-52a
Major Heat Generating Components Inside the Reactor Building

Component
Steam Generators
Pressurizer
Reactor Coolant Pumps and Motors
Reactor Vessel
Control Rod Drive Mechanisms
Pressurizer Relief Tank
Reactor Coolant Drain Tank Pumps
Regenerative Heat Exchanger
Excess Letdown Heat Exchangers
Ventilation Equipment Fan Motors
Piping
Equipment and Piping Supports and Restraints

Table 6.2-52b
Maximum Expected Leakage to the Auxiliary Building From
the Reactor Building Spray System

Leakage Source	Leakage (cc/hr)
Reactor Building Spray Pump Seals	130
Flanges	120
Process Valves	12
Instrumentation Valves	18
Valve Seats as Boundaries	420
Total	870

Table 6.2-52c
Refueling Water Storage Tank Drawdown Analysis Branch Data

No.	From Junction	To Junction	Pipe ID (Inch)	Straight Pipe (Feet)	90° Elbow	45° Elbow	Gate Valve	Check Valve	Tee Run	Tee Branch	Reducers	Total Equivalent Diameters (L/D)	Total Equivalent Diameters (Feet)	Elevation Change Feet
1	3	4	19.25	37.10	2	1	1		1		1	99.30	196.39	-13.80
2	4	5	11.94	75.60	2	1			1	1		94.30	169.43	5.00
3	5	6	11.94	43.20	2	2	1	1	2		1	210.60	252.75	-7.00
4	6	7	11.94	32.10	2	1	1			1		97.30	128.91	-21.70
5	7	8	10.02	4.70	1						1	18.70	20.31	-1.90
6	5	9	11.94	56.70	3	1	1	1	2	1		275.30	330.62	-7.00
7	9	10	11.94	38.40	4	2	1		1			91.60	129.54	-21.70
8	10	11	10.02	4.70	1						1	19.00	20.56	-1.90
9	4	12	19.25	3.00					2			20.00	35.08	0.00
10	12	13	13.12	78.20	2	1			2	1		114.30	203.17	5.00
11	13	14	13.12	93.10	6	3	1	1	2	1		340.90	465.82	-27.80
12	13	15	13.12	60.90	5		1	1	1	1		283.00	370.31	-27.80
13	12	16	19.25	3.00					1			10.00	19.04	0.00
14	16	17	7.98	10.90	1			1	1		1	185.10	133.99	0.00
15	17	18	7.98	2.60			1		1	1		73.00	51.14	0.00
16	18	19	7.98	37.90	2	1			1	2		144.30	133.86	-5.50
17	18	24	7.98	11.90	1		2		1	1		99.00	77.73	0.00
18	19	20	6.07	24.50	3		1				1	63.70	56.72	-4.60
19	17	21	7.98	3.60			1		2			33.00	25.54	0.00

Table 6.2-52c (continued)
Refueling Water Storage Tank Drawdown Analysis Branch Data

No.	From Junction	To Junction	Pipe ID (Inch)	Straight Pipe (Feet)	90° Elbow	45° Elbow	Gate Valve	Check Valve	Tee Run	Tee Branch	Reducers	Total Equivalent Diameters (L/D)	Total Equivalent Diameters (Feet)	Elevation Change Feet
20	21	22	7.98	48.00	4	1			2			90.30	108.05	-5.50
21	22	23	6.07	23.40	3		1				1	63.70	55.62	-4.60
22	21	24	7.98	11.20			2		1	1		86.00	68.39	0.00
23	24	25	7.98	23.50	4	1			1			70.30	70.25	-5.50
24	25	26	6.07	16.20	2	1	1				1	59.00	46.04	-4.60
25	31	32	3.07	56.90	3	1	1		2	1	2	145.10	94.02	-7.00
26	32	9	3.07	57.60	8	2	1	1		2	1	368.60	151.90	-7.00
27	32	6	3.07	32.00	3		1	1	1	1	1	247.00	95.19	-7.00

Table 6.2-52d
Pump Head Data

Reactor Building Spray Pumps A and B

Flow (gpm)	0.0	1500.0	2000.0	2500.0	3000.0	3500.0	4000.0
Head (feet)	506.0	482.0	471.0	450.0	430.0	400.0	369.0

Charging Pump A

Flow (gpm)	0.0	200.0	300.0	400.0	500.0	600.0	700.0
Head (feet)	6100.0	6000.0	5780.0	5300.0	4690.0	3820.0	2900.0

Charging Pump B

Flow (gpm)	0.0	200.0	300.0	400.0	500.0	600.0	700.0
Head (feet)	6075.0	5975.0	5740.0	5260.0	4600.0	3750.0	2900.0

Charging Pump C

Flow (gpm)	0.0	200.0	300.0	400.0	500.0	600.0	700.0
Head (feet)	6020.0	5980.0	5700.0	5150.0	4470.0	3650.0	2700.0

Residual Heat Removal Pump A

Flow (gpm)	0.0	1000.0	2000.0	3000.0	3500.0	4000.0	5000.0
Head (feet)	347.0	325.0	310.0	280.0	261.0	240.0	193.0

Residual Heat Removal Pump B

Flow (gpm)	0.0	1000.0	2000.0	3000.0	3500.0	4000.0	5000.0
Head (feet)	350.0	325.0	310.0	279.0	260.0	238.0	195.0

Table 6.2-52e
Tank Parameters

Tank	ID	* Outlet Elevation	Minimum Fill Level Elevation	Maximum Fill Level Elevation
Refueling Water Storage Tank	40’	415.25’	464’ - 3”	466’ - 5”
Sodium Hydroxide Storage Tank	45”	413.50’	450’ - 7 1/16”	451’ - 8 1/8”

* Center Line

Table 6.2-52f
Specific Volume and Viscosity Curves

	NaOH (20 w/o)		NaOH (22 w/o)	
Temp. (°F)	ρ^{-1} (ft^3/lb)	ν (lbm/ft-sec)	ρ^{-1} (ft^3/lb)	ν (lbm/ft-sec)
40	1.306×10^{-2}	6.100×10^{-3}	1.282×10^{-2}	7.150×10^{-3}
50	1.309×10^{-2}	4.650×10^{-3}	1.285×10^{-2}	5.650×10^{-3}
60	1.312×10^{-2}	3.600×10^{-3}	1.288×10^{-2}	4.490×10^{-3}
70	1.315×10^{-2}	2.840×10^{-3}	1.292×10^{-2}	3.600×10^{-3}
80	1.318×10^{-2}	2.280×10^{-3}	1.295×10^{-2}	2.900×10^{-3}
90	1.322×10^{-2}	1.900×10^{-3}	1.299×10^{-2}	2.390×10^{-3}
100	1.326×10^{-2}	1.630×10^{-3}	1.302×10^{-2}	1.990×10^{-3}

Table 6.2-52g
Reactor Building Spray and ECCS Storage Tanks Drawdown Transient Analysis
Analytical Results to Minimum Sodium Hydroxide Initial Conditions

	TEMP (°F)	CONCENTRATION (w/o)	INITIAL LEVEL (feet)	TIME (min)	FINAL LEVEL (feet)	VOLUME DRAWN FROM TANK (gallons)	MASS OF CHEMICAL (lbs)	MASS OF WATER (lbs)
Reactor Building Spray System								
Design Case				67.49				
Refueling Water Storage Tank	70	1.429	51.15		1.55	466,220	55,490	3,838,770
Sodium Hydroxide Storage Tank	70	20	37.00		3.47	2,770	5,630	22,540
Normal Case				39.06				
Refueling Water Storage Tank	70	1.429	51.15		1.55	466,220	55,490	3,838,770
Sodium Hydroxide Storage Tank	70	20	37.00		0.38	3,020	6,140	24,570
Normal Case With One RBSS Pump Inoperable				49.25				
Refueling Water Storage Tank	70	1.429	51.15		1.55	466,220	55,490	3,838,770
Sodium Hydroxide Storage Tank	70	20	37.00		9.63	2,260	4,600	18,380
Normal Case With One RHR Pump Inoperable				43.55				
Refueling Water Storage Tank	70	1.429	51.15		6.73	417,530	49,700	3,437,860
Sodium Hydroxide Storage Tank	70	20	37.00		0.00	3,060	6,220	24,900
				48.660				
Refueling Water Storage Tank					1.55	466,220	55,490	3,838,770
Sodium Hydroxide Storage Tank					0.00	3,060	6,220	24,900

Table 6.2-52h
Reactor Building Spray and ECCS Storage Tanks Drawdown Transient Analysis
Analytical Results to Maximum Sodium Hydroxide Initial Conditions

	TEMP (°F)	CONCENTRATION (w/o)	INITIAL LEVEL (feet)	TIME (min)	FINAL LEVEL (feet)	VOLUME DRAWN FROM TANK (gallons)	MASS OF CHEMICAL (lbs)	MASS OF WATER (lbs)
Reactor Building Spray System								
Design Case				64.60				
Refueling Water Storage Tank	70	1.314	49.00		1.55	446,010	48,810	3,672,360
Sodium Hydroxide Storage Tank	70	22	38.00		3.89	2,820	6,420	22,770
Normal Case				37.41				
Refueling Water Storage Tank	70	1.314	49.00		1.55	446,010	48,810	3,672,360
Sodium Hydroxide Storage Tank	70	22	38.00		1.07	3,050	6,940	24,630
Normal Case With One RBSS Pump Inoperable				47.16				
Refueling Water Storage Tank	70	1.314	49.00		1.55	446,010	48,810	3,672,360
Sodium Hydroxide Storage Tank	70	22	38.00		10.23	2,290	5,210	18,490
Normal Case With One RHR Pump Inoperable				42.22				
Refueling Water Storage Tank	70	1.314	49.00		6.00	404,180	44,230	3,327,940
Sodium Hydroxide Storage Tank	70	22	38.00		0.00	3,140	7,150	25,350
				46.55				
Refueling Water Storage Tank					1.55	446,010	48,810	3,672,360
Sodium Hydroxide Storage Tank					0.00	3,140	7,150	25,350

Table 6.2-53
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2 -52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
101	Reactor Building Purge Exhaust	AH	Air	56	1	No	36"	18"	No	D-912-103-G-11
102	Reactor Building Cooling Unit B Return	SW	Water	57	12	Yes	16"	31’3”	No	D-302-222-G-03
103	Post Accident Hydrogen Purge Line	HR	Air	56	1	No	6"	20’	No	D-302-861-G-11
NOZZ 104	Spare	--	--	--	--	--	--	--	--	Sleeve size - 18"
105A	H2 Analyzer Supply	HR	Air	56	1	Yes	3/8”	--	No	D-302-861-E-11
105B	H2 Analyzer Discharge	HR	Air	56	1	Yes	3/8”	--	No	D-302-861-E-11
NOZZ 106	Spare	--	--	--	--	--	--	--	--	Sleeve size - 18"
107	Fuel Transfer Tube	SF	Water	56	13	No	20"	--	Yes	D-302-651-H-10
108	Spare	--	--	--	--	--	--	--	--	Sleeve size - 18"
201	Reactor Building Leak Rate Test Flow Test Line	LR	Air	56	21	No	2"	8’6”	Yes	D-302-811-J-08 Type B test for blind flanges in process line
202	Main Steam Loop C	MS	Steam	57	11A	Yes	32"	150’	No	D-302-011-F-10
203	Feedwater Loop C	FW	Water	57	11B	No	18"	16’9”	No	D-302-083-G-10
204	Component Cooling to Reactor Coolant Pumps	CC	Water	57	2	No	3"	21’3”	No	D-302-612-F-01
205	Emergency Feedwater B	EF	Water	57	11D	Yes	4"	8’6”	No	D-302-083-H-10

Table 6.2-53 (continued)
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2 -52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
206	Feedwater Loop B	FW	Water	57	11B	No	18"	7’6”	No	D-302-083-E-10
207	Main Steam Loop B	MS	Steam	57	11A	Yes	32"	88’9”	No	D-302-011-D-11
208	Spare	--	--	--	--	--	--	--	--	Sleeve size – 12”
209	Spare	--	--	--	--	--	--	--	--	Sleeve size – 12”
210	Reactor Building Leak Rate Test Pressure Sensing Line	LR	Air	56	21	No	2"	8’6”	Yes	D-302-811-J-7 Type B test for blind flanges in process line
211	Reactor Building Leak Rate Test Blowdown	LR	Air	56	21	No	8"	13’	Yes	D-302-811-J-7 Type B test for blind flanges in process line
212	Reactor Building Leak Rate Test Blowdown	LR	Air	56	21	No	8"	9’9”	Yes	D-302-811-J-10
213	Emergency Feedwater C	EF	Water	57	11D	Yes	4"	21’	No	D-302-083-H-9
214	Spare	--	--	--	--	--	--	--	--	Sleeve size - 10"
215	Spare	--	--	--	--	--	--	--	--	Sleeve size - 12"
216	Reactor Building Leak Rate Test Pressurization Line	LR	Air	56	21	No	8"	5’	Yes	D-302-811-J-11 Type B test for blind flanges in process line

Table 6.2-53 (continued)
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2 -52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
217	Reactor Building Pressure Sensing	--	See remarks	56	14	Yes	1/4”	--	--	D-302-861-B-3 The capillary between bellows and transmitter is fluid filled.
218	Spare	--	--	--	--	--	--	--	--	Sleeve size - 10"
219	Steam Generator Blowdown Loop C	BD	Water	57	11C	No	3"	17’8”	No	D-302-781-H-9
220	Steam Generator Blowdown Loop C Sampling Line	SS	Water	57	11C	No	3/8”	15’	No	D-302-771-G-10
221	Seal Injection to Reactor Coolant Pump C	CS	Water	55	2	No	1-1/2”	15’6”	No	E-302-673-H-15
222	High Head Safety Injection to Reactor Loops	SI	Water	55	6	Yes	3"	15’6”	No	E-302-691-C-9
223	Sampling Line from Reactor Coolant Loop C	SS	Water	55	1	No	3/8”	15’	No	D-302-771-E-10
224	Steam Generator Blowdown Loop B	BD	Water	57	11C	No	3"	16’6”	No	D-302-781-F-9
225	Steam Generator Blowdown Loop B Sampling Line	SS	Water	57	11C	No	3/8”	15’	No	D-302-771-F-10
226	Residual Heat Removal Pump Suction for Reactor Coolant Loop C	RH	Water	55	3	Yes	12"	--	No	E-302-641-F-13
227	Low Head Safety Injection to Reactor Coolant Loops	SI	Water	55	2	Yes	10"	12’9”	No	E-302-693-G-14
228	Spare	--	--	--	--	--	--	--	--	Sleeve size 10"

Table 6.2-53 (continued)
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2-52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
229	Seal Injection to Reactor Coolant Pump B	CS	Water	55	2	No	1-1/2”	11’6”	No	E-302-672-H-15
230A	Reactor Vessel Level Sensing Line	RC	See remarks	57	25	Yes	1/4”	--	--	E-302-601-G-5 Fluid between bellows & transmitter is water
230B	Reactor Vessel Level Sensing Line	RC	See remarks	57	25	Yes	1/4”	--	--	E-302-601-G-5 Fluid between bellows & transmitter is water
230C	Reactor Vessel Level Sensing Line	RC	See remarks	57	25	Yes	1/4”	--	--	E-302-601-G-5 Fluid between bellows & transmitter is water
230D	Spare	--	--	--	--	--	3/8”	--	--	Capped spare
230E	Spare	--	--	--	--	--	3/8”	--	--	Capped spare
231	Demineralized Water	DN	Air	56	17	No	1"	3’	No	D-302-715-P-11
232	Spare	--	--	--	--	--	--	--	--	Sleeve size 12"
301A	H2 Analyzer Supply	HR	Air	56	15	Yes	3/8”	--	No	D-302-861-C-11
301B	H2 Analyzer Discharge	HR	Air	56	22	Yes	3/8”	--	No	D-302-861-C-11
302	Alternate R.B. Purge Line	HR	Air	56	1	No	6"	9’9”	No	D-302-861-K-10
303	Supply to Reactor Building Spray Nozzles - Train B	SP	Water	56	2	Yes	10"	22’6”	No	D-302-661-E-11

Table 6.2-53 (continued)
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2-52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
304	Service Water from Reactor Building Cooling Unit A	SW	Water	57	12	Yes	16"	27’3”	No	D-302-222-C-5
305	Service Water from Reactor Building Cooling Unit A	SW	Water	57	12	Yes	16"	24’3”	No	D-302-222-C-2
306	Feedwater Loop A	FW	Water	57	11B	No	18"	11’0”	No	D-302-083-B-9
307	Number Not Used	--	--	--	--	--	--	--	--	Not Used
308	Emergency Feedwater A	EF	Water	57	11D	Yes	4"	18’9”	No	D-302-083-C-9
309	Abandoned Rad Monitor and Check Source	RM	NA	--	23	No	--	Note 6	No	Sleeve size 10" welded shut inside containment
310	Reactor Building Station Service Air	SA	Air	56	16	No	2"	13’9”	No	D-302-241-B-10
311	Reactor Building Instrument Air	IA	Air	56	2	No	2"	13’9”	No	D-302-273-G-4
312	Component Cooling Water to Reactor Coolant Pump Bearings	CC	Water	57	2	No	8"	19’	No	D-302-612-H-11
313	Nitrogen Supply to Feedwater Lines	NG	N2	56	16	No	1"	1’	No	D-302-311-B-12
314	Sampling Line from Reactor Coolant Loop B	SS	Water	55	1	No	3/8”	16’	No	D-302-771-D-10
315	Spare	--	--	--	--	--	--	--	--	Sleeve size 18"
316	Residual Heat Removal Pump Suction from Reactor Coolant Loop A	RH	Water	55	3	Yes	12"	--	No	E-302-641-H-13

Table 6.2-53 (continued)
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2 -52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
317	Fill Line to Accumulators	SI	Water	56	2	No	1"	9’9”	No	E-302-692-G-3
318	Reactor Coolant to Letdown Heat Exchanger	CS	Water	55	20	No	3"	16’	No	E-302-673-A-3
319	Reactor Building Instrument Air Compressor Suction Line	IA	Air	56	1	No	6"	14’3”	No	D-302-273-B-4
320	Accumulator Nitrogen Supply	SI	N2	56	2	No	1"	10’6”	No	E-302-692-A-3
321	Accumulator Test Line	SI	Water	56	1	No	3/4”	11’3”	No	E-302-692-B-14
322	Low Head Safety Injection to Reactor Coolant Loops	SI	Water	55	2	Yes	10"	12’9”	No	E-302-693-E-14
323	Accumulator Sampling Line	SS	Water	57	8	No	3/8”	11’3”	No	D-302-771-J-10
324	Breathing Air	IA	Air	56	17	No	2"	8’0”	No	D-302-274-C-4
325	Low Head Safety Injection to Reactor Coolant Loop Hot Legs	SI	Water	55	4	Yes	10"	12’9”	No	E-302-693-C-14
326	Steam Generator Blowdown Loop A	BD	Water	57	11C	No	3"	12’6”	No	D-302-781-C-9
327	Spray Pump A Suction from Reactor Building Recirculation Sump	SP	Water	56	5	Yes	12"	53’ (Note 5)	Yes	D-302-661-F-11
328	Spray Pump B Suction from Reactor Building Recirculation Sump	SP	Water	56	5	Yes	12"	34’ (Note 5)	Yes	D-302-661-F-11
329	RHR Pump A Suction from Reactor Building Recirculation Sump	SI	Water	56	5	Yes	14"	44’3” (Note 5)	Yes	E-302-693-J-14

Table 6.2-53 (continued)
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2 -52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
330	Component Cooling Water from Reactor Coolant Pump Bearings	CC	Water	57	7	No	8"	13’6”	No	D-302-612-H-12
401	Supply to Reactor Building Spray Nozzles Train A	SP	Water	56	2	Yes	10"	27’9”	No	D-302-661-E-11
402	Reactor Building Purge Supply	AH	Air	56	1	No	36"	18"	No	D-912-103-D-5
403	Reactor Building Cooling Unit B Supply	SW	Water	57	12	Yes	16"	40’	No	D-302-222-K-6
404	Fire Service Hose Reel Supply	FS	Air	56	17	No	4"	14’	No	D-302-231-D-6
405	Sampling Line from Pressurizer	SS	Steam or Water	55	15	No	3/8”	14’	No	D-302-771-C-10
406A	Spare	--	--	--	--	--	1/4”	--	--	B-814-028 Spare - tube seal welded.
406B	Reactor Building Pressure Sensing Line	--	See remarks	56	24	Yes	1/4”	--	--	D-302-861-B-3 The capillary between bellows and transmitter is fluid filled.
407A	Radiation Monitor Supply	SS	Air	56	1	No	1"	2’-5”	No	D-302-771-E-14
407B	Radiation Monitor Return	SS	Air	56	1	No	1"	2’-5”	No	D-302-771-E-14
408	Seal Injection to Reactor Coolant Pump A	CS	Water	55	2	No	1-1/2”	17’3”	No	E-302-671-H-16
409	Charging Line to Regenerative Heat Exchanger	CS	Water	55	2	No	3"	16’6”	No	E-302-673-A-3

Table 6.2-53 (continued)
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2 -52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
410	Reactor Coolant Pump Seal Water Return	CS	Water	55	7	No	2"	12’9”	No	E-302-673-C-3
411	Steam Generator Blowdown Loop A Sampling Line	SS	Water	57	11C	No	3/8”	12’6”	No	D-302-771-F-10
412	High Head Safety Injection to Reactor Coolant Loops	SI	Water	55	6	Yes	3"	11’3”	No	E-302-691-C-8
413	Spare	--	--	--	--	--	--	--	--	Sleeve size - 10"
414	Spare	--	--	--	--	--	--	--	--	Sleeve size - 10"
415	High Head Safety Injection to Reactor Coolant	SI	Water	55	6	Yes	3"	11’3”	No	E-302-691-C-6
416	Spare	--	--	--	--	--	--	--	--	Sleeve size - 10"
417A	Reactor Vessel Level Sensing Line	RC	See remarks	57	25	Yes	1/4”	--	--	E-302-601-J-5 Fluid between bellows & transmitter is water
417B	Reactor Vessel Level Sensing Line	RC	See remarks	57	25	Yes	1/4”	--	--	E-302-601-J-5 Fluid between bellows & transmitter is water
417C	Reactor Vessel Level Sensing Line	RC	See remarks	57	25	Yes	1/4”	--	--	E-302-601-J-5 Fluid between bellows & transmitter is water

Table 6.2-53 (continued)
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2 -52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
417D	Sample Return to PRT	SS	Water	56	1	No	3/8”	2’0”	No	D-302-772-J-3
417E	Spare	--	--	--	--	--	3/8”	--	--	Capped spare
418	Reactor Coolant Drain Tank to Vent Header and H2	WL	H2	56	1	No	3/4”	20’6”	No	E-302-735-B-12
419	Refueling Cavity Drain Line	SF	Air	56	17	No	3"	5’	No	D-302-651-H-12
420	Pressure Relief Tank	RC	N2	56	1	No	1"	15’6”	No	E-302-602-B-6
421	Refueling Cavity Fill Line	SF	Air	56	17	No	3"	3’3”	No	D-302-651-H-12
422	Pressure Relief Tank Makeup	RC	Water	56	2	No	3"	16’	No	E-302-602-B-3
423	Reactor Coolant Drain Tank	WL	Water	56	1	No	3"	11’3”	No	E-302-735-C-5
424	Reactor Building Sump Drain	ND	Water	56	1	No	3"	14’6”	No	D-302-821-A-9
425	RHR Pump B Suction from Reactor Building Recirculation Sump	SI	Water	56	5	Yes	14"	24’ (Note 5)	Yes	E-302-693-H-14
426	High Head Safety Injection to Reactor Coolant Loops	SI	Water	55	18	Yes	3"	16’	No	E-302-691-C-15
427	Fire Service Deluge	FS	Water	56	2	No	4"	11’9”	No	D-302-231-D-6
428	Main Steam Loop A	MS	Steam	57	11A	Yes	32"	176’9”	No	D-302-011-B-10
500	Reactor Building Pressure Sensing	--	See remarks	56	14	Yes	1/4”	--	No	D-302-861-A-3 The capillary between bellows and transmitter is fluid filled.

Table 6.2-53 (continued)
Isolation Summary

Penetration No. XRP- (Unless Noted)	Service	System (Note 1)	Fluid	General Design Criteria	Valve Arrang. Figure 6.2-52a	Essential (Note 2)	Line Size	Pipe Length to Vlv. (Note 3)	Type B Leak Test (Note 4)	Drawing Remarks
505	Outage Penetration	--	Air	56	21	No	18"	--	Yes	E-511-106-F-2 Type B Test for Blind Flanges
600	Outage Penetration	--	Air	56	21	No	12"	--	Yes	E-511-106-E-4 Type B Test for Blind Flanges
602	Outage Penetration	--	Air	56	21	No	18"	--	Yes	E-511-106-D-2 Type B Test for Blind Flanges
703	Reactor Building Pressure Sensing	--	See remarks	56	24	Yes	1/4”	--	No	D-302-861-A-3 The capillary between bellows and transmitter is fluid filled.

Table 6.2-53(Continued)
Isolation Summary

1 System abbreviations are as follows:

AH	-	Air Handling System
BD	-	Steam Generator Blowdown System
CC	-	Component Cooling Water System
CS	-	Chemical and Volume Control System
DN	-	Demineralized Water, Nuclear Services System
EF	-	Emergency Feedwater
FS	-	Fire Service System
FW	-	Feedwater System
HR	-	Post Accident Hydrogen Removal System
IA	-	Instrument Air System
LR	-	Leak Rate Test System
MS	-	Main Steam System
ND	-	Reactor Building and Auxiliary Building Sump Pumps System
NG	-	Nitrogen Blanketing System
RC	-	Reactor Coolant System
RM	-	Radiation Monitoring System
SA	-	Service Air System
SF	-	Spent Fuel Cooling System
SI	-	Safety Injection System
SP	-	Reactor Building Spray System
SS	-	Nuclear Sampling System
SW	-	Service Water System
WL	-	Liquid Waste Processing System

Table 6.2-53(Continued)
Isolation Summary

NOTES TO TABLE 6.2-53 (Continued)

2 "Yes" indicates that the penetration serves a system which is essential for safe shutdown or accident mitigation. Penetrations which may provide some post-accident services (e.g., sampling) are not indicated as essential.

3 This is the distance, along the pipe, from the outer edge of the concrete of the reactor building to the nearest edge of the outside containment isolation valve. Where there are one or more branches from the pipe, the distance is to the largest valve to the farthest of more than one equal size valves.

4 "No" indicates that these penetrations are sealed inside containment by a flat plate of 1/2 inch thickness or thicker, welded to both the penetration sleeve and process pipe. Since this isolation barrier does not utilize a resilient or flexible seal, these penetrations do not require Type B leakage tests.

5 This distance is measured as in Note 3 but it should be noted that the valve is within the valve compartment discussed in Section 6.2.4.2.2.

6 Isolation valve arrangement and pipe length to valve are not applicable since penetration is sealed inside containment by a welded cap.

Table 6.2-53a
Summary of Valves Subjected to Type C Leakage Tests

Penetration Number	Service	System	Type C Leakage Test [1] Inside Containment	Type C Leakage Test [1] Outside Containment
101	Reactor Building Purge Exhaust	AH	Yes [6]	Yes
102 [7]	Reactor Building Cooling Unit B Return	SW	N/A	No [10]
103	Post-Accident Hydrogen Purge Line	HR	Yes	Yes
104	Spare	-	N/A	N/A
105A	H2 Analyzer Supply	HR	Yes	Yes
105B	H2 Analyzer Discharge	HR	Yes	Yes
106	Spare	-	N/A	N/A
107	Fuel Transfer Tube	SF	No [2]	No [2]
108	Spare	-	N/A	N/A
201 [7]	Reactor Building Leak Rate Test Flow Test Line	LR	No [2]	No [2]
202	Main Steam Loop C	MS	N/A	No [3]
203	Feedwater Loop C	FW	N/A	No [3]
204 [7]	Component Cooling to Reactor Coolant Pumps	CC	Yes	Yes
205	Emergency Feedwater B	EF	N/A	No [3]
206	Feedwater Loop B	FW	N/A	No [3]
207	Main Steam Loop B	MS	N/A	No [3]
208	Spare	--	N/A	N/A
209	Spare	--	N/A	N/A
210 [7]	Reactor Building Leak Rate Test Pressure Sensing Line	LR	No [2]	No [2]
211 [7]	Reactor Building Leak Rate Test Blowdown	LR	No [2]	No [2]
212 [7]	Reactor Building Leak Rate Test Blowdown	LR	No [2]	No [2]
213	Emergency Feedwater C	EF	N/A	No [3]
214	Spare	-	N/A	N/A
215	Spare	-	N/A	N/A
216 [7]	Reactor Building Leak Rate Test Pressurization Line	LR	No [2]	No [2]
217	Reactor Building Pressure Sensing	-	N/A	N/A

Table 6.2-53a (continued)
Summary of Valves Subjected to Type C Leakage Tests

Penetration Number	Service	System	Type C Leakage Test [1] Inside Containment	Type C Leakage Test [1] Outside Containment
218	Spare	-	N/A	N/A
219	Steam Generator Blowdown Loop C	BD	N/A	No [3]
220	Steam Generator Blowdown Loop C Sampling Line	SS	N/A	No [3]
221	Seal Injection to Reactor Coolant Pump C	CS	Yes	Yes
223	Sampling Line from Reactor Coolant Loop C	SS	Yes	Yes
224	Steam Generator Blowdown Loop B	BD	N/A	No [3]
225	Steam Generator Blowdown Loop B Sampling Line	SS	N/A	No [3]
226 [7]	Residual Heat Removal Pump Suction from Reactor Coolant Loop C	RH	Yes [8]	N/A
227 [7]	Low Head Safety Injection to Reactor Coolant Loops	SI	No[5]	No[10]
228	Spare	-	N/A	N/A
229	Seal Injection to Reactor Coolant Pump B	CS	Yes	Yes
230A	Reactor Vessel Level Sensing Line	RC	N/A	N/A
230B	Reactor Vessel Level Sensing Line	RC	N/A	N/A
230C	Reactor Vessel Level Sensing Line	RC	N/A	N/A
230 D&E	Spare	-	N/A	N/A
231	Demineralized Water	DN	Yes	Yes
232	Spare	-	N/A	N/A
301A	H2 Analyzer Supply	HR	Yes	Yes
301B	H2 Analyzer Discharge	HR	Yes	Yes
302	Alternate R.B. Purge Line	HR	Yes	Yes
303	Supply to Reactor Building Spray Nozzles - Train B	SP	Yes	Yes
304 [7]	Service Water to Reactor Building Cooling Unit A	SW	N/A	No[10]
305 [7]	Service Water from Reactor Building Cooling Unit A	SW	N/A	No[10]
306	Feedwater Loop A	FW	N/A	No [3]

Table 6.2-53a (continued)
Summary of Valves Subjected to Type C Leakage Tests

Penetration Number	Service	System	Type C Leakage Test [1] Inside Containment	Type C Leakage Test [1] Outside Containment
307	Number Not Used	-	N/A	N/A
308	Emergency Feedwater A	EF	N/A	No [3]
309	Abandoned Rad Monitor and Check Source	RM	N/A	N/A
310	Reactor Building Station Service Air	SA	Yes	Yes
311	Reactor Building Instrument Air	IA	Yes	Yes
312 [7]	Component Cooling Water to Reactor Coolant Pump Bearings	CC	Yes	Yes
313	Nitrogen Supply to Feedwater Lines	NG	Yes	Yes
314	Sampling Line from Reactor Coolant Loop B	SS	Yes	Yes
315	Spare	-	N/A	N/A
316[7]	Residual Heat Removal Pump Suction from Reactor Coolant Loop A	RH	Yes [8]	N/A
317	Fill Line to Accumulators	SI	Yes	Yes
318	Reactor Coolant to Letdown Heat Exchanger	CS	Yes	Yes
319	Reactor Building Instrument Air Compressor Suction Line	IA	Yes	Yes
320	Accumulator Nitrogen Supply	SI	Yes	Yes
321	Accumulator Test Line	SI	Yes	Yes
322 [7]	Low Heat Safety Injection to Reactor Coolant Loops	SI	No [5]	No [10]
323	Accumulator Sampling Line	SS	N/A	Yes
324	Breathing Air	IA	Yes	Yes
325 [7]	Low Head Safety Injection to Reactor Coolant Loop Hot Legs	SI	No[5]	Yes [8]
326	Steam Generator Blowdown Loop A	BD	N/A	No [3]
327	Spray Pump A Suction from Reactor Building Recirculation Sump	SP	N/A	No[10]
328	Spray Pump B Suction from Reactor Building Recirculation Sump	SP	N/A	No[10]
329	RHR Pump A Suction from Reactor Building Recirculation Sump	SI	N/A	No[10]
330 [7]	Component Cooling Water from Reactor Coolant Pump Bearings	CC	Yes	Yes

Table 6.2-53a (continued)
Summary of Valves Subjected to Type C Leakage Tests

Penetration Number	Service	System	Type C Leakage Test [1] Inside Containment	Type C Leakage Test [1] Outside Containment
401 [4-1]	Supply to Reactor Building Spray Nozzles Train A	SP	Yes	Yes
402	Reactor Building Purge Supply	AH	Yes [6]	Yes
403 [7]	Reactor Building Cooling Unit B Supply	SW	N/A	No [10]
404	Fire Service Hose Reel Supply	FS	Yes	Yes
405	Sampling Line from Pressurizer	SS	Yes	Yes
406A	Spare	-	N/A	N/A
406B	Reactor Building Pressure Sensing Line	-	N/A	N/A
407A	Radiation Monitor Supply	SS	Yes	Yes
407B	Radiation Monitor Return	SS	Yes	Yes
408	Seal Injection to Reactor Coolant Pump A	CS	Yes	Yes
409	Charging Line to Regenerative Heat Exchanger	CS	Yes	Yes
410	Reactor Coolant Pump Seal Water Return	CS	Yes	Yes
411	Steam Generator Blowdown Loop A Sampling	SS	N/A	No [3]
413	Spare	-	N/A	N/A
414	Spare	-	N/A	N/A
416	Spare	-	N/A	N/A
417 A,B,C	Reactor Vessel Level Sensing	RC	N/A	N/A
417D	Sample Return to PRT	SS	Yes	Yes
417E	Spare	-	N/A	N/A
418	Reactor Coolant Drain Tank to Vent Header and H_2	WL	Yes	Yes
419	Refueling Cavity Drain Line	SF	Yes	Yes
420	Pressure Relief Tank	RC	Yes	Yes
421	Refueling Cavity Fill Line	SF	Yes	Yes
422	Pressure Relief Tank Makeup	RC	Yes	Yes
423	Reactor Coolant Drain Tank	WL	Yes	Yes
424	Reactor Building Sump Drain	ND	Yes	Yes
425	RHR Pump B Suction from Reactor Building Recirculation Sump	SI	N/A	No [10]

Table 6.2-53a (continued)
Summary of Valves Subjected to Type C Leakage Tests

Penetration Number	Service	System	Type C Leakage Test [1] Inside Containment	Type C Leakage Test [1] Outside Containment
427	Fire Service Deluge	SF	Yes	Yes
428	Main Steam Loop A	MS	N/A	No [3]
500	Reactor Building Pressure Sensing	-	N/A	N/A
505	Outage Penetration	-	No [2]	No [2]
600	Outage Penetration	-	No [2]	No [2]
602	Outage Penetration	-	No [2]	No [2]
703	Reactor Building Pressure Sensing	-	N/A	N/A

Table 6.2-53a (Continued)
Summary of Valves Subjected To Type C Leakage Tests

NOTES:

1 N/A - not applicable.

2 These piping penetrations, which utilize blind flanges as isolation barriers, are subject to Type B leakage testing as indicated in Table 6.2-53.

3 Isolation valves located in secondary side piping that penetrates containment are exempt from Type C leakage testing since the requirements of Appendix J to 10CFR 50 for leak testing of these valves applies only to direct cycle boiling water power reactors. These valves are called Containment Boundary Valves (CBV) on the system flow diagrams.

4 Deleted RN 03-035, 10-21-2003

5 These check valves are not testable due to their location and orientation within their systems.

6 These valves are tested in the reverse direction due to system design and their orientation.,

7 In operation during Integrated Leak Rate Test or during LOCA.

8 Meets 10CFR50 Appendix J Type C leak test requirements by Type C air leak test or by taking credit for 30 day water seal capability upon passing a water leak test.

9 XVG08889-SI is equipped with a bonnet relief system that allows the test medium to be introduced between the valves disc. This allows the leakage to be measured in both directions.

10 Per ANS/ANSI-56.8, the associated valve is exempt from Type C leakage testing since the boundary does not constitute a potential primary containment atmospheric pathway during or following a LOCA. This valve is a Containment Isolation Valve as indicated on the system flow diagram.

Table 6.2-54
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
101	1	Inside	XVB-2B	Butterfly	36	AO/FC	-	H(B)	Yes	Closed	Closed	Closed	Closed	IA-B	3 Sec Max	
		Outside	XVB-2A	Butterfly	36	AO/FC	-	H(A)	Yes	Closed	Closed	Closed	Closed	IA-A	3 Sec Max	
102	12	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed System inside
		Outside	3103B	Gate	16	EMO	HW	J(B)	Yes	Open	Open	Open	As Is	EP-B	45 Sec	
103	1	Inside	6056	Gate	6	AO/FC	-	K(A)	Yes	Closed	Closed	(See Remarks)	Closed	IA-A	5 Sec (Note 9)	Post accident position is initially "closed." Valves may be opened during accident if H_2 sample/purge is required.
		Outside	6057	Gate	6	AO/FC	-	K(B)	Yes	Closed	Closed	(See Remarks)	Closed	IA-B	5 Sec (Note 9)	
104	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped Spare
105A	1	Inside	6051B	Solenoid	3/8	EO	-	-	Yes	Closed	Closed	(See Remarks)	Closed	EP-B	NA (Note 11)	Post accident position is initially "closed." Valves may be opened during accident if H_2 sample/purge is required.
		Outside	6053B	Solenoid	3/8	EO	-	-	Yes	Closed	Closed	(See Remarks)	Closed	EP-B	NA (Note 11)	
105B	1	Inside	6050B	Solenoid	3/8	EO	-	-	Yes	Closed	Closed	(See Remarks)	Closed	EP-B	NA (Note 11)	Post accident position is initially "closed." Valves may be opened during accident if H_2 sample/purge is required.
		Outside	6052B	Solenoid	3/8	EO	-	-	Yes	Closed	Closed	(See Remarks)	Closed	EP-B	NA (Note 11)	

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
106	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped Spare
107	13	Inside	-	BI Flng	-	-	-	-	-	Closed	Closed	Closed	Closed	-	-	Double O-ring seal provides redundant isolation
108	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped Spare
201	21	Inside	-	BI Flng	-	-	-	-	-	Closed	Closed	Closed	Closed	-	-	
		Outside	-	BI Flng	-	-	-	-	-	Closed	Closed	Closed	Closed	-	-	
202	11a	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	2877B	Globe	1-1/2	AO/FC	HW	J(A, B)	Yes	Open	Closed	Open	Closed	IA-A/B	N/A	Dual Solenoids
		Outside	2020	Globe	8	AO/FC	HW	J(A, B)	Yes	Closed	Closed	Closed	Closed (note 8)	IA-A/B	N/A	Six Solenoids
		Outside	2802B	Gate	4	EMO	HW	J(B)	Yes	Open	Closed	Open	As Is	EP-B	N/A	
		Outside	2843C	Globe	1-1/2	AO/FC	HW	J(A, B)	Yes	Open	Closed	Open	Closed	IA-A/B	N/A	Dual Solenoids
		Outside	2869C	Globe	4	AO/FC	-	C(A, B)	Yes	Closed	Closed	Closed	Closed	IA-A/B	10 Sec	Dual Solenoids
		Outside	2801C	Globe	32	AO/FC	-	C(A, B)	Yes	Open	Closed	Closed	Closed	IA-A/B	7 Sec	Dual Solenoids
		Outside	2806K, L, M, N, P	Safety	6x10	PO/FC	-	None	No	Closed	Closed	Closed	Closed			Five Valves
203	11B	Outside	11672	Gate	3	HW	-	-	No	Closed	Closed	Closed	-	-	-	Locked Closed
203	11C	Inside	-	-	-	-	-	-	-	-	-	-	-		-	Closed System Inside
		Outside	1611C	Gate	18	AO/AC	-	M(A)	Yes	Open	Closed	Closed	Closed	IA-A	5 Sec (Note 12)	Dual A Train Solenoids
			1611C	Gate				M(B)	Yes	Open	Closed	Closed	As Is	IA-B		B Train Solenoid

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
204	2	Inside	9602	Check	3	-	-	-	-	-	-	-	-	None		
		Outside	9600	Gate	3	EMO	HW	P(A)	Yes	Open	Open	Closed	As Is	EP-A	60 Sec (Note 9)	
205	11D	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed System inside
		Outside	1009B	Spl Chk	4	AO/FC	-	J(B)	Yes	Closed	Closed	Open	Closed	IA-B	N/A	
		Outside	1633B	Stp Chk	1-1/2	EMO	HW	P(B)	Yes	Open	Open	Closed	As Is	EP-B	60 Sec (Note 9)	
206	11B	Outside	11671	Gate	3	HW	-	-	No	Closed	Closed	Closed	-	-	-	Locked Closed
206	11C	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed System Inside
		Outside	1611B	Gate	18	AO/AC	-	M(A)	Yes	Open	Closed	Closed	Closed	IA-A	5 Sec (Note 12)	Dual Train A Solenoids
			1611B	Gate				M(B)	Yes	Open	Closed	Closed	As Is	IA-B		Train B Solenoid
207	11A	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed System Inside
		Outside	2010	Globe	8	AO/FC	HW	J(A/B)	Yes	Closed	Closed	Closed	Closed (note Figure 8 a)	IA-A/B	N/A	Six Solenoids
		Outside	2802A	Gate	4	EMO	HW	J(A)	Yes	Open	Closed	Open	As Is	EP-A	N/A	
		Outside	2843B	Globe	1-1/2	AO/FC	HW	J(A/B)	Yes	Open	Closed	Open	Closed	IA-A/B	N/A	Dual Solenoids
		Outside	2801B	Globe	32	AO/FC	-	C(A/B)	Yes	Open	Closed	Closed	Closed	IA-A/B	7 Sec	Dual Solenoids
		Outside	2869B	Globe	4	AO/FC	-	C(A, B)	Yes	Closed	Closed	Closed	Closed	IA-A/B	10 Sec	Dual Solenoids
		Outside	2806F, G, H, I, J	Safety	6x10	PO/FC	-	None	No	Closed	Closed	Closed	Closed	-	-	Five Valves
210	21	Inside		BI Flng	-	-	-	-	-	Closed	Closed	Closed	Closed	-	-	

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
		Outside	-	BI Flng	-	-	-	-	-	Closed	Closed	Closed	Closed	-	-	
211	21	Inside	-	BI Flng	-	-	-	-	-	Closed	Closed	Closed	Closed	-	-	
		Outside	-	BI Flng	-	-	-	-		Closed	Closed	Closed	Closed	-	-	
212	21	Inside	-	BI Flng	-	-	-	-	-	Closed	Closed	Closed	Closed	-	-	
		Outside	-	BI Flng	-	-	-	-		Closed	Closed	Closed	Closed	-	-	
213	11D	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	1009C	Spl Chk	4	AO/FC	-	J(A)	Yes	Closed	Closed	Open	Closed	IA-A	N/A	
		Outside	1633C	Stp Chk	1-1/2	EMO	HW	P(A)	Yes	Open	Open	Closed	As Is	EP-A	60 Sec (Note 9)	
214	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped spare
215	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped spare
216	21	Inside	-	BI Flng	-	-	-	-	-	Closed	Closed	Closed	Closed	-	-	
		Outside	-	BI Flng	-	-	-	-		Closed	Closed	Closed	Closed	-	-	
217	14	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Bellows inside
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Transmitter Outside
218	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped spare
219	11C	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	503C	Gate	3	AO/FC	HW	F(A/B)	Yes	Open	Closed	Closed	Closed	IA-A/B	40 Sec (Note 9)	Two solenoids in series
220	11C	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
		Outside	9398C	Globe	1	EO	-	F(B)	Yes	Open	Open	Closed	Closed	EP-B	40 Sec (Note 9)	
221	2	Inside	8368C	Check	1-1/2	-	-	-	No	-	-	-	-	-	-	
		Outside	8102C	Globe	1-1/2	EMO	HW	J(B)	Yes	Open	Open	Open	As Is	EP-B	N/A	
222	6	Inside	8995A	Check	2	-	-	-	No	-	-	-	-	-	-	
		Inside	8995B	Check	2	-	-	-	No	-	-	-	-	-	-	
		Inside	8995C	Check	2	-	-	-	No	-	-	-	-	-	-	
		Outside	8885	Gate	3	EMO	HW	J(A)	Yes	Closed	Closed	Closed	As Is	EP-A	10 Sec	Open for post accident recirc phase
223	1	Inside	9364C	Globe	3/8	EO	-	T(A)	Yes	Closed	Closed	Closed	Closed	EP-A	40 Sec (Note 9)	Intermittent operation post Accident
		Outside	9365C	Globe	3/8	EO	-	T(B)	Yes	Closed	Closed	Closed	Closed	EP-B	40 Sec (Note 9)	Intermittent operation post Accident
224	11C	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	503B	Gate	3	AO/FC	HW	F(A/B)	Yes	Open	Closed	Closed	Closed	IA-A/B	40 Sec (Note 9)	Two solenoids in series
225	11C	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	9398B	Globe	1	EO	-	F(B)	Yes	Open	Open	Closed	Closed	EP-B	40 Sec (Note 9)	
226	3	Inside	8701B	Gate	12	EMO	HW	J(B)	Yes	Closed	Open	Closed	As Is	EP-A	120 Sec	
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system outside
227	2	Inside	8974B	Check	10	-		-	No	-	-	-	-	-	-	

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
		Outside	8888B	Gate	10	EMO	HW	J(B)	Yes	Open	Open	Open	As Is	EP-B	15 Sec	Operated during post accident recirc phase
228	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped spare
229	2	Inside	8368B	Check	1-1/2	-	-	-	No	-	-	-	-	-	-	
		Outside	8102B	Globe	1-1/2	EMO	HW	J(B)	Yes	Open	Open	Open	As Is	EP-B	N/A	
230A	25	Inside	-	-		-	-	-	-	-	-	-	-	-	-	Bellows inside
		Outside	-	-		-	-	-	-	-	-	-	-	-	-	Transmitter Outside
230B	25	Inside	-	-		-	-	-	-	-	-	-	-	-	-	Bellows inside
		Outside	-	-		-	-	-	-	-	-	-	-	-	-	Transmitter Outside
230C	25	Inside	-	-		-	-	-	-	-	-	-	-	-	-	Bellows inside
		Outside	-	-		-	-	-	-	-	-	-	-	-	-	Transmitter Outside
230D	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped 3/8 spare
230E	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped 3/8 spare
231	17	Inside	8768	Diaph	1	HW	-	-	No	Closed	Closed	Closed	-	-	-	Locked Closed
		Outside	8767	Diaph	1	HW	-	-	No	Closed	Closed	Closed	-	-	-	Locked Closed
232	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped Spare

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
301A	15	Inside	6051A	Solenoid	3/8	EO	-	-	Yes	Closed	Closed	(See Remarks)	Closed	EP-A	N/A (Note 11)	Post accident position is initially "closed." Valves may be opened during accident if H_2 sample/purge is required.
		Inside	6051C	Solenoid	3/8	EO	-	-	Yes	Closed	Closed	(See Remarks)	Closed	EP-A	N/A (Note 11)	
		Outside	6053A	Solenoid	3/8	EO	-	-	Yes	Closed	Closed	(See Remarks)	Closed	EP-A	N/A (Note 11)	
301B	22	Inside	6050A	Solenoid	3/8	EO	-	T(A)	Yes	Open	Closed	(See Remarks)	Closed	EP-A	40 Sec (Note 9)	Post accident position is initially "closed." Valves may be opened during accident if H_2 sample/purge is required.
		Outside	6052A	Solenoid	3/8	EO	-	-	Yes	Closed	Closed	(See Remarks)	Closed	EP-A	N/A (Note 11)	
		Outside	6054	Solenoid	3/8	EO	-	T(B)	Yes	Open	Closed	(See Remarks)	Closed	EP-B	40 Sec (Note 9)	
302	1	Inside	6066	Gate	6	AO/FC	-	K(A)	Yes	Closed	Closed	(See Remarks)	Closed	IA-A	5 Sec (Note 9)	Post accident position is initially "closed." Valves may be opened during accident if H_2 sample/purge is required.
		Outside	6067	Gate	6	AO/FC	-	K(B)	Yes	Closed	Closed	(See Remarks)	Closed	IA-B	5 Sec (Note 9)	
303	2	Inside	3009B	Check	10	-	-	-	No	-	-	-	-	-	-	
		Outside	3003B	Gate	10	EMO	HW	T(B)	Yes	Closed	Closed	Open	As Is	EP-B	30 Sec (Note 13)	Signal opens valv
304	12	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	3106A	Butterfly	16	EMO	HW	I(A)	Yes	Closed	Closed	Open	As Is	EP-A	45 Sec	
		Outside	3110A	Butterfly	12	EMO	HW	I(A)	Yes	Open	Open	Closed	As Is	EP-A	70 Sec	

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
305	12	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	3103A	Gate	16	EMO	HW	J(A)	Yes	Open	Open	Open	As Is	EP-A	45 Sec	
306	11B	Outside	11670	Gate	3	HW	-	-	No	Closed	Closed	Closed	-	-	-	Locked Closed
306	11C	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	1611A	Gate	18	AO/AC	-	M(A)	Yes	Open	Closed	Closed	Closed	IA-A	5 Sec (Note 12)	Dual A train Solenoids
			1611A	Gate				M(B)	Yes	Open	Closed	Closed	As Is	IA-B		B Train Solenoids
307	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Not Used
308	11D	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	1633A	Stp Chk	1-1/2	EMO	HW	P(A)	Yes	Open	Open	Closed	As Is	EP-A	60 Sec (Note 9)	
		Outside	1009A	Spl Chk	4	AO/FC	-	J(A)	Yes	Closed	Closed	Open	Closed	IA-A	N/A	
309	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped rad mon abandoned
310	16	Inside	2913	Check	2	-	-		No	-	-	-	-	-	-	
		Outside	2912	Globe	2	HW			No	Closed	Closed	Closed	Closed	-	-	Locked closed
311	2	Inside	2661	Check	2	-	-		No	-	-	-	-	-	-	
		Outside	2660	Globe	2	AO/FC	-	T(A)	Yes	Open	Open	Closed	Open	IA-A	40 Sec (Note 9)	
312	2	Inside	9570	Check	8	-	-	-	No	-	-	-	-	-	-	
		Outside	9568	Gate	8	EMO	HW	P(A)	Yes	Open	Open	Closed	As-Is	EP-A	60 Sec (Note 9)	

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
313	16	Inside	6588	Check	1	-	-	-	No	-	-	-	-	-	-	
		Outside	6587	Globe	1	HW	-	-	No	Closed	Closed	Closed	Closed	-	-	Locked Closed
314	1	Inside	9364B	Globe	3/8	EO	-	T(A)	Yes	Closed	Closed	Closed	Closed	EP-A	40 Sec (Note 9)	Intermittent operation
		Outside	9365B	Globe	3/8	EO	-	T(B)	Yes	Closed	Closed	Closed	Closed	EP-B	40 Sec (Note 9)	Post Accident
315	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped spare
316	3	Inside	8701A	Gate	12	EMO	HW	J(A)	Yes	Closed	Open	Closed	As Is	EP-A	120 Sec	
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system outside
317	2	Inside	8861	Check	1	-	-	-	No	-	-	-	-	-	-	
		Outside	8860	Globe	1	AO/FC	-	T(B)	Yes	Closed	Closed	Closed	Closed	IA-B	40 Sec (Note 9)	
318	20	Inside	8149A	Globe	2	AO/FC	-	T(A)	Yes	Note 14	Note 14	Closed	Closed	IA-A	40 Sec (Note 9)	
		Inside	8149B	Globe	2	AO/FC	-	T(A)	Yes	Note 14	Note 14	Closed	Closed	IA-A	40 Sec (Note 9)	
		Inside	8149C	Globe	2	AO/FC	-	T(A)	Yes	Note 14	Note 14	Closed	Closed	IA-A	40 Sec (Note 9)	
		Inside	8117	Relief	2	-	-	-	No	Closed	Closed	Closed	Closed	-	-	
		Outside	8152	Globe	3	AO/FC	-	T(B)	Yes	Open	Open	Closed	Closed	IA-B	40 Sec (Note 9)	
319	1	Inside	2662B	Globe	6	AO/FC	-	T(B)	Yes	Open	Open	Closed	Open	IA-B	40 Sec (Note 9)	
		Outside	2662A	Globe	6	AO/FC	-	T(A)	Yes	Open	Open	Closed	Open	IA-A	40 Sec (Note 9)	
320	2	Inside	8947	Check	1	-	-	-	No	-	-	-	-	-	-	

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
		Outside	8880	Globe	1	AO/FC	-	T(B)	Yes	Closed	Closed	Closed	Closed	IA-B	40 Sec (Note 9)	
321	1	Inside	8871	Globe	3/4	AO/FC	-	T(A)	Yes	Closed	Closed	Closed	Closed	IA-A	40 Sec (Note 9)	
		Outside	8961	Globe	3/4	AO/FC	-	T(B)	Yes	Closed	Closed	Closed	Closed	IA-B	40 Sec (Note 9)	
322	2	Inside	8974A	Check	10	-	-		No	-	-	-	-	-	-	
		Outside	8888A	Gate	10	EMO	HW	J(A)	Yes	Open	Open	Open	As Is	EP-A	15 Sec	Operated during post accident recirc phase
323	8	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	9387	Globe	3/8	EO	-	T(B)	Yes	Closed	Closed	Closed	Closed	EP-B	40 Sec (Note 9)	
324	17	Inside	2680	Globe	2	HW	-	-	No	Closed	Closed	Closed	-	-	-	Locked Closed
		Outside	2679	Globe	2	HW	-	-	No	Closed	Closed	Closed	-	-	-	Locked Closed
325	4	Inside	8988A	Check	6	-	-	-	No	-	-	-	-	-	-	
		Inside	8988B	Check	6	-	-	-	No	-	-	-	-	-	-	
		Outside	8889	Gate	10	EMO	HW	J(A)	Yes	Closed	Closed	Closed	As Is	EP-A	15 Sec	Open for post accident recirc phase
326	11C	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	503A	Gate	3	AOFC	HW	F(A/B)	Yes	Open	Closed	Closed	Closed	IA-A/B	40 Sec (Note 9)	Two solenoids in series
327	5	Outside	3004A	Gate	12	EMO	HW	J(A)	Yes	Closed	Closed	Closed	As Is	EP-A	60 Sec Max	Open for post accident recirc phase

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Guard Pipe and chamber
328	5	Outside	3004B	Gate	12	EMO	HW	J(B)	Yes	Closed	Closed	Closed	As Is	EP-B	60 Sec Max	Open for post accident recirc phase
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Guard Pipe and chamber
329	5	Outside	8811A	Gate	14	EMO	HW	A(A)	Yes	Closed	Closed	Closed	As Is	EP-A	20 Sec	Open for post accident recirc phase
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Guard Pipe and chamber
330	7	Inside	9605	Gate	8	EMO	HW	P(A)	Yes	Open	Open	Closed	As Is	EP-A	60 Sec (Note 9)	
		Inside	9689	Check	3/4	-	-	-	No	-	-	-	-	-	-	
		Outside	9606	Gate	8	EMO	HW	P(B)	Yes	Open	Open	Closed	As Is	EP-B	60 Sec (Note 9)	
401	2	Inside	3009A	Check	10	-	-	-	No	-	-	-	-	-	-	
		Outside	3003A	Gate	10	EMO	HW	T(A)	Yes	Closed	Closed	Open	As Is	EP-A	30 Sec (Note 13)	Signal opens valve
402	1	Inside	000-1B	Butterfly	36	AO/FC	-	H(B)	Yes	Closed	Closed	Closed	Closed	IA-B	3 Sec Max	
		Outside	000-1A	Butterfly	36	AO/FC	-	H(A)	Yes	Closed	Closed	Closed	Closed	IA-A	3 Sec Max	
403	12	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	3106B	Butterfly	16	EMO	HW	I(B)	Yes	Closed	Closed	Open	As Is	EP-B	45 Sec	
		Outside	3110B	Butterfly	12	EMO	HW	I(B)	Yes	Open	Open	Closed	As Is	EP-B	70 Sec Max	

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
404	17	Inside	6773	Gate	4	HW	-	-	No	Closed	Closed	Closed	Closed	-	-	Locked closed
		Outside	6772	Gate	4	HW	-	-	No	Closed	Closed	Closed	Closed	-	-	Locked closed
405	15	Inside	9356A	Globe	3/8	EO	-	T(A)	Yes	Closed	Closed	Closed	Closed	EP-A	40 Sec (Note 9)	Intermittent operation post accident
		Inside	9356B	Globe	3/8	EO	-	T(A)	Yes	Closed	Closed	Closed	Closed	EP-A	40 Sec (Note 9)	Intermittent operation post accident
		Outside	9357	Globe	3/8	EO	-	T(B)	Yes	Closed	Closed	Closed	Closed	EP-B	40 Sec (Note 9)	Intermittent operation post accident
406A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Seal welded spare
406B	24	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Bellows inside
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Transmitter outside
407A	1	Outside	9311B	Ball	1	AO/FC	-	T(B)	Yes	Open	Open	Closed	Closed	IA-B	40 Sec (Note 9)	Intermittent operation post accident
		Inside	9311A	Ball	1	AO/FC	-	T(A)	Yes	Open	Open	Closed	Closed	IA-A	40 Sec (Note 9)	Intermittent operation post accident
407B	1	Outside	9312B	Ball	1	AO/FC	-	T(B)	Yes	Open	Open	Closed	Closed	IA-B	40 Sec (Note 9)	Intermittent operation post accident
		Inside	9312A	Ball	1	AO/FC	-	T(A)	Yes	Open	Open	Closed	Closed	IA-A	40 Sec (Note 9)	Intermittent operation post accident
408	2	Inside	8368A	Check	1-1/2	-	-	-	No	-	-	-	-	-	-	
		Outside	8102A	Globe	1-1/2	EMO	HW	J(B)	Yes	Open	Open	Open	As Is	EP-B	N/A	

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
409	2	Inside	8381	Check	3	-	-	-	No	-	-	-	-	-	-	
		Outside	8107	Gate	3	EMO	HW	S(A)	Yes	Open	Closed	Closed	As Is	EP-A	10 Sec (Note 10)	
410	7	Inside	8112	Globe	2	EMO	HW	T(A)	Yes	Open	Open	Closed	As Is	EP-A	40 Sec (Note 9)	
		Inside	8103	Check	3/4	-	-	-	No	-	-	-	-	-	-	
		Outside	8100	Globe	2	EMO	HW	T(B)	Yes	Open	Open	Closed	As Is	EP-B	40 Sec (Note 9)	
411	11C	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system inside
		Outside	9398A	Globe	1	EO	-	F(B)	Yes	Open	Open	Closed	Closed	EP-B-	40 Sec (Note 9)	
412	6	Inside	8990A	Check	2	-	-	-	No	-	-	-	-	-	-	
		Inside	8990B	Check	2	-	-	-	No	-	-	-	-	-	-	
		Inside	8990C	Check	2	-	-	-	No	-	-	-	-	-	-	
		Outside	8886	Gate	3	EMO	HW	J(B)	Yes	Closed	Closed	Closed	As Is	EP-B	10 Sec	Open for post accident recirc phase
413	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped spare
414	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped spare
415	6	Inside	8992A	Check	2	-	-	-	No	-	-	-	-	-	-	
		Inside	8992B	Check	2	-	-	-	No	-	-	-	-	-	-	
		Inside	8992C	Check	2	-	-	-	No	-	-	-	-	-	-	
		Outside	8884	Gate	3	EMO	HW	J(A)	Yes	Closed	Closed	Closed	As Is	EP-A	10 Sec	Open for post accident recirc phase

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
416	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped spare
417A	25	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Bellows inside
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Transmitter outside
417B	25	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Bellows inside
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Transmitter outside
417C	25	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Bellows inside
		Outside	-	-	-	-	-	-	-	-	-	-	-	-		Transmitter outside
417D	1	Inside	9339	Globe	3/8	EO	-	T(B)	Yes	Closed	Closed	Closed	Closed	EP-B	40 Sec (Note 9)	
		Outside	9341	Globe	3/8	EO	-	T(A)	Yes	Closed	Closed	Closed	Closed	EP-A	40 Sec (Note 9)	
417E	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Capped 3/8 spare
418	1	Inside	7126	Diaph	3/4	AO/FC	-	T(A)	Yes	Open	Open	Closed	Closed	IA-A	40 Sec (Note 9)	
		Outside	7150	Diaph	3/4	AO/FC	-	T(B)	Yes	Open	Open	Closed	Closed	IA-B	40 Sec (Note 9)	
419	17	Inside	6671	Diaph	3	HW	-	-	No	Closed	Closed	Closed	-	-	-	Locked Closed
		Outside	6672	Diaph	3	HW	-	-	No	Closed	Closed	Closed	-	-	-	Locked Closed
420	1	Inside	8047	Diaph	1	AO/FC	-	T(A)	Yes	Open	Open	Closed	Closed	IA-A	40 Sec (Note 9)	
		Outside	8033	Diaph	1	AO/FC	-	T(B)	Yes	Open	Open	Closed	Closed	IA-B	40 Sec (Note 9)	
421	17	Inside	6698	Diaph	3	HW	-	-	No	Closed	Closed	Closed	-		-	Locked Closed

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
		Outside	6697	Diaph	3	HW	-	-	No	Closed	Closed	Closed	-		-	Locked Closed
422	2	Inside	8046	Check	3	-	-	-	No	-	-	-	-	-	--	
		Outside	8028	Diaph	3	AO/FC	-	T(B)	Yes	Closed	Closed	Closed	Closed	IA-B	40 Sec (Note 9)	
423	1	Inside	7170	Diaph	3	AO/FC	-	T(A)	Yes	Open	Open	Closed	Closed	IA-A	40 Sec (Note 9)	
		Outside	7136	Diaph	3	AO/FC	-	T(B)	Yes	Open	Open	Closed	Closed	IA-B	40 Sec (Note 9)	
424	1	Inside	6242A	Diaph	3	AO/FC	-	T(A)	Yes	Closed	Closed	Closed	Closed	IA-A	40 Sec (Note 9)	
		Outside	6242B	Diaph	3	AO/FC	-	T(B)	Yes	Closed	Closed	Closed	Closed	IA-B	40 Sec (Note 9)	
425	5	Outside	8811B	Gate	14	EMO	HW	A(B)	Yes	Closed	Closed	Closed	As Is	EP-B	20 Sec	Open for post accident recirc phase
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Guard Pipe and chamber
426	18	Inside	8997A	Check	2	-	-	-	No	-	-	-	-	-	-	
		Inside	8997B	Check	2	-	-	-	No	-	-	-	-	-	-	
		Inside	8997C	Check	2	-	-	-	No	-	-	-	-	-	-	
		Outside	8801A	Gate	3	EMO	HW	S(A)	Yes	Closed	Closed	Open	As Is	EP-A	10 Sec (Note10)	Signal opens valve, Operated during Postaccident Recirc Phase
		Outside	8801B	Gate	3	EMO	HW	S(B)	Yes	Closed	Closed	Open	As Is	EP-B	10 Sec (Note10)	Signal opens valve, Operated during Postaccident Recirc Phase

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
427	2	Inside	6799	Check	4	-	-	-	No	-	-	-	-	-	-	
		Outside	6797	Gate	4	EMO	HW	T(B)	Yes	Open	Open	Closed	As Is	EP-B	40 Sec (Note 9)	
428	11A	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Closed system
		Outside	2877A	Globe	1-1/2	AO/FC	HW	J(A/B)	Yes	Open	Closed	Open	Closed	IA-A/B	N/A	Dual solenoids
		Outside	2000	Globe	8	AO/FC	HW	J(A/B)	Yes	Closed	Closed	Closed	Closed (Note 8)	IA-A/B	N/A	Six solenoids
		Outside	2843A	Globe	1-1/2	AO/FC	HW	J(A/B)	Yes	Open	Closed	Open	Closed	IA-A/B	N/A	Dual solenoids
		Outside	2869A	Globe	4	AO/FE	-	C(A/B)	Yes	Closed	Closed	Closed	Closed	IA-A/B	10 Sec	Dual solenoids
		Outside	2801A	Globe	32	AO/FC	-	C(A/B)	Yes	Open	Closed	Closed	Closed	IA-A/B	7 Sec	Dual solenoids
		Outside	2806A, B, C, D, E	Safety	6X10	PO/FC	-	-	No	Closed	Closed	Closed	Closed	-	-	Five valves
500	14	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Bellows inside
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Transmitter outside
505	21	Inside	-	Bl Flng	-	-	-	-	-	-	-	-	-	-	-	Outage penetration
		Outside	-	Bl Flng	-	-	-	-	-	-	-	-	-	-	-	
600	21	Inside	-	Bl Flng	-	-	-	-	-	-	-	-	-	-	-	Outage penetration
		Outside	-	Bl Flng	-	-	-	-	-	-	-	-	-	-	-	
602	21	Inside	-	Bl Flng	-	-	-	-	-	-	-	-	-	-	-	Outage penetration
		Outside	-	Bl Flng	-	-	-	-	-	-	-	-	-	-	-	
703	24	Inside	-	-	-	-	-	-	-	-	-	-	-	-	-	Bellows inside

Table 6.2-54 (continued)
Isolation Valve Summary

Penetration No.	Valve Arrang. Figure 6.2-52a	Location Referred to RB	Valve No.	Valve Type	Valve Size (in.)	Primary Method of Actuation (Note 1)	Backup Method of Actuation (Note 1)	Signal (Note 2)	Position Indication (Note 3)	Normal Valve Position	Shutdown Valve Position (Note 4)	Post Accident Position	Power Failure Position	Power Source (Note 5)	Closure Time (Note 6)	Remarks
		Outside	-	-	-	-	-	-	-	-	-	-	-	-	-	Transmitter outside

Table 6.2-54(Continued)
Isolation Valve Summary

General - This table does not include small manual valves on test connections or test vents used for Type C leak tests.

1 Method of Actuation

EMO	-	Electric motor operated
AO/FC	-	Air pressure to open; spring return, fail close on loss of air
AO/FO	-	Air pressure to close; spring return, fail open on loss of air
PO/FC	-	Process pressure to open; spring return, fail close on loss of process pressure
HW	-	Hand wheel, manual operation
EO	-	Energize solenoid coil to open
AO/AC	-	Air to open; and air to close, fail closed on loss of electric signal

2 Actuation Signal and Channel

S - Safety Injection Signal

(1) Low pressurizer pressure (2/3), or

(2) High containment pressure (2/3), or

(3) Differential steam line pressure (2/3 on two loops), or

(4) Low steam line pressure (2/3), or

(5) Manual (1/2).

T - Containment Isolation Signal (Phase A)

(1) Safety injection signal or

(2) Manual (1/2)

C - Main Steam Isolation Signal

(1) High reactor building pressure (2/3) (note, different from S(2), above), or

(2) High steam flow (2/3) in coincidence with or low-low T_{avg} (2/3), or

(3) Low Steam pressure (2/3), or

(4) Manual (1/2)

Table 6.2-54(Continued)
Isolation Valve Summary

NOTES TO TABLE 6.2-54 (Continued)

D - Feedwater Isolation Signal

(1) Safety injection signal, or

(2) Steam generator "hi-hi" level (2/3), or

(3) Low T_{avg} coincident with reactor trip

P - Containment Isolation (Phase B)

(1) High-high reactor building pressure (2/4), or

(2) Manual (2/2)

F - Steam Generator Blowdown Isolation Signal

(1) Containment isolation (Phase A), or

(2) Start of emergency feedwater system.

G - Valve opens on pump start signal (ESF Loading sequence)

H - Reactor Building purge supply and exhaust isolation

(1) Containment ventilation isolation signal, or

(2) High radiation in reactor building purge exhaust vent
(A train valves) or
containment atmosphere high radiation (B train valves), or

(3) Manual

I - Engineered safety features load sequencer (ESFLS)

(1) Safety injection signal, or

(2) Blackout, or

(3) Manual

J - Remote Manual

K - Reactor Building 6 inch purge supply and exhaust vent

(1) Containment isolation (Phase A), or

(2) High radiation in reactor building purge exhaust
vent (A train valves) or containment atmosphere high radiation (B train valves), or

(3) Manual

Table 6.2-54(Continued)
Isolation Valve Summary

NOTES TO TABLE 6.2-54 (Continued)

L - (Intentionally left Blank by Amendment 96-03).

M - Feedwater isolation valve isolation signal

(1) Feedwater isolation (comprised of D above, Train A only), or

(2) (Intentionally left blank by Amendment 02-01)

(3) (Intentionally left blank by Amendment 96-03)

(4) High-high intermediate sump level (2 of 3), or

(5) (Intentionally left blank by Amendment 02-01)

(6) Manual

A - Automatic actuation from refueling water storage tank Lo-Lo level coincident with safety injection signal.

CHANNEL

(A) Signal is from the A channel of the actuation system.

(B) Signal is from the B channel of the actuation system

(A/B) Signal is from both channels of the actuation system (e.g., dual solenoid valves for an air operated valve – one from channel A, the other from channel B)

3 "Yes" indicates remote position indication

4 "Shutdown" means normal shutdown on residual heat removal system. It does not include testing or refueling operations.

5 Power Source:

IA-A - Valve is operated by the non safety-related instrument air system. The associated solenoid valve is supplied from safety-related battery A.

IA-B - Valve is operated by the non safety-related instrument air system. The associated solenoid valve is supplied from safety-related battery B.

EP-A - Valve is supplied from the safety-related emergency power bus A.

EP-B - Valve is supplied from the safety-related emergency power bus B.

Table 6.2-54(Continued)
Isolation Valve Summary

NOTES TO TABLE 6.2-54 (Continued)

6 Closure time is only for electric motor operated valves and air operated valves larger than 2-1/2 inches. Stroke times listed are not necessarily representative of actual stroke times. Tabulated stroke times reflect Technical Specifications, accident analysis assumptions, and design specified values.

7 Valve closure times are verified during preoperational testing.

8 Valve is controlled by non-class 1E control signal or loss of Class 1E power to the Train A and B Solenoid valves.

9 This is the maximum closure time originally supplied by Technical Specification, Table 3.6-1, for satisfying system isolation requirements. Tech. Spec. Table 3.6-1 has since been deleted by Amendment No. 110 in accordance with Generic Letter 91-08.

10 This is maximum stroke time assumed in Accident Analysis.

11 Technical Specification 3.6.1 listed NA for maximum stroke time of these valves. Tech. Spec. Table 3.6.1 has since been deleted by Amendment No. 110 in accordance with Generic Letter 91-08.

12 For more information about FIV stroke time see FSAR Section 6.2.1.3.10.3.1 and Technical Specification 4.7.1.6 and Bases.

13 The stroke time for XVG3003A/B-SP is greater than 30 seconds as a result of re-gearing the actuators per MRF-21745 (40 seconds). This increased stroke time is acceptable on the basis that 100% flow is achieved at 75% of the valve’s stroke time. Therefore the 30 seconds required stroke is maintained (.75 x 40 second = 30 seconds)

14 During normal or shutdown operation, either one letdown isolation valve (8149B or C) or any combination of two letdown isolation valves inside containment may be open. During shutdown operation, all three letdown isolation valves may be open when RCS pressure is less than normal.

Table 6.2-54a
Reactor Building Electrical Penetrations

Penetration Tag Number	Nozzle Number and Size	Location Azimuth	Location Elevation	Type of Service	Penetration Designation	Voltage Rating	Safety Class	Sep. Group and Tray Class	Wiring Drawing Reference	Remarks	Flange Installation
XRP0001	504-18”	14°-10’	441’-0”	Med Volt Pwr	Reactor Coolant Pump “C”	15KV	2a/NNS	X-2	B-210-304	Junction Box Both Sides	Outside
XRP0003	601-18”	143°-50’	441’-0”	Med Volt Pwr	Reactor Coolant Pump “B”	15KV	2a/NNS	X-2	B-210-305	Junction Box Both Sides	Outside
XRP0006	710-18”	267°-10’	441’-0”	Med Volt Pwr	Reactor Coolant Pump “A”	15KV	2a/NNS	X-2	B-210-317	Junction Box Both Sides	Inside
XRP0007	501-12”	14°-10’	473’-0”	Low Volt Pwr	Reactor Building Cooling Unit Fan (Train “B”)	1000V	2a/1e	B-4	B-210-302		Outside
XRP0010	726-12”	245°-10’	473’-0”	Low Volt Pwr	Reactor Building Cooling Unit Fan (Train “A”)	1000V	2a/1e	A-4	B-210-329		Outside
XRP0011	727-12”	248°-50’	473’-0”	Low Volt Pwr	Reactor Building Cooling Unit Fan (Train “A”)	1000V	2a/1e	A-4	B-210-330		Outside
XRP0014	808-12”	337°-30’	473’-0”	Low Volt Pwr	Reactor Building Cooling Unit Fan (Train “B”)	1000V	2a/1e	A-4	B-210-333		Outside
XRP0015	805-12”	289°-10’	469’-0”	Low Volt Pwr	Reactor Building Polar Crane	1000V	2a/NNS	X-4	B-210-332		Outside
XRP0016	503-12”	17°-50’	469’-0”	Low Volt Pwr	Miscellaneous 480V Power	1000V	2a/NNS	X-5	B-210-303		Outside
XRP0017	704-12”	263°-30’	469’-0”	Control/ Low Volt Pwr	Control Train “A”	1000V	2a/1e	A-6	B-210-313	Note 6 (inside) FCR B:6668E	Outside
XRP0018	722-12”	259°-50’	469’-0”	Low Volt Pwr	Miscellaneous 480V Power	1000V	2a/NNS	X-5	B-210-326		Outside
XRP0019	717-12”	226°-50’	441’-0”	Low Volt Pwr	Miscellaneous 480V Power	1000V	2a/NNS	X-5	B-210-323		Inside
XRP0020	809-12”	274°-30’	441’-0”	Low Volt Pwr	Pressurizer Heaters (Control Group)	1000V	2a/NNS	X-4	B-210-334		Outside
XRP0021	810-12”	278°-10’	441’-0”	Low Volt Pwr	Pressurizer Heaters (Backup Group II)	1000V	2a/1e	X-4	B-210-335		Outside
XRP0022	815-12”	270°-50’	441’-0”	Low Volt Pwr	Pressurizer Heaters (Backup Group I)	1000V	2a/1e	X-4	B-210-338		Outside
XRP0023	700-12”	252°-30’	473’-0”	Low Volt Pwr	Control Rod Drive Power	1000V	2a/NNS	X-5	B-210-310		Outside
XRP0024	701-12”	256°-10’	473’-0”	Low Volt Pwr	Control Rod Drive Power	1000V	2a/NNS	X-5	B-210-311		Outside

Table 6.2-54a (continued)
Reactor Building Electrical Penetrations

Penetration Tag Number	Nozzle Number and Size	Location Azimuth	Location Elevation	Type of Service	Penetration Designation	Voltage Rating	Safety Class	Sep. Group and Tray Class	Wiring Drawing Reference	Remarks	Flange Installation
XRP0025	707-12”	252°-30’	469’-0”	Low Volt Pwr	Control Rod Drive Power	1000V	2a/NNS	X-5	B-210-315		Outside
XRP0026	708-12”	256°-10’	469’-0”	Low Volt Pwr	Control Rod Drive Power	1000V	2a/NNS	X-5	B-210-316		Outside
XRP0028	705-12”	241°-30’	469’-0”	Control/ Low Volt Pwr	Control Train “A”/Channel I	1000V	2a/1e	A-6	B-210-314	Note 6 (inside) FCR B:6616E	Outside
XRP0030	723-12”	223°-10’	425’-0”	Control/ Low Volt Pwr	Control Train “B”/Channel III	1000V	2a/1e	B-6	B-210-327	Note 6 (inside) FCR B:6670E	Outside
XRP0031	712-12”	215°-50’	441’-0”	Control/ Low Volt Pwr	Moveable Incore Detector Drive Control Power Circuits	1000V	2a/NNS	X-6	B-210-319	Note 6 (outside) NNSRCR 1E-1703	Inside
XRP0032	714-12”	223°-10’	441’-0”	Instrument	Incore Detector Position Indication	-	2a/NNS	X-9	B-210-320	Note 6 (outside) NNSRCR 1E-1704	Inside
XRP0033	725-12”	241°-30’	441’-0”	Control	Miscellaneous Control	1000V	2a/NNS	X-6	B-210-328	Note 6 (outside) NNSRCR 1E-1701	Inside
XRP0034	812-12”	344°-50’	449'-0"	Control	Miscellaneous Control	1000V	2a/NNS	X-6	B-210-336	Note 6 (inside) NNSRCR 1E-1605	Outside
XRP0035	800-12”	270°-50’	469’-0”	Instrument	Process (Control) Instrumentation Group 2 (D)	-	2a/1e	D-9	B-210-331	Note 6 (inside) FCR B:6741E	Outside
XRP0036	715-12”	215°-50’	425’-0”	Instrument	Process (Control) Instrumentation Group 4 (E)	-	2a/1e	E-9	B-210-321	Note 6 (inside) FCR B:6893E	Outside
XRP0037	711-12”	212°-10’	441’-0”	Instrument	Control Rod Position Indication and Incore Temp THCPLES	-	2a/NNS	X-9	B-210-318	Note 6 (outside) NNSRCR 1E-1706	Inside
XRP0039	716-12”	230°-30’	441’-0”	Instrument	Miscellaneous Instrumentation	-	2a/NNS	X-9	B-210-322	Note 6 (outside) NNSRCR 1E-1706	Inside
XRP0040	718-12”	234°-10’	441’-0”	Instrument	Miscellaneous Instrumentation	-	2a/NNS	X-9	B-210-324	Note 6 (outside) NNSRCR 1E-1709	Inside
XRP0042	607-12”	136°-30’	429’-0”	Instrument	Miscellaneous Instrumentation	-	2a/NNS	X-9	B-210-309	Note 6 (Inside) NNSRCR 1E-1702	Outside
XRP0043	605-12”	125°-30’	425’-0”	Instrument	Nuclear and Protection Instrumentation Channel I	-	2a/1e	A-8&10	B-210-307	Junction Box Both Sides	Outside

Table 6.2-54a (continued)
Reactor Building Electrical Penetrations

Penetration Tag Number	Nozzle Number and Size	Location Azimuth	Location Elevation	Type of Service	Penetration Designation	Voltage Rating	Safety Class	Sep. Group and Tray Class	Wiring Drawing Reference	Remarks	Flange Installation
XRP0044	606-12”	169°-30’	425’-0”	Instrument	Nuclear and Protection Instrumentation Channel III	-	2a/1e	B-8&10	B-210-308	Junction Box Both Sides	Outside
XRP0045	721-12”	212°-10’	425’-0”	Instrument	Nuclear and Protection Instrumentation Channel II	-	2a/1e	D-8&10	B-210-325	Junction Box Both Sides	Outside
XRP0046	814-12”	289°-10’	425’-0”	Instrument	Nuclear and Protection Instrumentation Channel IV	-	2a/1e	E-8&10	B-210-337	Junction Box Both Sides	Outside
XRP0048	604-12”	169°-30’	429’-0”	Instrument	Process (Control) INST Group 3/Train “B” INST	-	2a/1e	B-9	B-210-306	Note 6 (inside) FCR B-7000E	Outside
XRP0051	702-12”	237°-50’	469’-0”	Instrument	Process (Control) INST Group 1/Train “A” INST	-	2a/1e	A-9	B-210-312	Note 6 (inside) FCR B-6630E	Outside
XRP0052	502-12”	14°-10’	469’-0”	Low Volt Pwr	Miscellaneous 480V Power	1000V	2a/NNS	X-5	B-210-339		Outside
XRP0053	802-12”	278°-10’	469’-0”	Low Volt Pwr	Miscellaneous 480V Power	1000V	2a/NNS	X-5	B-210-342		Outside
XRP0054	706-12”	245°-10’	469’-0”	Low Volt Pwr	Control Rod Drive Power	1000V	2a/NNS	X-5	B-210-340		Outside
XRP0055	728-12”	248°-50’	469’-0”	Low Volt Pwr	Control Rod Drive Power	1000V	2a/NNS	X-5	B-210-341		Outside
XRP0056	803-12”	281°-50’	469’-0”	Low Volt Pwr	Control Rod Drive Power	1000V	2a/NNS	X-5	B-210-343		Outside
XRP0057	804-12”	285°-30’	469’-0”	Low Volt Pwr	Control Rod Drive Power	1000V	2a/NNS	X-5	B-210-344		Outside
	603-12”	125°-30’	429’-0”		Spare Nozzle						
	709-18”	263°-30’	441’-0”		Spare Nozzle						
	713-12”	219°-30’	441’-0”		Spare Nozzle						
	719-12”	237°-50’	441’-0”		Spare Nozzle						
XRP0104	720-12”	212°-10’	429’-0”	Instrument	Instrument Group 3/Train “B” Instrument	-	2a/1e	B-9	B-210-346		Outside
	724-12”	226°-50’	425’-0”		Spare Nozzle						
	801-12”	274°-30’	469’-0”		Spare Nozzle						

Table 6.2-54a (continued)
Reactor Building Electrical Penetrations

Penetration Tag Number	Nozzle Number and Size	Location: Azimuth	Location: Elevation	Type of Service	Penetration Designation	Voltage Rating	Safety Class	Sep. Group and Tray Class	Wiring Drawing Reference	Remarks	Flange Installation
XRP0106	806-12”	330°-10’	469’-0”	Instrument	Instrument Group 1/Train “A” Instrument	-	2a/1e	A-9	B-210-345		Outside
	807-12”	337°-30’	469’-0”		Spare Nozzle						
	811-12”	285°-30’	425’-0”		Spare Nozzle						
	813-12”	289°-10’	429’-0”		Spare Nozzle						
XRP100A-ES		Aux Bldg	397’-0”		Penetration Junction Box for XVG3004A-SP			A	B-210-361	1-18C-#4 AWG Module	
XRP100B-ES		Aux Bldg	397’-0”		Penetration Junction Box for XVG3004B-SP			B	B-210-362	1-18C-#4 AWG Module	
XRP101A-ES		Aux Bldg	397’-0”		Penetration Junction Box for XVG8811A-SI			A	B-210-363	1-18C-#4 AWG Module	
XRP101B-ES		Aux Bldg	397’-0”		Penetration Junction Box for XVG8811B-SI			B	B-210-364	1-18C-#4 AWG Module	

(1) Cable Bill of Material is the same both inside and outside containment, unless otherwise noted.
(2) Field to install spare pigtails (through nozzle side only) and tag with pin and plug assignment. (See Note 9)
(3) For convenience spare pigtail cable B/M number is called out in B/M number column of field cable. Should spares be used in the future, information will be added.
(4) Spare plug pin position on junction box side of penetration flange to have blinding pins per vendor instructions. (See Note 9)
(5) The individual conductors coming from the plug shall be identified by wire marks as to which pin in the plug it comes from. When making the splice in the splice box, the field cable shall be spliced to the plug cable using the field cable term sheet to show which pin (plug conductor) it goes to.
(6) Field installed junction box.
(7) Spare cables should be coiled and put in a field mounted junction box or a suitable cable tray, on XRP0043,44,45, and 46. The spare cable should be coiled in the penetration junction box.
(8) All spare cables to use binding pins as specified c32c2103-pin #. (See Note 9)
(9) As required to facilitate construction/maintenance, the field shall replace all blinding pins on the junction box side. At the option of SCE&G or whenever the contractor enters a j-box side plug, all spare pins shall be wired out with 25’ long pigtails of the type cable specified. Tag all spare pigtails, per Note 5.

Table 6.2-55
Electric Hydrogen Recombiner Typical Parameters

Power (Maximum), kW	75
Capacity (Minimum), scfm	100
Heaters	
Number	5
Heater Surface Area/Heater, ft^2	35
Maximum Heat Flux, BTU/hr-ft^2	2850
Maximum Sheath Temperature, °F	1550
Gas Temperature	
Inlet, °F	80 to 155
In Heater Section, °F	1150 to 1400
Materials	
Outer Structure	300-Series Stainless Steel
Inner Structure	Inconel-600
Heater Element Sheath	Incoloy-800

Table 6.2-60
Containment Heat Sink Data Used for Region II (Large Break LOCA)
Calculation of Minimum Containment Pressure for V.C. Summer

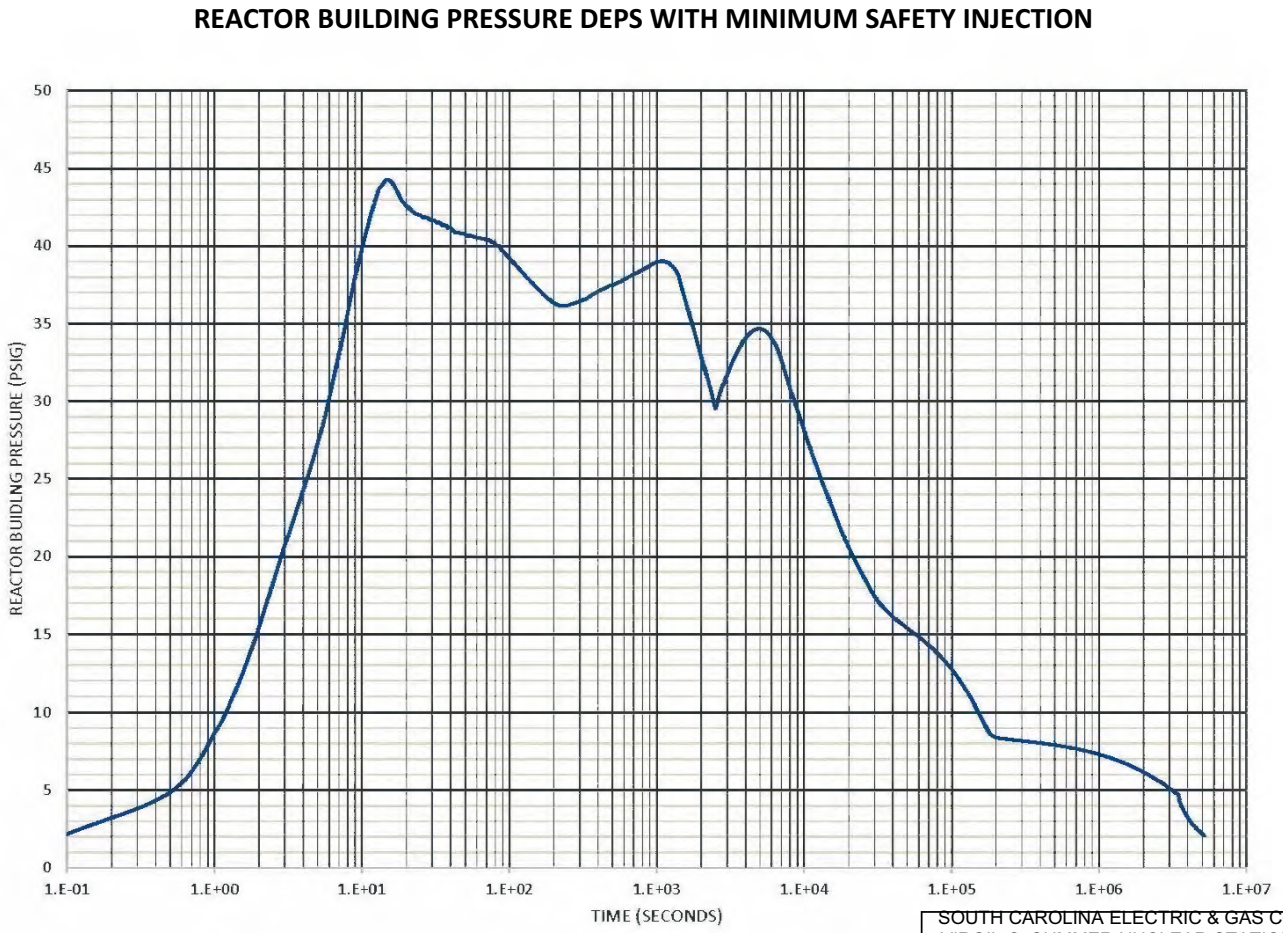
Wall	Area (ft^2)	Thickness (ft)	Material
1	63,137	0.0217 / 4.00	Carbon Steel / Concrete
2	22,265	0.0217 / 3.00	Carbon Steel / Concrete
3	9,755	4.00	Concrete
4	12,863	2.00 / 0.0104	Carbon Steel / Concrete
5	47,891	1.90	Concrete
6	11,892	1.00	Concrete
7	6,003	4.00	Concrete
8	5,165	2.25	Concrete
9	25,962	0.005	Carbon Steel
10	50,707	0.009	Carbon Steel
11	242,736	0.017	Carbon Steel
12	5,995	0.027	Carbon Steel
13	1,428	0.034	Carbon Steel
14	8,659	0.042	Carbon Steel
15	2,021	0.056	Carbon Steel
16	87	0.062	Carbon Steel
17	7,278	0.0654	Carbon Steel
18	12,804	0.069	Carbon Steel
19	2,148	0.0764	Carbon Steel
20	3,673	0.0782	Carbon Steel
21	2,825	0.083	Carbon Steel
22	37	0.292	Carbon Steel
23	3,300	0.556	Carbon Steel
24	1,393	0.870	Carbon Steel
25	4,674	1.757	Carbon Steel
26	66	0.005	Stainless Steel
27	4,358	0.009	Stainless Steel

Table 6.2-60 (continued)
Containment Heat Sink Data Used for Region II (Large Break LOCA)
Calculation of Minimum Containment Pressure for V.C. Summer

Wall	Area (ft^2)	Thickness (ft)	Material
28	24,098	0.017	Stainless Steel
29	1,295	0.028	Stainless Steel
30	661	0.034	Stainless Steel
31	982	0.043	Stainless Steel
32	102	0.053	Stainless Steel
33	10	0.059	Stainless Steel
34	77	0.063	Stainless Steel
35	715	0.071	Stainless Steel
36	438	0.077	Stainless Steel
37	606	0.094	Stainless Steel
38	3,166	0.117	Stainless Steel
39	79	0.127	Stainless Steel
40	1,521	0.152	Stainless Steel

Figure 6.2-1

DOUBLE ENDED PUMP SUCTION BREAK MINIMUM SAFETY INJECTION REACTOR BUILDING PRESSURE VS. TIME



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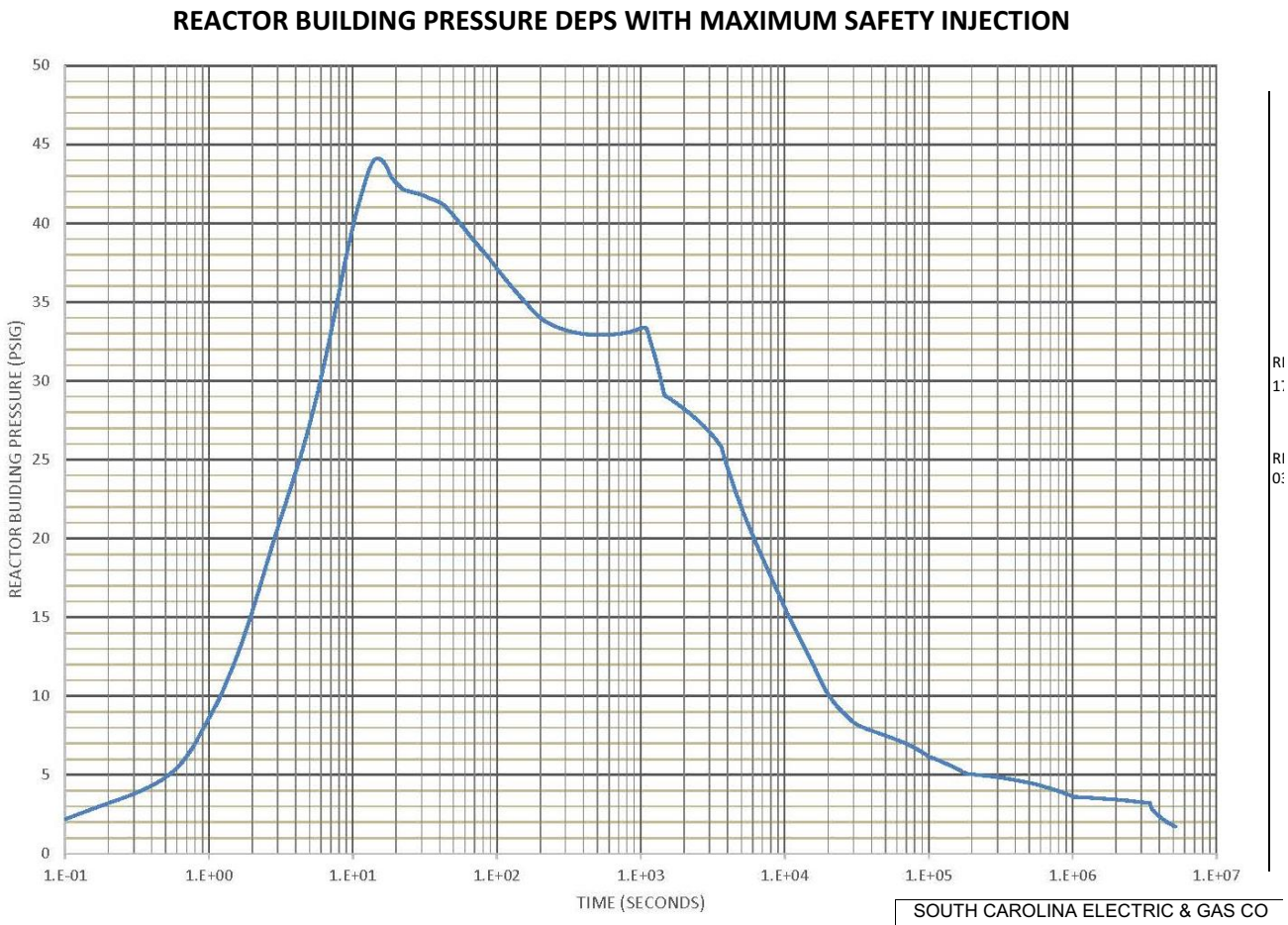
SOUTH CAROLINA ELECTRIC & GAS CO
VIRGIL C. SUMMER NUCLEAR STATION
Double Ended Pump Suction Break
Minimum Safety Injection
Reactor Building Pressure vs. Time
Figure 6.2-1

Figure 6.2-2

DOUBLE ENDED PUMP SUCTION BREAK MAXIMUM SAFETY INJECTION REACTOR BUILDING PRESSURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Double Ended Pump Suction Break Maximum Safety Injection Reactor Building Pressure vs. Time Figure 6.2-2

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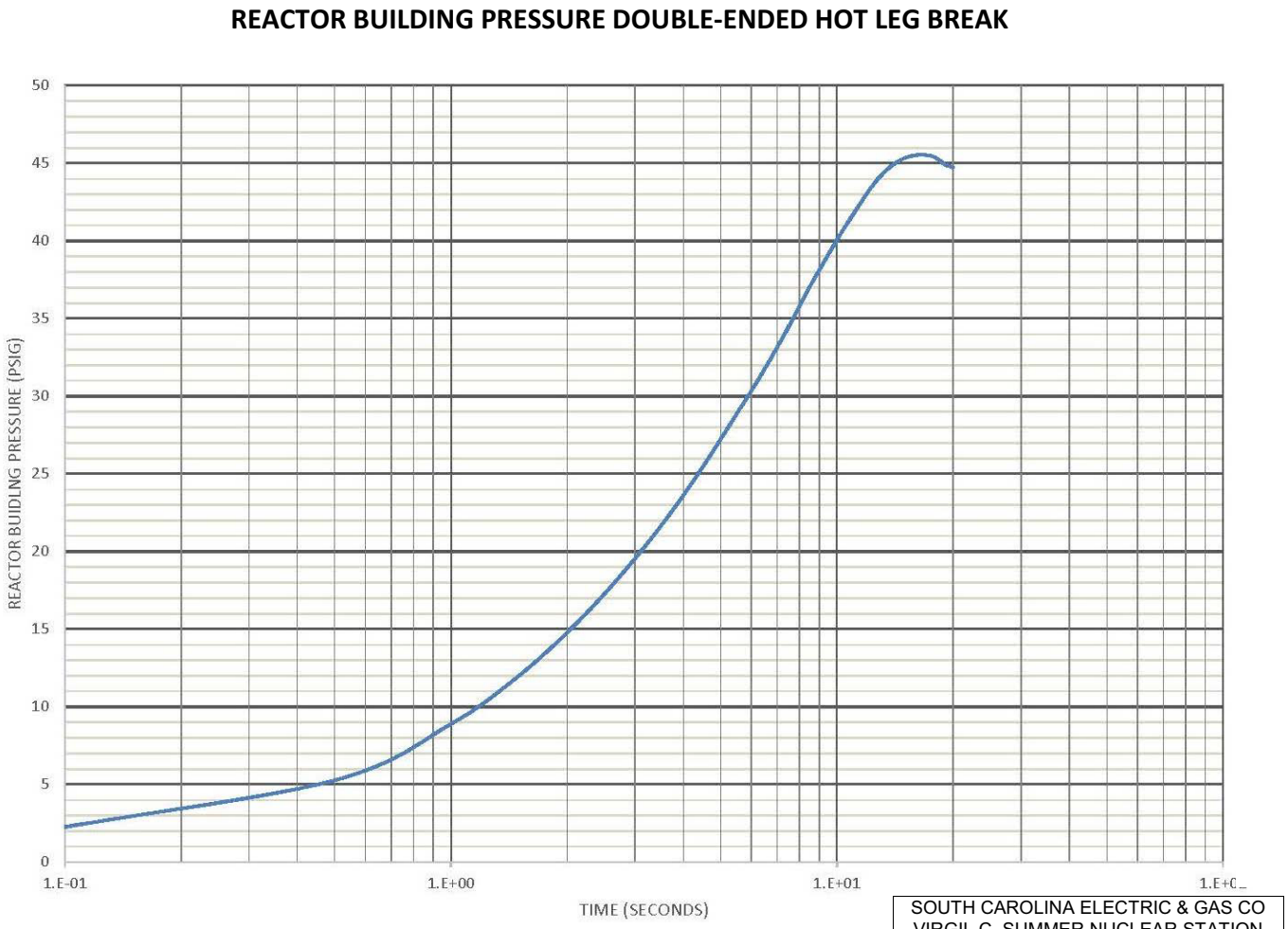
Figure 6.2-3

DOUBLE ENDED HOT LEG BREAK REACTOR BUILDING PRESSURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Double Ended Hot Leg Break Reactor Building Pressure vs. Time Figure 6.2-3

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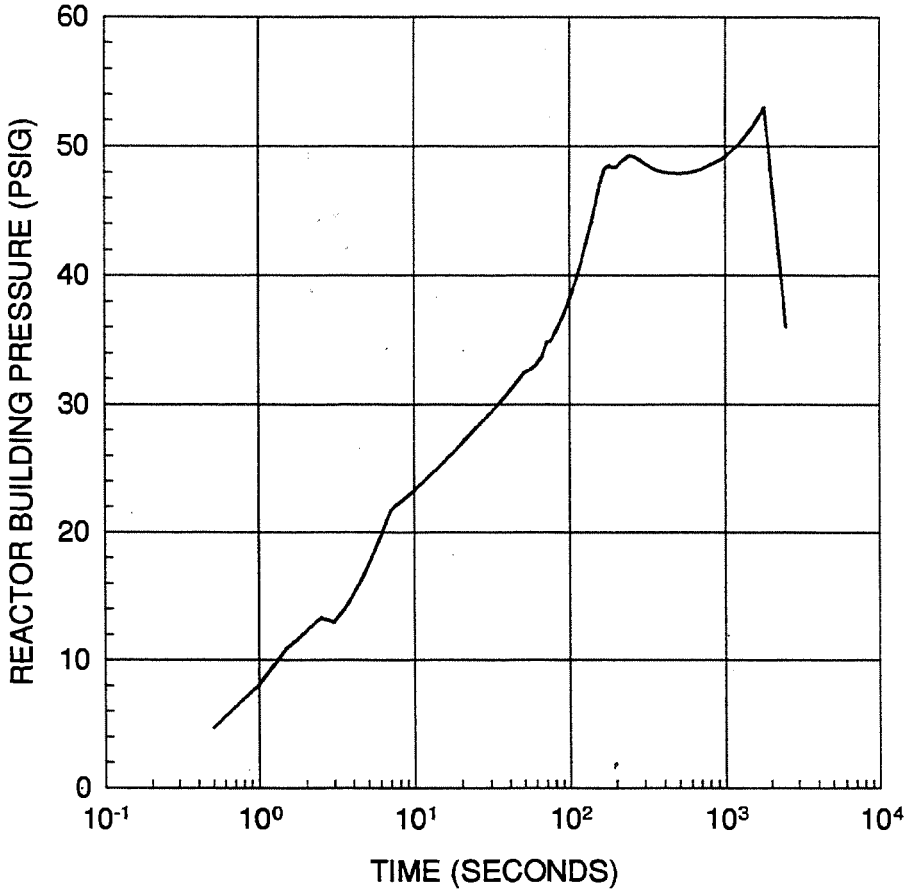
Figure 6.2-4

MAIN STEAM LINE BREAK (DESIGN BASIS ACCIDENT)
1.4 FT^2 DER AT 25% POWER
REACTOR BUILDING PRESSURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Line Break (Design Basis Accident) 1.4 ft^2 DER at 25% Power Reactor Building Pressure Vs. Time Figure 6.2-4

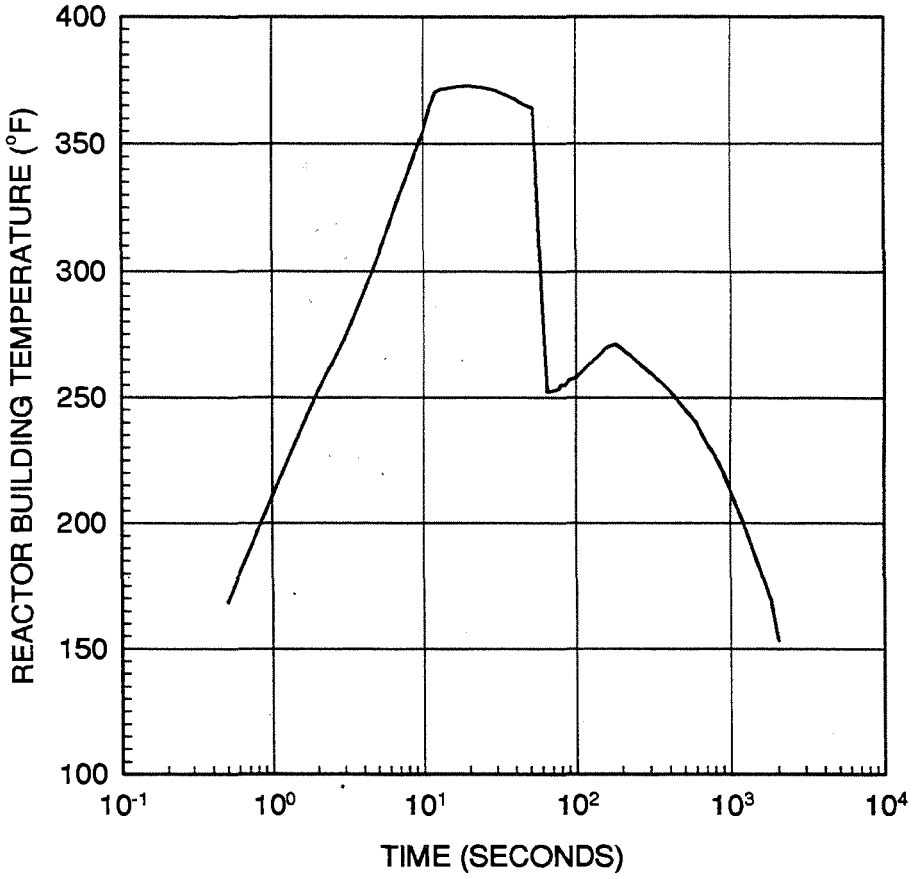
Figure 6.2-5
DELETED BY AMENDMENT 96-02

Figure 6.2-5a

WORST CASE (TEMPERATURE)

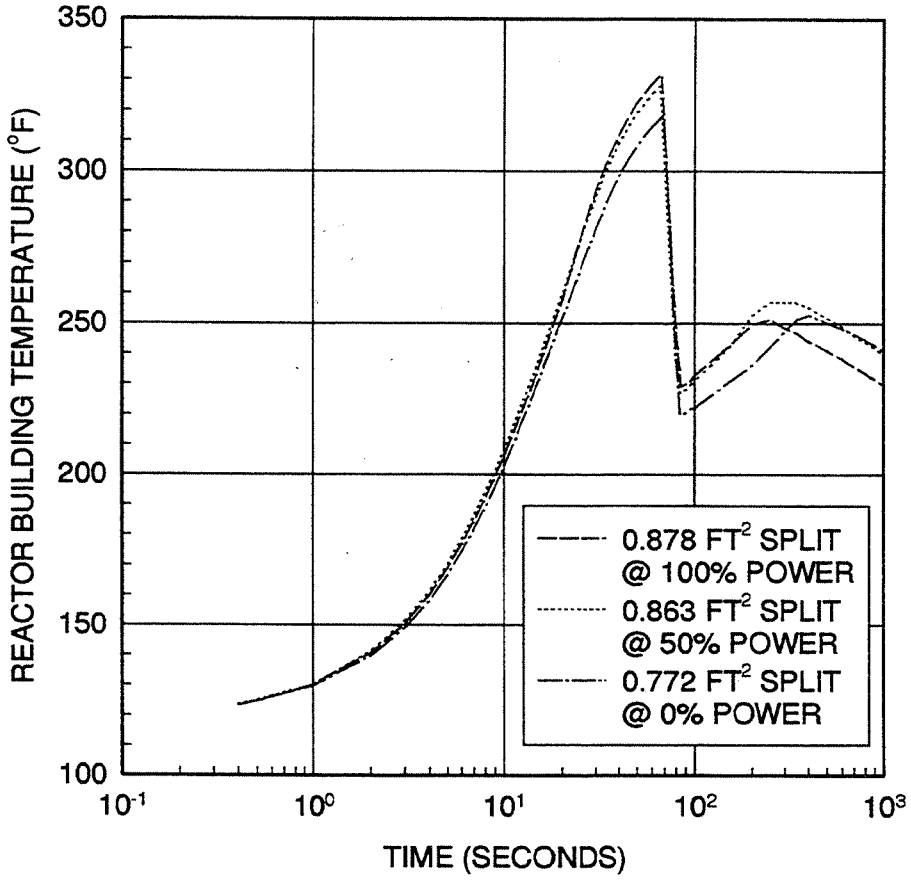
MAIN STEAM LINE BREAK 14 FT^2 DER AT 102% POWER

REACTOR BUILDING TEMPERATURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Worst Case (Temperature) Main Steam Line Break 1.4 ft^2 DER at 102% Power Reactor Building Temperature Vs. Time Figure 6.2-5a

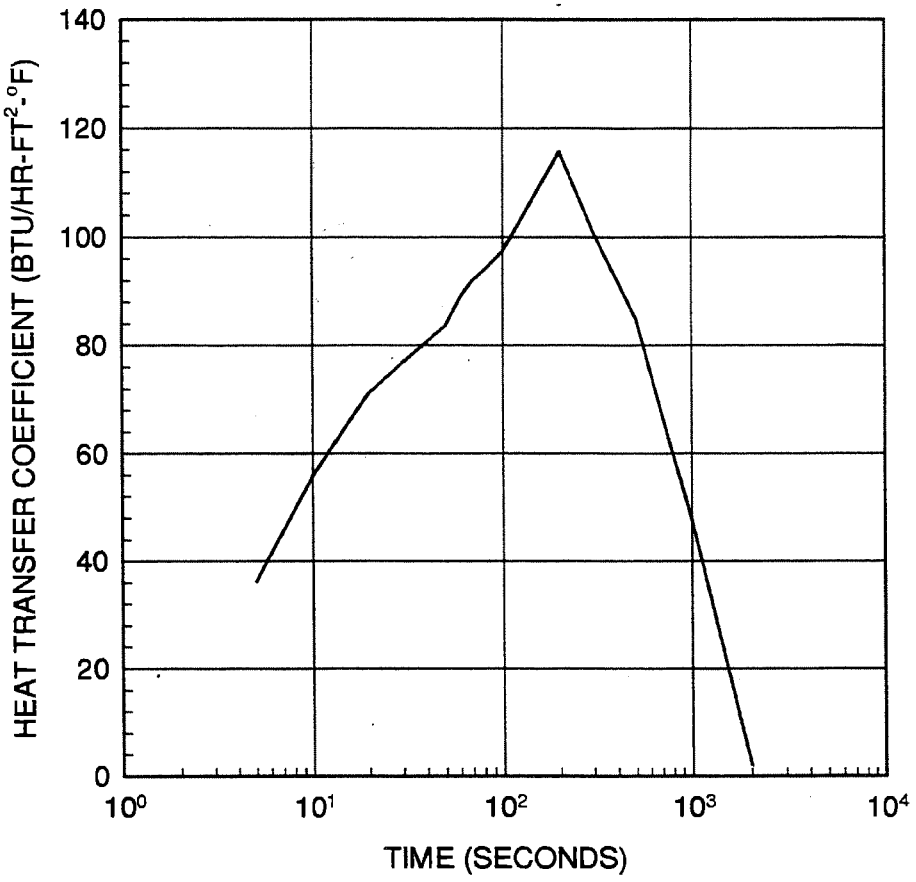
Figure 6.2-5b
REACTOR BUILDING VAPOR TEMPERATURE FOR A SPECTRUM OF SMALL MAIN STEAM LINE BREAKS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Building Vapor Temperature For A Spectrum of Small Main Steam Line Breaks Figure 6.2-5b

Figure 6.2-5c

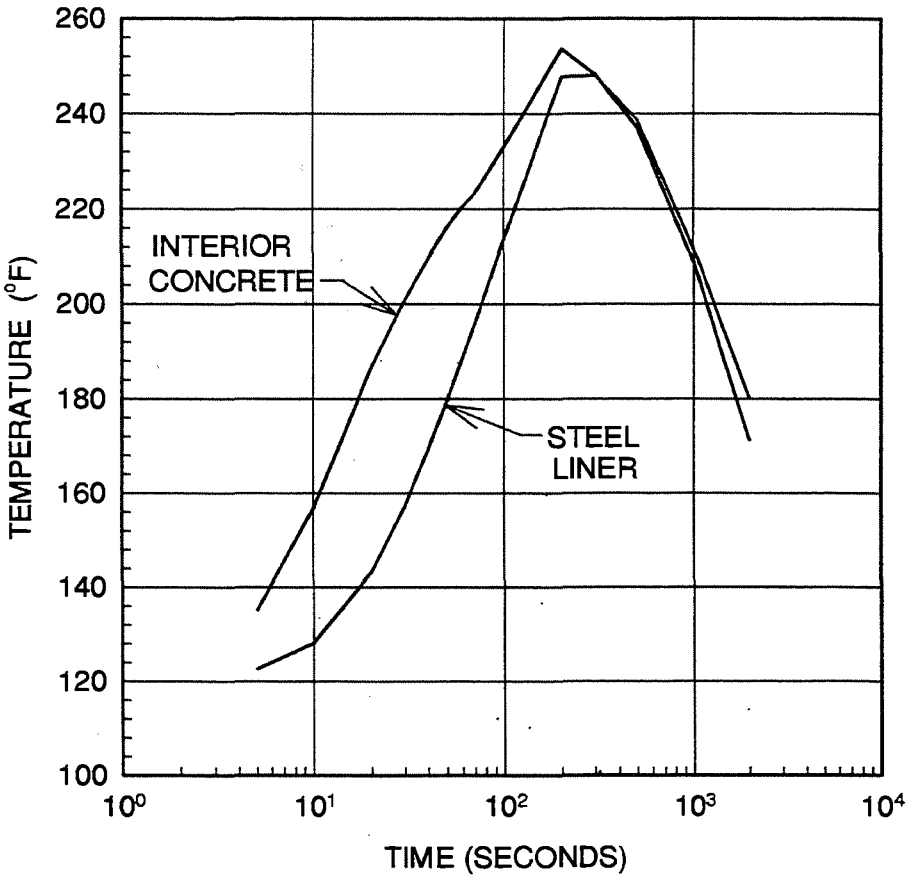
WORST CASE (TEMPERATURE) MAIN STEAM LINE BREAK
1.4 FT^2 DER AT 102% POWER LINER CONDENSING FILM HEAT TRANSFER COEFFICIENT (UCHIDA) VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Worst Case (Temperature) Main Steam Line Break 1.4 ft^2 DER at 102% Power Liner Condensing Film Heat Transfer Coefficient (UCHIDA) Vs. Time Figure 6.2-5c

Figure 6.2-5d

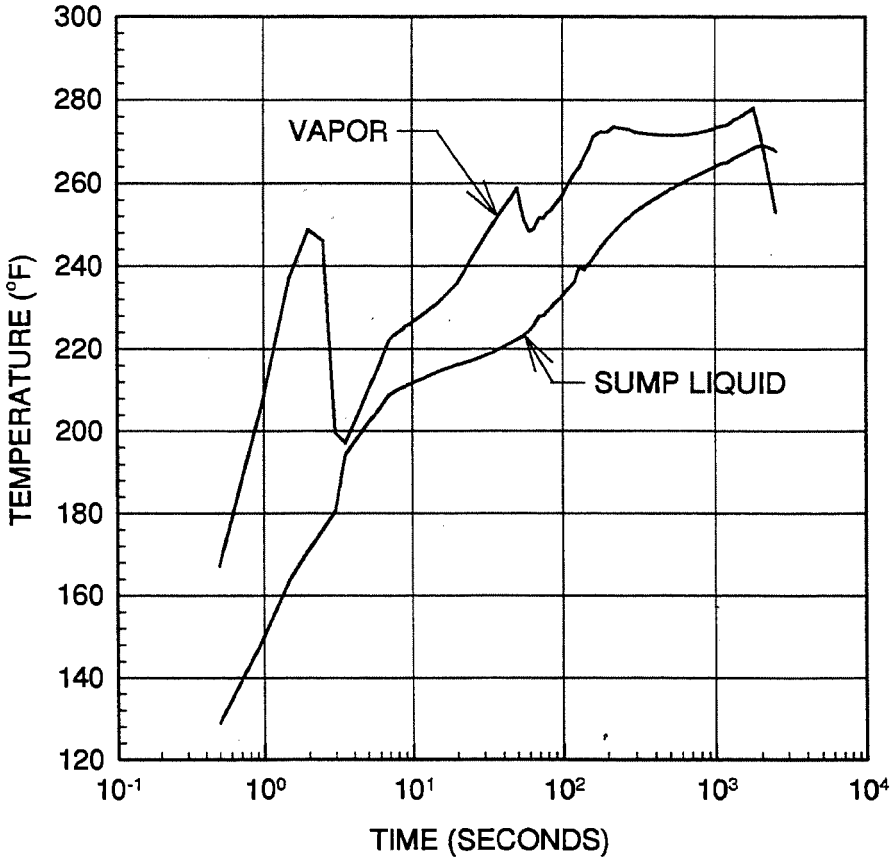
WORST CASE (TEMPERATURE) MAIN STEAM LINE BREAK 1.4 FT^2 DER AT 102% POWER REACTOR BUILDING LINER AND CONCRETE TEMPERATURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Worst Case (Temperature) Main Steam Line Break 1.4 ft^2 DER at 102% Power Reactor Building Liner and Concrete Temperature Vs. Time Figure 6.2-5d

Figure 6.2-6

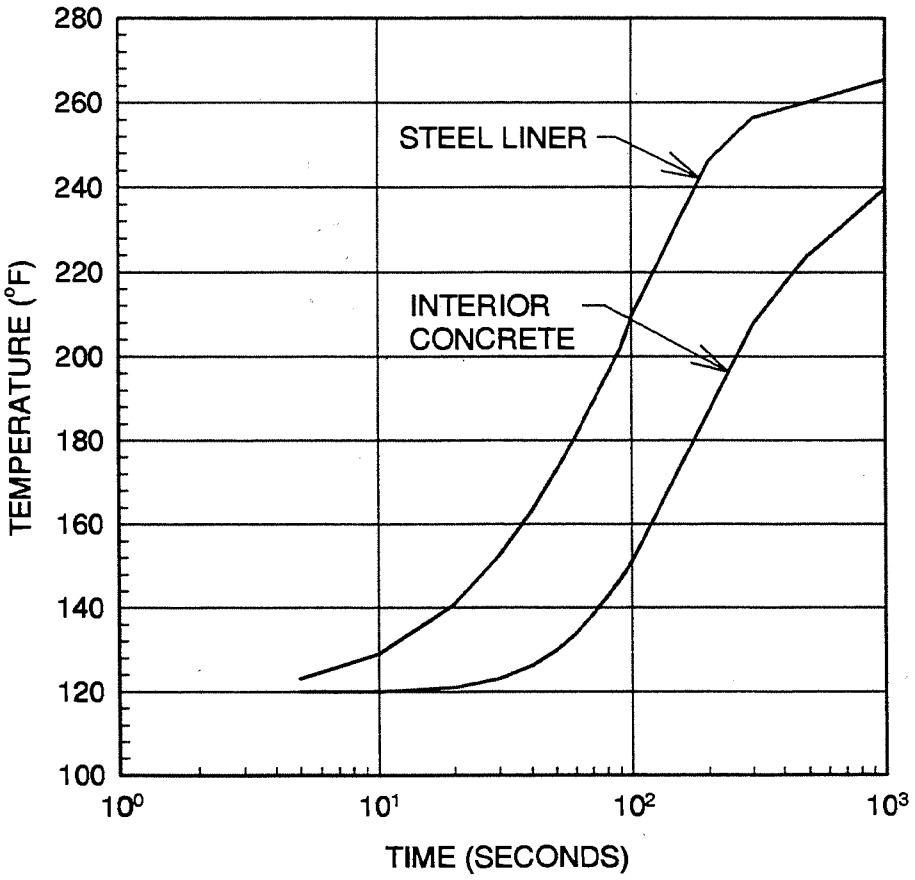
MAIN STEAM LINE BREAK (DESIGN BASIS ACCIDENT)
1.4 FT^2-DER AT 25% POWER REACTOR BUILDING VAPOR AND SUMP TEMPERATURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Line Break (Design Basis Accident) 1.4 ft^2 DER at 25% Power Reactor Building Vapor and Sump Temperature Vs. Time Figure 6.2-6

Figure 6.2-6a

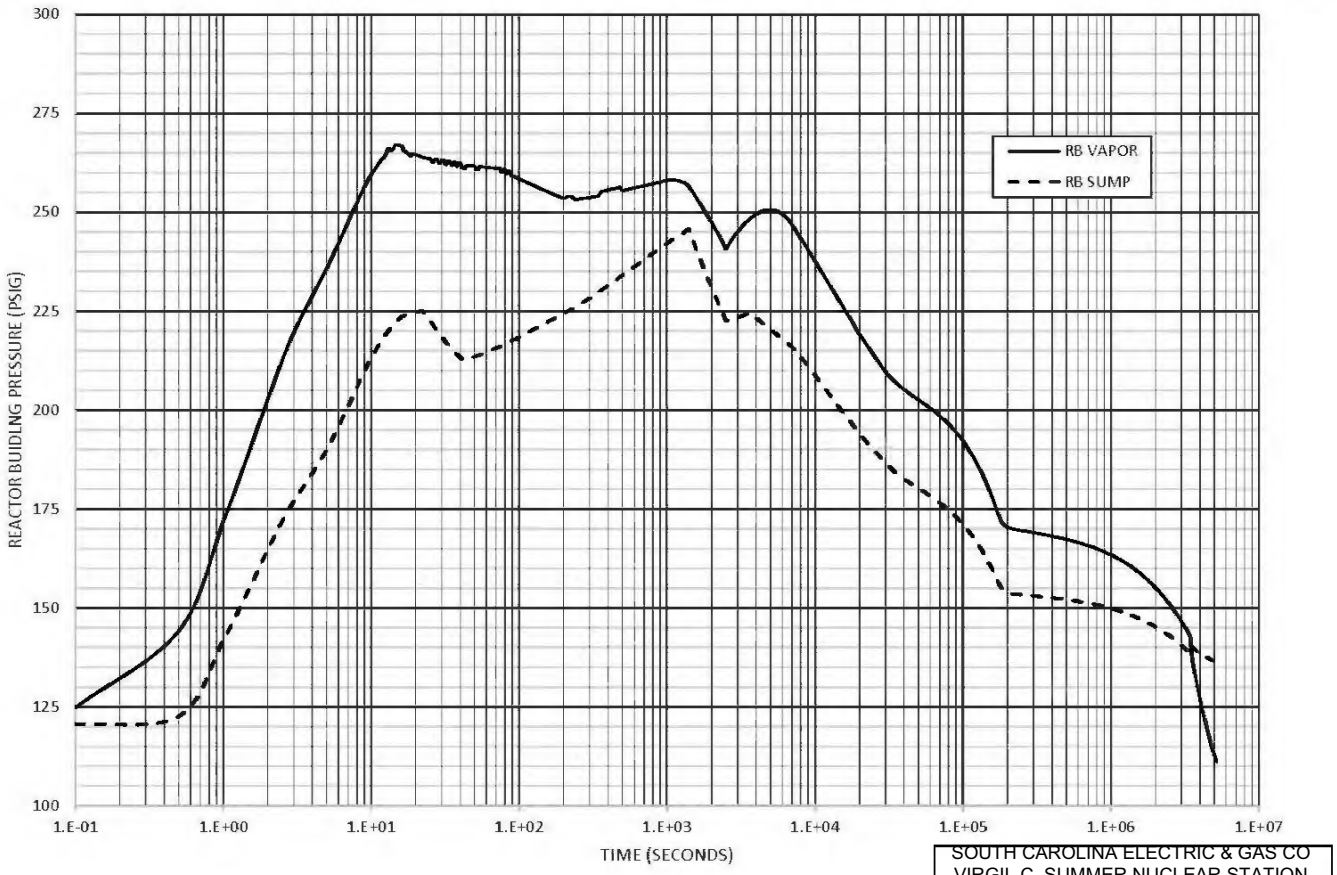
MAIN STEAM LINE BREAK (DESIGN BASIS ACCIDENT)
1.4 FT^2 DER AT 25% POWER REACTOR BUILDING
LINER AND CONCRETE
TEMPERATURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Line Break (Design Basis Accident) 1.4 ft^2 DER at 25% Power Reactor Building Liner and Concrete Temperature Vs. Time Figure 6.2-6a

Figure 6.2-7

DOUBLE ENDED PUMP SUCTION BREAK MINIMUM SAFETY INJECTION REACTOR BUILDING VAPOR AND SUMP TEMPERATURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Double Ended Pump Suction Break Minimum Safety Injection Reactor Building Vapor and Sump Temperature vs. Time Figure 6.2-7

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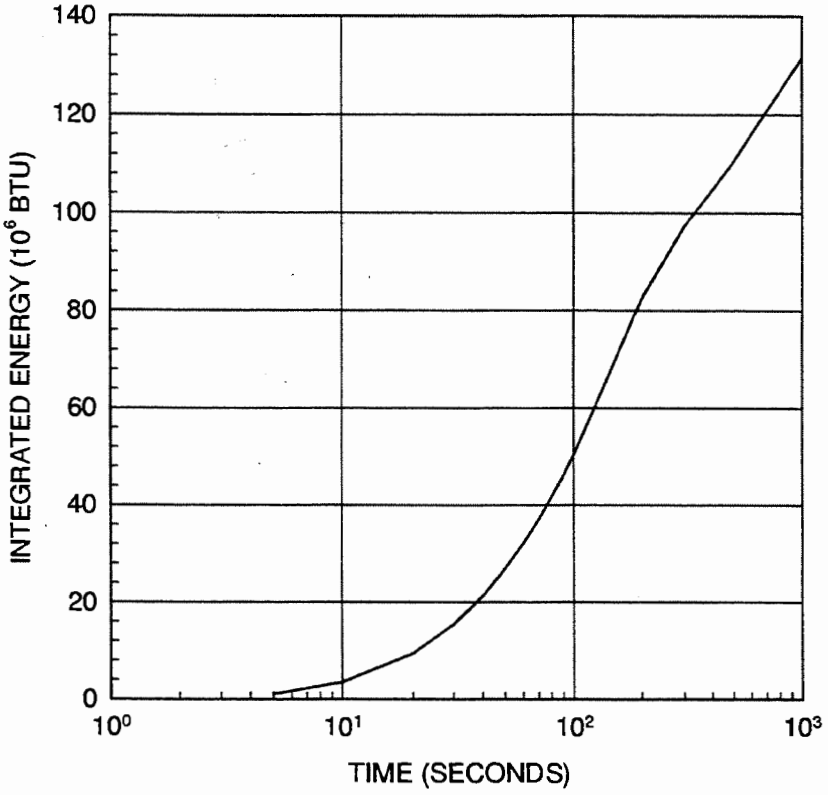
Figure 6.2-8

MAIN STEAM LINE BREAK (DESIGN BASIS ACCIDENT)
1.4 FT^2 DER AT 25% POWER TOTAL ENERGY IN HEAT SINKS VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Line Break (Design Basis Accident) 1.4 ft^2 DER at 25% Power Total Energy In Heat Sinks Vs. Time Figure 6.2-8

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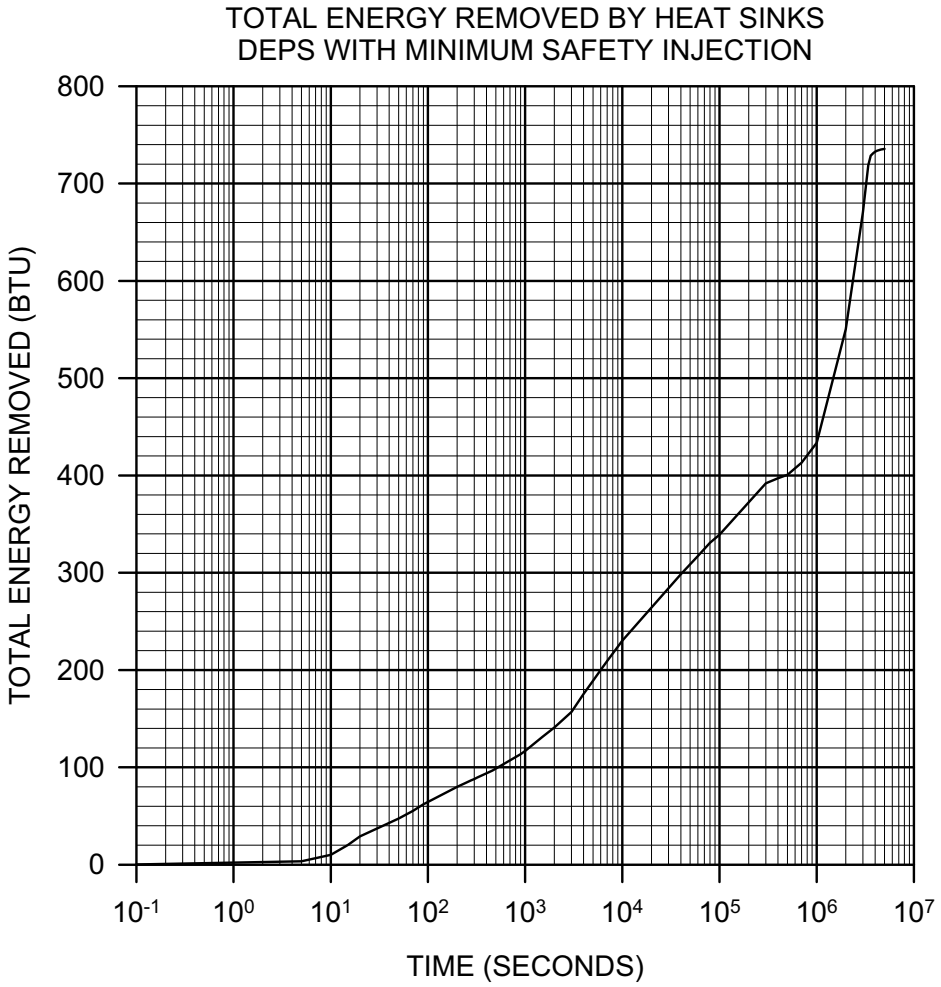
JULY 1996

Figure 6.2-9
DOUBLE ENDED PUMP SUCTION BREAK
MINIMUM SAFETY INJECTION
TOTAL ENERGY REMOVED BY HEAT SINKS



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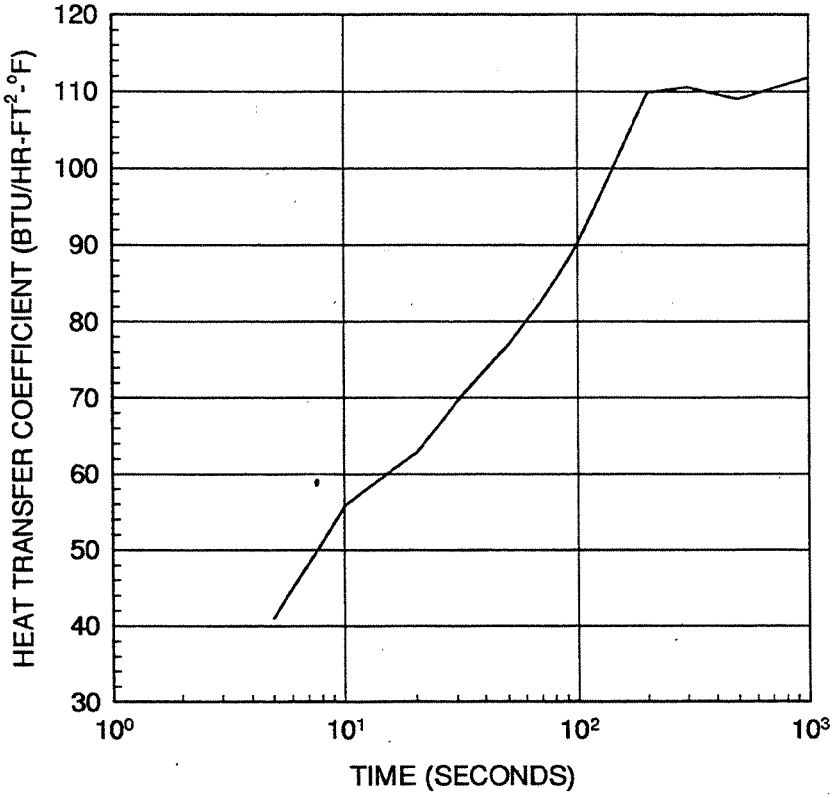
SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Double Ended Pump Suction Break Minimum Safety Injection Total Energy Removed by Heat Sinks Figure 6.2-9

Figure 6.2-10

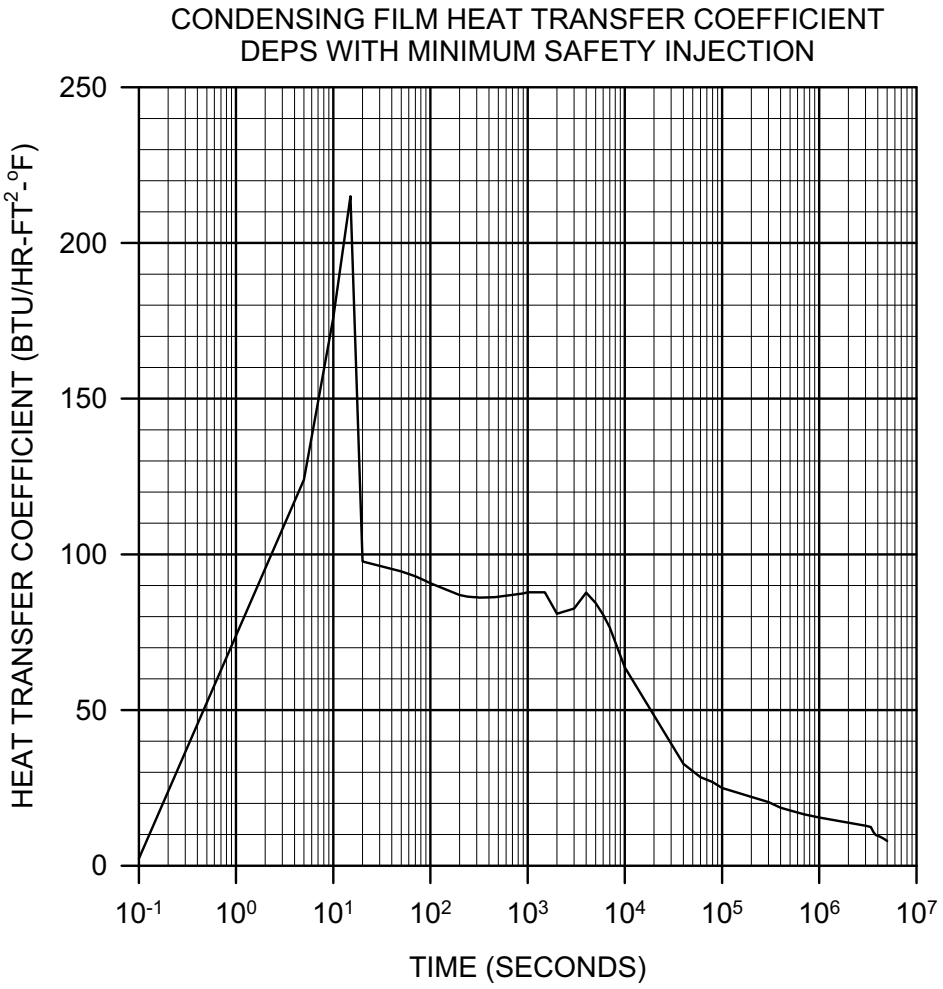
MAIN STEAM LINE BREAK (DESIGN BASIS ACCIDENT)
1.4 FT^2 DER AT 25% POWER CONDENSING FILM
HEAT TRANSFER COEFFICIENT (UCHIDA) VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Line Break (Design Basis Accident) 1.4 ft^2 DER at 25% Power Condensing Film Heat Transfer Coefficient (UCHIDA) Vs. Time Figure 6.2-10

Figure 6.2-11

DOUBLE ENDED PUMP SUCTION BREAK
MINIMUM SAFETY INJECTION
FILM HEAT TRANSFER COEFFICIENT (TAGAMI/UCHIDA)



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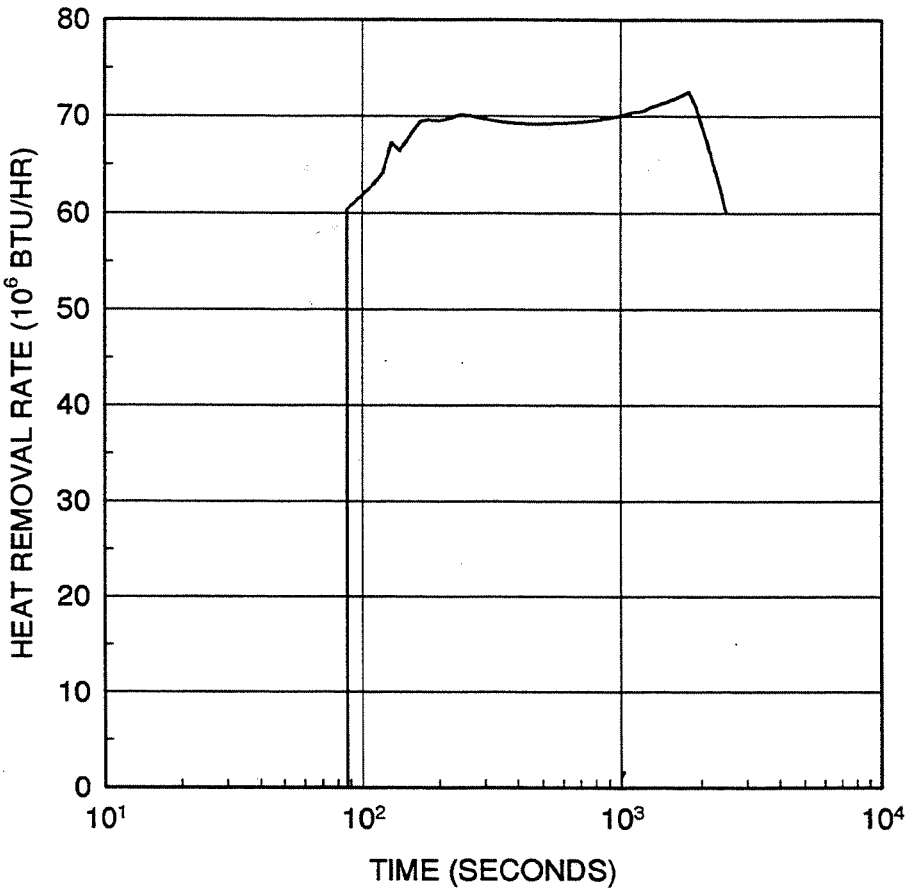
SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Double Ended Pump Suction Break Minimum Safety Injection Film Heat Transfer Coefficient Figure 6.2-11

Figure 6.2-12

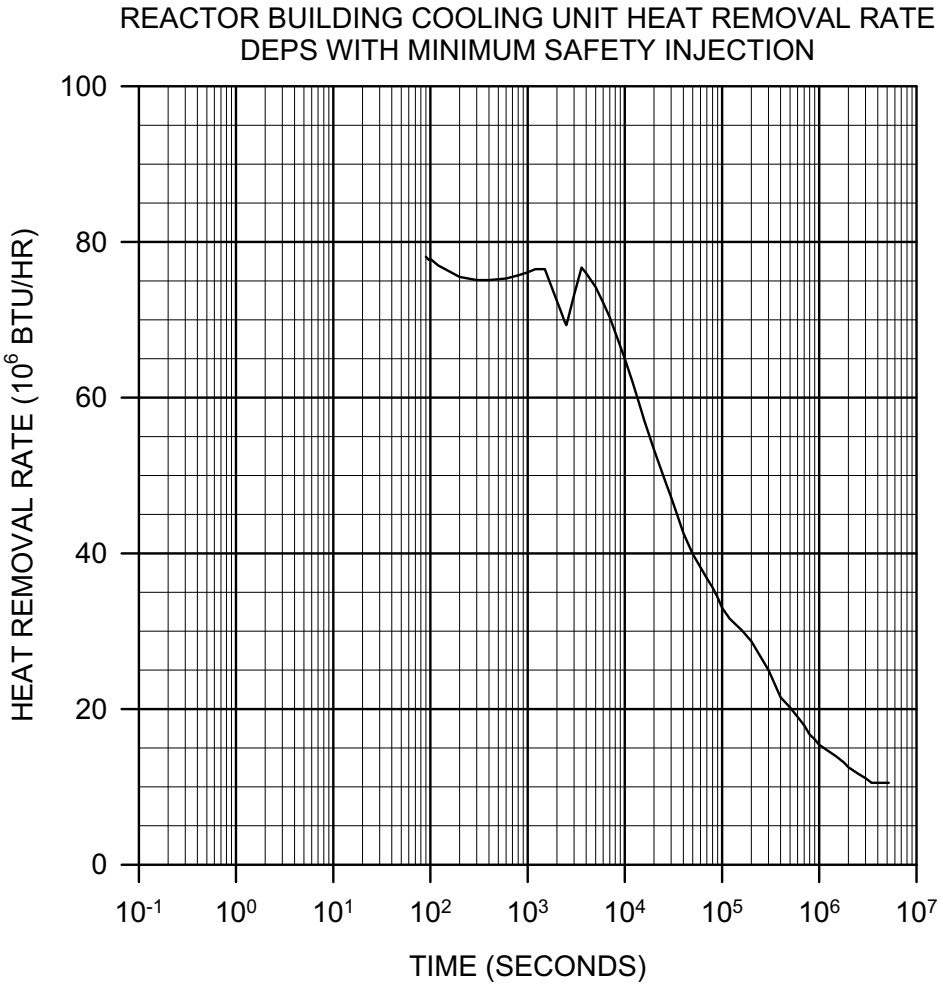
MAIN STEAM LINE BREAK (DESIGN BASIS ACCIDENT)
1.4 FT^2 DER AT 25% POWER REACTOR BUILDING COOLING UNIT HEAT REMOVAL RATE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Line Break (Design Basis Accident) 1.4 ft^2 DER at 25% Power Reactor Building Cooling Unit Heat Removal Rate Vs. Time Figure 6.2-12

Figure 6.2-13

DOUBLE ENDED PUMP SUCTION BREAK
MINIMUM SAFETY INJECTION REACTOR BUILDING
COOLING UNIT HEAT REMOVAL RATE VS. TIME



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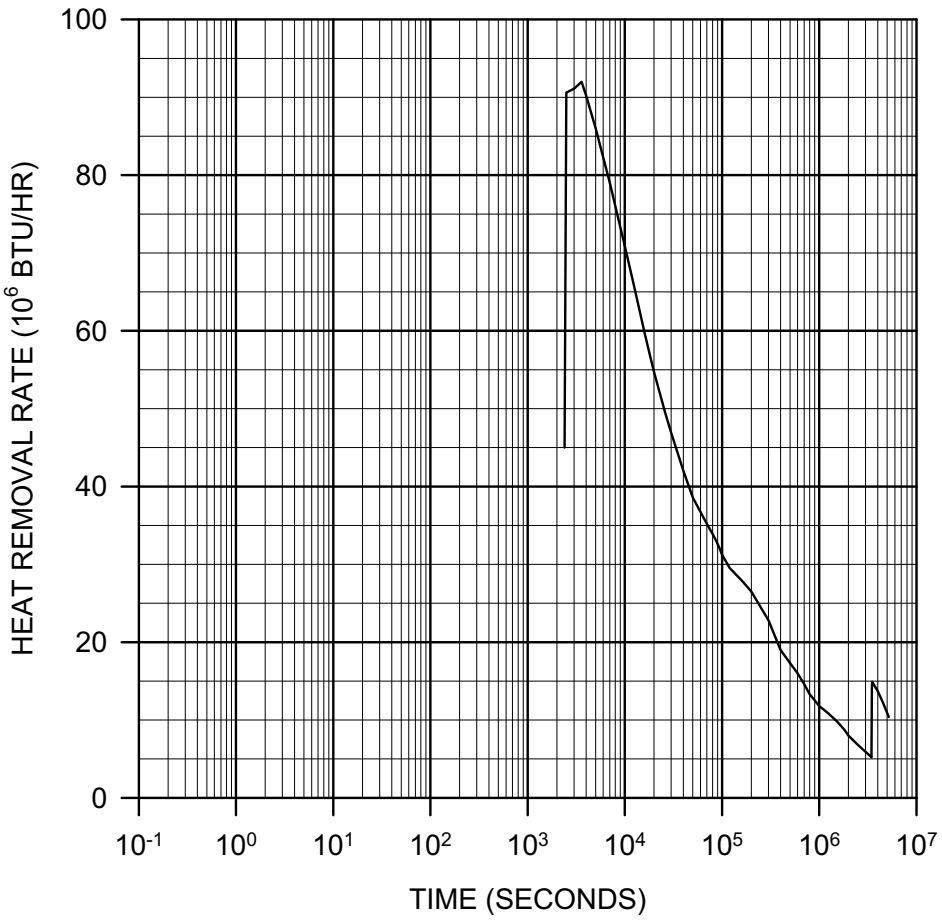
SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Double Ended Pump Suction Break Minimum Safety Injection Reactor Building Cooling Unit Heat Removal Rate vs. Time Figure 6.2-13

Figure 6.2-14

DOUBLE ENDED PUMP SUCTION BREAK
MINIMUM SAFETY INJECTION RESIDUAL HEAT REMOVAL
SYSTEM HEAT DUTY VS. TIME



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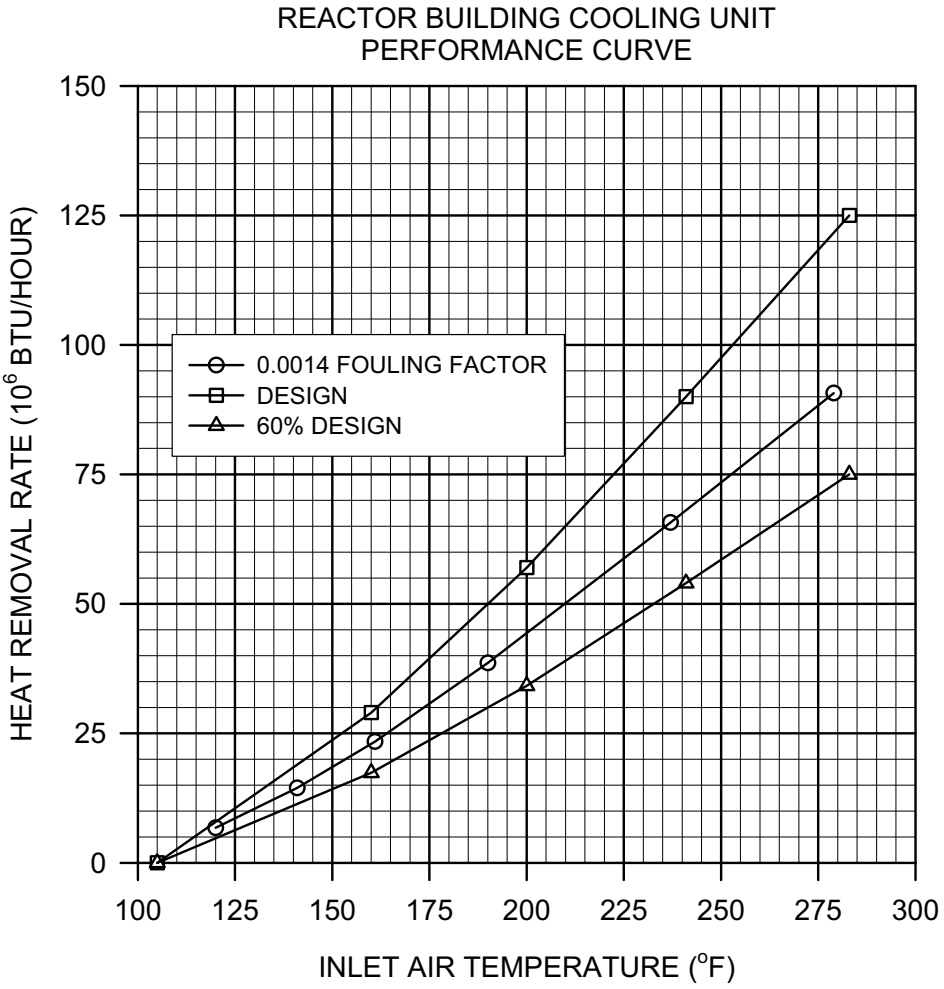
SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Double Ended Pump Suction Break Minimum Safety Injection Residual Heat Removal System Heat Duty vs. Time Figure 6.2-14

Figure 6.2-15
REACTOR BUILDING COOLING UNIT
DESIGN HEAT REMOVAL PERFORMANCE



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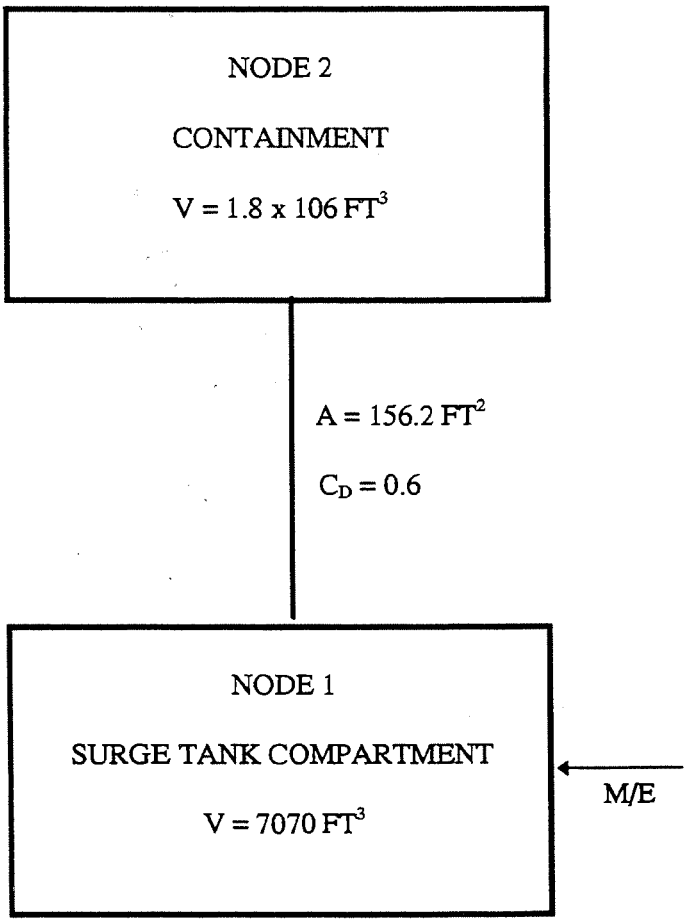
SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Reactor Building Cooling Unit Design Heat Removal Performance Figure 6.2-15

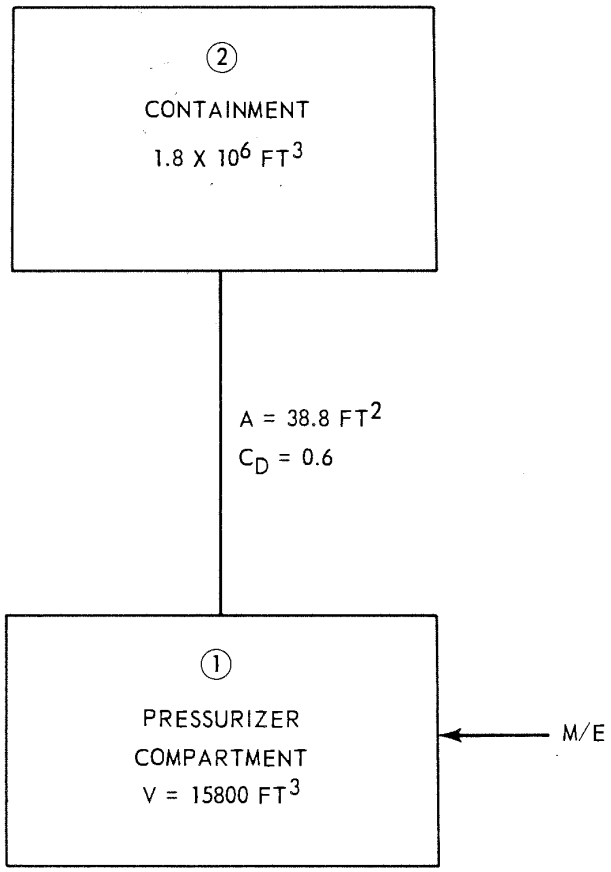
Figure 6.2-18

SURGE LINE RUPTURE IN SURGE TANK COMPARTMENT



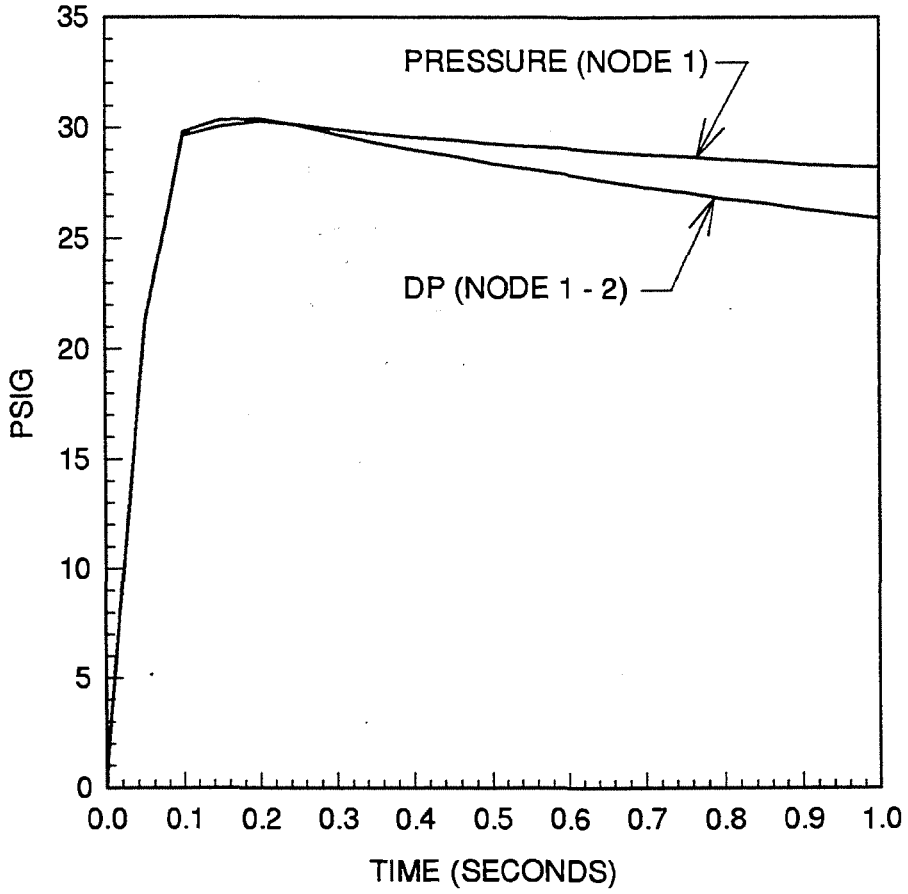
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Surge Line Rupture In Surge Tank Compartment Figure 6.2-18

Figure 6.2-19
SPRAY LINE RUPTURE IN PRESSURIZER COMPARTMENT



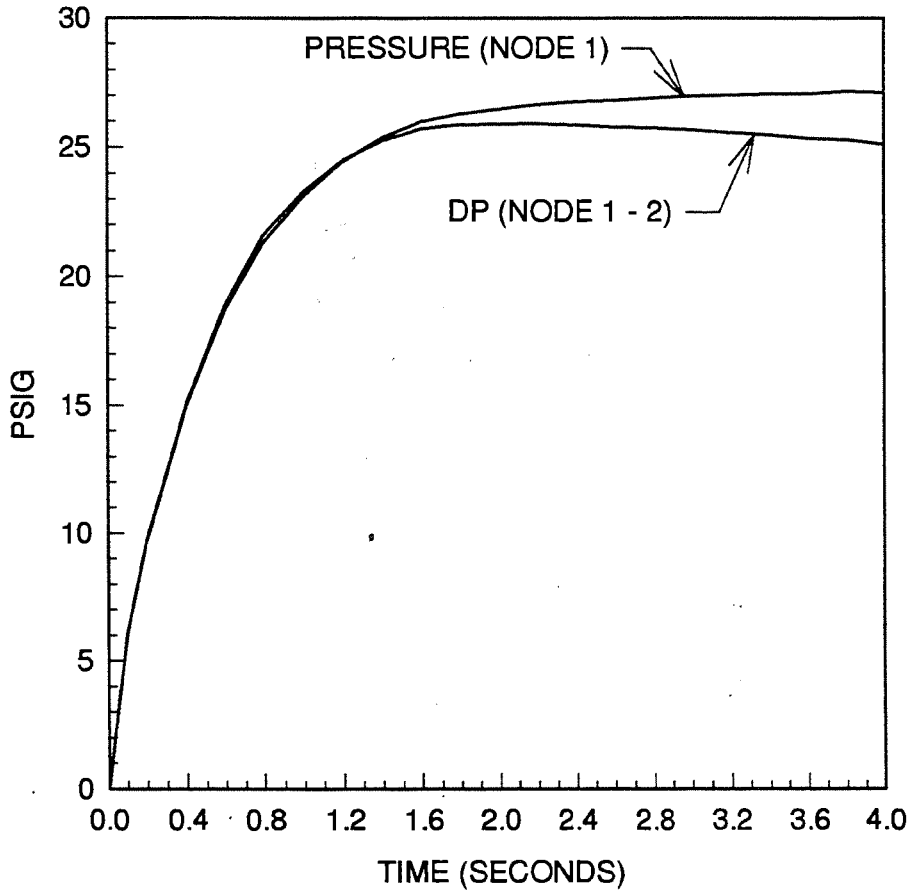
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Spray Line Rupture In Pressurizer Compartment Figure 6.2-19

Figure 6.2-20
SURGE TANK COMPARTMENT PRESSURIZATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Surge Tank Compartment Pressurization Figure 6.2-20

Figure 6.2-21
PRESSURIZER COMPARTMENT PRESSURIZATION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Pressurizer Compartment Pressurization Figure 6.2-21

Figure 6.2-22

GENERAL LAYOUT - STEAM GENERATOR COMPARTMENTS

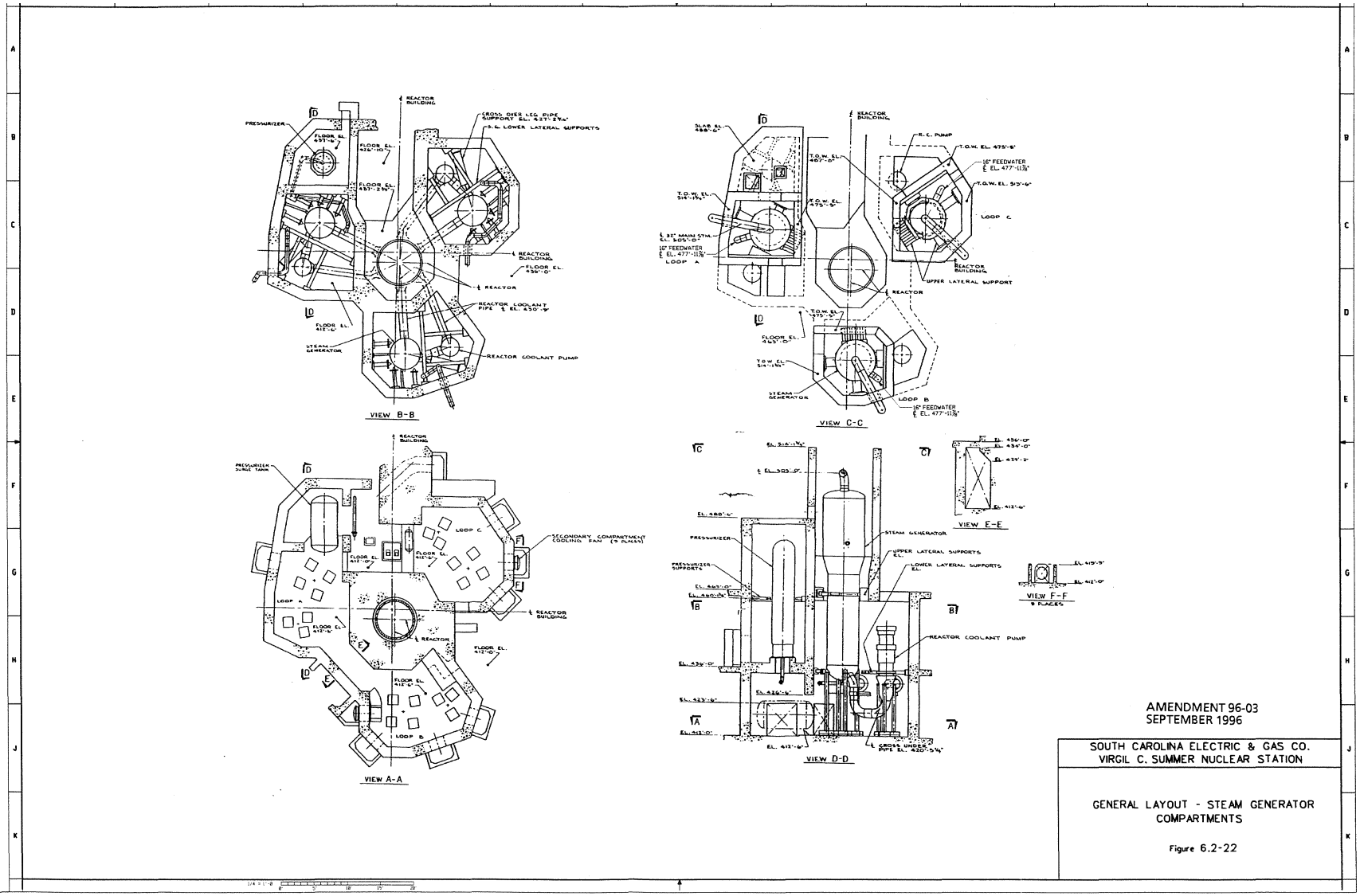


Figure 6.2-22a

LOOP A STEAM GENERATOR COMPARTMENT NODAL ARRANGEMENT 16 NODE MODEL, COLD LEG BREAK

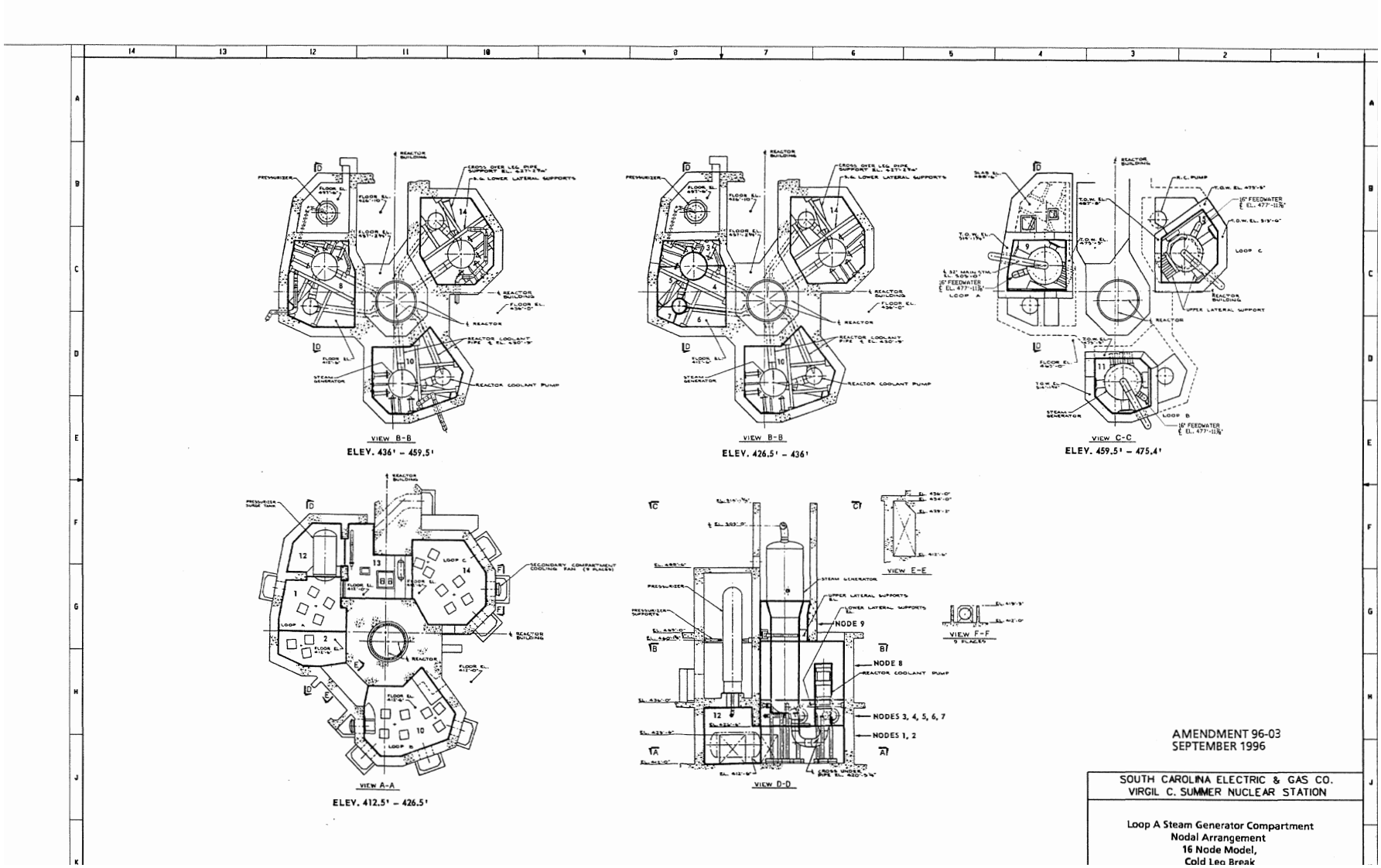
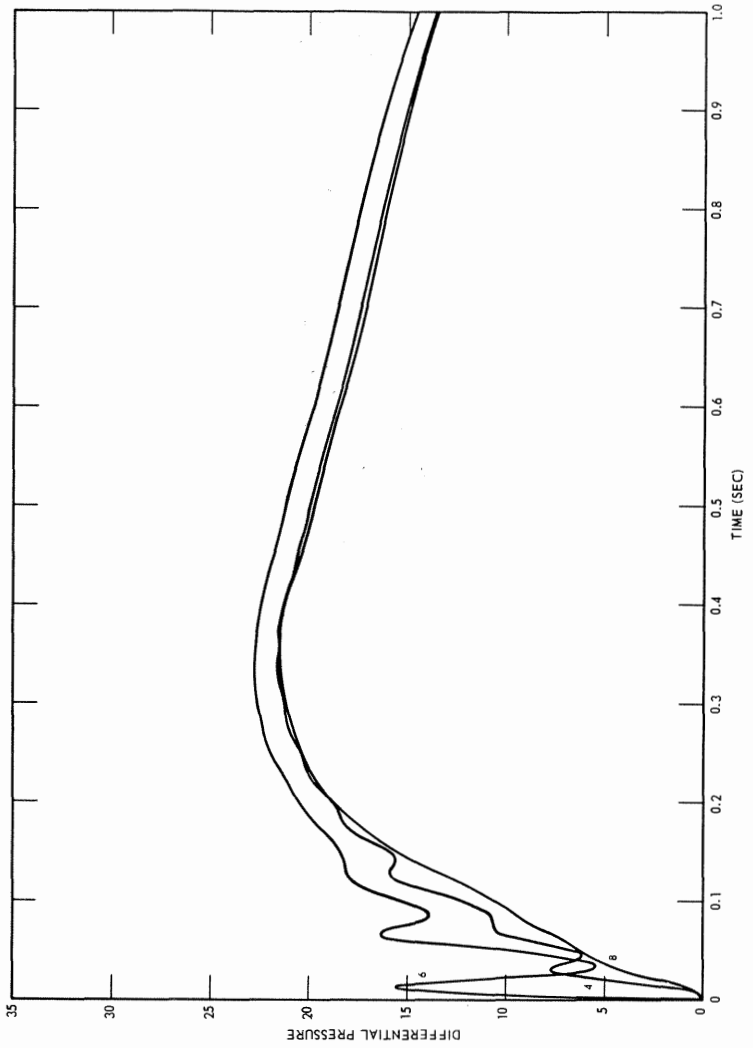


Figure 6.2-22b

LOOP A STEAM GENERATOR COMPARTMENT NODAL PRESSURES RELATIVE TO CONTAINMENT 16 NODE COLD LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Loop A Steam Generator Compartment
Nodal Pressures Relative to Containment
16 Node Cold Leg Break Model

Figure 6.2-22b

Figure 6.2-22c

LOOP A STEAM GENERATOR COMPARTMENT NODAL ARRANGEMENT 17 NODE MODEL, HOT LEG BREAK

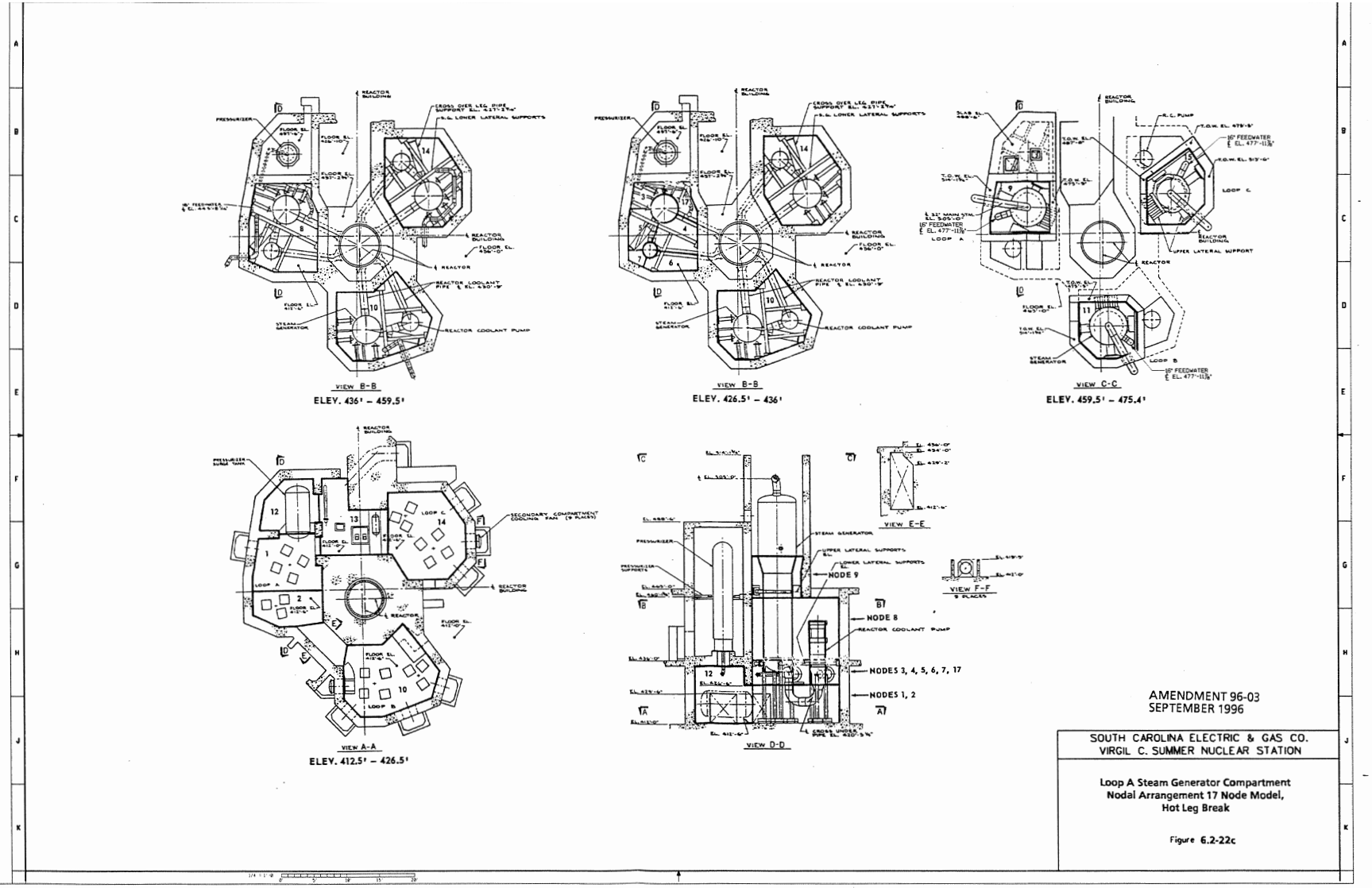
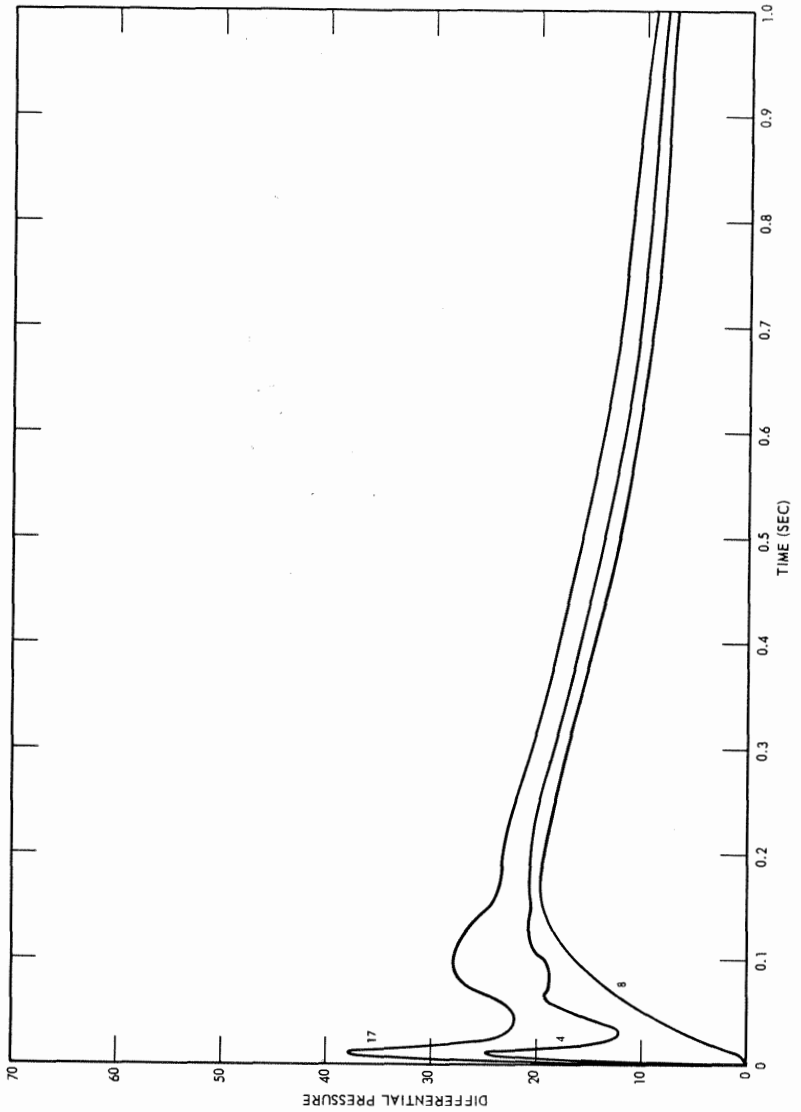


Figure 6.2-22d

LOOP A STEAM GENERATOR COMPARTMENT NODAL PRESSURES RELATIVE TO CONTAINMENT 17 NODE HOT LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loop A Steam Generator Compartment Nodal Pressures Relative to Containment 17 Node Hot Leg Break Model Figure 6.2-22d

Figure 6.2-22e

LOOP B STEAM GENERATOR COMPARTMENT NODAL ARRANGEMENT 12 NODE MODEL, COLD LEG BREAK

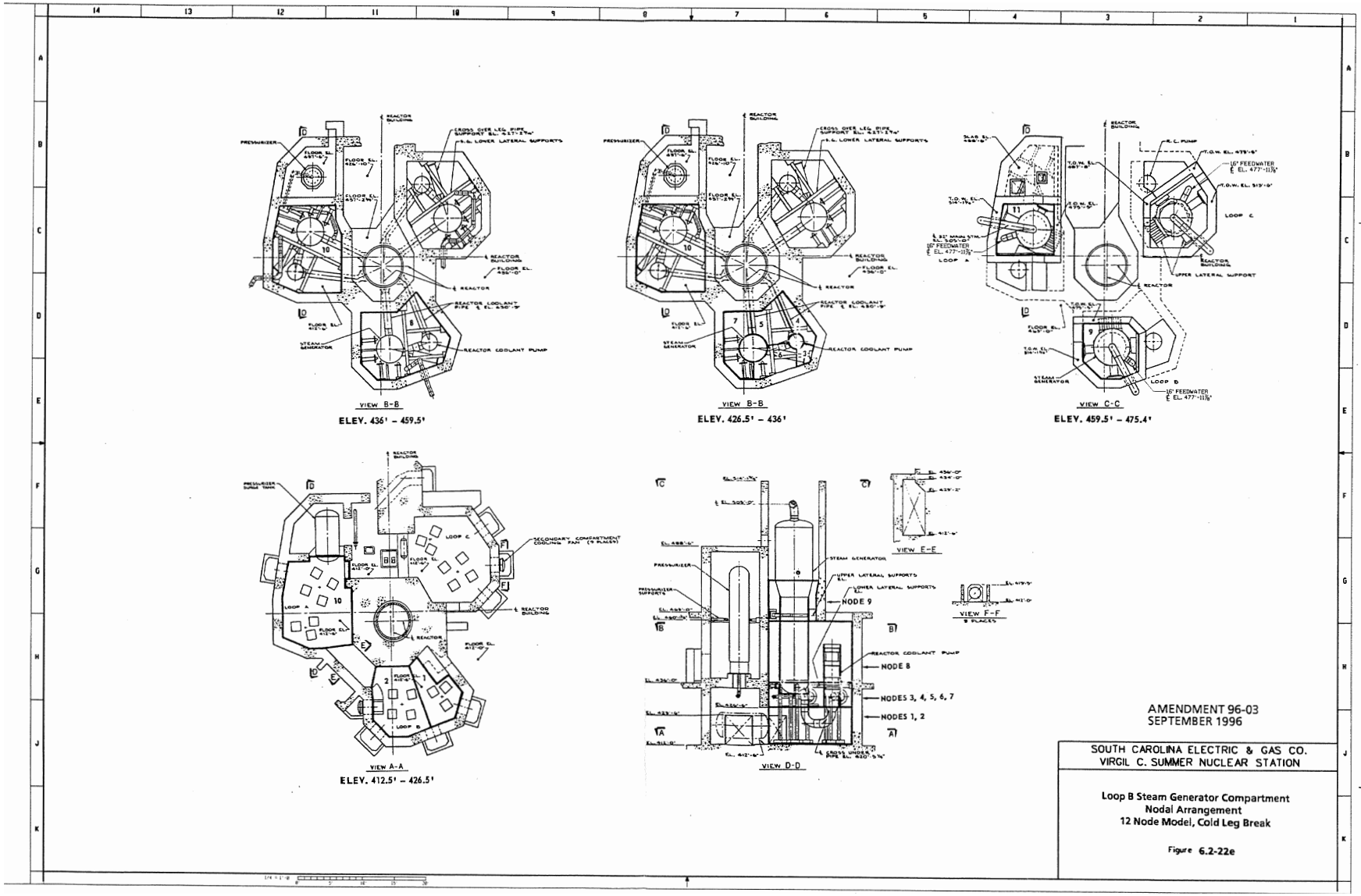
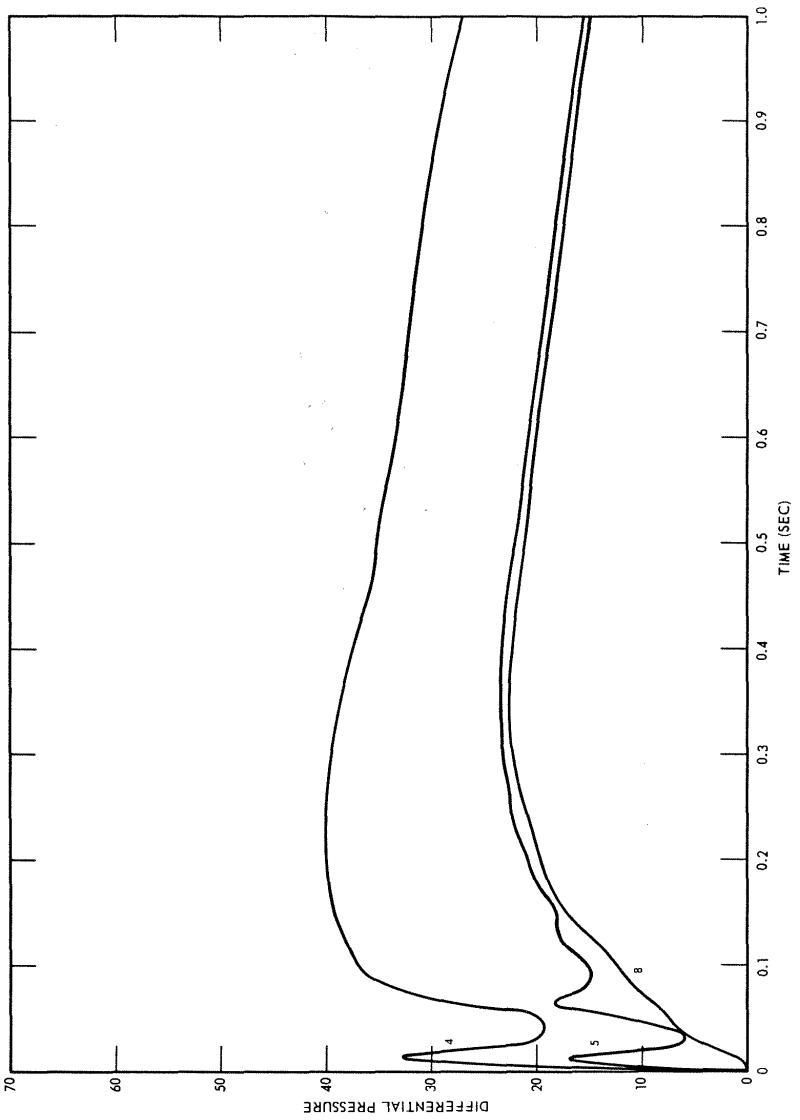


Figure 6.2-22f

LOOP B STEAM GENERATOR COMPARTMENT NODAL PRESSURES RELATIVE TO CONTAINMENT 12 NODE COLD LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loop B Steam Generator Compartment Nodal Pressures Relative to Containment 12 Node Cold Leg Break Model Figure 6.2-22f

Figure 6.2-22g

LOOP B STEAM GENERATOR COMPARTMENT NODAL ARRANGEMENT 13 NODE MODEL, HOT LEG BREAK

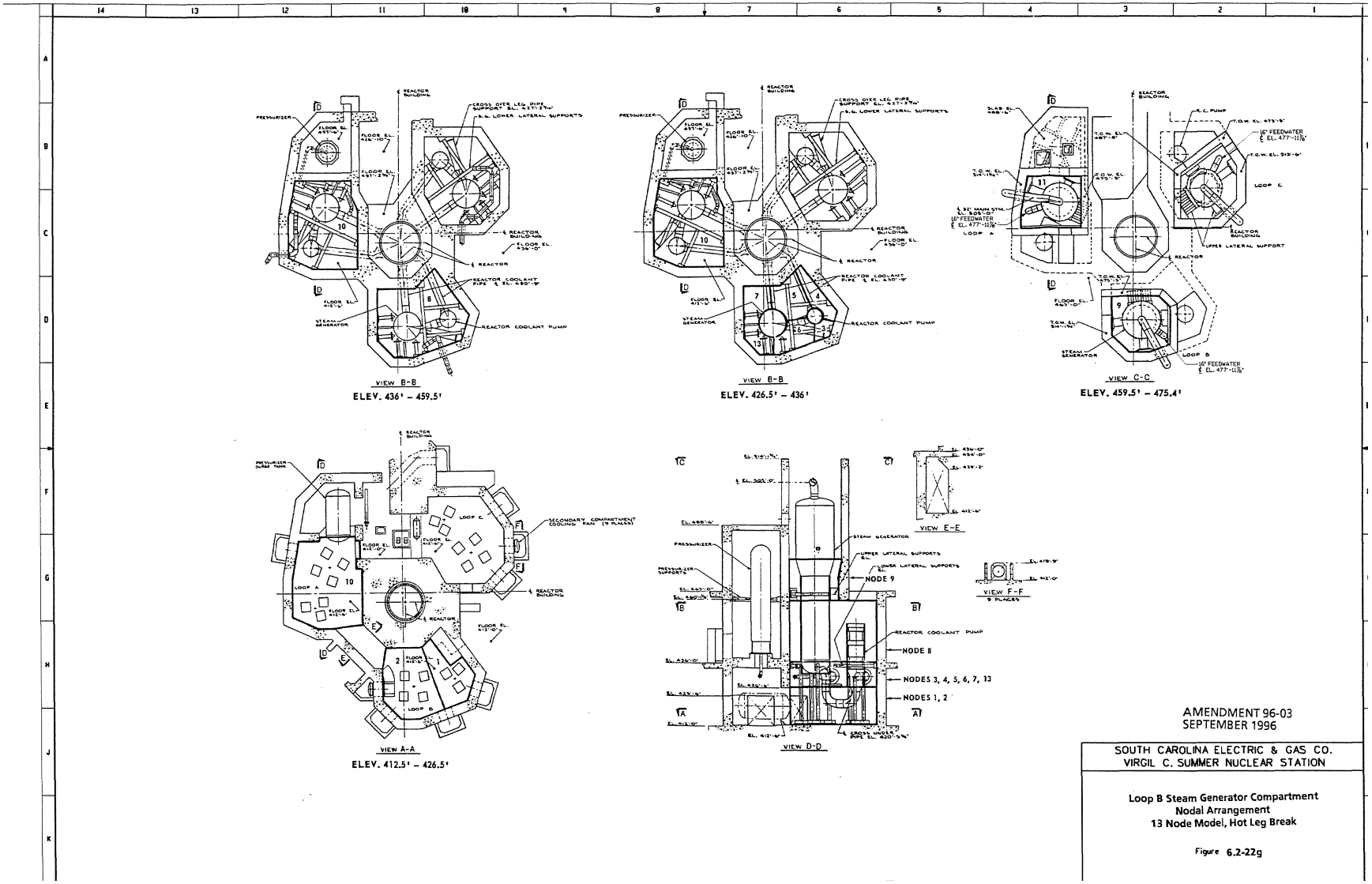
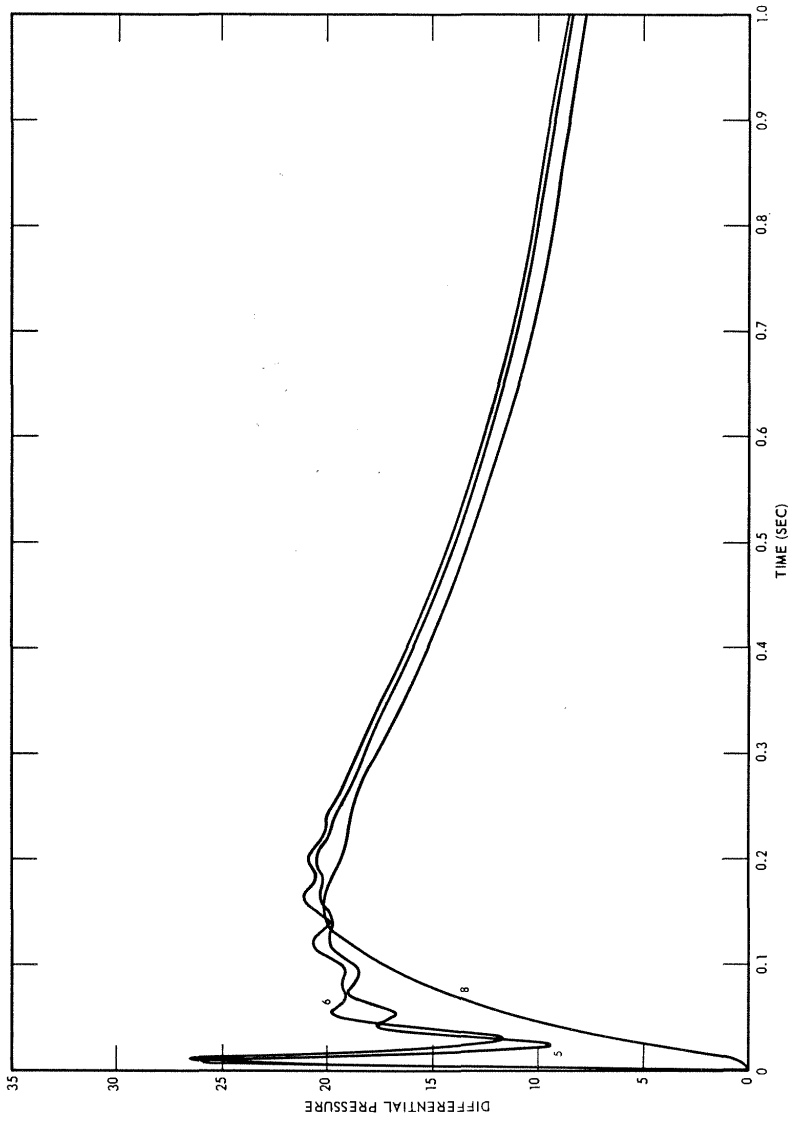


Figure 6.2-22h

LOOP B STEAM GENERATOR COMPARTMENT
NODAL PRESSURES RELATIVE TO CONTAINMENT
13 NODE HOT LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loop B Steam Generator Compartment Nodal Pressures Relative to Containment 13 Node Hot Leg Break Model Figure 6.2-22h

Figure 6.2-22i

LOOP C STEAM GENERATOR COMPARTMENT NODAL ARRANGEMENT 14 NODE MODEL, HOT AND COLD LEG BREAKS

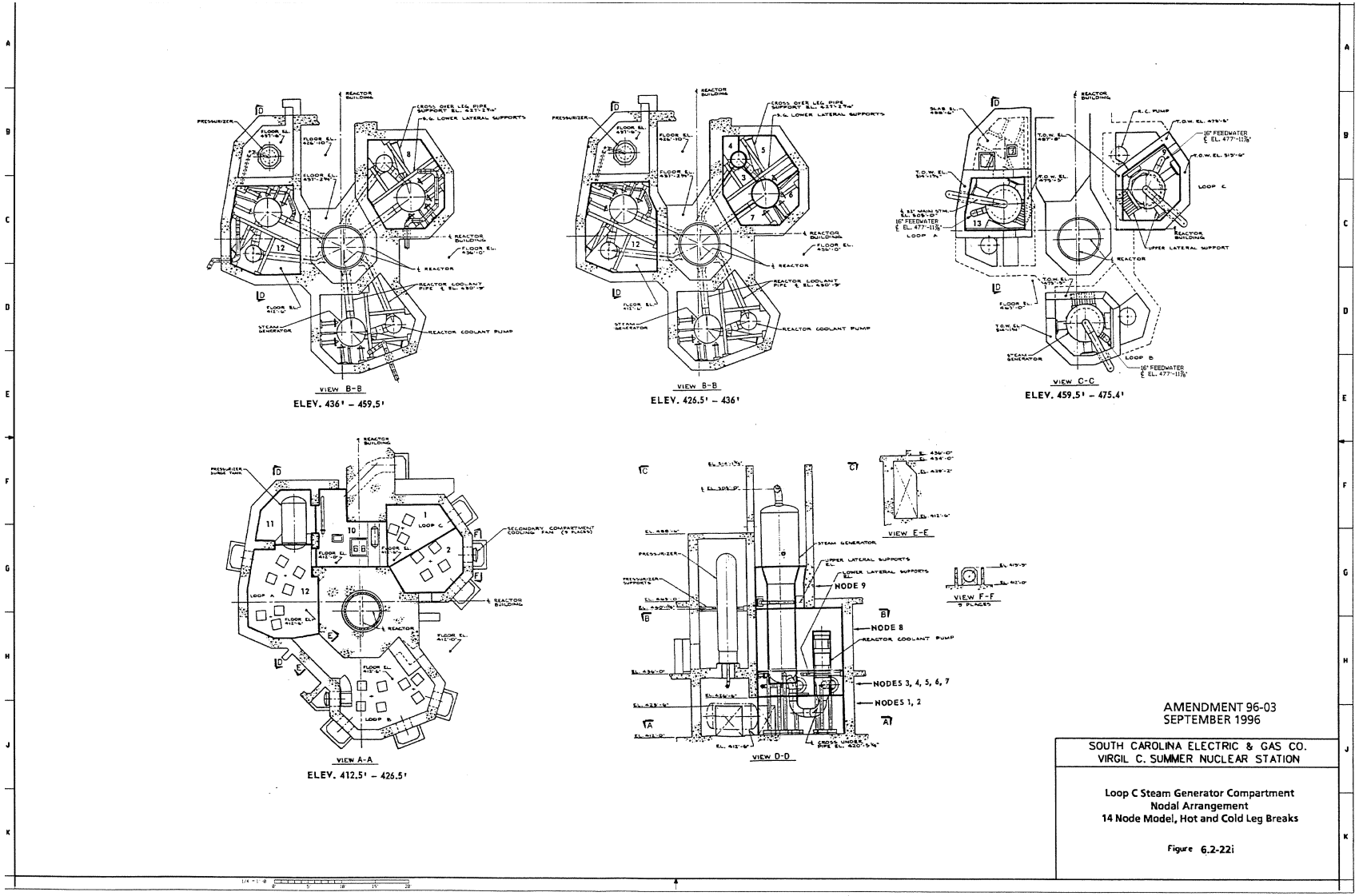
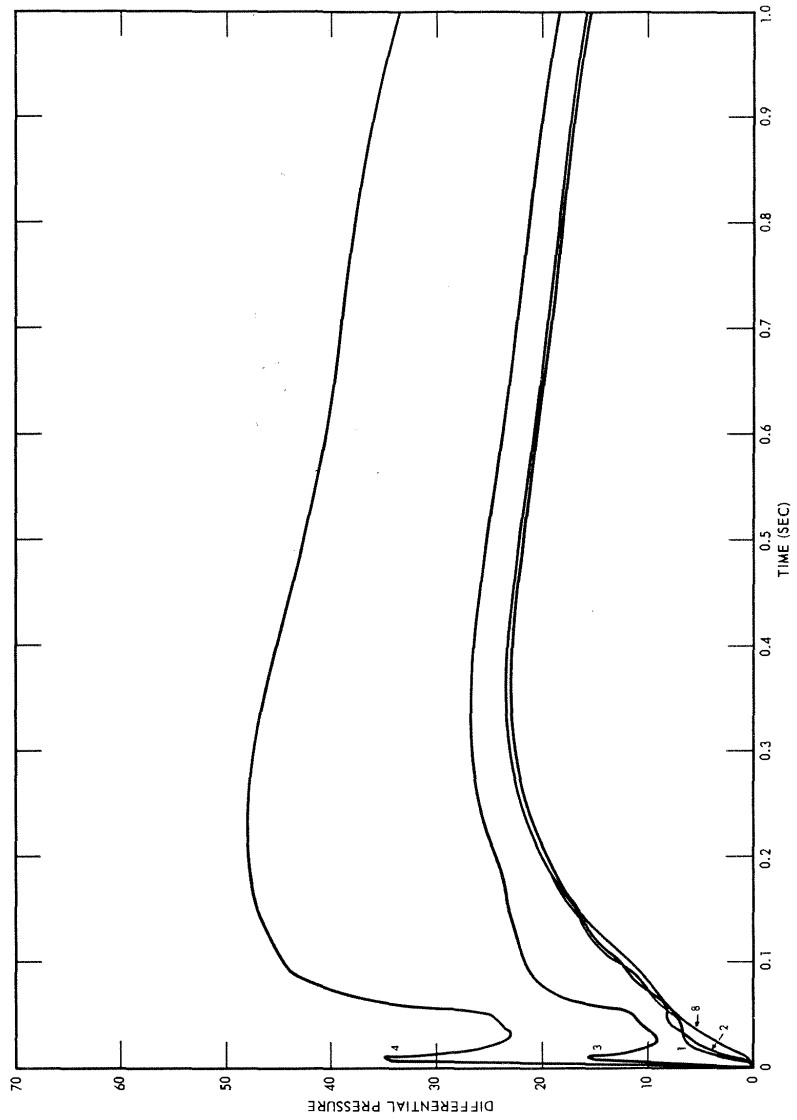


Figure 6.2-22j

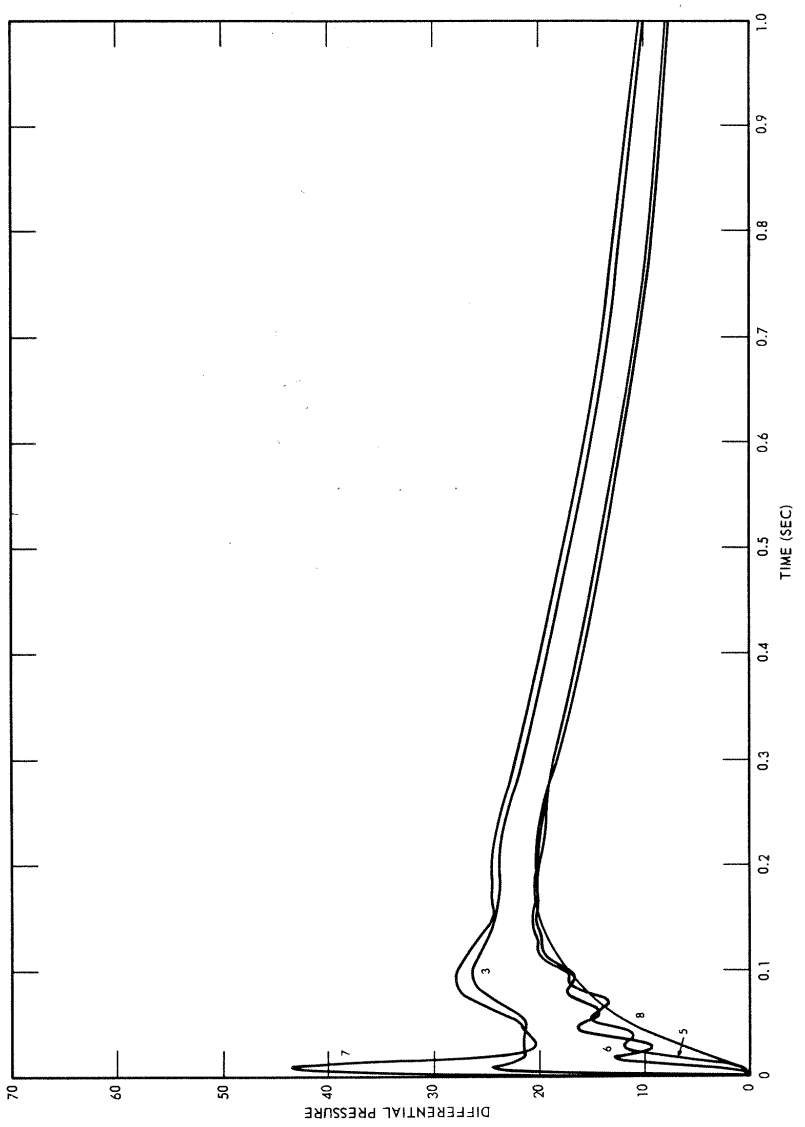
LOOP C STEAM GENERATOR COMPARTMENT
NODAL PRESSURES RELATIVE TO CONTAINMENT
14 NODE COLD LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loop C Steam Generator Compartment Nodal Pressures Relative to Containment 14 Node Cold Leg Break Model Figure 6.2-22j

Figure 6.2-22k

LOOP C STEAM GENERATOR COMPARTMENT
NODAL PRESSURES RELATIVE TO CONTAINMENT
14 NODE HOT LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loop C Steam Generator Compartment Nodal Pressures Relative to Containment 14 Node Hot Leg Break Model Figure 6.2-22k

Figure 6.2-23

LOOP C STEAM GENERATOR COMPARTMENT NODAL ARRANGEMENT 20 NODE MODEL, COLD LEG BREAKS

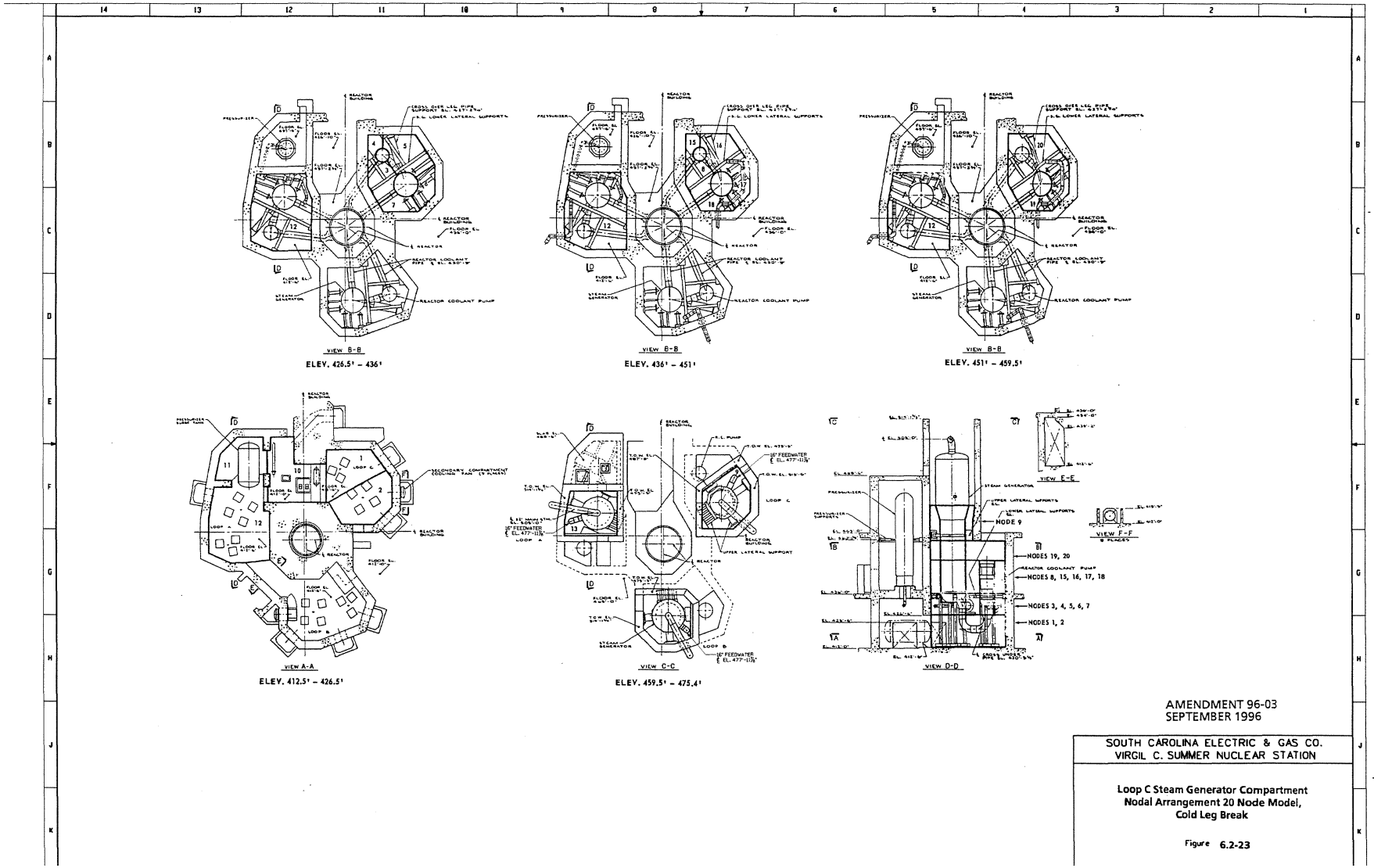
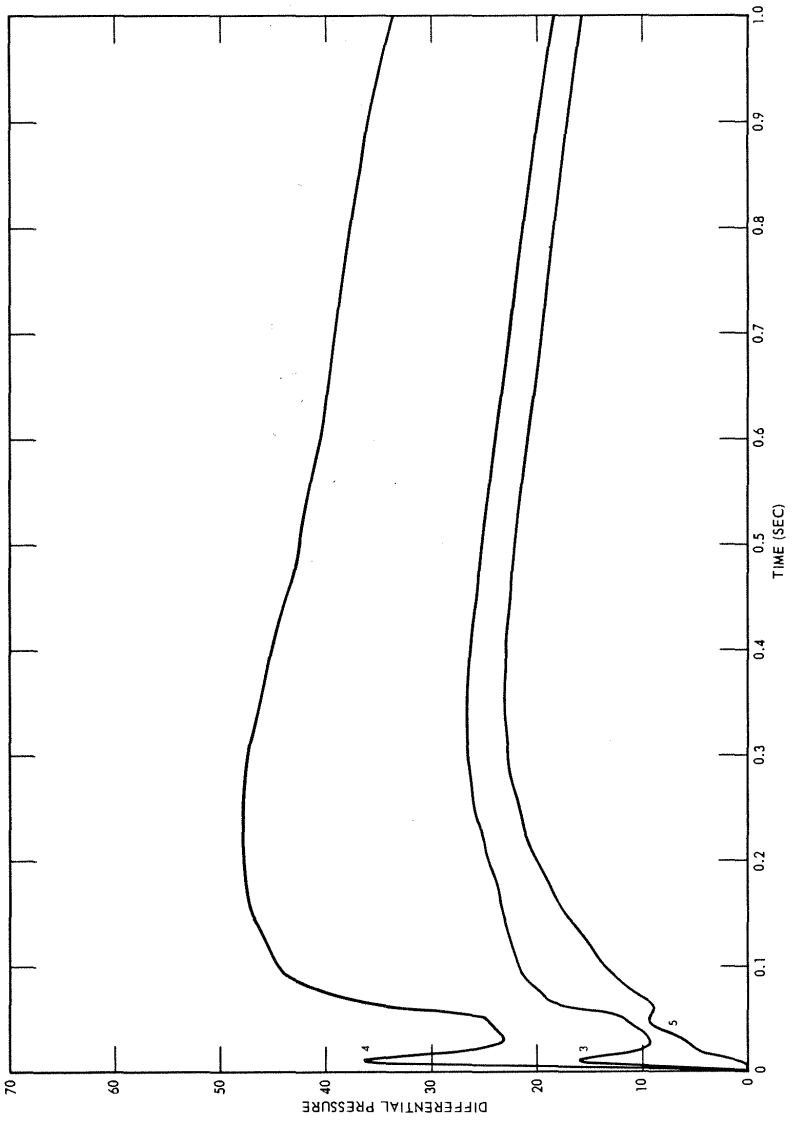


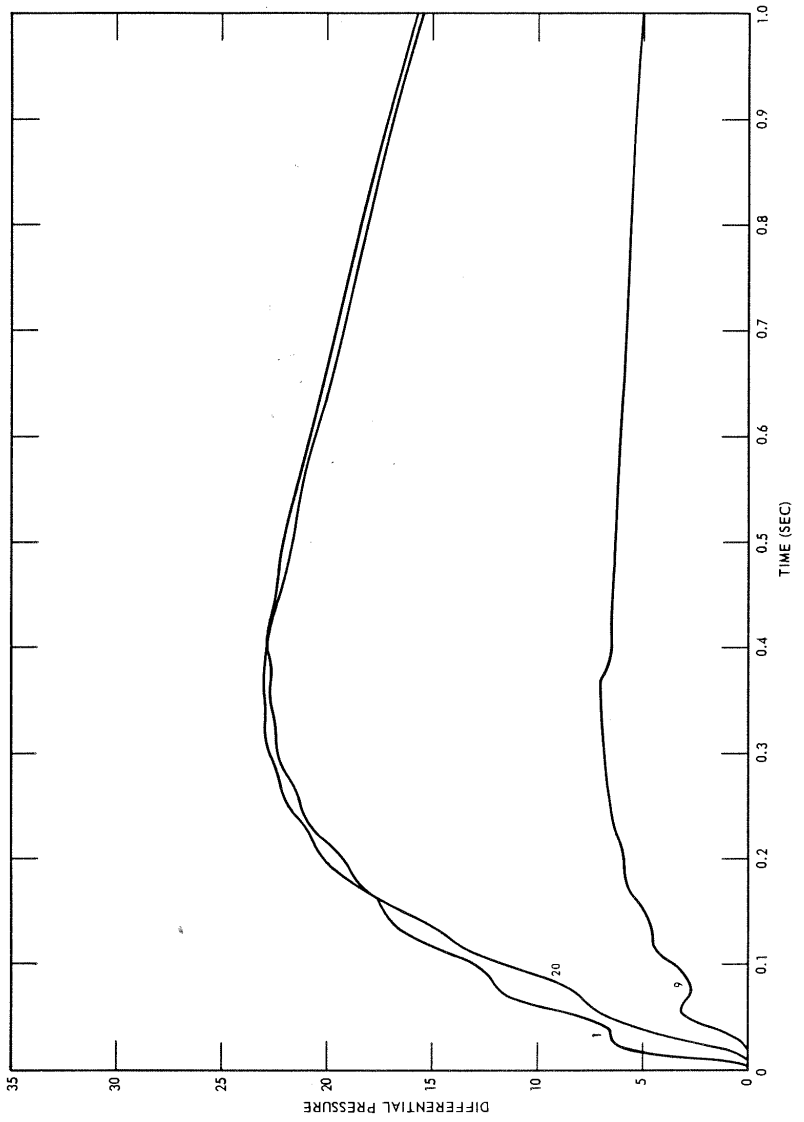
Figure 6.2-23a

LOOP C STEAM GENERATOR COMPARTMENT
NODAL PRESSURES RELATIVE TO CONTAINMENT
20 NODE COLD LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loop C Steam Generator Compartment Nodal Pressures Relative to Containment 20 Node Cold Leg Break Model Figure 6.2-23a

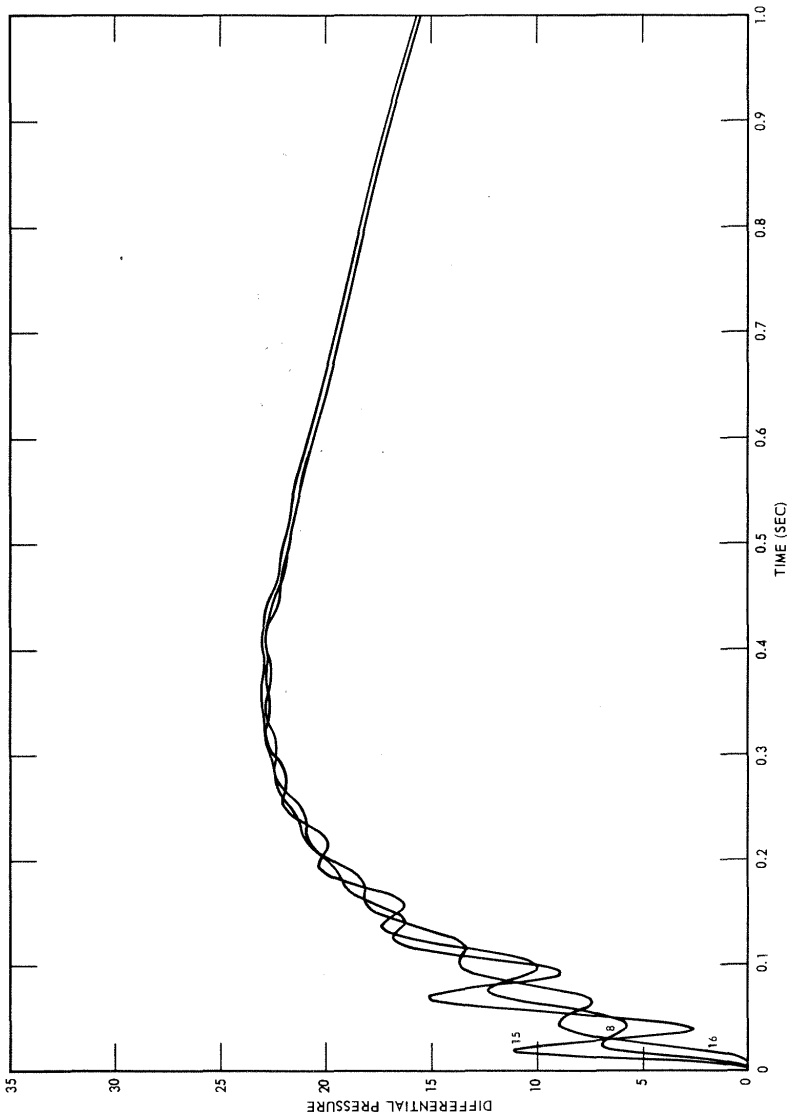
Figure 6.2-23b
LOOP C STEAM GENERATOR COMPARTMENT
NODAL PRESSURES RELATIVE TO CONTAINMENT
20 NODE COLD LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loop C Steam Generator Compartment Nodal Pressures Relative to Containment 20 Node Cold Leg Break Model Figure 6.2-23b

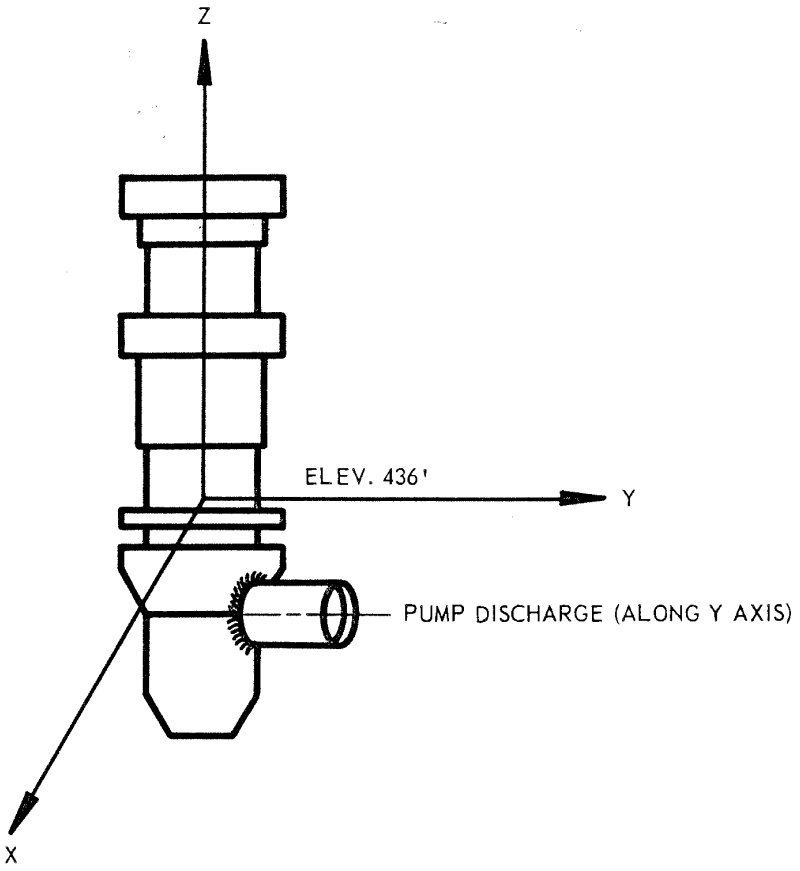
Figure 6.2-23c

LOOP C STEAM GENERATOR COMPARTMENT
NODAL PRESSURES RELATIVE TO CONTAINMENT
20 NODE COLD LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loop C Steam Generator Compartment Nodal Pressures Relative to Containment 20 Node Cold Leg Break Model Figure 6.2-23c

Figure 6.2-24
FORCES AND MOMENTS ON REACTOR COOLANT PUMP COORDINATE SYSTEM



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Forces and Moments on Reactor Coolant Pump Coordinate System Figure 6.2-24

Figure 6.2-25

LOOP C STEAM GENERATOR COMPARTMENT NODAL ARRANGEMENT 25 NODE MODEL, HOT LEG BREAK

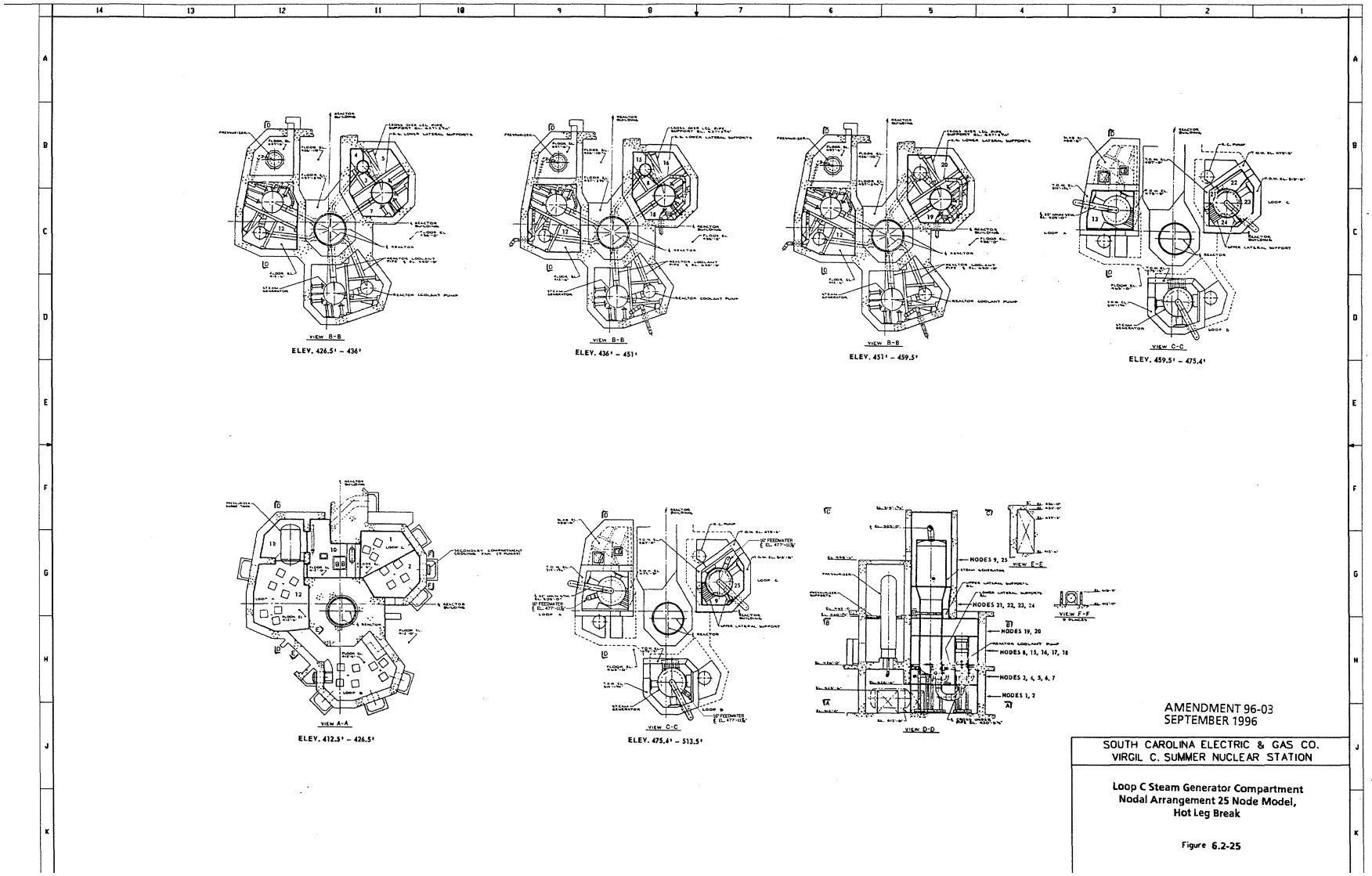
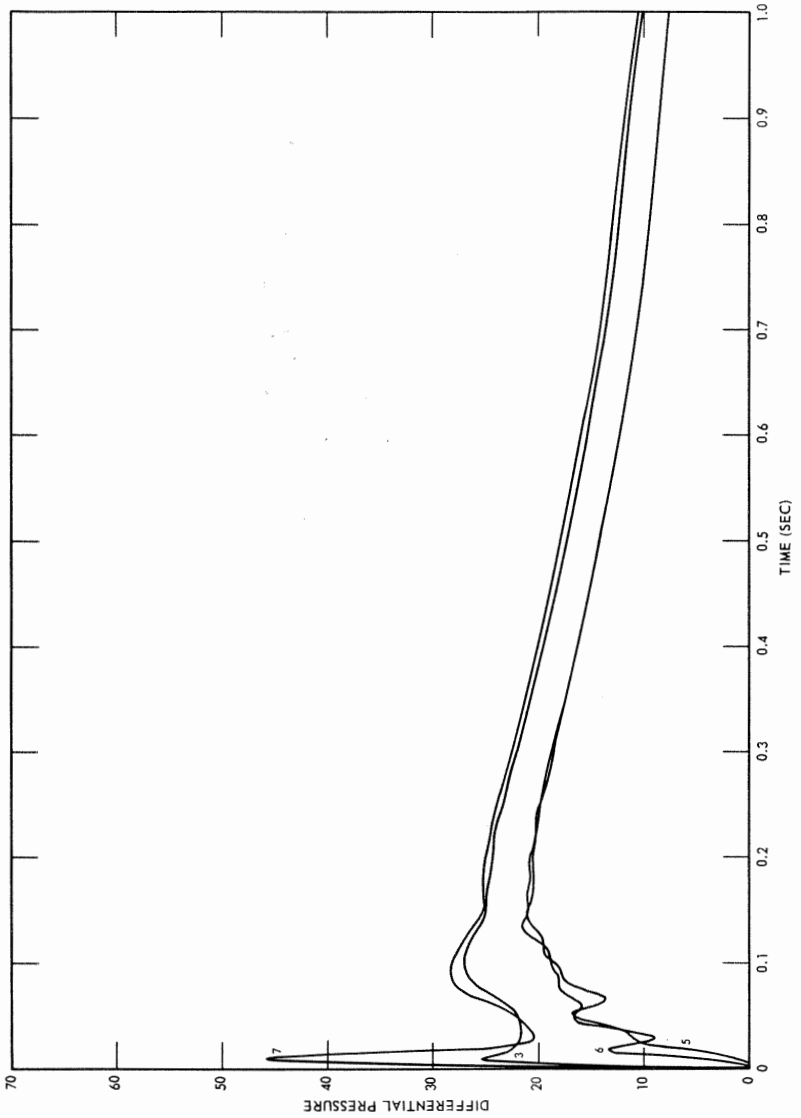


Figure 6.2-25a

LOOP C STEAM GENERATOR COMPARTMENT
NODAL PRESSURES RELATIVE TO CONTAINMENT
25 NODE HOT LEG BREAK MODEL



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Loop C Steam Generator Compartment
Nodal Pressures Relative to Containment
25 Node Hot Leg Break Model

Figure 6.2-25a

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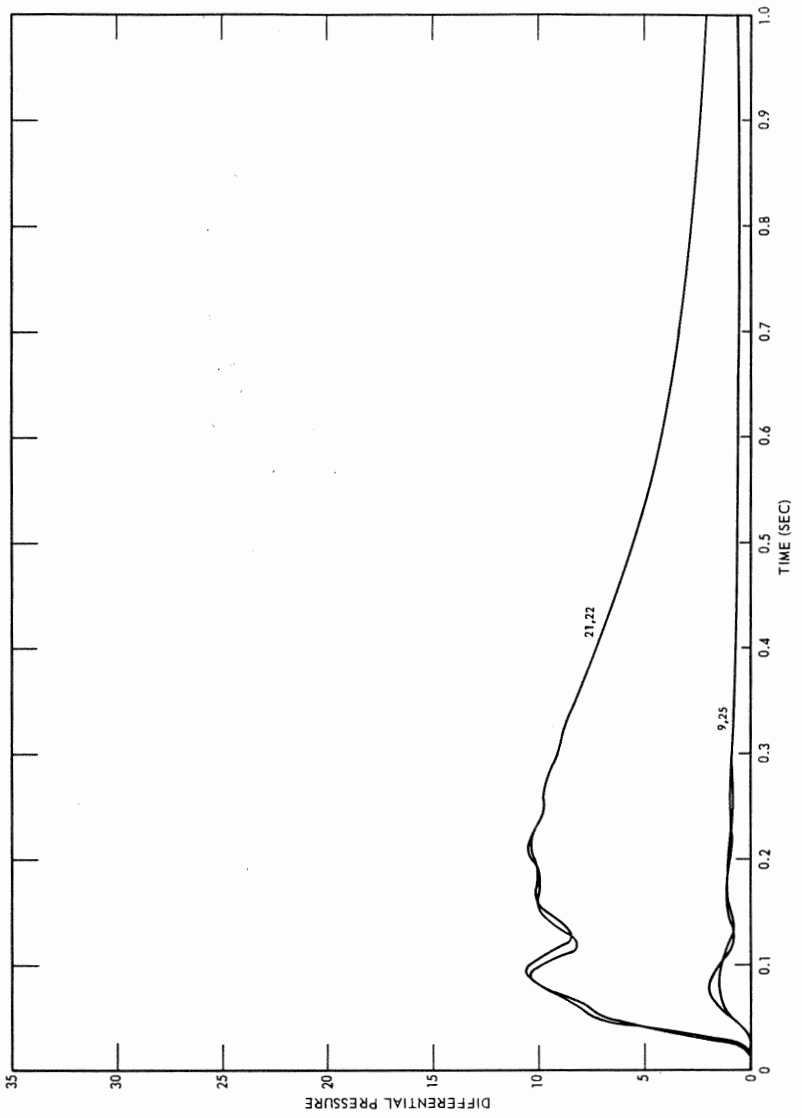
Figure 6.2-25b

LOOP C STEAM GENERATOR COMPARTMENT
NODAL PRESSURES RELATIVE TO CONTAINMENT
25 NODE HOT LEG BREAK MODEL



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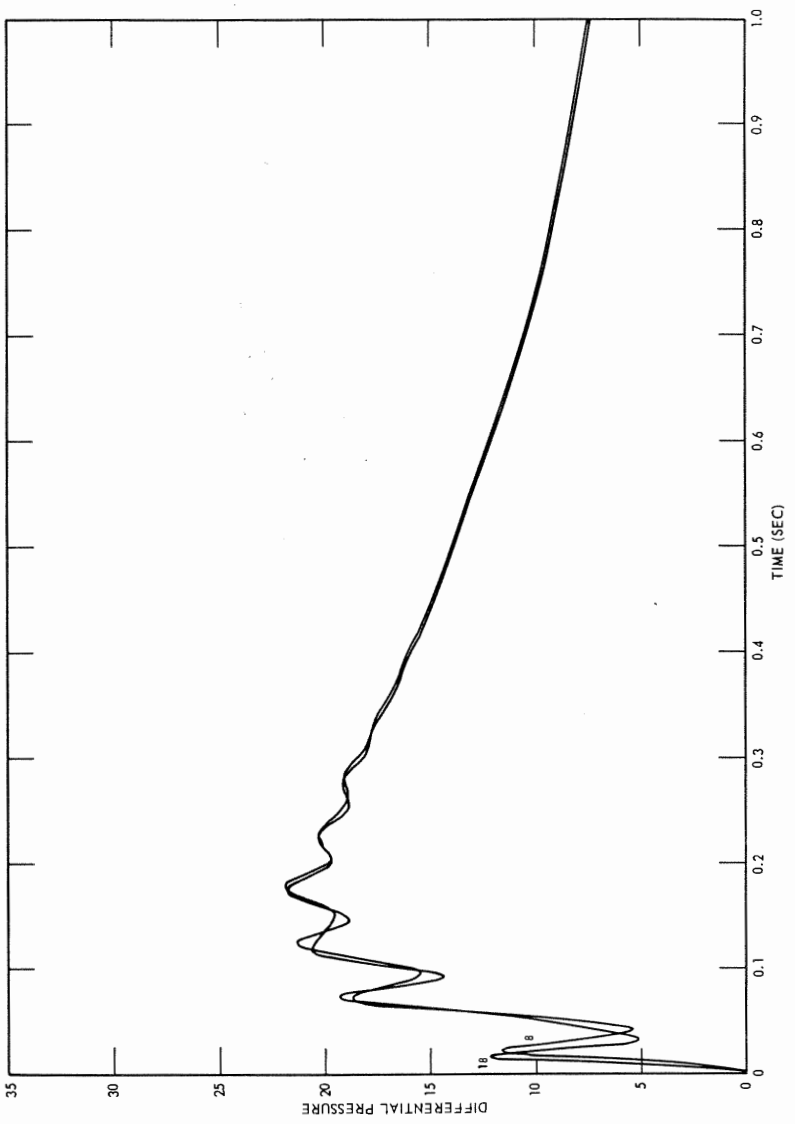
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Loop C Steam Generator Compartment
Nodal Pressures Relative to Containment
25 Node Hot Leg Break Model

Figure 6.2-25b

Figure 6.2-25c

LOOP C STEAM GENERATOR COMPARTMENT
NODAL PRESSURES RELATIVE TO CONTAINMENT
25 NODE HOT LEG BREAK MODEL



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SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Loop C Steam Generator Compartment
Nodal Pressures Relative to Containment
25 Node Hot Leg Break Model

Figure 6.2-25c

Figure 6.2-26
FORCES AND MOMENTS ON STEAM GENERATOR COORDINATE SYSTEM

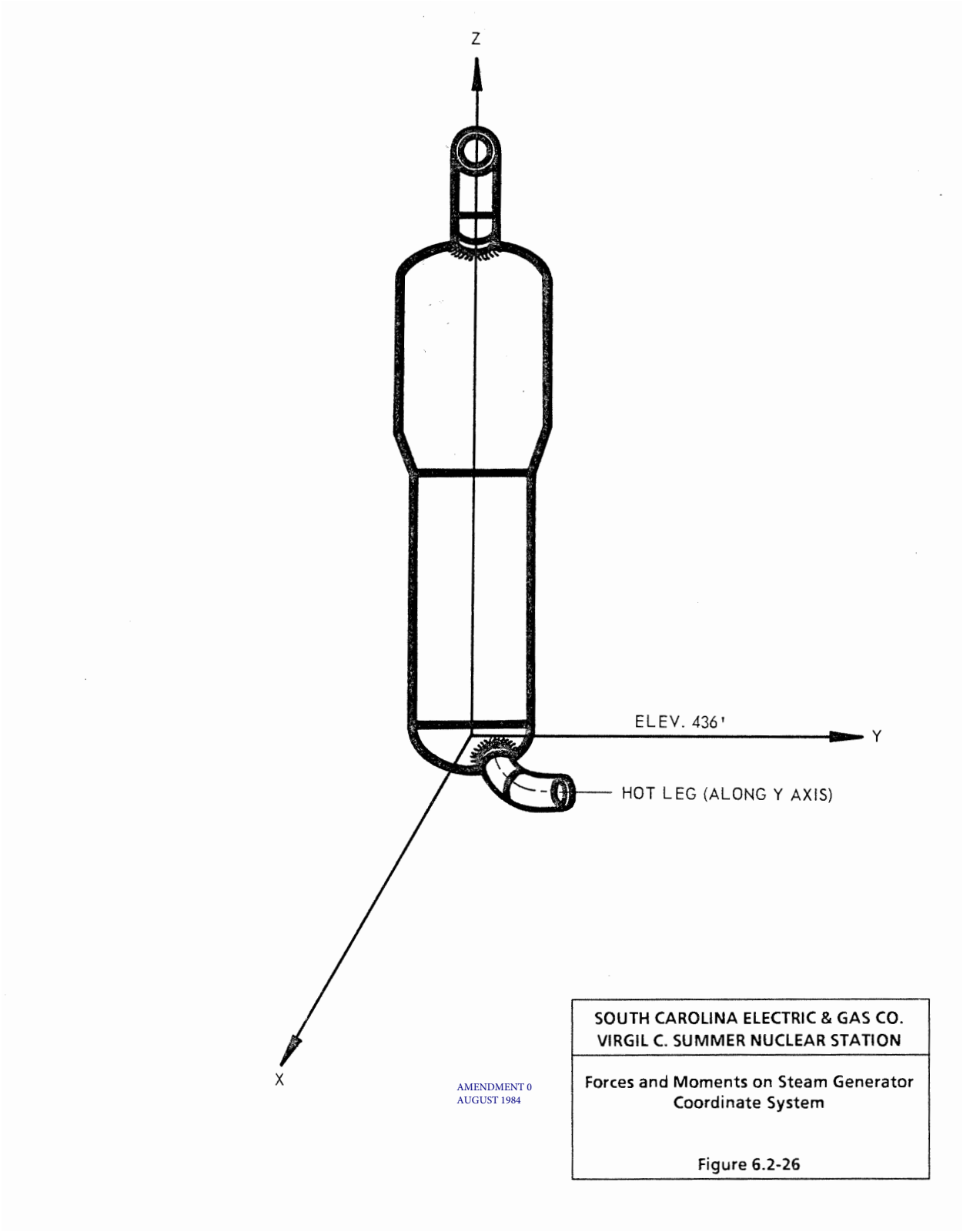


Figure 6.2-27
BREAK GEOMETRY

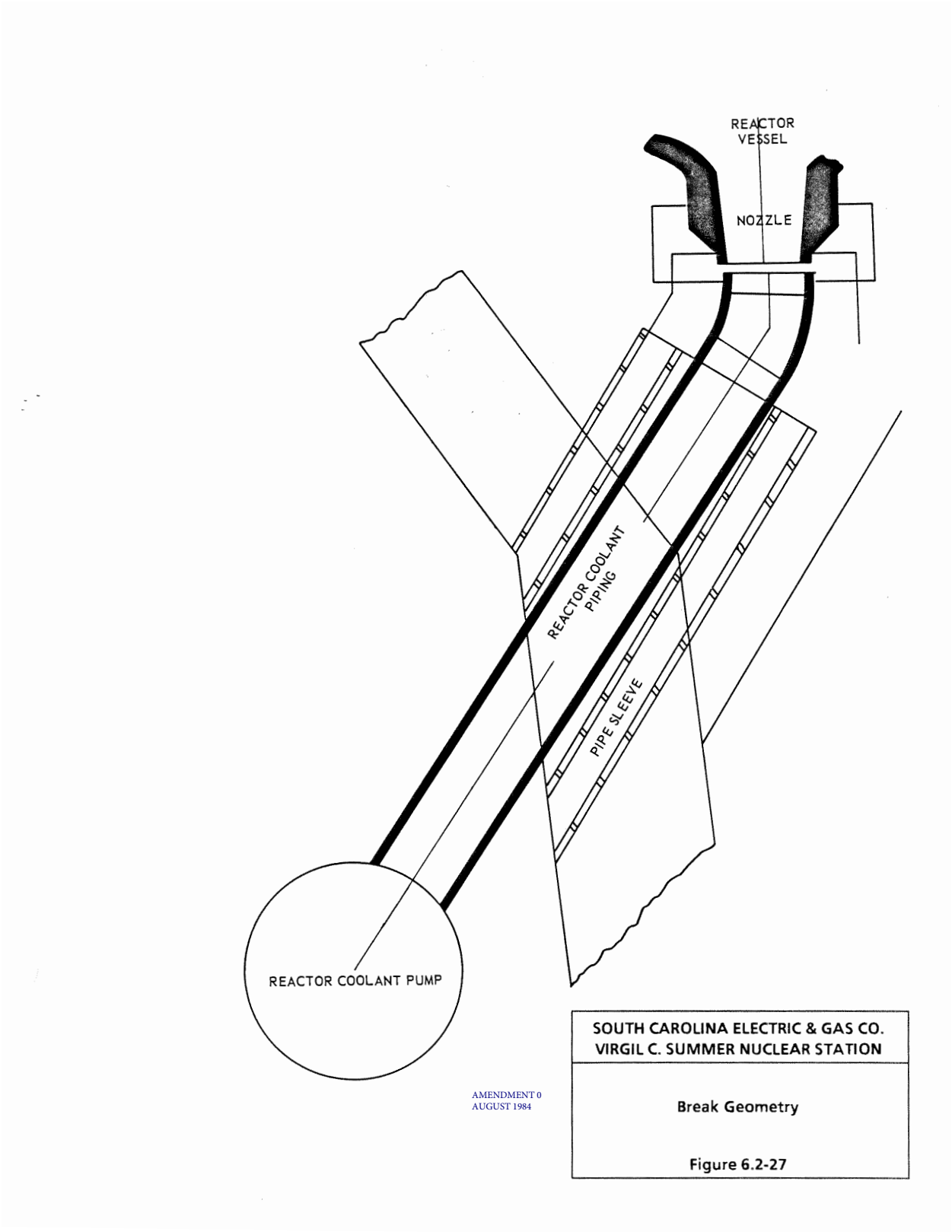


Figure 6.2-28

PRESSURE DISTRIBUTION REACTOR VESSEL CAVITY

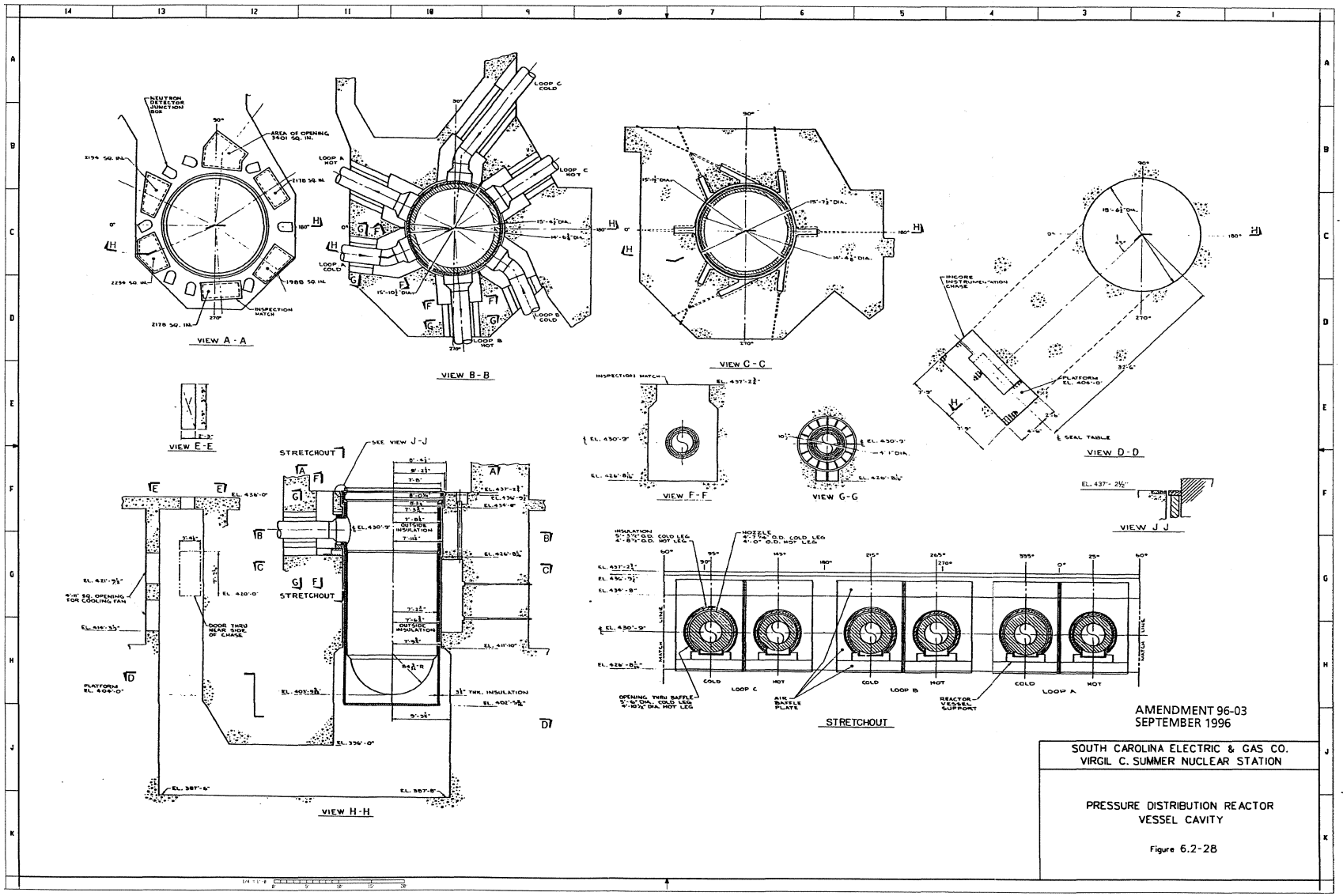
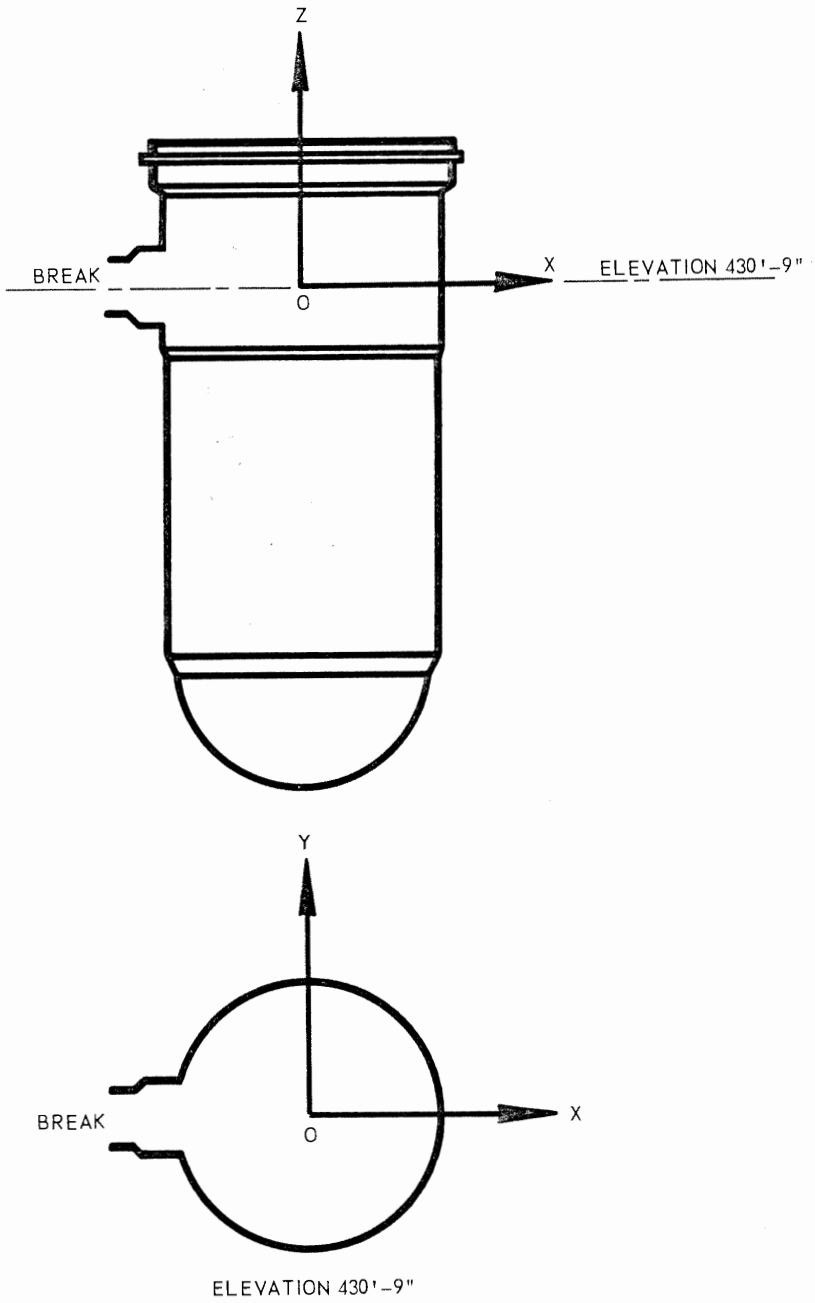


Figure 6.2-29
REACTOR VESSEL AXES FOR FORCES AND MOMENTS



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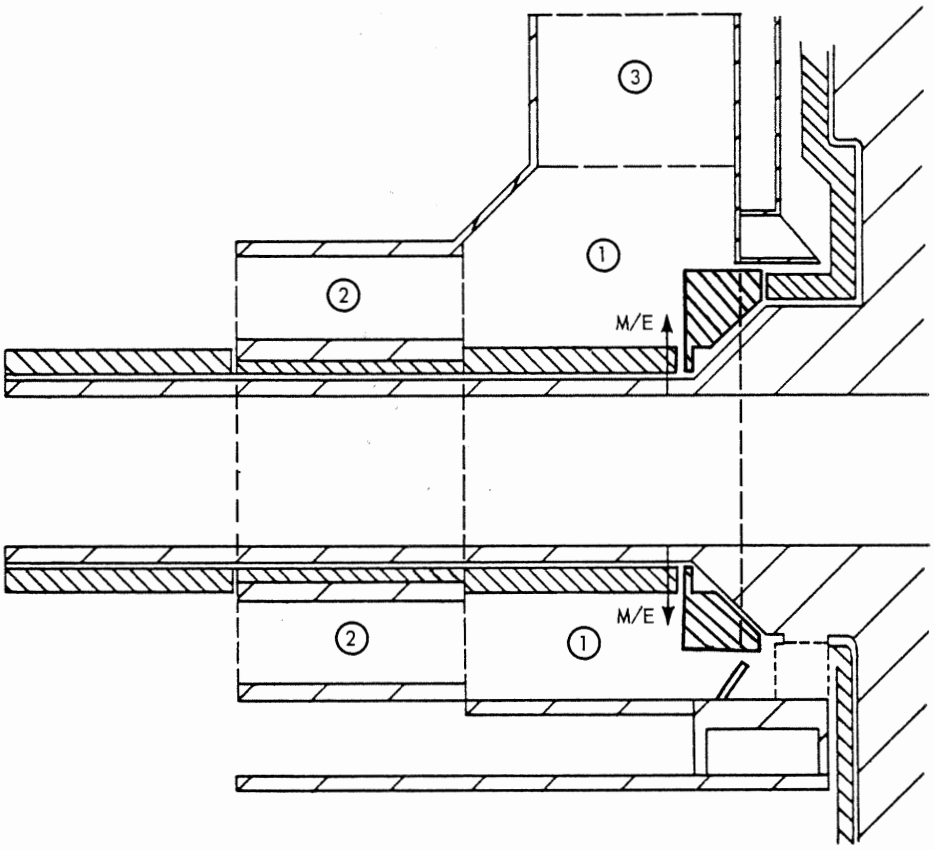
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Reactor Vessel Axes for
Forces and Moments

Figure 6.2-29

Figure 6.2-30
PENETRATION NODES FOR 22 AND 31 NODE REACTOR CAVITY MODELS



○ – CONTROL VOLUME NUMBER

– STEEL

– INSULATION

M/E – MASS/ENERGY RELEASES

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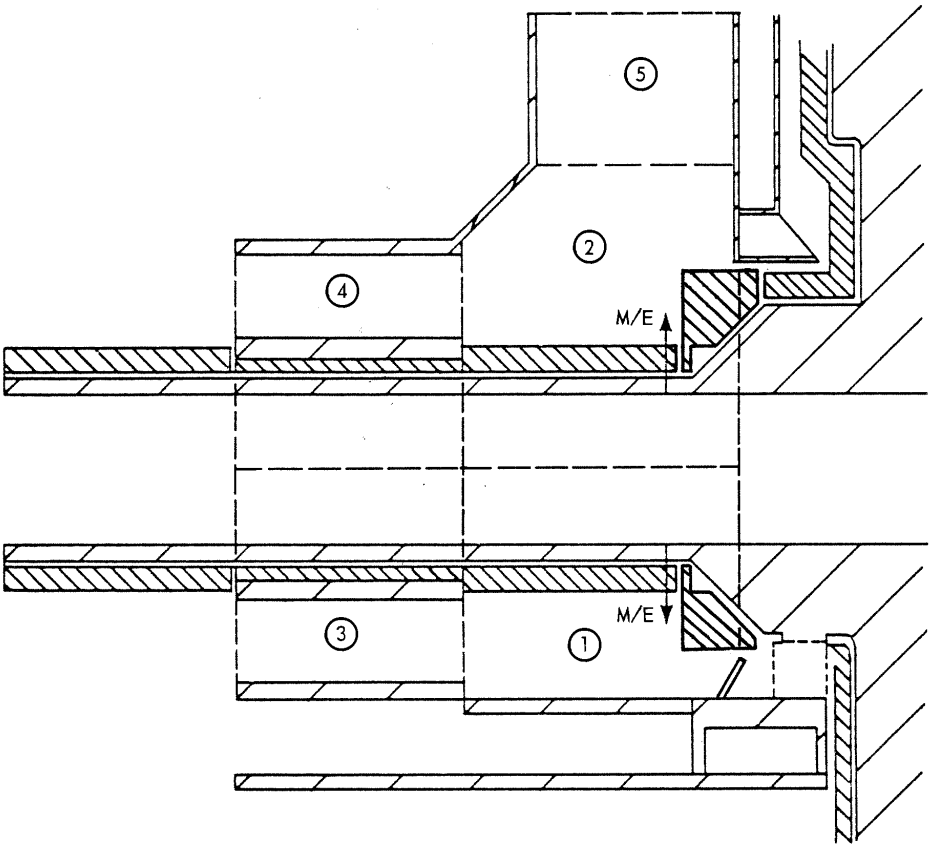
Penetration Nodes for 22 and 31 Node Reactor Cavity Models

Figure 6.2-30

Figure 6.2-30a

PENETRATION NODES FOR 33 NODE REACTOR CAVITY MODEL



○ – CONTROL VOLUME NUMBER

– STEEL

– INSULATION

M/E – MASS/ENERGY RELEASES

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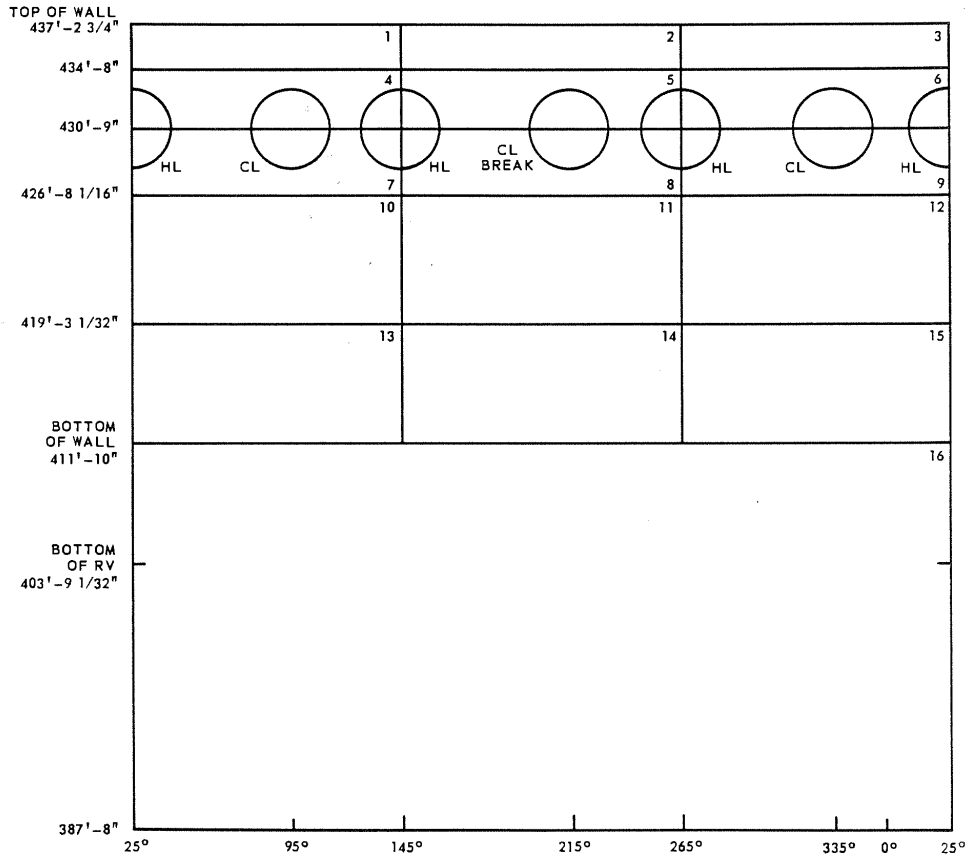
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Penetration Nodes for 33 Node Reactor Cavity Modell
Figure 6.2-30a

Figure 6.2-31
REACTOR VESSEL ANNULUS NODES FOR 22 NODE REACTOR CAVITY MODEL



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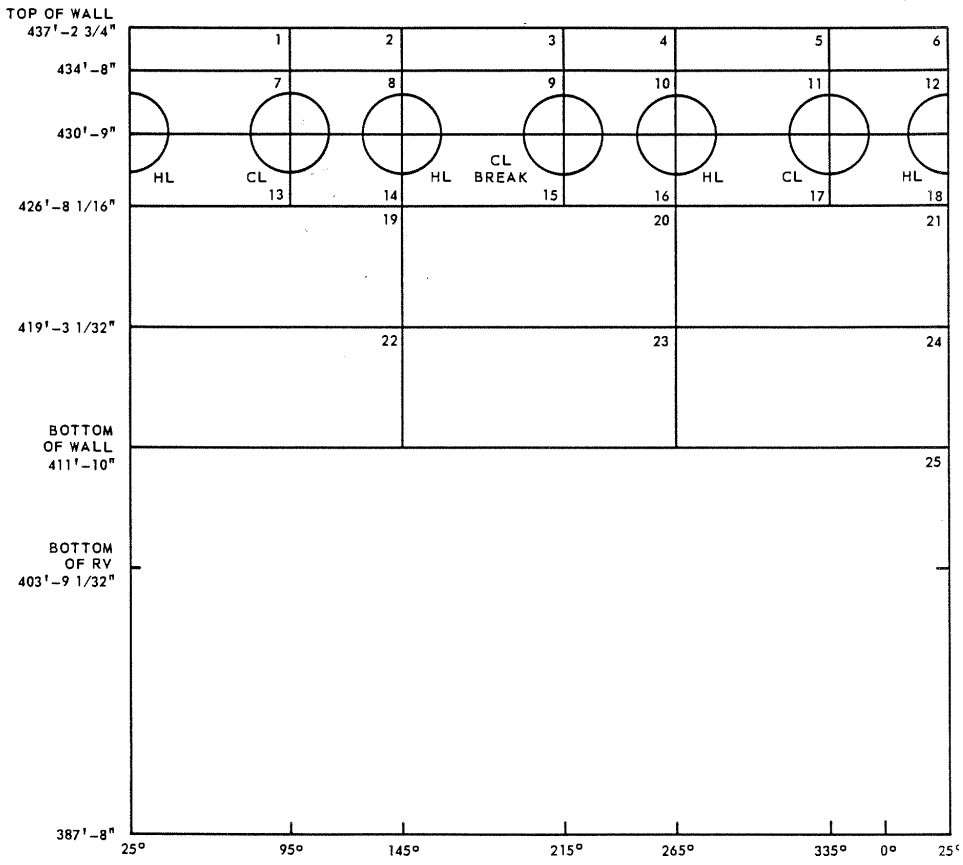
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Vessel Annulus Nodes for 22 Node Reactor Cavity Model
Figure 6.2-31

Figure 6.2-31a

REACTOR VESSEL ANNULUS NODES FOR 31 AND 33 NODE REACTOR CAVITY MODEL



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Reactor Vessel Annulus Nodes for 31 and 33 Node Reactor Cavity Model

Figure 6.2-31a

Figure 6.2-32
22 NODE REACTOR CAVITY MODEL

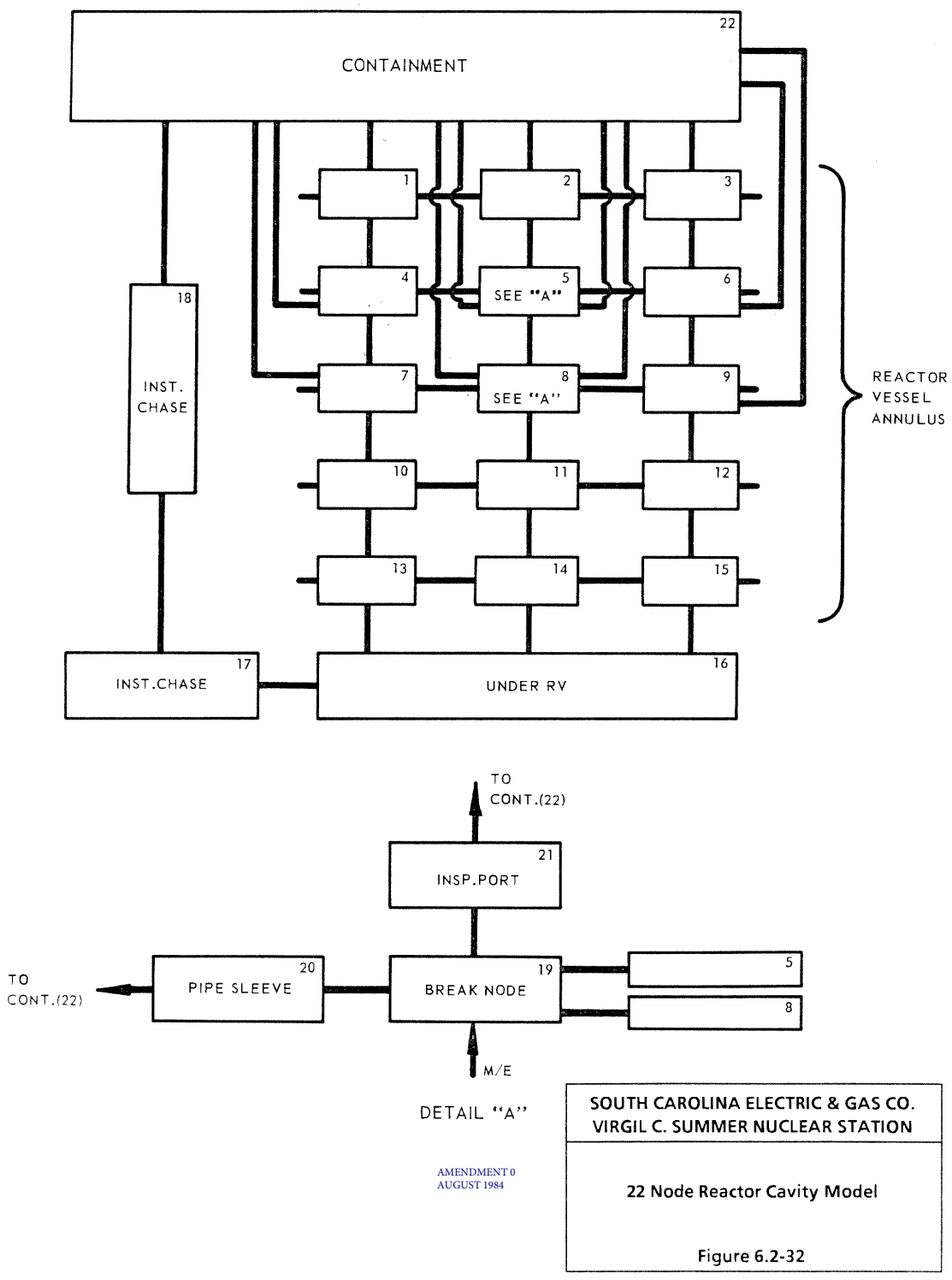
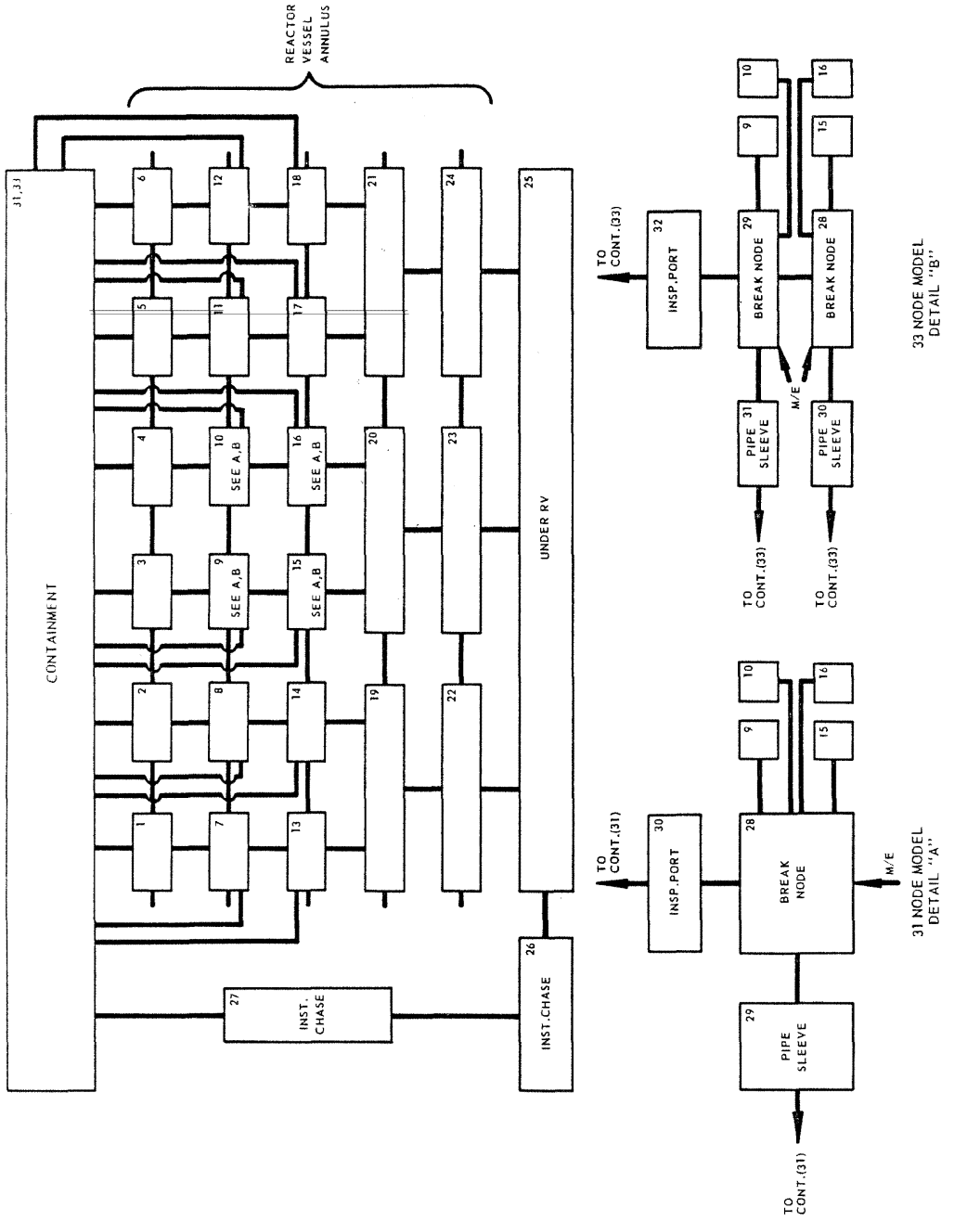


Figure 6.2-32a
31 AND 32 NODE REACTOR CAVITY MODEL



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31 and 32 Node Reactor Cavity Model
Figure 6.2-32a

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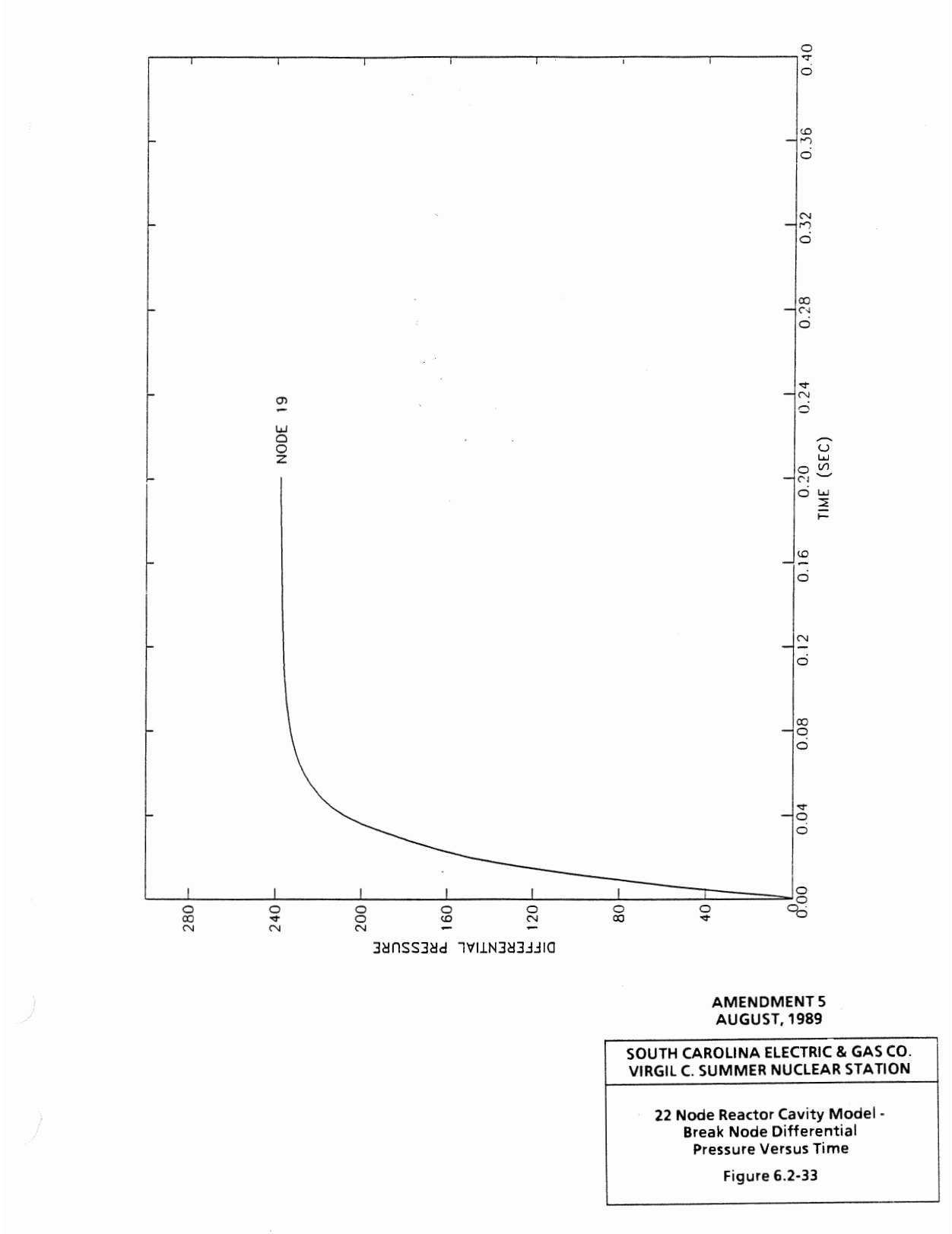
Figure 6.2-33

22 NODE REACTOR CAVITY MODEL - BREAK NODE DIFFERENTIAL PRESSURE VERSUS TIME



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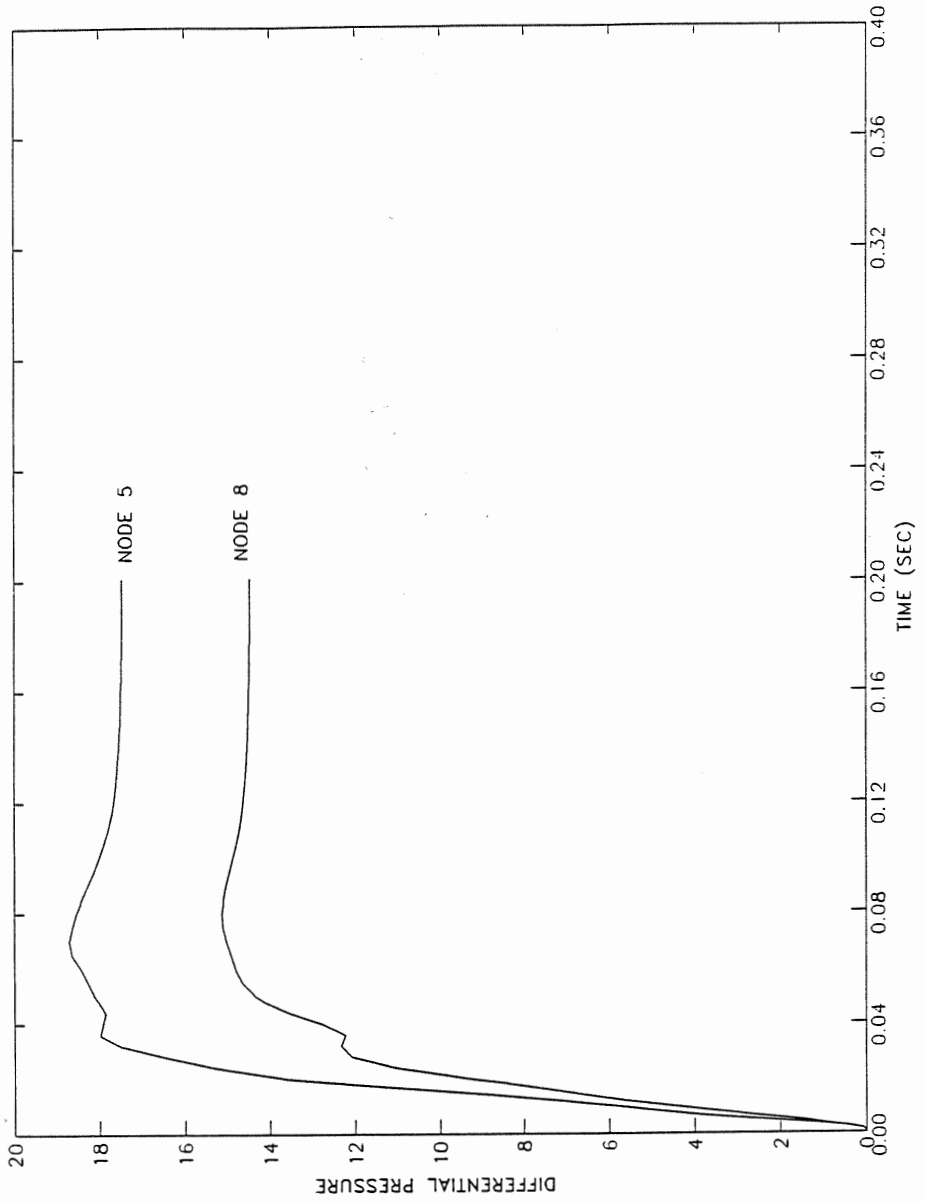
22 Node Reactor Cavity Model -
Break Node Differential
Pressure Versus Time

Figure 6.2-33

Figure 6.2-33a

22 NODE REACTOR CAVITY MODEL - DIFFERENTIAL PRESSURE AT SELECTED NODES VERSUS TIME



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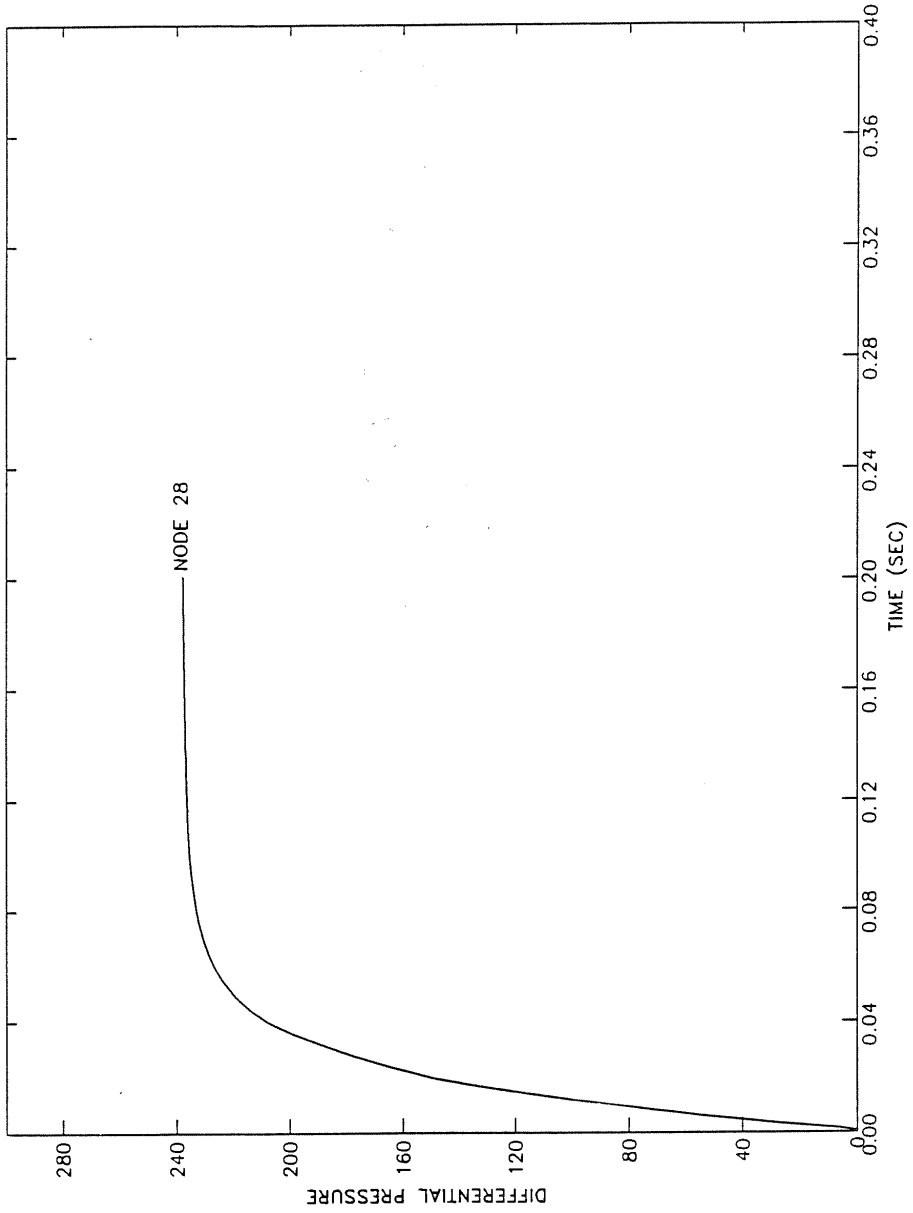
22 Node Reactor Cavity Model - Differential Pressure at Selected Nodes Versus Time

Figure 6.2-33a

Figure 6.2-33b

31 NODE REACTOR CAVITY MODEL - BREAK NODE DIFFERENTIAL PRESSURE VERSUS TIME



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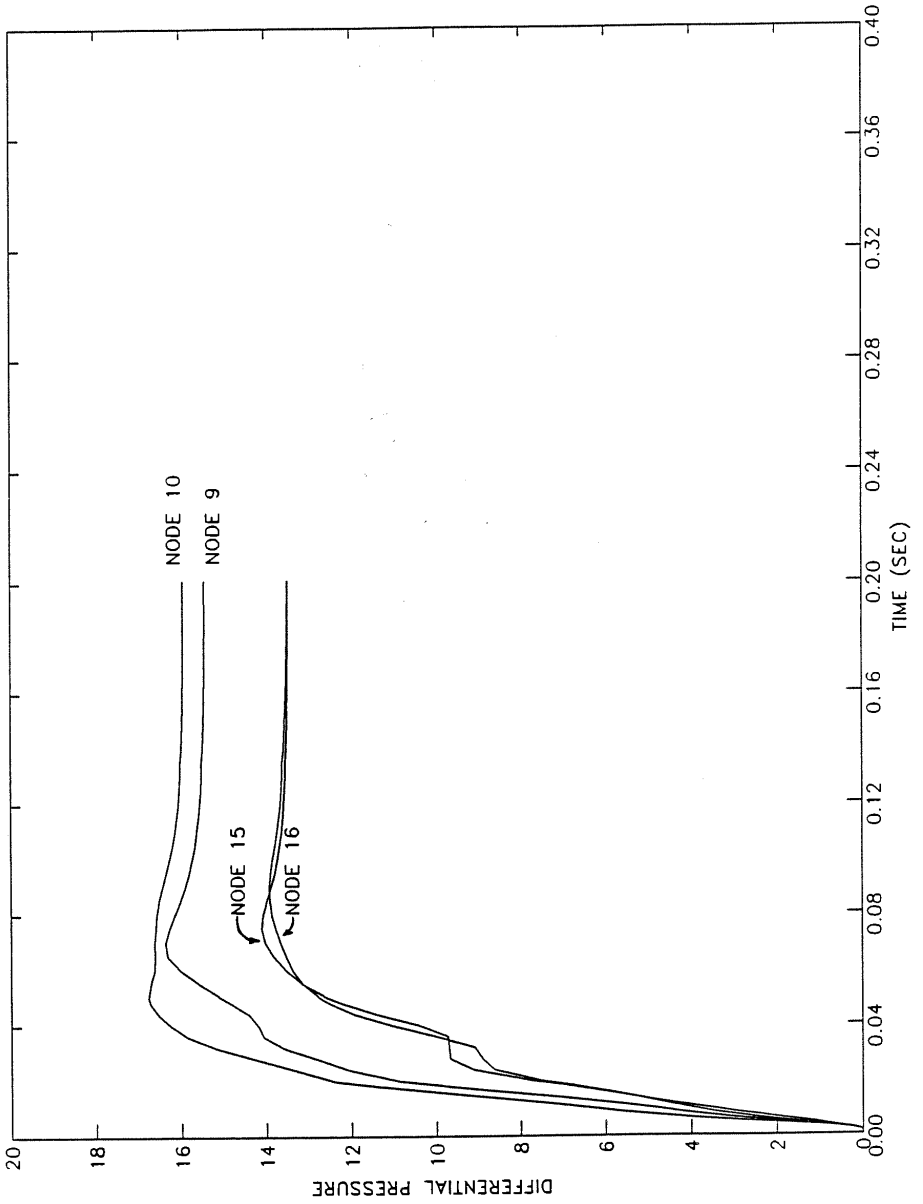
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
31 Node Reactor Cavity Model - Break Node Differential Pressure Versus Time Figure 6.2-33b

Figure 6.2-33c

31 NODE REACTOR CAVITY MODEL - DIFFERENTIAL PRESSURE AT SELECTED NODES VERSUS TIME



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SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
31 Node Reactor Cavity Model - Differential Pressure at Selected Nodes Versus Time Figure 6.2-33c

Figure 6.2-33d

33 NODE REACTOR CAVITY MODEL - BREAK NODE DIFFERENTIAL PRESSURE VERSUS TIME

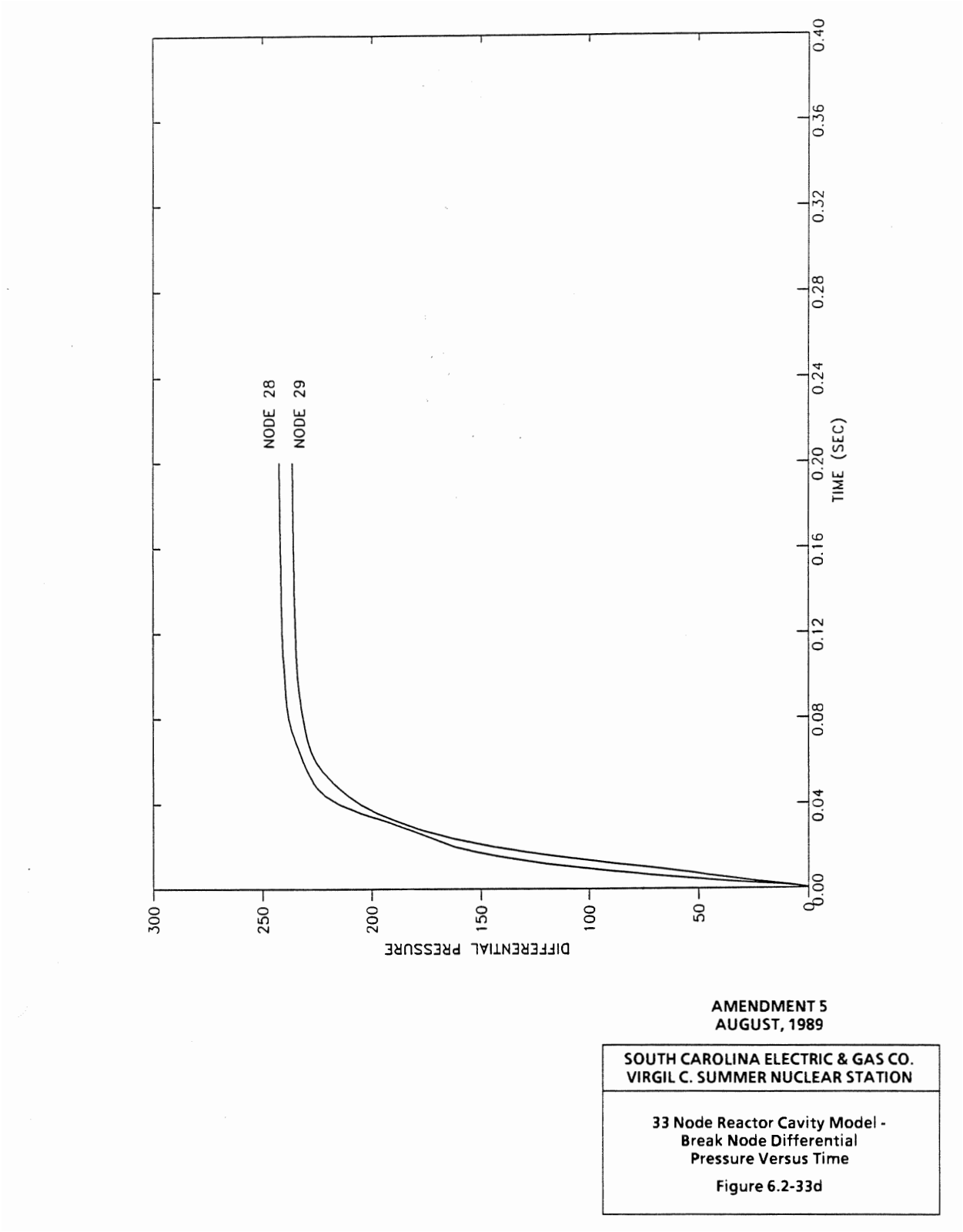
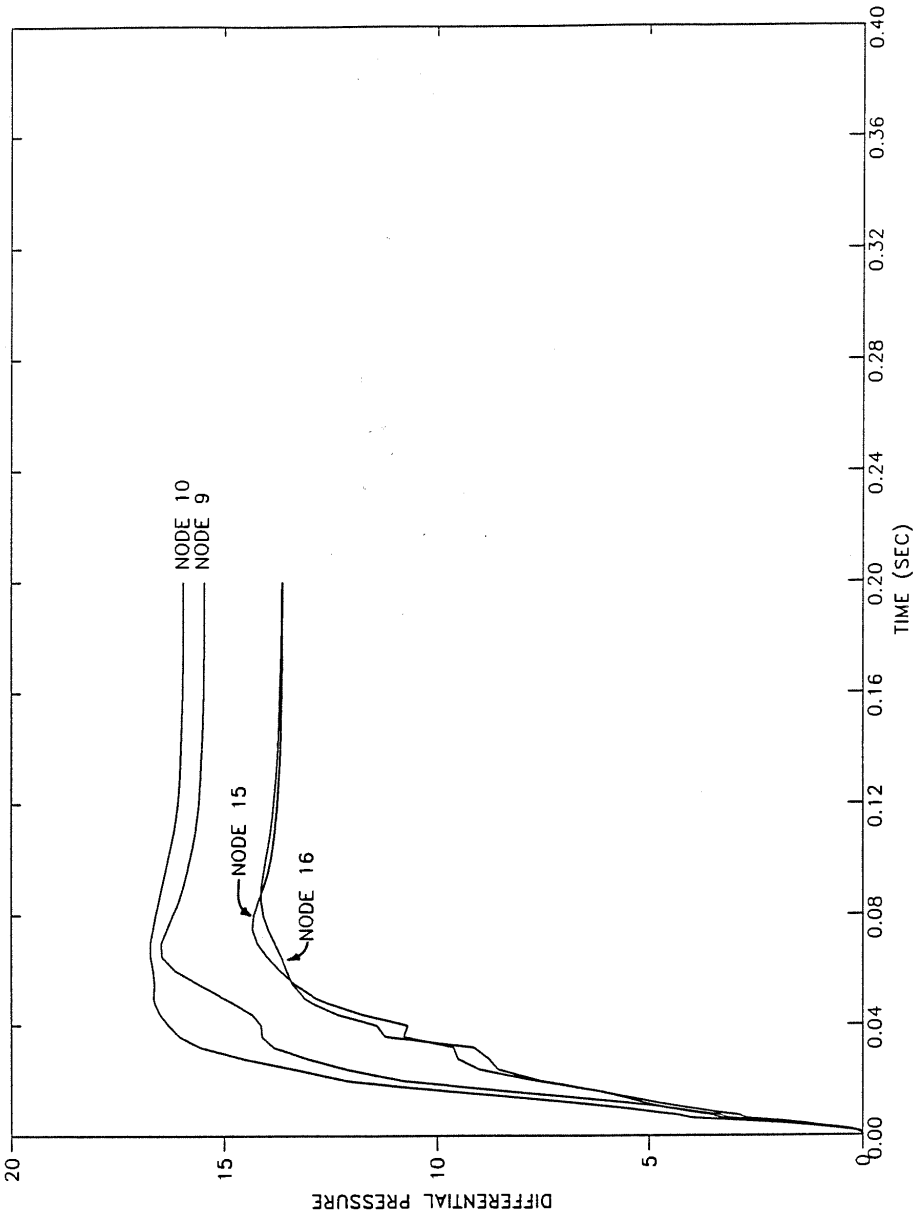


Figure 6.2-33e

33 NODE REACTOR CAVITY MODEL - DIFFERENTIAL PRESSURE AT SELECTED NODES VERSUS TIME



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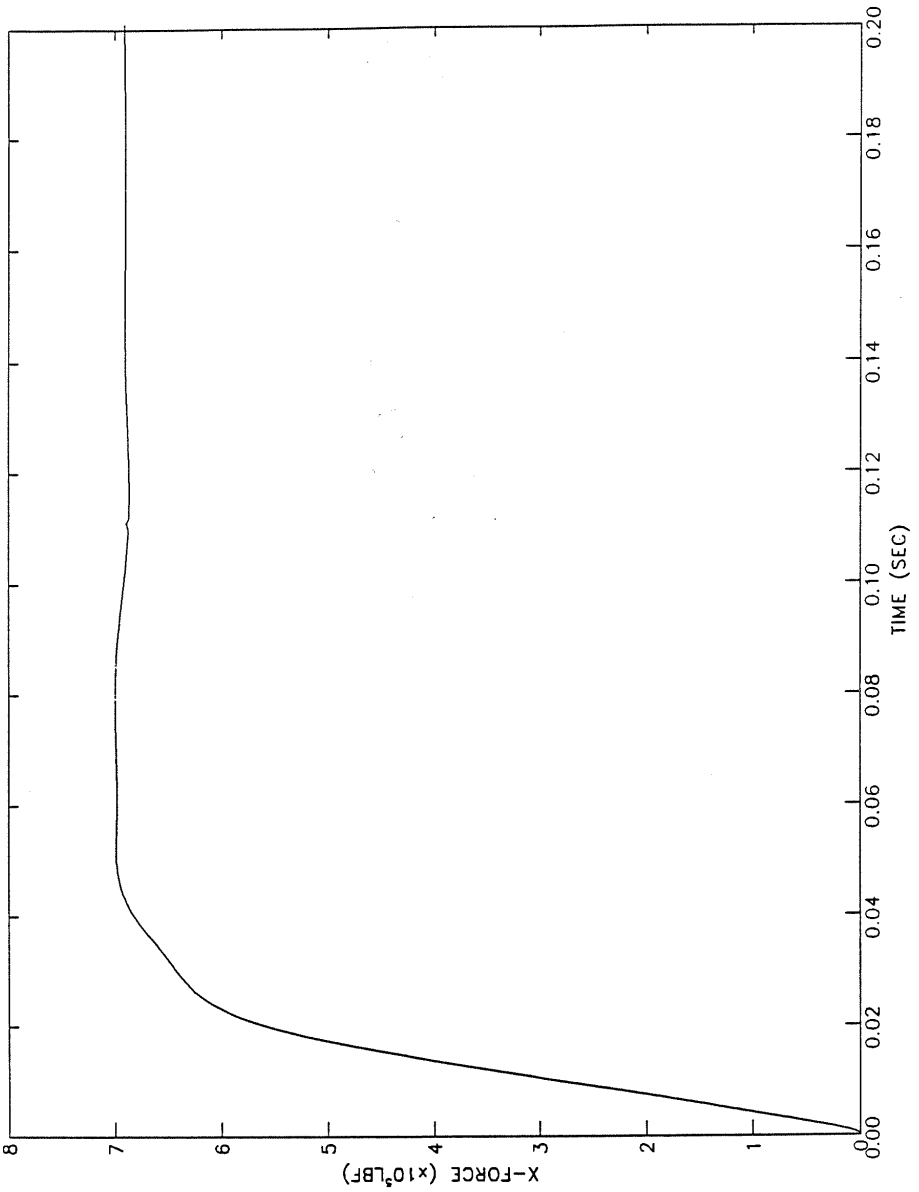
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
33 Node Reactor Cavity Model - Differential Pressure at Selected Nodes Versus Time Figure 6.2-33e

Figure 6.2-34
33 NODE REACTOR CAVITY MODEL - FORCE IN THE X DIRECTION



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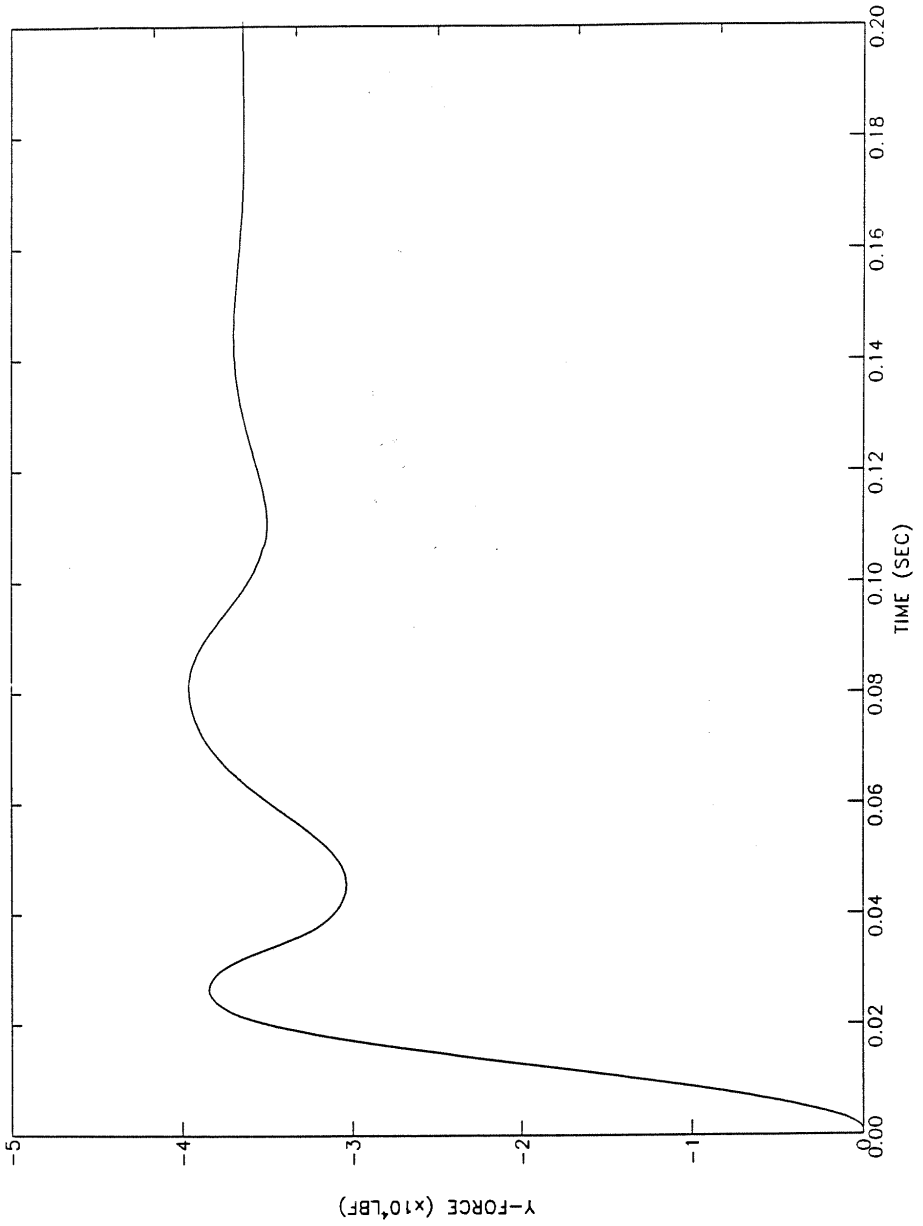
33 Node Reactor Cavity Model - Force in the X Direction Figure 6.2-34

Figure 6.2-34a

33 NODE REACTOR CAVITY MODEL - FORCE IN THE Y DIRECTION



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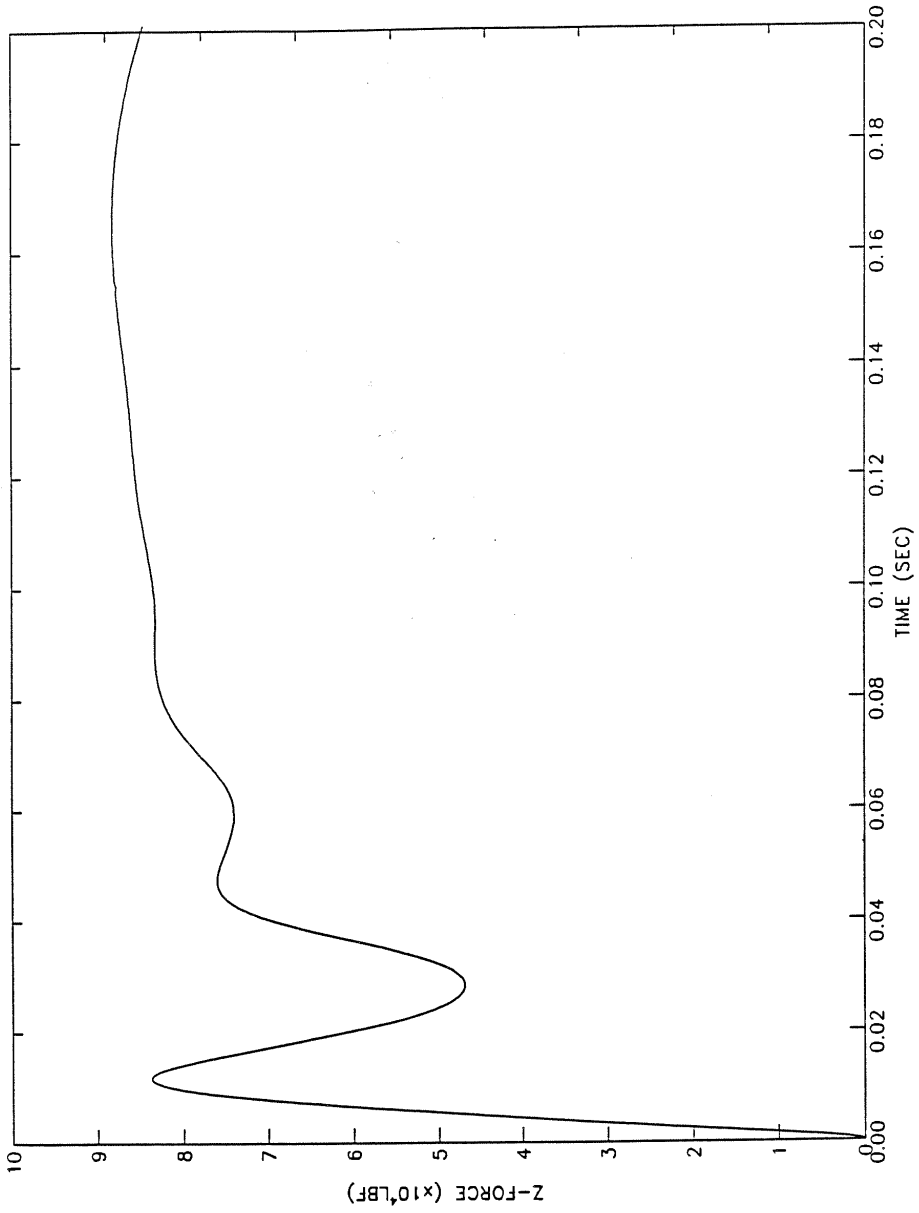
VIRGIL C. SUMMER NUCLEAR STATION

33 Node Reactor Cavity Model -
Force in the Y Direction

Figure 6.2-34a

Figure 6.2-34b

33 NODE REACTOR CAVITY MODEL - FORCE IN THE Z DIRECTION



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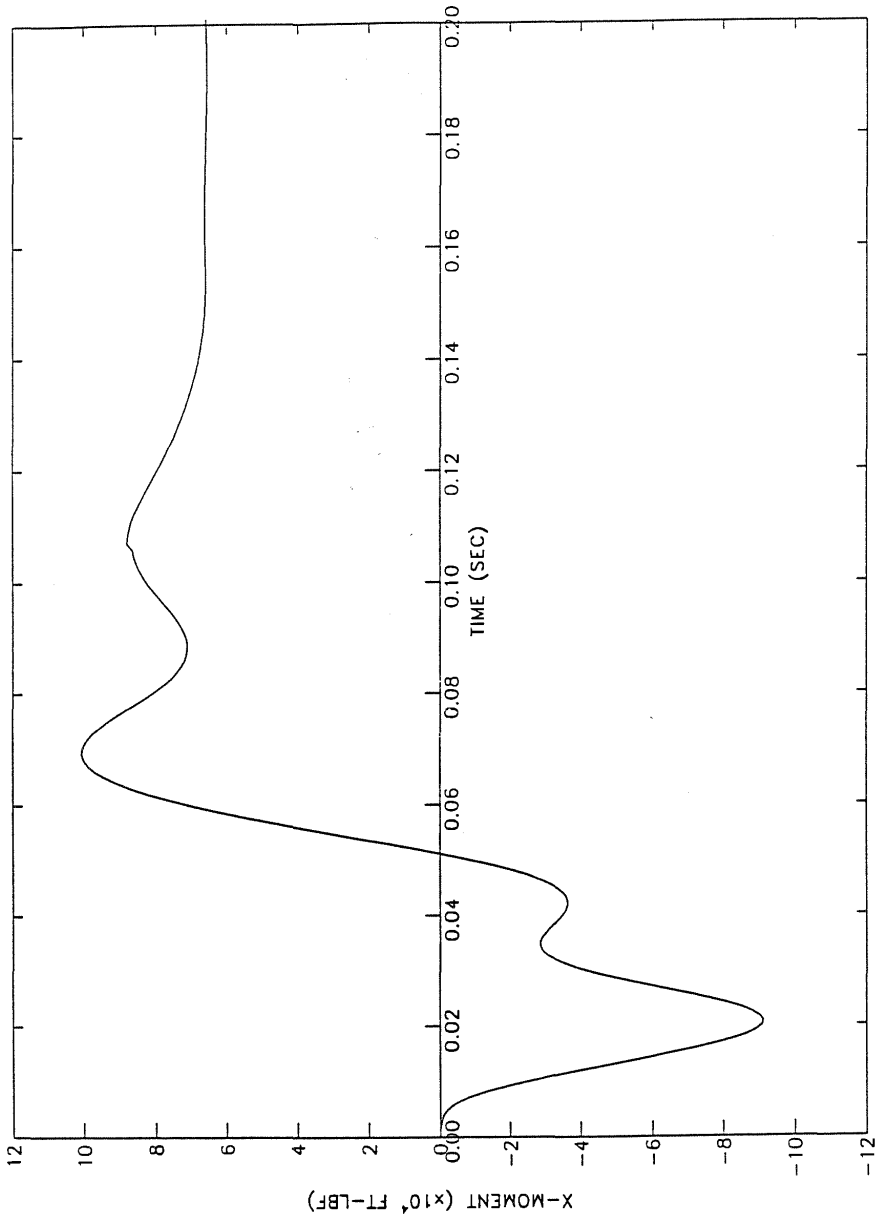
33 Node Reactor Cavity Model - Force in the Z Direction Figure 6.2-34b

Figure 6.2-35
33 NODE REACTOR CAVITY MODEL - MOMENT ABOUT THE X AXIS



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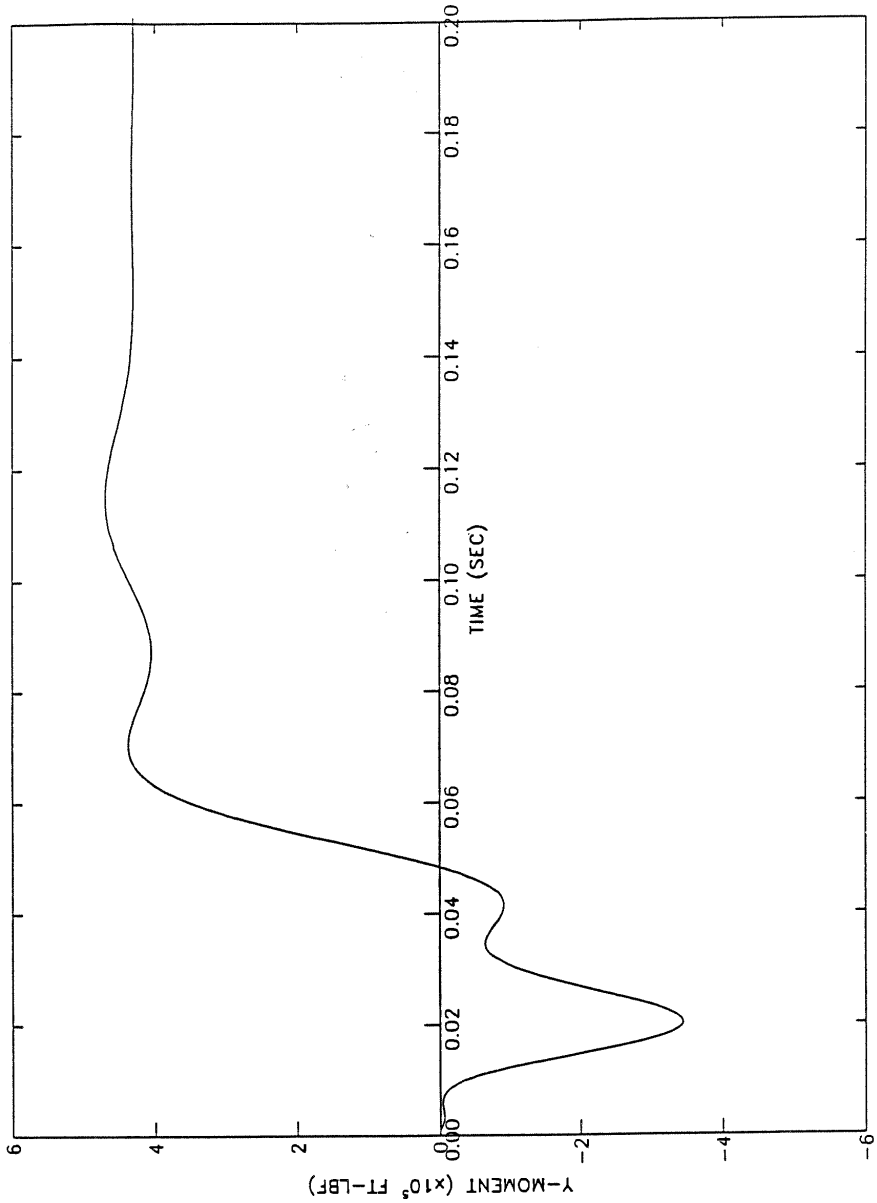
33 Node Reactor Cavity Model - Moment About the X Axis Figure 6.2-35

Figure 6.2-35a

33 NODE REACTOR CAVITY MODEL - MOMENT ABOUT THE Y AXIS



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SOUTH CAROLINA ELECTRIC & GAS CO.
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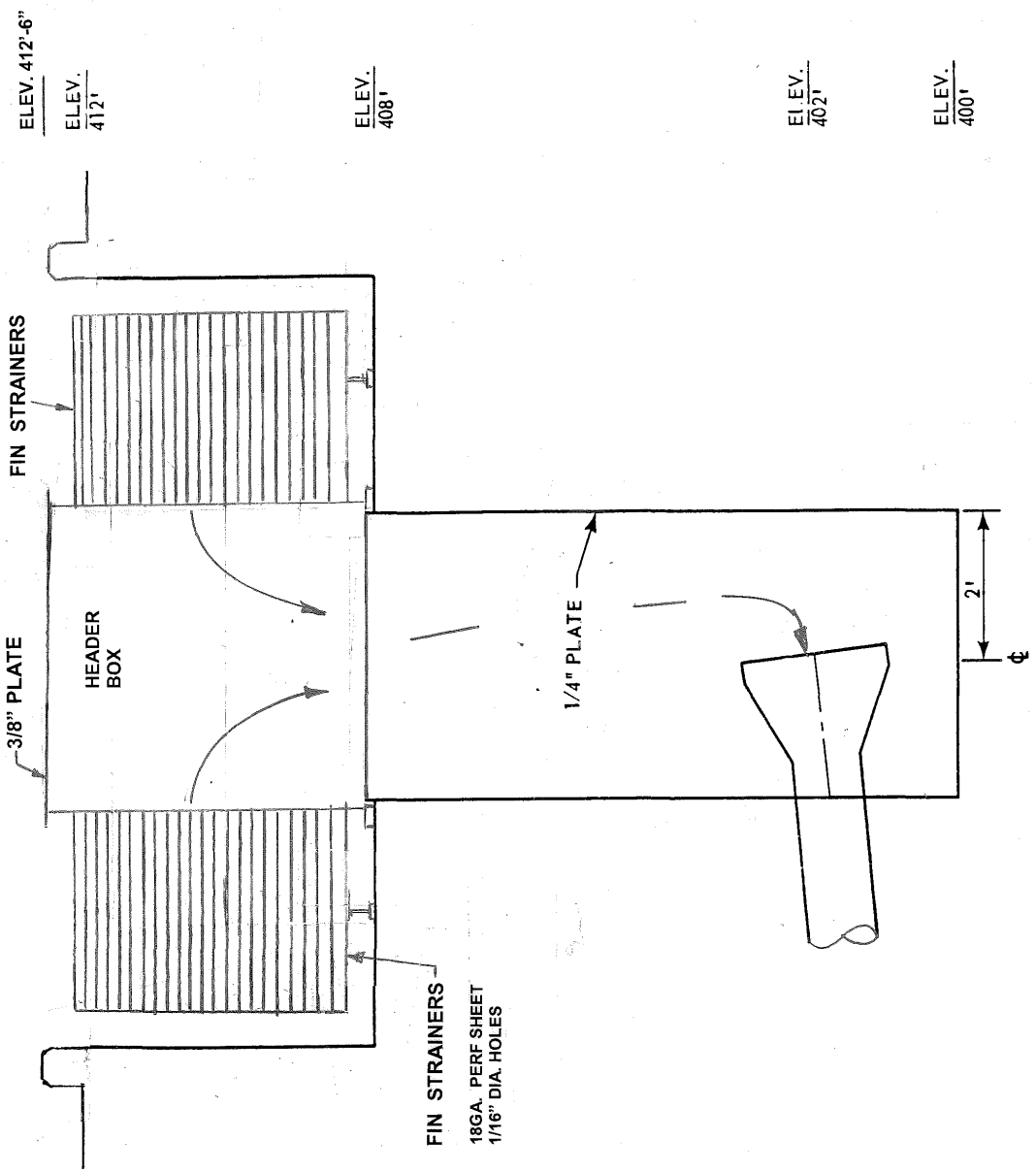
33 Node Reactor Cavity Model -
Moment About the Y Axis

Figure 6.2-35a

Figure 6.2-46
DRAWING D-302-661
FSAR FIGURE REFERENCE

Figure 6.2-47
DRAWING E-304-663
FSAR FIGURE REFERENCE

Figure 6.2-48
SECTION THROUGH TYPICAL SUMP



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Section Through Typical Sump Figure 6.2-48

Figure 6.2-49
DRAWING D-912-102
FSAR FIGURE REFERENCE

Figure 6.2-50, Sheet 1
DRAWING E-922-101
FSAR FIGURE REFERENCE

Figure 6.2-50, Sheet 2
DRAWING E-922-102
FSAR FIGURE REFERENCE

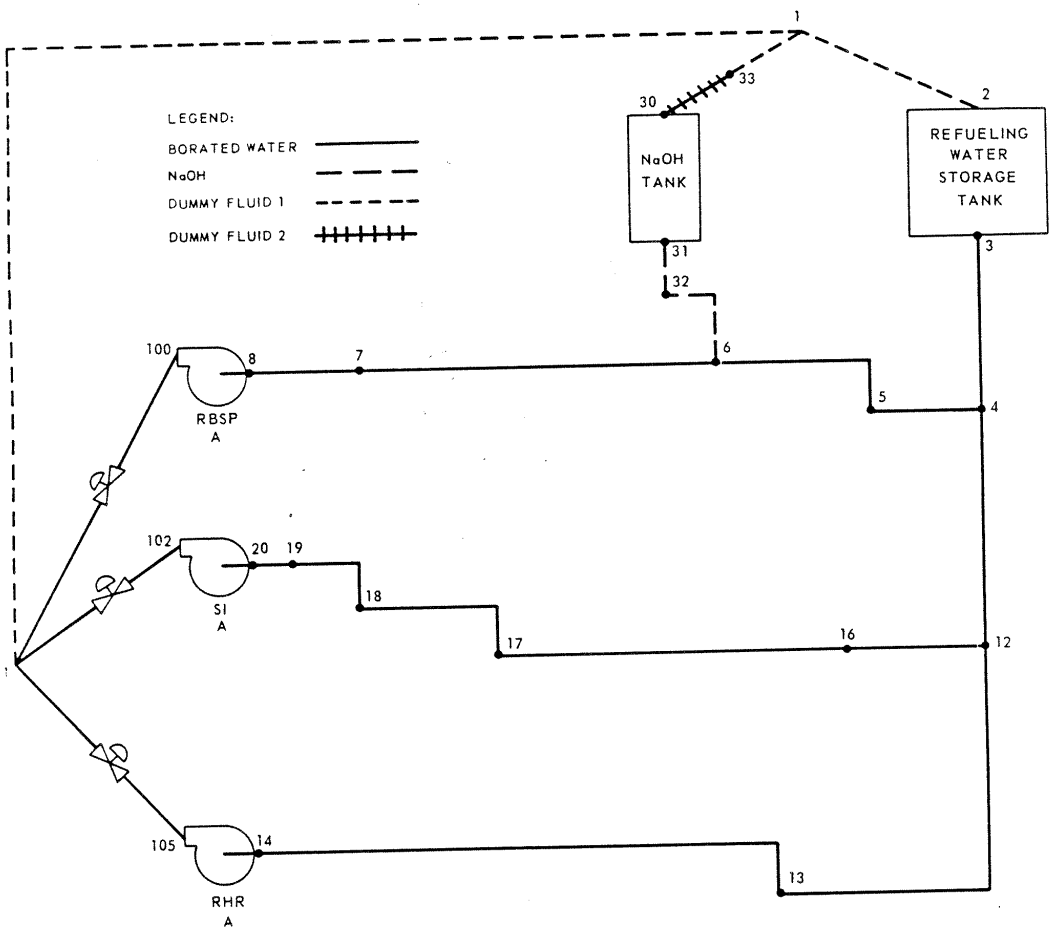
Figure 6.2-50, Sheet 3
DRAWING E-922-103
FSAR FIGURE REFERENCE

Figure 6.2-50, Sheet 4
DRAWING E-922-104
FSAR FIGURE REFERENCE

Figure 6.2-51
DRAWING E-922-105
FSAR FIGURE REFERENCE

Figure 6.2-51a

MODEL OF ECCS AND REACTOR BUILDING SPRAY SYSTEM FOR REACTOR BUILDING SPRAY SYSTEM DESIGN CASE



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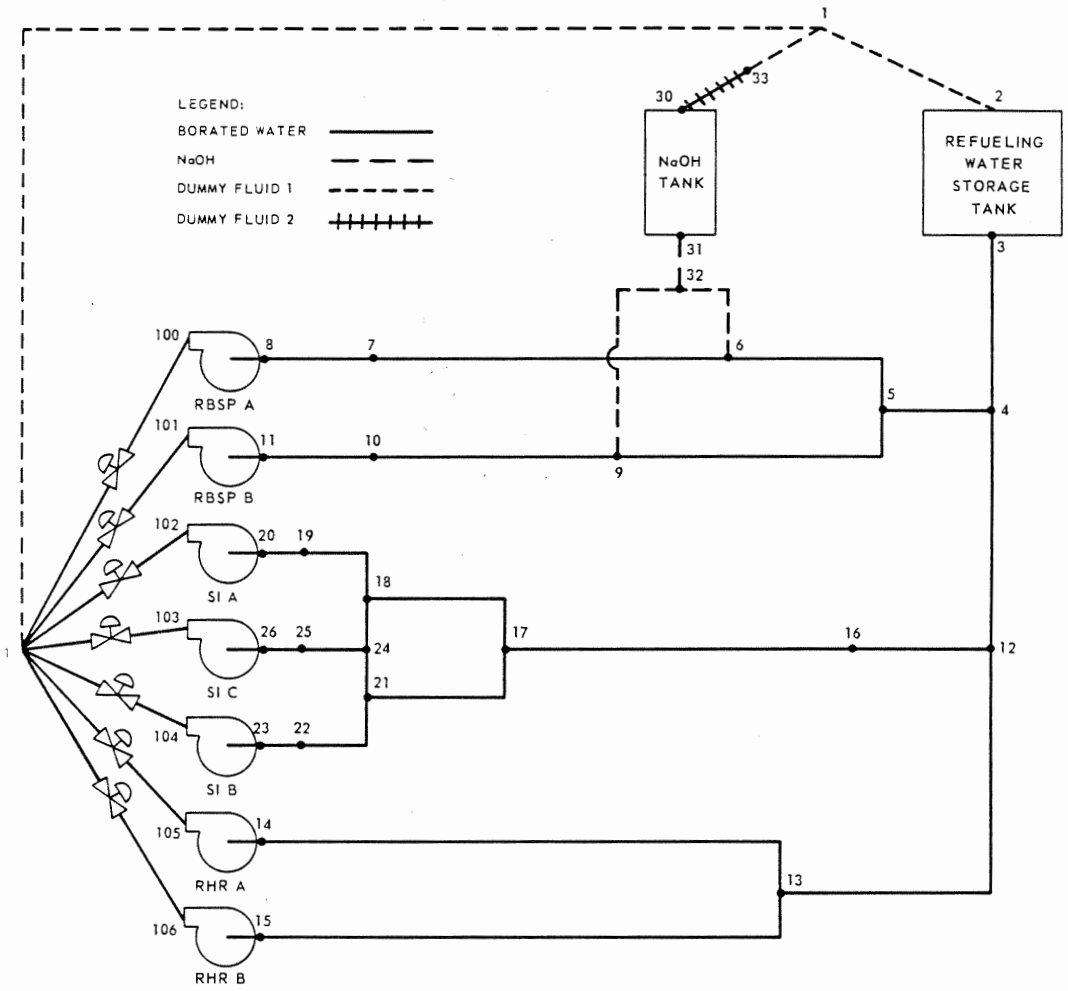
VIRGIL C. SUMMER NUCLEAR STATION

Model of ECCS and Reactor Building Spray System for Reactor Building Spray System Design Case

Figure 6.2-51a

Figure 6.2-51b
MODEL OF ECCS AND REACTOR BUILDING SPRAY SYSTEM FOR NORMAL CASE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Model of ECCS and Reactor Building Spray System for Normal Case Figure 6.2-51b

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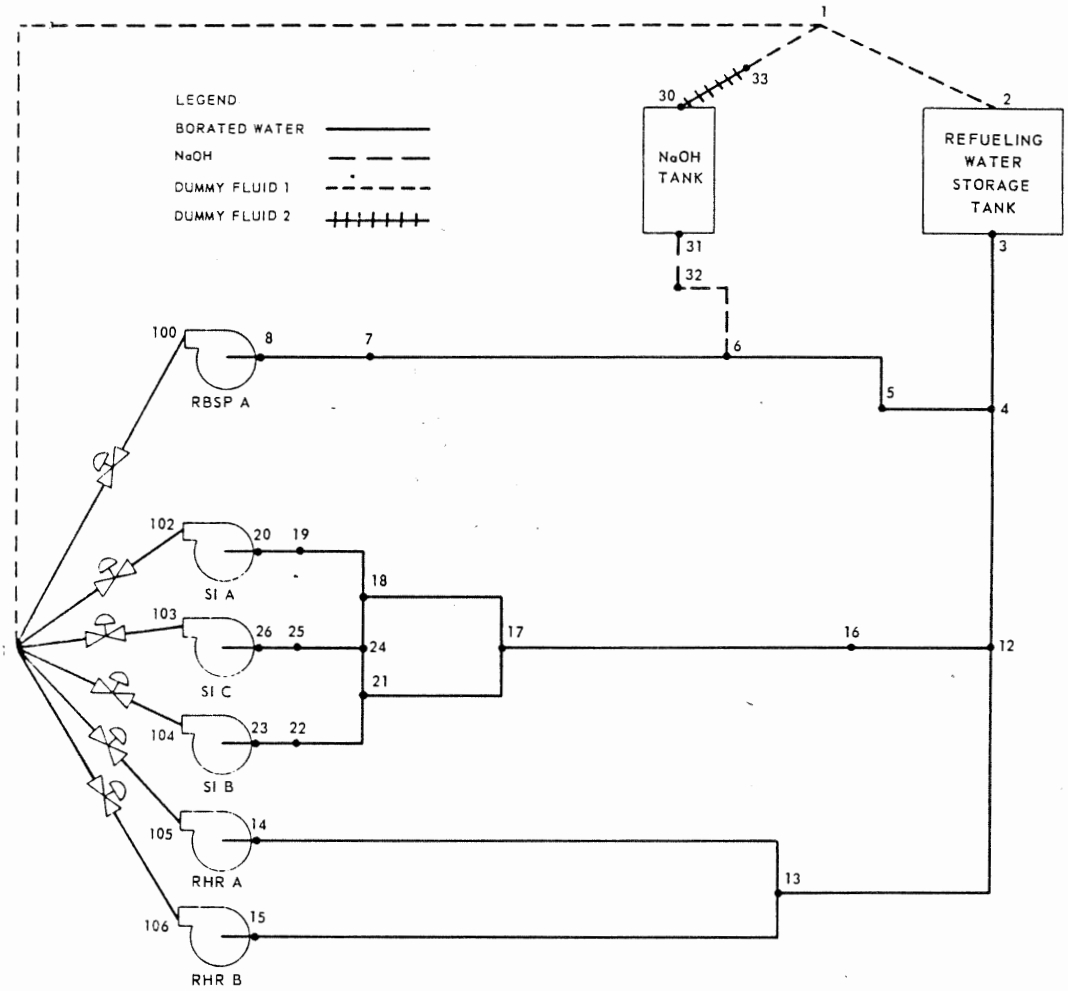
Figure 6.2-51c

MODEL OF ECCS AND REACTOR BUILDING SPRAY SYSTEM FOR NORMAL CASE WITH ONE REACTOR BUILDING SPRAY PUMP INOPERABLE



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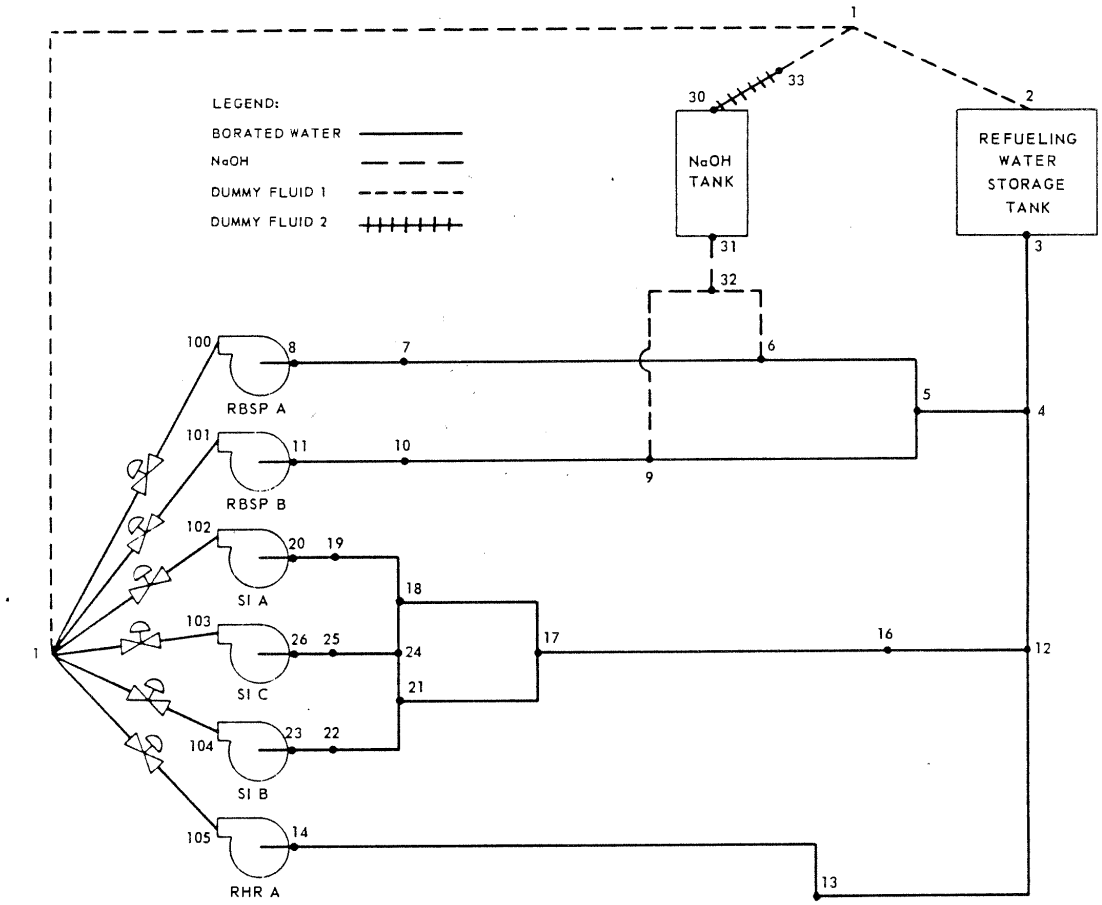
Model of ECCS and Reactor Building Spray System for Normal Case with One Reactor Building Spray Pump Inoperable

Figure 6.2-51c

Figure 6.2-51d

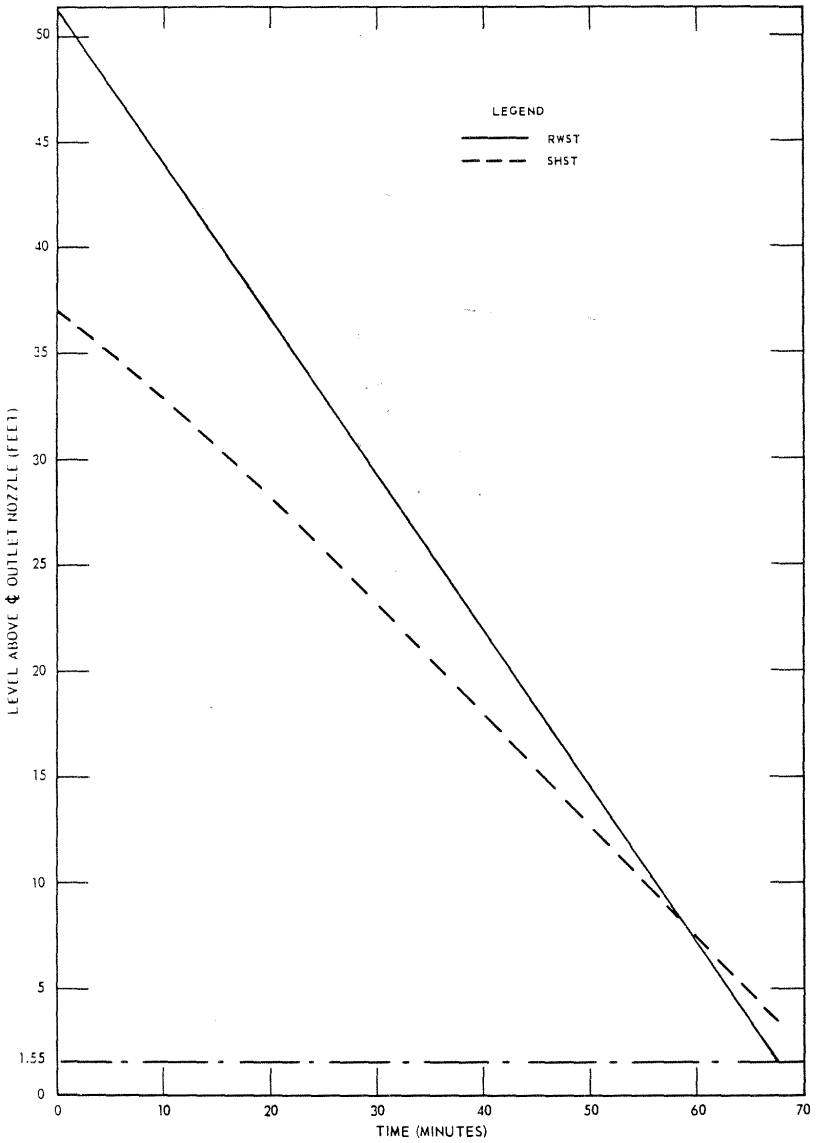
MODEL OF ECCS AND REACTOR BUILDING SPRAY SYSTEM FOR NORMAL CASE WITH ONE RESIDUAL HEAT REMOVAL PUMP INOPERABLE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Model of ECCS and Reactor Building Spray System for Normal Case with One Residual Heat Removal Pump Inoperable Figure 6.2-51d

Figure 6.2-51e

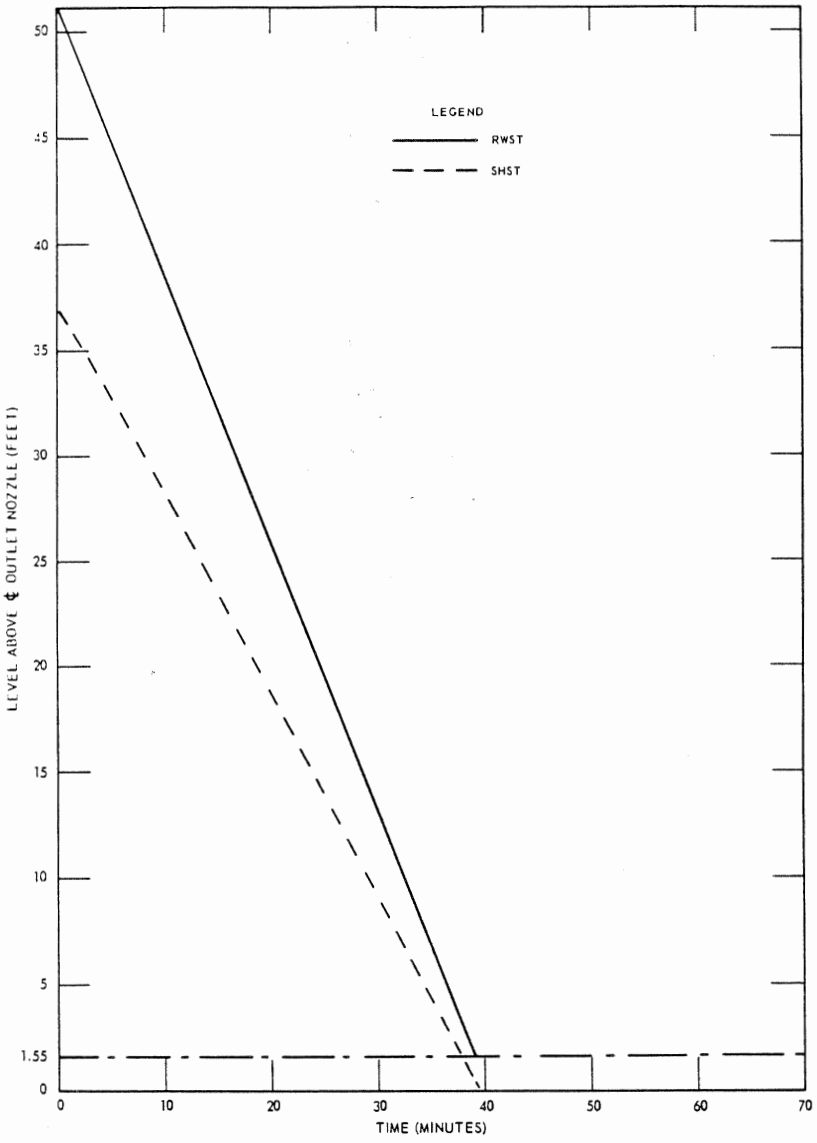
ANALYTICAL RESULTS - CHEMICAL DRAWDOWN - REACTOR BUILDING SPRAY SYSTEM DESIGN CASE - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Analytical Results - Chemical Drawdown - Reactor Building Spray System Design Case - Minimum Sodium Hydroxide Initial Conditions Figure 6.2-51e

Figure 6.2-51f

ANALYTICAL RESULTS - CHEMICAL DRAWDOWN - NORMAL CASE - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS



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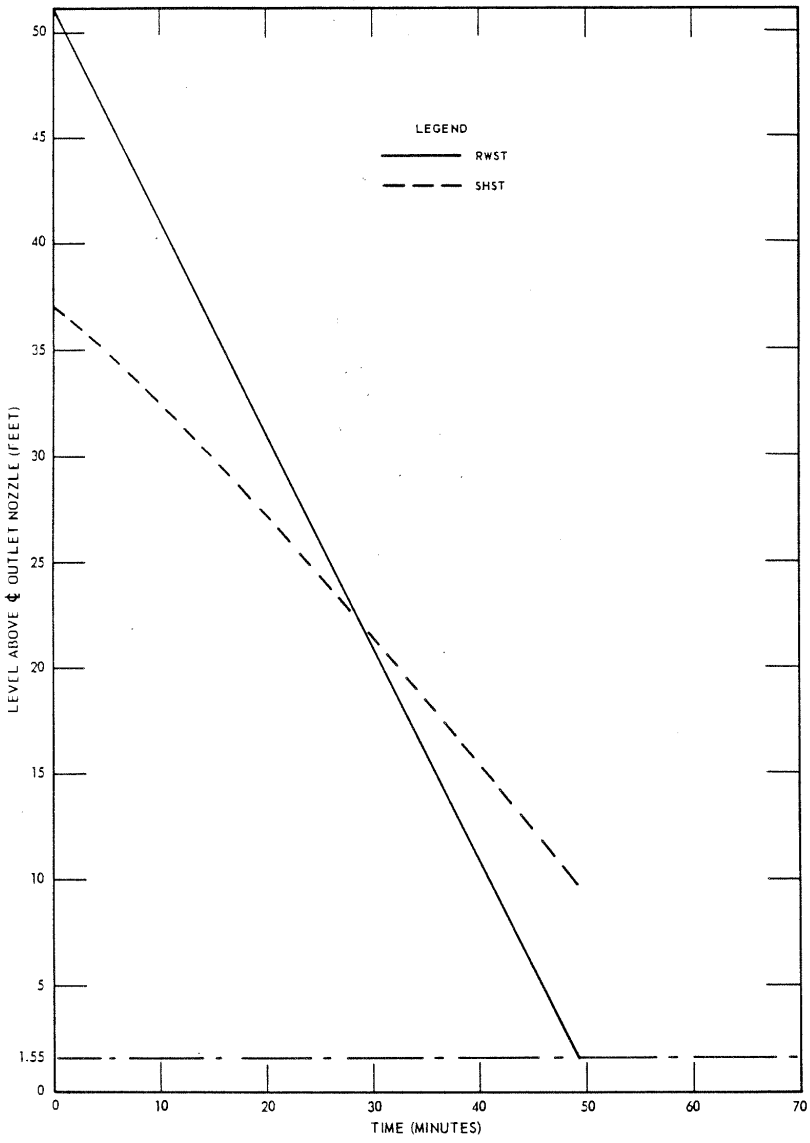
VIRGIL C. SUMMER NUCLEAR STATION

Analytical Results - Chemical Drawdown - Normal Case - Minimum Sodium Hydroxide Initial Conditions

Figure 6.2-51f

Figure 6.2-51g

ANALYTICAL RESULTS - CHEMICAL DRAWDOWN - NORMAL CASE - WITH ONE REACTOR BUILDING SPRAY PUMP INOPERABLE - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS



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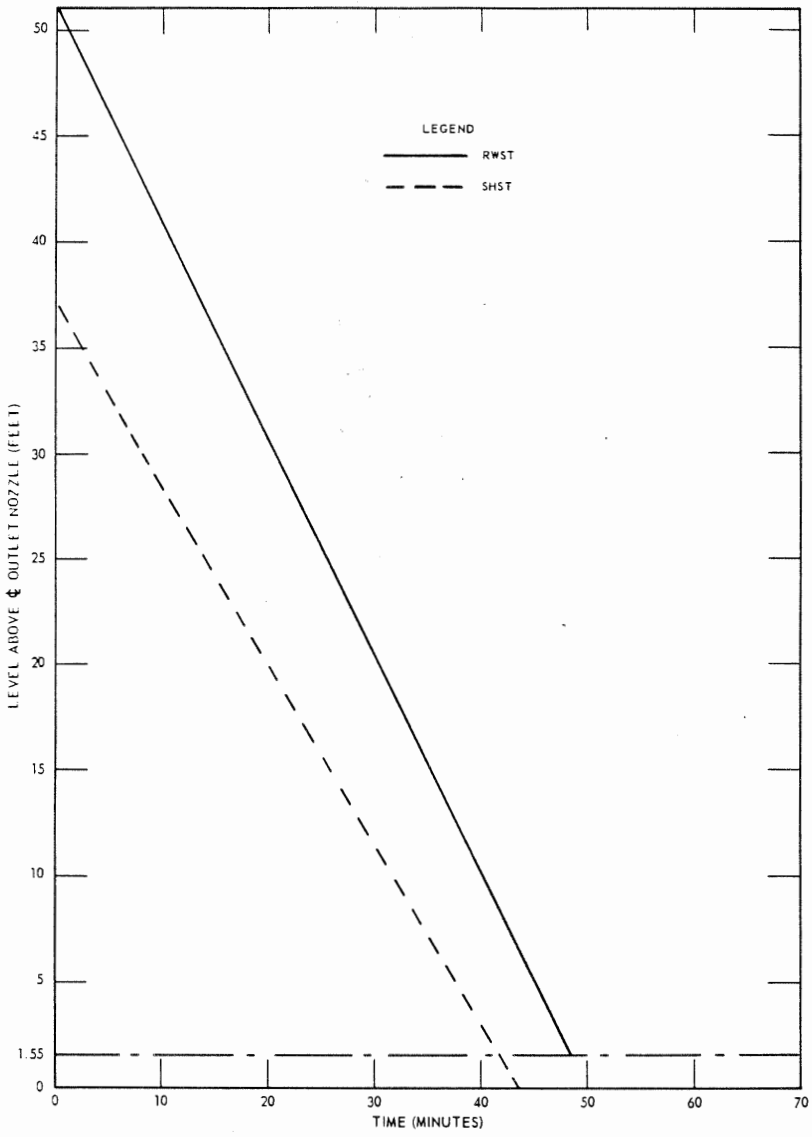
Analytical Results - Chemical Drawdown - Normal Case - With One Reactor Building Spray Pump Inoperable - Minimum Sodium Hydroxide Initial Conditions
Figure 6.2-51g

Figure 6.2-51h

ANALYTICAL RESULTS - CHEMICAL DRAWDOWN - NORMAL CASE - WITH ONE RESIDUAL HEAT REMOVAL PUMP INOPERABLE - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS



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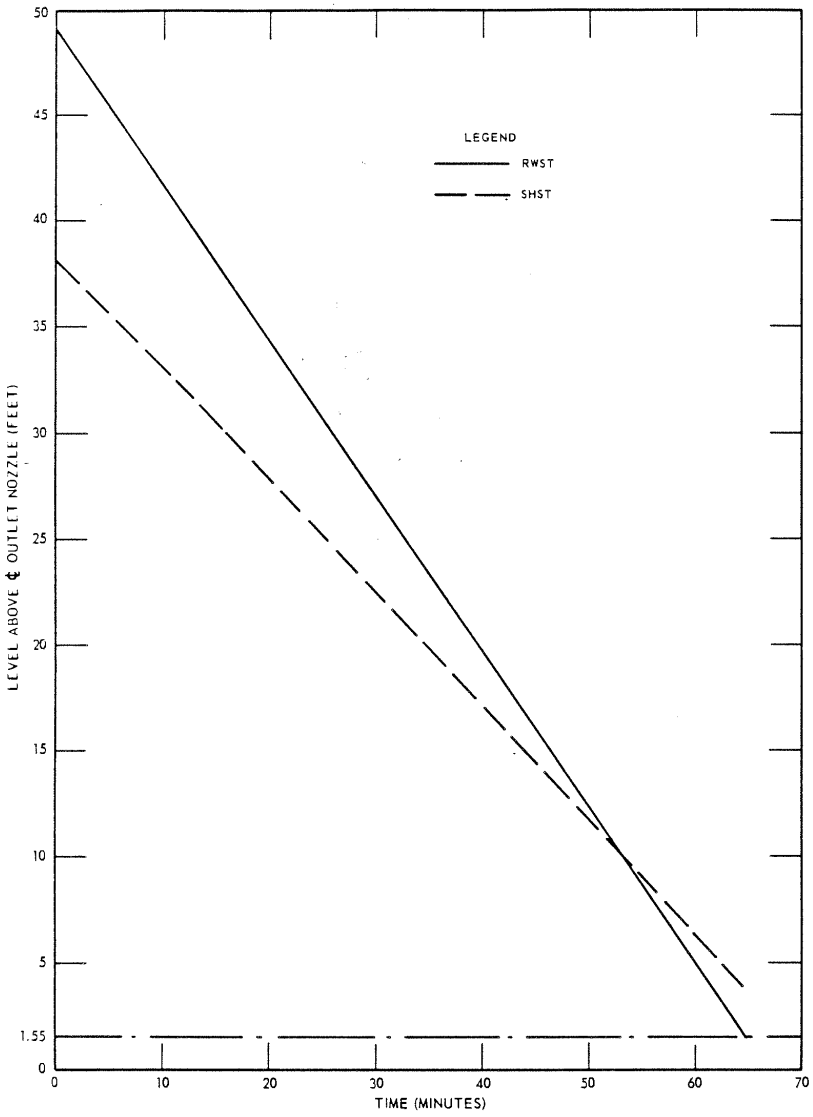
VIRGIL C. SUMMER NUCLEAR STATION

Analytical Results - Chemical Drawdown - Normal Case - With One Residual Heat Removal Pump Inoperable - Minimum Sodium Hydroxide Initial Conditions
Figure 6.2-51h

Figure 6.2-51i

ANALYTICAL RESULTS - CHEMICAL DRAWDOWN - REACTOR BUILDING SPRAY SYSTEM DESIGN CASE - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS



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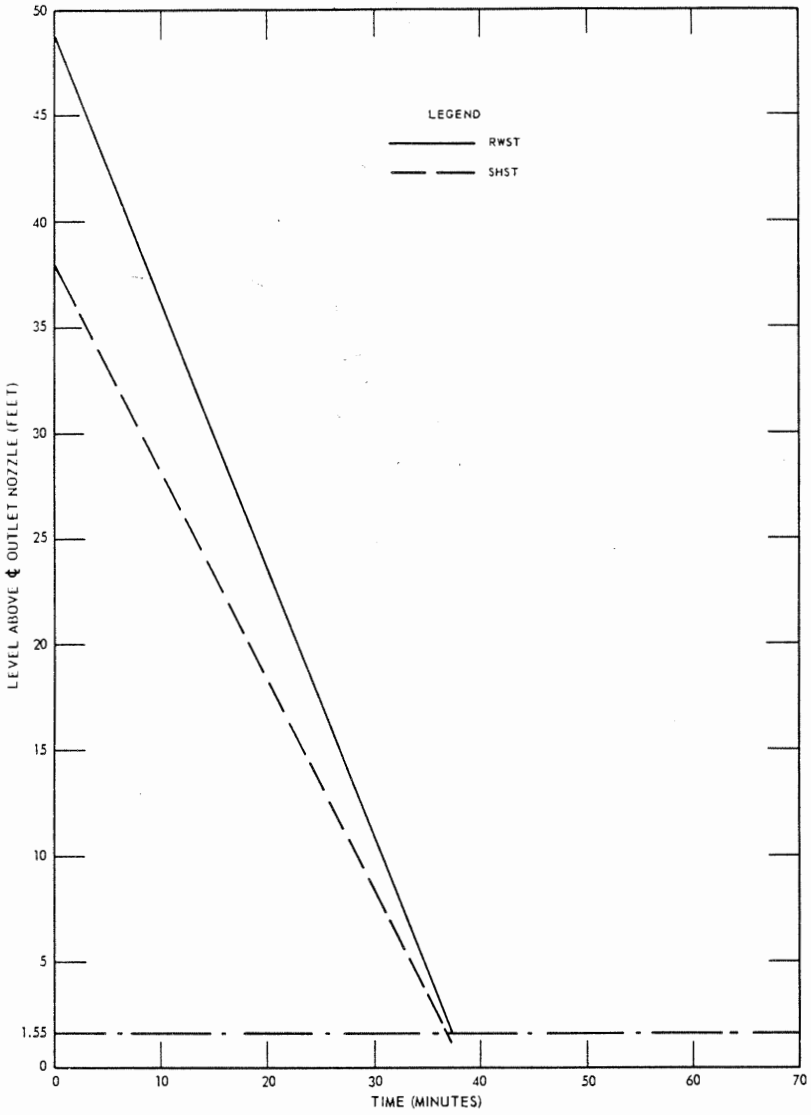
Analytical Results - Chemical Drawdown - Reactor Building Spray System Design Case - Maximum Sodium Hydroxide Initial Conditions Figure 6.2-51i

Figure 6.2-51j

ANALYTICAL RESULTS - CHEMICAL DRAWDOWN - NORMAL CASE - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS



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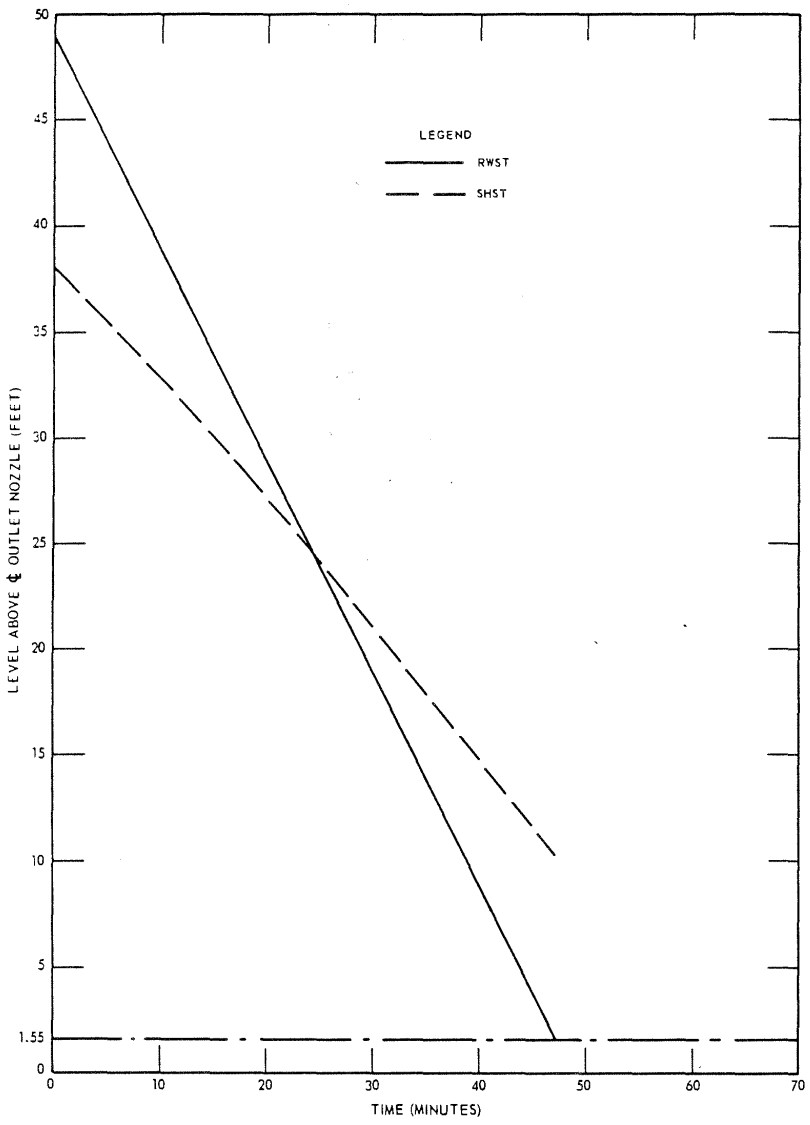
Analytical Results - Chemical Drawdown - Normal Case - Maximum Sodium Hydroxide Initial Conditions

Figure 6.2-51j

Figure 6.2-51k

ANALYTICAL RESULTS - CHEMICAL DRAWDOWN - NORMAL CASE WITH ONE REACTOR BUILDING SPRAY PUMP INOPERABLE - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS



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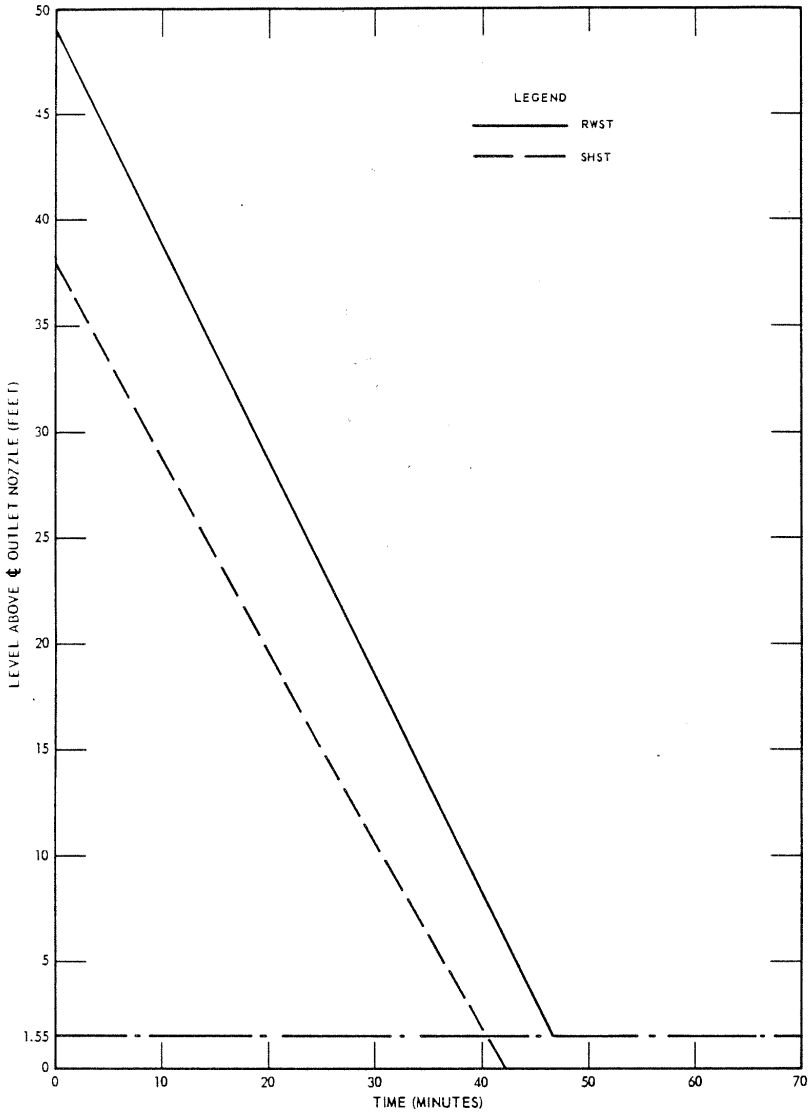
Analytical Results - Chemical Drawdown - Normal Case With One Reactor Building Spray Pump Inoperable - Maximum Sodium Hydroxide Initial Conditions Figure 6.2-51k

Figure 6.2-511

ANALYTICAL RESULTS - CHEMICAL DRAWDOWN - NORMAL CASE WITH ONE RESIDUAL HEAT REMOVAL PUMP INOPERABLE - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS



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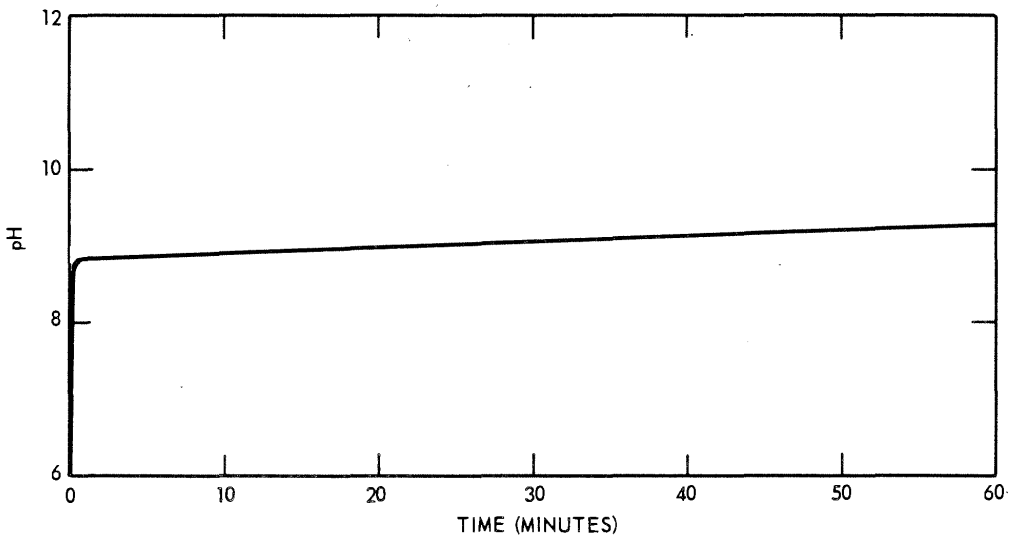
Analytical Results - Chemical Drawdown - Normal Case With One Residual Heat Removal Pump Inoperable - Maximum Sodium Hydroxide Initial Conditions
Figure 6.2-511

Figure 6.2-51m

SPRAY HEADER PH DURING INITIAL INJECTION - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - REACTOR BUILDING SPRAY SYSTEM DESIGN CASE



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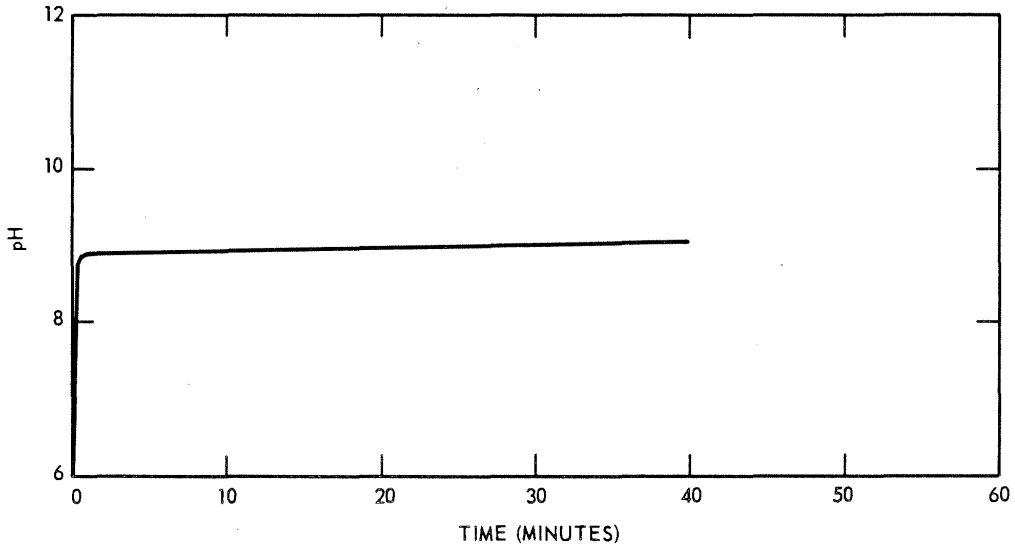
VIRGIL C. SUMMER NUCLEAR STATION

Spray Header pH During Initial Injection - Minimum Sodium Hydroxide Initial Conditions - Reactor Building Spray System Design Case
Figure 6.2-51m

Figure 6.2-51n

SPRAY HEADER PH DURING INITIAL INJECTION - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE



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Spray Header pH During Initial Injection - Minimum Sodium Hydroxide Initial Conditions - Normal Case Figure 6.2-51n

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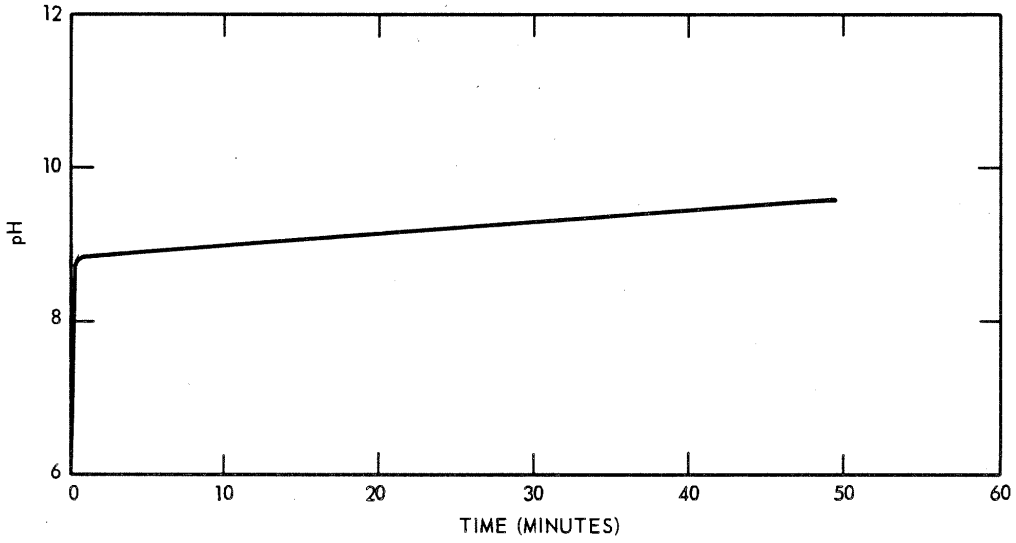
Figure 6.2-51o

SPRAY HEADER PH DURING INITIAL INJECTION - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE WITH ONE SPRAY PUMP INOPERABLE



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Spray Header pH During Initial Injection - Minimum Sodium Hydroxide Initial Conditions - Normal Case with One Spray Pump Inoperable
Figure 6.2-51o

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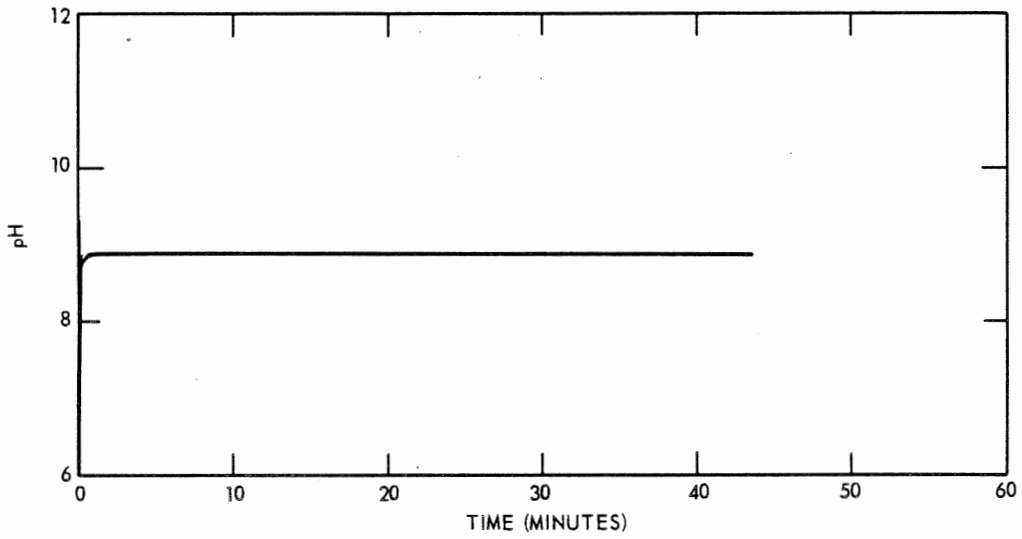
Figure 6.2-51p

SPRAY HEADER PH DURING INITIAL INJECTION - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE WITH ONE RHR PUMP INOPERABLE



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Spray Header pH During Initial Injection - Minimum Sodium Hydroxide Initial Conditions - Normal Case with One RHR Pump Inoperable Figure 6.2-51p

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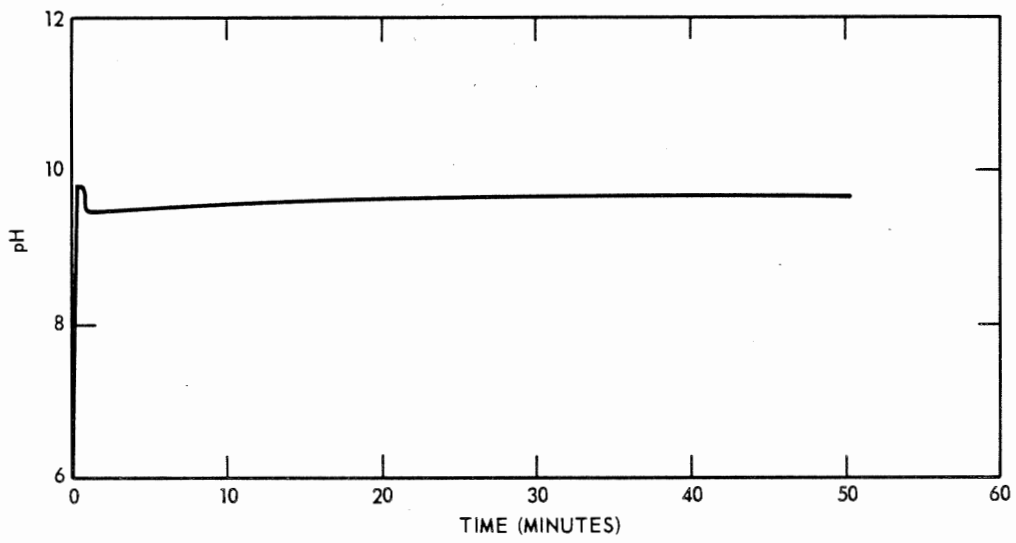
Figure 6.2-51q

SPRAY HEADER PH DURING INITIAL INJECTION - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - REACTOR BUILDING SPRAY SYSTEM DESIGN CASE



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Spray Header pH During Initial Injection - Maximum Sodium Hydroxide Initial Conditions - Reactor Building Spray System Design Case Figure 6.2-51q

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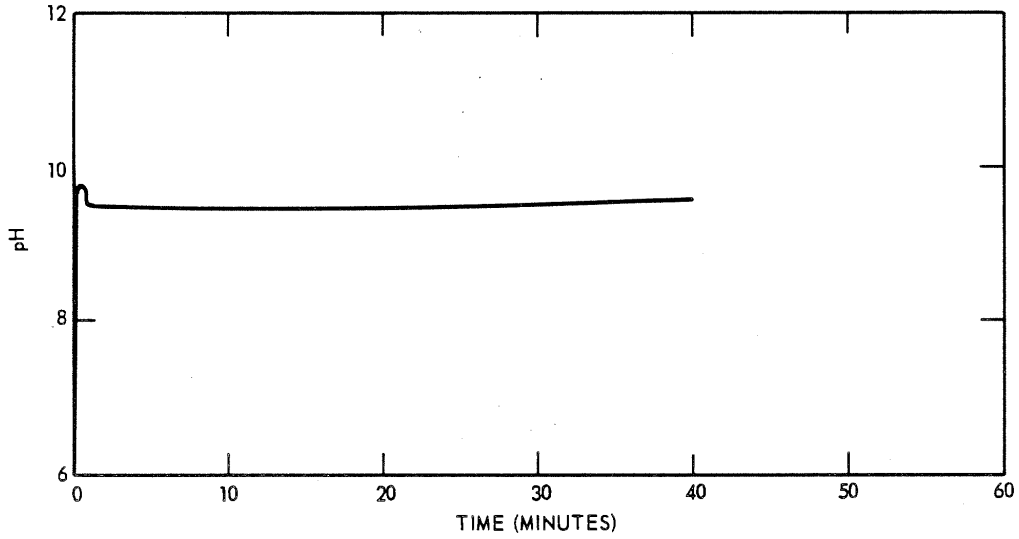
Figure 6.2-51r

SPRAY HEADER PH DURING INITIAL INJECTION - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE



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Spray Header pH During Initial Injection - Maximum Sodium Hydroxide Initial Conditions - Normal Case Figure 6.2-51r

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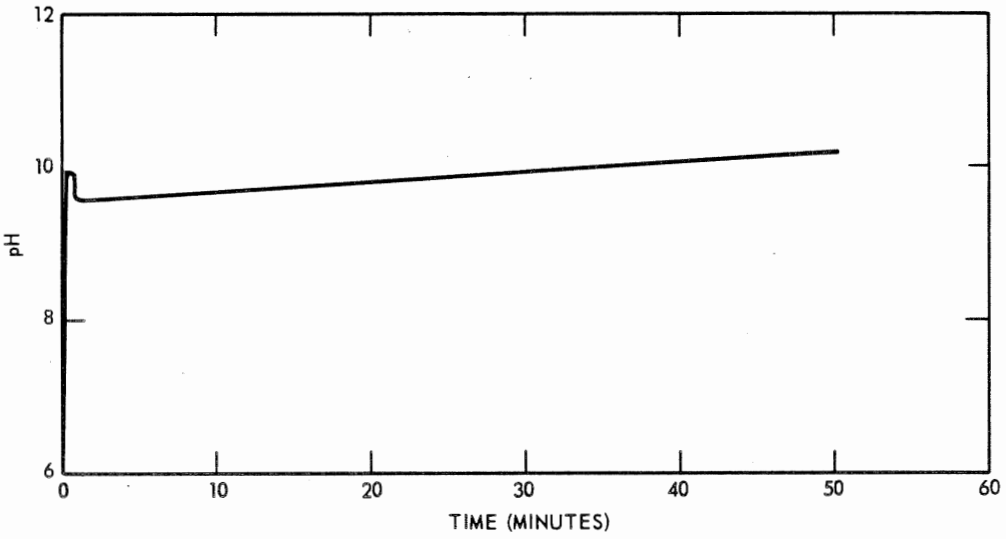
Figure 6.2-51s

SPRAY HEADER PH DURING INITIAL INJECTION - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE WITH ONE SPRAY PUMP INOPERABLE



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Spray Header pH During Initial Injection - Maximum Sodium Hydroxide Initial Conditions - Normal Case with One Spray Pump Inoperable Figure 6.2-51s

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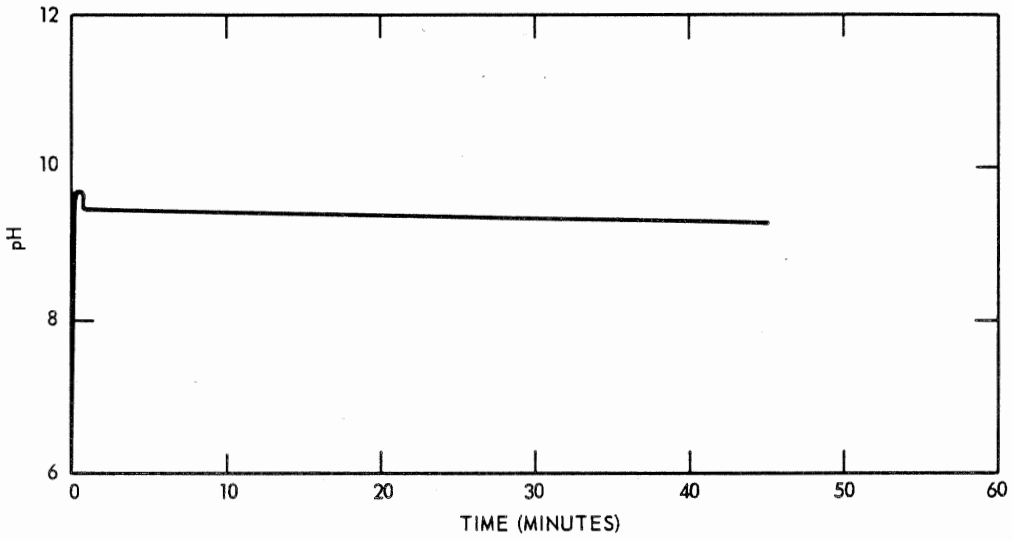
Figure 6.2-51t

SPRAY HEADER PH DURING INITIAL INJECTION - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE WITH ONE RHR PUMP INOPERABLE



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SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Spray Header pH During Initial Injection - Maximum Sodium Hydroxide Initial Conditions - Normal Case with One RHR Pump Inoperable Figure 6.2-51t

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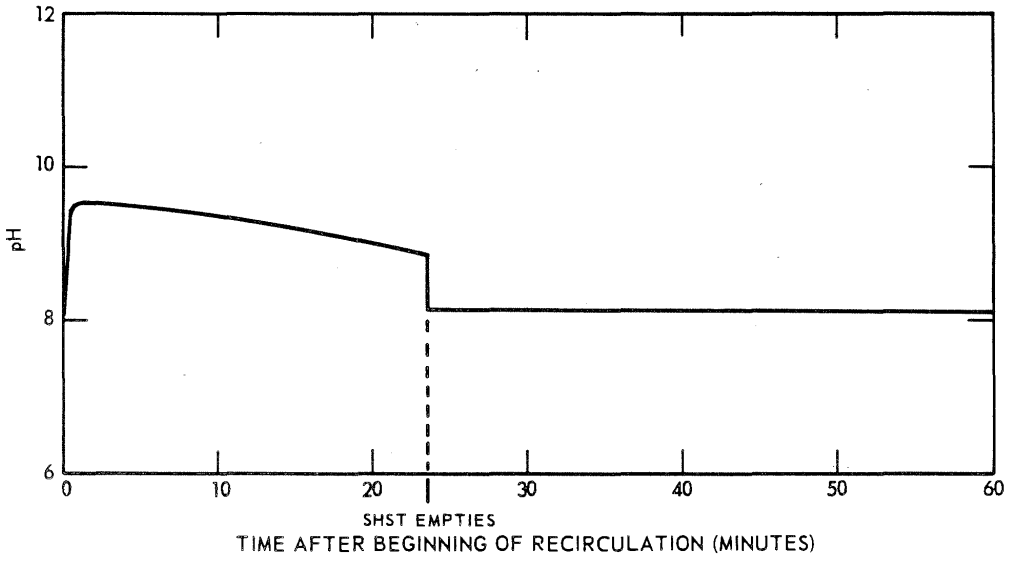
Figure 6.2-51u

SPRAY HEADER PH DURING RECIRCULATION - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - REACTOR BUILDING SPRAY SYSTEM DESIGN CASE



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SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Spray Header pH During Recirculation - Minimum Sodium Hydroxide Initial Conditions - Reactor Building Spray System Design Case Figure 6.2-51u

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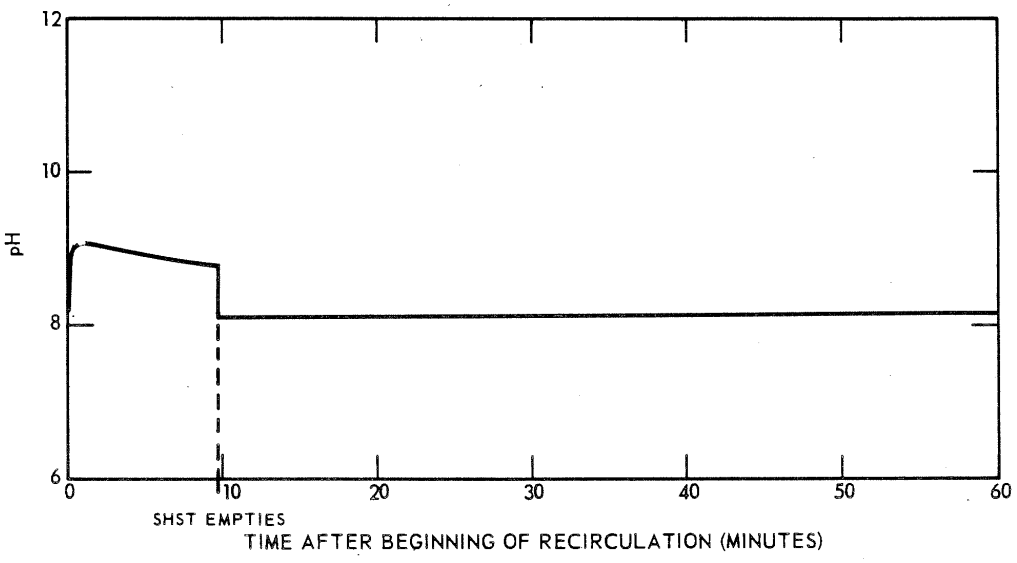
Figure 6.2-51v

SPRAY HEADER PH DURING RECIRCULATION - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE



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SOUTH CAROLINA ELECTRIC & GAS CO.
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Spray Header pH During Recirculation - Minimum Sodium Hydroxide Initial Conditions - Normal Case

Figure 6.2-51v

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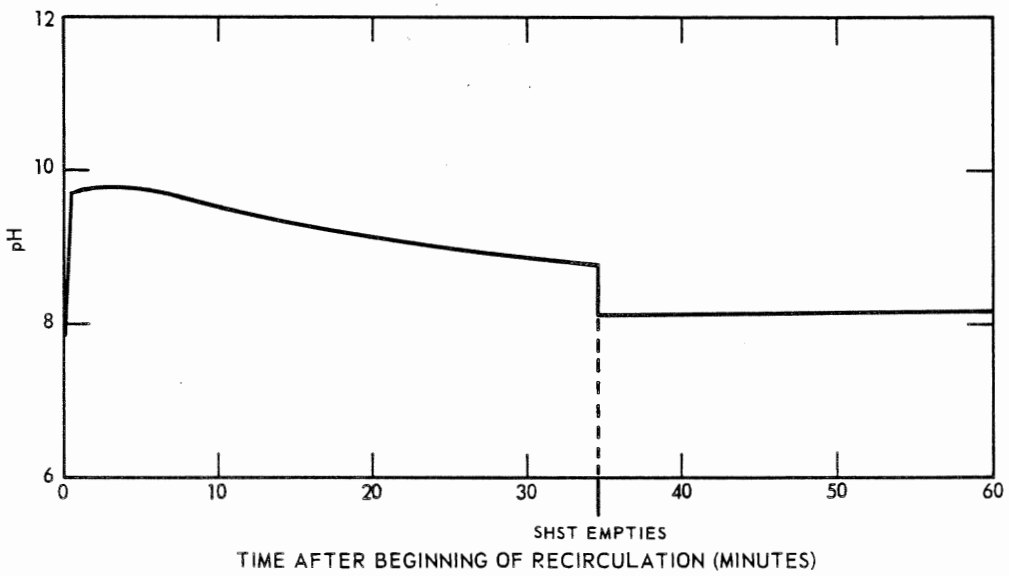
Figure 6.2-51w

SPRAY HEADER PH DURING RECIRCULATION - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE WITH ONE SPRAY PUMP INOPERABLE



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SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Spray Header pH During Recirculation - Minimum Sodium Hydroxide Initial Conditions - Normal Case with One Spray Pump Inoperable
Figure 6.2-51w

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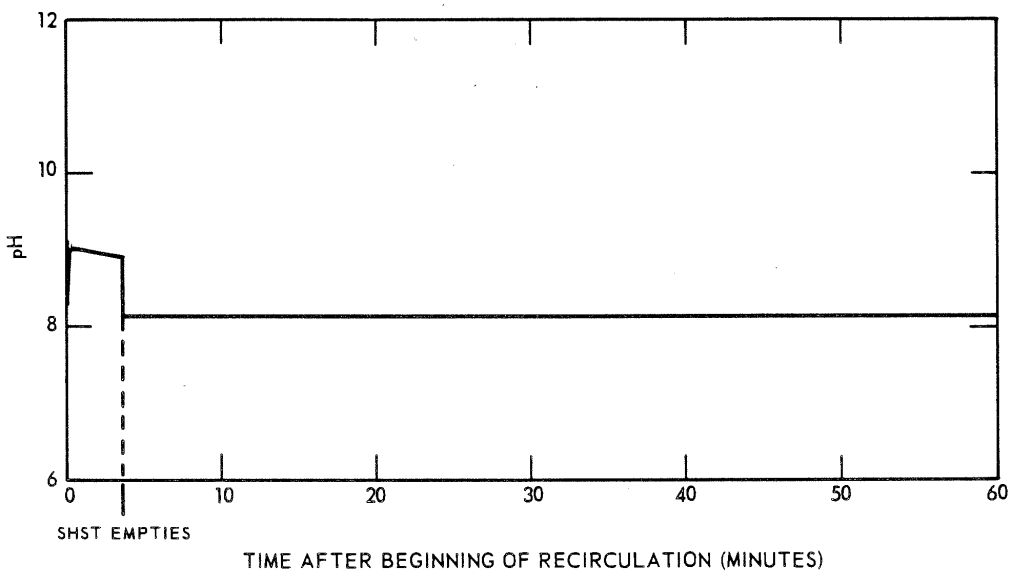
Figure 6.2-51x

SPRAY HEADER PH DURING RECIRCULATION - MINIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE WITH ONE RHR PUMP INOPERABLE



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VIRGIL C. SUMMER NUCLEAR STATION

Spray Header pH During Recirculation - Minimum Sodium Hydroxide Initial Conditions - Normal Case with One RHR Pump Inoperable
Figure 6.2-51x

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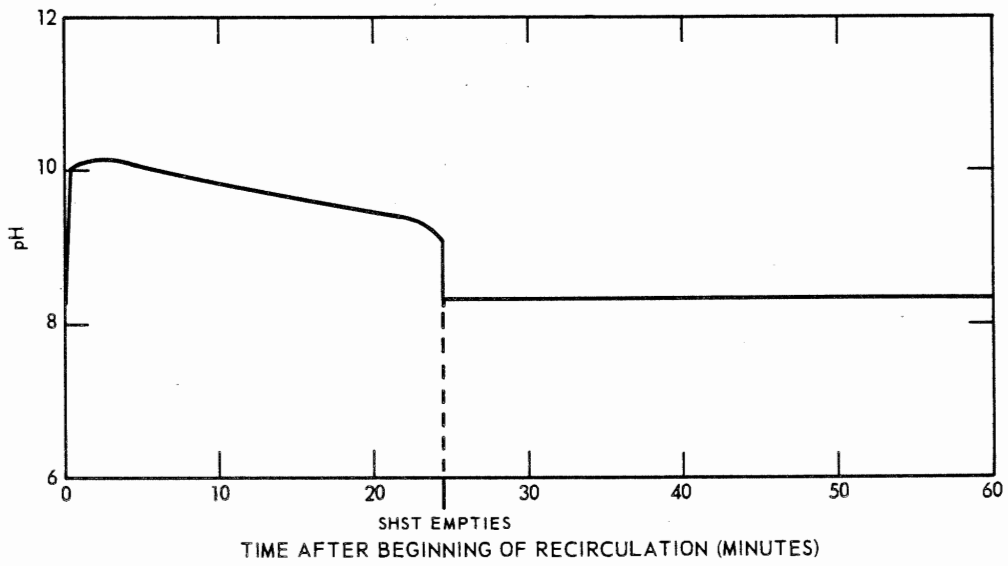
Figure 6.2-51y

SPRAY HEADER PH DURING RECIRCULATION - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - REACTOR BUILDING SPRAY SYSTEM DESIGN CASE



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Spray Header pH During Recirculation - Maximum Sodium Hydroxide Initial Conditions - Reactor Building Spray System Design Case Figure 6.2-51y

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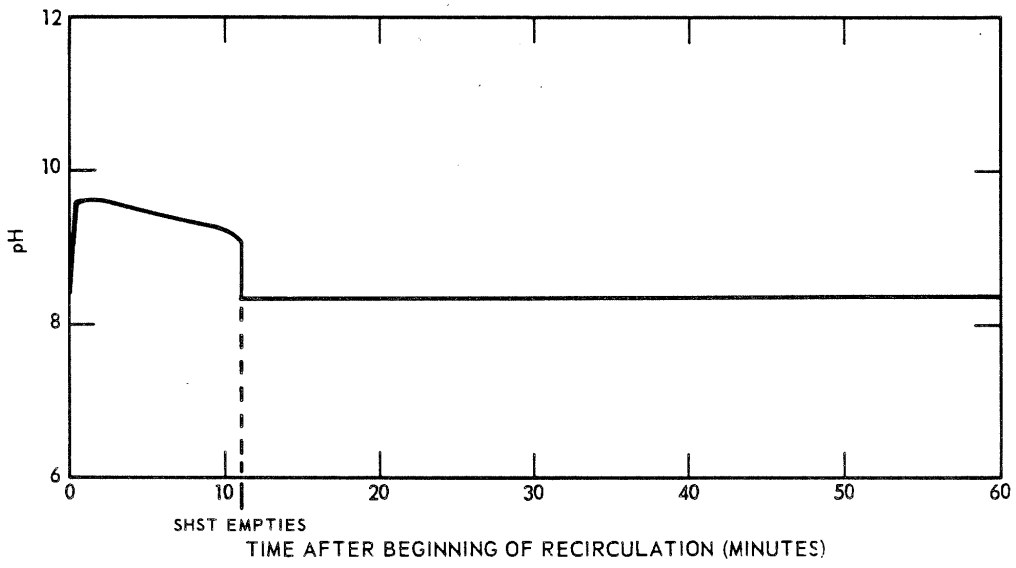
Figure 6.2-51z

SPRAY HEADER PH DURING RECIRCULATION - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE



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Spray Header pH During Recirculation - Maximum Sodium Hydroxide Initial Conditions - Normal Case Figure 6.2-51z

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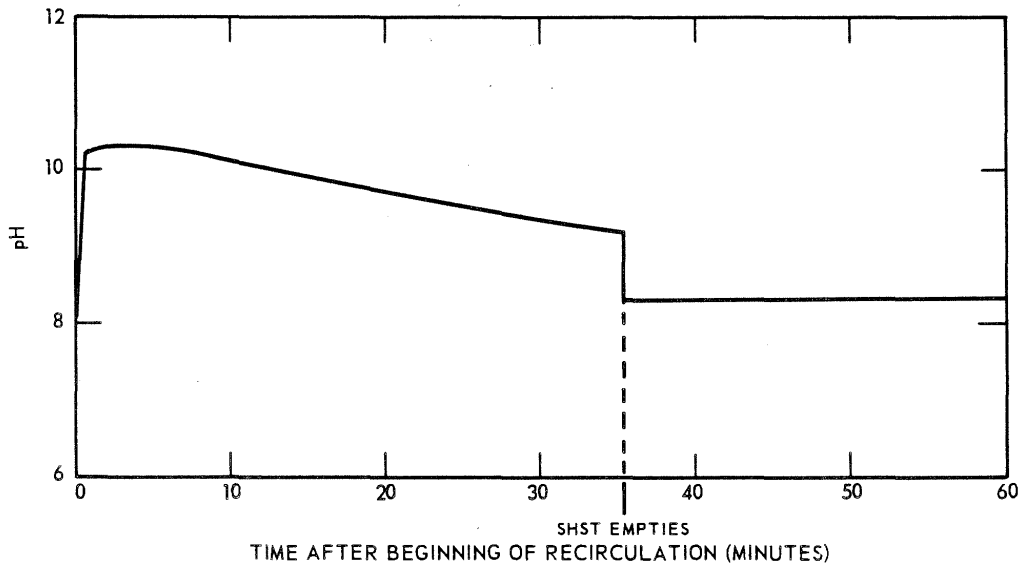
Figure 6.2-51aa

SPRAY HEADER PH DURING RECIRCULATION - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE WITH ONE SPRAY PUMP INOPERABLE



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VIRGIL C. SUMMER NUCLEAR STATION

Spray Header pH During Recirculation - Maximum Sodium Hydroxide Initial Conditions - Normal Case with One Spray Pump Inoperable
Figure 6.2-51aa

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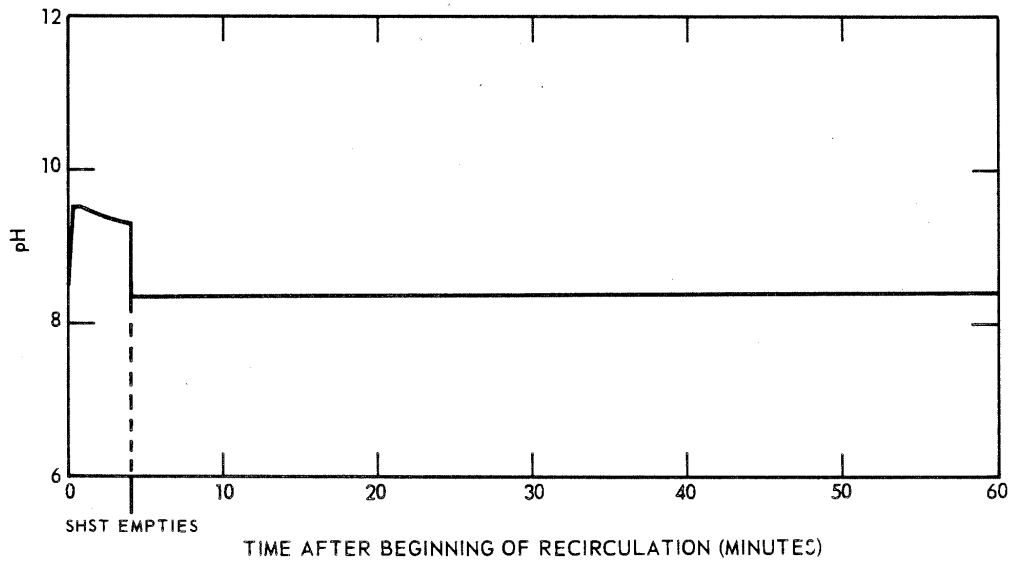
Figure 6.2-51bb

SPRAY HEADER PH DURING RECIRCULATION - MAXIMUM SODIUM HYDROXIDE INITIAL CONDITIONS - NORMAL CASE WITH ONE RHR PUMP INOPERABLE



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SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Spray Header pH During Recirculation - Maximum Sodium Hydroxide Initial Conditions - Normal Case with One RHR Pump Inoperable Figure 6.2-51bb

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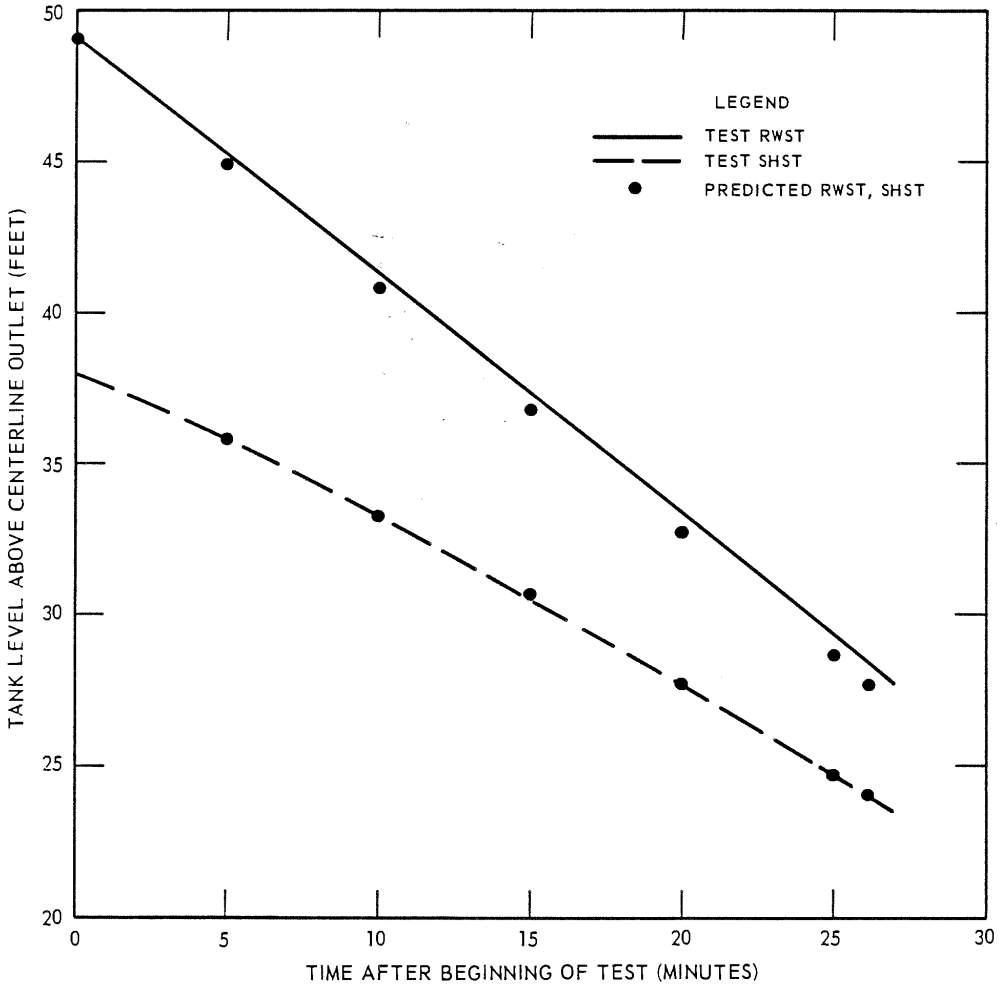
Figure 6.2-51cc

ANALYTICAL PREDICTION TO WATER TEST
CASE 1: REACTOR BUILDING SPRAY SYSTEM DESIGN CASE



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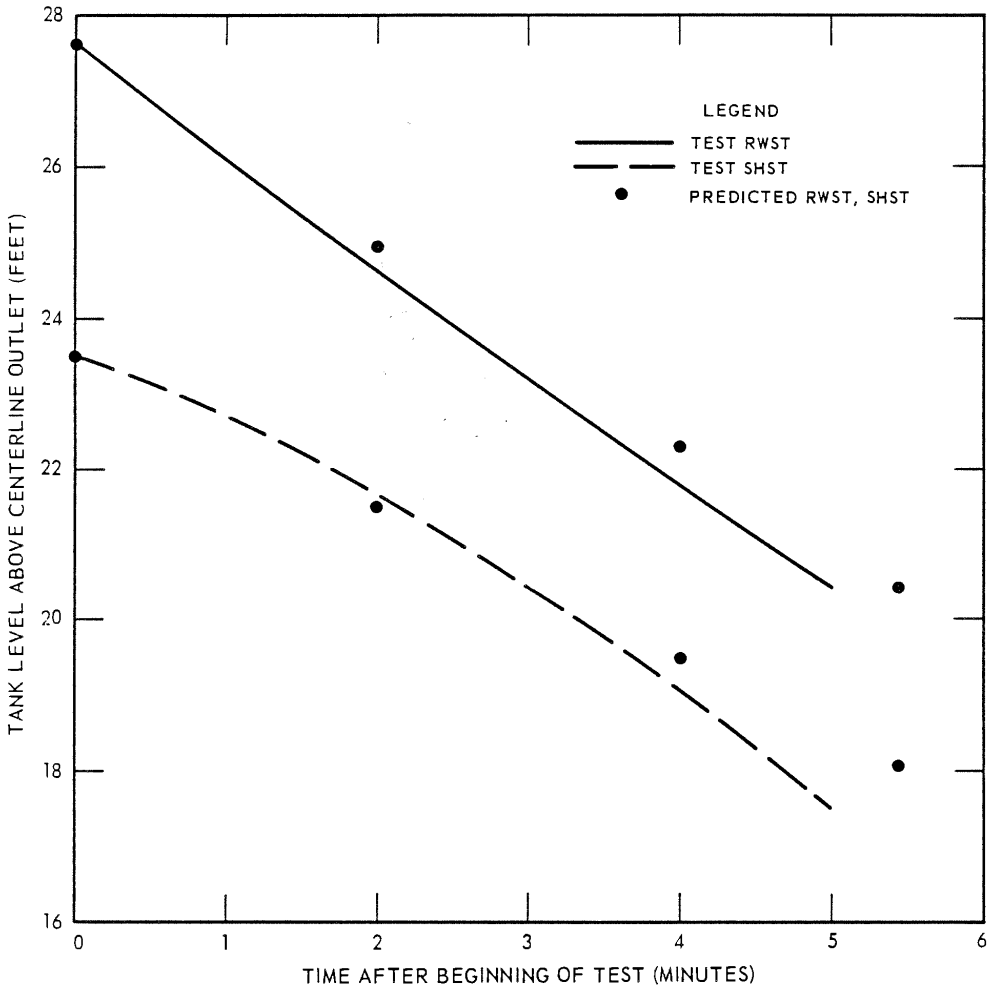
Analytical Prediction to Water Test Case 1: Reactor Building Spray System Design Case Figure 6.2-51cc

Figure 6.2-51dd
ANALYTICAL PREDICTION TO WATER TEST
CASE 2: NORMAL CASE



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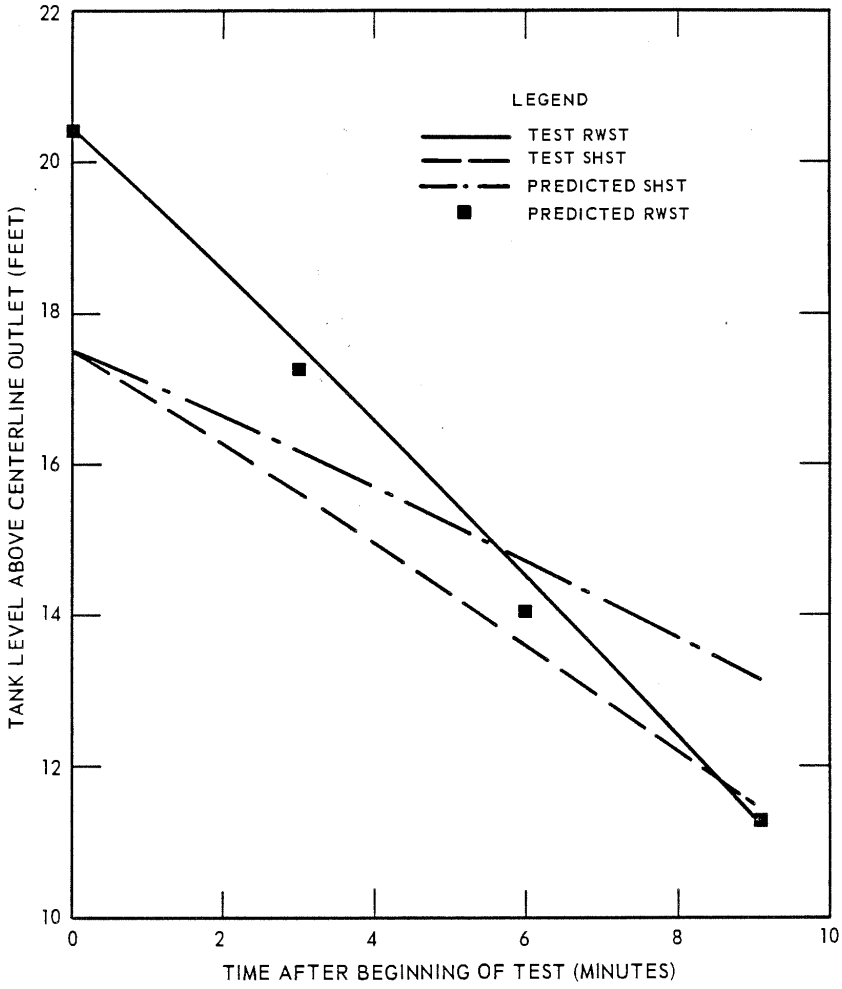
Analytical Prediction to Water Test Case 2: Normal Case Figure 6.2-51dd

Figure 6.2-51ee

ANALYTICAL PREDICTION TO WATER TEST CASE 3: NORMAL CASE WITH ONE REACTOR BUILDING SPRAY PUMP INOPERABLE



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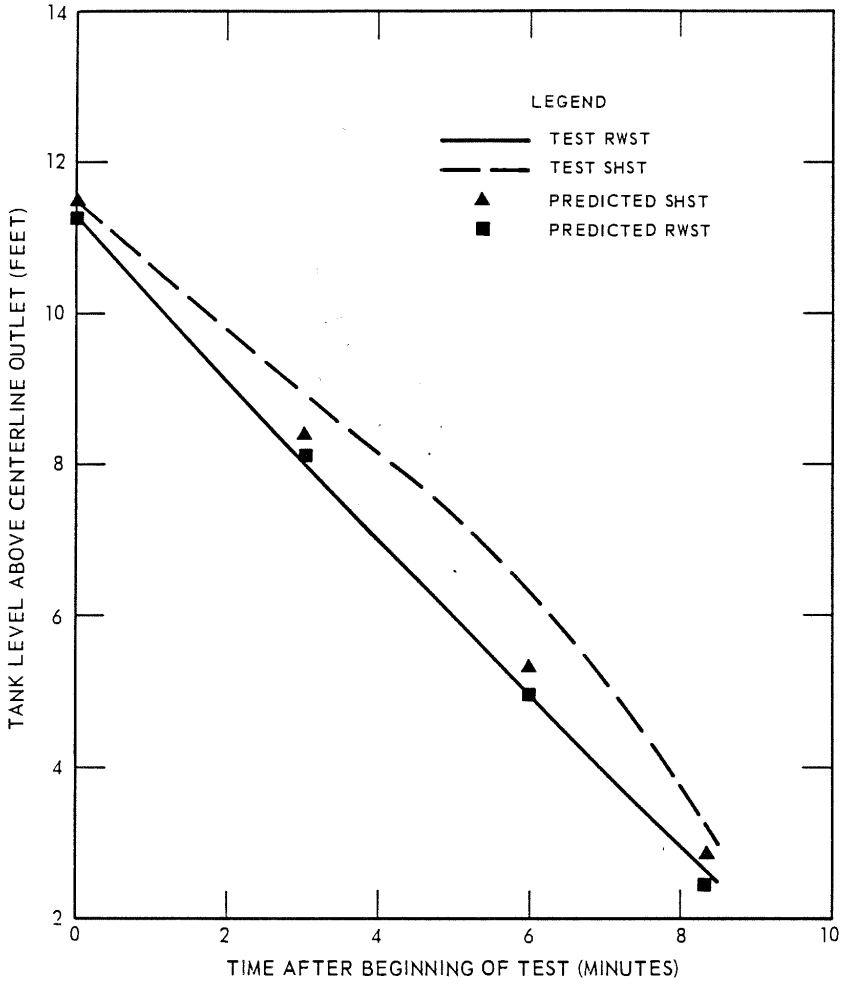
Analytical Prediction to Water Test
Case 3: Normal Case with One Reactor
Building Spray Pump Inoperable

Figure 6.2-51ee

Figure 6.2-51ff

ANALYTICAL PREDICTION TO WATER TEST
CASE 4: NORMAL CASE WITH ONE RHR PUMP INOPERABLE



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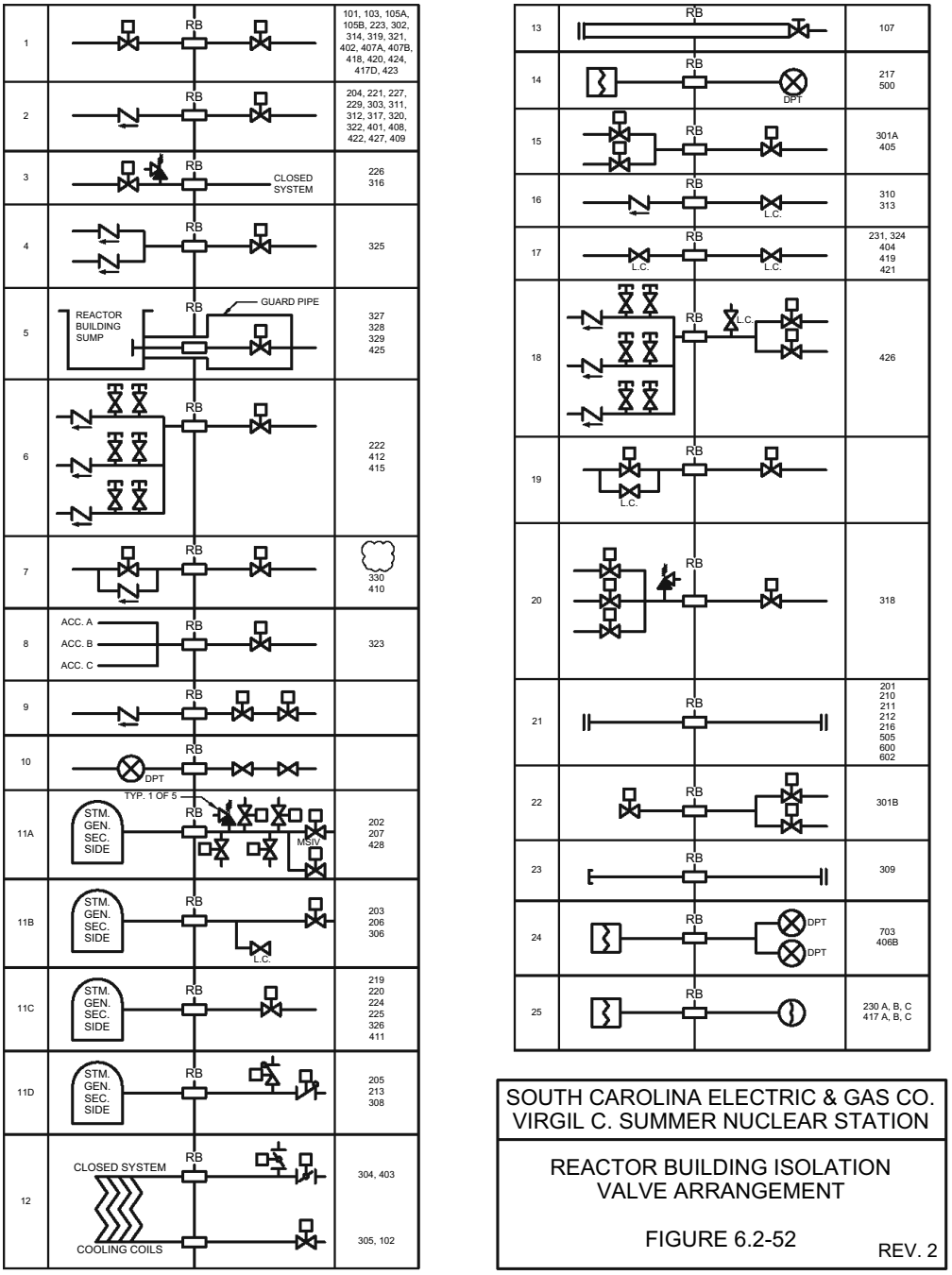
Analytical Prediction to Water Test
Case 4: Normal Case with One RHR Pump Inoperable

Figure 6.2-51ff

Figure 6.2-52

REACTOR BUILDING ISOLATION VALVE ARRANGEMENT



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REACTOR BUILDING ISOLATION VALVE ARRANGEMENT FIGURE 6.2-52	REV. 2

Figure 6.2-53

ELECTRIC HYDROGEN RECOMBINER

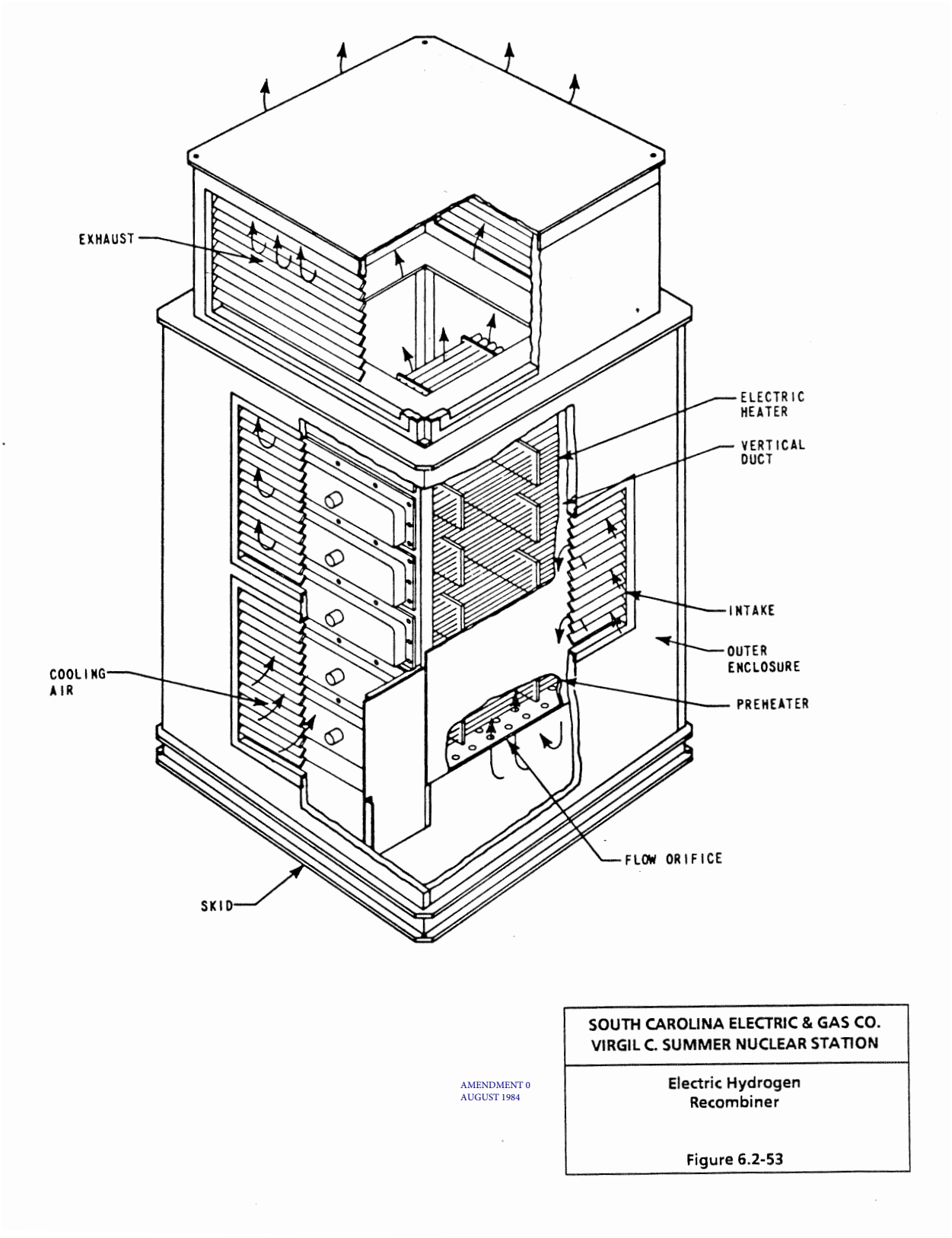
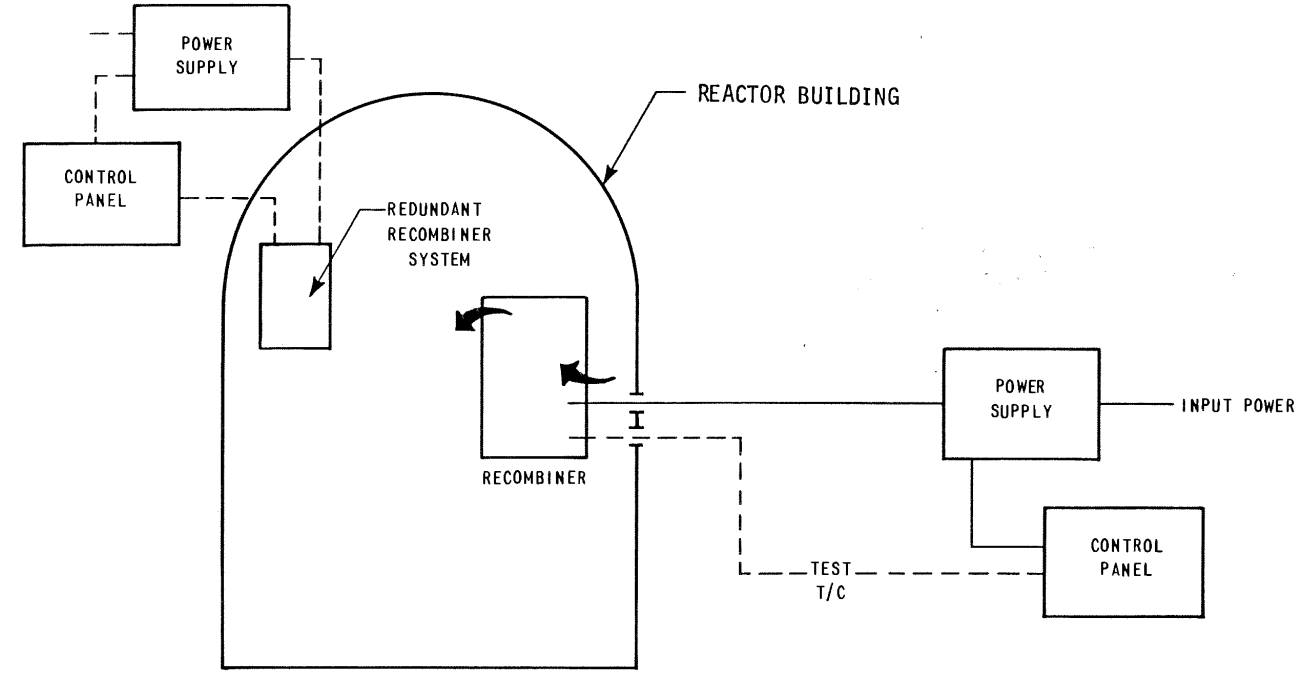


Figure 6.2-54

SCHEMATIC ELECTRIC RECOMBINER SYSTEM



BOTH RECOMBINERS ARE LOCATED ON THE OPERATING FLOOR ELEVATION 463'-0"

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Schematic Electric Recombiner System
Figure 6.2-54

Figure 6.2-58
DRAWING D-302-861
FSAR FIGURE REFERENCE

Figure 6.2-59
DRAWING D-302-811
FSAR FIGURE REFERENCE

Figure 6.2-60
DRAWING C-811-002
FSAR FIGURE REFERENCE

Figure 6.2-60a
DRAWING B-809-466
FSAR FIGURE REFERENCE

Figure 6.2-61
DELETED PER RN 01-073

Figure 6.2-62 Through 6.2-64
DELETED PER RN 06-040

Figure 6.2-65
DRAWING E-511-219
FSAR FIGURE REFERENCE

Figure 6.2-66
DRAWING E-511-220
FSAR FIGURE REFERENCE

Figure 6.2-67
DRAWING E-511-221
FSAR FIGURE REFERENCE

Figure 6.2-68

REACTOR BUILDING COMPOSITE PLAN BELOW ELEVATION 463'-0' (GAI DWG. NO. E-303-131)

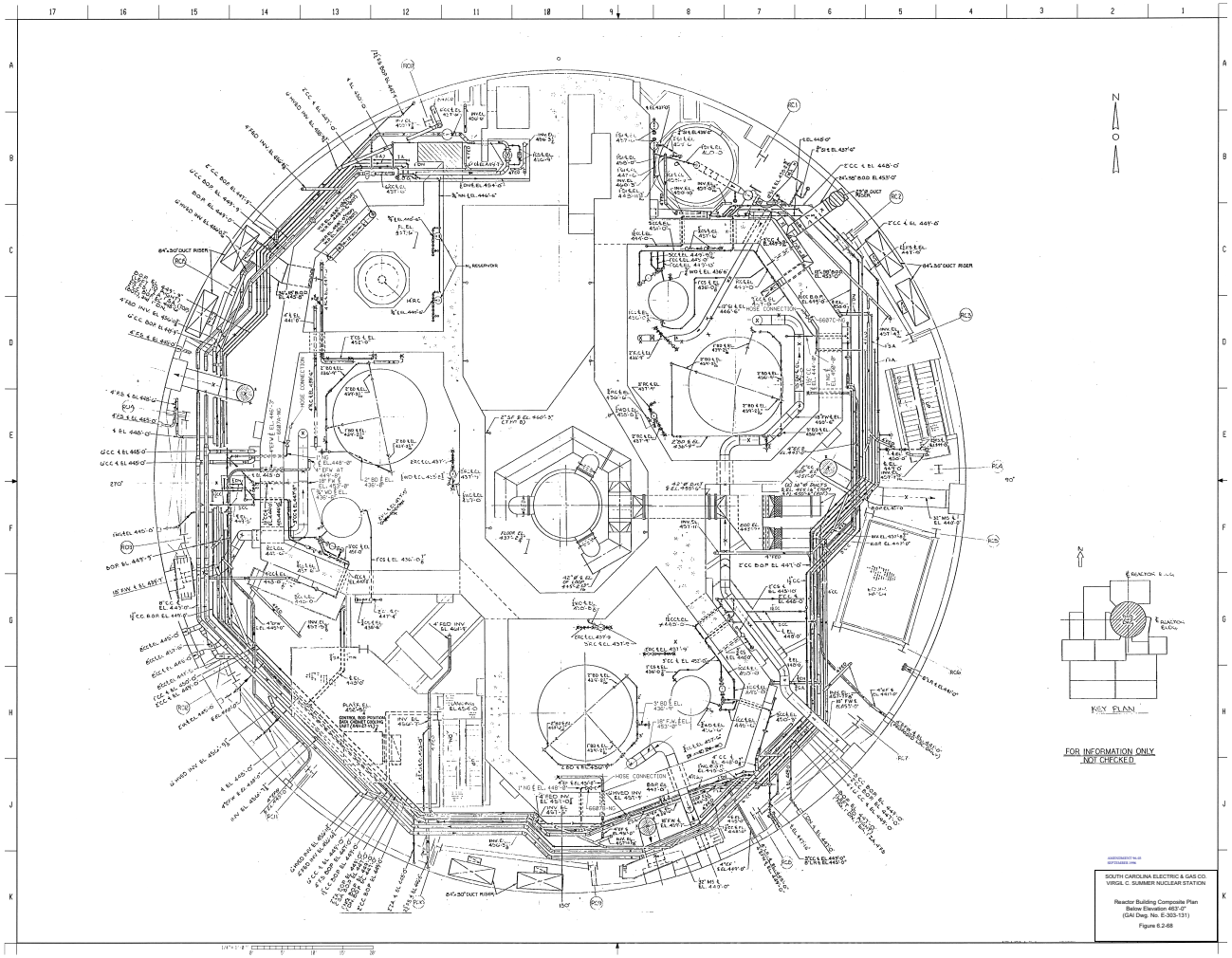
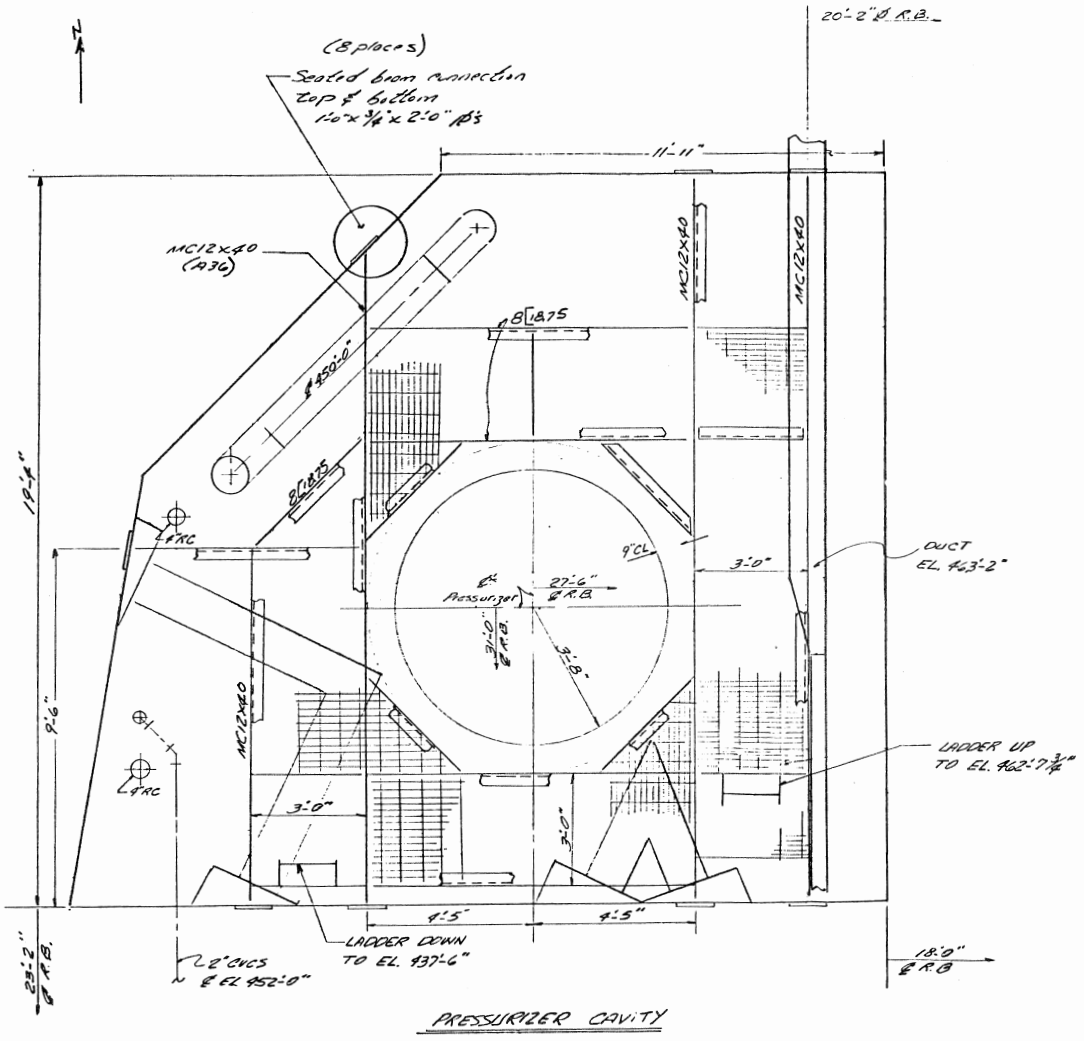


Figure 6.2-69
DRAWING E-304-601
FSAR FIGURE REFERENCE

Figure 6.2-70
DRAWING E-304-011
FSAR FIGURE REFERENCE

Figure 6.2-71

REACTOR BUILDING - ISI PLATFORM
PRESSURIZER CAVITY PLATFORM
ELEVATION 452' - 6"



PRESSURIZER CAVITY

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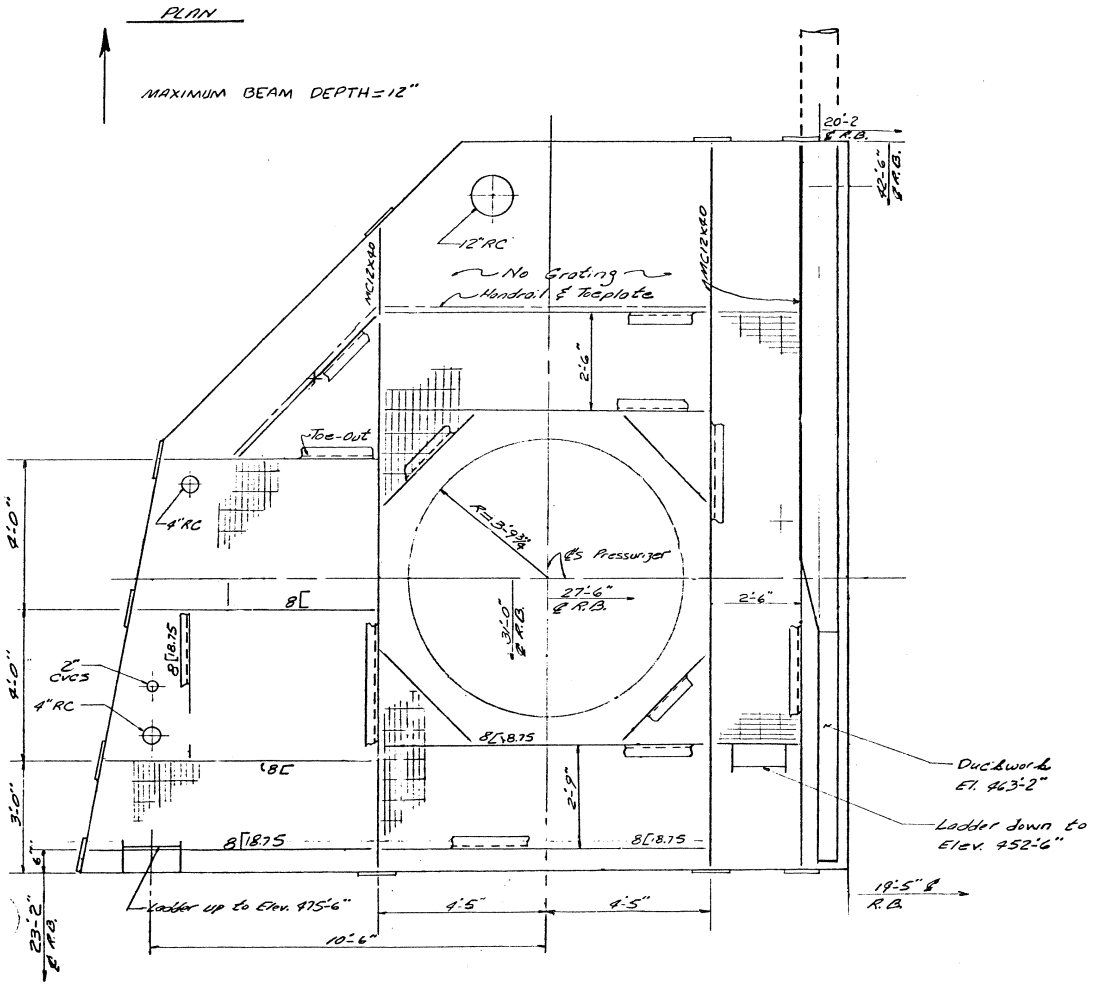
Reactor Building - ISI Platform Pressurizer Cavity Platform Elevation 452' - 6" Figure 6.2-71

Figure 6.2-72

REACTOR BUILDING - ISI PLATFORM
PRESSURIZER CAVITY PLATFORM
ELEVATION 462' - 7-3/4"



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Reactor Building - ISI Platform Pressurizer Cavity Platform Elevation 462' - 7-3/4" Figure 6.2-72

Figure 6.2-73

REACTOR BUILDING - ISI PLATFORM LOOP A PLATFORMS
ELEVATION 435' - 11-1/4"
ELEVATION 436' - 7 1/16"
ELEVATION 439' - 13/4"

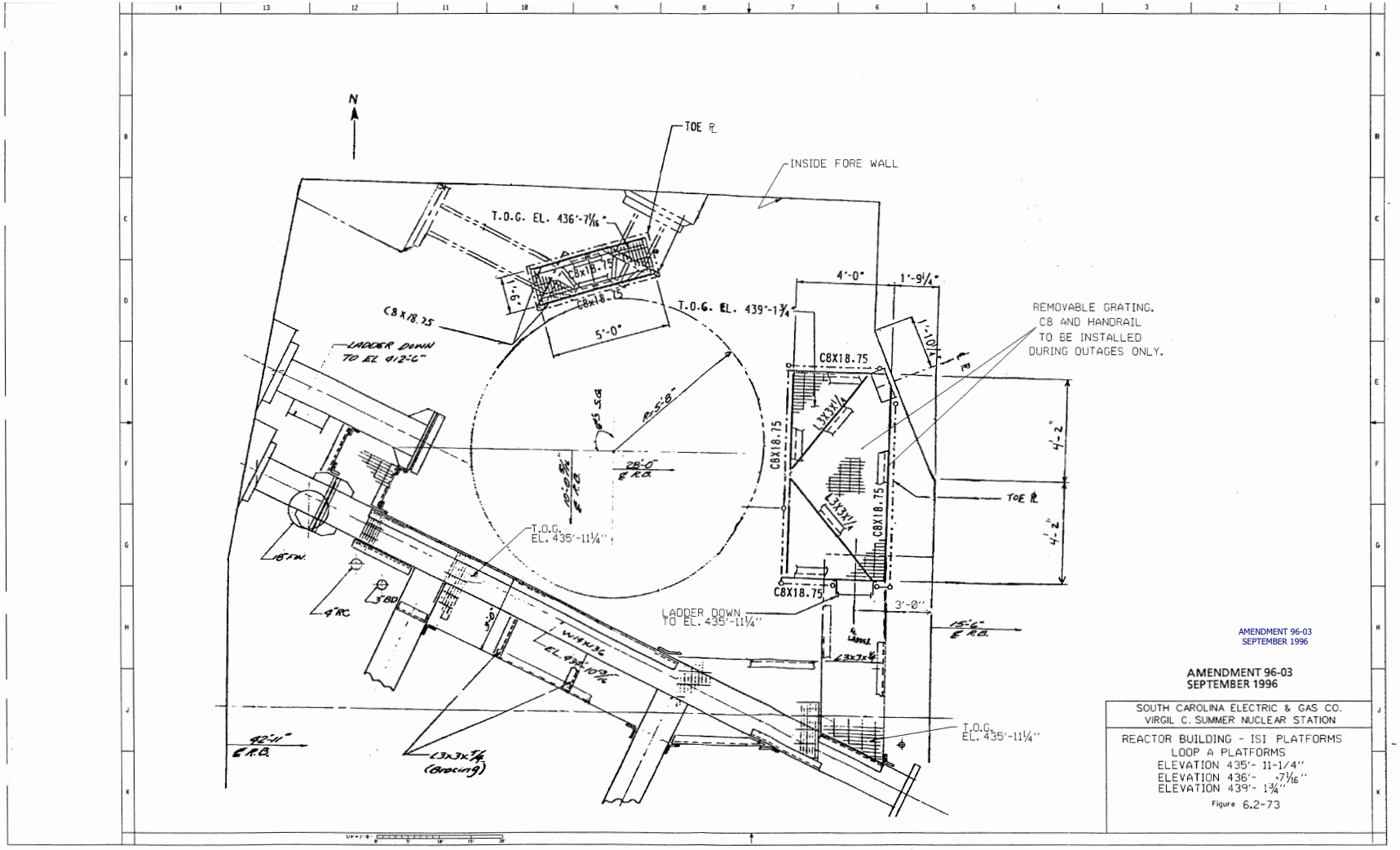


Figure 6.2-73a

REACTOR BUILDING - ISI PLATFORMS LOOP A PLATFORMS ELEVATION 466'-11"

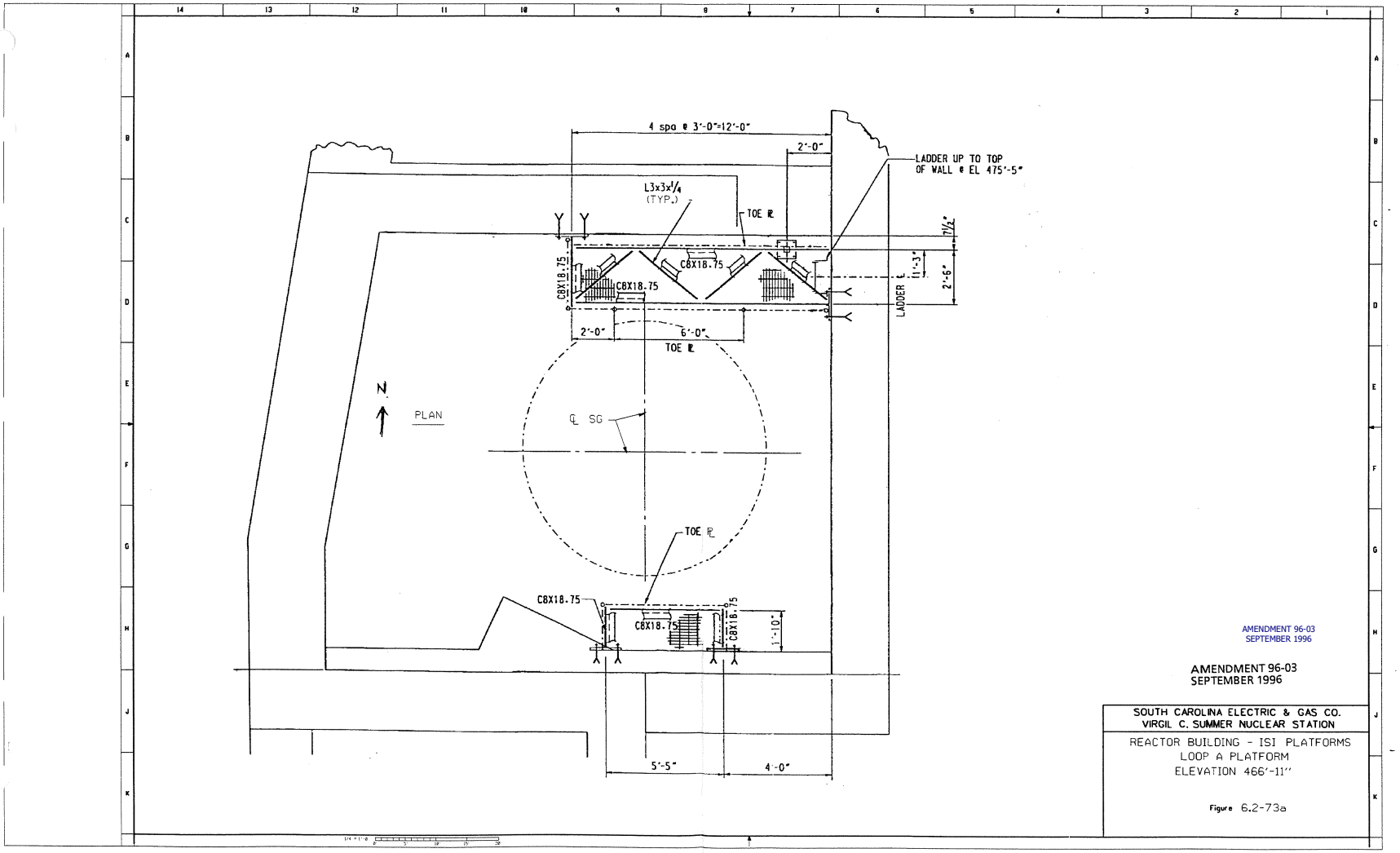
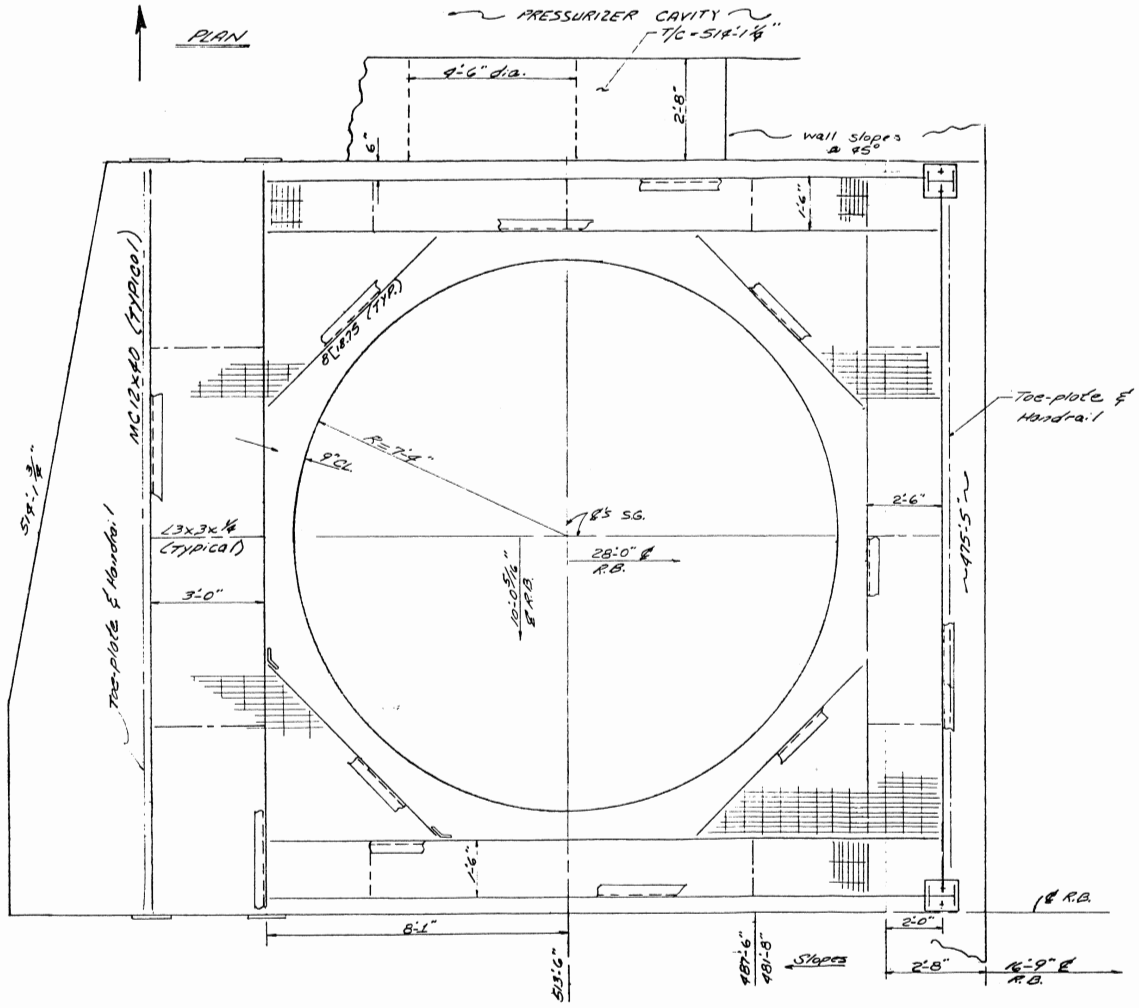


Figure 6.2-74

REACTOR BUILDING - ISI PLATFORMS LOOP A PLATFORMS ELEVATION 488' - 6"



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Reactor Building - ISI Platforms Loop A Platform Elevation 488' - 6" Figure 6.2-74

Figure 6.2-75

REACTOR BUILDING - ISI PLATFORMS LOOP B PLATFORMS
ELEVATION 435' - 11-1/4"
ELEVATION 436' - 41/2"

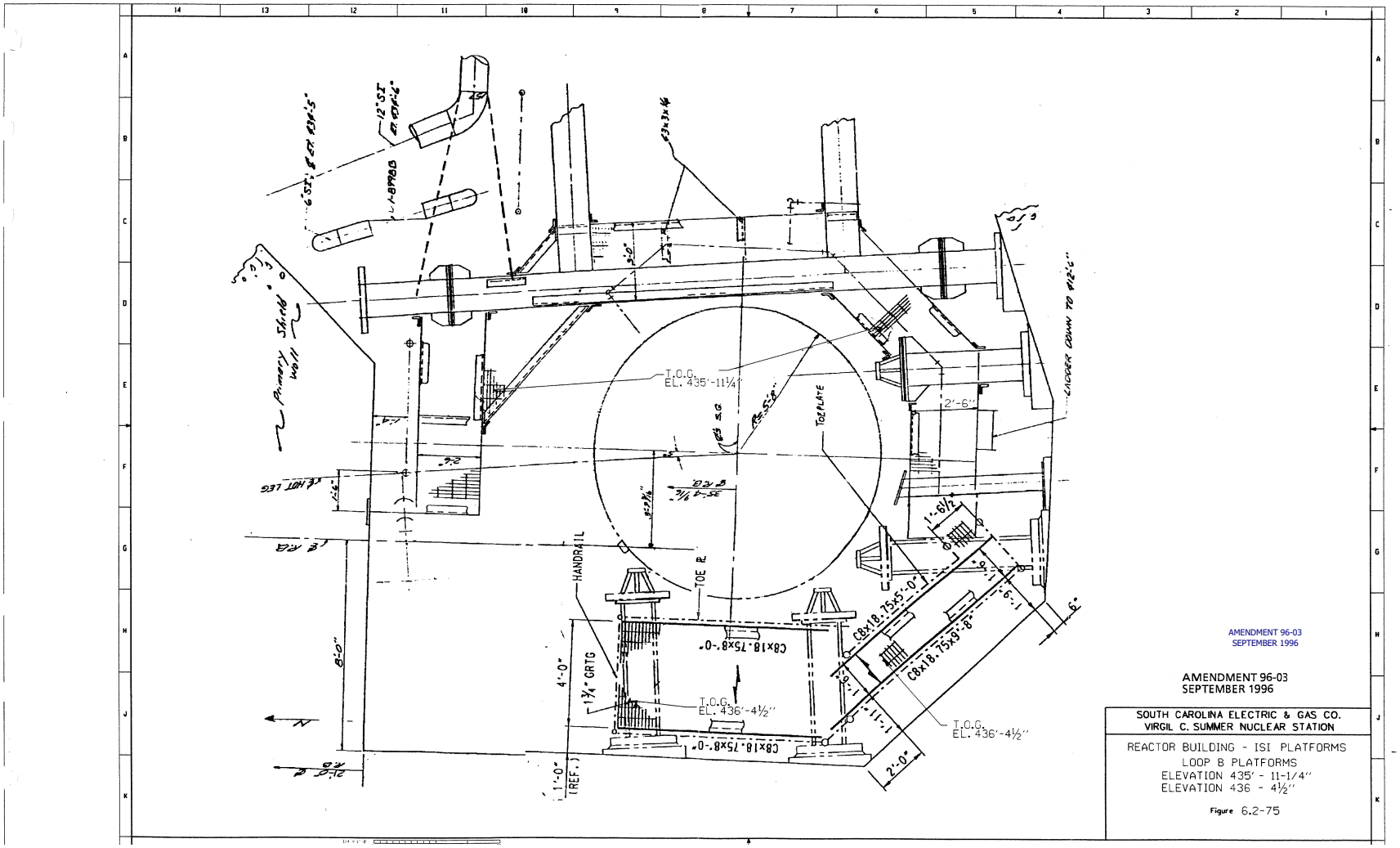


Figure 6.2-76

REACTOR BUILDING - ISI PLATFORMS LOOP B PLATFORM ELEVATION 467' - 9"

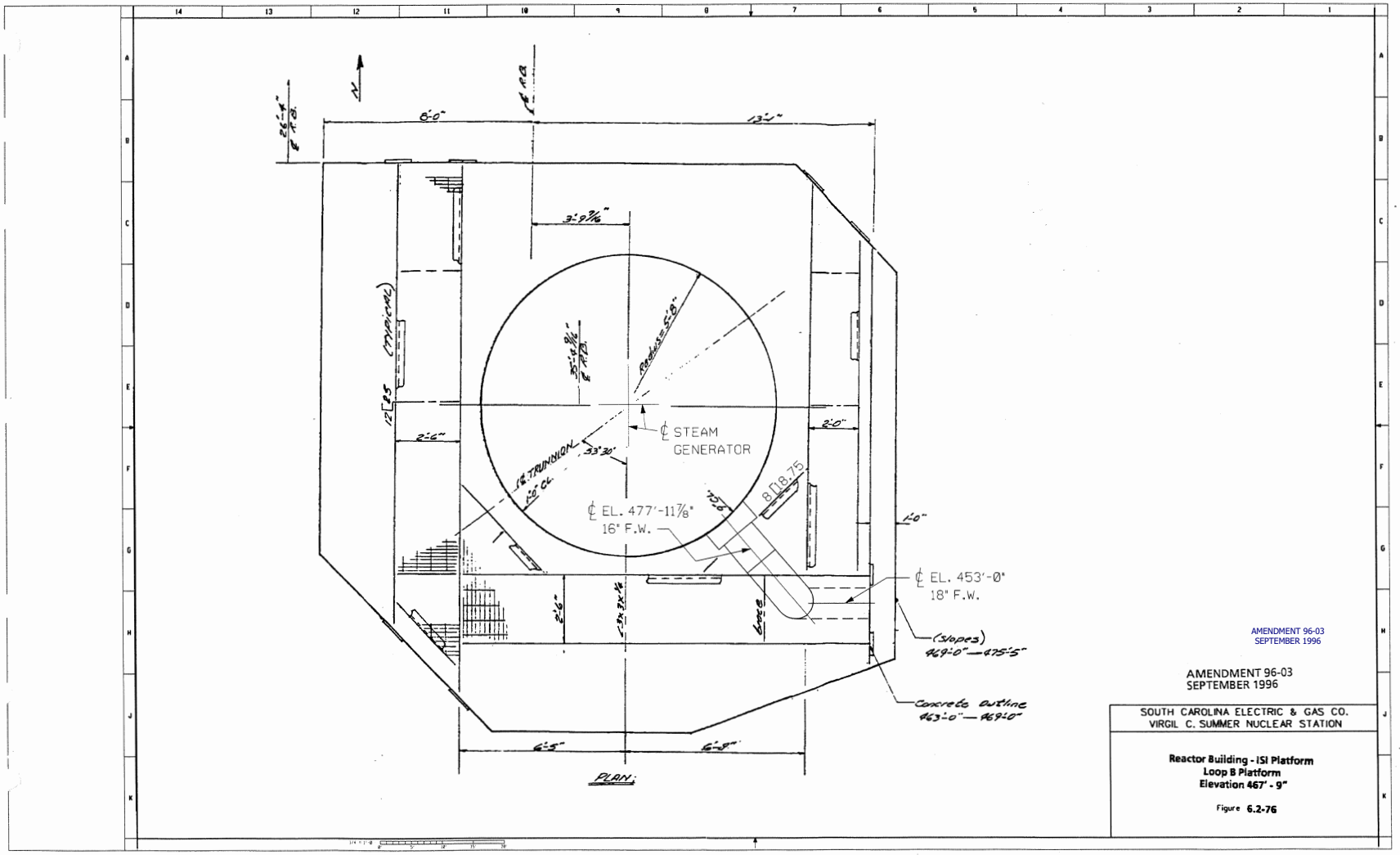


Figure 6.2-77

REACTOR BUILDING - ISI PLATFORMS LOOP B PLATFORM
ELEVATION 487' - 6"

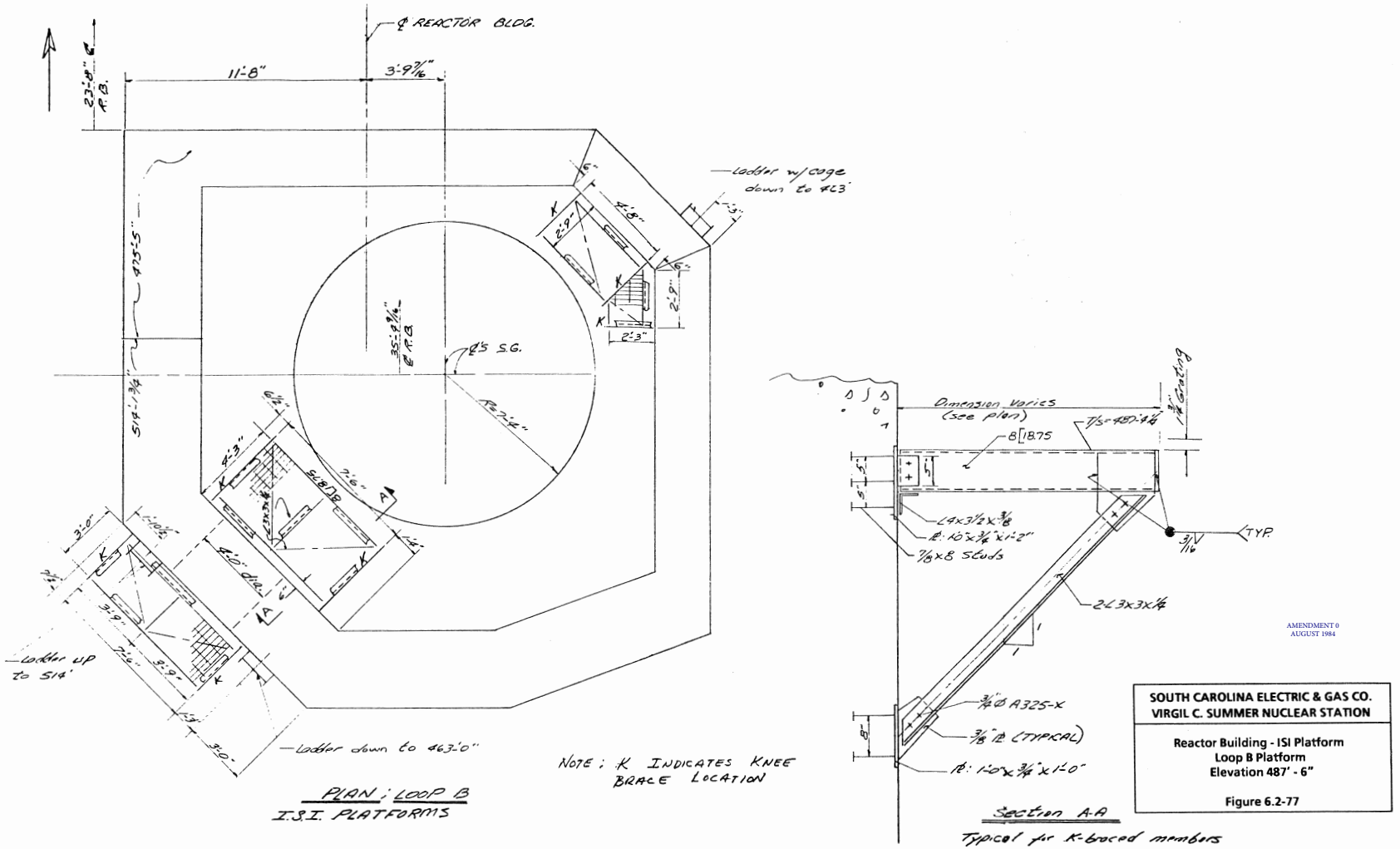


Figure 6.2-78

REACTOR BUILDING - ISI PLATFORMS LOOP C PLATFORMS
ELEVATION 435' - 11-1/4"
ELEVATION 438' - 0"

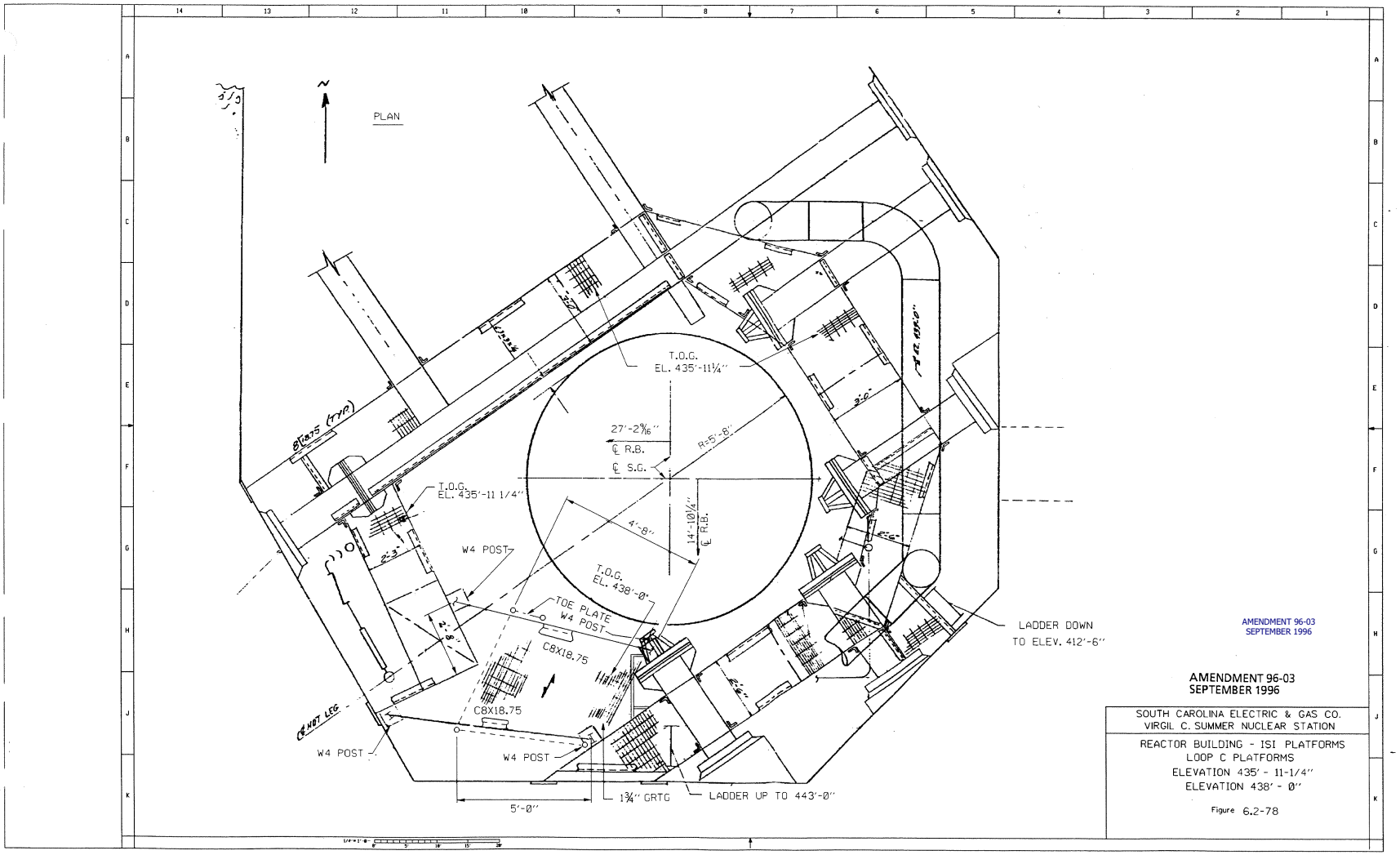


Figure 6.2-79

REACTOR BUILDING - ISI PLATFORMS LOOP C PLATFORMS ELEVATION 443' - 0"

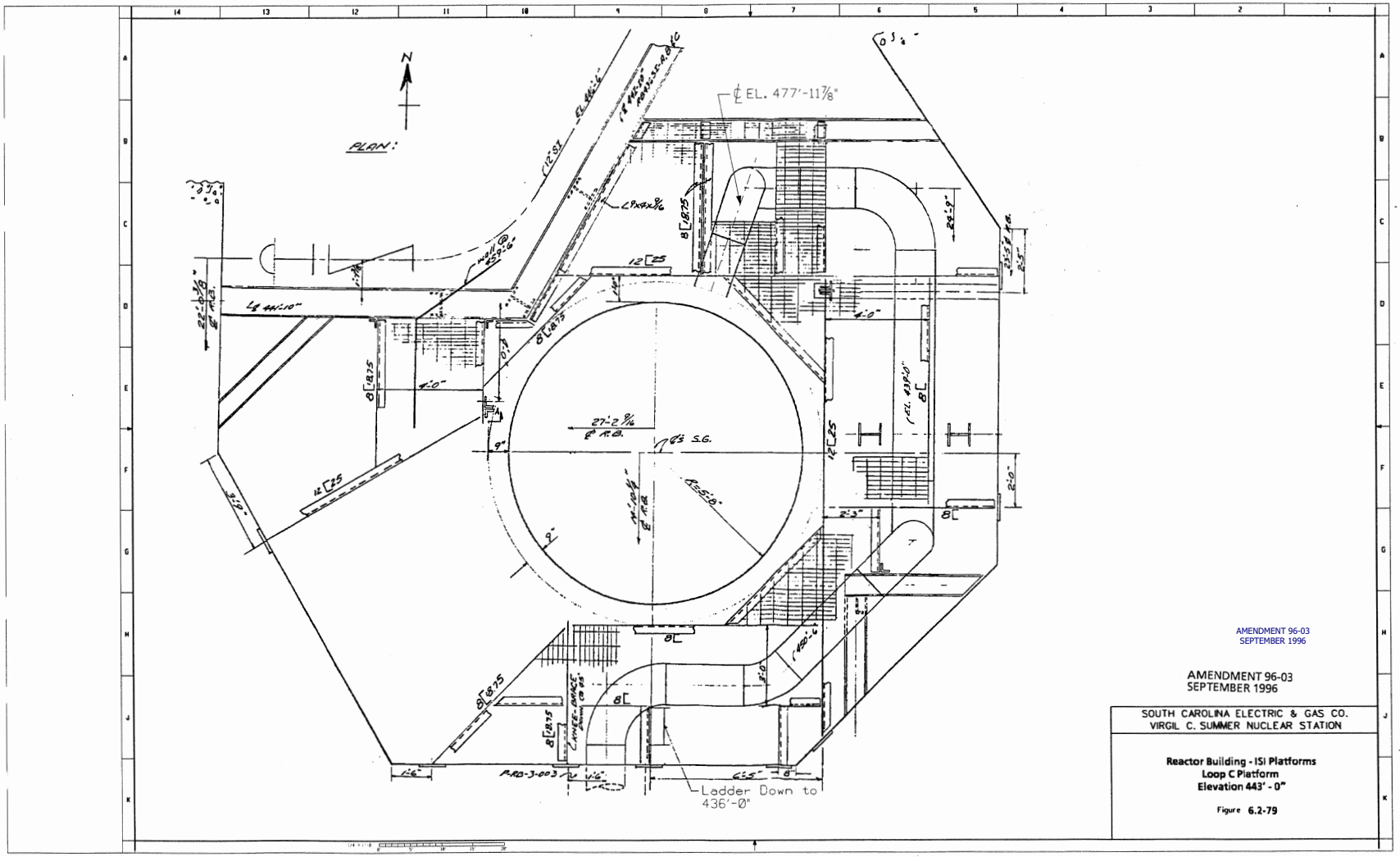


Figure 6.2-79a

REACTOR BUILDING - ISI PLATFORMS LOOP C PLATFORMS
ELEVATION 467' - 0"

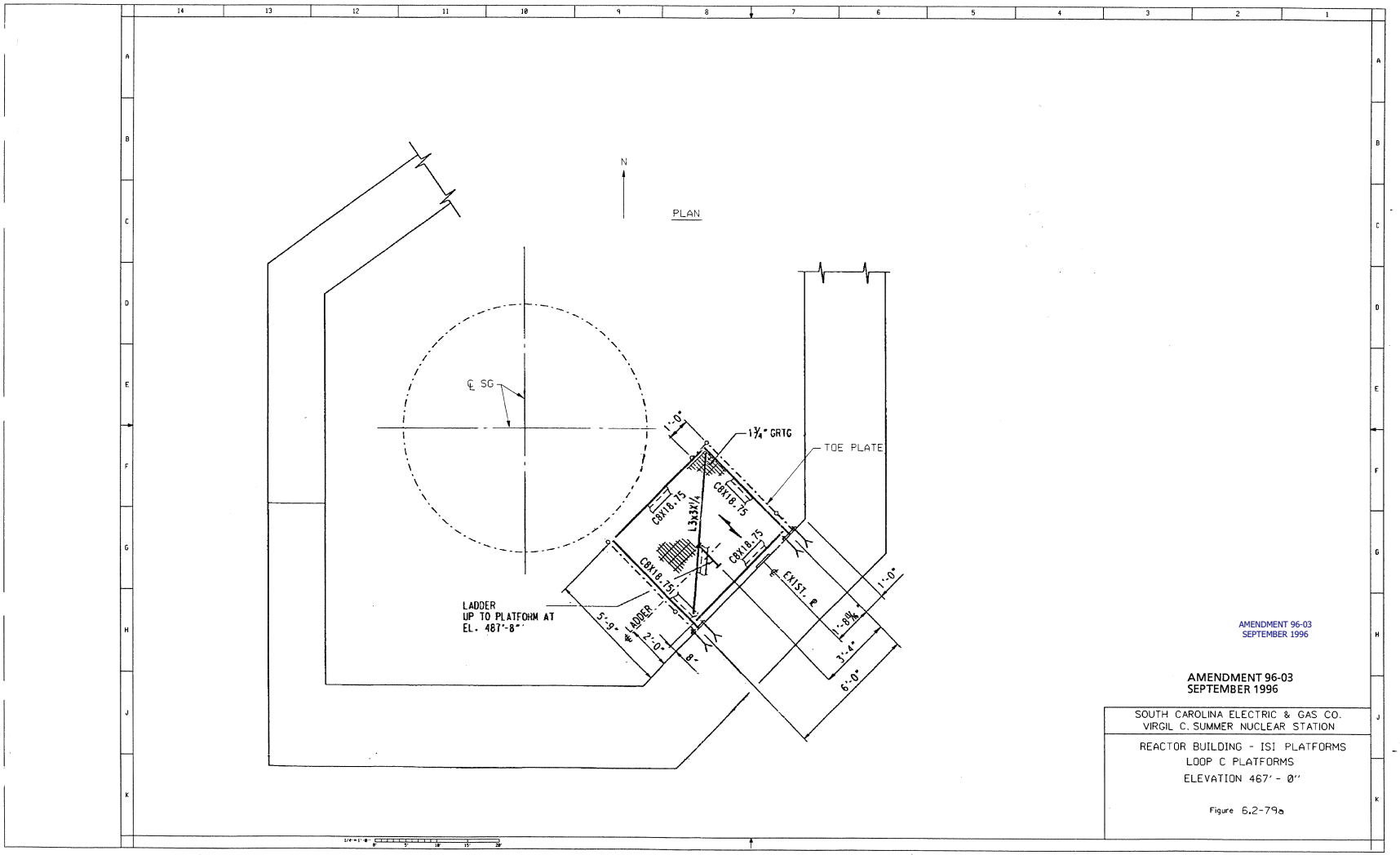
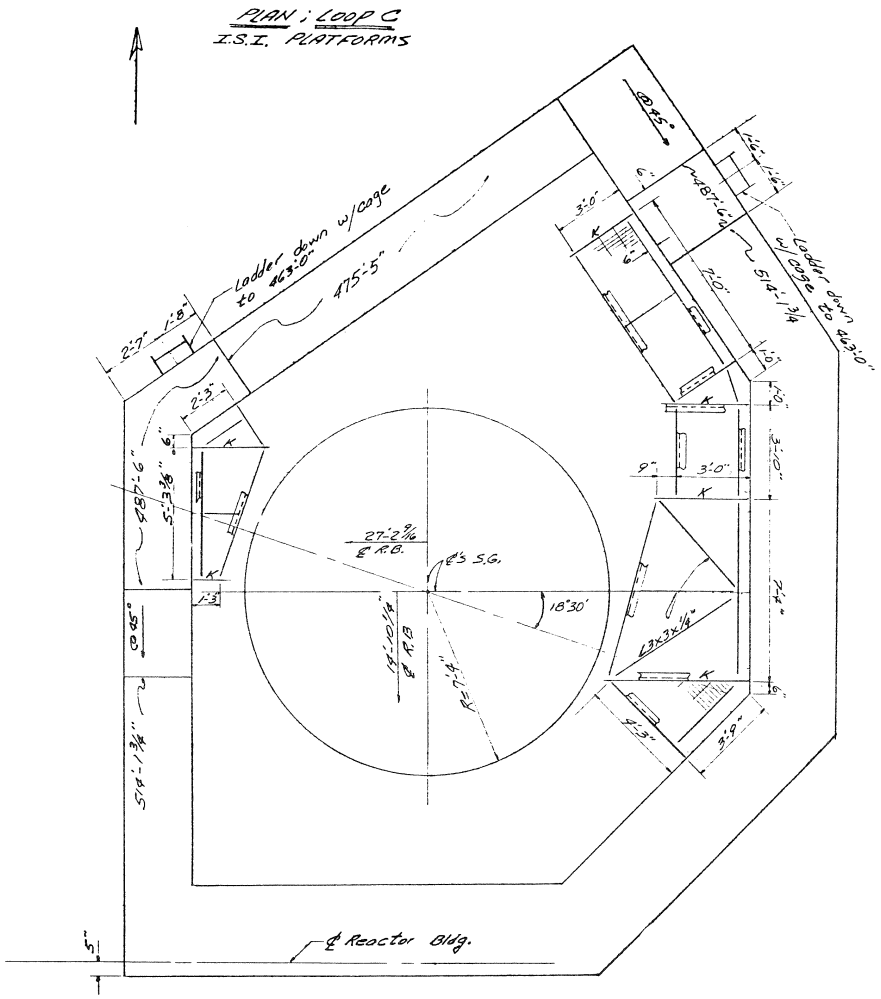


Figure 6.2-80

REACTOR BUILDING - ISI PLATFORMS LOOP C PLATFORMS
ELEVATION 487' - 6", 487' - 8"



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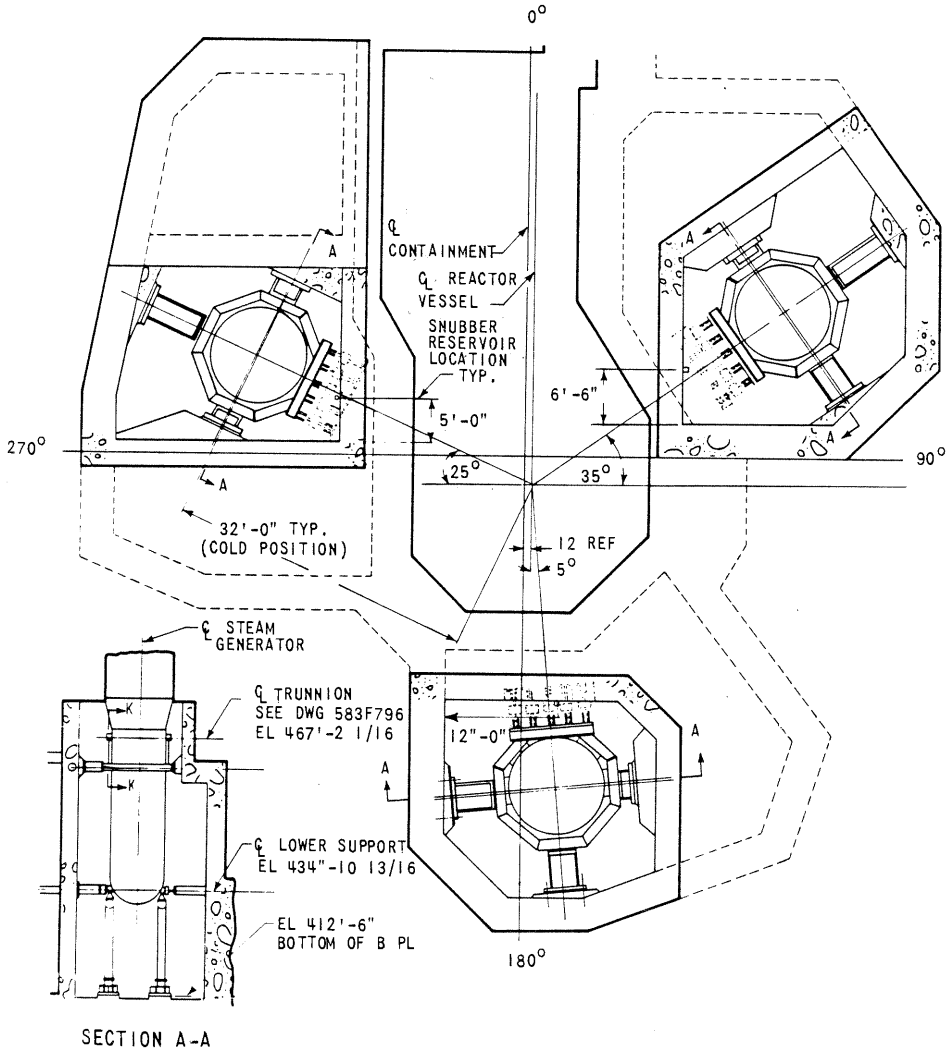
Reactor Building - ISI Platforms Loop C Platform Elevations 487' - 6", 487' - 8" Figure 6.2-80

Figure 6.2-81

STEAM GENERATOR UPPER LATERAL SUPPORTS - GENERAL ARRANGEMENT



AMENDMENT 0
AUGUST 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Steam Generator Upper Lateral Supports - General Arrangement
Figure 6.2-81

Figure 6.2-82
DRAWING E-304-661
FSAR FIGURE REFERENCE

Figure 6.2-83
DRAWING E-304-662
FSAR FIGURE REFERENCE

Figure 6.2-84
DRAWING E-304-667
FSAR FIGURE REFERENCE

6.3 EMERGENCY CORE COOLING SYSTEM

6.3.1 Design Bases

6.3.1.1 Range of Coolant Ruptures and Leaks

The emergency core cooling system (ECCS) is designed to cool the reactor core as well as to provide additional shutdown capability following initiation of the following accident conditions:

1. Pipe breaks in the reactor coolant system (RCS) which cause a discharge larger than that which can be made up by the normal makeup system, up to and including the instantaneous circumferential rupture of the largest pipe in the RCS.
2. Rupture of a control rod drive mechanism causing a rod cluster control assembly ejection accident.
3. Pipe breaks in the steam system, up to and including the instantaneous circumferential rupture of the largest pipe in the steam system.
4. A steam generator tube rupture.

The acceptance criteria for the consequences of each of these accidents are described in Chapter 15 in the respective accident analyses sections.

6.3.1.2 Fission Product Decay Heat

The primary function of the ECCS following a loss of coolant accident is to remove the stored and fission product decay heat from the reactor core such that fuel rod damage, to the extent that it would impair effective cooling of the core, is prevented. The acceptance criteria for the accidents, as well as analyses of the accidents are provided in Chapter 15.

6.3.1.3 Reactivity Required for Cold Shutdown

The ECCS provides shutdown capability following the accidents listed in Section 6.3.1.1 by means of injecting borated water. The most critical accident for shutdown capability, relative to this system, is the steam line break and for this the ECCS meets the criteria defined in Chapter 15.

6.3.1.4 Capability to Meet Functional Requirements

To ensure that the ECCS will perform its desired function during the accidents listed in Section 6.3.1.1, it is designed to tolerate a single active failure during the short term immediately following an accident, or to tolerate a single active or passive failure during the long term following an accident. This subject is detailed in Sections 3.1 and 6.3.2.11.

6.3.1.5 Loss of Offsite Power

The ECCS is designed to meet its minimum required level of functional performance with onsite electrical power system operation (assuming offsite power is not available) or with offsite

electrical power system operation for any of the above abnormal occurrences assuming a single failure as defined above.

6.3.1.6 Seismic Requirements

The ECCS is designed to perform its function of ensuring core cooling and providing shutdown capability following an accident under simultaneous safe shutdown earthquake (SSE) loading. The seismic requirements are defined in Chapter 3.

6.3.2 System Design

The ECCS components are designed such that a minimum of two accumulators, one charging pump and one residual heat removal pump together with their associated valves and piping will assure adequate core cooling in the event of a Design Basis Accident. The redundant onsite emergency diesels assure adequate emergency power to all electrically operated components in the event that a loss of offsite power occurs simultaneously with a loss of coolant accident, even assuming a single failure in the emergency power system such as the failure of one diesel to start. Also, at strategically identified local high points, the ECCS is provided with indicating air-traps to ensure the ECCS remains void free (reference NRC GL 2008-01).

6.3.2.1 Schematic Piping and Instrumentation Diagrams

Schematic piping and instrumentation and process flow diagrams of the ECCS are shown in Figure 6.3-1 (Sheets 1 through 3) and Figure 6.3-2, respectively. Pertinent design and operating parameters for the components of the ECCS are given in Table designed are listed in Table 3.2-1.

6.3.2.2 Equipment and Component Descriptions

The component design and operating conditions are specified as the most severe conditions to which each respective component is exposed. For each component, these conditions are considered in relation to the Code to which it is designed. By designing the components in accordance with applicable codes, and with due consideration for the design and operating conditions, the fundamental assurance of integrity of the ECCS components is maintained. Components of the ECCS are designed to withstand the appropriate seismic loadings in accordance with their safety class as given in Table 3.2-1.

The major mechanical components of the ECCS are discussed in Sections 6.3.2.2.1 through 6.3.2.2.6.

6.3.2.2.1 Accumulators

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. During normal operation each accumulator is isolated from the RCS by two check valves in series. Should the RCS pressure fall below the Accumulator pressure, the check valves open and borated water is forced into the RCS. One accumulator is attached to each of the cold

legs of the RCS. Mechanical operation of the swing-disc check valves is the only action required to open the injection path from the accumulators to the core via the cold leg.

Connections are provided for remotely adjusting the level and boron concentration of the borated water in each accumulator during normal operation as required. Accumulator water level may be adjusted either by draining to the refueling water storage tank or by pumping borated water from the refueling water storage tank to the accumulator. Samples of the solution in the accumulators are taken periodically for checks of boron concentration.

Accumulator pressure is provided by a supply of nitrogen gas, and can be adjusted as required during normal plant operation; however, the accumulators are normally isolated from this nitrogen supply. Gas relief valves on the accumulators protect them from pressures in excess of design pressure.

The accumulators are located within the reactor building but outside of the secondary shield wall which protects them from missiles. Since the accumulators are located within the reactor building, a release of the nitrogen gas in the accumulators would cause an increase in normal containment pressure. Containment pressure increase following release of the gas from all accumulators has been calculated and is well below the containment pressure setpoint for ECCS actuation.

Release of accumulator gas is indicated by the accumulator pressure indicators and alarms. Thus, the operator takes action promptly as required to maintain plant operation within the requirements of the Technical Specification covering accumulator operability.

6.3.2.2.2 Boron Injection Tank

Deleted by Amendment 3.

6.3.2.2.3 Boron Injection Surge Tank

Deleted by Amendment 3.

6.3.2.2.4 Pumps

6.3.2.2.4.1 Residual Heat Removal Pumps

In the event of a loss of coolant accident the residual heat removal pumps are started automatically on receipt of a safety injection signal. The residual heat removal pumps deliver water to the RCS from the refueling water storage tank during the injection phase and from the reactor building sump during the recirculation phase. Each residual heat removal pump is a single stage, vertical position, centrifugal pump. It has an integral motor-pump shaft driven by an induction motor. The unit has a self-contained mechanical seal cooled by component cooling water.

A minimum flow bypass line is provided for the pumps to recirculate and return the pump discharge fluid to the pump suction should the pumps be started with their normal flow paths

blocked. Once flow is established to the RCS, the bypass line is automatically closed. This line prevents deadheading of the pumps and permits pump testing during normal operation.

The residual heat removal pumps are discussed further in Section 5.5.7. A pump performance curve is given in Figure 6.3-3.

6.3.2.2.4.2 Centrifugal Charging Pumps

In the event of an accident. the two operable charging pumps are started automatically on receipt of a safety injection signal and are automatically aligned to take suction from the refueling water storage tank during injection. During recirculation, suction is provided by the residual heat removal pumps.

These pumps deliver flow to the RCS at the prevailing RCS pressure. Each centrifugal charging pump is a multistage diffuser design, barrel-type casing with vertical suction and discharge nozzles. The pump is driven through a speed increaser connected to an induction motor. The unit has a self-contained lubrication system which is cooled by component cooling water and a self-contained mechanical seal cooling system.

A minimum flow bypass line is provided on each pump discharge to recirculate flow to the volume control tank after cooling via the seal water heat exchanger during normal plant operation. Each minimum flow bypass line contains a valve which may be closed during the switchover from injection to recirculation. The common minimum flow bypass line also contains a valve which may be closed during the switchover to recirculation. A safety injection signal closes the valves to isolate the normal charging line and volume control tank and opens the charging pump/refueling water storage tank suction valves to align the high head portion of the ECCS for injection. During normal plant operation, at least one charging pump is continuously in service. The second pump is a non-running pump on the inactive loop and the third, if available, is designated as a spare and its breaker(s) are racked out. The other charging pumps may be tested during power operation via the minimum flow bypass lines.

Pump performance curves are given in Figures 6.3-4a, 6.3-4b, and 6.3-4c.

6.3.2.2.4.3 Boron Injection Recirculation Pumps

Deleted by Amendment 3.

6.3.2.2.4.4 Positive Displacement Hydrostatic Test Pump

This pump serves two functions, neither of which is safety-related. Permanent connections are provided to the accumulators to allow addition of borated water from the refueling water storage tank. Temporary connections permit the use of this pump in hydro-testing the plant piping systems and leak testing check valves as described in Section 5.2.2.4.

6.3.2.2.5 Residual Heat Exchangers

The residual heat exchangers are conventional shell and U-tube type units. The tubes are seal welded to the tubesheet. During normal cooldown operation, the residual heat removal pumps circulate reactor coolant through the tube side while component cooling water flows through the shell side. During emergency core cooling recirculation operation, water from the reactor building sump flows through the tube side.

A further discussion of the residual heat exchangers is found in Section 5.5.7.

6.3.2.2.6 Valves

Design parameters for all types of valves used in the ECCS are given in Table 6.3-1. Operability requirements are discussed in Section 3.9.

Design features employed to minimize valve leakage include:

1. Where possible, packless valves are used.
2. Other valves which are normally open, except check valves and those which perform a control function, are provided with backseats to limit stem leakage.
3. Normally closed globe valves are installed with recirculation fluid pressure under the seat to prevent stem leakage of recirculated (radioactive) water.
4. Relief valves are enclosed, i.e., they are provided with closed bonnet.

6.3.2.2.6.1 Motor Operated Valves

The seating design of all motor operated gate valves is of the Crane flexible wedge design. These designs release the mechanical holding force during the first increment of travel so that the motor operator works only against the frictional component of the hydraulic unbalance on the disc and the packing box friction. The discs are guided throughout the full disc travel to prevent chattering and to provide ease of gate movement. The seating surfaces are hard faced to prevent galling and to reduce wear. The discs for the SI/RHR sump recirc valves, XVG08811A(B)-SI and XVG08812A(B)-SI have been drilled with a 1/8 inch hole to provide assurance against pressure locking. This hole provides a drain path from the bonnet to the bearing block void space then through the hole to one side of the disc. A bonnet relief system has been installed on the bonnet of XVG08889-SI to eliminate postulated pressure locking conditions.

Where a gasket is employed for the body to bonnet joint, it is either a fully trapped, controlled compression, spiral wound gasket with provisions for seal welding, or it is of the pressure seal design with provisions for seal welding. The valve stuffing boxes are designed with a lantern ring leakoff connection with a minimum of a full set of packing below the lantern ring and a minimum of one-half of a set of packing above the lantern ring. A full set of packing is defined as a depth of packing equal to 1-1/2 times the stem diameter. The motor operator incorporates a “hammer blow” feature that allows the motor to impact the discs away from the seat upon opening or backseat upon closing. This “hammer blow” feature not only impacts the disc but allows the

motor to attain its operational speed prior to impact. Valves which must function against system pressure are designed such that they function with a pressure drop equal to full system pressure across the valve disc.

Each of the three centrifugal charging pump minimum flow bypass lines is equipped with a motor operated globe valve. The valves are of the bolted bonnet design utilizing a spiral wound asbestos gasket with provisions for seal welding. The seating surfaces are hard faced to prevent galling and reduce wear. The valve stuffing box contains six rings of packing. During normal operation with the valves open, fluid pressure at the packing glands is 40 psig due to the presence of restricting orifices upstream of the valves. Installation of the valves is such that the charging pump discharge pressure is under the valve seat to prevent stem leakage when the valve is closed.

6.3.2.2.6.2 Manual Globe, Gate, and Check Valves

Gate valves are either wedge design or parallel disc and are straight through. The wedge is either split or solid. All gate valves have backseat and outside screw and yoke.

Globe valves, “T” and “Y” style are full ported with outside screw and yoke construction.

Check valves are spring loaded lift piston types for sizes 2 inches and smaller, and swing type for sizes greater than 2 inches. Stainless steel check valves have no penetration welds other than the inlet, outlet, and bonnet. The check hinge is serviced through the bonnet.

The stem packing and gasket of the stainless steel manual globe and gate valves are similar to those described above for motor operated valves. Carbon steel manual valves are employed to pass nonradioactive fluids only and therefore do not contain the double packing and seal weld provisions.

The High Head Safety Injection Throttle valve(s) is a 2-inch y-pattern globe valve that does contain valve packing. The valve design provides the required stem travel for allowing sump debris to pass through.

6.3.2.2.6.3 Accumulator Check Valves (Swing-disc)

The accumulator check valve is designed with a low pressure drop configuration with all operating parts contained within the body.

Design considerations and analyses which assure that leakage across the check valves located in each accumulator injection line does not impair accumulator availability are as follows:

1. During normal operation the check valves are in the closed position with a nominal differential pressure across the disc of approximately 1650 psi. Since the valves remain in this position except for testing or when called upon to open following an accident, and are therefore not subject to the abuse of flowing operation or impact loads caused by sudden

flow reversal and seating, they do not experience significant wear of the moving parts, and are expected to function with minimal backleakage. This backleakage can be checked via the test connection as described in Section 6.3.4.

2. When the RCS is being pressurized during the normal plant heatup operation, the check valves are tested for leakage as soon as reactor system pressure reaches about 2000 psi. This test confirms the seating of the disc and whether or not there has been an increase in the leakage since the last test. When this test is completed the accumulator discharge line motor operated isolation valves are re-opened. There should be no increase in leakage from this point on since increasing reactor coolant pressure increases the seating force and decreases the leakage.
3. The experience derived from the check valves employed in the emergency injection systems indicate that the system is reliable and workable; check valve leakage has not been a problem. This is substantiated by the satisfactory experience obtained from operation of the Robert Emmett Ginna Station and subsequent plants where the usage of check valves is identical to this application.
4. The accumulators can accept some inleakage from the RCS without affecting availability. Inleakage would require, however, that the accumulator water volume be adjusted in accordance with Technical Specification requirements.

6.3.2.2.6.4 Relief Valves

Relief valves are installed in various sections of the ECCS to protect lines which have a lower design pressure than the RCS. Valves that are, or potentially could be, in contact with borated water are constructed with stainless steel bodies. The bonnets of valves equipped with a balancing bellows are carbon steel. Bonnets of valves which are not equipped with a balancing bellows are stainless steel. The accumulator nitrogen supply relief valve does not have a potential to contact borated water, and the body and bonnet are constructed of carbon steel. Table 6.3-2 lists the systems relief valves with their capacities and setpoints.

6.3.2.2.6.5 Butterfly Valves

Each main residual heat removal line has an air operated butterfly valve which is normally open and is designed to fail in the open position. The actuator is arranged such that air pressure on the diaphragm overcomes the spring force, causing the linkage to move the butterfly to the closed position. Upon loss of air pressure, the spring returns the butterfly to the open position. These valves are left in the full open position during normal operation to maximize flow from this system to the RCS during the injection mode of the ECCS operation. These valves are used during normal residual heat removal system (RHRS) operation to control cooldown flowrate.

Each residual heat removal heat exchanger bypass line has an air operated butterfly valve which is normally closed and is designed to fail closed. These valves are used during normal cooldown to avoid thermal shock to the residual heat exchanger.

Monitor lights on the control board and alarms via the Bypass Inoperable Status Indication (BISI) CRT displays in the Control Room provide indication that the valves are and remain in the correct (open) position.

6.3.2.2.7 System Operation

The operation of the ECCS, following a loss of coolant accident, can be divided into two distinct modes:

1. The injection mode in which any reactivity increase following the postulated accident is terminated; initial cooling of the core is accomplished; and coolant lost from the primary system is replenished, and
2. The recirculation mode in which long term core cooling is provided during the accident recovery period.

A discussion of these modes follows.

The principal mechanical components of the ECCS which provide core cooling immediately following a loss of coolant accident are the accumulators, the centrifugal charging pumps, and the residual heat removal pumps.

For large pipe ruptures, the RCS is depressurized and voided of coolant rapidly, and a high flowrate of emergency coolant is required to quickly cover the exposed fuel rods and limit possible core damage. This high flow is provided by the passive accumulators, followed by the charging pumps and the residual heat removal pumps discharging into the cold legs of the RCS.

Emergency cooling is provided for small ruptures primarily by high head Injection.(1) Small ruptures are those which do not immediately depressurize the RCS below the accumulator discharge pressure. The centrifugal charging pumps deliver borated water at the prevailing RCS pressure to the cold legs of the RCS. During the injection mode, the charging pumps take suction from the refueling water storage tank. Evaluation of these small ruptures is also discussed in Sections 3.6.1.1.3 and 15.3.1.

The residual heat removal pumps take suction from the refueling water storage tank and deliver borated water to the RCS. These pumps begin to deliver water to the RCS only after the pressure has fallen below the pump shutoff head.

(1) The centrifugal charging pumps are commonly referred to as “high head pumps” and the residual heat removal pumps as “low head pumps.” Likewise, the term “high head injection” is used to denote charging pump injection and “low head injection” refers to residual heat removal pump injection.

Core protection is afforded with the minimum engineered safety feature equipment. The minimum engineered safety feature equipment is defined by consideration of the single failure criteria as discussed in Sections 3.1, 6.3.1.4, and 6.3.2.11. The minimum design case will ensure the entire break spectrum is accounted for and core cooling design bases of Section 6.3.1 are met. The analyses for this case are presented in Sections 15.3 and 15.4.

The Technical Specifications permit various pumps of the ECCS to be inoperable during power operation and for an additional time period while the reactor is at hot shutdown, provided that the remaining pump has been demonstrated to be operable prior to the repair. With regard to these repair times:

1. In most cases, repairs will be completed within the allowable time period.
2. If it is determined that this time period is not adequate to restore the component to the operable condition, putting the reactor in the hot shutdown condition significantly reduces the cooling requirements following a postulated loss of coolant accident.
3. Failure to complete repairs within the designated time interval after going to hot shutdown is considered indicative of a requirement for major maintenance and therefore the reactor is put in the cold shutdown condition.

The injection mode of emergency core cooling is initiated by the safety injection signal. This signal is actuated by any of the following:

1. Low pressurizer pressure
2. High Reactor Building pressure
3. High differential pressure between any two steam lines
4. Low Steam line pressure
5. Manual actuation

Operation of the ECCS during the injection mode is completely automatic. The safety injection signal automatically initiates the following actions:

1. Starts the emergency diesel generators, which if all other sources of power are lost, supplies the engineered safety feature buses.
2. Starts the charging pumps and the residual heat removal pumps.
3. Aligns the charging pumps for injection by:
   a. Closing the valves in the charging pump discharge line to the normal charging line.
   b. Opening the high head injection isolation valves.
   c. Opening the valves in the charging pumps suction line from the refueling water storage tank.

d. Closing the valves in the charging pump normal suction line from the volume control tank.

Remotely operated valves for the injection mode which are under manual control (i.e., valves which normally are in their ready position and do not require a safety injection signal) have their positions indicated on a common portion of the control board. If a component is out of its proper position, its monitor light will indicate this on the control board. At any time during operation when one of these valves is not in the ready position for injection, this condition is alarmed and shown visually on the board.

Process instrumentation available to the operator in the control room to provide him with appropriate and useful information during the automatic injection mode of operation are listed in Section 7.5.

The injection mode continues until the residual heat removal pumps have been realigned to the recirculation mode. During the injection mode all pumps take suction from the refueling water storage tank until a lo-lo level signal from the refueling water storage tank aligns the residual heat removal pumps to take suction from the reactor building sump. This signal also actuates an alarm to alert the operator to complete the realignment of the ECCS to the recirculation mode. The switchover procedure that must be performed by the operator is given in Table 6.3-3.

After the injection operation, water collected in the reactor building sump is cooled and returned to the RCS via the low/high head recirculation flow paths. The residual heat removal pumps are aligned to take suction from the reactor building sump and to deliver directly to the RCS and to supply suction to the charging pumps. The charging pumps deliver flow directly to the RCS cold legs. This latter mode of operation assures flow in the event of a small rupture where the depressurization proceeds more slowly such that the RCS pressure is still in excess of the shutoff head of the residual heat removal pumps at the onset of recirculation.

The maximum predicted water level elevation inside the Reactor Building following a postulated large break LOCA is elevation 419.229 feet. This height was calculated based upon the following:

1. The total amount of water available to flood the bottom of the Reactor Building is conservatively assumed to include:
   a. Water in the refueling water storage tank (RWST) from the maximum full level to the empty level alarm.
   b. The entire water inventory of the safety injection accumulators.
   c. The entire water inventory of the sodium hydroxide storage tank.
   d. The inventory of the reactor coolant system above the level of the reactor vessel nozzles.
2. The effective height of the Reactor Building basement floor was determined by weighing the heights of the various portions of the floor by the area of each portion.
3. The volume of all significant structures and equipment that reduces the free volume above the basement floor is explicitly accounted for in the calculations.

4. The volumes of the sumps and the incore instrumentation pit, which would fill with water following a LOCA and, thus reduce the volume of the water above the basement floor, are explicitly accounted for in the calculations.

As part of a Cycle 12 specific evaluation, an additional flood elevation was determined for LOCA with no single failures. The Reactor Building flood elevation was recalculated at 418.883' (418' 10.956") for this case. This flood level was calculated using operator time lines for swap-over. This no single failure case is also analyzed with the RWST filled to the overflow as an initial condition.

A calculation was also performed for a double ended main steam line break which resulted in a predicted flood level below the LOCA level. This calculation was performed using the same methodology and assumptions used for the LOCA calculation described above, except that the inventory of the safety injection accumulators and the inventory of the reactor coolant system above the reactor vessel nozzles was not included.

The location of equipment inside the Reactor Building has been reviewed to identify safety grade and associated non-safety grade equipment that would be submerged as a result of an accident.

The review resulted in the identification of valves and instrumentation that would be below a design value for the flood level of 420'0". Submerged instrumentation identified as a result of the review is in one of the following categories:

1. Instrumentation is non-safety grade but is associated with safety grade equipment. Fuses and/or circuit breakers provide sufficient protection to prevent adverse consequences to the safety grade equipment. Instruments in this category include level, pressure, and temperature monitoring devices that are used for normal control purposes and do not have any protection system functions.
2. The instrumentation is safety grade and is submerged while required to operate. Instrumentation in this category has been qualified as discussed in revised Section 3.11.1.2. Instruments in this category include post accident monitoring instrumentation associated with the reactor building RHR pump sumps and reactor building spray pump sumps (recirculation sumps).

Flooding outside the Reactor Building as a result of an accident will not affect safety grade equipment since protection is provided as follows:

1. Curbs are located at entrances to cubicles housing safety grade equipment.
2. Leakage detection systems, described in Section 7.6.5, are provided.

For a discussion of flooding outside the Reactor Building as a result of site flooding, see Section 3.4.

The location of valves inside the Reactor Building has been reviewed to identify safety grade and associated nonsafety grade valves flooded as a result of an accident. The review resulted in

identification of the valves discussed below which have some portion of the electrical circuits associated with the valve operators below the design flood level. Features that preclude adverse safety consequences or adverse consequences follows:

1. Valve, Tag No. HCV00137

   This valve, which is associated nonsafety grade equipment, is used for letdown flow control. Fuses provide sufficient protection to prevent adverse consequences to safety grade equipment. The electrical circuitry associated with this valve consists of a 4 to 20 ma signal transmitted from a Westinghouse Remote/Manual Setpoint Station which is connected to a 45 volt d-c power supply. This 45 volt d-c power is protected by a 1/2 ampere fuse on the load side of the power supply. The circuitry is not “protection grade” and serves only a “control function.” Loss of this circuit does not jeopardize plant safety.

2. Valve, Tag No. LCV01003

   This valve, which is associated with nonsafety grade equipment, is used for level control in the reactor coolant drain tank. It is provided with a positioning signal from the waste processing panel. The electrical circuitry associated with this valve is not “protection grade” and serves only a “control function.” Loss of this circuit does not jeopardize plant safety.

3. Valve, Tag No. XVM08143

   This valve, which is associated with nonsafety grade equipment, is used to direct excess letdown flow to either the volume control tank or the reactor coolant drain tank. Fuses provide sufficient protection to prevent adverse consequences to safety grade equipment. Electrical circuits for this valve are illustrated by GAI Drawing B-208-021, Sheet CS79, submitted as part of the Wiring and Schematic Package (see also Section 1.7).

4. Valves, Tag Nos. XVT08153 and 8154

   These valves, which are located in series, are used for redundant isolation of the reactor coolant system from the excess letdown heat exchangers. These valves are closed during normal plant operation, except as an alternate Letdown Flow path if normal Letdown has been isolated. These valves are open only during startup. Fuses provide sufficient protection to prevent spurious operation after flooding since limit switches are not used for seal-in or interlock functions. Electrical circuits for these valves are illustrated by GAI Drawings B-208-021, Sheet CS87 (valve 8153) and Sheet CS88 (valve 8154) submitted as part of the Wiring and Schematic Package (see also Section 1.7).

5. Valve, Tag No. XVG08701A

   Safety functions of this valve are isolation of residual heat removal system from the reactor coolant system, containment isolation, and interlock of external limit switch to valve 8706A. Performance of these isolation functions are assured by the institution of administrative controls to close the valve, and open the circuit breaker at the motor control center during power operation. The external limit switch, which is interlocked to valve 8706A, is above the design flood level.

6. Valve, Tag No. XVG08701B

   Safety function of this valve are isolation of residual heat removal system from the reactor coolant system, containment isolation, and interlock of external limit switch to valve 8706B. Performance of the isolation functions are assured by the institution of administrative controls to close the valve and open the circuit breaker at the motor control center during power operation. The external limit switch, which is interlocked to valve 8706B, is above the design flood level.

7. Valve, Tag No. XVG08702A

   Safety functions of this valve are isolation of residual heat removal to reactor coolant system and interlock of external limit switch to valve 8706A. Performance of the isolation function is assured by the institution of administrative controls to close the valve and open the circuit breaker at the motor control center during power operation. The external limit switch, which is interlocked to valve 8706A, is moved above the design flood level.

8. Valve, Tag No. XVG08702B

   Safety functions of this valve are isolation of residual heat removal system from the reactor coolant system and interlock of external limit switch to valve 8706B. Performance of the isolation function is assured by the institution of administrative controls to close the valve and open the circuit breaker at the motor control center during power operation. The external limit switch, which is interlocked to valve 8706B, is above the design flood level.

9. Valves, Tag No. LCV00459 and 460

   These valves, which are located in series, are used for redundant isolation of the reactor coolant system letdown. These valves are open during normal plant operation. They do not get an automatic closure signal from the reactor protection system and are not required to close in an accident condition. They are fail closed valves and are not required to function in accident conditions. Isolation of the RCS is provided by the Letdown Isolation valves, XVT08149A, B, and C and XVT08152. Fuses provide sufficient protection to prevent the valves' controls from adversely affecting any other components.

Within 8 hours following the loss of coolant accident, simultaneous hot leg and cold leg recirculation will be initiated to avoid boron precipitation in the core and to terminate boiling.

Core cooling during recirculation can be maintained by the flow from one residual heat removal pump if RCS pressure is low. If RCS pressure remains high, one charging pump operating in series with one residual heat removal pump provides sufficient additional head.

Initially the recirculated water is at a slightly subcooled condition. The residual heat removal pumps deliver this sump water to the RCS via the residual heat exchangers which subcool the water further. When the water is delivered to the reactor vessel, the majority of the subcooled water spills back to the sump through the broken RCS loop. The system pressure at the time recirculation is initiated is dependent on the initiating break size. Heat removal is accomplished from the recirculated sump water by operation of one or both of the residual heat exchangers.

The ECCS recirculation loop piping and components external to the Reactor Building are surrounded by shielding. This shielding is designed to permit access for maintenance to a component such as a pump while the redundant component is recirculating sump fluid.

Pressure relieving devices, from portions of the ECCS located outside the Reactor Building which might contain radioactivity, discharge to the recycle holdup tanks.

An analysis has been performed to evaluate the radiological effects of recirculation loop leakage. A discussion of the analysis and releases is provided in Section 15.4.1.4.2. A loop is assumed to include a centrifugal charging pump, a residual heat removal pump, a residual heat exchanger, and the associated piping. Thus, two separate loops are provided, each of which is adequate for core cooling.

Since redundant flow paths are provided during recirculation, a leaking component in one of the flow paths may be isolated. This action curtails any further leakage and renders the component available for corrective maintenance. Maximum potential external recirculation loop leakage is given in Table 6.3-4.

During recirculation, significant margin exists between the design and operating conditions (in terms of pressure and temperature) of the ECCS components.

6.3.2.3 Applicable Codes and Classifications

The codes and standards to which the individual components of the ECCS are designed are listed in Table 3.2-1.

6.3.2.4 Materials Specifications and Compatibility

Materials employed for components of the ECCS are given in Table 6.3-5. Materials are selected to meet the applicable material requirements of the codes in Table 3.2-1 and the following additional requirements:

1. All parts of components in contact with borated water are fabricated of or clad with austenitic stainless steel or equivalent corrosion resistant material.

2. All parts of components in contact (internal) with sump solution during recirculation are fabricated of austenitic stainless steel or equivalent corrosion resistant material. A soft seat material that is approved for system chemistry and design requirements is used in selected manual valves to minimize potential leakage.
3. Valve seating surfaces are hard faced with Stellite Number 6 or equivalent to prevent galling and to reduce wear.
4. Valve stem materials are selected for their corrosion resistance, high tensile properties, and resistance to surface scoring by the packing.

No cold worked austenitic stainless steel having a yield strength greater than 90,000 psi is used in the ECCS.

The elevated temperature of the sump solution during recirculation is well within the design temperature of all ECCS components. In addition, consideration has been given to the potential for corrosion of various types of metals exposed to the fluid conditions prevalent immediately after the accident or during long term recirculation operations.

Environmental testing of ECCS equipment inside the Reactor Building, which is required to operate following a loss of coolant accident, is discussed in Section 3.11. These components were qualified to function following exposure to a chemical spray solution equivalent to the Post LOCA spray described in Section 3.11.5.1.2. The environmental qualification test results of the engineered safety feature equipment indicate that this equipment will operate satisfactorily during and following exposure to the combined Reactor Building post accident environments of temperature, pressure, chemistry and radiation.

In addition to environmental testing of ECCS equipment, discussed in Section 3.11, the integrity of the materials of construction of engineered safety features equipment when exposed to post-design basis accident (DBA) conditions has been evaluated. Post-DBA conditions were conservatively represented by test conditions. The test program (Reference 2) performed by Westinghouse considered spray and core cooling solutions of the design chemical compositions, as well as the design chemical compositions contaminated with corrosion and deterioration products which may be transferred to the solution during recirculation. The effects of sodium (free caustic), chlorine (chloride), and fluorine (fluoride) on austenitic stainless steels were considered. Based on the results of this investigation, as well as testing by Oak Ridge National Laboratory (ORNL) and others, the behavior of austenitic stainless steels in the post-DBA environment will be acceptable. No cracking is anticipated on any equipment even in the presence of postulated levels of contaminants, provided the core cooling and spray solution pH is maintained at an adequate level. The inhibitive properties of alkalinity (hydroxyl ion) against chloride cracking and the inhibitive characteristic of boric acid on fluoride cracking have been demonstrated.

6.3.2.5 Design Pressures and Temperatures

The component design pressure and temperature conditions are given in Table 6.3-1. These pressure and temperature conditions are specified as the most severe conditions to which each

respective component (including the piping) is exposed. For each component, these conditions are considered in relation to the code to which it is designed. By designing the components in accordance with applicable codes (see Section 3.2) and with due consideration for the design and operation conditions, the fundamental assurance of structural integrity of the ECCS components is maintained.

6.3.2.6 Coolant Quantity

A minimum volume is required to be stored in the refueling water storage tank (see Table 6.3-6) to ensure that after RCS pipe ruptures, sufficient water will be injected to satisfy LOCA requirements and then be available within the Reactor Building to permit recirculation of cooling flow to the core, and to meet the net positive suction head requirements of the charging, residual heat removal pumps, and RB spray pumps. Also, sufficient water must be available for the prevention of RWST vortex formation, especially during the transition from cold leg injection to cold leg recirculation.

The sizing design bases for the refueling water storage tank (RWST) include the following design allowances:

a. A minimum volume of water (350,000 gallons) is maintained above the nominal lo-lo level semi-automatic switchover setpoint. This amount is more than sufficient to satisfy the injection requirements for LOCA. The RWST is designed to be kept at the “normal full” level during normal power operation. The volume of water in the RWST between the nominal “normal full” level and the nominal “lo-lo” level semi-automatic switchover setpoint is 387,245 gallons. This provides a margin of 37,245 gallons as compared to the 350,000 gallons.
b. The normal and accident errors for the RWST level instrumentation are accounted for in the time line for completing the transition from the injection phase to the recirculation phase.
c. For normal working allowance, the operator has at least 4,627 gallons between the maximum full level and the minimum full level (lo level), with normal instrument error conservatively combined.
d. The RWST level accounts for the “lo-lo” level setpoint error.
e. No-failure and various single failures that hinder the automatic actions of the transfer are considered for manual operator action timing to complete the transition.
f. The unusable volume in the RWST, from the tank bottom to the critical vortex level is 38,671 gallons. However, 10,266 gallons of the 38,671 gallons are above the top of the outlet nozzle.

In addition to the design allowances outlined above, the design of RWST includes an anti-vortex baffle assembly (see Figure 6.3-7) which consists of a horizontal plate supported over the outlet nozzle. Welded to the end of the horizontal plate is a vertical plate extending downward to the tank bottom. The water must enter the two open sides of the “box” formed by the two plates and

the tank, and make a 90-degree turn before exiting into the outlet pipe. The baffle assembly greatly reduces the tank level where air-inducing vortices begin to form. To show the effectiveness of the baffle, tests were performed on a ¼ scale model of the RWST. The results of the tests show that critical vortex levels are a linear function with total RWST outflow. At the maximum RWST outflow of 14,575 gpm, the critical vortex level is 5% RWST level, which is ~ 1 foot above the top of the outlet pipe and is coincident with the top of the baffle assembly.

Maximum total RWST outflow during injection mode operation, for LBLOCA, is 14,575 gpm and, for SBLOCA is 6975 gpm (975 gpm for two CHG pumps and 3000 gpm/pump for two RB Spray pumps). Given the minimum volume of 350,000 gallons above the lo-lo setpoint, the shortest times from LOCA initiation to receipt of the lo-lo semi-automatic switchover signal are approximately 24 minutes and 50 minutes for LB and SBLOCA respectively.

The switchover portion of the ECCS system features a semi-automatic scheme. The “lo-lo” level semi-automatic switchover signal in the RWST, coincident with a safety injection signal causes the RHR and Reactor Building spray suction valves from the Reactor Building recirculation sumps to automatically open (valves 3004A(B), 3005A(B), 8811A(B), and 8812A(B)). The RWST suction isolation valves (8809A(B) and 3001A(B) auto close on full open signals from the corresponding recirculation sump suction valves. To ensure that ECCS pumps and RB spray pumps have a suction source, the operator must complete actions to accomplish the transition from injection to recirculation mode prior to the depletion of the transfer allowance. The required operator actions are detailed in Table 6.3-3. The time available for switchover is dependent upon the flow rate out of the RWST as the switchover actions are performed. In order to provide conservative time allowances for the completion of these actions, the following are assumed:

1. The RWST volume available for switchover is defined as the transfer allowance.
2. The operator will secure all pumps taking suction from the RWST at 10% RWST indicated level.
3. Containment and RCS pressures for large break conditions are assumed to be 0 psig. Thus, no credit is taken for the reduction in RWST outflow that will result with higher containment and RCS pressures following a large break.

   The same conservative assumption is made for the small break conditions (except that RCS pressure is assumed to be greater than RHR pump shutoff head resulting in no RHR pump flow to the RCS for small break conditions). Because the RHR pump is deadheaded during the small break, backflow from the RWST to the sump will occur when the RHR sump suction valves open at the lo-lo semi-automatic switchover setpoint when 0 psig RB pressure is assumed. This effect is considered in the timeline development.
4. Flow out of the RWST during switchover includes allowances for both pumped flow to the RCS and containment and backflow to the Reactor Building recirculation sumps based upon the 0 psig containment pressure assumption. Pump flow rates are assumed to be constant during switchover and include the following conservative flow rates:
   a. Charging pump - 975 gpm for two pumps and 688 gpm for one pump
   b. RHR pump - 7600 gpm for two pumps and 4500 gpm for one pump

c. Reactor Building Spray Pump – 3000 gpm per pump

Backflow to the Reactor Building recirculation sumps will occur during ECCS switchover based upon the 0 psig containment pressure assumption if the RWST suction and Sump suction valves are both open and the corresponding RHR or RB Spray pump is secured (or RHR pump is deadheaded in a SBLOCA). Backflow will vary as the switchover proceeds, depending upon ECCS alignment and postulated failures.

5. Flow rates out of the RWST for both the no failure condition and the worst single failure condition vary as the switchover proceeds. The RWST outflow vs. time is calculated and used to determine limiting allowed timelines for the completion of switchover before the transfer allowance is depleted.

The large break cases are limiting with respect to the targeted timelines. The timelines presented provide sufficient time for the operator to successfully complete the switchover. It may be necessary to secure pump(s) when it is determined that the suction(s) cannot be transferred from the RWST. This conserves RWST water for the completion of the switchover in the event of a failure.

6.3.2.6.1 Containment Sump and its Effect on Long Term Cooling Following a LOCA

The Virgil C. Summer Nuclear Station Technical Specifications require that each Emergency Core Cooling System (ECCS) subsystem be demonstrated operable by a visual inspection. This visual inspection verifies that no loose debris is present in the Reactor Building which could be transported to the RHR and RB Spray sumps to cause restriction of their pump suctions. This inspection is performed immediately:

1. For all accessible areas of the Reactor Building prior to establishing CONTAINMENT INTEGRITY, and
2. In the areas affected within the Reactor Building at the completion of each Reactor Building entry when CONTAINMENT INTEGRITY is established.

Station Surveillance Test Procedures cover these requirements.

The Virgil C. Summer Nuclear Station Technical Specifications require a visual inspection of each containment sump and subsystem suction inlet at least once every 18 months. Station Surveillance Test Procedures have been written to satisfy these requirements. The suction inlets and sump components are inspected to ensure that debris is not present and that no evidence exists of structural distress or abnormal corrosion.

An instruction dealing with possible ECCS sump blockage is contained in the Virgil C. Summer Nuclear Station Emergency Operating Procedures (EOP-2.2). This procedure addressed long term cooling and requires the operator to monitor pump discharge pressure and motor amps when in the sump recirculation mode. It also cautions the operator that if pump discharge pressure or amps decrease, the cause may be sump blockage. If there is an indication of sump blockage, the

operator is instructed to close the associated bypass valve and throttle the outlet valve to stabilize pump amps. If suction is completely lost, the operator is instructed to stop the affected pump. If at least one flow path from RHR sumps to RCS can not be established or maintained, the operator is directed to EOP-2.4 Loss of Emergency Coolant Recirculation.

Two separate redundant ECCS Sumps, Sump A and Sump B, are provided for the Virgil C. Summer Nuclear Station. Sump A and Sump B each includes a separate deep sump pit for RHR and for RB spray. The strainer assemblies located over each deep sump pit and the cross duct between the RHR and RB Spray header boxes within each sump are described in Section 6.2.2.2.1.1. FSAR Figure 1.2-4 shows the physical separation between these sumps and the Reactor Building drain sump. The Reactor Building drainage system as well as the Refueling Canal drain are located such that this drainage water flow does not directly impinge in the sump areas. There are no high energy lines in the areas which will subject the sumps to postulated pipe whip or jet impingement loads and cause subsequent damage.

There is also a 6 inch high toe plate around the perimeter of the mezzanine and operating floors that prevents water from cascading down through the space between the floor perimeter and the containment wall to the sumps below. Water on the operating floor at 463’ will tend to go down through the stair wells for Stairways A and B. At the Stairway A on mezzanine floor at 436’, a 6 inch high toe plate incorporated into a hinged gate is located across the head of Stairway A. The gate is in the closed position during operation and the toe plate on the bottom of the gate diverts water flowing across the elevation 436’ floor from entering Stairway A and falling near Sump A at the 412’ basement floor level. Water flowing across the 436’ floor falls to the sump level at the 412’ floor either through the Stairway B or through two 8 foot long openings provided through the floor perimeter toe plate and which are located around the containment perimeter away from the ECCS Sumps A and B.

Sump A is surrounded on four sides and Sump B on three sides by a continuous 6 inch high curb at the basement floor level 412’. The fourth side of Sump B is bounded by a concrete secondary compartment wall. The floor level within the sumps is at elevation 408’. The sump strainer assemblies located at the 408’ level preclude debris entry down into the deep sump pits and into the recirculation piping. The LOCA condition water level when recirculation begins is approximately 6 to 7 feet above the general sump floor at elevation 408’. A horizontal grating with top elevation 412’-9” is provided over the sumps. The 6 inch curb and grating serve to limit debris and trash from transport down to the sump strainers. An engineered opening is provided through the grating to provide sufficient flow into the sumps assuming a postulated worst case where the horizontal grating surface is covered by debris following a postulated LOCA. The suction strainer assembly design is described in Section 6.2.2.2.1.1. The strainer openings are limited to 1/16 inch diameter holes to limit the size and quantity of debris permitted to pass through the strainers. The strainer fins and header box are designed with openings (maximum 1/16 inch hole size) that provide venting for air in the system as the sump fills. A hinged and bolted hatch cover is provided on the top of each of the four sump strainer header boxes located over the deep sump pits to permit personnel entry to the deep sump pit for inspection purposes. Components of the ECCS sumps are seismically designed for Seismic Category 1 conditions and are constructed of stainless steel.

In addition to the curbing around the sumps and grating over the sumps which serve to limit trash and debris transport to the sump strainers at the 408’ level, two partitions with integral gates consisting of welded stainless steel bars are provided at the 412’ floor level, one on either side of the area in which Sump A and Sump B are located. These partitions have bar spacing approximately 8 inches by 8 inches maximum and serve to stop postulated large trash items inadvertently left in the Reactor Building following a refueling outage from transporting to the sump strainers. The partitions are a minimum of approximately 7 feet high and span across the perimeter circumferential corridor between the secondary compartment concrete wall and the Reactor Building inside surface. A separation space is provided between the partitions and the Reactor Building inside surface to ensure no interaction under design base conditions including seismic. The welded stainless steel bar gates and partitions are designed for Seismic Category 1 conditions. The gates are maintained in the closed position when the plant is in operation.

Analysis and testing have been completed to evaluate sump strainer blockage and head loss in response to Generic Letter 2004-02. The analysis is comprised of five steps:

1. Debris Generation covers LOCA jet impact on insulation and Level 1 coatings, latent debris (dust and dirt on containment surfaces), coatings, labeling and placards which may disbond during design basis events and containment Foreign Material Exclusion which are identified during containment closeout inspection.
2. Debris Transport determines the fraction of debris (based on type, size and location) that may transport to the sump strainer. The analysis uses Computational Fluid Dynamics (CFD) modeling to determine post-LOCA sump flow velocities and experimental data on debris transport velocities.
3. Debris Accumulation combines the Generation and Transport analysis to develop debris loading cases for the strainer which includes type and quantity of debris.
4. Chemical Effects analysis which determines the quantity and time-line for aluminum corrosion precipitant entering the sump fluid and adding to the debris load.
5. Debris Headloss determines the pressure drop across the strainer screen using the strainer surface area, debris load and expected fluid velocity. For V. C. Summer Nuclear Station (VCSNS) the head loss is based on small scale chemical effects testing covered in Technical Report TR04560-004 (Reference 3).

Three (3) types of insulation are used inside the Reactor Building: all stainless steel reflective insulation, encapsulated Marinite XL, and TempMat. The Marinite XL and TempMat are used in limited applications and are encased in stainless steel.

The stainless steel reflective insulation is used on most piping and major components within the Reactor Building such as the steam generators, pressurizer and reactor vessel. If impacted by a LOCA jet, the stainless steel insulation cassettes may detach and break apart when the cassette hits the floor. If a cassette breaks open, the inner stainless foil is released. The foil and cassette body sink to the bottom of the containment pool. Testing and analysis have demonstrated that the stainless steel insulation debris does not readily transport (tumble along the floor) for the recirculation flow velocities calculated at VCSNS. Only a small amount is conservatively

predicted to reach the sump pit and would not present a sump blockage concern. Large scale testing of the sump strainer was also completed with the test strainer assembly completely covered in stainless steel insulation debris. The strainer head loss was well within acceptable limits and did not provide a design limiting sump strainer blockage case.

The Marinite XL is a mass type insulation used only around the reactor pressure vessel loop nozzles and portions of the reactor coolant pipe that penetrate the primary shield wall. The Marinite XL insulation cassettes around the nozzles serve a dual purpose for the VCSNS design. The first is thermal insulation. The second is a robust barrier around the nozzle to limit LOCA jet expansion into the reactor vessel cavity and pressurization of the primary shield wall. The insulation cassettes are Marinite XL machined to fit the nozzle taper and encased in 1/4 inch stainless steel. The cassettes are specifically designed to withstand the LOCA jet forces from a double ended guillotine break at the reactor vessel nozzle safe end. Due to this robust design, Marinite XL around the reactor vessel nozzles is not postulated to become LOCA generated debris.

A 1 inch thickness of Marinite XL is also used around the primary loop piping as it passes through the primary shield wall. For a break within the primary shield wall, the Marinite XL insulation is assumed to be fully particulated by the LOCA jet and mechanical damage from pipe whip within the wall. In particulate form the Marinite XL is 100 percent transportable to the sump strainer. Only the Marinite XL insulation around one pipe is postulated to become debris since each pipe is physically separated within the primary shield wall. The limiting break location for Marinite XL debris load is the loop C cold leg nozzle which has the largest volume of Marinite XL.

TempMat fibrous insulation is used on pressurizer ventilation ducts and steam generator level instrument lines in the loop A and loop C compartments. The TempMat insulating material is encased with stainless steel in each location. The three locations are in separate rooms such that only one location can be impacted by a LOCA jet. Debris Generation and Debris Transport calculations determine the limiting TempMat debris load is from the A loop compartment with a break at the steam generator outlet on the 31 inch cross-over leg.

In response to an NRC RAI, the limiting debris load cases for Marinite XL and for TempMat were tested to determine the limiting debris load for strainer head loss. Tests were carried out on a small scale test loop and demonstrated that the Marinite XL debris load is limiting by a substantial margin.

Other postulated debris sources include:

1. Rubber boots for reactor nozzle and support feet ventilation (six total).
2. Fifteen (15) fibrous reinforced silicon rubber enclosures which provide forced air cooling of equipment inside the pressurizer cubicle.
3. Rubber expansion joints in the ring header duct.
4. Kaowool wrapping (with stainless steel encasement sealed on edges with an elastomer sealant) for electrical conduit to meet separation criteria of electrical circuits for fire protection.

5. M-Board (with stainless steel encasement sealed on edges with an elastomer sealant) for electrical conduit and cable trays to meet separation criteria of electrical circuits for fire protection.
6. Unqualified labels and placards.
7. Failed and Unqualified coatings.
8. Latent Debris.

Two rubber boots on the reactor nozzle and support feet ventilation are located in each of the three loop compartments. The boots are bolted to the primary shield wall and clamped to the primary loop piping. The sump strainer analysis assumes two of the boots are dislodged by the LOCA jet and transported (100 percent) to the sump strainer. The analysis models the rubber boot debris load as a loss of surface area of the strainer. The rubber enclosures in the pressurizer cubicle are within the pressurizer cubicle and not subject to LOCA jet impingement from a loop compartment. The surface area of the rubber enclosures in the pressurizer compartment are bounded by the two rubber boots within a loop compartment, so the pressurizer rubber boots are not a limiting debris source. The ductwork expansion joints are located high in the Reactor Building along the perimeter. These are not subject to LOCA jet impingement and are not a sump strainer debris source.

The Kaowool is totally enclosed by a stainless steel corrugated tube which is split along the axial direction and installed over the Kaowool. The split tube is held in place by half inch wide banding straps. Strap spacing is 4 inches in the axial direction except at conduit supports. The ends of the encasement are sealed by an elastomer sealant to preclude entrance of any spray fluid into the encasement. The encasement assembly will also withstand seismic inputs to the installation without loss of structural integrity or sealing function. All Kaowool is located outside the Secondary Shield wall and are not subject to LOCA jet impingement. Kaowool does not enter the sump debris pool.

The M-Board installations are designed with total encasement of each M-Board by stainless steel sheets with the edges sealed by overlap of the sheets or angle clamps to preclude entrance of spray fluid. The assemblies of the various M-Board shapes are joined by angles and channels by bolting for structural strength and rigidity. The various sections which make up particular fire barrier are seismically qualified to remain in place. All of the M-Board installations are above post-LOCA sump fluid levels. One M-Board installation is located within the secondary shield wall, directly under the pressurizer. This location is only subject to LOCA jet impingement from a pressurizer surge line break. The M-Board fire barrier at this location is relative small and bounded by the Marinite XL debris load case.

A small amount of unqualified labels and placards were identified in response to Generic Letter 2004-02. These include items such as fire zone floor labeling, communication device labeling and similar material not qualified for design basis LOCA conditions. This material is assumed to disbond and transport to the sump strainer. The material is modeled as a loss of sump strainer surface area.

Failed coating assumptions for debris loading were made to provide operating margin for the Level 1 coating program. Unqualified coatings (non-Level 1 coatings) were also identified as a part of the Generic Letter 2004-02 response. All particulate is assumed to be 100 percent transportable to the sump strainer. Paint chips were a part of the Debris Transport calculation. Paint chips that arrived at the sump strainer were modeled as a loss of strainer surface area in the analysis.

Latent debris (dust and dirt) is based on containment housekeeping. Walk downs and sampling were completed in response to Generic Letter 2004-02 to develop a latent debris load. This debris is 100 percent transportable to the containment sump strainer.

Debris which washes down to the sump and passes through the strainer is evaluated for both blockage and erosion of downstream systems and components. The size of debris is limited by the 1/16 inch round holes in the perforated plate strainer. System and component downstream effects are analyzed based on methodology in WCAP-16406, Rev. 1 (Reference 4). The downstream effect on potential core blockage is a continuing industry effort with Virgil C. Summer Nuclear Station resolution plans specifically identified to the NRC in SCE&G letter RC-13-0006 from T. D. Gatlin to the Document Control Desk, Virgil C. Summer Nuclear Station (VCSNS) Unit 1, Path Forward for Resolution of Generic Safety Issue (GSI)-191.

The design basis head loss through the sump strainers was determined via testing on the small scale chemical effects test loops by the strainer vendor, Atomic Energy of Canada, Ltd. The test featured small scale corregated fins representative of those installed, debris addition tank and chemical additions. The test report is presented in Technical Report TR04650-004.

The analysis and testing was summarized and submitted to the NRC for review and approval. The submittals, NRC response and Request for Additional Information (RAI) are documented in the following correspondence:

1. SCE&G Letter RC-08-0031 (ADAMS Accession No. ML080640545) from Jeffrey B. Archie to Document Control Desk dated February 29, 2008, “Supplemental Response to NRC Generic Letter 2004-02: Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors.”
2. NRC Letter (ADAMS Accession No. ML090270927) from Robert E. Martin to Jeffrey B. Archie dated February 3, 2009, “V. C. Summer Nuclear Station - Request for Additional Information for Generic Letter 2004-02 (TAC NO. MC4721).”
3. SCE&G Letter RC-09-0134 (ADAMS Accession No. ML093360336) from Jeffrey B. Archie to Document Control Desk dated November 29, 2009, “Response to Request for Additional Information for Generic Letter 2004-02.”
4. SCE&G Letter RC-10-0165 (ADAMS Accession No. ML103610171) from T. D. Gatlin to Document Control Desk dated December 17, 2010, “Follow-up Response to Request for Additional Information for Generic Letter 2004-02.”

5. NRC Meeting Notes - “Summary of September 14, 2009 Public Conference Call to Discuss Responses to Generic Letter 2004-02 Requests for Additional Information (TAC NO. MC4721) (ADAMS Accession No. ML093000573).
6. NRC Memorandum E. L. Geiger to M. L. Scott, “Staff Review of WCAP-16571-P Referenced in Virgil C. Summer’s GL 2004-02 Supplemental Response for Downstream Effects Evaluation of Components,” May 17, 2010 (ADAMS Accession No. ML100920035).

RHR and RB Spray pump flow beyond rated runout is another condition which requires evaluation. Due to the different known and unknown conditions of operation, this evaluation is more important for the RHR system. Therefore, full scale tests of the RHR pumps were performed at the Virgil C. Summer Nuclear Station for the different modes of injection and recirculation. As a result of these tests, flow restricting orifices have been installed at the outlet of each heat exchanger. A retest of the RHR system will be performed to insure the adequacy of these orifices.

A full scale test of the RB Spray discharge ring headers and spray nozzles is not feasible. However, this system is only subjected to two worst case operating conditions, injection and recirculation, as its design basis. Full scale tests have been performed using the suction and recirculation test returns to the RWST. Test data on the suction piping has been compared to the results of the design calculations as a measure of their accuracy. A detailed analysis was then performed of the Reactor Building Spray System’s calculations to ensure that flow rates beyond runout are not possible with subsequent pump damage.

6.3.2.7 Pump Characteristics

Design parameters for the ECCS pumps are given in Table 6.3-1. Pump characteristic curves are shown in Figures 6.3-3 and 6.3-4a to 6.3-4c, see Section 5.5.7 for residual heat removal component data.

6.3.2.8 Heat Exchanger Characteristics

The design basis for the residual heat exchanger is discussed in Section 5.5.7. Design parameters appear in Table 5.5-8. The design is based on a normal cooldown rather than the recirculation phase of ECCS operation following a loss of coolant accident. This is due to the relatively small ΔT that exists on the tube side of the heat exchanger during the latter part of normal cooldown. Moreover, no credit is taken for the residual heat removal heat exchanger with respect to core cooling.

6.3.2.9 Emergency Core Cooling System Flow Diagrams

Piping and instrumentation and process flow diagrams of the ECCS are given in Figure 6.3-1 (Sheets 1 through 3) and Figure 6.3-2, respectively.

6.3.2.10 Relief Valves

The ECCS relief valves, their capacities, and settings are given in Table 6.3-2.

6.3.2.11 System Reliability

1. Definitions of Terms

   a. Period of Recovery

      The time necessary to bring the plant to a cold shutdown and regain access to faulted equipment. The recovery period is the sum of the short and long term periods defined below.

   b. Incident

      Any natural or accidental event of infrequent occurrence and its related consequences which affect the plant operation and require the use of engineered safeguards systems. Such events, which are analyzed independently and are not assumed to occur simultaneously, include the loss of coolant accident, steam line ruptures, steam generator tube ruptures, etc. A loss of offsite power may be an isolated occurrence or may be concurrent with any event requiring engineered safeguards systems use.

   c. Short Term

      The time immediately following the incident during which automatic actions are performed, system responses are checked, type of incident is identified, and preparations for long term recovery operation are made. The short term is the injection phase for loss of coolant accidents and is the first 24 hours following initiation of the event for all others.

   d. Long Term

      The remainder of the recovery period following the short term. In comparison with the short term where the main concern is to prevent or limit site release, the long term period of operation involves bringing the plant to cold shutdown conditions where access to the Reactor Building can be gained and repair effected.

e. Active Failure

The failure of a powered component such as a piece of mechanical equipment, component of the electrical supply system or instrumentation and control equipment to act on command to perform its design function. Examples include the failure of a motor operated valve to move to its correct position, the failure of an electrical breaker or relay to respond, the failure of a pump, fan or diesel generator to start, etc.

f. Passive Failure

The structural failure of a static component which limits the component's effectiveness in carrying out its design function. When applied to a fluid system, this means a break in the pressure boundary resulting in abnormal leakage not exceeding 50 gpm for 30 minutes. Such leak rates are consistent with limited cracks in pipes, sprung flanges, valve packing leaks, or pump seal failures.

2. Active Failure Criteria

The ECCS is designed to accept a single failure following the incident without loss of its protective function. The system is designed to tolerate the failure of any single active component in the ECCS itself or in the necessary associated service systems at any time during the period of required system operations following the incident.

A single active failure analysis is presented inTable 6.3-7, and demonstrates that the ECCS can sustain the failure of any single active component in either the short or long term and still meet the level of performance for core cooling.

Since the operation of the active components of the ECCS following a steam line rupture is identical to that following a loss of coolant accident, the same analysis is applicable and the ECCS can sustain the failure of any single active component and still meet the level of performance for the addition of shutdown reactivity.

3. Passive Failure Criteria

The following philosophy provides for necessary redundancy in component and system arrangement to meet the intent of the General Design Criteria on single failure as it specifically applies to failure of passive components in the ECCS. Thus, for the long term, the system design is based on accepting either a passive or an active failure, assuming no failures in the short term.

6.3.2.11.1 Redundancy of Flow Paths and Components for Long Term Emergency Core Cooling

In design of the ECCS, Westinghouse utilizes the following criteria.

1. During the long term cooling period following a loss of coolant, the emergency core cooling flow paths shall be separable into two subsystems, either of which can provide minimum core cooling functions and return spilled water from the floor of the Reactor Building back to the RCS.
2. Either of the two subsystems can be isolated and removed from service in the event of a leak outside the Reactor Building.
3. Adequate redundancy of check valves is provided to tolerate failure of a check valve during the long term as a passive component.
4. Should one of these two subsystems be isolated in this long term period, the other subsystem remains operable.
5. Provisions are also made in the design to detect leakage from components outside the Reactor Building, collect this leakage, and to provide for maintenance of the affected equipment. Level switches are located in alarm drain sumps and certain floor drain sumps. Excessive leakage actuates an alarm in the control room, alerting the operator to take action to isolate the leak.

Thus, for the long term emergency core cooling function, adequate core cooling capacity exists with one flow path removed from service.

6.3.2.11.2 Leakage from Engineered Safety Features Systems Outside Containment

Leakage from the engineered safety feature systems is collected by the Auxiliary Building drain system. Excessive leakage is detected by level switches located in pump room sumps and specially provided alarm drains. These alarm drains are strategically located in areas housing ECCS and reactor building spray system equipment. Leakage source identification is facilitated by zoning of the alarm drains with respect to ECCS and reactor building spray system equipment trains.

When leakage exceeds a flowrate of 25 gpm for the floor drains or 45 gpm for the sump drains, an alarm is activated in the Control Room. Alarm response time for leakage in excess of the maximum expected ranges from a few seconds for the alarm drains to less than four (4) minutes for the Residual Heat Removal pump room B sump. Upon actuation of this alarm, the operator can determine which level switch caused the alarm and, thus, identify which area housing ECCS or reactor building spray system equipment is affected. The operator then takes the required action to isolate the leak.

Components of the leakage detection system are seismically qualified, redundant, and can be tested during any phase of plant operation.

The largest sudden leak potential would be the sudden failure of an RHR pump shaft seal with a conservatively calculated leakage rate of 7.5 gpm. The results of an evaluation to determine RHR pump shaft leak rates are shown by Figure 6.3-5. Figure 6.3-6 illustrates the leakage rates after severe operation.

A single passive failure analysis is presented by Table 6.3-8. This analysis demonstrates that the ECCS can sustain a single passive failure during the long term phase and still retain an intact flow path to the core to supply sufficient flow to maintain the core covered and effect the removal of decay heat. The procedure followed to establish the alternate flow path also isolates the component which failed.

6.3.2.11.3 Integrity of Systems Outside Containment Likely to Contain Radioactive Materials

The design of systems that normally contain radioactive fluids includes a number of features for minimizing leakage paths from these systems to the surrounding environment. These features are outlined as follows:

1. Minimize the Use of Flanged Connections

   As standard practice for the V. C. Summer Project, piping system connections are socket-welded for 2" and smaller piping, and butt-welded for 2-1/2” and larger piping.

2. Use of Valve Leakoff Connections

   All 2-1/2” or greater air-operated or motor-operated valves in radioactive fluid systems, incorporate lantern-ring leakoff connections which are hard-piped to waste liquid holdup tanks. Therefore, leakage by the valve packings is directed to holdup tanks to prevent contamination of the area around the valves.

3. Use of “Zero-Leakage” Valves

   Manually-operated valves in systems that contain radioactive fluids are “zero-leakage” type valves, i.e., designed to prevent leakage within the environment of the valves. These valves include, but are not limited to, bellows-stem-seal type, metal-diaphragm seal, and diaphragm valves. An example of the metal-diaphragm seal type is the Rockwell-Edward’s “Hermavalve” (hermetically-sealed). Drain and vent valves are discussed as a separate feature.

4. Dual Barrier Design for Drain and Vent Valve Connections

   Drain and vent connections in radioactive fluid systems are provided with either (a) two (2) normally-closed isolation valves or (b) one (1) normally-closed isolation valve with a pipe or tube extension that is capped or incorporated a fluid flange. These schemes provide a dual barrier against potential leakage paths from radioactive fluid systems.

5. Use of Mechanical Shaft Seals for Critical Pumps

   The use of mechanical shaft seals for critical pumps limits the amount of radioactive fluid leakage for both normal and adverse operating conditions. For further discussion of pump shaft seals, see FSAR Section 6.3.2.11.2.

6. Use of “Alarm Drains” for Monitoring Leakage from the ECCS Systems

   The “Alarm Drains” are strategically located to monitor and alarm leakage from the ECCS Systems during the injection and recirculation modes of operation following a LOCA. For further discussion of the Alarm Drain System, See FSAR Section 6.3.2.11.2.

A single passive failure analysis is presented in Table 6.3-8. This analysis is discussed in Section 6.3.2.11.2.

Those systems and components outside the containment whose function may be required during serious transient or accident conditions which could or would contain highly radioactive fluids have been identified. In addition, these systems and component interfaces with other systems and components which would not be required to function to achieve cold stable conditions following an accident have been identified.

These systems and components are incorporated into leak reduction programs including, but not limited to, Inservice Inspection Hydrostatic and Leak Detection Testing, Preventative Maintenance Programs, Integrated System Leakage Testing as provided for by Technical Specification Surveillance Requirements, and existing Leak Detection systems.

6.3.2.12 Protection Provisions

The provisions taken to protect the system from damage that might result from dynamic effects are discussed in Section 3.6. The provisions taken to protect the system from missiles are discussed in Section 3.5. The provisions to protect the system from seismic damage are discussed in Sections 3.7, 3.9, and 3.10. The provisions to maintain the refueling water storage tank at or above 40°F and for freeze protection of outdoor piping connected to the tank are discussed in Sections 9.1.3.2 and 9.1.3.5.5. Thermal stresses on the RCS are discussed in Section 5.2.

6.3.2.13 Provisions for Performance Testing

The provisions incorporated to facilitate performance testing are discussed in Section 6.3.4.

6.3.2.14 Pump Net Positive Suction Head

The ECCS is designed so that adequate net positive suction head (NPSH) is provided to system pumps. The NPSH available is a function of Reactor Building pressure, water temperature, static head of water, friction losses in the pump suction piping and pressure drop across the sump strainer as follows:

$$NPSH_a = P_c \quad P_s + \Delta H_z - \Delta H_f - \Delta H_s$$

Where:

$NPSH_a$ = NPSH available at the pump suction.

P_c = Reactor Building pressure.

P_s = Saturation pressure of the pumped water.

ΔH_z = Elevation pressure due to the height of water above the pump nozzle.

ΔH_f = Pressure loss due to friction in the suction line.

ΔH_s = Pressure loss across the sump strainer (in the recirculation mode).

In the recirculation mode of operation, the pressure in the Reactor Building (P_c) will always equal or exceed the vapor pressure of the water in the sump because water will evaporate from the sump to increase the vapor pressure of the atmosphere if P_c starts to decrease below P_s. Generally, the partial pressure of the air in the atmosphere will maintain P_c greater than P_s. For conservatism, no containment overpressure is assumed so $P_c = P_s$. This is consistent with the guidance provided in Regulatory Guide 1.1.

Adequate net positive suction head is shown to be available for all pumps as follows:

1. Residual Heat Removal Pumps

   The net positive suction head of the residual heat removal pumps is evaluated for normal plant cooldown operation, and for both the injection and recirculation modes of operation for the Design Basis Accident. Recirculation operation gives the limiting net positive suction head requirement, and the net positive suction head available is determined from the Reactor Building sump level relative to the pump elevation and the pressure drop in the suction piping from the sump to the pumps. The net positive suction head evaluation is based on one residual heat removal pump delivering to three RCS loops and the suction of one charging pump.

A summary of the results for the RHR pump in the recirculation mode is as follows:

	Flow (gpm)	NPSH Available (ft)	NPSH Required (ft)	Margin (ft)
Pump A	4300	20.2	17	3.2
Pump B	4200	20.8	16	4.8

2. Centrifugal Charging Pumps

   The net positive suction head for the centrifugal charging pumps is evaluated for both the injection and recirculation modes of operation for the Design Basis Accident. The end of the injection mode of operation gives the limiting net positive suction head available. The net positive suction head available is determined from the elevation head and vapor pressure of the water in the refueling water storage tank, which is at atmospheric pressure, and the pressure drop in the suction piping from the tank to the pumps. When a predetermined low refueling water storage tank level is reached the charging pumps are manually aligned to take suction from the residual heat removal pump discharge headers. The net positive suction head requirements of these pumps are therefore satisfied by the discharge head of the residual heat removal pumps.

6.3.2.15 Accumulator Motor Operated Valve Controls

As part of the plant shutdown administrative procedures, the operator is required to close these valves. This prevents a loss of accumulator water inventory to the RCS and is done shortly after the RCS has been depressurized to between 900 and 950 psig. The redundant pressure and level alarms on each accumulator would remind the operator to close these valves, if any were inadvertently left open. Power is disconnected after the valves are closed.

During plant startup, the operator is instructed via procedures to energize and open these valves before the RCS pressure is between 900 and 950 psig. Monitor lights in conjunction with an audible alarm will alert the operator should any of these valves be left inadvertently closed once the RCS pressure increases above the safety injection block setpoint (P-11).

For each accumulator isolation valve (8808A, 8808B, or 8808C) position indicating design provisions include the following:

1. Visual indicating in the main control room by means of an ESF monitor light that will be “bright” when the valve is not open. Section 7.5.4 provides a more detailed explanation of the operation of the ESF monitor lights. An alarm will be annunciated via a common monitor light alarm if an accumulator valve is not open. This grouping highlights a valve not properly lined up. This light is energized from an ESF monitor light supply different from the valve control power and actuated by a valve motor operator switch. In addition to this visual position information, there are also red (open) and green (closed) position indicating lights at

the control switch for each valve. These lights are actuated by valve motor operator limit switches and are powered by valve control power which is distributed through the same accumulator valve breaker that feeds power to the motor operator.

2. Audible and visual alarm annunciator points will be activated by both a valve motor operator limit switch and by a valve position limit switch activated by stem travel whenever an accumulator valve is not fully open for any reason with the system at pressure (the pressure at which the safety injection block is unblocked). The alarm activated by the motor operator limit switch will be recycled by a timer at approximately 60 minute intervals to remind the operator of the improper valve line up. Both the alarm reflash annunciator point and the timer will be energized separately from the valve control power.

The accumulator isolation valves are considered to be “operating bypasses” in the context of IEEE 279-1971, which requires that bypasses of protective functions be removed automatically whenever permissive conditions are not met. The automatic unblock is derived from P-11 (1985 psig) which is the Safety Injection setpoint.

In that these valves are required by Technical Specifications to be open and incapable of being closed during power operation and do not act as active valves during any accident condition, the requirements of IEEE 279-1971 are not applicable for this situation in that an operating bypass function is not required for these valves. For a discussion of limiting conditions for operation and surveillance requirements of these valves, refer to the Technical Specifications.

The accumulator isolation valves receive a safety injection signal to ensure that they are open in the event of an accident which initiates safety injection.

For further discussions of the instrumentation associated with these valves refer to Sections 6.3.5, 7.3.1.1.2, and 7.6.4.

6.3.2.16 Motor Operated Valves and Controls

Remotely operated valves for the injection mode which are under manual control (i.e., valves which normally are in their ready position and do not require a safety injection signal) have their positions indicated on a common portion of the control board. If a component is out of its proper position, its monitor light will indicate this on the control panel. At any time during operation when one of these valves is not in the ready position for injection, this condition is shown visually on the board, and an audible alarm is sounded in the control room.

6.3.2.17 Manual Actions

No manual actions are required of the operator for proper operation of the ECCS during the injection mode of operation. Only limited manual actions are required by the operator to complete realignment of the system for the cold leg recirculation mode of operation, and, within 8 hours after event initiation, for the simultaneous hot leg and cold leg recirculation mode of operation. See Table 6.3-3 for the cold and hot leg recirculation switchover procedures.

6.3.2.18 Process Instrumentation

Process instrumentation available to the operator in the control room to assist in assessing post loss of coolant accident conditions are tabulated in Section 7.5.

6.3.2.19 Materials

Materials employed for components of the ECCS are given in Table 6.3-5. These materials are chosen based upon their ability to resist radiolytic and pyrolytic decomposition (see Section 6.3.2.4).

6.3.2.20 Power Lockout of Manually Controlled Electrically Operated Valves

Manually controlled electrically operated valves in the ECCS which require power lockout in accordance with Branch Technical Position EICSB 18 are 8808A, B, and C (accumulator isolation valves); 8884 and 8886 (high head safety injection hot leg injection isolation valves); 8888A and B (low head, safety injection cold leg isolation valves); 8889 (low head safety injection hot leg injection isolation valve); and 8133A and B (high head safety injection discharge cross-connect valves).

Power is locked out to accumulator isolation valves 8808A, B, and C (see Technical Specification 3/4.5.1 and to reactor head vent system isolation valves 8095A, B and 8096A, B by padlocking the breaker operating mechanism of the motor control center.

The power, control, and indication circuits for motor operated valves 8884, 8886, 8888A and B, 8889, and 8133A and B will satisfy the main control board “removal and restoration” requirements identified below:

1. Removal and restoration of electrical power for the valve power circuit will be accomplished from the main control board. A power contactor will be installed in XMCIDA2Y and wired in series to reversing starters for valves 8884, 8888A and 8889. When the contactor is open, it will break power to the starters. A similar situation exists in XMCIDB2X for valves 8886 and 8888B. Power lockouts are also installed in XMC1DA2Y for valve 8133A and XMC1DB2Y for valve 8133B. Before the valve position can be changed, the power lockout contactor must be closed from the main control board to provide power to the starters. Then, using a separate switch on the main control board, the starter must be actuated to open or close the valve. Using these normally de-energized power lockout contactors in series with the starters, no single electrical fault could cause valve motion.
2. Valve position indications, not defeated by the control circuit electrical power removal and restoration, are provided at the main control board. Valve position sensing for these position indicators is provided by the cam operated switch within the motor operator. AC Power for the indicators is supplied from the power lockout contactor control transformer in the motor control center (MCC).

3. Redundant valve position indicators, powered from the DC train opposite to the valve motive power train, are provided at the main control board. Valve position sensing for these position indicators is by separate, stem mounted limit switches.

6.3.3 Performance Evaluation

6.3.3.1 Evaluation Model

The following analyses are performed to ensure that the limits on core behavior following a pipe rupture are met by the ECCS operating with minimum design equipment:

1. Large pipe rupture analysis
2. Small pipe rupture analysis
3. Steam line rupture analysis

The performance characteristic is derived from the performance characteristic for each pump with system piping resistance, based upon final piping layouts.

The pump performance characteristics utilized in the accident analyses includes a 3.5% head reduction for the high head pumps and a 7% head reduction for the low head pumps for margin. The loss of coolant accident analysis is also based on the spilling of one injection line through the postulated break. This accounts for the case where the initiating incident is assumed to be the severance of an injection line.

6.3.3.2 Emergency Core Cooling System Performance

The large pipe rupture analysis is used to evaluate the initial thermal transient for a spectrum of pipe ruptures up to and including the instantaneous, double ended, circumferential rupture of the largest pipe in the RCS. The results of this analysis are presented in Section 15.4.

The flow delivered to the RCS by the ECCS as a function of the RCS pressure is also shown in Section 15.4. This flowrate is based on one injection path spilling out the postulated break, the loss of offsite power, and the assumed single failure of an onsite emergency diesel generator to start; leaving two accumulators, one charging pump, and one residual heat removal pump available for core cooling, with the injection path of least resistance assumed to be spilling.

RCS loop-to-loop flow imbalance of 5% is considered, to incorporate the effects of the RCS Flow Asymmetry, per Westinghouse Nuclear Safety Advisory Letter (NSAL) 00-008.

Initial core cooling is provided by the passive accumulators. Injection flow from the ECCS pumps is required subsequent to accumulator injection to complete vessel refill, reflood the core, and eventually return the core to a subcooled state. The results of the analysis presented in Section 15.4 indicate the peak clad temperature attained at any point in the core is such that the limits on core behavior as specified in Section 15.4 are met.

During shutdown the following operator actions pertain to the isolation of ECCS equipment and would affect a LOCA during the time accumulator isolation valves are closed with power locked out. (Startup is not addressed since shutdown is more limiting due to the higher core decay heat generation):

1. The operator is instructed to manually block the pressurizer safety injection signal when pressurizer pressure has decreased below 1985 psig and the steamline safety injection signal when T_{avg} decreases below 552 °F. All other safety injection signals including containment high pressure and high steam line differential pressure are armed and will actuate safety injection if their setpoints are exceeded. Manual safety injection actuation is also available.
2. With the RCS pressure maintained between 900 and 950 psig, the operator closes and locks out the safety injection accumulator isolation valves. At this time, two residual heat removal pumps (low head safety injection) would be available from either automatic or manual safety injection actuation.
3. At less than 425 psig and 350 °F, the operator aligns the suction of both trains of RHRS to the RCS. The valves in the line from the refueling water storage tank (RWST) are closed. Prior to dropping below 300 °F, the operator also locks out all but one high head charging pump.

The significance of these actions on the mitigation of a LOCA when power is locked out to the isolation valves is that:

1. Between 950 psig and 425 psig, a portion of the ECCS may be actuated automatically on containment high pressure or high steam line differential pressure signals or manually by the operator. The equipment that can be energized are two residual heat removal and one high head charging pumps. Subsequently, the operator would reinstitute power at the motor control centers to the other high head charging pump as necessary to maintain water level in the reactor vessel.
2. Below 425 psig and 350° F, the system is in the residual heat removal mode with both trains of RHRS aligned to the RCS and only one train in service until Mode 5. The opposite train is protected such that in the event of a LOCA, it is capable of performing its Mode 4 ECCS function. If required, the operator would manually realign the protected train per abnormal operating procedure for mitigation of a LOCA. In addition, the procedures direct the operator to start additional SI pumps, as necessary, to maintain water level in the reactor vessel.

6.3.3.3 Alternate Methods of Analysis

6.3.3.3.1 Small Pipe Break

The small pipe break analysis is used to evaluate the initial core thermal transient for a spectrum of pipe ruptures greater than 3/8 inches in diameter. For a rupture 3/8 inches in diameter or smaller, the charging system can maintain the pressurizer level. The ECCS would not be required and would not be automatically actuated in the short term, although it is actuated by low pressurizer pressure. A range of reactor coolant system small pipe breaks have been evaluated, as discussed in Section 15.3.1 and Section 15.4.1. The results of the small break analysis indicate that the limits on core behavior are adequately met as shown in Section 15.3 and Section 15.4.

6.3.3.3.2 Steam Line Rupture

Following a steam line rupture the ECCS is automatically actuated to deliver borated water to the RCS. The response of the ECCS following a steam line break is identical to its response during the injection mode of operation following a loss of coolant accident.

The safety injection signal initiates identical actions as described for the injection mode of the loss of coolant accident, even though not all of these actions are required following a steam line rupture, e.g., the residual heat removal pumps are not required since the RCS pressure will remain above their shutoff head.

The charging pumps deliver borated water from the refueling water storage tank, until enough water has been added to the RCS to make up for the shrinkage due to cooldown. After pressurizer water level has been restored, the injection is manually terminated.

The sequence of events following a postulated steam line break is described in Section 15.4.

6.3.3.4 Fuel Rod Perforation

Discussions of peak clad temperatures and metal-water reactions appear in Sections 15.3.1 and 15.4.1. Analyses of the radiological consequences of a fission product release due to the rupture of a pipe in the RCS are presented in Section 15.4.

6.3.3.5 Not applicable to Pressurized Water Reactors.

6.3.3.6 Not applicable to Pressurized Water Reactors.

6.3.3.7 Not applicable to Pressurized Water Reactors.

6.3.3.8 Not applicable to Pressurized Water Reactors.

6.3.3.9 Not applicable to Pressurized Water Reactors.

6.3.3.10 Not applicable to Pressurized Water Reactors.

6.3.3.11 Effects of ECCS Operation on the Core

The effects of ECCS operation on the reactor core are presented in Sections 15.3 and 15.4.

6.3.3.12 Use of Dual Function Components

The ECCS contains components which have no other operating function as well as components which are shared with other systems. Components in each category are as follows:

1. Components of the ECCS which perform no other function are:

a. One accumulator for each loop which discharges borated water into its respective cold leg of the reactor coolant loop piping.

b. Piping, valves and instrumentation associated with the accumulators or high head injection.

c. Valves and piping associated with RB sump recirculation.

2. Components which also have a normal operating function are as follows:

a. The residual heat removal pumps and the residual heat exchangers are normally used during the latter stages of normal reactor cooldown and when the reactor is held at cold shutdown for core decay heat removal. However, during all other plant operating periods, they are aligned to perform the low head injection function.

b. The centrifugal charging pumps are normally aligned for charging service. As a part of the chemical and volume control system, the normal operation of these pumps is discussed in Chapter 9.

c. The refueling water storage tank is used to fill the refueling canal for refueling operations. However, during other plant operating periods it is aligned to the suction of the residual heat removal pumps. The charging pumps are automatically aligned to the suction of the refueling water storage tank upon receipt of the safety injection signal.

An evaluation of all components required for operation of the ECCS demonstrates that either:

1. The component is not shared with other systems, or
2. If the component is shared with other systems, it is aligned during normal plant operation to perform its accident function; or if not aligned to its accident function, two valves in parallel are provided to align the system for injection, and two valves in series are provided to isolate portions of the system not utilized for injection. These valves are automatically actuated by the safety injection signal. During the recirculation mode of operation, manual valve alignments are required. (Reference 6.3.2.2.7)

Table 6.3-9 indicates the alignment of components during normal operation, and the realignment required to perform the accident function.

6.3.3.13 Lag Times

The minimum active components will be capable of delivering full rated flow within a specified time interval after process parameters reach the setpoints for the safety injection signal. Response of the system is automatic, with appropriate allowances for delays in actuation of circuitry and active components. The active portions of the system are actuated by the safety injection signal. In analyses of system performance, delays in reaching the programmed trip points and in actuation of components are established on the basis that only emergency onsite power is available.

In the loss of coolant accident analyses presented in Sections 15.3 and 15.4, no credit is assumed for partial flow prior to the establishment of full flow and no credit is assumed for the availability

of normal offsite power sources. After the initiation parameter achieves the setpoint, a delay is assumed for signal transmission, diesel startup, load sequencing, and pump startup, as discussed in Sections 15.4.1.1.3 and 15.4.1.1.4 and Table 15.4-1a.

For smaller loss of coolant accidents, there is some additional delay before the process variables reach their respective programmed trip setpoints since this is a function of the severity of the transient imposed by the accident. This is allowed for in the analyses of the range of loss of coolant accidents.

Accumulator injection occurs immediately when RCS pressure has decreased below the operating pressure of the accumulator.

6.3.3.14 Thermal Shock Considerations

Thermal shock considerations are discussed in Section 5.2.

6.3.3.15 Limits on System Parameters

The analyses show that the Performance characteristic of the ECCS is adequate to meet the requirements for core cooling following a loss of coolant accident with the minimum engineered safety feature equipment operating. In order to ensure this capability in the event of the simultaneous failure to operate any single active component, Technical Specifications are established for reactor operation.

Normal operating status of ECCS components is given in Table 6.3-6.

The ECCS components are available whenever the coolant energy is high and the reactor is critical. During low temperature physics tests there is a negligible amount of stored energy in the coolant and low decay heat; therefore, an accident comparable in severity to accidents occurring at operating conditions is not possible and ECCS components are not required.

A comprehensive testing program has been undertaken to demonstrate that ECCS components and associated instrumentation and electrical equipment which are located inside the Reactor Building will operate for the time period required in the combined post loss of coolant accident conditions of temperature, pressure, humidity, radiation, chemistry, and seismic phenomena (see Section 3.11).

Components such as remote motor operated valves have been shown capable of operating for the required post accident periods, when exposed to post loss of coolant environmental conditions. All other ECCS components are located outside of the Reactor Building.

The specification of individual parameters as given in Table 6.3-1 considers allowances for margin over and above the required performance value (e.g., pump flow and net positive suction head), and the most severe conditions to which the component could be subjected (e.g., pressure, temperature, and flow).

This consideration ensures that the ECCS is capable of meeting its minimum required level of functional performance.

6.3.4 Tests and Inspections

To demonstrate the readiness and operability of the ECCS, the components are subjected to periodic tests and inspections. Performance tests of the components are performed in the manufacturer's shop. An initial system flow test is performed to demonstrate the proper functioning of the components.

6.3.4.1 Quality Control

Tests and inspections are carried out during fabrication of each of the ECCS components. These tests are conducted and documented in accordance with the Quality Assurance Program discussed in Chapter 17.

6.3.4.2 Preoperational Tests

These tests are intended to evaluate the hydraulic and mechanical performance of the passive and active components involved in the injection mode by demonstrating that they have been installed and adjusted so they will operate in accordance with the design intent. These tests are divided into three individual sections that may be performed as plant conditions allow without compromising the integrity of the tests.

One of these individual sections consists of system actuation tests to verify: the operability of ECCS valves initiated by the safety injection signal (S), the phase A containment isolation signal (T), and the phase B containment isolation signal (P); the operability of safeguard pump circuitry down through the pump breaker control circuits; and the proper operation of valve interlocks.

Another of the individual sections is the accumulator injection test. The objective of this section is to check the accumulator injection line to verify that the lines are free from obstructions and that the accumulator check valves operate correctly. The test objectives will be met by a low pressure blowdown of each accumulator. The test will be performed with the reactor head and internals removed.

The last of the individual sections consists of operational tests of the major pumps (i.e., the charging pumps and the residual heat removal pumps). The purpose of these tests is to evaluate the hydraulic and mechanical performance of the pumps delivering through the flow paths required for emergency core cooling. These tests will be divided into two parts: pump operation under minimum flow conditions and pump operation at full flow conditions.

The predicted system resistance will be verified by measuring the flow in various piping branches, as each pump delivers from the refueling water storage tank to the open reactor vessel, and adjustments made where necessary to assure that no one branch has an unacceptably low or high resistance. During this flow test, the system will also be checked to assure there is sufficient total line resistance to prevent excessive runout of the pump. At the completion of the flow test,

the total pump flow and relative flow between the branch lines will be compared with the performance characteristics used in the accident analysis of Chapter 15.

The systems are accepted only after demonstration of proper actuation of components and after demonstration of flow delivery of components within design requirements.

6.3.4.3 Periodic Component Testing

Routine periodic testing of the ECCS components and necessary support systems at power is planned. Valves which operate after a loss of coolant accident are operated through a complete cycle, and pumps are operated individually. The testing is conducted on minimum flow and at full flow for the charging pumps and at full flow for the RHR pumps. If such testing indicates a need for corrective maintenance, the redundancy of equipment in these systems permits such maintenance, to be performed without shutting down or reducing load under certain conditions. These conditions include considerations such as the period within which the component should be restored to service and the capability of the remaining equipment to provide the minimum required level of performance during such a period.

The condition of the remote stop valve and the check valve in each accumulator tank discharge line may be tested by opening the remote test line valves just downstream of the stop valve and check valve respectively. Flow through the test line can be observed on instruments and the opening and closing of the discharge line stop valve can be sensed on this instrumentation.

Where series pairs of check valves form the high pressure to low pressure isolation barrier between the RCS and ECCS piping outside the Reactor Building, testing of these check valves must be performed to provide assurance that certain postulated failure modes will not result in a loss of coolant from the low pressure system outside the Reactor Building with a simultaneous loss of safety injection pumping capacity. The tests performed verify that each of the series check valves can independently sustain differential pressure across its disc, and also verify that the valve is in its closed position. The required periodic tests are to be performed after refuelings, on a performance-based frequency just prior to plant startup, after the RCS has been pressurized.

Lines in which the series check valves are to be tested are the residual heat removal pump cold leg and hot leg injection lines.

To implement the periodic component testing requirements, Technical Specifications are established. During periodic system testing, a visual inspection of pump seals, valve packings, flanged connections, and relief valves is made to detect leakage. Inservice inspection provides further confirmation that no significant deterioration is occurring in the ECCS fluid boundary.

Design measures have been taken to assure that the following testing can be performed:

1. Active components are tested periodically for operability (e.g., pumps, certain valves, etc.).
2. An integrated system test (1) can be performed when the plant is cooled down and the RHRS is in operation. This test does not introduce flow into the RCS but does demonstrate the operation of the valves, pump circuit breakers, and automatic circuitry including diesel starting and the automatic loading of ECCS components on the diesels (by simultaneously simulating a loss of offsite power).
3. An initial flow test of the full operational sequence can be performed.

The design features which assure this test capability are specifically:

1. Power sources are provided to permit individual actuation of each active pump and valve component of the ECCS.
2. The residual heat removal pumps are used every time the RHRS is put into operation. They can also be tested periodically when the plant is at power.
3. The centrifugal charging pumps are either normally in use for charging service or can be tested periodically on minimum flow, or full flow during plant shutdown.
4. Remote operated valves can be exercised during routing plant maintenance. These valves are tested both quarterly and/or during plant shutdowns based on operating and test requirements.
5. Level and pressure instrumentation is provided for each accumulator tank, for continuous monitoring of these parameters during plant operation.
6. Flow from each accumulator discharge tank can be directed at any time through a test line to determine check valve leakage.
7. Flow indicators are provided in the charging pump headers and in the residual heat removal pump headers. Pressure instrumentation is also provided in the residual heat removal pump headers and in the charging pump headers.

6.3.4.4 Inservice Tests and Inspections

The ECCS components are designed and fabricated to permit inspection and inservice tests in accordance with the ASME Code, prescribed under 10CFR50.55a. Inservice inspection is discussed in Section 5.7.

(1) Details of the testing of the sensors and logic circuits associated with the generation of a safety injection signal together with the application of this signal to the operation of each active component are given in Section 7.2.

6.3.5 Instrumentation Requirements

Instrumentation and associated analog and logic channels employed for initiation of ECCS operation is discussed in Section 7.3 This section describes the instrumentation employed for monitoring ECCS components during normal plant operation and also ECCS post accident operation. Alarms are annunciated in the control room.

6.3.5.1 Temperature Instrumentation

6.3.5.1.1 Boron Injection Tank Temperature

Deleted by Amendment 3.

6.3.5.1.2 Residual Heat Exchanger Inlet and Outlet Temperature

The fluid temperature at the inlet and outlet of each residual heat exchanger is recorded in the control room.

6.3.5.1.3 Boron Injection Surge Tank Temperature

Deleted by Amendment 3.

6.3.5.2 Pressure Instrumentation

6.3.5.2.1 High Head Injection Pressure

High head injection pressure is indicated in the control room. A high pressure alarm is provided.

6.3.5.2.2 Accumulator Pressure

Duplicate pressure channels are installed on each accumulator. Pressure indication in the control room and high and low pressure alarms are provided by each channel.

6.3.5.2.3 Hydrotest Pump Discharge Pressure

This instrument provides local indication of hydrotest pump discharge pressure.

6.3.5.2.4 Test Line Pressure

A local pressure indicator used to check for proper seating of the accumulator check valves is installed on the leakage test line.

6.3.5.2.5 Residual Heat Removal Pump Discharge Pressure

Residual heat removal discharge pressure for each pump is indicated in the control room. A high pressure alarm is actuated by each channel.

6.3.5.3 Flow Instrumentation

6.3.5.3.1 Boric Acid Recirculation Flow

Deleted by Amendment 3.

6.3.5.3.2 Charging Pump Injection Flow

These flow transmitters located in the hot leg and cold leg injection headers provide flow indication in the control room.

6.3.5.3.3 Residual Heat Removal Pump Injection Flow

Flow through each residual heat removal pump header is indicated in the control room. A low flow alarm is provided.

6.3.5.3.4 Test Line Flow

Local indication of the leakage test line flow is provided to check for proper seating of the accumulator check valves between the injection lines and the RCS.

6.3.5.3.5 Residual Heat Removal Pump Minimum Flow

A flowmeter installed in each residual heat removal pump discharge header provides control for the valve located in the pump minimum flow line.

6.3.5.4 Level Instrumentation

6.3.5.4.1 Refueling Water Storage Tank Level

Four independent refueling water storage tank level channels are provided for automatic actuation of the residual heat removal pump valves to initiate recirculation upon receipt of two out of four (2/4) lo-lo level signals coincident with the receipt of a safety injection signal (the residual heat removal pumps continue in the operating mode).

The refueling water storage tank water level is indicated in the control room. Two of the four channels also provide a high, low, and an empty level alarm. The high level (maximum fill) alarm is provided to protect against possible overflow of the refueling water storage tank. The low level (minimum fill) alarm is provided to assure that a sufficient volume of water is always available in the refueling water storage tank in conformance with the Technical Specifications.

6.3.5.4.2 Accumulator Water Level

Duplicate water level channels are provided for each accumulator. Both channels provide indication in the control room and actuate high and low water level alarms.

6.3.5.4.3 Boron Injection Surge Tank Level

Deleted by Amendment 3.

6.3.5.5 Valve Position Indication

Valve positions for those valves provided with engineered safety features monitoring lights (see Section 7.5) are indicated on the control board by a “bright-dim” system; i.e., should the valve not be in its proper position, a bright white light will be lit and thus give a highly visible indication to the operator. Valve position for remote manual ECCS valves is also indicated on the control board by red and green indicator lights.

The accumulator motor operated valves are provided with red (open) and green (closed) position indicating lights located at the control switch for each valve. These lights are powered by valve control power and actuated by valve motor operator limit switches.

A monitor light that is bright when the valve is not fully open (i.e., mispositioned) is provided in an array of monitor lights that are all dim when their respective valves are in proper position enabling engineered safety features operation. This light is energized from a separate monitor light supply and actuated by a valve motor operated limit switch.

An alarm annunciator point is activated by both a valve motor operator limit switch and by a valve position limit switch activated by stem travel whenever an accumulator valve is not fully open for any reason with the system at pressure (the pressure at which the safety injection block is unblocked approximately 1900 psig). A separate annunciator point is used for each accumulator valve.

The manual valve (XVG-6700-SF) in the common header from the refueling water storage tank is provided with a limit switch which alarms the main control room if the valve is not full open.

6.3.6 References

1. Deleted (RN 99-069)
2. *Behavior of Austenitic Stainless Steel in Post Hypothetical Loss of Coolant Accident Environment*, WCAP-7798-L (Proprietary) and WCAP-7803 (Non-Proprietary), January 1972.
3. Technical Report TR04650-004, Rev. 0, *Chemical Effects Testing for V. C. Summer Replacement Sump Strainers*.
4. WCAP-16406-P-A, Rev. 1, *Evaluation of Downstream Sump Debris Effects in Support of GSI-191*.

Table 6.3-1
Emergency Core Cooling System
Component Parameters

Accumulators	
Number	3
Design Pressure, psig	700
Design Temperature, °F	300
Operating Temperature, °F	60-150
Nominal Operating Pressure, psig	628 psig
Total Volume, ft^3	1450 each
Nominal Water Volume, ft^3	1014 each
Nominal Volume N_2 Gas ft^3	436 each
Boric Acid Concentration, minimum, ppm	2200
Relief Valve Setpoint, psig	700
Centrifugal Charging Pumps	
Number	3
Design Pressure, psig	2900
Design Temperature, °F	300
Design Flowrate(1), gpm	150
Design Head, ft	5800
Maximum Flowrate, gpm	688
Design Discharge Head at Shutoff, ft	6200
Motor Rating(2), bhp	900

(1) Includes minimum flow
(2) 1.15 service factor not included

Table 6.3-1 (continued)
Emergency Core Cooling System
Component Parameters

Hydrotest Pump	
Number	1
Design Pressure, psig	3300
Design Temperature, °F	300
Normal Operating Temperature, °F	Ambient
Design Flowrate, gpm	24.5
Developed Head of Design Flowrate, ft	7100
Residual Heat Removal Pumps	
(See Section 5.5.7 for design parameters)	
Residual Heat Exchangers	
(See Section 5.5.7 for design parameters)	
Boron Injection Tank	
Deleted by Amendment 3.	
Boron Injection Surge Tank	
Deleted by Amendment 3.	
Heaters	
Deleted by Amendment 3.	
Boron Injection Tank Recirculation Pump	
Deleted by Amendment 3.	

Table 6.3-1 (continued)
Emergency Core Cooling System
Component Parameters

Component Valves	Parameter	
1. Motor Operated Valves	Design Opening or Closing Time	
a. 4 inches and under	Time, sec	≤ 10
b. > 4 inches, ≤ 10 inches	Time, sec	≤ 15*
c. Over 10 inches	Time, sec	≤ 20
2.Leakage		
a. Conventional Globe Valves	Disc Leakage, cc/hr/in of nominal pipe size	3
	Backseat Leakage (when open), cc/hr/in of stem diameter	1
b. Gate Valves	Disc Leakage, cc/hr/in of nominal pipe size	3
	Backseat Leakage (when open), cc/hr/in of stem diameter	1
c. Check Valves	Disc Leakage, cc/hr/in of nominal pipe size	3
d. Diaphragm Valves	Disc Leakage	none
e. Accumulator Check Valves	Disc Leakage, cc/hr/in of nominal pipe size	3
f. Seal Water Injection Filter Vent and Drain Ball Valves	Seat and External Leakage, cc/hr	3

* 8 inch valves 8130A/B and 8131A/B are currently tested to ≤ 30 seconds.

Table 6.3-2
Emergency Core Cooling System Relief Valve Data

Description	Fluid Discharged	Fluid Inlet Temperature Normal	Set Pressure Psig	Back Pressure Constant	Psig Buildup	Capacity
N_2 Supply to Accumulators (See Note)	N_2	120	700	0	0	1500 scfm
Residual Heat Removal Pump Safety Injection Lines	Water	350	600	3	50	20 gpm
Accumulator to Reactor Building	N_2 Gas	120	700	0	0	1500 scfm
Hydrotest Pump Discharge (See Note)	Water	120	800	0	0	30 gpm
Safety Injection Pumps Suction Lines	Water	115	220	3	50	25 gpm

Note: The N2 supply header and hydrostatic test pump relief valves are included in the SI system but are outside the boundary of the ECCS. The N_2 supply relief valve protects the N_2 supply line from overpressurization due to failure of the pressure regulator. The hydrostatic test pump relief valve protects the pump discharge piping during accumulator makeup operations.

Table 6.3-3
Sequence of Switchover Operation
From Injection to Recirculation

The following manual operator actions are required to complete the switchover operation from the injection mode to the recirculation mode in accordance with the provisions of Branch Technical Position (BTP) EICSB20. During the injection mode, the operator verifies that all ECCS pumps (not including the spare or out of service charging pump) are operating and monitors the RWST and reactor building recirculation sump levels in anticipation of switchover. The operator opens, or verifies open, the component cooling water inlet isolation valves to the residual heat removal heat exchanger prior to switchover initiation. Upon receipt of the RWST "lo-lo" level signal in conjunction with the safety injection signal, the reactor building recirculation sump isolation valves (3004A & B, 3005A & B, 8811A & B, and 8812A & B) automatically open. Following these automatic actions, the operator is required to initiate the following manual actions to complete switchover.

The following manual actions must be completed in a timely manner following switchover initiation to align the charging pumps suction to the residual heat removal pumps discharge.

1. Verify that the reactor building recirculation sump isolation valves (3004A & B, 3005A & B, 8811A & B, and 8812A & B) are open, the residual heat removal pump suction valves (8809A & B) and the reactor building spray pump suction valves (3001A & B) from the refueling water storage tank are closed.
2. Close the valves (8887A & B) in the crossover line downstream of the residual heat removal heat exchanger.
3. Close the valves (8106, 8109A, B, & C) in the charging pump miniflow lines.
4. Open residual heat removal pump discharge valves (8706A & B) to the suction of the charging pumps.

Note that the four basic steps above are followed even if a single failure occurs; however, it may be necessary to secure pump(s) when it is determined that the suction(s) cannot be transferred from the RWST to conserve RWST water for the completion of the switchover.

All ECCS pumps are now aligned with suction flow from the reactor building recirculation sumps. The operator verifies proper operation and alignment of all ECCS components and proceeds to complete the following manual actions to align the ECCS in redundant flow paths for long term recirculation operation:

1. Close charging pump suction valves (LCV-115B & D) from the refueling water storage tank.
2. Close valves (8130A & B or 8131A & B) (depending on operating charging pumps) in the suction headers to establish two separate high head recirculation suction systems.

Table 6.3-3 (continued)
Sequence of Switchover Operation
From Injection to Recirculation

3. Open valve (8885) in the alternate high head cold leg recirculation line.
4. Close valves (8132A & B or 8133A & B) (depending on operating charging pumps) in the discharge header to establish two separate high head recirculation discharge systems.

SEQUENCE OF SWITCHOVER OPERATION
FROM COLD LEG TO HOT LEG RECIRCULATION
(Procedure is executed one train at a time)

The following manual operator actions are required to perform the changeover operation from the cold leg recirculation mode to the hot leg and cold leg recirculation mode.

1. Stop charging pump no. 1.
2. Close the alternate high head cold leg header isolation valve (8885) and open the corresponding high head hot leg header isolation valve (8884).
3. Restart charging pump no. 1.
4. Stop charging pump no. 2.
5. Close the high head injection isolation valves (8801A/B) and open the corresponding high head hot leg header isolation valve (8886).
6. Restart charging pump no. 2.

Table 6.3-4
Maximum Expected External Recirculation Loop Leakage

	Items	Number of Units	Type of Leakage Control and Unit Leakage Rate	Leakage to Atmosphere cc/hr	Leakage to Drain Tank cc/hr
1.	Residual Heat Removal Pumps (Low Head Safety Injection)	2	Mechanical seal with leakoff 50 cc/hr	100	0
2.	Charging Pumps (High Head Safety Injection)	3	Mechanical seal with leakoff 180 cc/hr	540	0
3.	Flanges:				
	a. Pumps	6	Gasket - adjusted to zero	180	0
	b. Valves Bonnet to Body (Larger than 2 inches)	40	leakage following any test - 10 drops/min/flange used	1200	0
	c. Control Valves (Butterfly)	8	30 cc/hr	240	0
	d. Heat Exchangers (2)	4	-	120	0
4.	Valves - Steam Leakoffs	25	Backseated double packing with leakoff - 1 cc/hr/in stem diameter used	0	25
5.	Miscellaneous Small Valves	108	Flanged body packed stems - 1 drop/min used (3 cc/hr)	324	0
6.	Miscellaneous Large Valves (Larger than 2 inches)	20	Double packing - 1 cc/hr/in stem diameter used	20	0
	Total			2724	25

Table 6.3-5
Materials Employed for Emergency
Core Cooling System Components

Component	Material
Accumulators	Carbon Steel, Clad with Austenitic Stainless Steel
Pumps	
Centrifugal Charging	Austenitic Stainless Steel
Residual Heat Removal	Austenitic Stainless Steel
Residual Heat Exchangers	
Shell	Carbon Steel
Shell End Cap	Carbon Steel
Tubes	Austenitic Stainless Steel
Channel	Austenitic Stainless Steel
Channel Cover	Austenitic Stainless Steel
Tubesheet	Austenitic Stainless Steel
Valves	
Motor Operated Valves Containing Radioactive Fluids	
Pressure Containing Parts	Austenitic Stainless Steel or Equivalent
Body-to-Bonnet Bolting and Nuts	Stainless Steel or Alloy Steel
Seating Surfaces	Stellite Number 6 or Equivalent
Stems	17-4 PH Stainless Steel

Table 6.3-5 (continued)
Materials Employed for Emergency
Core Cooling System Components

Component	Material
Accumulator Check Valves	
Parts Contacting Borated Water	Austenitic Stainless Steel or Alloy Steel
Clapper Arm Shaft	PH Nickel Alloy
Seating Surfaces	Stellite GB
Relief Valves	
Stainless Steel Bodies	Stainless Steel
Carbon Steel Bodies (XVR-8857-SI Only)	Carbon Steel
All Nozzles, Discs, Spindles and Guides	Stainless Steel or Alloy Steel
Bonnets for Stainless Steel Valves Without a Balancing Bellows	Stainless Steel
All Other Bonnets	Carbon Steel
Air Operated Valves	
Parts Contacting Borated Water	Stainless Steel
Seating Surfaces	Stainless Steel or Stellite
Stems	Stainless Steel
Body to Bonnet Bolting and Nuts	Stainless Steel or Alloy Steel
Piping	
All Piping in Contact with Borated Water	Austenitic Stainless Steel

Table 6.3-6
Normal Operating Status of Emergency Core
Cooling System Components for Core Cooling

Number of Charging Pumps Operable	2*
Number of Residual Heat Removal Pumps Operable	2
Number of Residual Heat Exchangers Operable	2
Refueling Water Storage Tank Volume	
Minimum Contained Volume, gal	453,800
Maximum Contained Volume, gal	514,665
Boron Concentration in Refueling Water Storage Tanks, Minimum, ppm	2,300
Boron Concentration in Accumulator, Minimum, ppm	2,200
Number of Accumulators	3
Nominal Accumulator Pressure, psig	628
Nominal Accumulator Water Volume, ft^3	1,014
System Valves, Interlocks, and Piping Required for the Above Components which are Operable	All

* The third pump is a designated spare and has its circuit breaker(s) racked out.

Table 6.3-7
Single Active Failure Analysis for Emergency
Core Cooling System Components Injection Mode

Component	Injection Mode Malfunction	Comments
1. Pumps		
a. Centrifugal charging	Fails to start	Three provided, evaluation based on operation of one.
b. Residual heat removal	Fails to start	Two provided, evaluation based on operation of one.
2. Automatically Operated Valves		
a. High head injection isolation	Fails to open	Two parallel lines; one valve in either line required to open.
b. Centrifugal Charging Pumps		
i. Suction line from refueling water storage tank	Fails to open	Two parallel lines; only one valve in either line required to open.
ii. Discharge line to the normal charging path	Fails to close	Two valves in series; only one valve required to close.
iii. Suction from volume control tank	Fails to close	Two valves in series; only one valve required to close.
c. Residual Heat Removal Pumps		
i. Minimum flow bypass line	Fails to close	Partial loss of maximum flow from one of two pumps. Evaluation based on flow from only one pump.

Table 6.3-7 (continued)
Single Active Failure Analysis for Emergency
Core Cooling System Components Injection Mode

Recirculation Mode

Component Valves	Malfunction	Comments
1. Residual heat removal pumps suction line to refueling water storage tank	Fails to close	Two parallel lines; each with a gate and check valve. Operation of a gate or check in each line is required.
2. Centrifugal Charging Pump		
a. Suction line from refueling water storage tank	Fails to close	Check valve in series with two parallel gate valves. Operation of either the check valve or the gate valves required.
b. Minimum flow bypass line	Fails to close	One valve in each of three parallel lines backed up by one valve in common line. Only three parallel valves or one common valve required to close
3. Residual heat removal pumps suction line from reactor building sump	Fails to open	Two parallel lines, with two valves in series in each line, one pair of valves in either line is required to open.
4. Centrifugal charging/high head pump suction line at discharge of residual heat exchanger	Fails to open	One line provided from discharge of each residual heat removal pump, valve in only one required to open.
5. Residual heat removal cross-connect line	Fails to close	Two valves in series; operation of one required.

Table 6.3-7 (continued)
Single Active Failure Analysis for Emergency
Core Cooling System Components Injection Mode

Component	Malfunction	Comments
6. Residual heat removal cross-connect line	Fails to open	Two valves provided: Hot leg recirculation flow from one RHR pump via one valve adequate.
7. Charging/high head safety injection pump suction header and discharge header cross-connect isolation valves	Fails to close	Two valves in series. One required to close.
8. High head cold leg recirculation header isolation valves	Fails to open	Header containing redundant parallel valves open during safety injection. Other header is redundant and contains one valve that opens. One header required.
9. High head hot leg recirculation header isolation valves	Fails to open	Redundant headers in parallel with one valve in each header. One header required.
10. RHR cold leg recirculation/injection isolation valves	Fails to close	One cold leg RHR recirculation isolation valve provided per RHR pump. Hot leg recirculation flow from one pump adequate.
11. RHR hot leg recirculation isolation valve	Fails to open	Sufficient hot leg recirculation flow provided via two charging high head pumps.
12. High head cold leg recirculation header isolation valves	Fails to close	Two headers; one header contains redundant parallel valves that close during hot leg recirculation, the other header contains one valve that closes. One header is required to be isolated.

Table 6.3-8
Emergency Core Cooling System Recirculation Piping Passive
Failure Analysis Long Term Phase

Flow Path	Indication of Loss of Flow Path	Alternate Flow Path
Low Head Recirculation		
From reactor building sump to low head injection header via the residual heat removal pumps and the residual heat exchangers	Accumulation of water in a residual heat removal pump compartment or auxiliary building sump actuates an alarm in the control room	Via the independent, identical low head flow path utilizing the second residual heat exchanger and residual heat removal pump
High Head Recirculation		
From reactor building sump to the high head injection header via residual heat removal pump, residual heat exchanger and the high head injection pumps	Accumulation of water in a residual heat removal pump compartment or the auxiliary building sump or charging pump compartments actuates an alarm in the control room	From reactor building sump to the high head injection headers via alternate residual heat removal pump, residual heat exchanger, or charging pump

Table 6.3-9
Emergency Core Cooling System Shared Functions Evaluation

Component	Normal Operating Arrangement	Accident Arrangement
Refueling Water Storage Tank	Lined up to suction of residual heat removal pumps	Lined up to suction centrifugal charging and residual heat removal pumps. Valves for realignment meet single failure criteria.
Centrifugal Charging Pumps	Lined up for charging service	Lined up to cold leg injection. Valves for realignment meet single failure criteria.
Residual Heat Removal Pumps	Lined up to cold legs of reactor coolant piping	Lined up to cold legs of reactor coolant piping
Residual Heat Exchangers	Lined up to cold legs of reactor coolant piping	Lined up to cold legs of reactor coolant piping

Figure 6.3-1, Sheet 1
DRAWING E-302-691
FSAR FIGURE REFERENCE

Figure 6.3-1, Sheet 2
DRAWING E-302-692
FSAR FIGURE REFERENCE

Figure 6.3-1, Sheet 3
DRAWING E-302-693
FSAR FIGURE REFERENCE

Figure 6.3-2

EMERGENCY CORE COOLING SYSTEM PROCESS FLOW DIAGRAM (SHEET 1 OF 3)

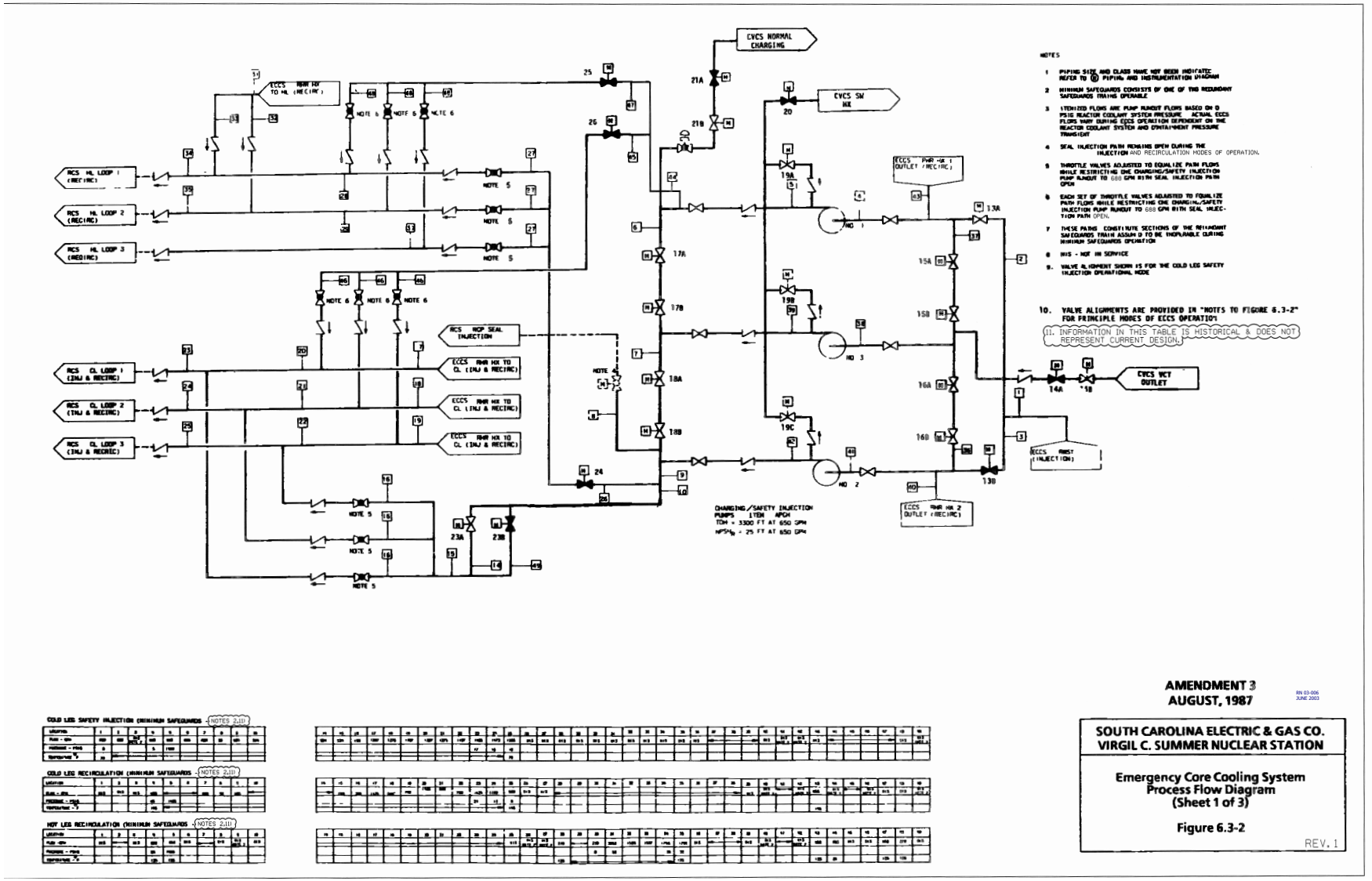


Figure 6.3-2

EMERGENCY CORE COOLING SYSTEM
PROCESS FLOW DIAGRAM (SHEET 2 OF 3)

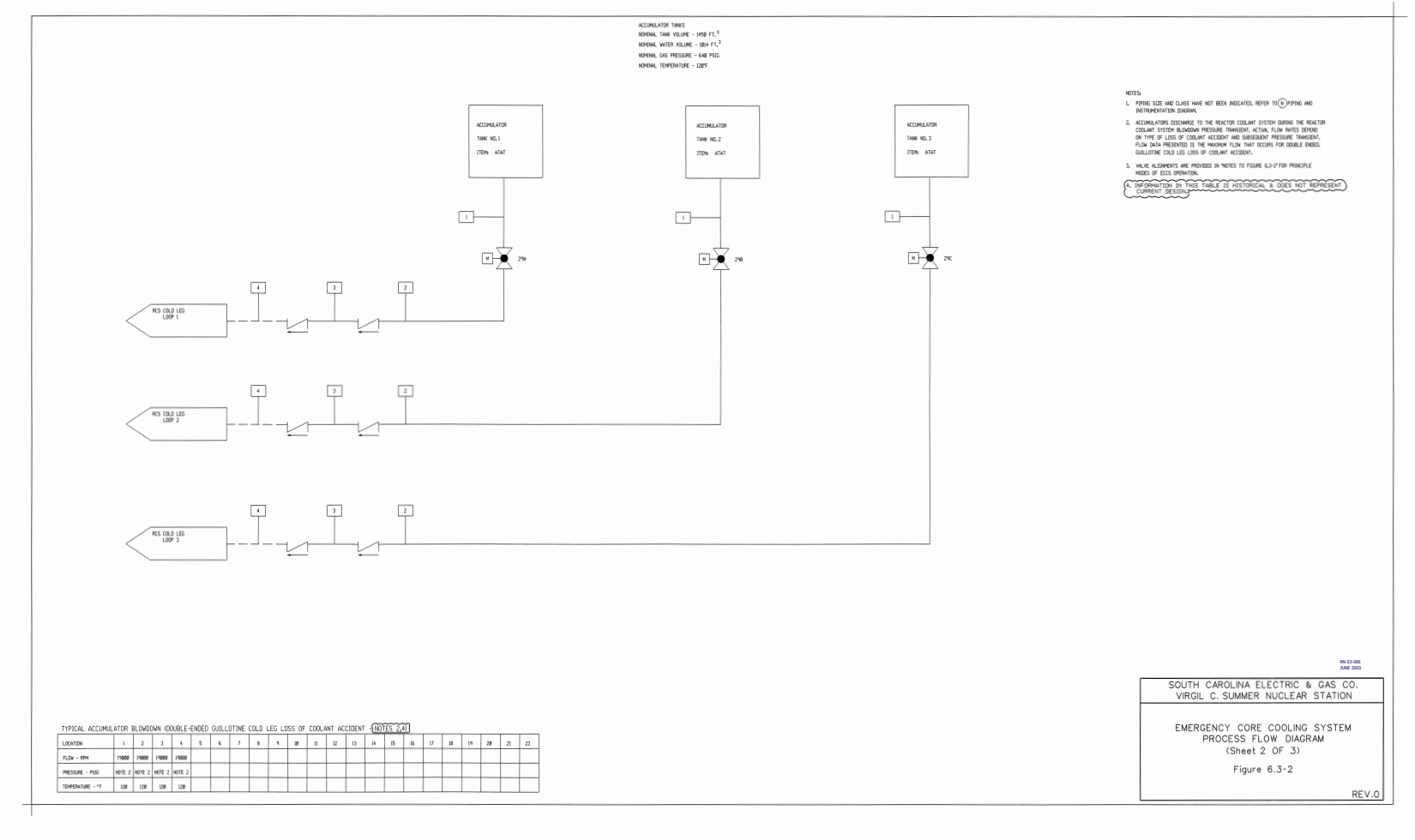
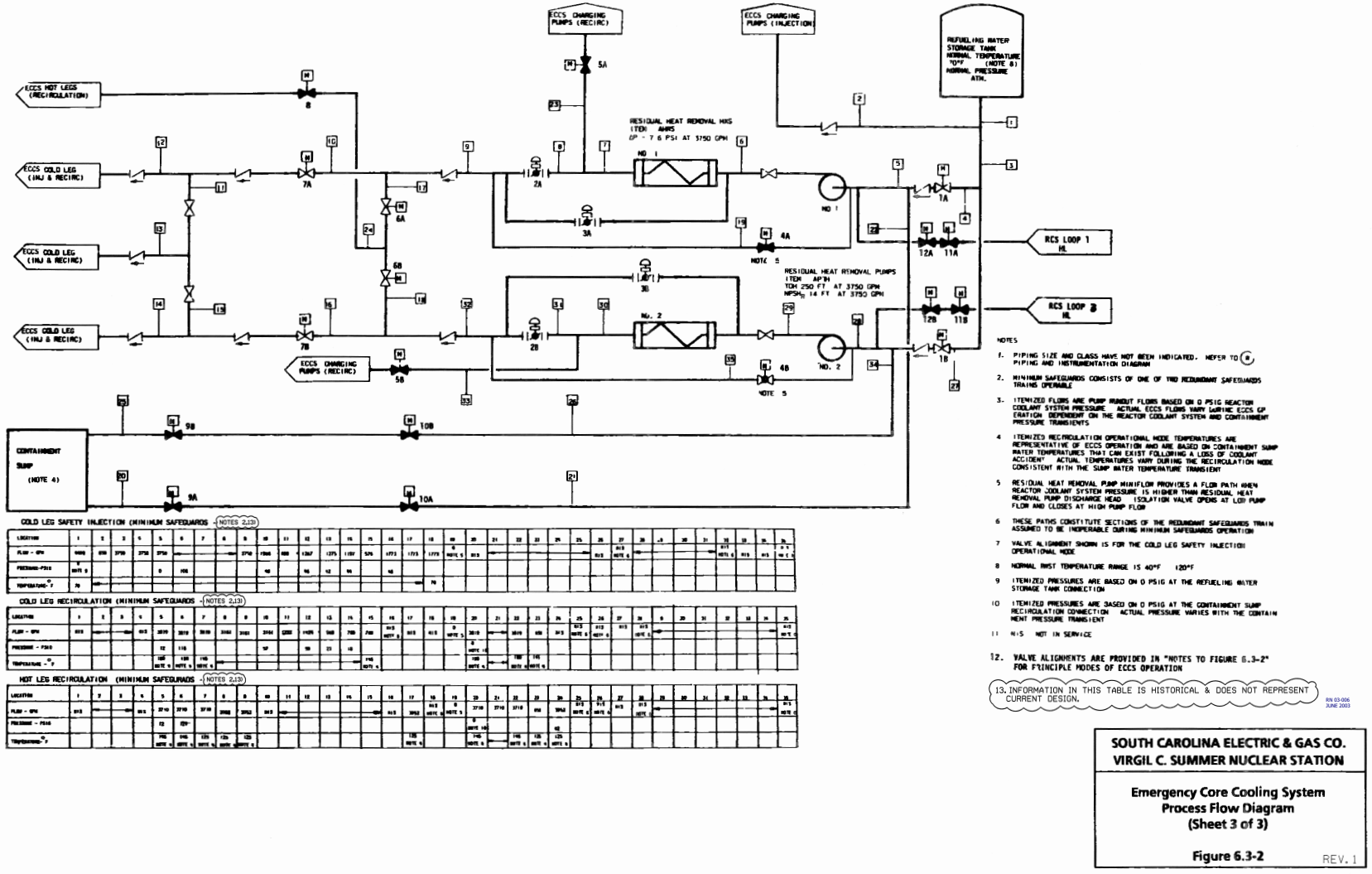


Figure 6.3-2

EMERGENCY CORE COOLING SYSTEM
PROCESS FLOW DIAGRAM (SHEET 3 OF 3)



NOTES TO FIGURE 6.3-2 (Sheet 1 of 4)

1. Westinghouse process flow diagrams are provided for illustrative purposes only and are not intended to represent the flow rates used by Westinghouse in various accident analyses. Flow rates to the RCS are provided in Chapter 15, where appropriate. The process flow diagrams are developed to provide representative best estimate system performance data based on minimum safeguards systems alignment. The flow rates in the FSAR accident analyses are developed based on pump test curves degraded by 5 - 7 percent (see Section 6.3.3.1) and worst case assumptions pertaining to spilling line system resistances (e.g., maximum allowable resistances in lines connected to unbroken loops and minimum allowable resistances in the line connected to the broken loop) and RCS pressures.
2. The minimum safeguards alignments are for Train A components only. Minimum alignments assume a loss of power to Train B at the beginning of the event.
3. Charging pump suction and discharge valves are listed as Closed during the recirculation mode. In actuality, two suction and two discharge header valves will be open, depending on which charging pumps are in operation to establish two separate high head recirculation discharge flowpaths. (Reference Table 6.3-3)
4. RHR minimum recirculation valves are controlled automatically. During periods of low RHR injection flow rates, these valves open to maintain pump minimum flow requirements. (Reference Section 6.3.2.2.4.1)
5. In order to minimize procedure complexity, the preferred lineup for hot leg recirculation is to align the Charging SI pumps to the RCS cold legs and the RHR SI pumps to the hot legs. Adequate core cooling is ensured with either the preferred lineup or by aligning Charging SI pumps to the hot legs and the RHR SI pumps to the cold legs.

NOTES TO FIGURE 6.3-2 (SHEET 2 OF 4)
VALVE ALIGNMENT FOR PRINCIPLE MODES OF ECCS OPERATION

Valve No.	A Normal Standby	B Injection Maximum Safeguards	C Injection Minimum Safeguards (Train A Only - See Note 2)	D Cold Leg Recirculation Maximum Safeguards	E Cold Leg Recirculation Minimum Safeguards (Train A Only - See Note 2)	F Hot Leg Recirculation Maximum Safeguards (See Note 5)	G Hot Leg Recirculation Minimum Safeguards (Train A Only - See Note 2 and Note 5)
1A	O	O	O	C	C	C	C
1B	O	O	O	C	O	C	O
2A	O	O	O	O	O	O	O
2B	O	O	O	O	O	O	O
3A	C	C	C	C	C	C	C
3B	C	C	C	C	C	C	C
4A (Note 4)	O	C	C	C	C	C	C
4B (Note 4)	O	C	O	C	O	C	O
5A	C	C	C	O	O	O	O
5B	C	C	C	O	C	O	C
6A	O	O	O	C	C	C	C
6B	O	O	O	C	O	C	C
7A	O	O	O	O	O	O	C
7B	O	O	O	O	O	O	O
8	C	C	C	C	C	C	C
9A	C	C	C	O	O	O	O
9B	C	C	C	C	C	O	C

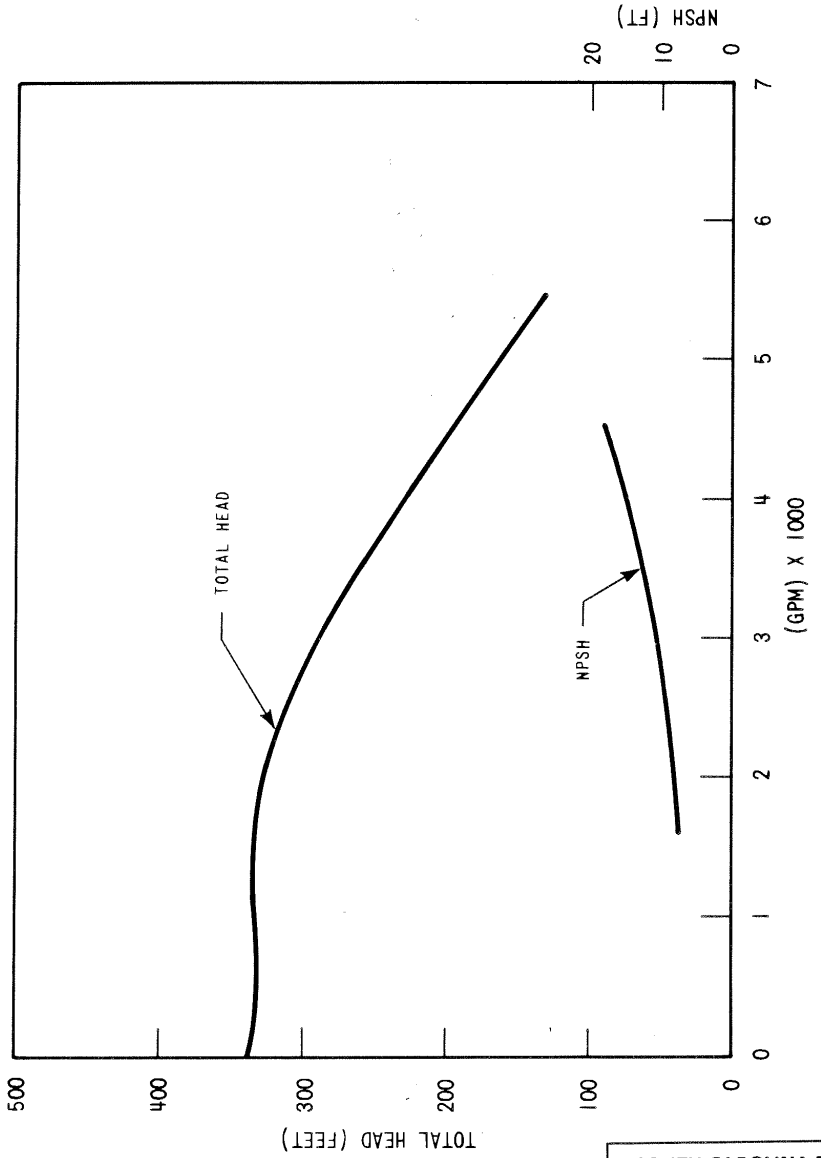
NOTES TO FIGURE 6.3-2 (SHEET 3 OF 4)
VALVE ALIGNMENT FOR PRINCIPLE MODES OF ECCS OPERATION

Valve No.	A Normal Standby	B Injection Maximum Safeguards	C Injection Minimum Safeguards (Train A Only - See Note 2)	D Cold Leg Recirculation Maximum Safeguards	E Cold Leg Recirculation Minimum Safeguards (Train A Only - See Note 2)	F Hot Leg Recirculation Maximum Safeguards (See Note 5)	G Hot Leg Recirculation Minimum Safeguards (Train A Only - See Note 2 and Note 5)
10A	C	C	C	O	O	O	O
10B	C	C	C	O	C	O	C
11A	C	C	C	C	C	C	C
11B	C	C	C	C	C	C	C
12A	C	C	C	C	C	C	C
12B	C	C	C	C	C	C	C
13A	C	O	O	C	C	C	C
13B	C	O	C	C	C	C	C
14A	O	C	O	C	O	C	O
14B	O	C	C	C	C	C	C
15A (Note 3)	O	O	O	C	C	C	C
15B (Note 3)	O	O	O	C	O	C	O
16A (Note 3)	O	O	O	C	C	C	C
16B (Note 3)	O	O	O	C	O	C	O
17A (Note 3)	O	O	O	C	C	C	C
17B (Note 3)	O	O	O	C	O	C	O

NOTES TO FIGURE 6.3-2 (SHEET 4 OF 4)
VALVE ALIGNMENT FOR PRINCIPLE MODES OF ECCS OPERATION

	A	B	C	D	E	F	G
Valve No.	Normal Standby	Injection Maximum Safeguards	Injection Minimum Safeguards (Train A Only - See Note 2)	Cold Leg Recirculation Maximum Safeguards	Cold Leg Recirculation Minimum Safeguards (Train A Only - See Note 2)	Hot Leg Recirculation Maximum Safeguards (See Note 5)	Hot Leg Recirculation Minimum Safeguards (Train A Only - See Note 2 and Note 5)
18A (Note 3)	O	O	O	C	C	C	C
18B (Note 3)	O	O	O	C	O	C	O
19A	O	O	O	C	O	C	O
19B	O	O	O	C	O	C	O
19C	O	O	O	C	O	C	O
20	O	O	O	C	C	C	C
21A	O	C	C	C	C	C	C
21B	O	C	O	C	O	C	O
23A	C	O	O	O	O	C	C
23B	C	O	C	O	C	C	C
24	C	C	C	C	C	O	C
25	C	C	C	C	C	O	O
26	C	C	C	O	C	C	C
29A	O	O	O	O	O	O	O
29B	O	O	O	O	O	O	O
29C	O	O	O	O	O	O	O

Figure 6.3-3
PERFORMANCE CURVE FOR RESIDUAL HEAT REMOVAL PUMP



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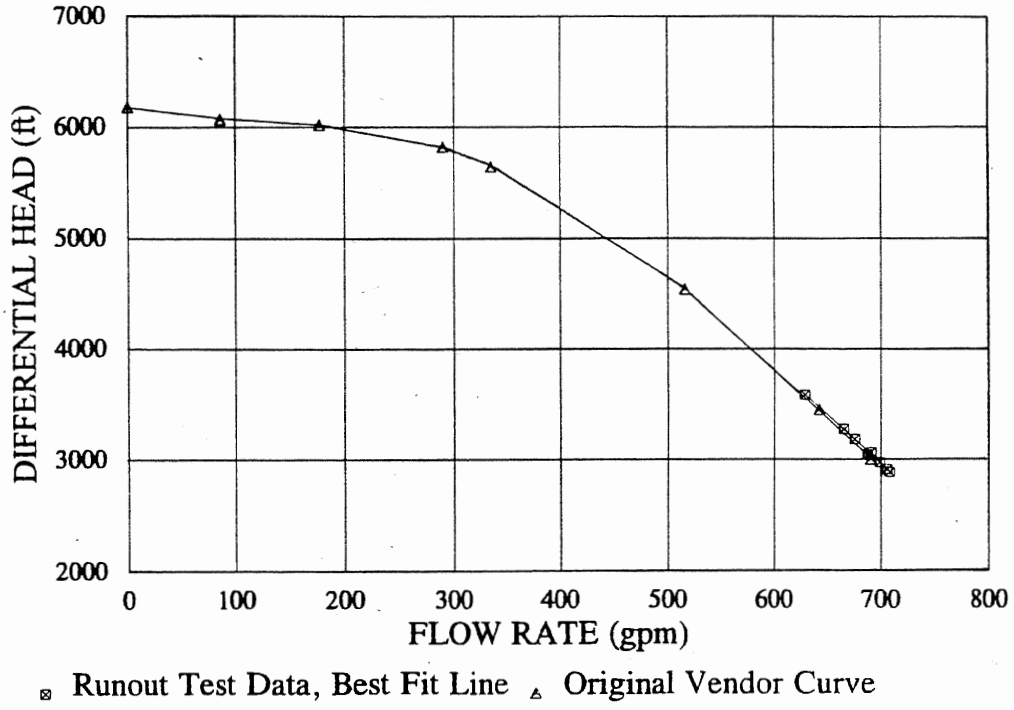
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Performance Curve for Residual Heat Removal Pump
Figure 6.3-3

Figure 6.3-4a
PERFORMANCE CURVE FOR CENTRIFUGAL CHARGING PUMP A



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Performance Curve For Centrifugal Charging Pump A Figure 6.3-4a

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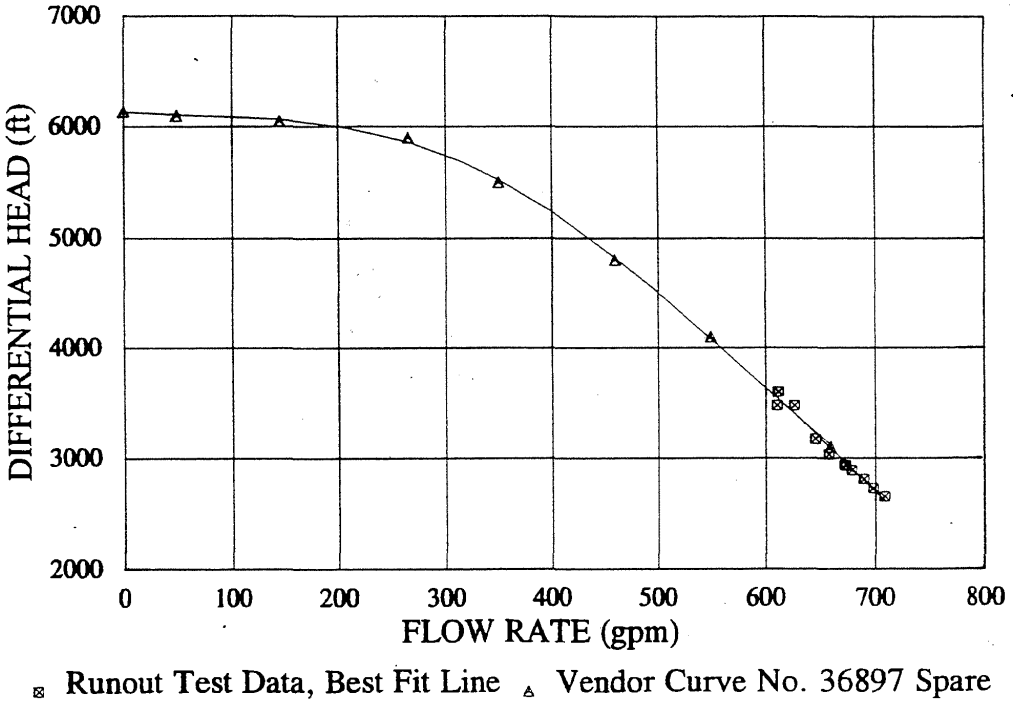
Figure 6.3-4b
PERFORMANCE CURVE FOR CENTRIFUGAL CHARGING PUMP B



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Performance Curve For Centrifugal Charging Pump B Figure 6.3-4b

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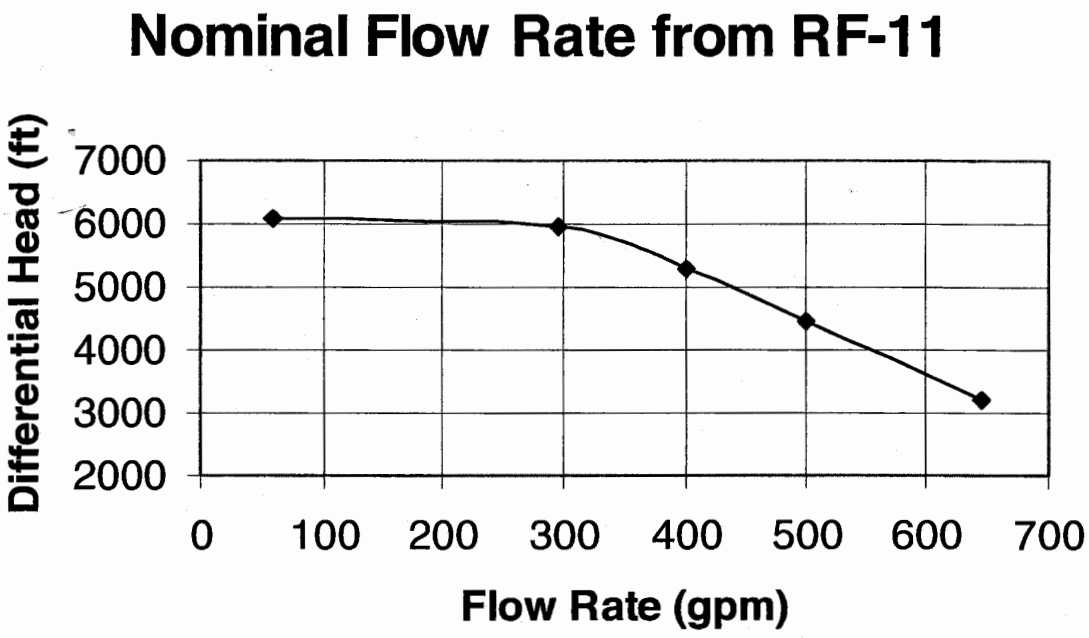
Figure 6.3-4c
PERFORMANCE CURVE FOR CENTRIFUGAL CHARGING PUMP C



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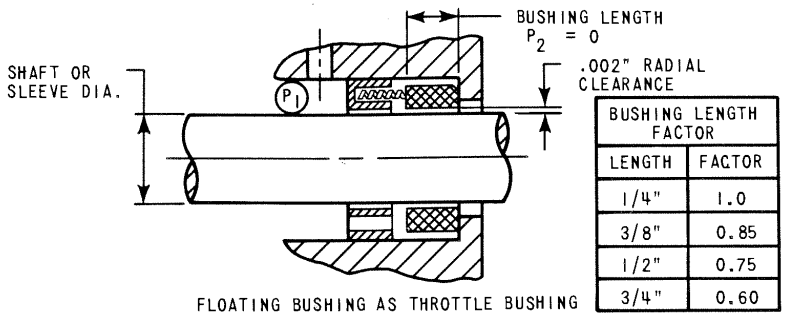
SOUTH CAROLINA ELECTRIC AND GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Performance Curve For Centrifugal Charging Pump C Figure 6.3-4c

Figure 6.3-5

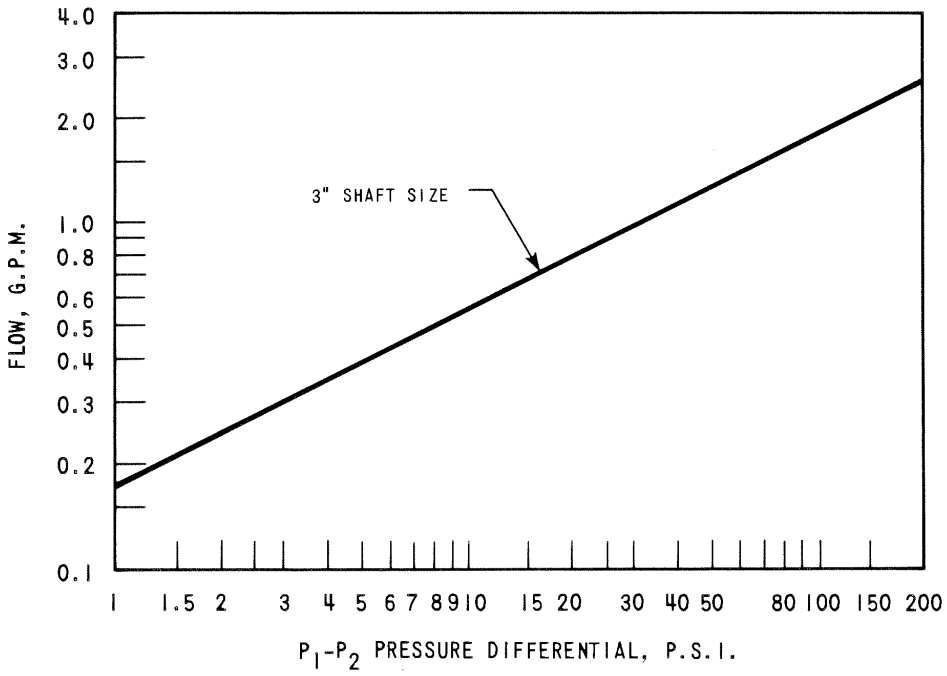
FLOW RATES FOR FLOATING BUSHING



FLOATING BUSHING AS THROTTLE BUSHING

BUSHING LENGTH FACTOR	
LENGTH	FACTOR
1/4"	1.0
3/8"	0.85
1/2"	0.75
3/4"	0.60

EXAMPLE - FLOATING BUSHING AS THROAT BUSHING
BOX PRESSURE - P_2 = 25 P.S.I.
FLUSHING FLUID PRESSURE - P_1 = 50 P.S.I.
SHAFT DIA = 2" BUSHING LENGTH = 1/2"
PRESSURE DIFFERENTIAL = P_1-P_2 = 50-25 = 25 P.S.I.
FROM CHART FOR 25 P.S.I. AND 2" SHAFT DIA. FLOW IS 0.64"G.P.M. BUSHING LENGTH FACTOR FOR 1/2" BUSHING IS .75. FLOW = 0.64 G.P.M. X .75 = 0.48 G.P.M.



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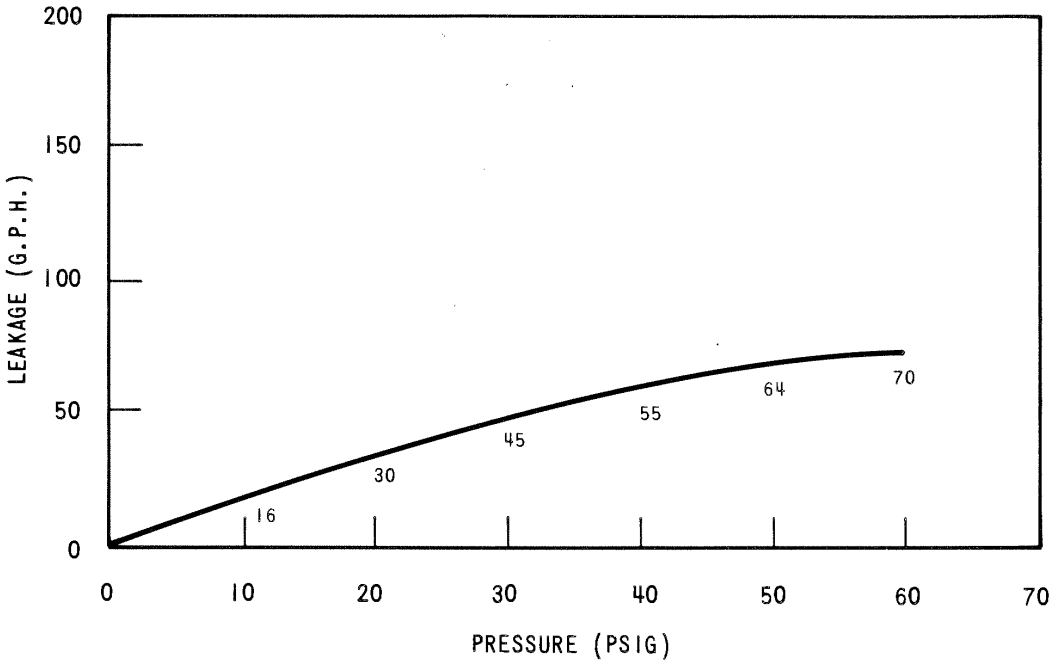
Flow Rates for Floating Bushing

Figure 6.3-5

Figure 6.3-6

BUSHING LEAK RATE AFTER SEVERE OPERATION



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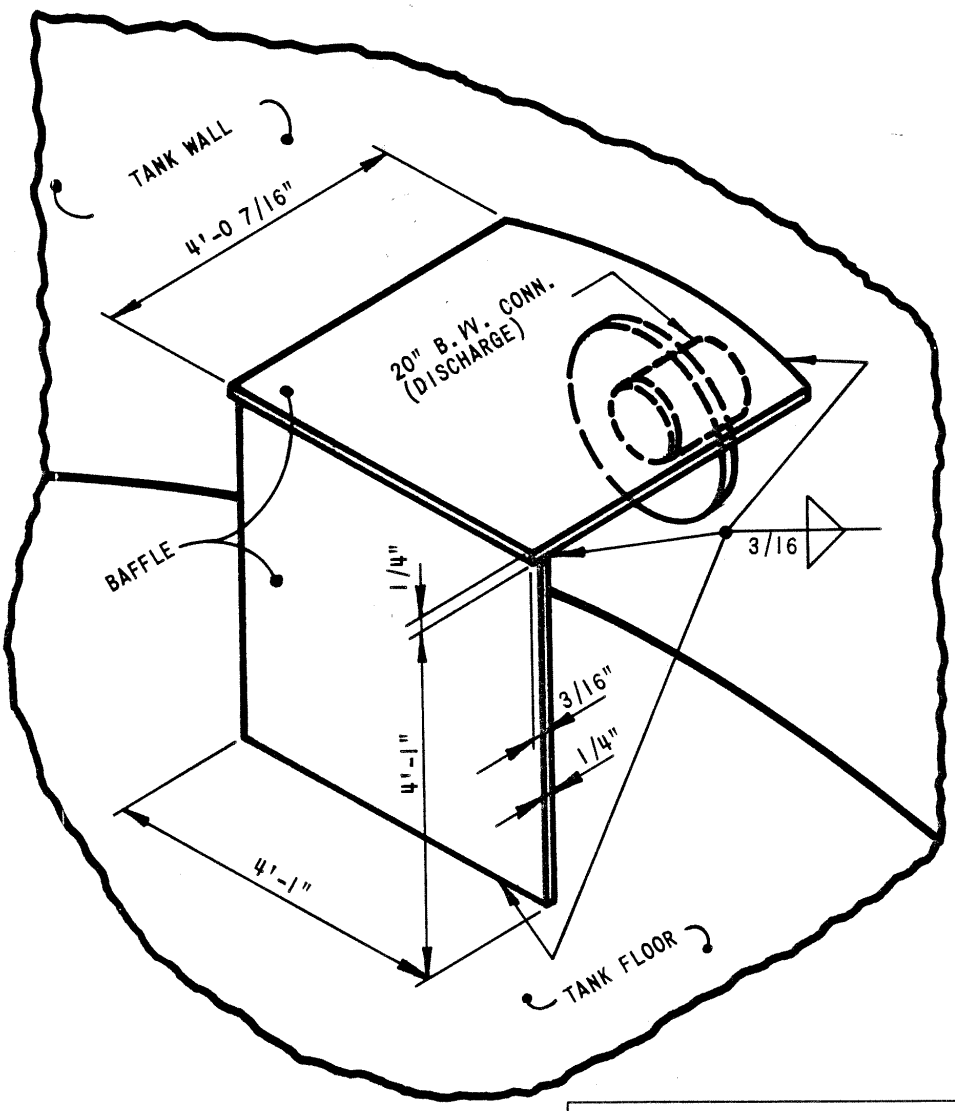
Bushing Leak Rate After Severe Operation Figure 6.3-6

Figure 6.3-7
REFUELING WATER STORAGE TANK
20" DISCHARGE BAFFLE



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Refueling Water Storage Tank
20" Discharge Baffle

Figure 6.3-7

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6.4 HABITABILITY SYSTEMS

Control room systems are designed in accordance with the design bases described in Section 6.4.1 so that habitability of the control room can be maintained under normal and accident conditions. The general guidance contained in Regulatory Guide 1.78 and the specific guidance contained in Regulatory Guide 1.95 is reflected throughout this section.

6.4.1 Habitability Systems Functional Design

6.4.1.1 Design Bases

The design bases for control room habitability systems are as follows:

1. Control Room Envelope

   The control room envelope includes most areas located on the 448’ and 463’ elevations of the Control Building. Housed within this control room envelope are the monitoring equipment, instrumentation, and control panels required for safe operation and shutdown of the plant. The control room envelope is provided with fire protection equipment, adequate lighting, communications equipment and kitchen, sanitary, administrative and storage facilities, and spaces necessary for normal plant operation and required to maintain the plant in a safe condition following an accident. The control room envelope ambient atmosphere is normally maintained at 75°F ± 2°F, drybulb and 50 percent relative humidity.

2. Period of Habitability

   The control room envelope is equipped to sustain seven people for a period of seven days following an accident.

3. Capacity

   The normal occupancy level of the control room is six people.

4. Food, Water, Medical Supplies, and Sanitary Facilities

   First aid equipment, food, and water are provided to sustain seven people for seven days following an accident. Chemical toilet facilities are provided for use in the event that normal sanitary facilities become inoperative.

5. Radiation Protection

   Radiation protection, as required by 10 CFR 50, Appendix A, Criterion 19, is provided by shield walls on the four exposures, shield slabs at floor and ceiling, radiation monitoring equipment, and emergency filtering systems. The control room atmosphere is monitored for radiation. When required, the control room atmosphere can be recirculated through the emergency filter system to remove contaminants. This filter system consists of roughing, high efficiency particulate air (HEPA), and charcoal filters. Assumptions and analyses regarding sources and amounts of radioactivity which may surround or leak into the control room and related shielding requirements are discussed in Chapters 12 and 15. The Radiation Monitoring System is discussed in Sections 11.4, 12.1.4 and 12.2.4.

6. Noxious Gas Protection

   Smoke detectors located in the control room air supply duct and in the emergency filter system discharge duct actuate alarms to indicate the presence of smoke in these locations. Additionally, the control room can be purged with outside air if required. Regulatory Guides 1.78 and 1.95 are discussed in Appendix 3A.

7. Respiratory, Eye, and Facial Protection for Emergencies

   Self-contained breathing apparatus are provided for control room occupants.

8. Habitability System Operation during Emergencies

   Operation of the habitability system during emergencies is discussed in Section 9.4.1.2.1.

9. Emergency Monitors and Control Equipment

   Emergency monitors and control equipment are discussed in Section 13.3.

6.4.1.2 System Design

6.4.1.2.1 Definition of Control Room Envelope

The areas to which the control room operator could require access during an emergency are the following:

1. Control room main control board and monitoring panel area - continuous occupancy required.
2. Chart and storage room - infrequent access required.
3. Shift Manager’s office - infrequent access required.
4. Kitchen facility - infrequent access required.
5. Toilet room - infrequent access required.

The equipment to which the control room operator could require access during an emergency is listed in Table 6.4-1.

6.4.1.2.2 Ventilation System Design

Normal and emergency ventilation of the control room are discussed in Section 9.4.1.2.1. The system diagram, Figure 9.4-1, indicates major components, ducts, dampers, instrumentation, and normal and emergency air flows.

System isolation dampers are pneumatically operated, spring opposed. Damper leakage does not exceed 20 cfm/ft^2 of damper area against a static pressure of 4 inches, water gage. Outside air inlet valves are 14 inch butterfly valves which have negligible leakage. Table 6.4-2 provides a summary of system isolation damper/valve data.

Components, essential instrumentation, ducting and outside air intake, and relief vents of the Control Building Ventilation System are designed in accordance with Seismic Category I requirements.

The components are not subject to the effects of floods, catastrophic weather, internal or external missiles, pipe whip, or jet impingement.

Figures 1.2-15 and 1.2-16 present layout drawings of the control room indicating doors, corridors, stairwells, shielded walls, ventilation equipment, and the location of outside air intakes.

The location of potential radioactive gas releases and their effect upon control room operation and the monitoring instrumentation and controls located therein are discussed in Chapter 15.

A description of the emergency filter system and a discussion of Regulatory Guide 1.52 is presented in Section 6.5.1 and Appendix 3A.

6.4.1.2.3 Leak Tightness

The control room system is designed so that, when operating in a normal or an emergency mode (admitting outside air), positive differential pressure is maintained between the control room and adjacent spaces. In the emergency mode, outside air is filtered by the emergency filter system and is used to pressurize the control room.

The potential paths of air leakage into the control room include: outside air valves in the non-operating redundant system and relief air dampers; openings around supply and return ducts in the control room walls and in duct chase floors; openings for electrical conduit and cables in the control room and chase walls and floors; doors; and piping. A review of these paths, as summarized below, indicates that air leakage through these paths during the emergency mode is minimal:

1. In the non-operating redundant system, the outside air is sealed from the control room by two 14 inch butterfly valves in series. Both valves are the low leakage type and fail closed upon loss of control air or power. The maximum leakage through a single closed 14 inch butterfly valve is negligible.
2. The relief dampers are two 36 inch by 36 inch dampers, one in each train. Both dampers are gasketed and blanked closed, except during control room purge, to ensure negligible air leakage.
3. The purge dampers are two 42 inch by 42 inch dampers in series. The inlet plenum to these dampers is gasketed and blanked closed, except during control room purge to ensure negligible air leakage. These dampers are fixed in the full open position.
4. Openings around supply and return ducts in the walls and floors of the control room and chases are sealed with air tight expanded silicone foam with a fire resistance rating of three hours. Negligible air leakage is present in these openings.
5. Openings for electrical conduit and cables in the walls and floors of the control room and chases are sealed in the same manner as the openings noted in item 4, above.
6. Doors from the control room to the chase area are three hour fire rated doors with closures. The maximum anticipated total air gap around each door is 0.21 ft^2. The doors leading from the turbine building to the control room are gasketed, pressure tight doors.
7. Piping to plumbing fixtures, drains, and potable water leaving the control room are sealed in the manner noted in item 4, above.

None of the control room doors lead directly to the outside. Doors lead to closed chase spaces, stairwells, or corridor spaces. Thus, neither outside wind conditions or other ventilation system cause infiltration or leakage into the control room.

6.4.1.2.4 Interaction With Other Zones and Pressure Containing Equipment

The Control Room Ventilation System is not interconnected with other building areas where potential for radioactivity exists. The system interconnects with cable spreading areas and with chase spaces through closed fire doors. There are no pressure containing pipes or equipment containing hazardous materials in the control room, cable spreading areas or duct chases.

The Turbine Building contains sources of carbon dioxide and steam but releases of these substances are diluted by the large Turbine Building volume and would be unlikely to reach the control room in any significant quantity since entry is protected by a pressure retaining door, a corridor, and a second door.

The normal and emergency operating modes of the Control Room Ventilation System maintain a positive pressure differential between the control room and adjacent spaces. Thus, the likelihood of infiltration is reduced. A radiation monitor sensing control room atmospheric radioactivity immediately causes the ventilation system to shift into the emergency mode upon detection of high gaseous activity. Thus, the potential for entry of outside airborne material into the control room is minimal. The Control Room Ventilation System can also be manually controlled to purge

the control room with outside air. The outside air purge rate is variable up to 100 percent of the system flow rate.

6.4.1.2.5 Shielding Design

The control room shielding design is discussed in Section 12.1.

6.4.1.3 Design Evaluation

Each of the operating systems which ensures control room habitability is discussed in detail in other sections. These systems and the FSAR section in which they are discussed are as follows:

1. Control Room Ventilation System, 9.4.1.
2. Fire Protection System, 9.5.1.
3. Communications System, 9.5.2.
4. Lighting System, 9.5.3.
5. Offsite power system, 8.2.
6. Onsite power system, 8.3.
7. Radiation Monitoring System, 11.4, 12.1.4, 12.2.4.

A summary evaluation of control room habitability based upon selected considerations is presented in Sections 6.4.1.3.1 through 6.4.1.3.6.

6.4.1.3.1 Radiological Protection

The evaluation of radiological exposures to control room operators for postulated accident conditions is presented in Section 15.4.

6.4.1.3.2 Toxic Gas Protection

While chlorine is not permanently stored on-site, it would be the primary hazardous chemical in sufficient quantities which may under accidental release approach toxicity limits in the control room should the use of chlorine be re-implemented.

In accordance with the recommendations of Item C2 of Regulatory Guide 1.95 chlorine, if stored on-site, would be in containers having a single container inventory of 150 pounds or less. Chlorine would be stored in the chlorine shed adjacent to the Water Treatment Building which is greater than 150 meters from the control room intake. Indication of a chlorine leak is provided by a chlorine leak detector located in the chlorine shed which annunciates an alarm locally and in the control room. Capability for manual isolation of the Control Room Ventilation System is described in Section 9.4.1. For discussion of postulated off-site hazardous chemical releases see Section 2.2.

In the absence of chlorine, ammonium hydroxide would be the primary hazardous chemical on-site. In sufficient quantities it may, under accidental release, approach toxicity limits in the control room.

One 7,000-gallon storage tank, XTK-105, containing between 1,000 and 4,000 gallons of aqueous ammonia (ammonium hydroxide) is located outside of the northeast corner of the water treatment building. The tank supplies aqueous ammonia to the auxiliary boiler chemical injection system and is filled by a two-inch liquid connection line.

A weir around the tank contains small liquid spills while large spills drain by gravity into a trough to the waste neutralizing basin. The worst-case situation for an accidental release of gas from the tank would be a catastrophic failure of the tank during a time of wind drift directly toward a Control Building air intake. In the unlikely event of such a failure, ammonia gas would be released from the tank's vapor space and the evaporation of the liquid pooled on the ground could result in ammonia gas leaking into the Control Room.

Analysis of the tank failure shows that the operators would detect the gas and have enough time to don protective equipment before reaching the exposure limit of 2 minutes at 100 ppm described in Regulatory Guide 1.78.

6.4.1.3.3 Control Room Filtering System

The general arrangement and control of the Control Room Filtering Systems are as described in Section 9.4.1.

6.4.1.3.4 Control of the Control Room Thermal Environment

The Control Room Air Handling System operates during normal and emergency periods to maintain an environment suitable for personnel and equipment. The conditions maintained and general system description are presented in Section 9.4.1.

6.4.1.3.5 Fire Protection

Evaluation of the Fire Protection System is presented in Section 9.5.1.

6.4.1.3.6 Food, Water and Sanitation

A seven day supply of food is provided in the control room for emergency use. If the emergency requires confinement for periods longer than seven days, additional food will be brought onsite in protected containers. Site accessibility will be determined by the plant Health Physicist.

Potable water is normally available from the Potable Water System described in Section 9.2.4. Should this system become unavailable during an emergency period, stored, bottled water is available in an area immediately adjacent to the control room. Additional bottled water could be brought into the control room if required.

Normal sanitation facilities are available as described in Section 9.2.4. Chemical toilets are also available in these areas for use in the event that the normal facilities become inoperative following an emergency.

6.4.1.4 Testing and Inspection

The equipment which maintains control room habitability includes the Emergency Filter System, the Control Room Air Handling System, and the Chilled Water System.

The testing and inspection is further described in Section 9.4.1.4.

6.4.1.5 Instrumentation Requirements

Habitability systems instrumentation and control equipment provides for control and monitoring of performance and status during system operation and testing. The instrumentation and control provisions for each of the systems used to ensure control room habitability are discussed in other sections of the FSAR. A list of these systems and the sections in which they are discussed is presented in Section 6.4.1.3.

6.4.2 System Operational Procedures

The normal and emergency operating modes of normal and emergency control room habitability equipment, instrumentation, and the associated controls are described in Section 9.4.1.2.1.

Table 6.4-1
Equipment to Which the Control Room Operator
Could Require Access During an Emergency

Item or Equipment	Location Within Control Room Envelope
Control and Monitoring Panels	Identified on Figure 1.2-15
Portable Radiation Measuring Instruments	Store Room
Emergency Procedures, Manuals and Drawings	Operator's desk
Self-Contained Breathing Apparatus	Store Room
Communications Equipment	Operator's desk
Fire Extinguishing Equipment	On control room wall outside Shift Manager's office
Food Supplies	Kitchen

Table 6.4-2
Control Room Ventilation System
Isolation Damper/Valve Summary

Damper Function	Size (in)	Identification	Failure Position
Purge Air Inlets	42 by 42	XDP-18A, 19A-AH	Open*
Purge Air Inlets	42 by 42	XDP-18B, 19B-AH	Open*
System Relief Air	36 by 36	XDP-21A, 21B-AH	Closed**
System Return Air	42 by 42	XDP-22A, 22B-AH	Closed
Equipment Room Relief Air	72 by 48	XDP-133A, 133B-AH	Closed
Equipment Room Relief Air	72 by 48	XDP-234A, 234B-AH	Closed
Emergency Filter Inlet Damper	42 by 42	XDP-23A, 23B-AH	Open
Emergency Filter Fan Discharge Damper	42 by 42	XDP-24A, 24B-AH	Open
Outside Air Inlets	14 (in) Butterfly Valve	XVB-3A, 4A-AH	Closed
Outside Air Inlets	14 (in) Butterfly Valve	XVB-3B, 4B-AH	Closed

* Inlet plenum blanked to ensure no air ingress
** Outlet plenum blanked to ensure no air leakage

Table 6.4-3
Information Required for Control
Room Habitability Evaluation

Reference: NUREG-0737, Section III.D.3.4, Attachment 1

	Subject	FSAR Source	Response
(1)	Control room mode of operation	6.4.1.2.4 9.4.1.2.1 15.4.1.4.3	Zone isolation with filtered air recirculation and positive zone air pressurization
(2)	Control room characteristics:		
	(a) Control room volume	Table 15.4-17	226,040 ft^3 (free volume)
	(b) Control room emergency zone	6.4.1.1 6.4.1.2.1	Most areas located on elevation 463'0" of the Control Building
	(c) Control room ventilation system schematic		FSAR Figure 9.4-1 FSAR Table 6.4-2
	(d) Infiltration leakage rate	Table 15.4-17	1508 cfm (Total)
	(e) Filter efficiencies	9.4.1.2.1	
	1. Charcoal filters		95% for all species of iodine
	(f) Closest distance between release points and control room air intake	Table 2.3-122	See Table 2.3-122
	(g) Layout drawing	1.2	FSAR Figures 1.2-1 and 1.2-26
	(h) Control room shielding	6.4.1.1 15.4.1.4.3	2 ft. concrete
	(i) Automatic isolation capability		
	1.Valve closing time		N/A – Valves remain open for Control Room pressurization See 6.5.1.5.2
	2. Valve leakage	Table 6.4-2	Negligible
	3. Valve area		113 in^2

Table 6.4-3 (continued)
Information Required for Control
Room Habitability Evaluation

	Subject	FSAR Source	Response
	(j) Chlorine detectors or tube gas (local or remote)	6.4.1.3.2	Detector in chlorine shed with annunciation both local and in control room.
	(k) Self-contained breathing apparatus availability	6.4.1.1 Table 12.3-4	1 unit/control room operator
	(l) Bottled air supply	Appendix 3A RG 1.78	3.5 hours (30 min/person)
	(m) Emergency food and potable water supply	6.4.1.1 6.4.1.3.6	7 persons for 7 days Resupply considered for periods longer than 7 days
	(n) Control room personnel capacity (normal and emergency)	6.4.1.1 7.7.3	Normal = 6 person (control room) Emergency = 7 persons (control room) and ≥ 25 persons (technical support center)
	(o) Potassium iodide drug supply		Will be available
(3)	Onsite storage of chlorine and other hazardous chemicals		
	(a) Total amount and size of containers	2.2.3.1.1 6.4.1.3.2	2 containers - with 150 lb chlorine/container
		6.4.1.3.2	Single 7,000 gallon tank – with 1,000 – 4,000 gallons ammonium hydroxide
	(b) Closest distance from control room intake	2.2.3.1.1 6.4.1.3.2	Chlorine: Approximately 507 feet southeast of Control Building. Ammonium Hydroxide: Approximately 400 feet southeast of Control Building

Table 6.4-3 (continued)
Information Required for Control
Room Habitability Evaluation

	Subject	FSAR Source	Response
(4)	Offsite manufacturing, storage, or transportation facilities of hazardous materials		
	(a) Identify facilities within a 5 mile radius	2.2 Table 2.2-1	1. Nyline Corporation 2. Farm Milling Service 3. Interstate Materials Inc., Div. of Clement Bros. Co. 4. Winnsboro Granite Corp.
	(b) Distance from control room	Table 2.2-1	1. 2.6 miles southeast 2. 3.6 miles northeast 3. 3.0 miles northeast 4. 4.8 miles northeast
	(c) Quantity of hazardous chemicals in one container	Table 2.2-1	Gross quantities are: 1. 42,000 lbs caprolactan 2. 150 - 200 tons ammonium nitrate 3. 25,000 lbs ammonium nitrate and torpex 50,000 lbs ammonium nitrate and fuel oil (ANFOPRILL) 4. 100 lbs black powder 200 blasting caps
	(d) Frequency of hazardous chemical transportation traffic (truck, rail, and barge)	2.2.3	Refer to FSAR Section 2.2.3
(5)	Technical specifications		
	(a) Chlorine detection system	2.2 6.4 Appendix 3A	Not required in technical specification
	(b) Control room emergency filtration system	6.4 9.4	Technical Specification Section 3.7.6

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 Engineered Safety Feature Filter Systems

The engineered safety features (ESF) filter systems include:

1. The high efficiency particulate air (HEPA) filters in the Reactor Building Cooling System.
2. The control room emergency filter plenums.
3. The Fuel Handling Building charcoal exhaust system.

6.5.1.1 Design Bases

The ESF filter systems are designed and sized to perform the following functions. Non ESF filter systems are discussed in Section 9.4.

1. Satisfy the radiation control requirements of 10 CFR 20.
2. Satisfy requirements of General Design Criteria 19, 41, 42 and 43.
3. Remove particulate fission products from the post accident Reactor Building atmosphere (Reactor Building Cooling System only).
4. Remove gaseous and particulate fission products from the spent fuel pool surface and from general areas of the Fuel Handling Building.

6.5.1.2 System Design

Descriptive information concerning the ESF filter systems is presented in the following sections:

1. Reactor Building cooling system HEPA filters:
   a. Design bases - Sections 6.5.1.1 through 6.5.1.3
   b. General description - Section 6.2.2.2.2
   c. System design features - Section 6.2.2.2.2.1
2. Control room emergency filter plenums:
   a. Design bases - Section 9.4.1.1
   b. General description - Section 9.4.1.2
   c. System design features - Section 9.4.1.2.1
3. Fuel Handling Building charcoal exhaust system.
   a. Design bases - Section 9.4.3.1
   b. General description - Section 9.4.3.2
   c. System design features - Section 9.4.3.2.1

Table 6.5-1 provides a comparison of the emergency filter systems with the requirements of Regulatory Guide 1.52. General compliance with Regulatory Guide 1.52 is discussed in Appendix 3A.

6.5.1.3 Design Evaluation

The general arrangement and control of the ESF filter systems are described in Sections 6.2.2, 9.4.1, and 9.4.3. System components are separated, redundant, powered by Class 1E electric systems, and are housed in Seismic Category 1 structures. The control room system is not subject to jet impingement, pipe whip or flooding. The HEPA filter systems in the Reactor Building are physically separated so that no more than 1 unit is subject to these occurrences. The Fuel Handling Building charcoal exhaust system plenums are housed in shielded and separated cubicles. The exhaust fans of this system are adjacent to each other. Neither the exhaust fans nor the filter plenums are subject to jet impingement, pipe whip or flooding. The ESF filter systems can sustain a single component failure without impairing their full functional capability. Additionally, provision is made for suitable maintenance and change-out space and adequate instrumentation and lighting, all of which reduce personnel exposure by reducing time exposure.

The control room emergency filter system is required in the event of radioactive leakage from the outside into the Control Building following a LOCA. Post LOCA operation of the control room filter systems is ensured by automatic actuation as a result of a safety injection signal or high radiation in the control room signal from the radiation monitor (RM-A1).

The Reactor Building cooling system and control room emergency filter trains provide a minimum of 99.97 percent removal efficiency for particulates. The control room emergency filters also provide a minimum of 95 percent removal efficiency for methyl iodine at 85 percent relative humidity and 70°F (see Reference 1).

6.5.1.4 Tests and Inspections

Details of the tests and inspections for the ESF filter systems are provided in the following sections:

6.2.2.4.2 - Reactor Building Cooling System HEPA Filters
9.4.1.4 - Control Room Emergency Filters
9.4.3.4 - Fuel Handling Building Charcoal Exhaust System

Laboratory tests, inplace tests, and test acceptance criteria are in accordance with the requirements of Regulatory Guide 1.52 (see Table 6.5-1).

6.5.1.5 Instrumentation Requirements

Each of the ESF filter systems include instrumentation for system performance and status monitoring during normal plant operation, system tests, and system operation following a design basis accident. The instrumentation and control features of the ESF filter systems are described in Sections 6.5.1.5.1 and 6.5.1.5.2.

6.5.1.5.1 Reactor Building Cooling System HEPA Filter Instrumentation

Activation of this filtering system is initiated automatically by a safety injection signal (from the ESF actuation system) or by manual action at the main control board. A separate automatic initiation signal is supplied to each redundant train. Under accident conditions, the filter bypass dampers of both trains (4 units) receive a signal to automatically close, 1 preselected cooling unit in each train is automatically started in low speed.

Main control board switches are provided for each fan motor (high and low) and for the filter bypass damper of each reactor building cooling unit.

Instrumentation used for monitoring the performance of this filter system including bypass damper position indication, is described in Section 6.2.2.5.2.

6.5.1.5.2 Control Room Emergency Filter Instrumentation

Activation of the control room emergency filter system is initiated automatically by a safety injection signal, a high control room radiation signal (RM-A1), (see Section 12.2.4) or by manual action at the HVAC control board in the control room. Other elements of the control room ventilation system are operated in conjunction with this emergency filter system to carry out the air cleaning function. In particular, the relief dampers and outside air supply dampers of the control room ventilation system are automatically tripped closed by the signals listed above. HVAC control board switches are provided for each emergency filtering fan. The fan inlet and discharge dampers operate in conjunction with their respective fans.

The overall operation of the control room ventilation system is described in Section 9.4.1. Instrumentation used for monitoring the performance of this filter system, including fan and damper status indication, is described in Section 9.4.1.2.1.

6.5.1.5.3 Fuel Handling Building Charcoal Exhaust System Instrumentation

The Fuel Handling Building charcoal exhaust system components (2 filter plenums, one exhaust fan) are in continuous operation during normal, shutdown and refueling periods. The ESF function of the fuel building charcoal exhaust system is only required during the movement of fuel in the spent fuel pool or during crane operation with loads over the pool. Instrumentation used for monitoring system performance, including fan and damper status indication, is described in Section 9.4.3.2.1.

6.5.1.6 Materials

Filter materials employed in the ESF filter systems are discussed in Section 6.5.1.6.1 and 6.5.1.6.2.

6.5.1.6.1 Reactor Building Cooling System HEPA Filter Materials

Each of four Reactor Building cooling system filter plenums includes 120 HEPA cells. Cells are nominally 24 inches square by 12 inches deep. Cells include media of high strength, waterproof glass fiber without separators, high temperature silicon adhesive, metal cell sides and silicon rubber closed cell sponge gasketing.

6.5.1.6.2 Control Room Emergency Filter and Fuel Handling Building Charcoal Exhaust System Filter Materials

Both of the control room emergency filter plenums contain 1 prefilter bank, each with 15 prefilter cells. Each of the 3 Fuel Handling Building charcoal exhaust system filter plenums contains 1 prefilter bank, each with 12 prefilter cells. The prefilters satisfy the requirements of and are marked for Underwriters Standard UL-900 (Reference 2), Class I; and therefore, the radiolytic or pyrolytic decomposition products will not interfere with safe ESF operation.

Both of the control room emergency filter plenums contain 2 banks of HEPA filters with 15 HEPA filters per bank. Each of the Fuel Handling Building charcoal exhaust system filter plenums includes 2 banks of HEPA filters with 12 HEPA filters per bank. Each filter is 24 inches square by 12 inches deep and includes glass media. The HEPA filters satisfy the requirements of MIL-C-51068C, MIL-F-51079 and are qualified to Underwriters Standard UL-586 (Reference 3); and therefore, the radiolytic or pyrolytic decomposition products will not interfere with safe ESF operation.

The 2 control room emergency filter plenums and the 3 Fuel Handling Building charcoal exhaust system filter plenums are of the vertical bed design. The control room plenums contain 11 sections and the Fuel Handling Building charcoal exhaust system plenums contain 8 sections. Media is impregnated, activated coconut shell charcoal which meets the requirements of Regulatory Guide 1.52, Revision 2.

6.5.2 References

1. American Air Filter Report, *TR-7102 Impregnated Activated Carbon for Removal of Radioiodine Compounds from Reactor Containment Atmospheres*.
2. *Air Filter Units*, Underwriters Laboratories, UL-900.
3. *High Efficiency, Particulate, Air Filter Units*, Underwriters Laboratories, UL-586.

Table 6.5-1
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

1. Reactor Building Cooling System HEPA Filters

Regulatory Guide 1.52 Item	
1-a	The system complies with this requirement.
1-b,c	The filters comply with the integrated radiation dose criteria as required by items 1-b, c.
1-d	The system complies with this requirement.
1-e	Not applicable.
2-a	Filter plenums include only demisters and HEPA filters. Systems are redundant. Charcoal adsorbers are not included since the reactor building spray system serves this function.
2-b	The system complies with this requirement.
2-c	The system complies with this requirement.
2-d	The system complies with this requirement.
2-e	The system complies with this requirement.
2-f	The capacity of each plenum is 120,000 cfm. The plenum is arranged as three filter modules, each four filters high and ten filters wide. Space limitations make use of multiple 30,000 cfm plenums for this system physically impractical.
2-g	The system is instrumented to indicate differential pressure drop across demisters and HEPA filters by means of alarms in the control room and to indicate filter damper position. Since the filters are used only following a LOCA or during test, the additional instrumentation specified would provide minimum benefit and, therefore, was not added.
2-h	See Chapters 7.0 and 8.0 for IEEE compliance.

Table 6.5-1 (continued)
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

1. Reactor Building Cooling System HEPA Filters (Continued)

Regulatory Guide 1.52 Item	
2-i	The system complies with Regulatory Guide 8.8 through provision of service platforms and arrangement of HEPA filters for "bagging" during the changing procedure. As noted for item 2-f, above, capacity of the unit made change as a single unit physically impractical. Also, high radiation deposits are not expected to accumulate on these filters from normal operation. Therefore, filter replacement as a single unit loses importance.
2-j	Not applicable
2-k	Duct and housing leakage is not of primary importance since this system is a recirculation type system housed inside the reactor building
3-a	The system complies with this requirement.
3-b	Not applicable.
3-c	The system complies with this requirement.
3-d	The system complies with this requirement, except that filter tests were performed by the manufacturer.
3-e	The system complies with this requirement.
3-f	The system complies with this requirement.
3-g	The system complies with this requirement.
3-h	Not applicable since there is no fire spray system to this plenum.
3-i	Not applicable since there are no adsorption filters in this system.
3-j	Not applicable since there are no adsorption filters in this system.
3-k	Not applicable since there are no adsorption filters in this system.

Table 6.5-1 (continued)
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

1. Reactor Building Cooling System HEPA Filters (Continued)

Regulatory Guide 1.52 Item	
3-l	The system complies with this requirement.
3-m	The system complies with this requirement.
3-n	The system complies with this requirement.
3-o	The system complies with this requirement.
4-a	The system complies with this requirement.
4-b	The system complies with this requirement.
4-c	The capacity of this system makes this requirement physically impractical.
4-d	External connections have been provided for field insertion of test probes and manifolds.
4-e	Operating procedures satisfy this request.
4-f	System procedures comply with this request.
5-a	Startup and test and operating procedures comply with this requirement except testing will be performed every 18 months in lieu of once per operating cycle and after 720 hours of system operation. The visual test will be performed before each in place air flow distribution test, or DOP test (Note 1).
5-b	Filter plenum testing procedures comply with this requirement.
5-c	Operating procedures and filter plenum testing procedures comply with this requirement except testing will be performed every 18 months in lieu of once per operating cycle and after 720 hours of system operation. (Note 1).
5-d	Not applicable since there are no adsorption filters in this system.
6-a	Not applicable since there are no adsorption filters in this system.
6-b	Not applicable since there are no adsorption filters in this system.

Table 6.5-1 (continued)
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

2. Control Room Emergency Filter

Regulatory Guide 1.52 Item	
1-a	The listed criteria, except radiation dose rate, relative to this system are not affected by the DBA. The dose rate following DBA was considered in the filter design.
1-b	The filters comply with the integrated radiation dose criteria as required by items 1-b, c.
1-d	Not applicable.
1-3	Not applicable.
2-a	Filter plenums include all sequential components listed, except demisters and heating/cooling coils. Demisters are not included because there is no source of water spray coincident with continuing filter operation. Heating/cooling coils are not included because relative humidity is not expected to exceed 50 percent. Systems are redundant.
2-b	The system complies with this requirement.
2-c	The system complies with this requirement.
2-d	Not applicable since filter plenums are not in an area where pressure surges could occur.
2-e	The system complies with this requirement.
2-f	The system complies with this requirement.
2-g	The system complies with this requirement through provision of control room indication of isolation damper position, high temperature and smoke. Recorders are not considered pertinent since this system is operated only for test or under accident conditions. Provisions have been made for local indication of pressure drop across filter sections.
2-h	See Chapters 7.0 and 8.0 for IEEE compliance.
2-i	The system complies with this requirement.

Table 6.5-1 (continued)
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

2. Control Room Emergency Filter (Continued)

Regulatory Guide 1.52 Item	
2-j	Not applicable.
2-k	Ducts were specified to satisfy leakage testing requirements of SMACNA, Chapter 8, 1967. Plenums were specified to indicate no leakage through soap bubble testing with ducts at 2 psig. Neither the plenum nor the attached ducts are in any contaminated area between the plenum equipment area and the control room.
3-a	Not applicable since this system will not be exposed to a water spray.
3-b	No heaters are included in the design. The filters process room return air and room relative humidity should not exceed 50 percent. Therefore, heaters are not required.
3-c	The system complies with this requirement.
3-d	The system complies with this requirement.
3-e	The system complies with this requirement.
3-f	The system complies with this requirement.
3-g	The system complies with this requirement.
3-h	The system complies with this requirement.
3-i	The system complies with this requirement. New activated carbon meets the physical property specifications given in Table 5.1 of ANSI N509-1976. (Note 1) New and used activated carbon meet the laboratory testing criteria of ASTM D3803-1989, at a relative humidity of 70% and a temperature of 30° C (86° F) with a methyl iodide penetration of less than 2.5%.
3-j	The system complies with this requirement.
3-k	The system complies with this requirement.
3-l	The system complies with this requirement.
3-m	The system complies with this requirement.
3-n	The system complies with this requirement.

Table 6.5-1 (continued)
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

2. Control Room Emergency Filter (Continued)

Regulatory Guide 1.52 Item	
3-o	The system complies with this requirement.
4-a	The system complies with this requirement.
4-b	The system complies with this requirement.
4-c	The system complies with this requirement.
4-d	External connections have been provided for field insertion of test probes and manifolds.
4-e	Operating procedures satisfy this request.
4-f	System procedures comply with this request.
5-a	Startup and test and operating procedures comply with this requirement except testing will be performed every 18 months in lieu of once per generating cycle and after 720 hours of system operation. The visual test will be performed before each in place air flow distribution test, DOP test or activated carbon adsorber section leak test. (Note 1)
5-b	Filter plenum testing procedures comply with this requirement.
5-c	Operating procedures and filter plenum testing procedures comply with this requirement except testing will be performed every 18 months in lieu of once per operating cycle and after 720 hours of system operation. (Note 1)
5-d	Filter plenum testing procedures comply with this requirement except adsorber testing will be done with then DOP test is performed and following removal of an adsorber sample for laboratory testing if the integrity of the adsorber section is affected. (Note 1)
6-a	The system analysis complies with this requirement. New activated carbon meets the physical property specifications given in Table 5.1 of ANSI N 509-1976 (Note 1)

Table 6.5-1 (continued)
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

2. Control Room Emergency Filter (Continued)

Regulatory Guide 1.52 Item	
6-b	The system analysis complies with this requirement except laboratory tests will be performed every 18 months in lieu of once per operating cycle. New unused activated carbon meeting the physical requirements of Table 5.1 of ANSI N 509-1976 will be used if (1) Testing is in accordance with footnote c of Table 3 (except as noted above) results in a representative sample failing to pass the applicable test in Table 3 or (2) no representative sample is available for testing. (Note 1) New and used activated carbon meet the laboratory testing criteria of ASTM D3803-1989, at a relative humidity of 70% and a temperature of 30° C (86° F) with a methyl iodide penetration of less than 2.5%.

3. Fuel Handling Building Charcoal Exhaust System

Regulatory Guide 1.52 Item	
1-a	The system complies with this requirement.
1-b, c	The filter plenums comply with the integrated radiation dose criteria as required by items 1-b, c.
1-d	The system complies with this requirement.
1-e	Not applicable.
2-a	Filter plenums include all sequential components listed, except demisters and heating/cooling coils. Demisters are not included because there is no source of water spray coincident with continuing filter operation. Heating/cooling coils are not provided because the relative humidity is not expected to exceed 70 percent. Plenums and fans are redundant.
2-b	The plenums are physically separated. The fans are adjacent to each other but are not in an area exposed to missiles.

Table 6.5-1 (continued)
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

3. Fuel Handling Building Charcoal Exhaust System (Continued)

Regulatory Guide 1.52 Item	
2-c	The system complies with this requirement.
2-d	Not applicable since the filter plenums are not in an area where pressure surges could occur.
2-e	The system complies with this requirement.
2-f	The system complies with this requirement.
2-g	Temperature of the charcoal filter sections of the plenums is recorded in the control room and detection of high temperature actuates alarms in the control room. Fan operation and isolation damper position are indicated in the control room. Filter bank pressure drop is indicated locally.
2-h	See Chapters 7.0 and 8.0 for IEEE compliance.
2-i	The system complies with this requirement.
2-j	Not applicable.
2-k	Ducts were specified to satisfy leakage testing requirements of SMACNA Chapter 8, 1967. Plenums were specified to indicate no leakage through soap bubble testing with ducts at 2 psig.
3-a	Not applicable since this system will not be exposed to a water spray.
3-b	No heaters are included in the design. The filters process room air and room relative humidity should not exceed 70 percent. Therefore, a heater is not required.
3-c	The system complies with this requirement.
3-d	The system complies with this requirement.
3-e	The system complies with this requirement.
3-f	The system complies with this requirement.
3-g	The system complies with this requirement.
3-h	The system complies with this requirement.

Table 6.5-1 (continued)
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

3. Fuel Handling Building Charcoal Exhaust System (Continued)

Regulatory Guide 1.52 Item	
3-i	The system complies with this requirement. New activated carbon meets the physical property specifications given in Table 5.1 of ANSI N509-1976. (Note 1) New and used activated carbon meet the laboratory testing criteria of ASTM D3803-1989, at a test media temperature of 30° C (86° F).
3-j	The system complies with this requirement.
3-k	The system complies with this requirement.
3-l	The system complies with this requirement.
3-m	The system complies with this requirement.
3-n	The system complies with this requirement.
3-o	The system complies with this requirement.
4-a	The system complies with this requirement.
4-b	The system complies with this requirement.
4-c	The system complies with this requirement.
4-d	External connections have been provided for field insertion of test probes and manifolds.
4-e	Operating procedures comply with this request.
4-f	System procedures comply with this request.
5-a	Startup and test and operating procedures comply with this requirement except testing will be performed every 18 months in lieu of once per operating cycle and after 720 hours of system operation. The visual test will be performed before each in place air flow distribution test, DOP test or activated carbon adsorber leak test. (Note 1)
5-b	Filter plenum testing procedures comply with this requirement.

Table 6.5-1 (continued)
Comparison of Engineered Safety Features Filter Systems
With Regulatory Guide 1.52 (Revision 1, 7/76) Requirements

3. Fuel Handling Building Charcoal Exhaust System (Continued)

Regulatory Guide 1.52 Item	
5-c	Operating procedures and filter plenum testing procedures comply with this requirement except testing will be performed every 18 months in lieu of once per operating cycle and after 720 hours of system operation. (Note 1)
5-d	Filter plenum testing procedures comply with this requirement except adsorber testing will be done when the DOP test is performed and following removal of an adsorber sample for laboratory testing if the integrity of the adsorber section is affected. (Note 1)
6-a	The system analysis complies with this requirement. New activated carbon meets the physical property specifications given in Table 5-1 of ANSI N 509-1976. (Note 1)
6-b	The system complies with this requirement except laboratory tests will be performed every 18 months in lieu of once per operating cycle (Note 1) and every 720 hours (since units run continuously) during the period of time there is fuel or crane movement with loads over the pool. New unused activated carbon meets the physical requirements of Table 5.1 of ANSI N 509-1976 will be used if (1) testing is in accordance with footnote C of Table 3 (except as noted above) results in a representative sample failing to pass the applicable test in Table 3 or (2) no representative sample is available for testing. (Note 1) New and used activated carbon meet the laboratory testing criteria of ASTM D3803-1989, at a media temperature of 30° C (86° F).

Note 1 - Exceptions and clarifications are consistent with revisions made to these sections in Revision 2 of Regulatory Guide 1.52.

V.C. Summer Power Station
Safety Analysis Report

Instrumentation and Controls

Chapter 7

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 7 - INSTRUMENTATION AND CONTROLS

7.0 INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

This chapter presents the various plant instrumentation and control systems by relating the functional performance requirements, design bases, system descriptions, design evaluations, and tests and inspections for each. The information provided in this chapter emphasizes those instruments and associated equipment which constitute the protection system as defined in IEEE Standard 279-1971 "IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations," (Reference 1).

The primary purpose of the instrumentation and control systems is to provide automatic protection and exercise proper control against unsafe and improper reactor operation during steady-state and transient power operations (ANS Conditions I, II, III) and to provide initiating signals to mitigate the consequences of faulted conditions (ANS Condition IV). ANS conditions are discussed in Chapter 15. Consequently, the information presented in this chapter emphasizes those instrumentation and control systems which are central to assuring that the reactor can be operated to produce power in a manner that ensures no undue risk to the health and safety of the public.

It is shown that the applicable criteria and codes, such as General Design Criteria and IEEE Standards, concerned with the safe generation of nuclear power are met by these systems. See Table 7.1-1 for a listing of applicable criteria.

Terminology used in this chapter is based on the definitions given in IEEE Standard 279-1971 which is listed in Table 7.1-1. In addition, the following definitions apply:

1. Degree of Redundancy

   The difference between the number of channels monitoring a variable and the number of channels which when tripped, will cause an automatic system trip.

2. Minimum Degree of Redundancy

   The degree of redundancy below which operation is prohibited, or otherwise restricted by the Technical Specifications.

3. Cold Shutdown Condition

   When the reactor is subcritical by at least 1 percent $\Delta k/k$ and T_{avg} is $\leq$ 200 °F.

4. Hot Shutdown Condition

   When the reactor is subcritical, by an amount greater than or equal to the margin specified in the applicable Technical Specification and T_{avg} is in the range specified in the applicable Technical Specification.

5. Phase A Containment Isolation

   Closure of all nonessential process lines which penetrate the Reactor Building, except engineered safety features lines, component cooling lines and steam lines into and out of the Reactor Building, initiated by the safety injection signal, or manually.

6. Phase B Containment Isolation

   Closure of remaining process lines, initiated by Reactor Building Hi-3 pressure signal or manually (process lines do not include engineered safety features lines). Steam lines will previously have been closed by Reactor Building Hi-2 pressure signal.

7. System Response Times

   a. Reactor Trip System Response Time

      The Reactor Trip System response time shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage.

   b. Engineered Safety Features Actuation System Response Time

      The Engineered Safety Features Actuation System response time shall be that time interval from when the monitored parameter exceeds its engineered safety features actuation setpoint at the channel sensor until the engineered safety features equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays where applicable.

8. Reproducibility

   This definition is taken from Scientific Apparatus Manufactures Association (SAMA) Standard PMC-20.2-1973, Process Measurement and Control Terminology: "the closeness of agreement among repeated measurements of the output for the same value of input, under normal operating conditions over a period of time, approaching from both directions." It includes drift due to environmental effects, hysteresis, long term drift, and repeatability. Long term drift (aging of components, etc.) is not an important factor in accuracy requirements since, in general, the drift is not significant with respect to the time elapsed between testing. Therefore, long term drift may be eliminated from this definition. Reproducibility, in most cases, is a part of the definition of accuracy (see item 9).

9. Accuracy

   This definition is derived from Scientific Apparatus Manufactures Association (SAMA) Standard PMC-20.2-1973, Process Measurement and Control Terminology. An accuracy statement for a device falls under Note 2 of the Scientific Apparatus Manufactures Association definition of accuracy, which means reference accuracy or the accuracy of that device at reference operating conditions: "Reference accuracy includes conformity, hysteresis and repeatability." To adequately define the accuracy of a system, the term reproducibility is useful as it covers normal operating conditions. The following terms, "trip accuracy" and "indicated accuracy," etc., will then include conformity and reproducibility under normal operating conditions. Where the final result does not have to conform to an actual process variable but is related to another value established by testing, conformity may be eliminated, and the term reproducibility may be substituted for accuracy.

10. Normal Operating Conditions

    Normal operating conditions include normal process temperature and pressure changes, and ambient temperature changes around the transmitter and racks. The normal operating conditions exclude those parameters experienced under post accident conditions.

11. Readout Devices

    For consistency the final device of a complete channel is considered a readout device. This includes indicators, recorders, and controllers.

12. Channel Accuracy

    This definition includes accuracy of primary element, transmitter and rack modules. It does not include readout devices or rack environmental effects, but does include process and environmental effects on field mounted hardware. Rack environmental effects are included in the next 2 definitions to avoid duplication due to dual inputs.

13. Indicated and/or Recorded Accuracy

    This definition includes channel accuracy, accuracy of readout devices and rack environmental effects.

14. Trip Accuracy

    This definition includes comparator accuracy, channel accuracy, for each input, and rack environmental effects. This is the tolerance expressed in process terms (or percent or span) within which the complete channel must perform its intended trip function. This includes all instrument errors but no process effects such as streaming. The term "actuation accuracy" may be used where the word "trip" might cause confusion (for example, when starting pumps and other equipment).

15. Control Accuracy

    This definition includes channel accuracy, accuracy of readout devices (isolator, controller), and rack environmental effects. Where an isolator separates control and protection signals, the isolator accuracy is added to the channel accuracy to determine control accuracy, but credit is taken for tuning beyond this point; i.e., the accuracy of these modules (excluding controllers) is included in the original channel accuracy. It is simply defined as the accuracy of the control signal in percent of the span of that signal. This will then include gain changes where the control span is different from the span of the measured variable. Where controllers are involved, the control span is the input span of the controller. No error is included for the time in which the system is in a non-steady-state condition.

7.1.1 Identification of Safety-Related Systems

7.1.1.1 Safety-Related Systems

The Nuclear Steam Supply System (NSSS) instrumentation discussed in Chapter 7 that is required to function to achieve the system responses assumed in the safety evaluations, and those needed to shutdown the plant safely are given in this section. Table 7.1-2 identifies safety related instrumentation and control systems.

7.1.1.1.1 Reactor Trip System

The Reactor Trip System is a functionally defined system described in Section 7.2. The equipment which provides the trip functions is identified and discussed in Section 7.2. Design bases for the Reactor Trip System are given in Section 7.1.2.1. Figure 7.1-1 includes a single line diagram of this system. Additional background information on the Reactor Trip System is contained in Reference 2.

7.1.1.1.2 Engineered Safety Features Actuation System

The Engineered Safety Features Actuation System is a functionally defined system described in Section 7.3. The equipment which provides the actuation functions is identified and discussed in Section 7.3. Design bases for the Engineered Safety Features Actuation System are given in Section 7.1.2.1.

7.1.1.1.3 Instrumentation and Control Power Supply System

Design bases for the Instrumentation and Control Power Supply System are given in Section 7.1.2.1. Further description of this system is provided in Section 7.6.1.

7.1.1.2 Safety-Related Display Instrumentation

Display instrumentation provides the operator with information to enable him to monitor the results of engineered safety features actions following a Condition II, III, or IV event. Section 7.5

describes the instrumentation required to maintain the plant in a hot shutdown condition or to proceed to cold shutdown.

7.1.1.3 Instrumentation and Control System Designers

Systems discussed in Chapter 7 have definitive functional requirements developed on the basis of the Westinghouse Nuclear Steam Supply System design. Figure 7.2-1 defines scope interface. Regardless of the supplier, the functional requirements necessary to assure plant safety and proper control are clearly delineated.

7.1.1.4 Plant Comparison

System functions for all systems discussed in Chapter 7 are similar to those of the Joseph M. Farley Nuclear Plant. A comparison table is provided in Section 1.3.

7.1.2 Identification of Safety Criteria

Section 7.1.2.1 gives design bases for the systems given in Section 7.1.1.1. Design bases for non-safety related systems are provided in the sections which describe the systems. Conservative considerations for instrument errors are included in the accident analyses presented in Chapter 15. Functional requirements, developed on the basis of the results of the accident analyses, which have utilized conservative assumptions and parameters are used in designing these systems and a preoperational testing program verifies the adequacy of the design. Accuracies are given in Sections 7.2, 7.3, and 7.5.

The documents listed in Table 7.1-1 were considered in the design of the systems given in Section 7.1.1. In general, the scope of these documents is given in the document itself. This determines the systems or parts of systems to which the document is applicable. A discussion of compliance with each document for systems in its scope is provided in the referenced sections given in Table 7.1-1 for each criterion. Because some documents were issued after design and testing had been completed, the equipment documentation may not meet the format requirements of some standards. Justification for any exceptions taken to each document for systems in its scope is provided in the referenced sections.

Table 7.1-2 outlines the design criteria that have been implemented in the design of safety related instrument and control systems.

7.1.2.1 Design Bases

7.1.2.1.1 Reactor Trip System

The Reactor Trip System acts to limit the consequences of Condition II events (faults of moderate frequency), such as loss of feedwater flow, by, at most, a shutdown of the reactor and turbine, with the plant capable of returning to operation after corrective action. The Reactor Trip System features impose a limiting boundary region to plant operation which ensures that the reactor safety limits are not exceeded during Condition II events and that these events can be

accommodated without developing into more severe conditions. Reactor trip setpoints are given in the Technical Specifications.

The design requirements for the Reactor Trip System are derived by analyses of plant operating and fault conditions where automatic rapid control rod insertion is necessary in order to prevent or limit core or reactor coolant boundary damage. The design bases addressed in IEEE Standard 279-1971 are discussed in Section 7.2.1. The design limits specified by Westinghouse for the Reactor Trip System are:

1. There shall be at least a 95% probability (at a 95% confidence level) that departure from nucleate boiling (DNB) will not occur as a result of any anticipated transient or malfunction (Condition II faults).
2. Power density shall not exceed the rated linear power density for Condition II faults. See Chapter 4 for fuel design limits.
3. The stress limit of the Reactor Coolant System for the various conditions shall be as specified in Chapter 5.
4. Release of radioactive material shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius as a result of any Condition III fault.
5. For any Condition IV fault, release of radioactive material shall not result in an undue risk to public health and safety.

7.1.2.1.2 Engineered Safety Features Actuation System

The Engineered Safety Features Actuation System acts to limit the consequences of Condition III events (infrequent faults such as primary coolant spillage from a small rupture which exceeds normal charging system makeup and requires actuation of the Safety Injection System). The Engineered Safety Features Actuation System acts to mitigate Condition IV events (limiting faults, which include the potential for significant release of radioactive material).

The design bases for the Engineered Safety Features Actuation System are derived from the design bases given in Chapter 6 for the engineered safety features. Design bases requirements of IEEE Standard 279-1971 are addressed in Section 7.3.1.2. General design requirements are given below:

1. Automatic Actuation Requirements

   The primary requirement of the Engineered Safety Features Actuation System is to receive input signals (information) from the various on-going processes within the reactor plant and containment and automatically provide, as output, timely and effective signals to actuate the various components and subsystems comprising the Engineered Safety Features System.

2. Manual Actuation Requirements

   The Engineered Safety Features Actuation System must have provisions in the control room for manually initiating the functions of the Engineered Safety Features System.

7.1.2.1.3 Instrumentation and Control Power Supply System

The Instrumentation and Control Power Supply System provides continuous, reliable, regulated single phase a-c power to all instrumentation and control equipment required for plant safety. Details of this system are provided in Section 7.6. The design bases are given below:

1. The inverter shall have the capacity and regulation required for the a-c output for proper operation of the equipment supplied.
2. Redundant loads shall be assigned to different distribution panels which are supplied from different inverters.
3. Auxiliary devices that are required to operate dependent equipment shall be supplied from the same distribution panel to prevent the loss of electric power in one protection set from causing the loss of equipment in another protection set. No single failure shall cause a loss of power supply to more than one distribution panel.
4. Each of the distribution panels shall have access only to its respective inverter supply and a standby power supply.
5. The system shall comply with IEEE Standard 308-1971, paragraph 5.4.

7.1.2.1.4 Emergency Power

Design bases and system description for the emergency power supply are provided in Chapter 8.

7.1.2.1.5 Interlocks

Interlocks are discussed in Sections 7.2, 7.3, 7.6, and 7.7. The Reactor Trip and Engineered Safety Features Actuation System protection (P) interlocks are given on Tables 7.2-2 and 7.3-3. The safety analyses demonstrate that even under conservative critical conditions for either postulated or hypothetical accidents, the protective systems ensures that the Nuclear Steam Supply System will be put into and maintained in a safe state following an ANS Condition II, III, or IV accident commensurate with applicable Technical Specifications and pertinent ANS Criteria. Therefore, the protective systems have been designed to meet IEEE Standard 279-1971 and are entirely redundant and separate, including all permissives and blocks. All blocks of a protective function are automatically cleared whenever the protective function would be required to function in accordance with General Design Criteria 20, 21, and 22 and paragraphs 4.11, 4.12 and 4.13 of IEEE Standard 279-1971. Control interlocks (C) are identified on Table 7.7-1. Because control interlocks are not safety-related, they have not been specifically designed to meet the requirements of IEEE Protection System Standards.

7.1.2.1.6 Bypasses

Bypasses of protective functions are designed to meet the requirements of IEEE Standard 279-1971, paragraphs 4.11, 4.12, 4.13, and 4.14. A discussion of bypasses provided is given in Sections 7.2 and 7.3.

7.1.2.1.7 Equipment Protection

The criteria for equipment protection are given in Chapter 3. Equipment related to safe operation of the plant is designed, constructed and installed to protect it from damage. This is accomplished by working to accepted standards and criteria aimed at providing reliable instrumentation which is available under varying conditions. As an example, certain equipment is seismically qualified in accordance with IEEE Standard 344-1971. During construction, independence and separation is achieved, as required by IEEE Standard 279-1971 and IEEE Standard 384-1974, either by barriers, physical separation or demonstration by test. This serves to protect against complete destruction of a system by fires, missiles or other natural hazards.

7.1.2.1.8 Diversity

Functional diversity has been designed into the system. Functional diversity is discussed in Reference 3. The extent of diverse system variables has been evaluated for a wide variety of postulated accidents. Generally, 2 or more diverse protection functions would automatically occur to mitigate the consequences of an accident.

For example, there are automatic reactor trips based upon neutron flux measurements, reactor coolant loop temperature and flow measurements, steam generation level measurements, pressurizer pressure and level measurements, feedwater flow measurements, and reactor coolant pump underfrequency and undervoltage measurements, as well as manually, and by initiation of a safety injection signal or turbine trip.

Regarding the Engineered Safety Features Actuation System for a loss of coolant accident, a safety injection signal can be obtained manually or by automatic initiation from any one of the following diverse parameter measurements:

1. Low pressurizer pressure.
2. High Reactor Building pressure (Hi-1).

For a steam break accident, safety injection signal actuation is provided by:

1. Low steam line pressure.
2. High steam line differential pressure.
3. For a steam break inside Reactor Building, high Reactor Building pressure (Hi-1) provides an additional parameter for generation of the signal.

All of the above sets of signals are redundant and physically separated and meet the requirements of IEEE Standard 279-1971.

7.1.2.1.9 Bistable Trip Setpoints

Westinghouse specifies 3 setpoints applicable to reactor trip and engineered safety features actuation:

1. Safety limit setpoint.
2. Limiting setpoint.
3. Nominal setpoint.

The safety limit is the value assumed in the accident analysis and is the least conservative value.

The limiting setpoint is the Technical Specification value and is obtained by subtracting a safety margin from the safety limit. The safety margin accounts for instrument error, process uncertainties such as flow stratification and transport factor effects, etc.

The nominal setpoint is the value set into the equipment and is obtained by subtracting allowances for instrument drift and calibration uncertainty from the limiting setpoint. The nominal setpoint allows for the normal expected instrument setpoint drifts such that the Technical Specification limits will not be exceeded under normal operation.

The setpoints that require trip action are given in the Technical Specifications. A further discussion on setpoints is found in Section 7.2.2.2.1.

The trip setpoint is determined by factors other than the most accurate portion of the instrument's range. The safety limit setpoint is determined only by the accident analysis. As described above, allowance is then made for process uncertainties, instrument error, instrument drift, and calibration uncertainty to obtain the nominal setpoint value which is actually set into the equipment. The only requirement on the instrument's accuracy value is that over the instrument span, the error must always be less than or equal to the error value allowed in the accident analysis. The instrument does not need to be the most accurate at the setpoint value as long as it meets the minimum accuracy requirement. The accident analysis accounts for the expected errors at the actual setpoint.

Range selection for the instrumentation covers the expected range of the process variable being monitored consistent with its application. The design of the Reactor Protection and Engineered Safety Features Systems is such that the bistable trip setpoints do not require process transmitters to operate within 5% of the high and low end of their calibrated span or range. Functional requirements established for every channel in the Reactor Protection and Engineered Safety Features Systems stipulate the maximum allowable errors on accuracy, linearity, and reproducibility. The protection channels have the capability for, and are tested to ascertain that the characteristics throughout the entire span in all aspects are acceptable and meet functional

requirement specifications. As a result, no protection channel actuates within 5% of the limits of its specified span (activation setpoints are located between 5 – 95% of span).

In this regard, it should be noted that the specific functional requirements for response time, setpoint, and operating span was finalized based on the results and evaluation of safety studies carried out using data pertinent to the plant. Emphasis is placed on establishing adequate performance requirements under both normal and faulted conditions. This includes consideration of process transmitters margins such that even under a highly improbable situation of full power operation at the limits of the operating map (as defined by the high and low pressure reactor trip, ΔT overpower and overtemperature trip lines (departure from nucleate boiling protection) and the steam generator safety valve pressure setpoint) that adequate instrument response is available to ensure plant safety.

7.1.2.1.10 Engineered Safety Features Motor Specifications

Engineered safety features motor specifications are described in Section 8.3.1.1.4.

7.1.2.2 Independence of Redundant Safety-Related Systems

The safety related systems in Section 7.1.1.1 are designed to meet the independence and separation requirements of Criterion 22 of the 1971 General Design Criteria and paragraph 4.6 of IEEE Standard 279-1971.

The electrical power supply, instrumentation, and control conductors for redundant circuits of a nuclear plant have physical separation to preserve the redundancy and to ensure that no single credible event will prevent operation of the associated function due to electrical conductor damage. Critical circuits and functions include power, control and analog instrumentation associated with the operation of the Reactor Trip System or Engineered Safety Features Actuation System. Credible events shall include, but not be limited to, the effects of short circuits, pipe rupture, missiles, fire, etc., and are considered in the basic plant design.

7.1.2.2.1 General

Specifications for field wiring of redundant circuitry are discussed in Section 8.3.1.4.

The physical separation criteria for redundant safety related system sensors, sensing lines, wireways, cables, and components on control boards/racks within Westinghouse scope meet recommendations contained in Regulatory Guide 1.75 and Westinghouse letter NS-CE-604 of March 31, 1975 from C. Eicheldinger to the Secretary of the Commission.

7.1.2.2.2 Specific Systems

Independence is maintained throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs and Reactor Building penetrations for each redundant protection channel set.

Redundant analog equipment is separated by locating modules in different protection rack sets. Each redundant channel set is energized from a separate a-c power feed.

There are 4 separate process analog sets. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, Reactor Building penetrations, and analog protection cabinets to the redundant trains in the logic racks. Redundant analog channels are separated by locating modules in different cabinets.

Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the cabinet.

In the Nuclear Instrumentation System, Process Systems, and Solid-State Protection System input cabinets where redundant channel instrumentation are physically adjacent, there are no wireways, or cable penetrations which would permit, for example, a fire resulting from electrical failure in one channel to propagate into redundant channels in the logic racks. Redundant analog channels are separated by locating modules in different cabinets. Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the cabinet. Nevertheless, concerns relative to wiring of isolation devices within protection cabinets prompted Westinghouse programs aimed at alleviating them. A discussion is given in Section 7.2.2.2.3.7.

Two (2) reactor trip breakers are actuated by 2 separate logic matrices which interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all full length control rod drive mechanisms, permitting the rods to free fall into the core.

1. Reactor Trip System

   a. Separate routing shall be maintained for the 4 basic Reactor Trip System channel sets analog sensing signals, bistable output signals and power supplies for such systems. The separation of these 4 channel sets shall be maintained from sensors to instrument cabinets to logic system input cabinets.

   b. Separate routing of the redundant reactor trip signals from the redundant logic system cabinets shall be maintained, and in addition, they shall be separated by spatial separation or by provision of barriers or by separate cable trays or wireways from the 4 analog channel sets.

2. Engineered Safety Features Actuation System

   a. Separate routing shall be maintained for the 4 basic sets of Engineered Safety Features Actuation System analog sensing signals, bistable output signals and power supplies for such systems. The separation of these 4 channel sets shall be maintained from sensors to instrument cabinets to logic system input cabinets.

   b. Separate routing of the engineered safety features actuation signals from the redundant logic system cabinets shall be maintained. In addition, they shall be separated by spatial separation or by provisions of barriers or by separate cable trays or wireways from the 4 analog channel sets.

c. Separate routing of control and power circuits associated with the operation of engineered safety features equipment is required to retain redundancies provided in the system design and power supplies.

3. Instrumentation and Control Power Supply System

The separation criteria presented also apply to the power supplies for the load centers and buses distributing power to redundant components and to the control of these power supplies.

4. Control Board

A majority of the control board switches and associated lights are furnished in modules. These modules provide a high degree of physical protection for the switches, associated lights, and wiring. Control board switches and associated lights which are not located in modules and other devices within the control boards are located such that a minimum of 6 inches air separation is maintained between devices and wiring associated with different trains. Where this 6 inches of air space in all directions cannot be maintained, barriers are provided or an analysis of the installation is performed. This analysis is based on tests performed to determine the flame retardant characteristics of the wiring material, equipment, and other materials internal to the panel.

Where necessary to maintain separation, cabling from devices on the front of the control board to the horizontal metal wireways (gutters) within the control board is routed in flexible conduit or metallic braid. The redundant cables are then routed through separate gutters to the termination cabinets located beneath the control room via vertical metal wireways (risers). The termination cabinets are arranged to maintain the separated routing of the control board cables through the termination cabinets to the field wiring tray systems. In addition, separate metal wireways and termination cabinets are used for the various low-level analog channels and for the various control-level channels.

Relay subpanels located in or associated with the control boards contain Class 1E devices such as fuses, relays, and relay type isolation devices. Mutually redundant safety related devices are located on separate subpanels. Separate metal wireways provide separation for Class 1E wiring and non-Class 1E wiring departing the subpanels. Where relay panels contain relay type isolation devices, the separation of the wiring from the input and output terminals to the separate wireways may be less than 6 inches provided it is not less than the 1 inch distance between input and output terminals of the isolation device.

Flame resistant cable is used for internal module wiring and multi-conductor cables within the control board. Flame resistant single conductor cable with 30 MIL insulation is used for intraboard jumpers. Sizing of copper conductors is based upon conservative current carrying capacities set forth by the National Electric Code.

Inherent flame-retardant characteristics and properties were an important consideration in the selection, design, and fabrication of components and materials used in the control board; therefore, a postulated fire cannot propagate.

In order to maintain separation between wiring associated with different trains, mutually redundant safety train wiring is not terminated on a single device. Backup manual actuation switches link the separate trains by mechanical means to provide greater reliability of operator action for the manual reactor trip function and manual engineered safety features actuations. The linked switches are themselves redundant so that operation of either set of linked switches will actuate safety trains “A” and “B” simultaneously. This is shown in Figure 7.2-3. The design of the manual reactor trip function and manual engineered safety features actuations comply with Regulatory Guide 1.62 (see also Figure 7.3.2.2.7).

Manual actuation from the control room of each Reactor Protection or Engineered Safety Features System is provided by 2 functionally redundant, physically separate and independent switches meeting the requirements of IEEE-279-1971. In order to prevent inadvertent manual actuation of reactor building spray, a pair of switches must be operated simultaneously. A second pair of switches is provided for manual actuation so a single failure will not prevent manual actuation of the reactor building spray. Redundant switches are provided for the manual control of steam line isolation.

Control switches are provided on the control board for all components that are actuated by manual engineered safety features function initiation switches.

Manual controls for the reactor protection and engineered safety features are listed in Tables 7.2-1, 7.3-1, and 7.3-2.

Transmitted signals (flow, pressure, temperature, etc.) which cause actuation of the engineered safety features are either indicated or recorded. Redundant channels of post accident monitoring indicators are separated by barriers and/or air separation.

7.1.2.2.3 Fire Protection

Electrical equipment is supplied with noncombustible or fire retardant material. Materials which may ignite or explode from an electrical spark, flame, or from heating are not used. Current carrying capacities of instrument cabinet wiring preclude electrical fires resulting from excessive overcurrent (I^2R) losses. For example, wiring used for instrument cabinet construction has teflon or tefzel insulation and is adequately sized based on current carrying capacities set forth by the National Electric Code. In addition, fire retardant (intumescent) paint is used to prevent fire or heat propagation from rack to rack. The application of paint to interiors and/or exteriors of nuclear safety related electrical equipment located outside the Reactor Building containment is a non-nuclear safety related activity. Braided sheathed material is noncombustible.

For early warning and protection against propagation of electrical fires, smoke or other high sensitivity detectors are provided for fire detection, alarm and extinguishing systems in remote wireways or other unattended areas where large concentrations of cables are installed (see Section 8.3.3.2).

Details of the fire protection system are provided in Section 9.5.1.

7.1.2.3 Physical Identification of Safety-Related Equipment

There are 4 separate protection sets identifiable with process equipment associated with the Reactor Trip and Engineered Safety Features Actuation Systems. A protection set may be comprised of more than a single process equipment cabinet. The color coding of each process equipment rack nameplate coincides with the color code established for the protection set of which it is a part. Redundant channels are separated by locating them in different equipment cabinets. Separation of redundant channels begins at the process sensors and is maintained in the field wiring, Reactor Building penetrations and equipment cabinets to the redundant trains in the logic racks. The Solid-State Protection System input cabinets are divided into 4 isolated compartments, each service 1 of the 4 redundant input channels. Horizontal 1/8 inch thick solid steel barriers, coated with fire retardant paint, separate the compartments. Four (4), 1/8 inch thick solid steel, wireways coated with fire retardant paint enter the input cabinets vertically, even in its own quadrant. The wireway for a particular compartment is open only into that compartment so that flame could not propagate to affect other channels. At the logic racks the protection set color coding for redundant channels is clearly maintained until the channel loses its identity in the redundant logic trains. The color coded nameplates described below provide identification of equipment associated with protective functions and their channel set association:

PROTECTION SET	COLOR CODING
I	RED with BLACK lettering
II	ORANGE with BLACK lettering
III	BLUE with BLACK lettering
IV	YELLOW with BLACK lettering

Noncabinet mounted protective equipment and components are provided with an identification tag or nameplate. Small electrical components such as relays have nameplates on the enclosure which houses them. There are also identification nameplates on the input panels of the Solid-State Logic Protection System. The identification of cables, cable trays, conduits and electrical equipment is discussed in Section 8.3.1.5.

7.1.2.4 Conformance to Criteria

A listing of applicable criteria and the sections where conformance is discussed is given in Tables 7.1-1 and 7.1-2.

7.1.2.5 Conformance to Regulatory Guide 1.22

Periodic testing of the Reactor Trip and Engineered Safety Features Actuation Systems, as described in Sections 7.2.2 and 7.3.2, complies with Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Functions."

Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the Main Control Room by a separate annunciator for the train in test. Test circuitry does not allow 2 trains to be tested at the same time so that extension of the bypass condition to the redundant system is prevented.

The actuation logic for the Reactor Trip and Engineered Safety Features Actuation System is tested as described in Sections 7.2 and 7.3. As recommended by Regulatory Guide 1.22, where actuated equipment is not tested during reactor operation it has been determined that:

1. There is no practicable system design that would permit operation of the equipment without adversely affecting the safety or operability of the plant;
2. The probability that the protection system will fail to initiate the operation of the equipment is, and can be maintained, acceptably low without testing the equipment during reactor operation; and
3. The equipment can routinely be tested when the reactor is shutdown.

The list of equipment that cannot be tested at full power so as not to damage equipment or upset plant operation is:

1. Manual actuation switches.
2. Reactor coolant pump breakers.
3. Turbine.
4. Main steam line isolation valves (complete closure).
5. Main feedwater isolation valves (close).
6. Feedwater control valves and feedwater bypass control valves (close).
7. Main feedwater pump trip solenoids.
8. Reactor coolant pump component cooling water isolation valves (close).
9. Reactor coolant pump seal water return valves (close).
10. Instrument air supply to reactor building isolation valves (close).
11. Engineered safety features loading sequencer input buffer and output relays.

The justifications for not testing the above items at full power are discussed below:

1. Manual Actuation Switches

   These would cause initiation of their protection system function at power causing plant upset and/or reactor trip. The analog signals, from which the automatic safety injection signal is derived, is tested at power in the same manner as the other analog signals and as described in Section 7.2.2.2.3. The processing of these signals in the Solid-State Protection System wherein their channel orientation converts to a logic train orientation is tested at power by the built-in semiautomatic test provisions of the Solid-State Protection System. The reactor trip breakers are tested at power as discussed in Section 7.2.2.2.3.

2. Reactor Coolant Pump Breakers

   No credit is taken in the accident analyses for a reactor coolant pump breaker opening causing a reactor trip. Since testing them at power would cause plant upset, the reactor coolant pump breakers do not need to be tested at power.

3. Turbine

   Testing of main turbine trip signals during normal operation would result in a reactor trip. Although the EHC control system turbine trip logic is not qualified as a safety related system, it is a highly reliable system that consists of redundant (2-of-3 per train) trip actuation logic (as functionally shown on Figure 7.2-1, Sheet 15). The turbine trip logic allows for an “Online ETD Test” method which temporarily cycles applicable components, for the Electronic Trip Device (ETD) undergoing test, into its tripped state; the corresponding exercised components include Primary Trip Relay (PTR) logic output, one ETD solenoid, one ETD dump valve, and its dump valve position indication. This test method systematically verifies the functionality of each 1-of-3 ETD solenoid/dump valve in each of the two ETD trains, without actually tripping the Turbine. (Note that 2-of-3 Emergency Trip Relay (ETR) logic outputs (also shown on Figure 7.2-1, Sheet 15) are functionally verified only during offline testing, given its application as backup protection.)

   The interface between the Engineered Safety Features (ESF) System and the EHC control system is also shown functionally on Figure 7.2-1, Sheet 15. Trip signals received from these ESF System interfaces (or from other Turbine protection trip signals) will be processed by EHC control system trip actuation logic circuitry, which include PTRs (or the backup ETRs, where applicable). Receipt of 2-of-3 actuations via either PTRs or ETRs (in either train) will result in de-energized ETD solenoids and tripped-open ETD dump valves. The outcome of either train’s 2-of-3 dump valve actuation is ETS hydraulic fluid loss (dump), closure of Turbine Stop and Control Valves, and a Turbine Trip condition. This 2-of-3 Turbine Trip actuation can also result from a complete loss of both non-safety related power supply feeders to the EHC control system cabinet (including the loss of a dedicated EHC battery-backed uninterruptible power supply, in the alternate feeder circuit).

Given the identified problem (turbine trip initiation) incurred with periodic testing during power operation of the entire 2-of-3 turbine trip actuation logic, the proposed resolution (using the "Online ETD Test" method) meets the intent of Regulatory Guide 1.22, Section D.4 guidelines (see Appendix 3A). The "Online ETD Test" method provides for periodic testing of individual components within a practical system design, without adversely affecting the plant safety or operability. Use of the "Online ETD Test" method is further justified since: the probability of protection system failure to trip the Turbine is acceptably low, given trip system redundancy and power fail safe design features; and the complete turbine trip logic is routinely tested during refueling outages.

4. Main Steam Line Isolation Valves (Complete Closure)

   Main steam line isolation valves are routinely tested during refueling outages. Testing of the main steam line isolation valves to full closure at power is not practical. As the plant power is increased, the core average temperature is programmed to increase. If the valves are fully closed under these elevated temperature conditions, the steam pressure transient would unnecessarily operate the steam generator relief valves and possibly the steam generator safety valves. The steam pressure transient produced would cause shrinkage in the steam generator level, which would cause the reactor to trip on low-low steam generator water level. Testing during operation will decrease the operating life of the valve.

   Based on the above identified problems incurred with periodic testing of the main steam line isolation valves at power and since, 1) no practical system design will permit operation of the valves without adversely affecting the safety or operability of the plant, 2) the probability that the protection system will fail to initiate the actuated equipment is acceptably low due to test up to final actuation, 3) these valves will be routinely tested during refueling outages, and 4) these valves are tested during plant operation by partial closure (90 to 95 percent open) by actuating a test solenoid valve which does not inhibit an engineered safety feature automatic closure, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

5. Main Feedwater Isolation Valves (Close)

   The main feedwater isolation valves are routinely tested during refueling outages. Periodic testing of these feedwater isolation valves, closing them completely, or partially, at power would induce steam generator water level transients and oscillations which would trip the reactor. These transient conditions would be caused by perturbing the feedwater flow and pressure conditions necessary for proper operation of the variable-speed feedwater pump control system and the steam generator water level control system. An operation which induces perturbations in the main feedwater flow, whether deliberate or otherwise, may lead to a reactor trip and should be avoided.

Based on these identified problems incurred with periodic testing of the backup feedwater valves at power and since, 1) no practical system design will permit operation of these valves without adversely affecting the safety or operability of the plant, 2) the probability that the protection system will fail to initiate the activated equipment is acceptably low due to testing up to final actuation, and 3) these valves will be routinely tested during refueling outages, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

6. Feedwater Control Valves (Close)

   These valves are routinely tested during refueling outages. To close them at power would adversely affect the operability of the plant. The verification of operability of feedwater control valves at power is assured by confirmation of proper operation of the Steam Generator Water Level System. The actual actuation function of the solenoids, which provides the closing function is periodically tested at power as discussed in Section 7.3.2.2.5. The operability of the slave relay which actuates the solenoid, which is the actuating device, is verified during this test. Although the actual closing of these control valves is blocked when the slave relay is tested, all functions are tested to assure that no electrical malfunctions have occurred which could defeat the protective function. It is noted that the solenoids work on the de-energize-to-actuate principle, so that the feedwater control valves will fail close upon either the loss of electrical power to the solenoids or loss of air pressure.

   Based on the above, the testing of the isolating function of feedwater control valves meets the guidelines of Section D.4 of Regulatory Guide 1.22.

7. Main Feedwater Pump Trip Solenoids

   The containment integrity analysis assumes the feedwater isolation valves and/or feedwater control valves isolate feedwater flow and therefore the feedwater pump trip solenoids require no periodic testing.

   However, these trip solenoids are routinely tested during refueling outages. To close them at full power would adversely affect the operability of the plant. The actual actuation function of the solenoids, which provides the closing function is periodically tested at power as discussed in Section 7.3.2.2.5. The operability of the slave relay which actuates the solenoid, which is the actuating device, is verified during this test. Although the actual closing of these trip solenoids is blocked when the slave relay is tested, all functions are tested to assure that no electrical malfunctions have occurred which could defeat the function of the solenoids.

8. Reactor Coolant Pump Component Cooling Water Isolation

   Valves (Close)

Component cooling water supply and return containment isolation valves are routinely tested during refueling outages. Testing of these valves while the reactor coolant pumps are operating introduces an unnecessary risk of costly damage to all the reactor coolant pumps. Loss of component cooling water to these pumps is of economic consideration only, as the reactor coolant pumps are not required to perform any safety-related function.

The reactor coolant pumps will not seize due to complete loss of component cooling. Information from the pump manufacturer indicates that the bearing babbitt would eventually break down but not so rapidly as to overcome the inertia of the flywheel. If the pumps are not stopped within 3 to 10 minutes after component cooling water is isolated, pump damage could be incurred.

Also, since the component cooling water flowrates and temperatures are about equal during both plant power operation and plant refueling, periodic tests of these valves during a refueling outage would duplicate accident conditions. Additionally, possibility of failure of containment isolation is remote because an additional failure of the low pressure fluid system in addition to failure of both isolation valves would have to occur to open a path through the containment.

Based on the above described potential reactor coolant pump damage incurred with periodic testing of the component cooling water containment isolation valves at power, the duplication of at-power operating conditions during refueling outages, and since, 1) no practical system design will permit operation of these valves without adversely affecting the safety or operability of the plant, 2) the probability that the protection system will fail to initiate the activated equipment is acceptably low due to testing up to final actuation, and 3) these valves will be routinely tested during refueling outages when the reactor coolant pumps are not operating, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

9. Reactor Coolant Pump Seal Water Return Valves (Close)

   Seal return line isolation valves are routinely tested during refueling outages. Closure of these valves during operation would cause the safety valve to lift, with the possibility of valve chatter. Valve chatter would damage this relief valve. Testing of these valves at power would cause equipment damage. Therefore, these valves will be tested during scheduled refueling outages. As above, additional containment penetrations and isolation valves introduce additional unnecessary potential pathways for radioactive release following a postulated accident. Thus, the guidelines of Section D.4 of Regulatory Guide 1.22 are met.

10. Instrument Air Supply to Reactor Building Isolation Valves (Close)

    The Reactor Building instrument air isolation valves are routinely tested during refueling outages. Closing the valves completely at power would result in loss of instrument air supply inside containment, causing an upset to normal operation which could cause a reactor trip.

    Based on the above identified problem incurred with periodic testing of the Reactor Building instrument air isolation valves at power and since, 1) no practical system design will permit operation of the valves without adversely affecting the safety or operability of the plant, 2) the probability that the protection system will fail to initiate the actuated equipment is acceptably low due to test up to final actuation, and 3) these valves will be routinely tested during refueling outages, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

11. Engineered Safety Feature Loading Sequencer Input Buffer and Output Relays

    The Engineered Safety Feature Loading Sequencer output and input buffer relays are routinely tested during refueling outages. Testing the output relays will actuate plant equipment and requires extensive system and breaker alignments to perform the entire output relay test. Due to the intensity required for testing, plant operability and safety could be jeopardized. The Engineered Safety Feature Loading Sequencer is not designed to test the output relays by continuity of the electrical circuitry associated with the relays as a check in lieu of actual operation; therefore, the only test is by actuation. A reliability study showed that the probability of the output relays to fail when required to initiate the operation of equipment is, and can be, maintained acceptably low without periodic testing of the actuated equipment during reactor operation. The 18 month test frequency is acceptable. The Engineered Safety Feature Loading Sequencer is not designed to test the input buffer relays on line without actually initiating Safety Injection or Blackout sequence. The total testing by actuation of undervoltage relays and Safety Injection signals to final equipment actuation is performed every 18 months while plant is shutdown. The inputs and logic up through the output relay drivers are tested with the reactor operational is a continuous automatic test mode.

    Based on the above, the testing of the ESFLS meets the guidelines of Section D.4 of Regulatory Guide 1.22.

7.1.2.6 Conformance to Regulatory Guide 1.47

The principles described in Regulatory Guide 1.47 have been used to design the bypassed and inoperable status indication for the Engineered Safety Features Systems. System level indication is provided on the Control Room bypass and inoperable status indication CRT to display the operable status of each of the redundant portions of the Emergency Core Cooling System, the Reactor Building Cooling System, and the Reactor Building Spray System, and supporting systems: Engineered Safety Features Power System, Chilled Water System, Service Water System and Component Cooling Water System.

Inoperable indication occurs automatically when equipment vital to the operation of the system has been removed from service and a contact is available from the equipment to signify this condition (e.g., control switch in the "pull to lock" position, switchgear circuit breaker withdrawn from the operating position, safety system bypassed for logic testing). Inoperable indication also occurs when the operator, by administrative procedures, removes essential equipment from service and at the same time manually inputs the status into the Technical Support Center Computer. When automatic equipment inoperable indication occurs, it will be accompanied by an audible alarm.

The following criteria are utilized in providing contacts for automatic indication of inoperable status.

1. The bypass or inoperable condition effects one of the Emergency Core Cooling Systems, Reactor Building Cooling Systems, or Reactor Building Spray Systems, and/or the Auxiliary Support Systems for these systems are required to perform automatically a function important to the safety of the public.
2. The bypass or inoperable condition can reasonably be expected to occur more frequently than once per year.
3. The bypass or inoperable condition is expected to occur when the effected safety system is required to be operable.

7.1.2.7 Conformance to Regulatory Guide 1.53 and IEEE Standard 379-1972

The principles described in IEEE Standard 379-1972 were used in the design of the Westinghouse protection system. The system complies with the intent of this standard and the additional guidance of Regulatory Guide 1.53, although the formal analyses have not been documented exactly as outlined. Westinghouse has gone beyond the required analyses and has performed a fault tree analysis, Reference 3.

The referenced topical report provides details of the analyses of the protection systems previously made to show conformance with the single failure criterion set forth in paragraph 4.2 of IEEE Standard 279-1971. The interpretation of the single failure criterion provided by IEEE Standard 379-1972 does not indicate substantial differences with the Westinghouse interpretation of the criterion except in the methods used to confirm design reliability. Established design criteria in conjunction with sound engineering practices form the bases for the Westinghouse protection

systems. The Reactor Trip and Engineered Safety Features Actuation Systems are each redundant safety systems. The required periodic testing of these systems will disclose any failures or loss of redundancy which could have occurred in the interval between tests, thus ensuring the availability of these systems.

Chapters 6.0, 8.0, 9.0, and 10.0 discuss the single failure criteria for safety systems and auxiliary support systems within the balance of plant scope. Section 7.3.2.2 outlines the degree of conformance for the Engineered Safety Features loading sequence control panels. The degree of conformance for the undervoltage/underfrequency relay panels is addressed in Section 8.3.1.1.1.

Table 7.1-3 outlines, in detail, how the specific principles described by Regulatory Guide 1.53 and IEEE 379-1972, have been used in the design of balance of plant safety related instrumentation and control systems.

7.1.2.8 Conformance to Regulatory Guide 1.63

Regulatory Guide 1.63 is discussed in Appendix 3A.

7.1.2.9 Conformance to IEEE Standard 317-1972

Electrical penetrations are designed and fabricated in accordance with the requirements of IEEE Standard 317-1972.

7.1.2.10 Conformance to IEEE Standard 336-1971

Conformance with the scope of IEEE Standard 336-1971 for installation, inspection, and testing of instrumentation and electrical equipment during construction and startup is covered in Chapters 14 and 17.

7.1.2.11 Conformance to IEEE Standard 338-1971

The periodic testing of the Reactor Trip System and Engineered Safety Features Actuation System conforms to the requirements of IEEE Standard 338-1971 with the following comments:

1. The surveillance requirements of the Technical Specifications for the protection system ensure that the system functional operability is maintained comparable to the original design standards. Periodic tests at frequent intervals demonstrate this capability for the system, excluding sensors.

   Overall protection systems response times shall be demonstrated by test or verification. Sensors within Westinghouse scope will be demonstrated adequate for this design by vendor testing, in-site tests in operating plants with appropriately similar design, or by suitable type testing. The Nuclear Instrumentation System detectors are excluded since they exhibit response time characteristics such that delays attributable to them are negligible in the overall channel response time required for safety.

A periodic verification test program for sensors within Westinghouse scope, for determining any deterioration of installed sensor's response time, is currently being performed by on-site Surveillance Test Procedures (STP). Should sensor fail criteria outlined in the STP, the sensor is either replaced or repaired.

Each test shall include at least 1 logic train such that both logic trains are tested at least 1 per 36 months and 1 channel per function such that all channels are tested at least once every (N times 18 months), where N is the total number of redundant channels in a specific protective function.

The measurement of response time at the specified time intervals provides assurance that the protective and engineered safety features action function associated with each channel is completed within the time limit assumed in the accident analyses.

As an alternative to periodic measurement of instrument channel response time, Amendment 146 permits a verification of the channel response time by summation of allocated sensor, signal processing and actuation logic response times with actual response time tests performed on the remainder of the channel. The methodology is provided in References 4 and 5 and is only applicable to such equipment as was reviewed and approved by the NRC.

The response time may be verified for components that replace the components that were previously evaluated in References 4, 5, or 6 provided that the components have been evaluated in accordance with the NRC approved methodology as discussed in Attachment 1 to TSTF-569, "Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing," which was adopted by Amendment 221 (Reference 7 and 8).

The allocated times must be verified as bounding prior to placing a component in service and re-verified following any work that may adversely affect the component response time.

2. Surveillance test failures are trended and evaluated through various programs to ensure equipment reliability specified in the IEEE Standard 338-1971.
3. The periodic time interval discussed in paragraph 4.3 of IEEE Standard 338-1971, and specified in the Technical Specifications, is conservatively selected to assure that equipment associated with protection functions has not drifted beyond its minimum performance requirements. If any protection channel appears to be marginal or requires more frequent adjustments due to plant condition changes, the time interval will be decreased to accommodate the situation until the marginal performance is resolved.
4. The test interval discussed in paragraph 5.2 of IEEE Standard 338-1971, is developed primarily on past operating experience and modified if necessary to assure that system and subsystem protection is reliably provided. Analytic methods for determining reliability are not used to determine test interval.

Based on the scope definition given in IEEE Standard 338-1971, no other systems described in Chapter 7 are required to comply with this standard.

7.1.3 References

1. The Institute of Electrical and Electronic Engineers, Inc., *IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations*, IEEE Standard 279-1971.
2. Katz, D. N., *Solid-State Logic Protection System Description*, WCAP-7488-L (Proprietary), March, 1971 and WCAP-7672 (Non-Proprietary), May, 1971.
3. Gangloff, W. C. and Loftus, W. D., *An Evaluation of Solid-State Logic Reactor Protection in Anticipated Transients*, WCAP-7706-L (Proprietary) and WCAP-7706 (Non-Proprietary), February, 1973.
4. WCAP-13632-P-A, Revision 2, *Elimination of Pressure Sensor Response Time Testing Requirements*, January 1996.
5. WCAP-14036-P-A, Revision 1, *Elimination of Periodic Protection Channel Response Time Tests*, October 1998.
6. Amendment 146 to the Virgil C. Summer Nuclear Station Technical Specifications, *Response Time Testing Elimination*.
7. Attachment 1 to TSTF-569, *Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing*.
8. Amendment 221 to the Virgil C. Summer Nuclear Station Technical Specifications, *Issuance of Amendment No. 221 to Revise Technical Specifications to Adopt TSTF-569, Revision of Response Time Testing Definition*

Table 7.1-1
Listing of Applicable Criteria

Criteria	Title	Conformance Discussed IN
General Design Criteria (GDC), Appendix A to 10 CFR 50, 1,		
GDC-1	Quality Standards and Records	3.1.2, 7
GDC-2	Design Bases for Protection Against Natural Phenomena	3.1.2, 3.10, 7.2.1.1.11
GDC-3	Fire Protection	3.1.2, 7.1.2.2.3
GDC-4	Environmental and Missile Design Bases	3.1.2, 7.2.2.2
GDC-5	Sharing of Structures, Systems, and Components	3.1.2
GDC-10	Reactor Design	3.1.2, 7.2.2.2
GDC-12	Suppression of Reactor Power Oscillations	3.1.2
GDC-13	Instrumentation and Control	3.1.2, 7.3.1, 7.3.2
GDC-15	Reactor Coolant System Design	3.1.2, 7.2.2.2
GDC-17	Electric Power Systems	3.1.2, Chapter 8
GDC-19	Control Room	3.1.2

Table 7.1-1 (continued)
Listing of Applicable Criteria

Criteria	Title	Conformance Discussed IN
GDC-20	Protection System Functions	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-21	Protection System Reliability and Testability	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-22	Protection System Independence	3.1.2, 7.1.2.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-23	Protection System Failure Modes	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-24	Separation of Protection and Control Systems	3.1.2,7.2.2.2, 7.3.1, 7.3.2
GDC-25	Protection System Requirements for Reactivity Control Malfunctions	3.1.2, 7.3.2
GDC-26	Reactivity Control System Redundancy and Capability	3.1.2
GDC-27	Combined Reactivity Control Systems Capability	3.1.2, 7.3.1, 7.3.2
GDC-28	Reactivity Limits	3.1.2, 7.3.1, 7.3.2
GDC-29	Protection Against Anticipated Operational Occurrences	3.1.2, 7.2.2.2
GDC-33	Reactor Coolant Makeup	3.1.2
GDC-34	Residual Heat Removal	3.1.2
GDC-35	Emergency Core Cooling	3.1.2, 7.3.1, 7.3.2
GDC-37	Testing of Emergency Core Cooling System	3.1.2, 7.3.2
GDC-38	Containment Heat Removal	3.1.2, 7.3.1, 7.3.2

Table 7.1-1 (continued)
Listing of Applicable Criteria

Criteria	Title	Conformance Discussed IN
GDC-40	Testing of Containment Heat Removal System	3.1.2, 7.3.2
GDC-41	Containment Atmosphere Cleanup	3.1.2
GDC-43	Testing of Containment Atmosphere Cleanup Systems	3.1.2, 7.3.2
GDC-44	Cooling Water	3.1.2
GDC-46	Testing of Cooling Water System	3.1.2, 7.3.2
GDC-50	Containment Design Basis	3.1.2
GDC-54	Piping Systems Penetrating Containment	3.1.2
GDC-55	Reactor Coolant Pressure Boundary Penetrating Containment	3.1.2
GDC-56	Primary Containment Isolation	3.1.2
GDC-57	Closed Systems Isolation Valves	3.1.2

Table 7.1-1 (continued)
Listing of Applicable Criteria

	Criteria	Title	Conformance Discussed IN
2.	Institute of Electrical and Electronics Engineers (IEEE) Standards:		
	IEEE Std 279-1971 (ANSI N42.7-1972)	Criteria for Protection Systems for Nuclear Power Generating Stations	7.1, 7.2, 7.3, 7.6
	IEEE Std 308-1971	Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations	7.6
	IEEE Std 317-1972	Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations	7.1.2.9
	IEEE Std 323-1971	IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations	3.11
	IEEE Std 334-1971	Type Tests of Continuous-Duty Class 1 Motors Installed Inside the Containment of Nuclear Power Generating Stations	3A (RG 1.40)
	IEEE Std 336-1971 (ANSI N45.2.4-1972)	Installation, Inspection and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations	7.1.2.10
	IEEE Std 338-1971	Criteria for the Periodic Testing of Nuclear Power Generation Station Protection Systems	7.1.2.11

Table 7.1-1 (continued)
Listing of Applicable Criteria

Criteria	Title	Conformance Discussed IN
IEEE Std 344-1971 (ANSI N41.7)	Guide for Seismic Qualification of Class 1 Electrical Equipment for Nuclear Power Generating Stations	3.10
IEEE Std 379-1972 (ANSI N41.2)	Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems	7.1.2.7
IEEE Std 382-1972	Type Test of Class 1 Electric Valve Operators	3.11
IEEE Std 384-1974 (ANSI N41.14)	Criteria for Separation of Class 1E Equipment and Circuits	7.1.2.2.1

Table 7.1-1 (continued)
Listing of Applicable Criteria

	Criteria	Title	Conformance Discussed IN
3.	Regulatory Guides (RG)		
	RG 1.6	Independence Between Redundant Stand-by Onsite) Power Sources and Between Their Distribution Systems	Chapter 8
	RG 1.11	Instrument Lines Penetrating Primary Reactor Containment	3A, 7.3.1.1.2
	RG 1.22	Periodic Testing of Protection System Actuation Functions	3A, 7.1.2.5, 7.3.2.2.5
	RG 1.29	Seismic Design Classification	3A
	RG 1.30	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment	3A, Chapter 17
	RG 1.32	Use of IEEE Std 308-1971, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Station"	7.6
	RG 1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems	3A, 7.1.2.6
	RG 1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems	3A, 7.1.2.7
	RG 1.62	Manual Initiation of Protection Actions	3A, 7.3.2.2.7
	RG 1.63	Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants	3A

Table 7.1-1 (continued)
Listing of Applicable Criteria

Criteria	Title	Conformance Discussed IN
RG 1.68	Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors	3A, Chapter 14
RG 1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, Rev. 2	3A, Chapter 7
RG 1.73	Qualification Test of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants	3A
RG 1.75	Physical Independence of Electric Systems	3A, 7.1.2.2.1
RG 1.80	Preoperational Testing of Instrument Air Systems	3A, 9.3.1
RG 1.89	Qualification of Class 1E Equipment for Nuclear Power Plants	3A, 3.11
RG 1.95	Protection of Nuclear Power Plant Control Room Operators Against An Accident Chlorine Release	3A, 6.4
RG 1.97	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident	3A
RG 1.100	Seismic Qualification of Electric Equipment for Nuclear Power Plants	3A
RG 1.105	Instrument Spans and Setpoints	3A
RG 1.106	Thermal Overload Protection for Electric Motors on Motor-Operated Valves	
RG 1.114	Guidance on Being Operator at the Controls of a Nuclear Power Plant	3A

Table 7.1-1 (continued)
Listing of Applicable Criteria

	Criteria	Title	Conformance Discussed IN
	Branch Technical Positions (BTP)		
4.	EICSB		
	BTP EICSB 1	Backfitting of the Protection and Emergency Power Systems of Nuclear Reactors	Chapters 7, 8
	BTP EICSB 3	Isolation of Low Pressure Systems from the High Pressure Reactor Coolant System	7.6.2
	BTP EICSB 4	Requirements on Motor Operated Valves in the ECCS Accumulator Lines	7.6.4
	BTP EICSB 5	Scram Breaker Test Requirements - Technical Specifications	7.2.2.2.3, Technical Specifications (Table 4.3-1, Item 21)
	BTP EICSB 9	Definition and Use of "Channel - Calibration" - Technical Specifications	Technical Specifications (Table 4.3-1, Item 2)
	BTP EICSB 10	Electrical and Mechanical Equipment Seismic Qualification Program	3.10

Table 7.1-1 (continued)
Listing of Applicable Criteria

Criteria	Title	Conformance Discussed IN
BTP EICSB 12	Protection System Trip Point Changes for Operation with Reactor Coolant Pumps Out of Service	7.2.2.2.1, Technical Specifications (3/4.1)
BTP EICSB 13	Design Criteria for Auxiliary Feedwater Systems	7.3.2.3
BTP EICSB 14	Spurious Withdrawals of Single Control Rods in Pressurized Water Reactors	7.7.2.2, 15.2.1, 15.2.2, 15.3.6
BTP EICSB 15	Reactor Coolant Pump Breaker Qualification	3.10, 7.1.2.5, 7.2.1.1.2(4)
BTP EICSB 16	Control Element Assembly (CEA) Interlocks in Combustion Engineering Reactors	Not Applicable
BTP EICSB 18	Application of the Single Failure Criteria to Manually Controlled Electrically Operated Valves	Technical Specifications (3/4.5)
BTP EICSB 19	Acceptability of Design Criteria for Hydrogen Mixing and Drywell Vacuum Relief Systems	Not Applicable
BTP EICSB 20	Design of Instrumentation and Controls Provided to Accomplish Changeover from Injection to Recirculation Mode	7.6.5, 6.3.2.2.2, Table 6.3-3

Table 7.1-1 (continued)
Listing of Applicable Criteria

Criteria	Title	Conformance Discussed IN
BTP EICSB 21	Guidance for Application of Reg. Guide 1.47	7.1.2.6
BTP EICSB 22	Guidance for Application of Reg. Guide 1.22	7.1.2.5
BTP EICSB 23	Qualification of Safety-Related Display Instrumentation for Post Accident Condition Monitoring and Safe Shutdown	7.5
BTP EICSB 24	Testing of Reactor Trip System and Engineered Safety Feature Actuation System Sensor Response Times	7.1.2.11
BTP EICSB 25	Guidance for the Interpretation of General Design Criterion 37 for Testing the Operability of the Emergency Core Cooling System as a Whole	3.1.2
BTP EICSB 26	Requirements for Reactor Protection System Anticipatory Trips	7.2.1.1.2
BTP EICSB 27	Design Criteria for Thermal Overload Protection for Motors of Motor Operated Valves	8.3.1.3

Table 7.1-2
Applicable Criteria

See next page for pdf insert

TABLE 7.1-2

APPLICABLE CRITERIA

		REACTOR TRIP SYSTEM (RTS) 7.2			ENGINEERED SAFETY FEATURES SYSTEM (ESF) 7.3										ENGINEERED SAFETY FEATURES SUPPORTING SYSTEMS (ESF SUPPORTING)					SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4							SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4				SAFETY RELATED DISPLAY INSTRUMENTS (SR) 7.5				ALL OTHER INSTRUMENT SYSTEMS REQUIRED FOR SAFETY 7.6					CONTROL SYSTEMS NOT REQUIRED FOR SAFETY 7.7 (1)
		NSSS INPUTS	RCP INPUTS	TURBINE INPUTS (2)	7.3 ESFAS	6.2.2 RB HEAT REMOVAL	6.2.3 RB AIR PURIFICATION AND CLEANUP	6.2.4 CONTAINMENT ISOLATION	6.2.5 COMBUSTIBLE GAS CONTROL	6.2.6 CONTAINMENT LEAKAGE TESTING (3)	6.3 SI	6.4 HABITABILITY SYSTEMS	6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS	10.4.9 EMERGENCY FEEDWATER	9.2.2 CC SYSTEM	9.5 DG SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	6.2, 9.4 HVAC SYSTEMS (4)	9.2.2 CC SYSTEM	9.5 DG SYSTEM	10.4.9 EF SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	10.3 MS SYSTEM (5)	6.2, 9.4 HVAC SYSTEMS (4)	9.3.4 CHARGING PUMPS (6)	9.3.4 BA TRANSFER PUMPS	CREP MONITORING INDICATORS		PAM		ESF MONITOR LIGHTS		7.6.1 I & C POWER SUPPLY SYSTEM	7.6.2 RHR INTERLOCKS	7.6.3 REFUELING INTERLOCKS	7.6.4 ACCUMULATOR MOTOR OPERATED VALVES	7.6.5 LEAK DETECTION SYSTEMS	
																													W	BOP			W	BOP						
	GENERAL DESIGN CRITERIA																																							
GDC-1	QUALITY STANDARDS AND RECORDS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	–	X	X	57	X	7	
GDC-2	DESIGN BASES FOR PROTECTION AGAINST NATURAL PHENOMENA	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	X	X	X	57	X	X	
GDC-3	FIRE PROTECTION (8)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	X	X	X	57	X	X	
GDC-4	ENVIRONMENTAL AND MISSILE DESIGN BASES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	X	X	X	57	X	X	
GDC-5	SHARING OF STRUCTURES, SYSTEMS, AND COMPONENTS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-10	REACTOR DESIGN	X	–	–	X	–	–	–	–	–	X	–	–	X	X	–	X	–	–	X	–	X	X	–	X	–	X	X	–	X	X	–	X	X	X	–	X	–	
GDC-12	SUPPRESSION OF REACTOR POWER OSCILLATIONS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-13	INSTRUMENTATION AND CONTROL	X	X	X	X	X	X	X	X	–	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	X	X	–	X	X	X	–	X	X	
GDC-15	REACTOR COOLANT SYSTEM DESIGN	X	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-17	ELECTRIC POWER SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	X	–	–	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	
GDC-19	CONTROL ROOM	–	–	–	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	
GDC-20	PROTECTION SYSTEM FUNCTIONS	X	X	X	X	9	9	9	–	–	9	9	9	9	9	9	9	9	9	9	9	9	X	9	9	9	–	–	–	–	–	–	–	X	–	–	–	–	
GDC-21	PROTECTION SYSTEM RELIABILITY AND TESTABILITY	X	X	–	X	9	9	9	–	–	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	–	–	–	–	10	10	–	–	X	X 11	–	–	–	
GDC-22	PROTECTION SYSTEM INDEPENDENCE	X	X	X	X	9	9	9	–	–	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	–	–	–	–	12	12	–	–	X	–	–	–	–	
GDC 23	PROTECTION SYSTEM FAILURE MODES	X	X	13	13	9	9	9	–	–	13	9	9	9	9	13	9	9	9	9	13	9	9	9	9	9	–	–	–	–	–	–	–	–	13	–	–	–	–	
GDC-24	SEPARATION OF PROTECTION AND CONTROL SYSTEMS	X	X	–	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	X	X	X	–	–	–	–	–	X	
GDC-25	PROTECTION SYSTEM REQUIREMENTS FOR REACTIVITY CONTROL MALFUNCTIONS	14	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-26	REACTIVITY CONTROL SYSTEM REDUNDANCY AND CAPABILITY	15	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	15	–	–	–	–	–	–	–	–	–	–	–	
GDC-27	COMBINED REACTIVITY CONTROL SYSTEMS CAPABILITY	16	–	–	16	–	–	–	–	–	16	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-28	REACTIVITY LIMITS	17	–	–	17	–	–	–	–	–	17	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-29	PROTECTION AGAINST ANTICIPATED OPERATIONAL OCCURRENCES	X	X	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	X	X	X	X	X	X	–	X	X	
GDC-33	REACTOR COOLANT MAKEUP	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X	X	X	X	–	X	–	X	X	–	X	X 18	X 18	–	–	–	–	–	X	–	–	–	–	
GDC-34	RESIDUAL HEAT REMOVAL	–	–	–	X	–	–	–	–	–	19	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X 19	X	X	–	X	X	–	–	X	
GDC-35	EMERGENCY CORE COOLING	–	–	–	X	–	–	–	–	–	20	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	X	X	–	X	X	–	–	X	
GDC-37	TESTING OF EMERGENCY CORE COOLING SYSTEM	–	–	–	X	–	–	–	–	–	20	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	–	X	–	X	X	–	–	X	
GDC-38	CONTAINMENT HEAT REMOVAL	–	–	–	X	X	X	–	–	–	–	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	–	X	–	X	X	–	–	X	
GDC-40	TESTING OF CONTAINMENT HEAT REMOVAL SYSTEM	–	–	–	X	13	13	–	–	–	–	–	–	–	X	X	X 13	X 13	X	X	X	–	X 13	X 13	–	X	–	–	–	X	–	X	–	X	X	–	–	X	
GDC-41	CONTAINMENT ATMOSPHERE CLEANUP	–	–	–	X	13	13	–	13	–	–	–	13	–	–	X	X 13	X 13	X	–	X	–	X 13	X 13	–	X	–	–	–	X	–	X	–	X	X	–	–	X	
GDC-43	TESTING OF CONTAINMENT ATMOSPHERE CLEANUP SYSTEM	–	–	–	X	X 13	X 13	–	X 13	–	–	–	X 13	–	–	X	X 13	X 13	X	–	X	–	X 13	X 13	–	X	–	–	–	X	–	X	–	X	X	–	–	X	
GDC-44	COOLING WATER	–	–	–	X	–	–	–	–	–	–	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	–	X	–	X	X	–	–	X	
GDC-46	TESTING OF COOLING WATER SYSTEM	–	–	–	X	–	–	–	–	–	–	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	–	X	–	X	X	–	–	X	
GDC-50	CONTAINMENT DESIGN BASIS	–	–	–	–	–	–	X	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-54	PIPING SYSTEMS PENETRATING CONTAINMENT	–	–	–	X 13	–	–	X 13	–	X 13	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-55	REACTOR COOLANT PRESSURE BOUNDARY PENETRATING CONTAINMENT	–	–	–	13	–	–	13	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-56	PRIMARY CONTAINMENT ISOLATION	–	–	–	13	–	–	13	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-57	CLOSED SYSTEMS ISOLATION VALVES	–	–	–	13	–	–	13	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	IEEE STANDARDS																																						
IEEE 279-1971	CRITERIA FOR PROTECTION SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS	X	X	X	X	21	21	21	21 22	–	21 22	21 22	21	21	21	21	21	21	21	21	21	21	21	21	21	21	–	–	–	21	23	21	–	21	X	24	–	22	21	
IEEE 396-1971	CRITERIA FOR CLASS 1R ELECTRIC SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS	–	–	–	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X 26	26	26	X	X	26	26	X	X	–	X	26	
IEEE 317-1972	ELECTRIC PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURES FOR NUCLEAR POWER GENERATING STATIONS	X	–	–	X	X	X	X	X	X	X	–	X	–	X	–	X	–	X	X	–	–	X	–	–	X	–	–	X	X	X	X	X	X	–	X	–	X	X	
IEEE 323-1971	IEEE STANDARD FOR QUALIFYING CLASS 1E EQUIPMENT FOR NUCLEAR POWER GENERATING STATIONS	27	27	–	27	27	27	27	27	–	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	–	–	–	27	27	–	–	27	27	–	27	–	
IEEE 334-1971	TYPE TEST OF CONTINUOUS DUTY CLASS 1 MOTORS INSTALLED INSIDE THE CONTAINMENT OF NUCLEAR POWER GENERATING STATIONS	–	–	–	–	27 28	–	–	–	–	–	–	27 28	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
IEEE 336-1971	INSTALLATION, INSPECTION AND TESTING REQUIREMENTS FOR INSTRUMENTATION AND ELECTRIC EQUIPMENT DURING THE CONSTRUCTION OF NUCLEAR POWER GENERATING STATIONS	X	X	X	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	X	X	–	–	X	X	–	X	–	
IEEE 338-1971	CRITERIA FOR THE PERIODIC TESTING OF NUCLEAR POWER GENERATION STATION PROTECTION SYSTEMS (29)	X	X	X	X 9	9	9	9	9	X	9 30	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	–	–	–	–	X	X	–	–	9	11	–	30	–	
IEEE 344-1971	GUIDE FOR SEISMIC QUALIFICATION OF CLASS 1 ELECTRICAL EQUIPMENT FOR NUCLEAR POWER GENERATING STATIONS	31	31	–	31	31	31	31	31	–	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	–	–	31	31	31	–	–	31	31	57	31	32	
IEEE 379-1972	GUIDE FOR THE APPLICATION OF THE SINGLE FAILURE CRITERIA TO NUCLEAR POWER GENERATING STATION PROTECTION SYSTEMS	33	X	X	33	33	33	33	33 34	–	35	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	–	–	–	33	33	33	–	33	X	11	–	35	33	
IEEE 382-1972	TYPE TEST OF CLASS 1 ELECTRIC VALVE OPERATORS	–	–	–	–	27	27	27	27	–	27	27	27	27	27	–	27	27	27	27	–	27	27	27	27	27	–	–	–	–	–	–	–	–	–	27	–	27	–	
IEEE 384-1974	CRITERIA FOR SEPARATION OF CLASS 1E EQUIPMENT AND CIRCUITS	12	12	12	12	12	12	12	12	–	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	–	12 36	12	12	12	12	12	12	12	12	–	12	12	

X IS DEFINED AS MEANING THE INSTRUMENT AND CONTROL SYSTEM AND COMPONENTS MEET THE REFERENCED CRITERIA

– IS DEFINED AS MEANING THE REFERENCED CRITERIA IS NOT APPLICABLE TO THE INSTRUMENT AND CONTROL SYSTEM AND COMPONENTS

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TABLE 7.1-2

APPLICABLE CRITERIA (Continued)

		REACTOR TRIP SYSTEM (RTS) 7.2			ENGINEERED SAFETY FEATURES SYSTEM (ESF) 7.3										ENGINEERED SAFETY FEATURES SUPPORTING SYSTEMS (ESF SUPPORTING)					SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4							SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4				SAFETY RELATED DISPLAY INSTRUMENTS (SR) 7.5				ALL OTHER INSTRUMENT SYSTEMS REQUIRED FOR SAFETY 7.6					CONTROL SYSTEMS NOT REQUIRED FOR SAFETY 7.7 (1)
		NSSS INPUTS	RCP INPUTS	TURBINE INPUTS (2)	7.3 ESFAS	6.2.2 RB HEAT REMOVAL	6.2.3 RB AIR PURIFICATION AND CLEANUP	6.2.4 CONTAINMENT ISOLATION	6.2.5 COMBUSTIBLE GAS CONTROL	6.2.6 CONTAINMENT LEAKAGE TESTING (3)	6.3 SI	6.4 HABITABILITY SYSTEMS	6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS	10.4.9 EMERGENCY FEEDWATER	9.2.2 CC SYSTEM	9.5 DG SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	6.2, 9.4 HVAC SYSTEMS (4)	9.2.2 CC SYSTEM	9.5 DG SYSTEM	10.4.9 EF SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	10.3 MS SYSTEM (5)	6.2, 9.4 HVAC SYSTEMS (4)	9.3.4 CHARGING PUMPS (6)	9.3.4 BA TRANSFER PUMPS	CREP MONITORING INDICATORS		PAM		ESF MONITOR LIGHTS		7.6.1 I & C POWER SUPPLY SYSTEM	7.6.2 RHR INTERLOCKS	7.6.3 REFUELING INTERLOCKS	7.6.4 ACCUMULATOR MOTOR OPERATED VALVES	7.6.5 LEAK DETECTION SYSTEMS	
																														W	BOP									
	REGULATORY GUIDES (APPENDIX 3A DELINEATES THE APPLICABLE RG REVISION AND/OR DATE).																																							
RG 1.6	INDEPENDENCE BETWEEN REDUNDANT STANDBY (ONSITE) POWER SOURCES AND BETWEEN THEIR DISTRIBUTION SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	X	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	
RG 1.7	CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT FOLLOWING A LOSS-OF-COOLANT ACCIDENT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.11	INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT	–	–	–	38	–	–	38	X	39	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	38	–	–	–	–	–	–	–	
RG 1.12	INSTRUMENTATION FOR EARTHQUAKES (40)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.22	PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS	X	–	–	41	41	41	41	41	–	30 41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	–	–	–	–	10	10	–	–	24	–	30	–	
RG 1.29	SEISMIC DESIGN CLASSIFICATION	38	38	–	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	–	–	–	38	38	38	–	38	38	38	57	38	38	
RG 1.30	QUALITY ASSURANCE REQUIREMENTS FOR THE INSTALLATION, INSPECTION, AND TESTING OF INSTRUMENTATION AND ELECTRICAL EQUIPMENT (38)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	–	X	X	X	X	X	
RG 1.32	USE OF IEEE STANDARD 308-1971 "CRITERIA FOR CLASS 1E ELECTRIC SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS"	–	–	–	X 38	X 38	X 38	X 38	X 38	–	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 26 38	26	26 38	X	X 38	26	26 38	X 38	X	–	X 38	26 38	
RG 1.45	REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	42	
RG 1.47	BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS	–	–	–	X 43	X 43	X 43	X 43	X 43	–	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	–	–	–	–	–	–	X 43	–	–	–	–	
RG 1.53	APPLICATION OF THE SINGLE FAILURE CRITERION TO NUCLEAR POWER PLANT PROTECTION SYSTEMS	33	X	X	33	33	33	33	33 34	–	35	33	33	33	33	33	33	33	33	33	33	33	33	33	33	–	–	–	33	33	33	–	33	X	11	–	35	33	
RG 1.62	MANUAL INITIATION OF PROTECTION ACTIONS	X	–	–	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	
RG 1.63	ELECTRIC PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURES FOR WATER-COOLED NUCLEAR POWER PLANTS	38	–	–	38	38	38	38	38	38	38	–	38	–	38	–	38	–	38	38	–	–	38	–	38	–	–	38	38	38	38	38	–	38	–	38	38	
RG 1.68	PREOPERATIONAL AND INITIAL START-UP TEST PROGRAMS FOR WATER-COOLED POWER REACTORS	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	–	X 38	X 38	
RG 1.70	STANDARD FORMAT AND CONTENT OF SAFETY ANALYSIS REPORTS FOR NUCLEAR POWER PLANTS. REV. 1 (38)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
RG 1.73	QUALIFICATION TEST OF ELECTRIC VALVE OPERATORS INSTALLED INSIDE THE CONTAINMENT	–	–	–	–	27	27	27	27	–	27	–	27	–	27	–	27	–	–	27	–	–	27	–	–	–	–	–	–	–	–	–	–	27	–	27	–	
RG 1.75	PHYSICAL INDEPENDENCE OF ELECTRIC SYSTEMS	12	12	12	12	12	12	12	12	–	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12 36	–	12	12	12	12	12	12	–	12	12	
RG 1.80	PREOPERATIONAL TESTING OF INSTRUMENT AIR SYSTEMS (30)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.89	QUALIFICATION OF CLASS 1E EQUIPMENT FOR NUCLEAR POWER PLANTS	27	27	–	27	27	27	27	27	–	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	–	–	–	27	27	–	–	27	–	27	–	
RG 1.95	PROTECTION OF NUCLEAR POWER PLANT CONTROL ROOM OPERATORS AGAINST AN ACCIDENTAL CHLORINE RELEASE	–	–	–	–	–	–	–	–	–	–	44	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.97	INSTRUMENTATION FOR LIGHT WATER-COOLED NUCLEAR POWER PLANTS TO ACCESS PLANT CONDITIONS DURING AND FOLLOWING AN ACCIDENT	–	–	–	–	45	45	–	45	–	–	–	–	45	–	–	45	–	–	–	–	45	45	–	–	–	–	–	–	–	45	45	–	45	X	–	–	–	
RG 1.100	SEISMIC QUALIFICATION OF ELECTRIC EQUIPMENT FOR NUCLEAR POWER PLANTS	31	31	–	31	31	31	31	31	–	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	–	–	31	31	31	–	–	31	31	57	31	32	
RG 1.105	INSTRUMENT SPANS AND SETPOINTS	38	38	38	38	38	38	38	38	–	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	–	–	–	–	–	–	–	–	–	–	38	
RG 1.106	THERMAL OVERLOAD PROTECTION FOR ELECTRIC MOTORS ON MOTOR OPERATED VALVES	–	–	–	–	38	38	38	–	–	38	38	38	38	38	–	38	38	38	38	–	38	38	38	38	38	–	–	–	–	–	–	–	–	–	38	–	
RG 1.108	PERIODIC TESTING OF DIESEL GENERATOR UNITS USED AS ONSITE ELECTRIC POWER SYSTEMS AT NUCLEAR POWER PLANTS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	38	–	–	–	–	38	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.114	GUIDANCE ON BEING OPERATOR AT THE CONTROLS OF A NUCLEAR POWER PLANT	–	–	–	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	–	X 38	X 38	
RG 1.118	PERIODIC TESTING OF ELECTRIC POWER AND PROTECTION SYSTEMS (46)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.120	FIRE PROTECTION GUIDELINES FOR NUCLEAR POWER PLANTS (8)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	

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TABLE 7.1-2

APPLICABLE CRITERIA (Continued)

		REACTOR TRIP SYSTEM (RTS) 7.2			ENGINEERED SAFETY FEATURES SYSTEM (ESF) 7.3										ENGINEERED SAFETY FEATURES SUPPORTING SYSTEMS (ESF SUPPORTING)					SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4							SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4				SAFETY RELATED DISPLAY INSTRUMENTS (SR) 7.5				ALL OTHER INSTRUMENT SYSTEMS REQUIRED FOR SAFETY 7.6					CONTROL SYSTEMS NOT REQUIRED FOR SAFETY 7.7 (1)
		NSSS INPUTS	RCP INPUTS	TURBINE INPUTS (2)	7.3 ESFAS	6.2.2 RB HEAT REMOVAL	6.2.3 RB AIR PURIFICATION AND CLEANUP	6.2.4 CONTAINMENT ISOLATION	6.2.5 COMBUSTIBLE GAS CONTROL	6.2.6 CONTAINMENT LEAKAGE TESTING (3)	6.3 SI	6.4 HABITABILITY SYSTEMS	6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS	10.4.9 EMERGENCY FEEDWATER	9.2.2 CC SYSTEM	9.5 DG SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	6.2, 9.4 HVAC SYSTEMS (4)	9.2.2 CC SYSTEM	9.5 DG SYSTEM	10.4.9 EF SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	10.3 MS SYSTEM (5)	6.2, 9.4 HVAC SYSTEMS (4)	9.3.4 CHARGING PUMPS (6)	9.3.4 BA TRANSFER PUMPS	CREP MONITORING INDICATORS		PAM		ESF MONITOR LIGHTS		7.6.1 I & C POWER SUPPLY SYSTEM	7.6.2 RHR INTERLOCKS	7.6.3 REFUELING INTERLOCKS	7.6.4 ACCUMULATOR MOTOR OPERATED VALVES	7.6.5 LEAK DETECTION SYSTEMS	
																													W	BOP			W	BOP						
	EICSB BRANCH TECHNICAL POSITIONS																																							
BTP EICSB 1	BACKFITTING OF THE PROTECTION AND EMERGENCY POWER SYSTEMS OF NUCLEAR REACTORS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 3	ISOLATION OF LOW PRESSURE SYSTEMS FROM THE HIGH PRESSURE REACTOR COOLANT SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X 11	–	–	–	
BTP EICSB 4	REQUIREMENTS ON MOTOR OPERATED VALVES IN THE ECCS ACCUMULATOR LINES	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	47	–	
BTP EICSB 5	SCRAM BREAKER TEST REQUIREMENTS - TECHNICAL SPECIFICATIONS	X 48	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	v	–	–	–	–	–	–	–	–	–	
BTP EICSB 9	DEFINITION AND USE OF "CHANNEL - CALIBRATION" - TECHNICAL SPECIFICATIONS (49)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 10	ELECTRICAL AND MECHANICAL EQUIPMENT SEISMIC QUALIFICATION PROGRAM	31	31	–	31	31	31	31	31	–	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	–	–	31	31	–	–	31	31	57	31	32	
BTP EICSB 12	PROTECTION SYSTEM TRIP POINT CHANGES FOR OPERATION WITH REACTOR COOLANT PUMPS OUT OF SERVICE	50	–	–	50	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 13	DESIGN CRITERIA FOR AUXILIARY FEEDWATER SYSTEMS	–	–	–	X	–	–	–	–	–	–	–	–	X	–	X	X	X	X	–	X	X	X	X	X	X	–	–	–	–	X	–	X	X	–	–	–	
BTP EICSB 14	SPURIOUS WITHDRAWALS OF SINGLE CONTROL RODS IN PRESSURIZED WATER REACTORS (51)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 15	REACTOR COOLANT PUMP BREAKER QUALIFICATION (52)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 16	CONTROL ELEMENT ASSEMBLY (CEA) INTERLOCKS IN COMBUSTION ENGINEERING REACTORS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 18	APPLICATION OF THE SINGLE FAILURE CRITERIA TO MANUALLY CONTROLLED ELECTRICALLY OPERATED VALVES	–	–	–	–	–	–	–	–	–	53	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 19	ACCEPTABILITY OF DESIGN CRITERIA FOR HYDROGEN MIXING AND DRYWELL VACUUM RELIEF SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 20	DESIGN OF INSTRUMENTATION AND CONTROLS PROVIDED TO ACCOMPLISH CHANGEOVER FROM INJECTION TO RECIRCULATION MODE	–	–	–	X 54	–	–	–	–	–	X 54	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	–	–	
BTP EICSB 21	GUIDE FOR APPLICATION OF REGULATORY GUIDE 1.47	–	–	–	43	43	43	43	43	–	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	–	–	–	–	–	–	43	–	–	–	–	
BTP EICSB 22	GUIDE FOR APPLICATION OF REGULATORY GUIDE 1.22	X	–	–	41	41	41	41	41	–	30 41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	–	–	–	–	10	10	–	–	24	–	30	–	
BTP EICSB 23	QUALIFICATION OF SAFETY RELATED DISPLAY INSTRUMENTATION FOR POST ACCIDENT CONDITION MONITORING AND SAFE SHUTDOWN	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10	10	–	–	–	–	–	–	
BTP EICSB 24	TESTING OF REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURE ACTUATION SYSTEM SENSOR RESPONSE TIMES	55	–	–	55	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 25	GUIDANCE FOR THE INTERPRETATION OF GENERAL DESIGN CRITERION 37 FOR TESTING THE OPERABILITY OF THE EMERGENCY CORE COOLING SYSTEM AS A WHOLE	–	–	–	X	–	–	–	–	–	X 20	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 26	REQUIREMENTS FOR REACTOR PROTECTION SYSTEM ANTICIPATORY TRIPS	X	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 27	DESIGN CRITERIA FOR THERMAL OVERLOAD PROTECTION FOR MOTORS OF MOTOR OPERATED VALVES	–	–	–	–	56	56	56	–	–	56	–	56	–	56	–	56	–	–	56	–	–	56	–	56	–	–	–	–	–	–	–	–	–	56	–	

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NOTES TO TABLE 7.1-2

1. See Section 7.7 for a list of control systems typical of those not required for safety.
2. Although credit is not taken for the turbine trip inputs from the pressure sensors and turbine stop valves (as described in Section 7.2.1.1.2, Item 6) the circuits are classified as Associated with Class 1E, are seismically supported, and are separated in accordance with plant design criteria as described in Appendix 3A (RG 1.75) when located in Seismic Category 1 structures. Safety criteria apply only to the input devices and do not include the mechanical portions of the turbine generator.
3. Safety criteria apply only to those portions of the system that are part of containment.
4. Safety criteria apply only to those portions of HVAC systems that are safety related.
5. Safety criteria denoted as applicable for this input include only the main steam isolation valves, steam generator power operated relief valves, and valves that admit steam to the turbine driven emergency feedwater pump.
6. Applicability is limited to a chemical and volume control system function rather than a safety injection system function.
7. Instrumentation and associated wiring applies.
8. Design satisfies Branch Technical Position APCSB 9.5-1, Appendix A, to the extent outlined in the FPER.
9. Complies for those portions (components) of the system that are part of the protection system, i.e., inputs, logic, actuation device inputs, etc.
10. See Section 7.5.1 for discussion of compliance.
11. See Section 7.6.2 for discussion.
12. See Appendix 3A (RG 1.75) and Sections 7.1.2.2.1, 8.3.1.4, and 8.3.1.5 for discussion of compliance.
13. See Section 3.1.2 for discussion of compliance.

NOTES TO TABLE 7.1-2 (Continued)

14. See Section 3.1 for discussion of GDC 25. The analyses which are discussed in Chapter 15.0 are categorized as Condition II, III, and IV occurrences. These analyses show that the acceptance criteria for these categories are satisfied.
15. See Section 3.1 for discussion of GDC 26.
16. See Section 3.1 for discussion of GDC 27.
17. See Section 3.1 for discussion of GDC 28.
18. As noted in Section 7.4, nonaccident conditions are assumed.
19. See Sections 5.5.7, 6.3, and 7.6.5 for discussion of compliance.
20. See Sections 3.1.2, 6.3, and 7.6.5 for discussion of compliance.
21. 21. The general philosophy of IEEE-279 is met by addressing redundancy and independence on a redundant subsystem basis, i.e., A loop/train and B loop/train basis. Testing can be performed on a loop basis consistent with the requirements of Sections 4.9 and 4.10 of IEEE-279.
22. For Westinghouse scope it is noted that:
    a. IEEE-279-1971 is not required as a design basis for systems, equipment, or components to which this note is applicable.
    b. The scope of IEEE-279-1971 is limited to the protection system from sensors to actuation devices inputs.
23. See Section 7.5.1 for discussion of post-accident monitoring.
24. See Section 7.6.2.2 for discussion of residual heat removal system interlocks.
25. Deleted (RNs 99-015 and 99-114)
26. Non-Class 1E components fed from Class 1E power source.
27. See Section 3.11 and Appendix 3A for discussion of compliance.
28. Applicable only to reactor building cooling unit fan motors.
29. See Section 7.1.2.11 for description of details of conformance to IEEE-338-1971.

NOTES TO TABLE 7.1-2 (Continued)

30. See Section 6.3.4.3 for description of safety injection system testing.
31. See Section 3.10 and Appendix 3A (RG 1.100) for discussion of compliance.
32. See Section 7.6.5 for description of leakage detection system.
33. Complies as outlined in Section 7.1.2.7, Table 7.1-3, and Table 7.3-6.
34. See Sections 6.2.5 and 7.3.3 for discussion of hydrogen recombiner.
35. See Section 6.3.2.9 for discussion of safety injection.
36. Boric acid transfer pump power and control circuits are classified as Associated with Class 1E.
37. See Appendix 3A (RG 1.7), Section 6.2.5 and the response to NRC Question 031.56 for discussion of compliance.
38. See Appendix 3A for discussion of compliance.
39. See Appendix 3A (RG 1.11) and Section 6.2.6 for discussion of compliance.
40. Complies, see Section 3.7.4 and Appendix 3A (RG 1.12) for details.
41. Complies, for the protection system actuated devices, except as noted in Section 7.1.2.5.
42. See Appendix 3A (RG 1.45) and Section 5.2.7 for discussion of compliance.
43. Complies, as applicable to specific system components. Details are discussed in the response to NRC Question 031.49.
44. Complies, see Appendix 3A (RG 1.95).
45. See Appendix 3A (RG 1.97) and Sections 6.2.5 and 7.5 for discussion of compliance.
46. Reasons for non-applicability are outlined in Appendix 3A.
47. See Section 7.6.4 for discussion.

NOTES TO TABLE 7.1-2 (Continued)

48. See Section 7.2.2.2.3.10 for discussion. Also, see Chapter 16.0 (Technical Specifications), Table 4.3-1.
49. See Technical Specifications, Table 4.3-1.
50. See Technical Specifications, Section 3/4.4.1.
51. The results of analysis of a single rod cluster control assembly at full power are described in Section 15.3.
52. Accident analysis, as described in Sections 15.2.9 and 15.3.4, does not take credit for reactor coolant pump trip. Offsite electric system stability is described in Section 8.2.2.2.
53. BTP EICSB 18 applies to valves XVG8808A,B,C, XVG8884, XVG8885, XVG8886, XVG8888A,B, XVG8889, XVG8106, and XVG8133A,B in the Safety Injection System. See Chapter 16.0 (Technical Specifications), Section 3/4.5.1 and the responses to NRC Questions 040.18, 211.31, 211.32 and 211.37 for additional details.
54. See Section 6.3.2.7.
55. See Section 7.1.2.11 and Chapter 16.0 (Technical Specifications), Section 3/4.3.
56. See Appendix 3A (RG 1.106) for discussion of thermal overloads for electric motor operated valves.
57. See Section 9.1.4.1 (Item 6) and 9.1.4.3.1.2 (Item 5) and Tables 3.2-1, 3.2-2, and 3.2-3.

Table 7.1-3
Conformance With Regulatory Guide 1.53 and IEEE 379-1972, for
Balance of Plant Safety Related Instrumentation Control Systems

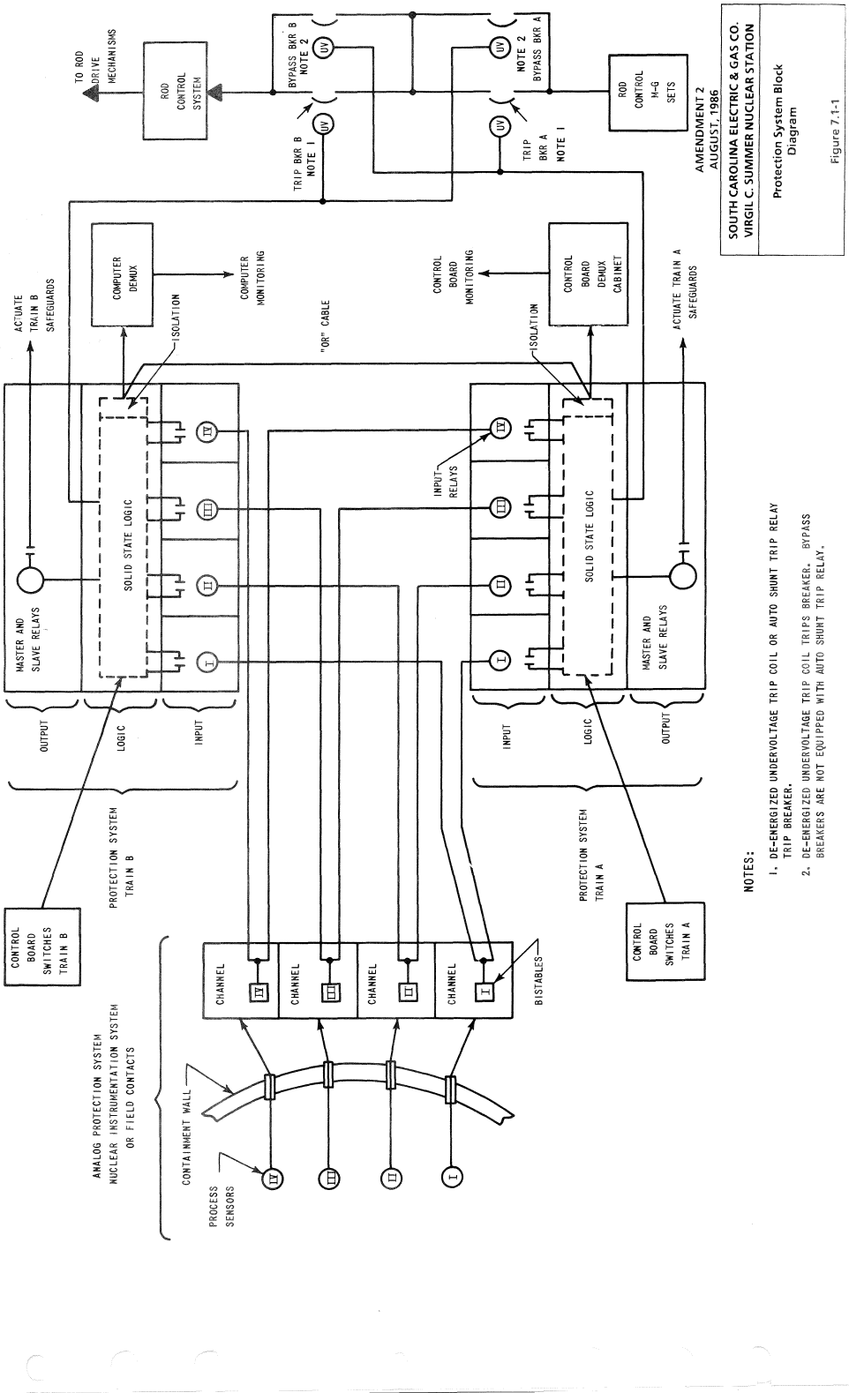
Criterion	Degree of Compliance
REGULATORY GUIDE 1.53	
C.1 IEEE 379-1972	See IEEE 379-1972, comparison, below.
C.2 Continuity Checks	Except as outlined by Sections 7.1.2.5 and 7.3.2.2.5, components are designed to allow operation while being tested during reactor operation.
C.3 Interconnections	Channel separation is maintained and integrity is assured through use of isolating devices where interconnections may occur or suitable barriers are employed.
C.4 Protection System Logic and Actuator System	Actuator circuits are designed to prevent a single failure from causing loss of a protective function.
IEEE 379-1972	
3(1) Redundancy	Redundancy is used and maintained to prevent a single failure in a channel or component from preventing operation of the redundant counterpart.
3(2) Detectability	Control room indication and alarms are provided and are used in conjunction with periodic testing.
3(3) Nondetectability	Not applicable, see Note 1.
3(4) Multiple Faults	Not applicable, see Note 1.
3(5) Completing Protective Functions	Systems are designed to prevent a single failure from resulting in noncompletion of the system protective function.
3(6) DBE and Single Failure	Concurrent occurrence of a design basis event and a single failure was considered in the design. System protective function will not be lost under such circumstances.
3(7) Operational Reliability	Not applicable, but included in the design concept.
5.1 Classification	Not applicable, but included in the design concept.

Table 7.1-3 (continued)
Conformance With Regulatory Guide 1.53 and IEEE 379-1972, for
Balance of Plant Safety Related Instrumentation Control Systems

Criterion	Degree of Compliance
5.2 Undetectable Failures	Not applicable, see Note 1. Also, see Regulatory Guide 1.53, Regulatory Position C.2, above.
5.3 Common Mode Failures	Concept was considered during design. Equipment qualification was used significantly in designing against common mode failures. Sections 3.10 and 3.11 outline qualification in more details.
6.1 General	See Note 1.
6.2 Channels	See Regulatory Guide 1.53, Regulatory Position C.3, above.
6.3 Protection System Logic	See Regulatory Guide 1.53, Regulatory Position C.3, above.
6.4 Actuator Circuit	See Regulatory Guide 1.53, Regulatory Position C.3, above.
Type 2 and 3 Single Failure Analysis	Equipment qualification was used significantly in designing against common mode failures. Sections 3.10 and 3.11 outline qualification in more detail.
6.6 Overall System - Failure Analysis	Concepts addressed were used during system design.

(1) Each applicable FSAR section presents a safety evaluation which addresses the single failure criteria.

Figure 7.1-1
PROTECTION SYSTEM BLOCK DIAGRAM



7.2 REACTOR TRIP SYSTEM

7.2.1 Description

7.2.1.1 System Description

The reactor trip system automatically keeps the reactor operating within a safe region by shutting down the reactor whenever the limits of the region are approached. The safe operating region is defined by several considerations such as mechanical/hydraulic limitations on equipment, and heat transfer phenomena. Therefore, the reactor trip system keeps surveillance on process variables which are directly related to equipment mechanical limitations, such as pressure, pressurizer water level (to prevent water discharge through safety valves, and uncovering heaters) and also on variables which directly affect the heat transfer capability of the reactor (e.g., flow and reactor coolant temperatures). Still other parameters utilized in the reactor trip system are calculated from various process variables. In any event, whenever a direct process or calculated variable reaches a setpoint the reactor will be shutdown in order to protect against either gross damage to fuel cladding or loss of system integrity which could lead to release of radioactive fission products into the containment.

The following systems make up the reactor trip system. Refer to References 1, 2, and 3 for additional background information.

1. Process Instrumentation and Control System.
2. Nuclear Instrumentation System.
3. Solid-State Logic Protection System.
4. Reactor Trip Switchgear.
5. Manual Actuation Circuit.

The reactor trip system consists of sensors which, when connected with analog circuitry consisting of 2 to 4 redundant channels, monitor various plant parameters and digital circuitry, consisting of 2 redundant logic trains, which receive inputs from the analog protection channels to complete the logic necessary to automatically open the reactor trip breakers.

Each of the two trains, A and B, is capable of opening a separate and independent reactor trip breaker, RTA and RTB, respectively and a bypass breaker, BYB and BYA, respectively. The 2 trip breakers in series connect three-phase a-c power from the rod drive motor generator sets to the rod drive power cabinets, as shown on Figure 7.2-1, Sheet 2. During plant power operation, a d-c undervoltage coil on each reactor trip breaker holds a trip plunger out against its spring, allowing the power to be available at the rod control power supply cabinets. For reactor trip, a loss of d-c voltage to the undervoltage coil, as well as energization of the shunt trip coil, trips open the breaker.

When either of the trip breakers opens, power is interrupted to the rod drive power supply, and the control rods fall, by gravity, into the core. The rods cannot be withdrawn until the trip breakers are

manually reset. The trip breakers cannot be reset until the abnormal condition which initiated the trip is corrected. Bypass breakers BYA and BYB are provided to permit testing of the trip breakers, as discussed in Figure 7.2.2.2.3.

7.2.1.1.1 Functional Performance Requirements

The reactor trip system automatically initiates reactor trip:

1. Whenever necessary to prevent fuel damage for an anticipated operational transient (Condition II).
2. To limit core damage for infrequent faults (Condition III).
3. So that the energy generated in the core is compatible with the design provisions to protect the reactor coolant pressure boundary for limiting fault conditions (Condition IV).

The reactor trip system initiates a turbine trip signal whenever reactor trip is initiated to prevent the reactivity insertion that would otherwise result from excessive reactor system cooldown. The turbine trip avoids unnecessary actuation of the engineered safety features actuation system.

The reactor trip system provides for manual initiation of reactor trip by operator action.

7.2.1.1.2 Reactor Trips

The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the reactor trip system reaches a preset level. To ensure a reliable system, high quality design, components, manufacturing, quality control and testing is used. In addition to redundant channels and trains, the design approach provides a reactor trip system which monitors numerous system variables, therefore providing protection system functional diversity. The extent of this diversity has been evaluated for a wide variety of postulated accidents.

Table 7.2-1 provides a list of reactor trips which are described below.

1. Nuclear Overpower Trips

   The specific trip functions generated are as follows:

   a. Power range high neutron flux trip

      The power range high neutron flux trip circuit trips the reactor when 2 of the 4 power range channels reach the trip setpoint.

There are 2 bistables (for each of the 4 power range channels), each with its own trip setting used for a high and a low range trip setting. The high trip setting provides protection during normal power operation and is always active. The low trip setting, which provides protection during startup, can be manually bypassed when 2 out of the 4 power range channels read above approximately 10% power (P-10). Three (3) out of the 4 channels below 10% automatically reinstates the trip function. Refer to Table 7.2-2 for a listing of all protection system interlocks.

b. Intermediate range high neutron flux trip

The intermediate range high neutron flux trip circuit trips the reactor when 1 out of the 2 intermediate range channels reaches the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked if 2 out of 4 power range channels are above approximately 10% power (P-10). Three (3) out of the 4 power range channels below this value automatically reinstates the intermediate range high neutron flux trip. The intermediate range channels (including detectors) are separate from the power range channels. The intermediate range channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing. This bypass action is annunciated on the control board.

c. Source range high neutron flux trip

The source range high neutron flux trip circuit trips the reactor when 1 of the 2 source range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup and plant shutdown, can be manually bypassed when 1 of the 2 intermediate range channels reads above the P-6 setpoint value and is automatically reinstated when both intermediate range channels decrease below the P-6 setpoint value. This trip is also automatically bypassed by 2 out of 4 logic from the power range protection interlock (P-10). This trip function can also be reinstated below P-10 by an administrative action requiring manual actuation of 2 control board mounted switches. Each switch will reinstate the trip function in 1 of the 2 protection logic trains. The source range trip point is set between the P-6 setpoint (source range cutoff power level) and the maximum source range power level. The channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

d. Power range high positive neutron flux rate trip

This circuit trips the reactor when a sudden abnormal increase in nuclear power occurs in 2 out of 4 power range channels.

This trip provides DNB protection against rod ejection accidents of low worthfrom mid-power and is always active.

Table 7.2-1, Sheet 3, shows the logic for all of the nuclear overpower and rate trips.

2. Core Thermal Overpower Trips

The specific trip functions generated are as follows:

a. Overtemperature ΔT trip

This trip protects the core against low DNBR and trips the reactor on coincidence as listed in Table 7.2-1 with 1 set of temperature measurements per loop. The setpoint for this trip is continuously calculated by analog circuitry for each loop by solving the following equation:

$$\Delta T_{setpoint} = \Delta T_O \left[K_1 - K_2 \left(\frac{1+\tau_1 S}{1+\tau_2 S} \right) \left(T_{avg} - T_{Oavg} \right) + K_3 (P - 2235) - f(\Delta\phi) \right]$$

Where:

ΔT_O	=	Indicated ΔT at rated thermal power
T_{avg}	=	Average reactor coolant temperature (°F)
T_{Oavg}	=	Indicated T_{avg} at rated thermal power
P	=	Pressurizer pressure (psig)
K_1	=	Preset bias
K_2	=	Preset gain which compensates for the temperature on the DNB limits
K_3	=	Preset gain which compensates for the effect of pressure on the DNB limits
τ_1, τ_2	=	Preset constants which compensate for piping and instrument time delay
s	=	Laplace transform operator (seconds^{-1})
$f(\Delta\phi)$	=	A function of the neutron flux difference between upper and lower long ion chambers (refer to Figure 7.2-2)

A separate long ion chamber unit supplies the flux signal for each overtemperature ΔT trip channel.

Increases in $\Delta\phi$ beyond a predefined deadband result in a decrease in trip setpoint. Refer to Figure 7.2-2.

The required 1 pressurizer pressure parameter per loop is obtained from separate sensors connected to 3 separate pressure taps at the top of the pressurizer. Refer to Section 7.2.2.3.3 for an analysis of this arrangement.

Figure 7.2-1, Sheet 5, shows the logic for overtemperature ΔT trip function.

b. Overpower ΔT trip

This trip protects against excessive power (fuel rod rating protection) and trips the reactor on coincidence as listed in Table 7.2-1, with 1 set of temperature measurements per loop. The setpoint for each channel is continuously calculated using the following equation:

$$\Delta T_{setpoint} = \Delta T_O \left[K_4 - K_5 \left(\frac{\tau_3 S}{1+\tau_3 S} \right) T_{avg} - K_6 \left(T_{avg} - T_{Oavg} \right) \right]$$

Where:

ΔT_O	=	Indicated ΔT at rated thermal power
K_4	=	A preset bias
K_5	=	A constant which compensates for piping and instrument time delay
K_6	=	A constant which compensates for the change in density flow and heat capacity of the water with temperature.
T_{Oavg}	=	Indicated T_{avg} at rated thermal power
T_{avg}	=	Average reactor coolant temperature (°F)
τ_3	=	Preset time constant (seconds)
s	=	Laplace transform operator ($seconds^{-1}$)

The source of temperature and flux information is identical to that of the overtemperature ΔT trip and the resultant ΔT setpoint is compared to the same ΔT. Figure 7.2-1, Sheet 5, shows the logic for this trip function.

3. Reactor Coolant System Pressurizer Pressure and Water Level Trips

The specific trip functions generated are as follows:

a. Pressurizer low pressure trip

The purpose of this trip is to protect against low pressure which could lead to DNB. The parameter being sensed is reactor coolant pressure as measured in the pressurizer. Above P-7 the reactor is tripped when the pressurizer measurements fall below preset limits. This trip is blocked below P-7 to permit startup. The trip logic and interlocks are given in Table 7.2-1.

The trip logic is shown on Figure 7.2-1, Sheet 6.

b. Pressurizer high pressure trip

The purpose of this trip is to protect the Reactor Coolant System against system overpressure.

The same sensors and transmitters used for the pressurizer low pressure trip are used for the high pressure trip except that separate bistables are used for trip. These bistables trip when uncompensated pressurizer pressure signals exceed preset limits on coincidence as listed in Table 7.2-1. There are no interlocks or permissives associated with this trip function.

The logic for this trip is shown on Table 7.2-1, Sheet 6.

c. Pressurizer high water level trip

This trip is provided as a backup to the high pressurizer pressure trip and serves to prevent water relief through the pressurizer safety valves. This trip is blocked below P-7 to permit startup. The coincidence logic and interlocks of pressurizer high water level signals are given in Table 7.2-1.

The trip logic for this function is shown on Figure 7.2-1, Sheet 6.

4. Reactor Coolant System Low Flow Trips

These trips protect the core from DNB in the event of a loss of coolant flow situation. Figure 7.2-1, Sheet 5 shows the logic for these trips. The means of sensing the loss of coolant flow are as follows:

a. Low reactor coolant flow

The parameter sensed is reactor coolant flow. Four (4) elbow taps in each coolant loop are used as a flow device that indicates the status of reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow has occurred. An output signal from 2 out of the 3 bistables in a loop would indicate a low flow in that loop.

The coincidence logic and interlocks are given in Table 7.2-1.

b. Reactor coolant pump undervoltage trip

This trip is required in order to protect against low flow which can result from loss of voltage to more than 1 reactor coolant pump motor (e.g., from loss of offsite power or reactor coolant pump breakers opening).

There are 3 undervoltage sensing relays connected for each pump (1 for each phase) at the motor side of each reactor coolant pump breaker. These relays provide an output signal when the pump voltage goes below approximately 70% of rated voltage. Signals from these relays are time delayed to prevent spurious trips caused by short term voltage perturbations. The coincidence logic and interlocks are given in Table 7.2-1.

c. Reactor coolant pump underfrequency trip

This trip protects against low flow resulting from pump underfrequency, for example a major power grid frequency disturbance. The function of this trip is to trip the reactor for an underfrequency condition greater than 2.5 Hz. The setpoint of the underfrequency relays is adjustable between 54.00 and 60.98 Hz (nominal).

There is 1 underfrequency sensing relay for each reactor coolant pump motor. Signals from relays for any 2 of the pump motors (time delayed up to approximately 0.1 seconds to prevent spurious trips caused by short term frequency perturbations) will trip the reactor if the power level is above P-7.

5. Steam Generator Trips

The specific trip functions generated are as follows:

a. Low feedwater flow trip

This trip protects the reactor from a sudden loss of heat sink. The trip is actuated by steam/feedwater flow mismatch (1 out of 2) in coincidence with low water level (1 out of 2) in any steam generator.

Figure 7.2-1, Sheet 7, shows the logic for this trip function.

There are no interlocks associated with this trip.

b. Low-Low steam generator water level trip

This trip protects the reactor from loss of heat sink in the event of a sustained steam/feedwater flow mismatch of insufficient magnitude to cause a low feedwater flow reactor trip. This trip is actuated on 2 out of 3 low-low water level signals occurring in any steam generator.

The logic is shown on Figure 7.2-1, Sheet 7.

6. Reactor Trip on a Turbine Trip (anticipatory)

The reactor trip on a turbine trip is actuated by 2 out of 3 logic from trip fluid pressure signals or by all closed signals from the turbine steam stop valves. A turbine trip causes a direct reactor trip above P-9. The reactor trip on turbine trip provides additional protection and conservatism beyond that required for the health and safety of the public. This trip is included as part of good engineering practice and prudent design. No credit is taken in any of the safety analyses (Chapter 15) for this trip.

The turbine provides anticipatory trips to the reactor protection system from contacts which change position when the turbine stop valves close or when the turbine emergency trip fluid pressure goes below its setpoint.

One of the design bases considered in the protection system is the possibility of an earthquake. With respect to these contacts, their functioning is unrelated to a seismic event in that they are anticipatory to other diverse parameters which cause reactor trip. The contacts are shut during plant operation and open to cause reactor trip when the turbine is tripped. No power is provided to the protection system from the contacts; they merely serve to interrupt power to cause reactor trip. This design functions in a de-energize-to-trip fashion to cause a plant trip if power is interrupted in the trip circuitry. This ensures that the protection system will in no way be degraded by this anticipatory trip because seismic design considerations do not form part of the design bases for anticipatory trip sensors. (The reactor protection system cabinets which receive the inputs from the anticipatory trip sensors are, of course, seismically qualified as discussed in Section 3.10.) The anticipatory trips thus meet IEEE Standard 279-1971, including redundancy, single failure, etc.

Prior to spring 2011 (RF-19), variations in the separation criteria (which still met the intent of IEEE 279 per previous FSAR discussion) existed with the turbine stop valve limit switches and the turbine electro-hydraulic control cabinet (EHC). This previously justified plant design configuration was eliminated by the digital EHC upgrade during RF-19, based upon the following:

- Turbine stop valve limit switches are now independent from non-safety EHC valve position sensors, safety-related limit switch cabling from each stop valve terminal box is separated from non-safety position sensor cabling, and safety related limit switch wiring is separated (from non-safety EHC position sensors) to the extent practical due to space limitations within each stop valve terminal box.
- Train-oriented reactor protection system reactor trip output signal contacts wired as EHC (turbine trip system) system inputs are isolated in train-oriented reactor protection system cabinets, prior to being routed in a common raceway system immediately upstream of the EHC cabinet. (It should be further noted that this circuit application differs as the exact opposite purpose of the subject of this subsection; i.e., reactor trip signal to turbine trip system input, versus turbine trip signal to an anticipatory reactor trip function.) Therefore, there is no concern with any lack of wire separation between these two isolated reactor trip signals (either upstream or within the EHC cabinet), since MSIV closure will cause turbine shutdown, and since manual operator verification of a turbine trip subsequent to a reactor trip is always performed.

The logic for this trip is functionally shown on Figure 7.2-1, Sheet 15.

7. Safety Injection Signal Actuation Trip

A reactor trip occurs when the safety injection system is actuated. The means of actuating the safety injection system are described in Section 7.3. This trip protects the core against a loss of reactor coolant or steam.

Figure 7.2-1, Sheet 8, shows the logic for this trip.

8. Manual Trip

The manual trip consists of 2 switches with 2 outputs on each switch. One (1) output is used to actuate the train A trip breaker and the train B bypass breaker; the other output actuates the train B trip breaker and the train A bypass breaker. Operating a manual trip switch removes the voltage from the undervoltage trip coil and energizes the shunt trip coil.

There are no interlocks which can block this trip. Figure 7.2-1, Sheet 3, shows the manual trip logic. The design conforms to Regulatory Guide 1.62 as shown in Figure 7.2-3.

7.2.1.1.3 Reactor Trip System Interlocks

1. Power Escalation Permissives

The overpower protection provided by the out of core nuclear instrumentation consists of 3 discrete, but overlapping, ranges. Continuation of startup operation or power increase requires a permissive signal from the higher range instrumentation channels before the lower range level trips can be manually blocked by the operator.

A 1 of 2 intermediate range permissive signal (P-6) is required prior to source range trip blocking. Source range trips are automatically reactivated when both intermediate range channels are below the permissive (P-6) setpoint. There are 2 manual reset switches for administratively reactivating the source range trip when between the permissive P-6 and P-10 setpoints, if required. Source range trip block is always maintained when above the permissive P-10 setpoint.

The intermediate range trip and power range (low setpoint) trip can only be blocked after satisfactory operation and permissive information are obtained from 2 of 4 power range channels. Four (4) individual blocking switches are provided so that the low range power range trip and intermediate range trip can be independently blocked (1 switch for each train). These trips are automatically reactivated when any 3 of the 4 power range channels are below the permissive (P-10) setpoint, thus ensuring automatic activation to more restrictive trip protection.

The development of permissives P-6 and P-10 is shown on Figure 7.2-1, Sheet 4. All of the permissives are digital; they are derived from analog signals in the nuclear power range and intermediate range channels.

Separation of circuits is maintained throughout the system where practical. An exception is in the wiring between the turbine stop valve limit switch junction box and the valve limit switches and where external circuits terminate within the junction box. However, wiring within the junction box is separated as far as is practical.

See Table 7.2-2 for the list of protection system interlocks.

2. Blocks at Reactor Trips at Low Power

   Interlock P-7 blocks a reactor trip at lower power (below approximately 10% of full power) on a low reactor coolant flow in more than 1 loop, reactor coolant pump undervoltage, reactor coolant pump underfrequency, pressurizer low pressure, or pressurizer high water level. See Figure 7.2-1, Sheets 5 and 6 for permissive applications. The low power signal is derived from 3 out of 4 power range neutron flux signals below the setpoint in coincidence with 2 out of 2 turbine first stage pressure signals below the setpoint (low plant load). See Figure 7.2-1, Sheets 4 and 15, for the derivation of P-7.

   The P-8 interlock blocks a reactor trip when the plant is below approximately 50% of full power, on a low reactor coolant flow in any 1 loop. The block action (absence of the P-8 interlock signal) occurs when 3 out of 4 neutron flux power range signals are below the setpoint. Thus, below the P-8 setpoint, the reactor will be allowed to operate with 1 inactive loop and trip will not occur until 2 loops are indicating low flow. See Figure 7.2-1, Sheet 4, for derivation of P-8, and Sheet 5 for applicable logic.

   Interlock P-9 blocks a reactor trip following a turbine trip below 50% power. See Figure 7.2-1 Sheet 15, for the implementation of the P-9 interlock. See Figure 7.2-1, Sheet 4, for the derivation of P-9.

   See Table 7.2-2 for the list of protection system blocks.

7.2.1.1.4 Coolant Temperature Sensor Arrangement

Narrow Range Hot and Cold Leg Temperature

The hot and cold loop temperature signals are required for input to the protection and control functions are obtained using thermowell mounted RTDs installed in each reactor coolant loop.

The hot leg temperature measurement in each loop is accomplished using 3 fast response narrow range dual element RTDs mounted in thermowells. The hot leg thermowells are located within the 3 scoops previously used for the RTD bypass manifold as locations 120° apart in the cross sectional sleeve. The scoops were modified by drilling a flow hole in the top of the scoops so that water flows in through the existing holes in the leading edge of the scoop, past the RTD and out through the new drilled hole.

Due to temperatures streaming, the 3 fast response hot leg RTDs are electronically averaged to generate the hot leg temperature.

The cold leg temperature measurements in each loop are accomplished by 1 fast response narrow range dual element RTD. The existing cold leg RTD bypass penetration nozzle was modified to accept the thermowell and RTD. Temperature streaming in the cold leg is not a concern due to the mixing action of the reactor coolant pump.

7.2.1.1.5 Pressurizer Water Level Reference Leg Arrangement

The design of the pressurizer water level instrumentation employs the usual tank level arrangement using differential pressure between an upper and a lower tap on a column of water. A reference leg connected to the upper tap is kept full of water by condensation of steam at the top of the leg.

7.2.1.1.6 Analog System

The analog system consists of two instrumentation systems; the process instrumentation system and the Nuclear Instrumentation System.

Process instrumentation includes those devices (and their interconnection into systems) which measure temperature, pressure, fluid flow, fluid level as in tanks or vessels, and occasionally physiochemical parameters such as fluid conductivity or chemical concentration. Process instrumentation specifically excludes nuclear and radiation measurements. The process instrumentation includes the process measuring devices, power supplies, indicators, recorders, alarm actuating devices, controllers, signal conditioning devices, etc., which are necessary for day-to-day operation of the nuclear steam supply system as well as for monitoring the plant and providing initiation of protective functions upon approach to unsafe plant conditions.

The primary function of nuclear instrumentation is to protect the reactor by monitoring the neutron flux and generating appropriate trips and alarms for various phases of reactor operating and shutdown conditions. It also provides a secondary control function and indicates reactor status during startup and power operation. The nuclear instrumentation system uses information from 3 separate types of instrumentation channels to provide 3 discrete protection levels. Each range of instrumentation (source, intermediate, and power) provides the necessary overpower reactor trip protection required during operation in that range. The overlap of instrument ranges provides reliable continuous protection beginning with source level through the intermediate and low power level. As the reactor power increases, the overpower protection level is increased by administrative procedures after satisfactory higher range instrumentation operation is obtained. Automatic reset to more restrictive trip protection is provided when reducing power.

Various types of neutron detectors, with appropriate solid-state electronic circuitry, are used to monitor the leakage neutron flux from a completely shutdown condition to 120% of full power. The power range channels are capable of recording overpower excursions up to 200% of full power. The neutron flux covers a wide range between these extremes. Therefore, monitoring with several ranges of instrumentation is necessary. The lowest range (“source” range) covers 6 decades of leakage neutron flux. The lowest observed count rate depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. This is generally greater than 2 counts per second. The next range (“intermediate” range) covers ten plus decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The highest range of instrumentation (“power” range) covers approximately 2 decades of the total instrumentation range. This is a linear range that overlaps with the higher portion of the intermediate range.

The system described above provides control room indication and recording of signals proportional to reactor neutron flux during core loading, shutdown, startup and power operation, as well as during subsequent refueling. Startup rate indication for the source and intermediate range channels is provided at the control board. Reactor trip, rod stop, control and alarm signals are transmitted to the reactor control and protection system for automatic plant control. Equipment failures and test status information are annunciated in the control room.

See References 1 and 2 for additional background information on the process and nuclear instrumentation systems.

7.2.1.1.7 Solid-State Logic Protection System

The solid-state logic protection system takes binary inputs (voltage/no voltage) from the process and nuclear instrument channels corresponding to conditions (normal/abnormal) of plant parameters. The system combines these signals in the required logic combination and generates a trip signal (no voltage) to the undervoltage trip attachment and shunt trip auxiliary relay coils of the reactor trip circuit breakers when the necessary combination of signals occur. The system also provides annunciator, status light and computer input signals which indicate the condition of bistable input signals, partial trip and full trip functions and the status of the various blocking, permissive and actuation functions. In addition the system includes means for semi-automatic testing of the logic circuits. Refer to Reference 3 for background information.

7.2.1.1.8 Isolation Amplifiers

Westinghouse considers it advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel, as permitted by IEEE Standard 279-1971.

Analog signals derived from protection channels for nonprotective functions are obtained through isolation amplifiers located in the analog protection racks. By definition, nonprotective functions include those signals used for control, remote process indication, and computer monitoring.

7.2.1.1.9 Energy Supply and Environmental Variations

The energy supply for the reactor trip system, including the voltage and frequency variations, is described in Section 7.6 and Chapter 8. The environmental variations, throughout which the system will perform, is given in Section 3.11 and Chapter 8.

7.2.1.1.10 Setpoints

The setpoints that require trip action are given in the Technical Specifications. A detailed discussion on setpoints is found in Section 7.1.2.1.9.

7.2.1.1.11 Seismic Design

The seismic design considerations for the reactor trip system are given in Section 3.10. This design meets the requirements of Criterion 2 of the 1971 General Design Criteria (GDC).

7.2.1.2 Design Bases Information

The information given below presents the design bases information requested by Section 3 of IEEE Standard 279-1971. Functional logic diagrams are presented in Figure 7.2-1.

7.2.1.2.1 Generating Station Conditions

The following are the generating station conditions requiring reactor trip:

1. DNBR approaching the safety limit.
2. Power density (kilowatts per foot) approaching rated value for Condition II faults (see Chapter 4 for fuel design limits).
3. Reactor Coolant System overpressure creating stresses approaching the limits specified in Chapter 5.

7.2.1.2.2 Generating Station Variables

The following are the variables required to be monitored in order to provide reactor trips (see Table 7.2-1).

1. Neutron flux.
2. Reactor coolant temperature.
3. Reactor coolant system pressure (pressurizer pressure).
4. Pressurizer water level.
5. Reactor coolant flow.
6. Reactor coolant pump operational status (voltage and frequency).
7. Steam generator feedwater flow.
8. Steam generator water level.
9. Turbine generator operational status (trip fluid pressure and stop valve position).
10. Steam flow

7.2.1.2.3 Spatially Dependent Variables

The following variable is spatially dependent:

1. Reactor coolant temperature (see Section 7.3.1.2 for a discussion of this variable spatial dependence).

7.2.1.2.4 Limits, Margins and Setpoints

The parameter values that will require reactor trip are given in the Technical Specifications, and in Chapter 15, Accident Analyses. Chapter 15 proves that the setpoints used in Chapter 16 are conservative.

The setpoints for the various functions in the reactor trip system have been analytically determined such that the operational limits so prescribed will prevent fuel rod clad damage and loss of integrity of the reactor coolant system as a result of any ANS Condition II incident (anticipated malfunction). As such, during any ANS Condition II incident, the reactor trip system limits the following parameters to:

1. Minimum DNBR ≥ safety limit.
2. Maximum system pressure ≤. 2750 psia
3. Fuel rod maximum linear power for determination of protection setpoints ≤ 18.0 kW/foot

The accident analyses described in Section 15.2 demonstrate that the functional requirements as specified for the reactor trip system are adequate to meet the above considerations, even assuming, for conservatism, adverse combinations of instrument errors (refer to Table 15.1-2). A discussion of the safety limits associated with the reactor core and reactor coolant system, plus the limiting safety system setpoints, are presented in the Technical Specifications.

7.2.1.2.5 Abnormal Events

The malfunctions, accidents or other unusual events which could physically damage reactor trip system components or could cause environmental changes are as follows:

1. Earthquakes (see Chapters 2 and 3).
2. Fire (see Section 9.5).
3. Missiles (see Section 3.5).
4. Flood (see Chapters 2 and 3).
5. Wind and Tornadoes (see Section 3.3).

The reactor trip system fulfills the requirements of IEEE Standard 279-1971 to provide automatic protection and to provide initiating signals to mitigate the consequences of faulted conditions.

7.2.1.2.6 Minimum Performance Requirements

1. Reactor trip system response times

Reactor trip system response time is defined in Section 7.1. Typical maximum allowable time delays in generating the reactor trip signal are tabulated in Table 7.2-3. (See Section 7.1.2.11 for a discussion of periodic response time verification

2. Reactor trip accuracies

   Accuracy is defined in Section 7.1. Reactor trip accuracies are tabulated in Table 7.2-3. An additional discussion on accuracy is found in Table 7.1.2.1.9.

3. Protection system ranges

   Typical protection system ranges are tabulated in Table 7.2.3. Range selection for the instrumentation covers the expected range of the process variable being monitored during power operation. Limiting setpoints are at least 5% from the end of the instrument span.

7.2.1.3 Final Systems Drawings

Functional block diagrams, electrical elementaries and other drawings required to assure electrical separation and perform a safety review are provided in the safety-related drawing package as discussed in Section 1.7.

7.2.2 Analysis

7.2.2.1 Failure Mode and Effects Analyses

An analysis of the reactor trip system has been performed. Results of this study and a fault tree analysis are presented in Reference 4.

7.2.2.2 Evaluation of Design Limits

While most setpoints used in the reactor protection system are fixed, there are variable setpoints, most notably the overtemperature ΔT and overpower ΔT setpoints. All setpoints in the reactor trip system have been selected on the basis of engineering design or safety studies. The capability of the reactor trip system to prevent loss of integrity of the fuel cladding and/or Reactor Coolant System pressure boundary during Condition II and III transients is demonstrated in Chapter 15. These accident analyses are carried out using those setpoints determined from results of the engineering design studies. Setpoint limits are presented in the Technical Specifications. A discussion of the intent for each of the various reactor trips and the accident analyses (where appropriate) which utilize this trip is presented below. It should be noted that the selection trip setpoints all provide for margin before protection action is actually required to allow for uncertainties and instrument errors. The design meets the requirements of Criteria 10 and 20 of the 1971 GDC.

7.2.2.2.1 Trip Setpoint Discussion

The accident analysis shows that below the DNBR safety limit, a potential for local fuel cladding failure exists. The DNBR existing at any point in the core for a given core design can be determined as a function of the core inlet temperature, power output, operating pressure and flow. Consequently, core safety limits in terms of a DNBR equal to the safety limit for the hot channel can be developed as a function of core ΔT, T_{avg} and pressure for a specified flow as illustrated by the solid lines in Figure 15.1-1. Also shown as solid lines in Figure 15.1-1 are the loci of conditions equivalent to 118% of power as a function of ΔT and T_{avg} representing the overpower (kW/ft) limit on the fuel. The dashed lines indicate the maximum permissible setpoint (ΔT) as a function of T_{avg} and pressure for the overtemperature and overpower reactor trip. Actual setpoint constants in the equation representing the dashed lines are as given in the Technical Specifications. These values are conservative to allow for instrument errors. The design meets the requirements of Criteria 10, 15, 20, and 29 of the 1971 GDC.

DNBR is not a directly measurable quantity; however, the process variables that determine DNBR are sensed and evaluated. Small isolated changes in various process variables may not individually result in violation of a core safety limit; whereas the combined variations, over sufficient time, may cause the overpower or overtemperature safety limit to be exceeded. The design concept of the reactor trip system takes cognizance of this situation by providing reactor trips associated with individual process variables in addition to the overpower/overtemperature safety limit trips. Process variable trips prevent reactor operation whenever a change in the monitored value is such that a core or system safety limit is in danger of being exceeded should operation continue. Basically, the high pressure, low pressure and overpower/overtemperature ΔT trips provide sufficient protection for slow transients as opposed to such trips as low flow or high flux which will trip the reactor for rapid changes in flow or flux, respectively, that would result in fuel damage before actuation of the slower responding ΔT trips could be effected.

Therefore, the reactor trip system has been designed to provide protection for fuel cladding and Reactor Coolant System pressure boundary integrity where: 1) a rapid change in a single variable or factor which will quickly result in exceeding a core or a system safety limit, and 2) a slow change in 1 or more variables will have an integrated effect which will cause safety limits to be exceeded. Overall, the reactor trip system offers diverse and comprehensive protection against fuel cladding failure and/or loss of reactor coolant system integrity for Condition II and III accidents. This is demonstrated by Table 7.2-4 which lists the various trips of the reactor trip system, the corresponding Technical Specification on safety limits and safety system settings and the appropriate accident discussed in the safety analyses in which the trip could be utilized.

The design meets the requirements of Criterion 21 of the 1971 GDC.

Preoperational testing is performed on reactor trip system components and systems to determine equipment readiness for startup. This testing serves as a further evaluation of the system design.

Analyses of the results of Condition I, II, III, and IV events, including considerations of instrumentation installed to mitigate their consequences are presented in Chapter 15. The

instrumentation installed to mitigate the consequences of load rejection and turbine trip is given in Section 7.4.

7.2.2.2.2 Reactor Coolant Flow Measurement

The elbow taps used on each loop in the primary coolant system are instrument devices that indicate the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow has occurred. The correlation between flow and elbow tap signal is given by the following equation:

$$\frac{\Delta P}{\Delta P_O} = \left(\frac{W}{W_O} \right)^2$$

where ΔP_0 is the pressure differential at the reference flow, w_0, and ΔP is the pressure differential at the corresponding flow, w. The full flow reference point is established during initial plant startup. The low flow trip point is then established by extrapolating along the correlation curve. The expected absolute accuracy of the channel is within ± 10% of full flow and field results have shown the repeatability of the trip point to be within ± 1%.

7.2.2.2.3 Evaluation of Compliance to Applicable Codes and Standards

The reactor trip system meets the criteria of the General Design Criteria as indicated. The reactor trip system meets the requirements of Section 4 of IEEE Standard 279-1971 as indicated below.

7.2.2.2.3.1 General Functional Requirement

The protection system automatically initiates appropriate protective action whenever a condition monitored by the system reaches a preset level. Functional performance requirements are given in Section 7.2.1.1.1. Section 7.2.1.2.4 presents a discussion of limits, margins and setpoints; Section 7.2.1.2.5 discusses unusual (abnormal) events; and Section 7.2.1.2.6 presents minimum performance requirements.

7.2.2.2.3.2 Single Failure Criterion

The protection system is designed to provide 2, 3, or 4 instrumentation channels for each protective function and 2 logic train circuits. These redundant channels and trainsare electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required. Loss of input power to a channel or logic train will result in a signal calling for a trip. This design meets the requirements of Criterion 23 of the 1971 GDC.

To prevent the occurrence of common mode failures, such additional measures as functional diversity, physical separation, and testing as well as administrative control during design,

production, installation and operation are employed. The design meets the requirements of Criteria 21 and 22 of the 1971 GDC.

7.2.2.2.3.3 Quality of Components and Modules

For a discussion on the quality of the components and modules used in the reactor trip system, refer to Chapter 17. The quality assurance applied conforms to Criterion 1 of the 1971 GDC.

7.2.2.2.3.4 Equipment Qualification

For a discussion of the type tests made to verify the performance requirements, refer to Section 3.11. The test results demonstrate that the design meets the requirements of Criterion 4 of the 1971 GDC.

7.2.2.2.3.5 Channel Integrity

Protection system channels required to operate in accident conditions maintain necessary functional capability under extremes of conditions relating to environment, energy supply, malfunctions, and accidents. The energy supply for the reactor trip system is described in Section 7.6 and Chapter 8. The environmental variations, throughout which the system will perform is given in Section 3.11.

7.2.2.2.3.6 Independence

Channel independence is carried throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs and containment penetrations for each redundant channel. Redundant analog equipment is separated by locating modules in different protection cabinets. Each redundant protection channel set is energized from a separate a-c power feed. This design meets the requirements of Criterion 21 of the 1971 GDC.

Two (2) reactor trip breakers are actuated by 2 separate logic matrices which interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all full length control rod drive mechanisms, permitting the rods to free fall into the core (see Figure 7.1-1).

The design philosophy is to make maximum use of a wide variety of measurements. The protection system continuously monitors numerous diverse system variables. Generally, 2 or more diverse protection functions would terminate an accident before intolerable consequences could occur. This design meets the requirements of Criterion 22 of the 1971 GDC.

7.2.2.2.3.7 Control and Protection System Interaction

The protection system is designed to be independent of the control system. In certain applications the control signals and other nonprotective functions are derived from individual protective

channels through isolation amplifiers. The isolation amplifiers are classified as part of the protection system and are located in the analog protective racks. Nonprotective functions include those signals used for control, remote process indication, and computer monitoring. The isolation amplifiers are designed such that a short circuit, open circuit, or the application of credible fault voltages from within the cabinets on the isolated output portion of the circuit (i.e., the nonprotective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation amplifiers are never returned to the protective racks. This design meets the requirements of Criterion 24 of the 1971 GDC and paragraph 4.7 of IEEE Standard 279-1971.

Moreover, Westinghouse programs in the period of late 1973 to mid 1976 have demonstrated by tests that credible faults or interference on cables associated with protection system racks cannot degrade system performance. The nuclear instrumentation and solid state protection systems tests are reported in the “Westinghouse Protection System Noise Tests” which were accepted by the NRC in support of the Diablo Canyon Application (Docket Numbers 50-275 and 50-323). The tests on the 7300 Series Process Control System are reported in Reference 5, a topical report accepted by the NRC.

In the Virgil C. Summer Nuclear Station, cables leaving the protection system racks are not routed with cables carrying potentials greater than those to which the systems were subjected in the Westinghouse test programs. Consequently these test programs are applicable to the Virgil C. Summer Nuclear Station and demonstrate that protection system performance cannot be degraded even if subjected to abnormal electrical conditions which far exceed those which can be reasonably postulated.

The results of applying various malfunction conditions on the output portion of the isolation amplifiers show that no significant disturbance to the isolation amplifier input signal occurred.

7.2.2.2.3.8 Derivation of System Inputs

To the extent feasible and practical, protection system inputs are derived from signals which are direct measures of the desired variables. Variables monitored for the various reactor trips are listed in Section 7.2.1.2.2.

7.2.2.2.3.9 Capability for Sensor Checks

The operational availability of each system input sensor during reactor operation is accomplished by cross checking between channels that bear a known relationship to each other and that have readouts available. Channel checks are discussed in Technical Specification 3/4.3 and Table 4.3-1 of the Technical Specifications.

7.2.2.2.3.10 Capability for Testing

The reactor trip system is capable of being tested during power operation. Where only parts of the system are tested at any one time, the testing sequence provides the necessary overlap between the parts to assure complete system operation. The testing capabilities are in conformance with Regulatory Guide 1.22 as discussed in Section 7.1.2.5.

The protection system is designed to permit periodic testing of the analog channel portion of the reactor trip system during reactor power operation without initiating a protective action unless a trip condition actually exists. This is because of the coincidence logic required for the reactor trip. These tests may be performed at any plant power from cold shutdown to full power. Before starting any of these tests with the plant at power, all redundant reactor trip channels associated with the function to be tested must be in the normal (unstripped) mode in order to avoid spurious trips. Setpoints are referenced in the precautions, limitations and setpoints portion of the plant technical manual.

1. Analog Channel Tests

   Analog channel testing is performed at the analog instrumentation rack set by individually introducing dummy input signals into the instrumentation channels and observing the tripping of the appropriate output bistables. Process analog output to the logic circuitry is interrupted during individual channel test by a test switch which, when thrown, de-energizes the associated logic input and inserts a proving lamp in the bistable output. Interruption of the bistable output to the logic circuitry for any cause (test, maintenance purposes, or removed from service) will cause that portion of the logic to be actuated (partial trip) accompanied by a partial trip alarm and channel status light actuation in the control room. Each channel contains those switches, test points, etc. necessary to test the channel. See Reference 1 for additional background information.

   The following periodic tests of the analog channels of the protection circuits are performed:

   a. T_{avg} and ΔT protection channel testing.
   b. Pressurizer pressure protection channel testing.
   c. Pressurizer water level protection channel testing.
   d. Steam/feedwater flow protection channel testing.
   e. Steam generator water level protection channel testing.
   f. Reactor coolant low flow, underfrequency, and undervoltage protection channels.
   g. Turbine first stage pressure channel testing.

2. Nuclear Instrumentation Channel Tests

The power range channels of the Nuclear Instrumentation System are tested by superimposing a test signal on the actual detector signal being received by the channel at the time of testing. The output of the bistable is not placed in a tripped condition prior to testing. Also, since the power range channel logic is 2 out of 4, bypass of this reactor trip function is not required.

To test a power range channel, a "TEST-OPERATE" switch is provided to require deliberate operator action and operation of which will initiate the "CHANNEL TEST" annunciator in the control room. Bistable operation is tested by increasing the test signal to its trip setpoint and verifying bistable relay operation by control board annunciator and trip status lights.

It should be noted that a valid trip signal would cause the channel under test to trip at a lower actual reactor power level. A reactor trip would occur when a second bistable trips. No provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the Nuclear Instrumentation System detector.

A Nuclear Instrumentation System channel which can cause a reactor trip through 1 of 2 protection logic (source or intermediate range) is provided with a bypass function which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing test. These bypasses are annunciated in the control room.

The following periodic tests of the Nuclear Instrumentation System are performed:

a. Testing at plant shutdown

   (1) Source range testing.

   (2) Intermediate range testing.

   (3) Power range testing.

b. Testing below P-6 permissive power level

   (1) Source range testing.

c. Testing below P-10 permissive power level

   (1) Intermediate range testing.

   (2) Power range, low setpoint testing.

d. Testing above P-10 permissive power level

   (1) Power range testing.

Any deviations noted during the performance of these tests are investigated and corrected in accordance with the established calibration and troubleshooting procedures provided in the plant technical manual for the Nuclear Instrumentation System. Control and protection trip settings are indicated in the plant technical manual under precautions, limitations, and setpoints.

For additional background information on the Nuclear Instrumentation System see Reference 2.

3. Solid-State Logic Testing

The reactor logic trains of the reactor trip system are designed to be capable of complete testing at power. After the individual channel analog testing is complete, the logic matrices are tested from the train A and train B logic rack test panels. This step provides overlap between the analog and logic portions of the test program. During this test, all of the logic inputs are actuated automatically in all combinations of trip and nontrip logic. Trip logic is not maintained sufficiently long enough to permit opening of the reactor trip breakers. The reactor trip undervoltage coils are "pulsed" in order to check continuity. During logic testing of 1 train, the other train can initiate any required protective functions. Annunciation is provided in the control room to indicate when a train is in test (train output bypassed) and when a reactor trip breaker is bypassed. Logic testing can be performed in less than 30 minutes.

A direct reactor trip resulting from undervoltage or underfrequency on the reactor coolant pump buses is provided as discussed in Section 7.2.1 and shown on Figure 7.2-1. The logic for these trips is capable of being tested during power operation. When parts of the trip are being tested, the sequence is such that an overlap is provided between parts so that a complete logic test is provided. Thus complete testing of Westinghouse equipment is possible.

This design complies with the testing requirements of IEEE Standard 279-1971 and IEEE Standard 338-1971 discussed in Section 7.1.2.11.

The permissive and block interlocks associated with the reactor trip system and engineered safety features actuation system are given on Tables 7.2-2 and 7.3-3 and designated protection or "P" interlocks. As a part of the protection system, these interlocks are designed to meet the testing requirements of IEEE Standards 279-1971 and 338-1971.

Testing of all protection system interlocks is provided by the logic testing and semi-automatic testing capabilities of the solid-state protection system. In the solid-state protection system the undervoltage trip attachment and shunt trip auxiliary relay coils (reactor trip) and master relays (engineered safeguards actuation) are pulsed for all combinations of trip or actuation logic with and without the interlock signals. For example, reactor trip on low flow (2 out of 3 loops showing 2 out of 3 low flow) is tested to verify operability of the trip above P-7 and nontrip below P-7 (see Figure 7.2-1, Sheet 5). Interlock testing may be performed at power.

Testing of the logic trains of the reactor trip system includes a check of the input relays and a logic matrix check. The following sequence is used to test the system:

a. Check of input relays

During testing of the process instrumentation system and Nuclear Instrumentation System channels, each channel bistable is placed in a trip mode causing one input relay in train A and one in train B to de-energize. A contact of each relay is connected to a universal logic printed circuit card. This card performs both the reactor trip and monitoring functions. Reactor trip inputs cause status lamps and annunciators on the control board to operate as shown in Figure 7.2-1. Either the Train A or Train B input relay operation will light the status lamp and annunciator.

Each train contains a multiplexing test switch. At the start of a process or Nuclear Instrumentation System test, this switch (in either train) is placed in the A + B position. The A + B position alternately allows information to be transmitted from the 2 trains to the control board. A steady status lamp and annunciator indicates that input relays in both trains have been de-energized. A flashing lamp means that the input relays in the 2 trains did not both de-energize. Contact inputs to the logic protection system, such as reactor coolant pump bus underfrequency relays, operate input relays which are tested by operating the remote contacts as described above and using the same type of indications as those provided for bistable input relays.

Actuation of the input relays provides the overlap between the testing of the logic protection system and the testing of those systems supplying the inputs to the logic protection system. Test indications are status lamps and annunciators on the control board. Inputs to the logic protection system are checked 1 channel at a time, leaving the other channels in service. For example, a function that trips the reactor when 2 out of 4 channels trip becomes a 1 out of 3 trip when 1 channel is placed in the trip mode. Both trains of the logic protection system remain in service during this portion of the test.

b. Check of logic matrices

Logic matrices are checked 1 train at a time. Input relays are not operated during this portion of the test. Reactor trips from the train being tested are inhibited with the use of the input error inhibit switch on the semi-automatic test panel in the train. At the completion of the logic matrix tests, one bistable in each channel of process instrumentation or nuclear instrumentation is tripped to check closure of the input error inhibit switch contacts.

The logic test scheme uses pulse techniques to check the coincidence logic. All possible trip and nontrip combinations are checked. Pulses from the tester are applied to the inputs of the universal logic card at the same terminals that connect to the input relay contacts. Thus there is an overlap between the input relay check and the logic matrix check. Pulses are fed back from the reactor trip breaker undervoltage trip attachment and shunt trip auxiliary relay coils to the tester. The pulses are of such short duration that the reactor trip breaker undervoltage coil armature cannot respond mechanically.

Test indications that are provided are an annunciator in the control room indicating that reactor trips from the train have been blocked and that the train is being tested, and green and red lamps on the semi-automatic tester to indicate a good or bad logic matrix test. Protection capability provided during this portion of the test is from the train not being tested.

The testing capability meets the requirements of Criterion 21 of the 1971 GDC.

4. Testing of Reactor Trip Breakers

Normally, reactor trip breakers 52/RTA and 52/RTB (see Figure 7.2-1, Sheet 2) are in service, and bypass breakers 52/BYA and 52/BYB are withdrawn (out of service). The following procedure describes the method used for testing the trip breakers:

a. With bypass breaker 52/BYA racked out, manually close and trip it to verify its operation.
b. Rack in and close 52/BYA. Manually trip 52/RTA through a protection system logic matrix while at the same time operating the “Auto Shunt Trip Block” pushbutton on the automatic shunt trip panel. This verifies operation of the Undervoltage Trip Attachment (UVTA) when the breaker trips. After reclosing RTA, trip it again by operation of the “Auto Shunt Trip Test” pushbutton on the automatic shunt trip panel. This is to verify tripping of the breaker through the shunt trip device.
c. Reset 52/RTA.
d. Trip and rack out 52/BYA.
e. Repeat above steps to test trip breaker 52/RTB using bypass breaker 52/BYB.

Auxiliary contacts of the bypass breakers are connected into the alarm system of their respective trains such that if either train is placed in test while the bypass breaker of the other train is closed, both reactor trip breakers and both bypass breakers will automatically trip.

Auxiliary contacts of the bypass breakers are also connected in such a way that if an attempt is made to close the bypass breaker in 1 train while the bypass breaker of the other train is already closed, both bypass breakers will automatically trip.

The train A and train B alarm systems operate separate annunciators in the control room. The 2 bypass breakers also operate an annunciator in the control room. Bypassing of a protection train with either the bypass breaker or with the test switches will result in audible and visual indications.

The complete reactor trip system is normally required to be in service. However, to permit online testing of the various protection channels or to permit continued operation in the event of a subsystem instrumentation channel failure, a Technical Specification, 3/4.3, defining the minimum number of operable channels has been formulated. This Technical Specification also defines the required restriction to operation in the event that the channel operability requirements cannot be met.

7.2.2.2.3.11 Channel Bypass or Removal from Operation

The protection system is designed to permit periodic testing of the analog channel portion of the reactor trip system during reactor power operation without initiating a protective action unless a trip condition actually exists. This is because of the coincidence logic required for reactor trip. Additional information is given in Section 7.3.2.2.5.

7.2.2.2.3.12 Operating Bypasses

Where operating requirements necessitate automatic or manual bypass of a protective function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are considered part of the protective system and are designed in accordance with the criteria of this section. Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service.

7.2.2.2.3.13 Indication of Bypasses

Bypass indication is discussed in Section 7.1.2.6 and Appendix 3A.

7.2.2.2.3.14 Access to Means for Bypassing

The design provides for administrative control of access to the means for manually bypassing channels or protective functions.

7.2.2.2.3.15 Multiple Setpoints

For monitoring neutron flux, multiple setpoints are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protective system circuits are designed to provide positive means or administrative control to assure that the more restrictive trip setpoint is used. The devices used to prevent improper use of less restrictive trip settings are considered part of the protective system and are designed in accordance with the criteria of this section.

7.2.2.2.3.16 Completion of Protective Action

The protection system is so designed that, once initiated, a protective action goes to completion. Return to normal operation requires action by the operator.

7.2.2.2.3.17 Manual Initiation

Switches are provided on the control board for manual initiation of protective action. Failure in the automatic system does not prevent the manual actuation of the protective functions. Manual actuation relies on the operation of a minimum of equipment.

7.2.2.2.3.18 Access

The design provides for administrative control of access to all setpoint adjustments, module calibration adjustments, and test points.

7.2.2.2.3.19 Identification of Protective Actions

Protective channel identification is discussed in Section 7.1.2.3. Indication is discussed in Section 7.2.2.2.3.20.

7.2.2.2.3.20 Information Read Out

The protective system provides the operator with complete information pertinent to system status and safety. All transmitted signals (flow, pressure, temperature, etc.) which can cause a reactor trip will be either indicated or recorded for every channel, including all neutron flux power range currents (top detector, bottom detector, algebraic difference and average of bottom and top detector currents).

Any reactor trip will actuate an alarm and an annunciator. Such protective actions are indicated and identified down to the channel level.

Alarms and annunciators are also used to alert the operator of deviations from normal operating conditions so that he may take appropriate corrective action to avoid a reactor trip. Actuation of any rod stop or trip of any reactor trip channel will actuate an alarm.

7.2.2.2.3.21 System Repair

The system is designed to facilitate the recognition, location, replacement, and repair of malfunctioning components or modules. Refer to the discussion in Section 7.2.2.2.3.10.

7.2.2.3 Specific Control and Protection Interactions

7.2.2.3.1 Neutron Flux

Four (4) power range neutron flux channels are provided for overpower protection. An isolated auctioneered high signal is derived by auctioneering of the 4 channels for automatic rod control. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection but will not cause control rod movement because of the auctioneer. Two (2) out of 4 overpower trip logic will ensure an overpower trip if needed even with an independent failure in another channel.

In addition, channel deviation signals in the control system will give an alarm if any neutron flux channel deviates significantly from the average of the flux signals. Also, the control system will respond only to rapid changes in indicated neutron flux; slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear power range

channel will block manual and automatic rod withdrawal. The setpoint for this rod stop is below the reactor trip setpoint.

7.2.2.3.2 Coolant Temperature

The accuracy of the resistance temperature detector temperature measurements is demonstrated during plant startup. Tests compare with each other as well as with the temperature measurements obtained from cold leg piping of each loop. The comparisons are done with the Reactor Coolant System in an isothermal condition. The linearity of the ΔT detectors as a function of plant power is also checked during plant startup as far as reactor protection is concerned. Reactor trip system setpoints are based upon percentages of the indicated ΔT at nominal full power rather than on absolute values of ΔT. This is done to account for loop differences which are inherent. Therefore, the percent ΔT scheme is relative, not absolute, and therefore provides better protective action without the expense of accuracy. For this reason, the linearity of the ΔT signals as a function of power is of importance rather than the absolute values of the ΔT. As part of the plant startup tests, the resistance temperature detector signals will be compared with the core exit thermocouple signals.

The input signals to the reactor control systems are obtained from electronically isolated protection T_{avg} and Delta-T signals, (one per loop). A Median Signal Selector (MSS) is implemented in the reactor control system, one for T_{avg} and one for Delta-T. The MSS receives three signals as input and selects the median signal for input to the appropriate control system. Any single failure (high or low) in a calculated temperature will not result in adverse control system behavior since the failed high or low temperature signal will be rejected by the MSS.

Hence, the implementation of a MSS in the reactor coolant systems in conjunction with the 2 out of 3 protection logic satisfies the requirements of IEEE 279-1971, Section 4.7, “Control and Protection System Interaction.”

In addition, channel deviation signals in the control system will give an alarm if any temperature channel deviates significantly from the median value. Automatic rod withdrawal blocks and turbine runback (power demand reduction) will also occur if any 2 of the 3 overtemperature or overpower ΔT channels indicate an adverse condition.

7.2.2.3.3 Pressurizer Pressure

The pressurizer pressure protection channel signals are used for high and low pressure protection and as inputs to the overtemperature ΔT trip protection function. Pressurizer pressure is sensed by fast response pressure transmitters. Control signals are not derived from protection channels.

A spurious high pressure signal from one control channel can cause decreasing pressure by actuation of either spray or relief valves. Protection is provided in the low pressurizer pressure reactor trip and in the logic for safety injection to ensure low pressure protection.

Overpressure protection is based upon the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power. The self-

actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2500 psia and an accumulation of 3%. Note that no credit is taken for the relief capability provided by the power operated relief valves during this surge.

In addition, operation of any 1 of the power operated relief valves can maintain pressure below the high pressure trip point for most transients. The rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available to alert the operator of the need for appropriate action.

One (1) tap on the pressurizer is shared for 1 each protection level and pressure transmitter, 2 control pressure transmitters and 1 wide range level transmitter. Redundancy is not compromised by having a shared tap since the logic for this trip is 2 out of 3. If the shared tap is plugged, the affected channels will remain static. If the impulse line bursts, the indicated pressure will drop to 0. In either case the fault is easily detectable, and the protective function remains operable.

7.2.2.3.4 Pressurizer Water Level

Three (3) pressurizer water level channels are used for reactor trip. Isolated signals from these channels are used for pressurizer water level control. A failure in the level control system could fill or empty the pressurizer at a slow rate (on the order of 30 minutes or more).

The high water level trip setpoint provides sufficient margin such that the undesirable condition of discharging liquid coolant through the safety valves is avoided. Even at full power conditions, which would produce the worst thermal expansion rates, a failure of the water level control would not lead to any liquid discharge through the safety valves. This is due to the automatic high pressurizer pressure reactor trip actuating at a pressure sufficiently below the safety valve setpoint.

For control failures which tend to empty the pressurizer, 2 out of 3 logic for safety injection action on low pressure ensures that the protection system can withstand an independent failure in another channel. In addition, ample time and alarms exist to alert the operator of the need for appropriate action.

7.2.2.3.5 Steam Generator Water Level and Feedwater Flow

The basic function of the reactor protection circuits associated with low steam generator water level and low feedwater flow is to preserve the steam generator heat sink for removal of long term residual heat. Should a complete loss of feedwater occur, the reactor would be tripped on coincidence of steam/feedwater flow mismatch and low steam generator water level or on low-low steam generator water level. In addition, redundant emergency feedwater pumps are provided to supply feedwater in order to maintain residual heat removal after trip. These reactor trips act before the steam generators are dry to reduce the required capacity and increase the starting time requirements of these emergency feedwater pumps and to minimize the thermal transient on the reactor coolant system and steam generators. Therefore, the following reactor trip circuits are provided for each steam generator to ensure that sufficient initial thermal capacity is available in the steam generator at the start of the transient:

1. A mismatch in steam and feedwater flow coincident with low steam generator water level;
2. A low-low steam generator water level regardless of steam/feedwater flowmismatch;

It is desirable to minimize thermal transients on a steam generator for credible loss of feedwater accidents. Hence, it should be noted that controller malfunctions caused by a protection system failure affect only 1 steam generator; the steam generator level signal used in the feedwater control originates separately from that used in the low feedwater reactor trip.

A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow preventing that channel from ultimately tripping. However, the mismatch between steam demand and feedwater flow produced by this spurious signal will actuate alarms to alert the operator of this situation in time for manual correction. If the condition is allowed to continue and the mismatch is not sufficient to trip the reactor, reactor trip will occur on a low-low water level signal independent of indicated feedwater flow.

A spurious low signal from the feedwater flow channel being used for control would cause an increase in feedwater flow. The mismatch between steam flow and feedwater flow produced by the spurious signal would actuate alarms to alert the operator of the situation in time for manual correction. If the condition continues, a 2 out of 3 high-high steam generator water level signal in any loop, independent of the indicated feedwater flow, will cause feedwater isolation and trip the turbine. The turbine trip will result in a subsequent reactor trip if power is above the P-9 setpoint. The high-high steam generator water level trip is an equipment protective trip preventing excessive moisture carryover which could damage the turbine blading.

In addition, the 3 element feedwater controller incorporates reset action on the level error signal, such that with expected controller settings a rapid increase or decrease in the flow signal would cause only a small change in level before the controller would compensate for the level error. A slow change in the feedwater signal would have no effect at all. A spurious low or high steam flow signal would have the same effect as high or low feedwater signal, discussed above.

A spurious high steam generator water level signal from the protection channel used for control will tend to close the feedwater valve. However, before a reactor trip would occur, 2 out of 3 channels for a steam generator would have to indicate a high water level. A spurious low steam generator water level signal will tend to open the feedwater valve. Again, before a reactor trip would occur, 2 out of 3 channels in a loop would have to indicate a low water level. Any slow drift in the water level signal will permit the operator to respond to the level alarms and take corrective action. Automatic protection is provided in case the spurious high level reduces feedwater flow sufficiently to cause low level in the steam generator. The reactor will trip either on a mismatch on steam and feedwater flow coincident with low water level or, ultimately, on low-low steam generator water level. Automatic protection is also provided in case the spurious low level signal increases feedwater flow sufficiently to cause high level in the steam generator. A turbine trip and feedwater isolation would occur on 2 out of 3 high-high steam generator water level in any loop.

7.2.2.4 Additional Postulated Accidents

Loss of plant instrument air or loss of component cooling water is discussed in Section 7.3.2. Load rejection and turbine trip are discussed in further detail in Section 7.7.

The control interlocks, called rod stops, that are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal are discussed in Section 7.7.1.4.1 and listed on Table 7.7-1. Excessively high power operation (which is prevented by blocking of automatic rod withdrawal), if allowed to continue, might lead to a safety limit (as given in the Technical Specifications) being reached. Before such a limit is reached, protection will be available from the reactor trip system. At the power levels of the rod block setpoints, safety limits have not been reached; and therefore these rod withdrawal stops do not come under the scope of safety-related systems, and are considered as control systems.

7.2.3 Tests and Inspections

The reactor trip system meets the testing requirements of IEEE Standard 338-1971 as discussed in Section 7.1.2.11. The testability of the system is discussed in Section 7.2.2.2.3. The initial test intervals are specified in the Technical Specifications. Written test procedures and documentation, conforming to the requirements of IEEE Standard 338-1971, will be available for audit by responsible personnel. Periodic testing complies with Regulatory Guide 1.22 as discussed in Sections 7.1.2.5 and 7.2.2.2.3.

7.2.4 References

1. Reid, J. B., *Process Instrumentation for Westinghouse Nuclear Steam Supply Systems,* WCAP-7913, January, 1973.
2. Lipchak, J. B., *Nuclear Instrumentation System*, WCAP-8255, January, 1974.
3. Katz, D. N., *Solid State Logic Protection System Description*, WCAP-7488-L Proprietary), March, 1971 and WCAP-7672 (Non-Proprietary), May, 1971.
4. Gangloff, W. C. and Loftus, W. D., *An Evaluation of Solid-State Logic Reactor Protection In Anticipated Transients,* WCAP-7706-L (Proprietary) and WCAP-7706 Non-Proprietary), February, 1973.
5. Siroky, R. M. and Marasco, F. W., *7300 Series Process Control System Noise Tests*, WCAP-8892A, June, 1977.

Table 7.2-1
List of Reactor Trips

	Reactor Trip	Coincidence Logic	Interlocks	Comments
1.	High neutron flux (Power Range)	2/4	Manual block of low setting permitted by P-10	High and low setting; manual block and automatic reset of low setting by P-10
2.	Intermediate range neutron flux	1/2	Manual block permitted by P-10	Manual block and automatic reset
3.	Source range neutron flux	1/2	Manual block permitted by P-6, interlocked with P-10	Manual block and automatic reset. Automatic block above P-10
4.	Power range high positive neutron flux rate	2/4	No interlocks	
5.	Overtemperature ΔT	2/3	No interlocks	
6.	Overpower ΔT	2/3	No interlocks	
7.	Pressurizer low pressure	2/3	Interlocked with P-7	Blocked below P-7
8.	Pressurizer high pressure	2/3	No interlocks	
9.	Pressurizer high water level	2/3	Interlocked with P-7	Blocked below P-7
10.	Low reactor coolant flow	a. 2/3 in 2/3 loops	Interlocked with P-7	Low flow in one loop will cause a reactor trip when above P-8 and a low flow in two loops will cause a reactor trip when above P-7; blocked below P-7
		b. 2/3 in any loop	Interlocked with P-8	

Table 7.2-1
List of Reactor Trips

	Reactor Trip	Coincidence Logic	Interlocks	Comments
11.	Reactor coolant pump undervoltage	2/3	Interlocked with P-7	
12.	Reactor coolant pump underfrequency	2/3	Interlocked with P-7	Underfrequency on 2 motors will trip all reactor coolant pump breakers and cause reactor trip; blocked below P-7
13.	Low feedwater flow	1/2 in any loop(1)	No interlocks	
14.	Low-Low Steam Generator Water Level	2/3 in any loop	No interlocks	
15.	Safety injection signal	Coincident with actuation of safety injection	No interlocks	(See Section 7.3 for engineered safety features actuation conditions)
16.	Turbine trip (anticipatory)			
	a. Trip fluid pressure	2/3	Interlocked with P-9	Blocked below P-9
	b. Turbine stop valve close	4/4	Interlocked with P-9	Blocked below P-9
17.	Manual	1/2	No interlocks	

(1) 1/2 steam/feedwater flow mismatch in coincidence with 1/2 low steam generator water level.

Table 7.2-2
Protection System Interlocks

I. POWER ESCALATION PERMISSIVES

Designation	Derivation	Function
P-6	Presence of P-6: 1/2 neutron flux (intermediate range) above setpoint	Allows manual block of source range reactor trip
	Absence of P-6: 2/2 neutron flux (intermediate range) below setpoint	Defeats the block of source range reactor trip
P-10	Presence of P-10: 2/4 neutron flux (power range) above setpoint	Allows manual block of power range (low setpoint) reactor trip
		Allows manual block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Blocks source range reactor trip (backup for P-6)
	Absence of P-10: 3/4 neutron flux (power range) below setpoint	Defeats the block of power range (low setpoint) reactor trip
		Defeats the block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Input to P-7

Table 7.2-2 (continued)
Protection System Interlocks

II. BLOCKS OF REACTOR TRIPS

Designation	Derivation	Function
P-7	Absence of P-7: 3/4 neutron flux (power range) below setpoint (from P-10)	Blocks reactor trip on: Low reactor coolant flow in more than one loop, undervoltage, underfrequency, pressurizer low pressure, and pressurizer high level
	and	
	2/2 turbine first stage pressure below setpoint (from P-13)	
P-8	Absence of P-8: 3/4 neutron flux (power range) below setpoint	Blocks reactor trip on low reactor coolant flow in a single loop
P-9	Absence of P-9: 3/4 neutron flux (power range) below setpoint	Blocks reactor trip on turbine trip
P-13	2/2 turbine first stage pressure below setpoint	Input to P-7

Table 7.2-3
Reactor Trip System Instrumentation

	Reactor Trip Signal	Range	Trip Accuracy	Time Response (sec)
1.	Power range high neutron flux	1 to 120% full power	± 1% of full power	0.5
2.	Intermediate range high neutron flux	10.2 decades of neutron flux overlapping source range by 5 decades and including 100% power	± 2.3% of full scale	0.5
3.	Source range high neutron flux	6 decades of neutron flux (1 to 10^6 counts/sec)	± 3.5% of full scale (1)	0.5
4.	Power range high positive neutron flux rate	± 15% of full	± 5% (1)	0.5
5.	Overtemperature ΔT	TH 530 to 650 °F TC 510 to 630 °F TAV 530 to 630 °F PPRZR 1700 to 2500 psig F (Δø) - 50.0 to +50% ΔT Setpoint 0 to 100 °F	± 2% ΔT span	8.5
6.	Overpower ΔT	TH 530 to 650 °F TC 510 to 630 °F TAV 530 to 630 °F ΔT Setpoint 0 to 100 °F (Δø) - 50.0 to +50% ΔT	± 2% ΔT span	8.5
7.	Pressurizer low pressure	1700 to 2500 psig	± 18 psi	1.0
8.	Pressurizer high pressure	1700 to 2500 psig	± 14 psi	1.0

Table 7.2-3 (continued)
Reactor Trip System Instrumentation

	Reactor Trip Signal	Range	Trip Accuracy	Time Response (sec)
9.	Pressurizer high water level	Entire distance between taps	± 2.25% of full range Δp between taps at design temperature and pressure	2.0
10.	Low reactor coolant flow	0 to 120% of rated flow	± 2.5% of full flow within range of 70% to 100% of full flow (1)	1.0
11.	Reactor coolant pump undervoltage	0 to 100% rated voltage	± 0.23% of rated voltage	1.5
12,	Reactor coolant pump	54.00 to 60.98 Hz (nominal) underfrequency	± 0.005 Hz	0.6
13.	Low feedwater flow (2)	0 to 120% maximum calculated feedwater flow	± 6.5% (3)	1.5
14.	Low-low steam generator water level	Total distance between narrow range steam generator level taps	± 2.25% of Δp signal over the pressure range of 700 to 1200 psig	1.5
15.	Turbine trip from low hydraulic fluid pressure	Differential pressure range 400 to 1200 psig	± 1.5% of differential pressure range	0.6

(1) Reproducibility (see definitions in Section 7.1)
(2) 1/2 steam/feedwater flow mismatch in coincidence with 1/2 low steam generator water level.
(3) Channel accuracy of feedwater flow analog signal is ± 2.5% of maximum calculated feedwater flow. Accuracy of steam flow signal is ± 3% of maximum calculated flow over the pressure range of 700 to 1200 psig.

Table 7.2-4
Reactor Trip Correlation

	TRIP[1]		ACCIDENT[2]	TECH SPEC [3]
1.	Power Range High Neutron Flux Trip (Low Setpoint)	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition (15.2.1)	2.2.1 Table 2.2-1 # 2
		2.	Excessive Heat Removal Due to Feedwater System Malfunctions (15.2.10)	
		3.	Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection) (15.4.6)	
		4.	Uncontrolled Boron Dilution (15.2.4)	
2.	Power Range High Neutron Flux Trip (High Setpoint)	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition (15.2.1)	2.2.1 Table 2.2-1 # 2
		2.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.2.2)	
		3.	Startup of an Inactive Reactor Coolant Loop (15.2.6)	
		4.	Excessive Heat Removal Due to Feedwater System Malfunctions (15.2.10)	
		5.	Excessive Load Increase Incident (15.2.11)	
		6.	Accidental Depressurization of the Main Steam System (15.2.13)	
		7.	Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection) (15.4.6)	

Table 7.2-4 (continued)
Reactor Trip Correlation

TRIP[1]		ACCIDENT[2]		TECH SPEC [3]
		8.	Uncontrolled Boron Dilution (15.2.4)	
3.	Intermediate Range High Neutron Flux Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition (15.2.1)	See Note 4 2.2.1 Table 2.2-1 # 5
4.	Source Range High Neutron Flux Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition (15.2.1)	See Note 4 2.2.1 Table 2.2-1 # 6
5.	Power Range High Positive Neutron Flux Rate Trip	1.	Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection) (15.4.6)	2.2.1 Table 2.2-1 # 3
6.	Overtemperature ΔT Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.2.2)	See Note 1 2.2.1 Table 2.2-1 # 7
		2.	Uncontrolled Boron Dilution (15.2.4)	
		3.	Loss of External Electrical Load and/or Turbine Trip (15.2.7)	
		4.	Excessive Heat Removal Due to Feedwater System Malfunctions (15.2.10)	
		5.	Excessive Load Increase Incident (15.2.11)	
		6.	Accidental Depressurization of the Reactor Coolant System (15.2.12)	
		7.	Accidental Depressurization of the Main Steam System (15.2.13)	

Table 7.2-4 (continued)
Reactor Trip Correlation

	TRIP[1]		ACCIDENT[2]	TECH SPEC [3]
7.	Overpower ΔT Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.2.2)	See Note 2 2.2.1 Table 2.2-1 # 8
		2.	Excessive Heat Removal Due to Feedwater System Malfunctions (15.2.10)	
		3.	Excessive Load Increase Incident (15.2.11)	
		4.	Accidental Depressurization of the Main Steam System (15.2.13)	
		5.	Major Secondary System Pipe Ruptures (15.4.2)	
8.	Pressurizer Low Pressure Trip	1.	Accidental Depressurization of the Reactor Coolant System (15.2.12)	2.2.1 Table 2.2-1 # 9
		2.	Loss of Reactor Coolant From Small Ruptured Pipes or From Cracks in Large Pipes Which Actuates ECCS (15.3.1)	
		3.	Major Reactor Coolant System Pipe Ruptures (LOCA) (15.4.1)	
		4.	Steam Generator Tube Rupture (15.4.3)	
		5.	Inadvertent Operation of the ECCS (15.2.14)	
9.	Pressurizer High Pressure Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.2.2)	2.2.1 Table 2.2-1 # 10
		2.	Loss of External Electrical Load and/or Turbine Trip (15.2.7)	

Table 7.2-4 (continued)
Reactor Trip Correlation

	TRIP[1]		ACCIDENT[2]	TECH SPEC [3]
10.	Pressurizer High Water Level Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank at Power (15.2.2)	2.2.1 Table 2.2-1 # 11
		2.	Loss of External Electrical Load and/or Turbine Trip (15.2.7)	
11.	Low Reactor Coolant Flow	1.	Partial Loss of Forced Reactor Coolant Flow (15.2.5)	2.2.1 Table 2.2-1 # 12
		2.	Loss of Offsite Power to the Station Auxiliaries (15.2.9)	
		3.	Complete Loss of Forced Reactor Coolant Flow (15.3.4)	
12.	Reactor Coolant Pump Undervoltage Trip	1.	Complete Loss of Forced Reactor Coolant Flow (15.3.4)	2.2.1 Table 2.2-1 # 15
13.	Reactor Coolant Pump Underfrequency Trip	1.	Complete Loss of Forced Reactor Coolant Flow (15.3.4)	2.2.1 Table 2.2-1 # 16
14.	Low Feedwater Flow Trip	1.	Loss of Normal Feedwater (15.2.8)	See Note 4 2.2.1 Table 2.2-1 # 14
		8.	Uncontrolled Boron Dilution (15.2.4)	
15.	Low-low Steam Generator Water Level Trip	1.	Loss of Normal Feedwater (15.2.8)	2.2.1 Table 2.2-1 # 13
		2.	Feedwater Line Break (15.4.2.2)	
16.	Reactor Trip on Turbine Trip	1.	Loss of External Electrical Load and/or Turbine Trip (15.2.7)	See Note 4 2.2.1 Table 2.2-1 # 17

Table 7.2-4 (continued)
Reactor Trip Correlation

TRIP[1]		ACCIDENT[2]		TECH SPEC [3]
		2.	Loss of Offsite Power to the Station Auxiliaries (15.2.9)	
		3.	Excessive Heat Removal Due to Feedwater System Malfunction (15.2.10)	
17.	Safety injection Signal Actuation Trip	1.	Accidental Depressurization of the Main Steam System (15.2.13)	See Note 5 2.2.1 Table 2.2-1 # 18
18.	Manual Trip (Chapter 15)		Available for all Accidents	See Note 4

(1) Trips are listed in order of discussion in Section 7.2
(2) References refer to accident analyses presented in Chapter 15.
(3) References refer to Virgil C. Summer Technical Specifications.
(4) A Technical Specification is not required because this trip is not assumed to function in the accident analyses.
(5) Accident assumes that the reactor is tripped at end of life (EOL) which is the worst initial condition for this case.

Figure 7.2-1

FUNCTIONAL DIAGRAMS INDEX AND SYMBOLS
(SHEET 1 OF 15)
(DWG. NO. 108D837 SH. 1)

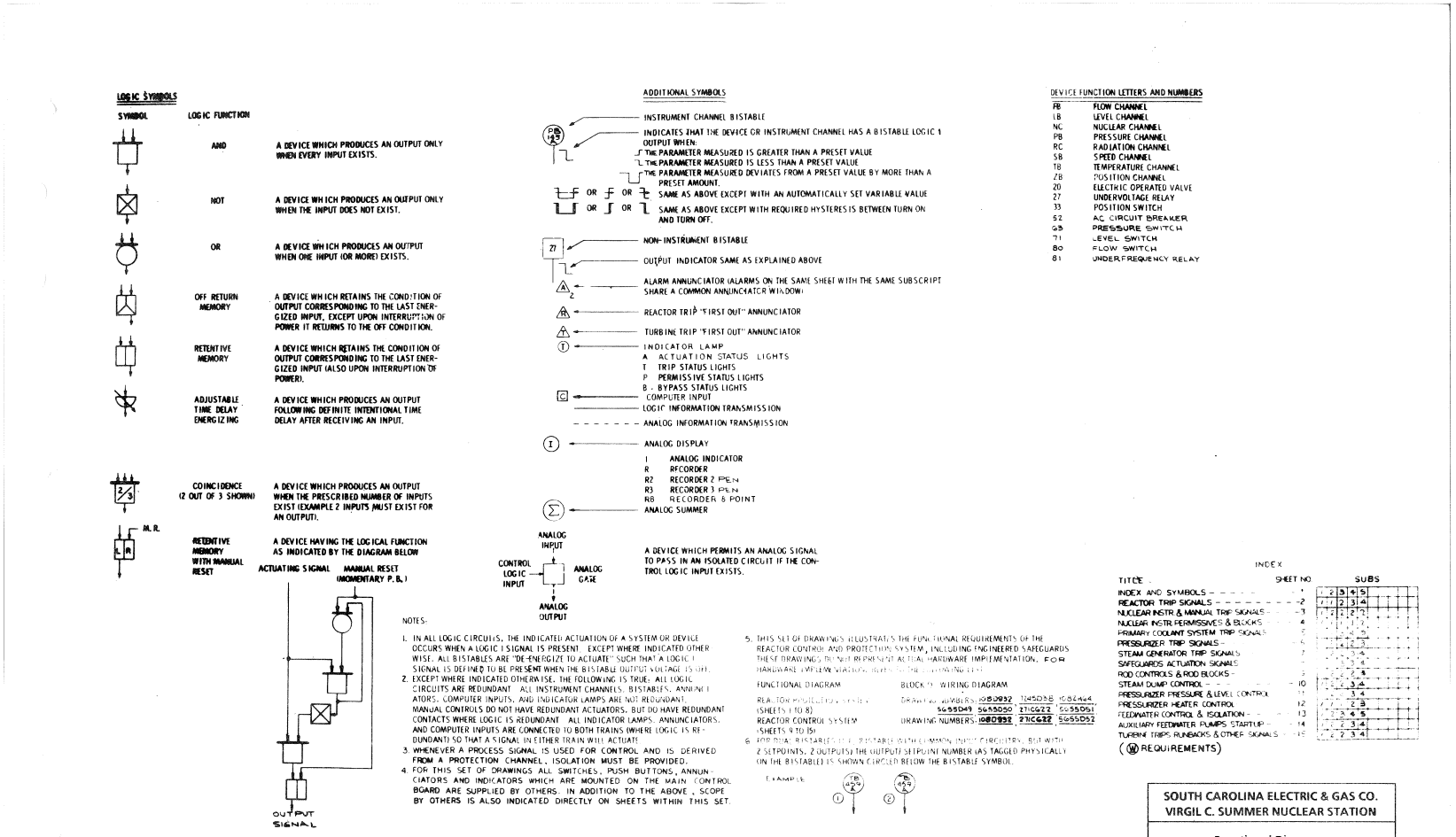
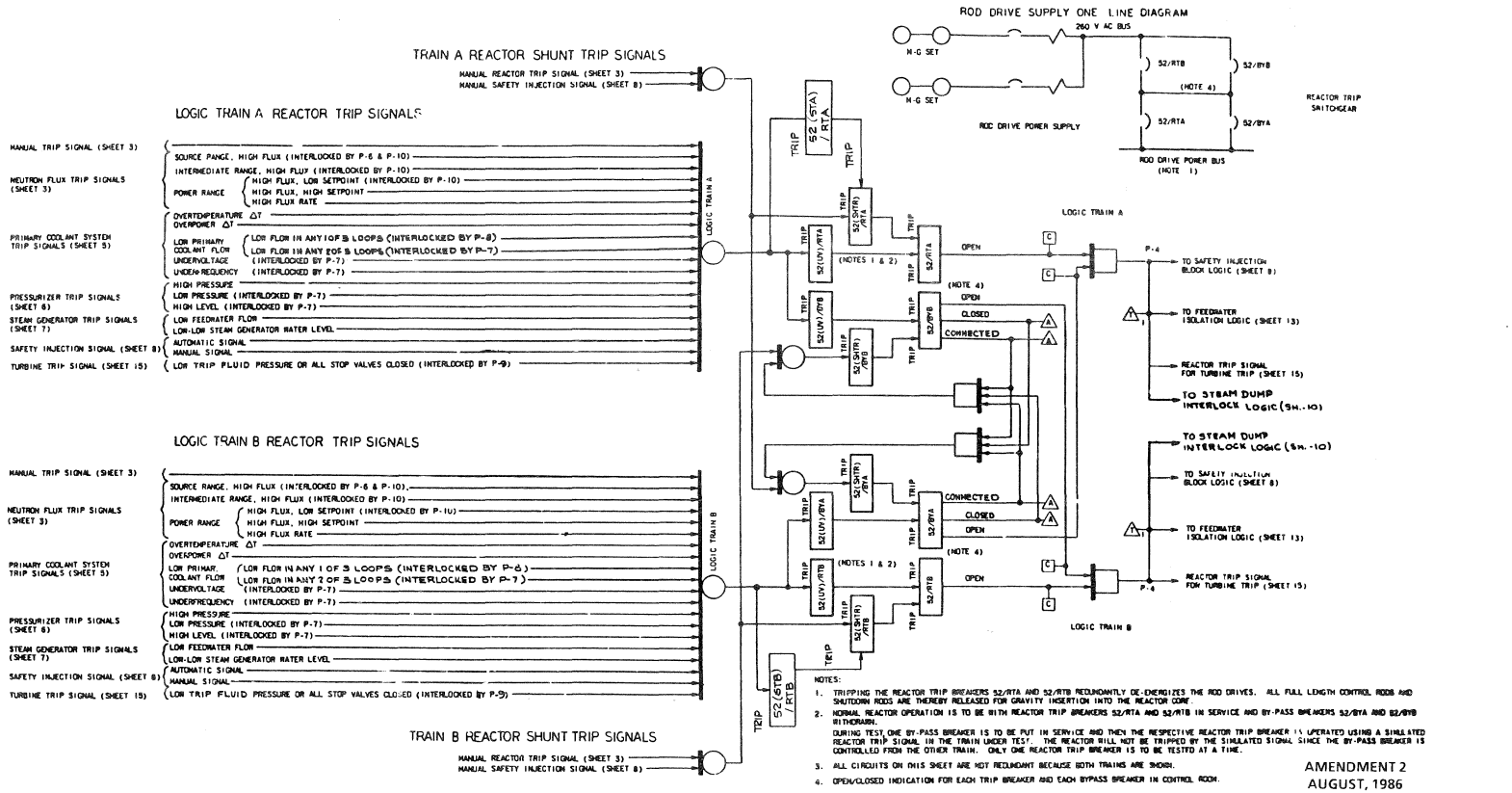


Figure 7.2-1

FUNCTIONAL DIAGRAMS REACTOR TRIP SIGNALS
(SHEET 2 OF 15)
(DWG. NO. 108D837 SH. 2)



AMENDMENT 2
AUGUST, 1986

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Functional Diagrams
Reactor Trip Signals
(Sheet 2 of 15)
(Dwg. No. 108D837, Sh. 2)
Figure 7.2-1

Figure 7.2-1

FUNCTIONAL DIAGRAMS
NUCLEAR INSTR. AND MANUAL TRIP SIGNALS
(SHEET 3 OF 15)
(DWG. NO. 108D837 SH. 3)

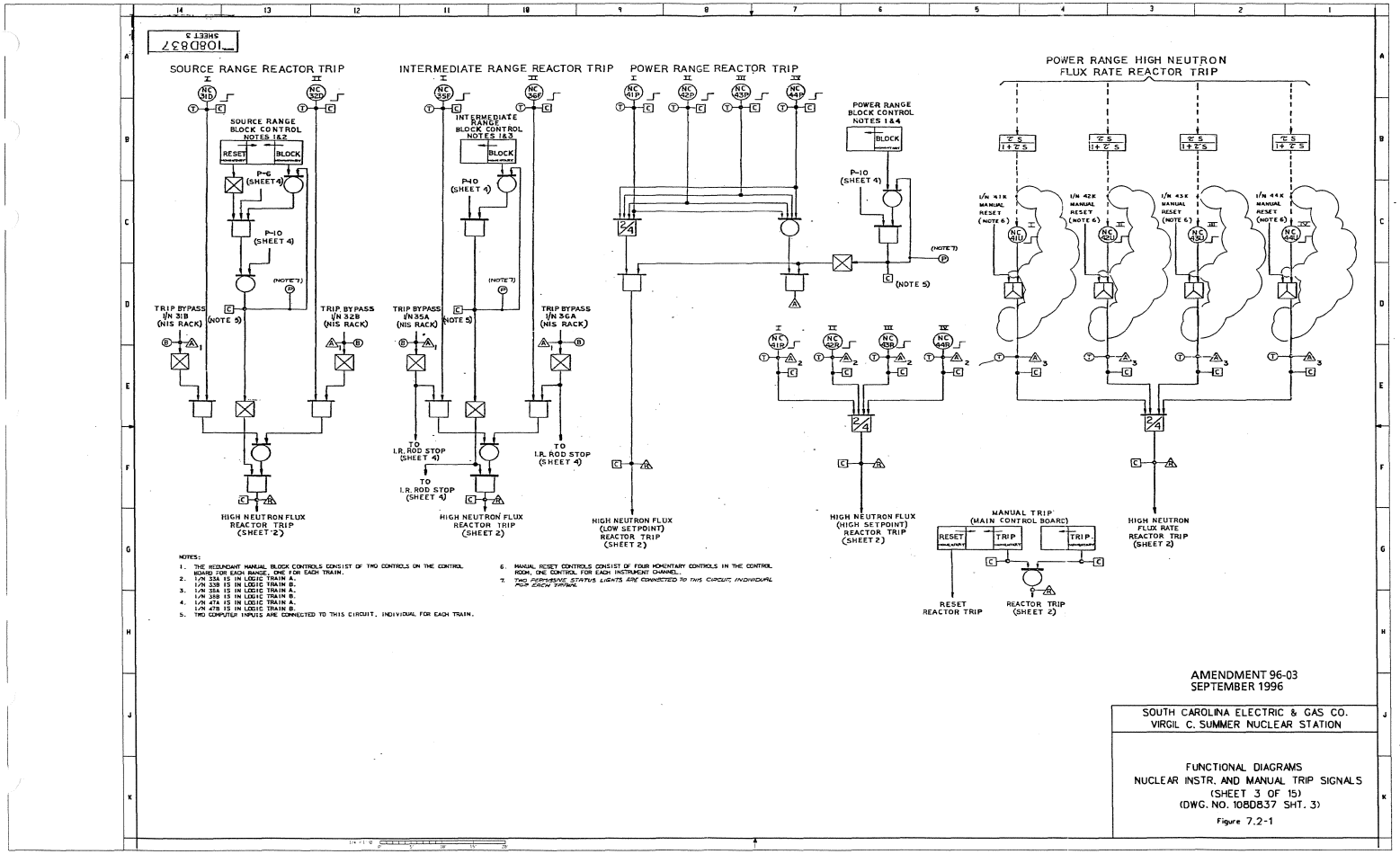
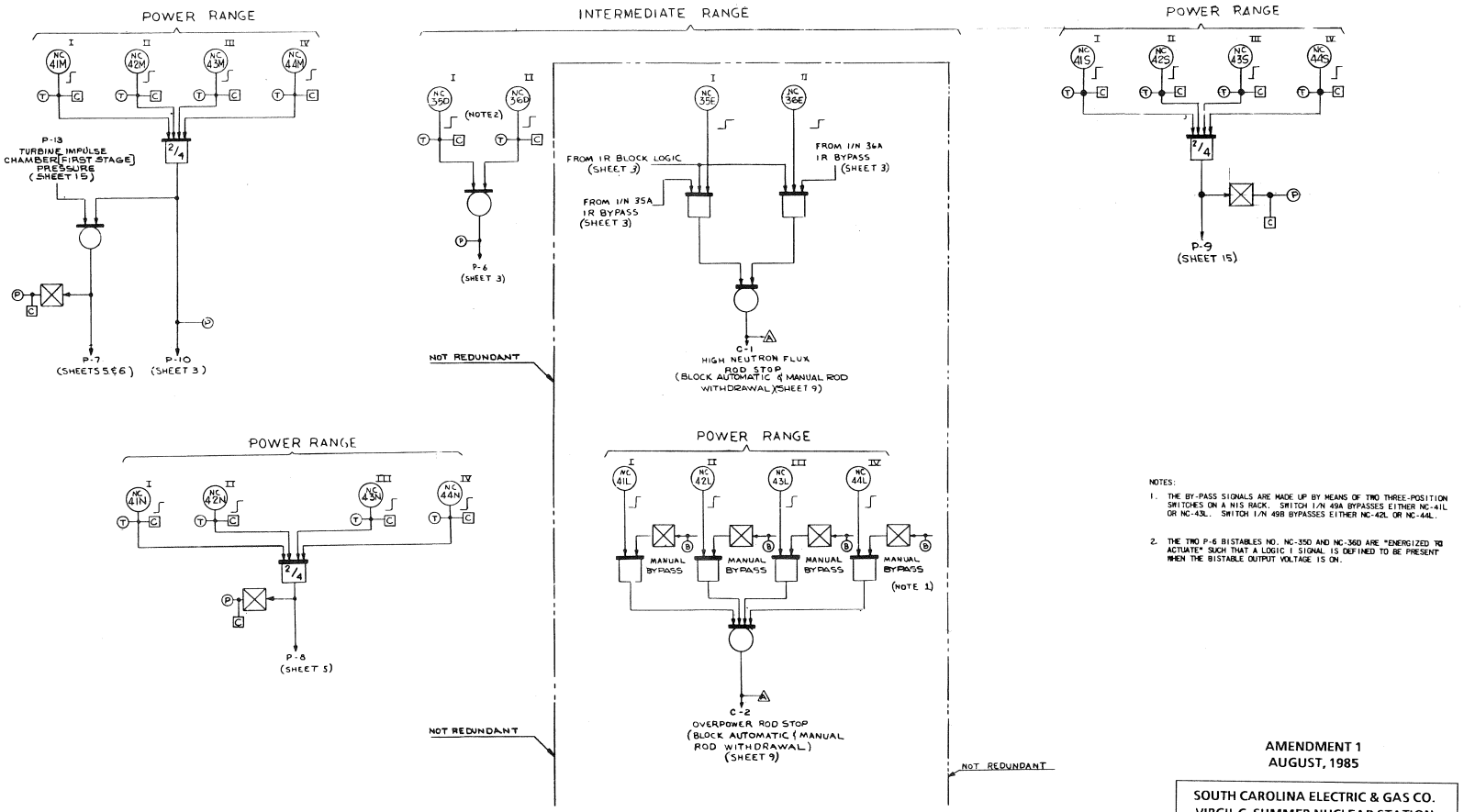


Figure 7.2-1

FUNCTIONAL DIAGRAMS
NUCLEAR INSTR. PERMISSIVE BLOCKS
(SHEET 4 OF 15)
(DWG. NO. 108D837 SH. 4)



NOTES:

1. THE BY-PASS SIGNALS ARE MADE UP BY MEANS OF TWO THREE-POSITION SWITCHES ON A NIS RACK. SWITCH I/N 49A BYPASSES EITHER NC-41L OR NC-43L. SWITCH I/N 49B BYPASSES EITHER NC-42L OR NC-44L.
2. THE TWO P-6 BISTABLES NO. NC-35D AND NC-36D ARE "ENERGIZED TO ACTUATE" SUCH THAT A LOGIC 1 SIGNAL IS DEFINED TO BE PRESENT WHEN THE BISTABLE OUTPUT VOLTAGE IS ON.

AMENDMENT 1
AUGUST, 1985

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Functional Diagrams Nuclear Instr. Permissives and Blocks (Sheet 4 of 15) (Dwg. No. 108D837, Sh. 4) Figure 7.2-1

Figure 7.2-1, Sheet 5
DRAWING 1MS-41-001
FSAR FIGURE REFERENCE

Figure 7.2-1

FUNCTIONAL DIAGRAMS
PRESSURIZER TRIP SIGNALS
(SHEET 6 OF 15)
(DWG. NO. 108D837 SH. 6

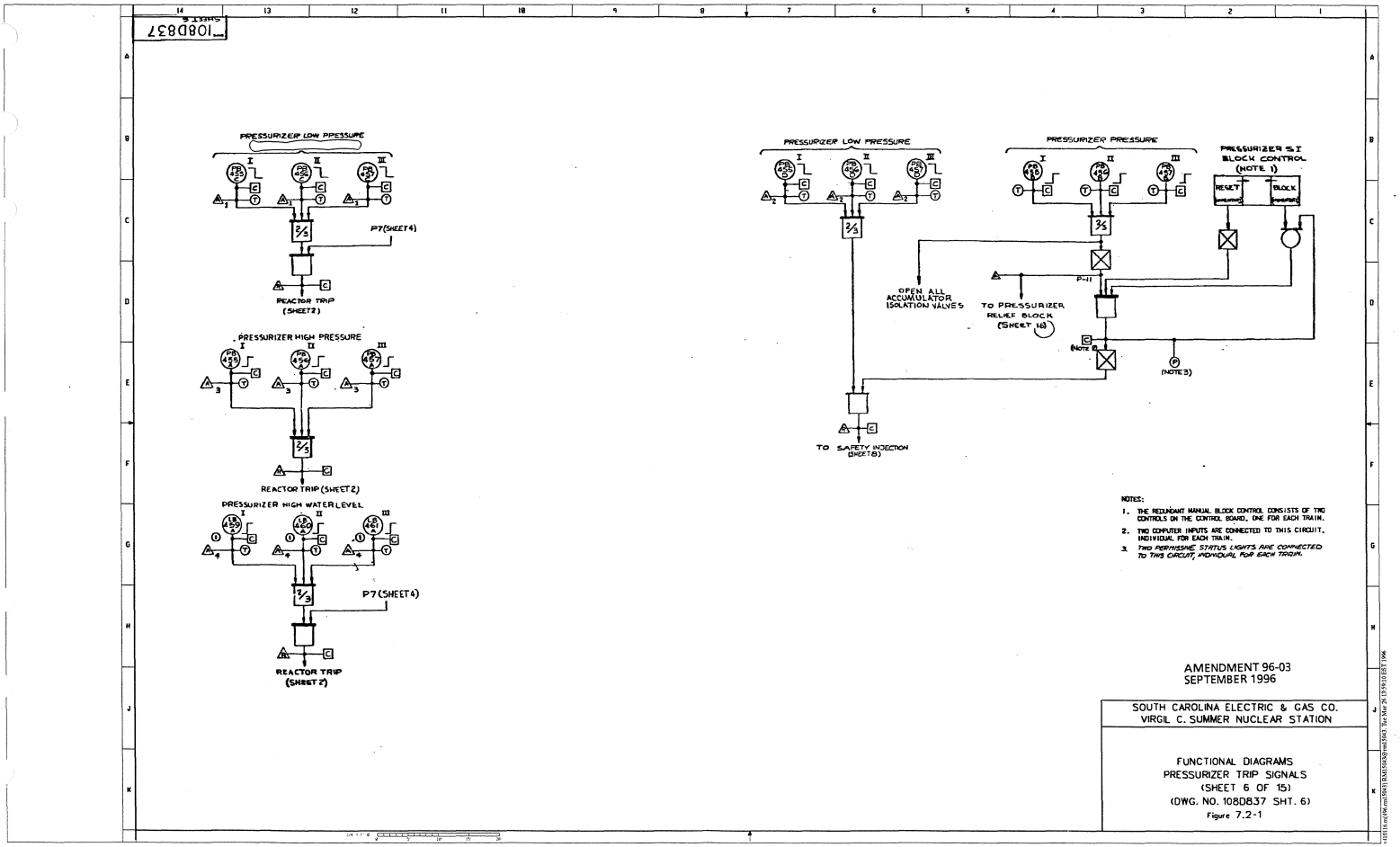
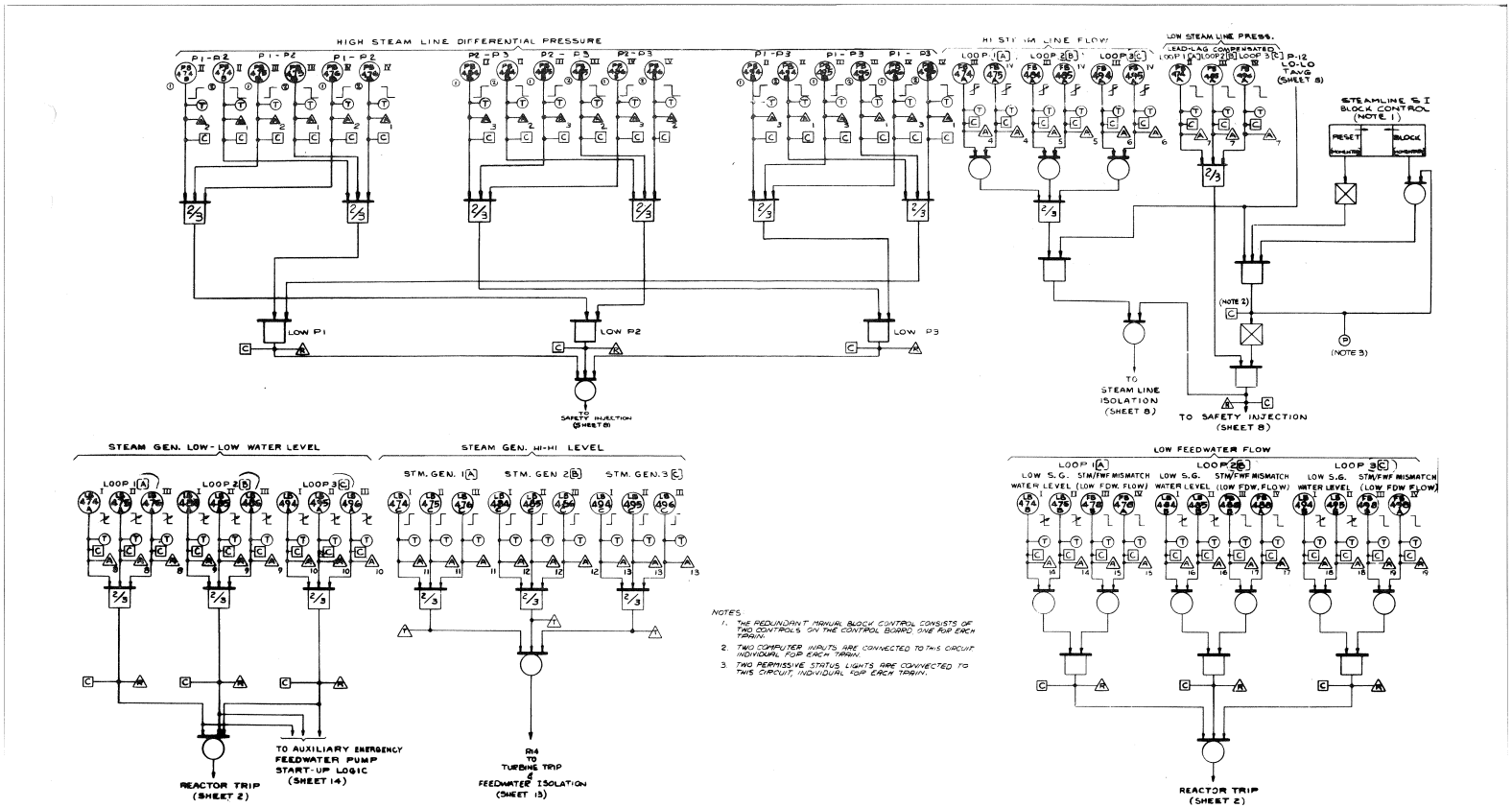


Figure 7.2-1

FUNCTIONAL DIAGRAMS
STEAM GENERATOR TRIP SIGNALS
(SHEET 7 OF 15)
(DWG. NO. 108D837 SH. 7

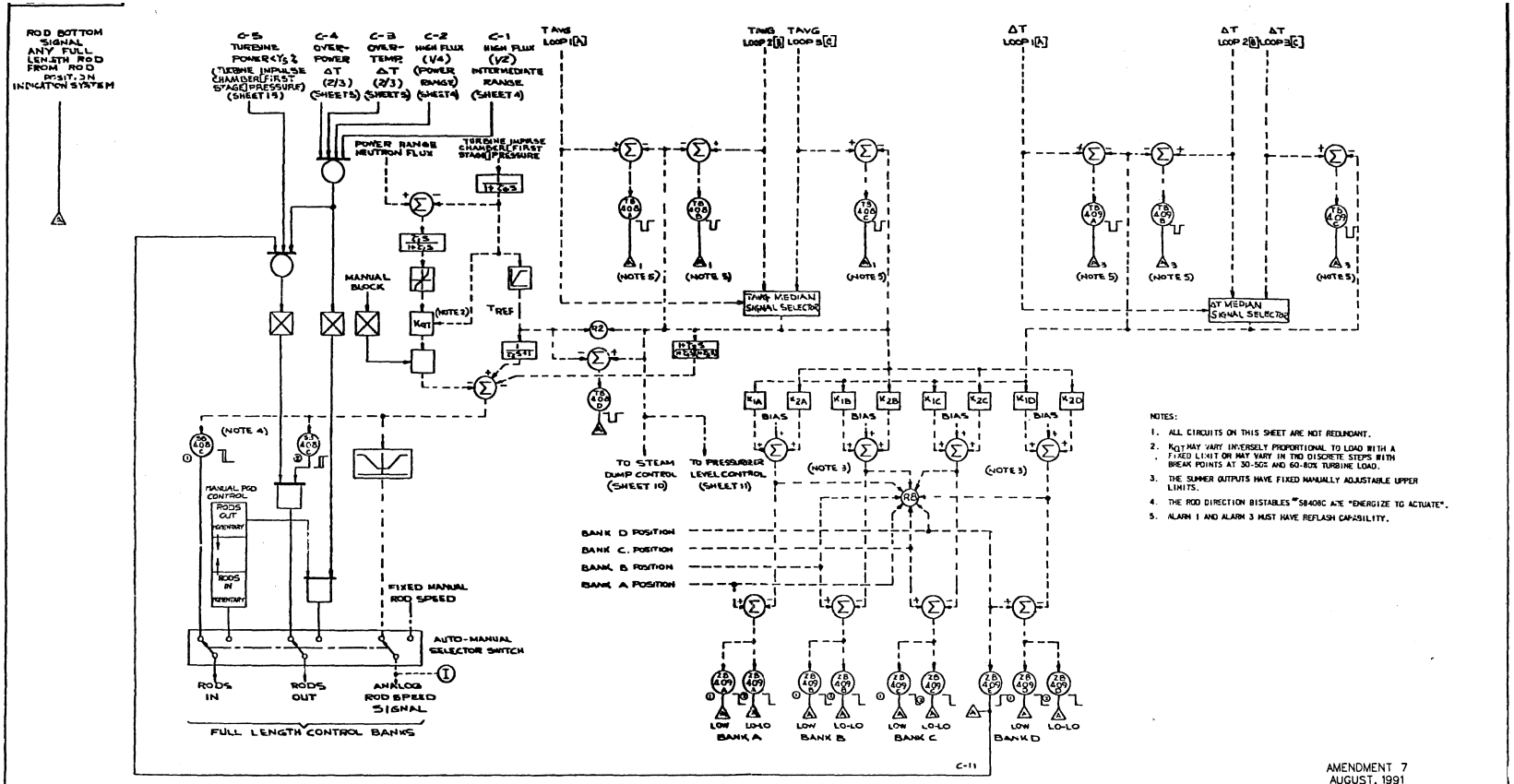


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Functional Diagrams Steam Generator Trip Signals (Sheet 7 of 15) (Dwg.No. 108D837 Sh. 7) Figure 7.2-1

Figure 7.2-1, Sheet 8
DRAWING 1MS-41-011
FSAR FIGURE REFERENCE

Figure 7.2-1

FUNCTIONAL DIAGRAMS
ROD CONTROLS AND ROD BLOCKS
(SHEET 9 OF 15)
(DWG. NO. 108D837 SH. 9



AMENDMENT 7
AUGUST, 1991

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Functional Diagrams
Rod Controls and Rod Blocks
(Sheet 9 of 15)
(Dwg. No. 108D837 Sh.9)

Figure 7.2-1

Figure 7.2-1

FUNCTIONAL DIAGRAMS
STEAM DUMP CONTROL
(SHEET 10 OF 15)
(DWG. NO. 108D837 SH. 10

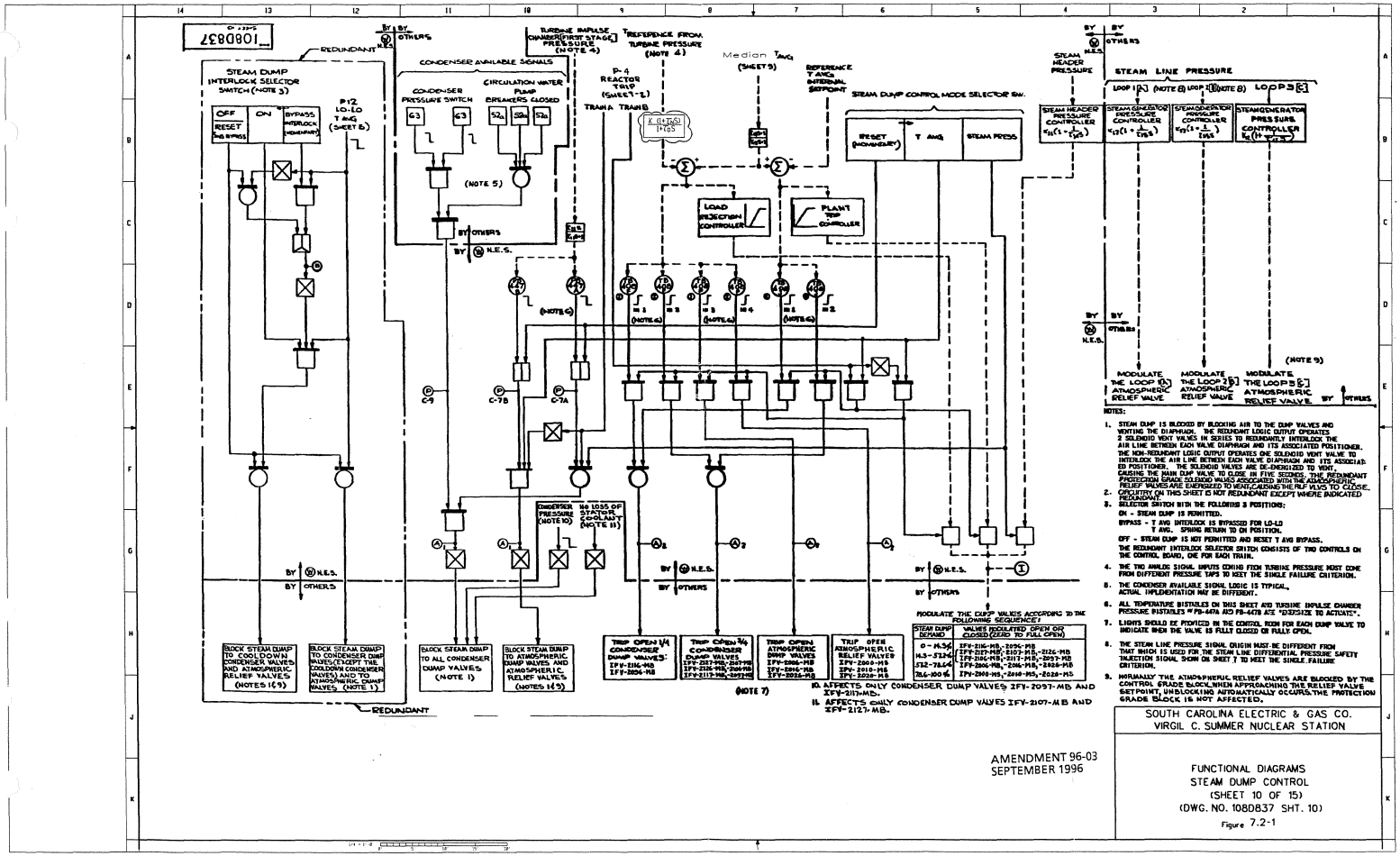


Figure 7.2-1

FUNCTIONAL DIAGRAMS
PRESSURIZER PRESSURE AND LEVEL CONTROL
(SHEET 11 OF 15)
(DWG. NO. 108D837 SH. 11

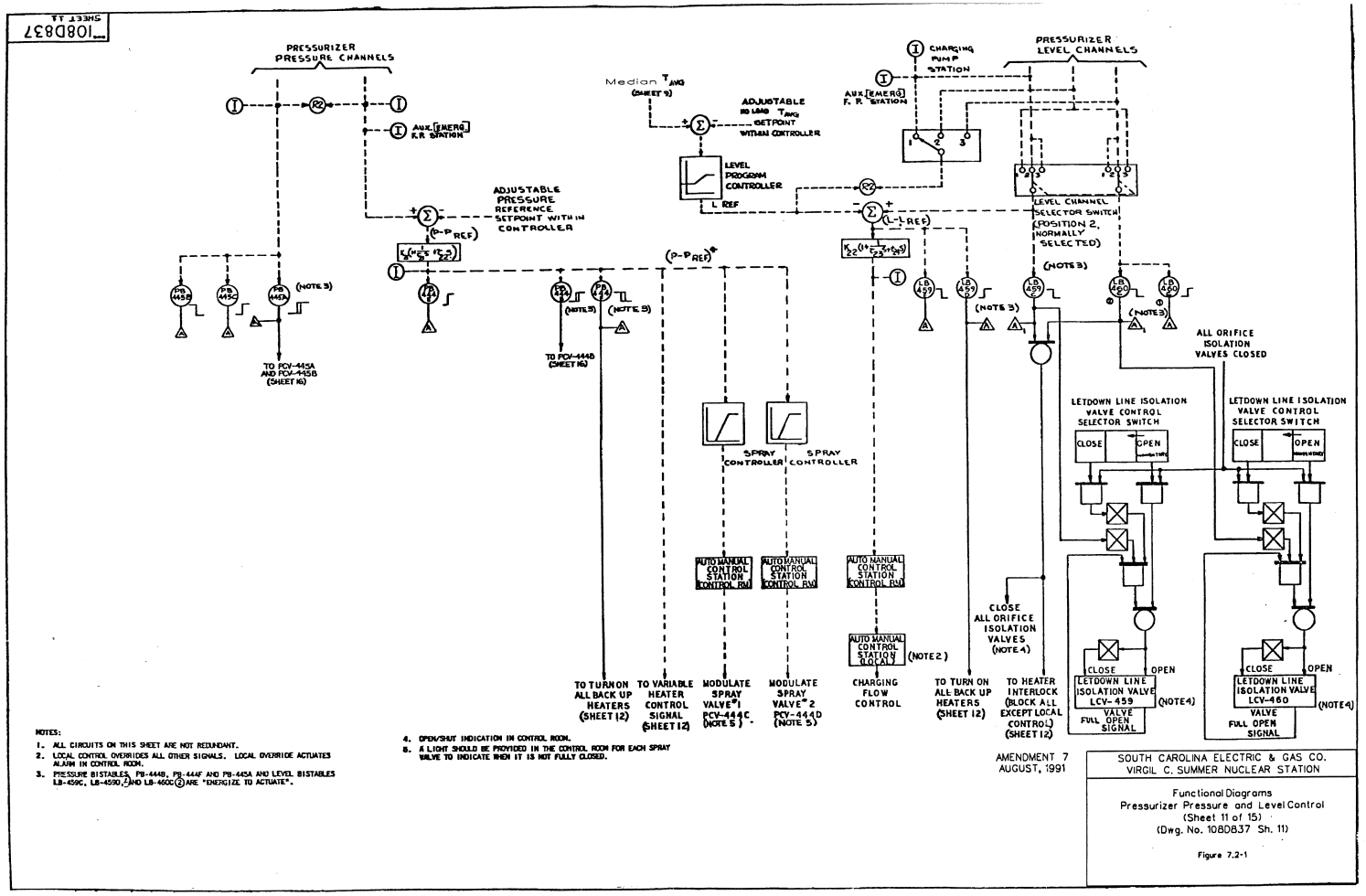
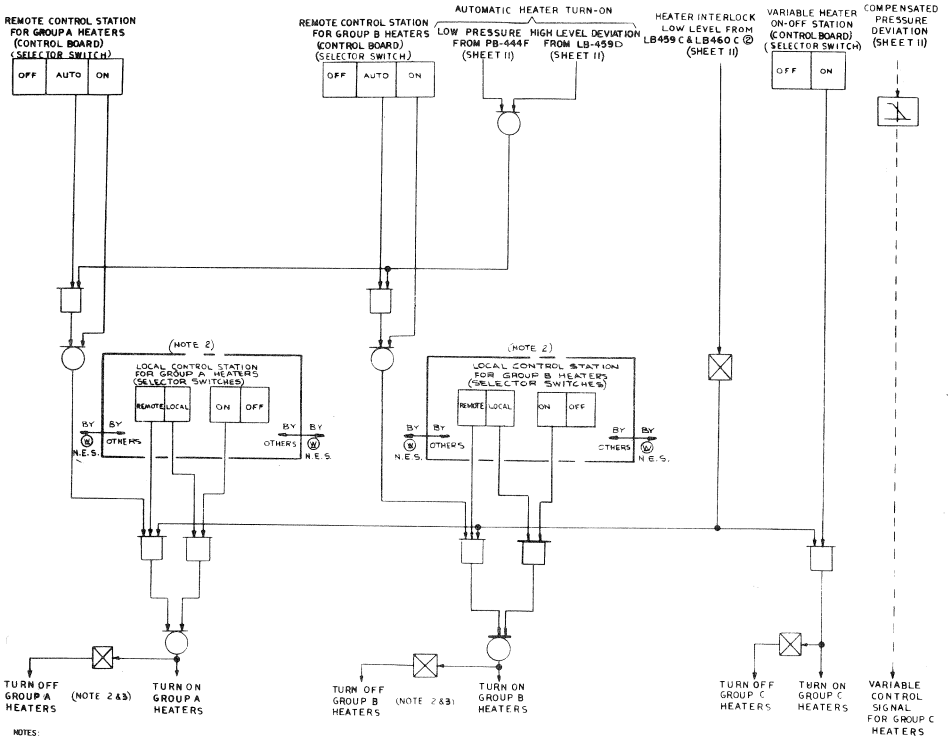


Figure 7.2-1

FUNCTIONAL DIAGRAMS
PRESSURIZER HEATER CONTROL
(SHEET 12 OF 15)
(DWG. NO. 108D837 SH. 12



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Functional Diagrams Pressurizer Heater Control (Sheet 12 of 15) (Dwg.No. 108D837 Sh. 12) Figure 7.2-1

Figure 7.2-1

FUNCTIONAL DIAGRAMS
FEEDWATER CONTROL AND ISOLATION
(SHEET 13 OF 15)
(DWG. NO. 108D837 SH. 13

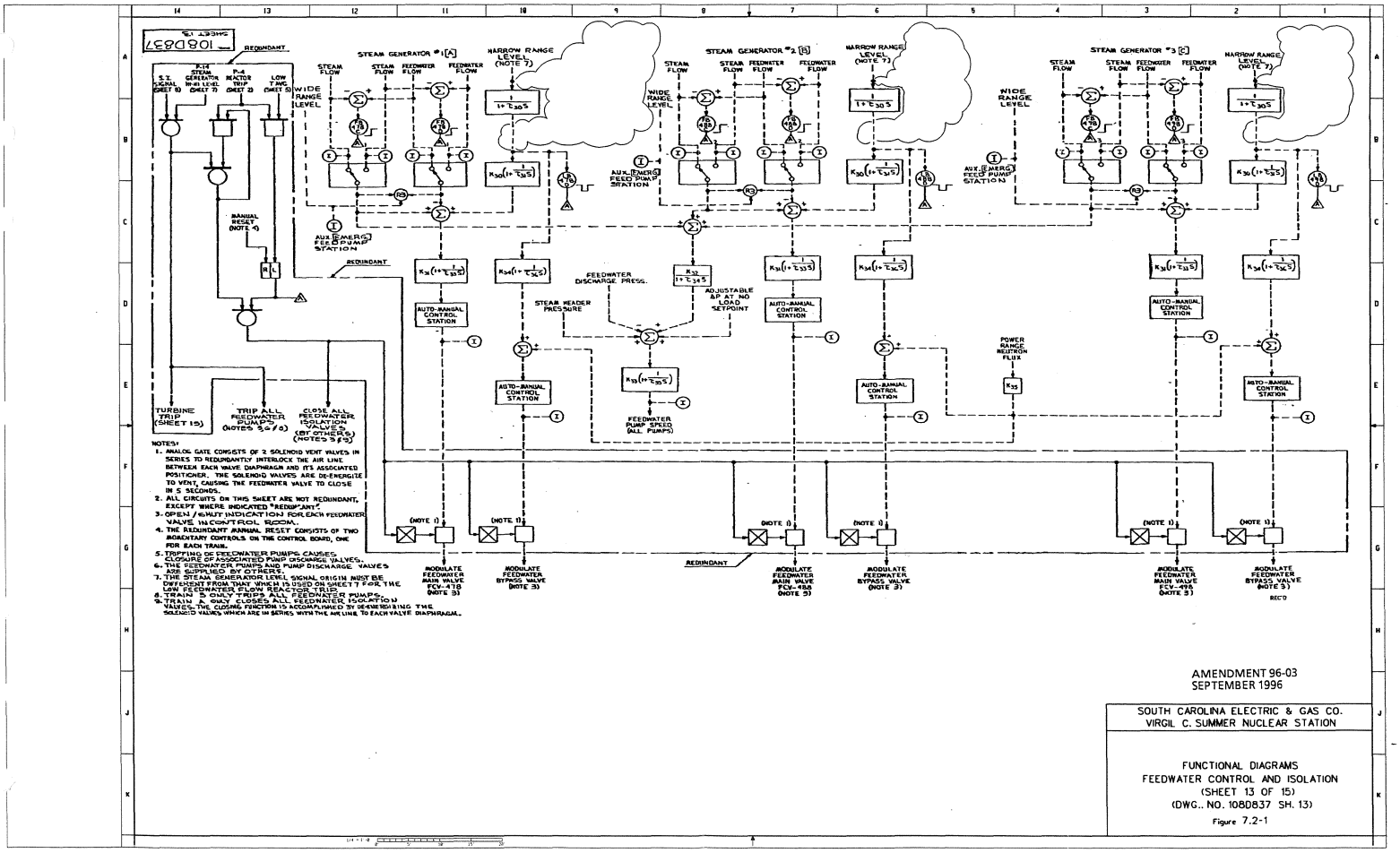
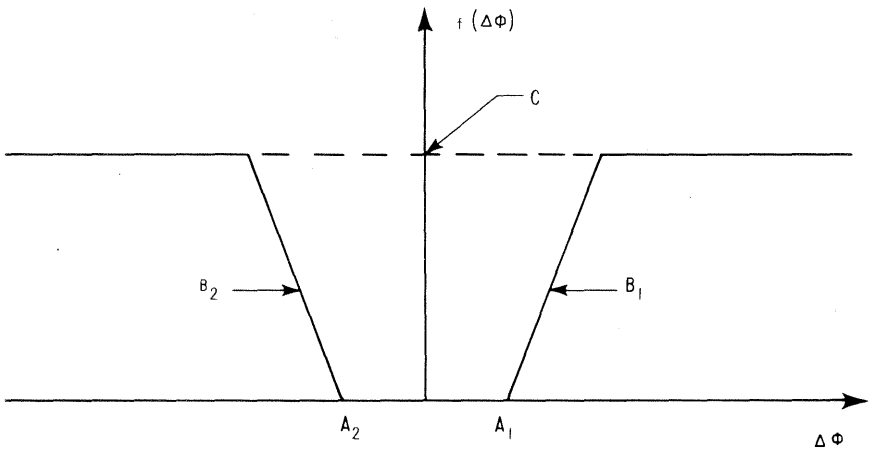


Figure 7.2-1, Sheet 14
DRAWING 1MS-41-011
FSAR FIGURE REFERENCE

Figure 7.2-1, Sheet 15
DRAWING 1MS-41-011
FSAR FIGURE REFERENCE

Figure 7.2-2
SETPOINT REDUCTION FUNCTION FOR OVERTEMPERATURE ΔT TRIP



ΔΦ - NEUTRON FLUX DIFFERENCE BETWEEN UPPER AND LOWER LONG ION CHAMBERS

A_1, A_2 - LIMIT OF F (ΔΦ) DEADBAND

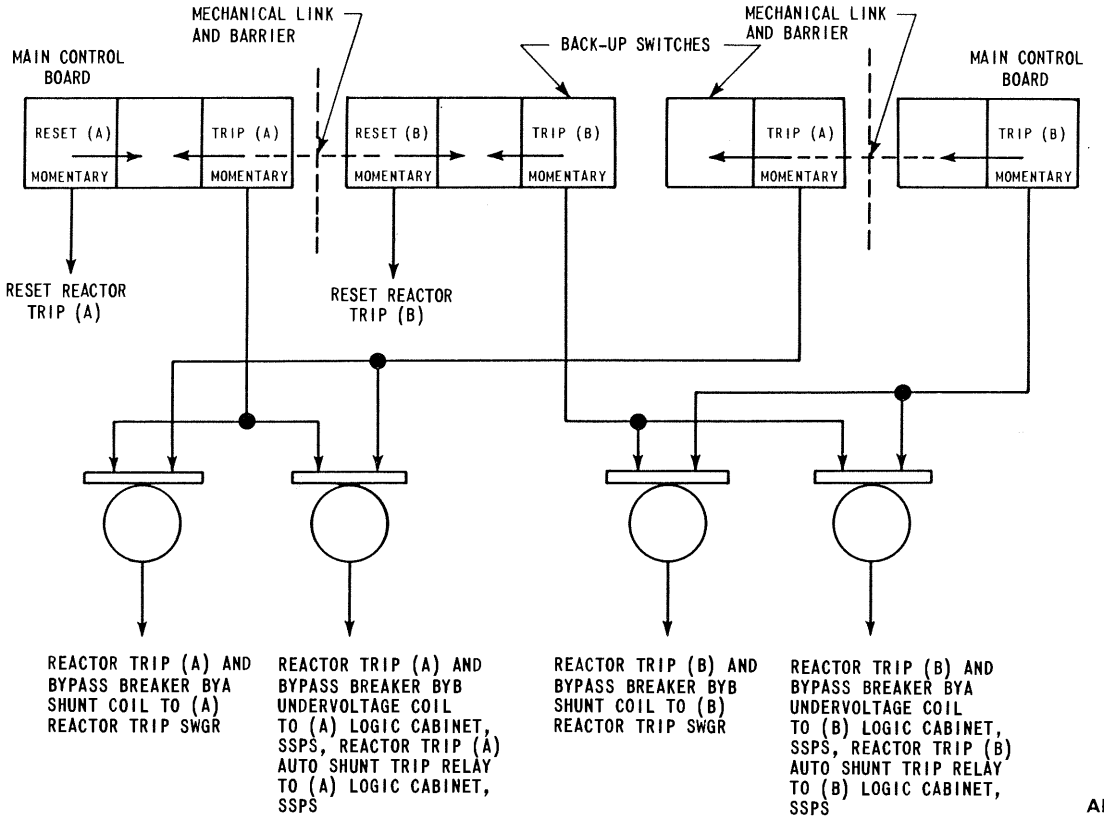
B_1, B_2 - SLOPE OF RAMP; DETERMINES RATE AT WHICH FUNCTION REACHES IT'S MAXIMUM VALUE ONCE DEADBAND IS EXCEEDED

C - MAGNITUDE OF MAXIMUM VALUE THE FUNCTION MAY ATTAIN

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Setpoint Reduction Function for Overtemperature ΔT Trip Figure 7.2-2

Figure 7.2-3

REACTOR TRIP/ESF ACTUATION MECHANICAL LINKAGE



AMENDMENT 2
AUGUST, 1986

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Reactor Trip / ESF Actuation Mechanical Linkage Figure 7.2-3

7.3 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

In addition to the requirements for a reactor trip for anticipated abnormal transients, the facility is provided with adequate instrumentation and controls to sense accident situations and initiate the operation of necessary engineered safety features. The occurrence of a limiting fault, such as a loss of coolant accident or a steam line break, requires a reactor trip plus actuation of one or more of the engineered safety features in order to prevent or mitigate damage to the core and Reactor Coolant System components, and ensure containment integrity.

In order to accomplish these design objectives the Engineered Safety Features System has proper and timely initiating signals which are to be supplied by the sensors, transmitters and logic components making up the various instrumentation channels of the Engineered Safety Features Actuation System.

7.3.1 Description

The Engineered Safety Features Actuation System uses selected plant parameters, determines whether or not predetermined safety limits are being exceeded and, if they are, combines the signals into logic matrices sensitive to combinations indicative of primary or secondary system boundary ruptures (Condition III or IV faults). Once the required logic combination is completed, the system sends actuation signals to the appropriate engineered safety features components. The Engineered Safety Features Actuation System meets the requirements of Criteria 13, 20, 27, 28, and 38 of the 1971 General Design Criteria (GDC).

7.3.1.1 System Description

The Engineered Safety Features Actuation System is a functionally defined system described in this section. The equipment which provides the actuation functions identified in Section 7.3.1.1.1 is listed below and discussed in this section and the references.

1. Process Instrumentation and Control System (Reference 1).
2. Solid-State Logic Protection System (Reference 2).
3. Engineered safety features test cabinet (Reference 3).
4. Engineered safety features loading sequence control panels.
5. Manual actuation circuits.

The Engineered Safety Features Actuation System consists of 2 discrete portions of circuitry: 1) An analog portion consisting of 3 to 4 redundant channels per parameter or variable to monitor various plant parameters such as the Reactor Coolant System and steam system pressures, temperatures and flows and Reactor Building pressures; and 2) a digital portion consisting of 2 redundant logic trains which receive inputs from the analog protection channels and perform the logic needed to actuate the engineered safety features. Each digital train is capable of actuating the engineered safety features equipment required. The intent is that any single failure within the Engineered Safety Features Actuation System shall not prevent system action when required.

The redundant concept is applied to both the analog and logic portions of the system. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, containment penetrations and analog protection racks terminating at the redundant safeguards logic racks. The design meets the requirements of Criteria 20, 21, 22, 23, and 24 of the 1971 GDC.

The variables are sensed by the analog circuitry as discussed in Reference 1 and in Section 7.2. The outputs from the analog channels are combined into actuation logic as shown on Figure 7.2-1, Sheets 5, 6, 7, and 8. Tables 7.3-1 and 7.3-2 give additional information pertaining to logic and function.

The interlocks associated with the Engineered Safety Features Actuation System are outlined in Table 7.3-3. These interlocks satisfy the functional requirements discussed in Section 7.1.2.

Manual actuation from the control board of both trains of containment isolation Phase A is provided by operation of either one of the redundant momentary containment isolation Phase A controls. Also on the control board is manual actuation of safety injection by one of the redundant controls and a manual activation of containment isolation Phase B by either of 2 sets of controls. Each set consists of 2 switches which also actuate reactor building spray.

Manual controls are also provided to supplement the semi-automatic switchover from the injection to the recirculation phase after a loss of coolant accident.

7.3.1.1.1 Function Initiation

The specific functions which rely on the Engineered Safety Features Actuation System for initiation are:

1. A reactor trip, provided one has not already been generated by the Reactor Trip System.
2. Cold leg injection isolation valves which are opened for injection of borated water by charging pumps into the cold legs of the Reactor Coolant System.
3. Charging pumps and associated valving which provide emergency makeup water to the cold legs of the Reactor Coolant System following a loss of coolant accident.
4. Phase A containment isolation, whose function is to prevent fission product release. (Isolation of all lines not essential to reactor protection.)
5. Steam line isolation to prevent the continuous, uncontrolled blowdown of more than one steam generator and thereby uncontrolled Reactor Coolant System cooldown.
6. Main feedwater line isolation to prevent or mitigate the effect of excessive cooldown.
7. Start the emergency diesels to assure backup supply of power to emergency and supporting systems components.
8. Isolate the control room intake ducts to meet control room occupancy requirements following a loss of coolant accident.

9. Reactor building spray actuation which performs the following functions:
    a. Initiates reactor building spray to reduce reactor building pressure and temperature following a loss of coolant or steam line break accident inside the Reactor Building. Iodine removal benefits are also obtained from reactor building spray following a loss of coolant accident.
    b. Initiates Phase B containment isolation which isolates the Reactor Building following a loss of reactor coolant accident, or a steam or feedwater line break within the Reactor Building to limit radioactive releases. (Phase B isolation together with Phase A isolation results in isolation of all but engineered safety features lines penetrating the Reactor Building.)
10. Initiates the engineered safety features loading sequence (ESFLS) which provides timing in order to load the buses at predetermined intervals, avoiding overload conditions on the associated bus. In addition, the engineered safety features loading sequence provides for tripping and blocking of loads. The engineered safety features loading sequence initiates the following functions:
    a. Those pumps which serve as part of the heat sink for Reactor Building cooling (i.e., service water) and associated supporting systems, such as component cooling water pumps and chilled water pumps.
    b. Motor driven emergency feedwater pumps.
    c. Residual heat removal pumps.
    d. Reactor building cooling units (recirculation fans and filtration system) which cool the Reactor Building and limit the potential for release of fission products from the Reactor Building by reducing pressure following an accident.
    e. Trip and lockout of non-engineered safety features loads.

7.3.1.1.2 Analog Circuitry

The process analog sensors and racks for the Engineered Safety Features Actuation System are covered in Reference 1. Discussed in this report are the parameters to be measured including pressures, flows, tank and vessel water levels, and temperatures as well as the measurement and signal transmission considerations. These latter considerations include the transmitters, orifices and flow elements, resistance temperature detectors, as well as automatic calculations, signal conditioning and location and mounting of the devices.

The sensors monitoring the primary system are located as shown on the piping flow diagrams in Chapter 5. The secondary system sensor locations are shown on the steam system flow diagrams given in Chapter 10.

Reactor Building pressure is sensed by 4 physically separated differential pressure transmitters mounted and supported outside of the Reactor Building. These transmitters, meeting Class 1E seismic criteria regarding mounting, are connected to the Reactor Building atmosphere by a filled transmission system. The distance from penetration to transmitter is kept to a minimum, and

separation is maintained. This arrangement, together with the pressure sensors external to the Reactor Building, meets the double barrier requirements of General Design Criteria-56 and Regulatory Guide 1.11.

Pumps and valves which are an integral part of, or associated with the engineered safeguards (used for injection, reactor building spray and recirculation) will have an operation/position status light.

Engineered safety features remote operated valves have position indication on the control board in 2 places to show proper positioning of the valves. Red and green indicator lights are located next to the manual control station showing open and closed positions. The engineered safety features (safety injection) positions of these valves are displayed by an energized bright light on the monitor light panels, which consist of an array of white lights which are dim when the valves are in their normal or required positions for power operations. The monitor lights for automatically actuated valves are energized when the valve is in the automatically actuated position. These monitor lights thus enable the operator to quickly assess the status of the Engineered Safety Features Systems. These indications are derived from contacts integral to the valve operators. The circuits for the engineered safety features monitor lights and red/green lights are classified as associated circuits and have electrical and physical separation. In the cases of the accumulator isolation valves, redundancy of position indication is provided by valve stem mounted limit switches which actuate annunciators on the control board when the valves are not correctly positioned for engineered safety features actuation. The stem mounted switches for the accumulator isolation valves are independent of the limit switches in the motor operators.

7.3.1.1.3 Digital Circuitry

The engineered safety features logic racks are discussed in detail in Reference 2. The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Reference 2 also covers certain aspects of online test provisions, provisions for test points, considerations for the instrument power source, considerations for accomplishing physical separation. The outputs from the analog channels are combined into actuation logic as shown on Sheets 5, 6, 7, 8, and 14 of Figure 7.2-1.

To facilitate engineered safety features actuation testing, 2 test cabinets (1 per train) are provided which enable operation, to the maximum practical extent, of safety features loads on a group by group basis until actuation of all devices has been checked (see Reference 3). Final actuation testing is discussed in detail in Section 7.3.2.

Separation and redundancy requirements are satisfied for the engineered safety features loading sequence by the provision of 2 independent engineered safety features load sequencer control panels. These physically separate control panels, located in the relay room, each consist of a logic output relay cabinet.

7.3.1.1.4 Final Actuation Circuitry

The outputs of the Solid-State Logic Protection System (the slave relays) are energized to actuate. These devices are listed as follows:

1. Safety Injection System pump and valve actuators. See Chapter 6 for flow diagrams and additional information.
2. Containment isolation (Phase A - “T” signal isolates all nonessential process lines on receipt of safety injection signal; Phase B - “P” signal isolates remaining process lines (which do not include engineered safety features lines) on receipt of 2/4 Hi-3 containment pressure signal). For further information, see Section 6.2.4.
3. Diesel start (see Chapter 8).
4. Feedwater isolation (see Chapter 10).
5. Ventilation isolation valve and damper actuators (see Chapter 6).
6. Steam line isolation valve actuators (see Chapter 10).
7. Reactor Building spray pump and valve actuators (see Chapter 6).
8. Engineered safety features loading sequence (see Section 7.3.1.1.5).

If an accident is assumed to occur coincident with a loss of offsite power, the engineered safety features loads must be sequenced onto the diesel generators to prevent overloading them. This sequence is discussed in Chapter 8. The design meets the requirements of Criterion 35 of the 1971 General Design Criteria.

7.3.1.1.5 Engineered Safety Features Loading Sequence Control Panels

The ESFLS automatically loads engineered safety features components to the ESF buses under the following conditions:

a. Loss of offsite power or degradation of voltage. Safety injection.
b. Safety injection.
c. Safety injection coincident with loss of offsite power or degradation of voltage.

The loss of offsite power or degradation of voltage considered here is related to the engineered safety features buses (7.2 V buses 1DA and/or 1DB). Loss of voltage is detected on either bus by 3/3 loss of voltage relays. Degraded voltage is detected on either bus by 3/3 degraded voltage relays. The safety injection signal is generated by the Solid-State Protection System. To assure component operation under the various initiating conditions, 2 initiating sequences are provided. These sequences are a “blackout sequence,” which loads the components needed to shut down the plant in the event of a loss of power or degraded voltage, and a “safety injection sequence,” which loads the components needed to mitigate the consequences of design bases accidents occurring coincident with a loss of offsite power or degradation of voltage.

The initiation of engineered safety features loads following safety injection with engineered safety features bus power available utilizes the same “safety injection sequence” identified above. Use of the loading sequencer during conditions when ESF bus power is available provides the following benefits:

1. Enhanced reliability due to a simplified logic for component actuation.
2. Improved online testing capability.

As discussed in Section 8.3, each 7.2 kV engineered safety features bus is fed from both the normal (offsite) and emergency (onsite) supplies and each engineered safety features bus is provided with loss of voltage and degraded voltage relays. This arrangement enables operation of the engineered safety features logic sequence independent of the source (offsite or onsite) of power.

When initiated, the sequencer provides timing to load the buses at 5 second intervals. Order of loading is determined by system requirements, design capabilities of the diesel and the type of incident or accident, as evaluated by the engineered safety features logic sequence logic circuitry (see Figure 7.3-1 and Section 8.3). In addition, the sequencer provides for tripping and blocking of loads. The engineered safety features logic sequence is located in the relay room and indication is provided on the main control board. It provides the operator with information on the progress of the loading sequence and consists of internal logic circuits and output relays (the relays are located in a cabinet in the relay room). The output of these relays actuates the required safety-related equipment.

Each engineered safety features loading sequence consists of the following components:

1. Logic circuits, located in the logic section of the control cabinet.
2. Indication, located on the monitor section of the control cabinet and on section XCP-6117 of the main control board. The indication on the main control board provides the operator with information necessary for evaluation of progress of the loading sequence.
3. Output relays, located in the relay cabinet, to provide multiple contacts for the various functions.

7.3.1.1.6 Support Systems

The following systems are required for support of the engineered safety features:

1. Service Water - Heat Removal (see Chapter 9).
2. Component Cooling Water Systems - Heat Removal (see Chapter 9).
3. Chilled Water System - Heat Removal (see Chapter 9).
4. Class 1E Electrical Power Distribution Systems (see Chapter 8).
5. Other Heating, Ventilating and Air Conditioning Systems (see Section 9.4.5).

7.3.1.2 Design Bases Information

The functional diagrams presented in Figure 7.2-1, Sheets 5, 6, 7, and 8 provide a graphic outline of the functional logic associated with requirements for the Engineered Safety Features Actuation System. Requirements for the Engineered Safety Features System are given in Chapter 6. Given below is the design bases information required in IEEE Standard 279-1971, Reference 4.

7.3.1.2.1 Generating Station Conditions

The following is a summary of those generating station conditions requiring protective action:

1. Primary System
   a. Rupture in small pipes or cracks in large pipes.
   b. Rupture of a reactor coolant pipe (loss of coolant accident).
   c. Steam generator tube rupture.
2. Secondary System
   a. Minor secondary system pipe breaks resulting in steam release rates equivalent to a single dump, relief, or safety valve.
   b. Rupture of a major steam pipe.

7.3.1.2.2 Generating Station Variables

The following list summarizes the generating station variables required to be monitored for the automatic initiation of safety injection during each accident identified in the preceding section. Post accident monitoring requirements are described in the VCSNS Environmental Qualification/Reg. Guide 1.97 Design Basis Document.

1. Primary System Accidents
   a. Pressurizer pressure.
   b. Reactor Building pressure (not required for steam generator tube rupture).
2. Secondary System Accidents
   a. Pressurizer pressure.
   b. Steam line pressures.
   c. Reactor Building pressure (steam or feedwater line break inside reactor building).
   d. Steam line differential pressure.

7.3.1.2.3 Spatially Dependent Variables

The only variable sensed by the Engineered Safety Features Actuation System which has spatial dependence is reactor coolant temperature. The effect on the measurement is negated by taking

multiple samples from the reactor coolant hot leg and averaging these samples by mixing in the resistance temperature detector bypass loop.

7.3.1.2.4 Limits, Margins, and Levels

Prudent operational limits, available margins, and setpoints before onset of unsafe conditions requiring protective action are discussed in Chapter 15 and the Technical Specifications.

7.3.1.2.5 Abnormal Events

The malfunctions, accidents, or other unusual events which could physically damage protection system components or could cause environmental changes are as follows:

1. Loss of coolant accident (see Sections 15.3 and 15.4).
2. Steam line breaks (see Sections 15.3 and 15.4).
3. Earthquakes (see Chapters 2 and 3).
4. Fire (see Section 9.5.1).
5. Explosion (Hydrogen buildup inside the Reactor Building) (see Section 15.4).
6. Missiles (see Section 3.5).
7. Flood (see Chapters 2 and 3).

7.3.1.2.6 Minimum Performance Requirements

Minimum performance requirements are as follows:

1. System Response Times

   The Engineered Safety Features Actuation System response time is defined as the interval required for the engineered safety features sequence to be initiated subsequent to the point in time that the appropriate variable(s) exceed setpoints. The response time includes sensor/process (analog) and logic (digital) delay plus, the time delay associated with tripping open the reactor trip breakers and control and latching mechanisms. The values listed herein are maximum allowable times consistent with the safety analyses and are systematically verified during plant preoperational startup tests. These maximum delay times thus include all compensation and therefore require that any such network be aligned and operating during verification testing.

   The Engineered Safety Features Actuation System is always capable of having response time tests performed using the same methods as those tests performed during the preoperational test program or following significant component changes.

   System response times for loss of coolant protection are:

a. Pressurizer pressure -1.0 second

b. Reactor building pressure - 1.5 seconds

Maximum allowable time delays in generating the actuation signal for steam break protection are given in Table 7.3-4.

2. System Accuracies

Accuracies required for generating the required actuation signals for loss of coolant protection are given in Table 7.3-5.

3. Ranges of sensed variables to be accommodated until conclusion of protective action is assured are given in Table 7.3-5.

7.3.1.3 Final System Drawings

The schematic diagrams for the systems discussed in this section are discussed in Section 1.7.

7.3.2 Analysis

7.3.2.1 Failure Mode and Effects Analyses

Failure mode and effects analyses have been performed on Engineered Safety Features Systems (ESFS) equipment within the scope of Westinghouse. The results verify that these systems meet protection single failure criteria as required by IEEE Standard 279-1971 and the Virgil C. Summer Nuclear Station (Engineered Safety Features Systems) equipment is designed to equivalent safety design criteria. The actuation of the Virgil C. Summer Nuclear Station Engineered Safety Features Systems is functionally the same as the systems studied in these analyses.

The failure mode and effects analysis (FMEA) which was performed on engineered safety features engineered safety features equipment within the scope of Westinghouse was for a typical Westinghouse Engineered Safety Features Actuation System (ESFAS). (See Reference [5]). The analysis has generic application to all Westinghouse Engineered Safety Features Actuation Systems of the Virgil C. Summer Nuclear Station vintage. The conclusion is that the analysis (1) qualitatively demonstrates the reliability of the Engineered Safety Features Actuation System to perform its intended function and (2) shows that the Engineered Safety Features Actuation System does comply with the single failure criterion, because no single failure was found which could prevent the Engineered Safety Features Actuation System from generating the proper actuation signal on demand for an engineered safety feature. Random single failures are either in a safe direction or a redundant channel or train ensures the necessary actuation capability.

The basis of a failure mode and effects analysis is principally that single failures are detectable, identifiable, and random. They are not systematic (common mode). The systematic failure considerations applied to equipment hardware, as well as actuation functions, are addressed elsewhere in the final safety analysis report, such as:

1. Seismic qualification of Seismic Category 1 instrumentation and electrical equipment (Section 3.10). This conforms to Section 4.7.4.2 of IEEE 279-1971.
2. Environmental design of mechanical and electrical equipment (Section 3.11). This conforms to Section 4.7.4.2 of IEEE 279-1971.
3. The Nuclear Instrumentation System, the Solid State Protection System, and the 7300 Series Process Control System noise tests (See Section 7.2.2.2.3.7 and Reference 5 in Section 7.2.4).
4. Manual initiation of protective actions (See Section 7.3.2.2.7).

7.3.2.2 Compliance With Standards and Design Criteria

Discussion of the General Design Criteria (GDC) is provided in various sections of Chapter 7 where a particular General Design Criteria is applicable. Applicable General Design Criteria include Criteria 13, 20, 21, 22, 23, 24, 25, 27, 28, 35, 37, 38, 40, 43, and 46 of the 1971 General Design Criteria. Compliance with certain IEEE Standards is presented in Sections 7.1.2.7, 7.1.2.9, 7.1.2.10, and 7.1.2.11. The discussion given below shows that the Engineered Safety Features Actuation System complies with IEEE Standard 279-1971, Reference 4. For the list of references to the discussions of conformance to applicable criteria, see Table 7.1-1.

Table 7.3-6 outlines the degree of conformance of the engineered safety features loading sequence control panels to Regulatory Guide 1.53 and IEEE Standard 379-1972, Reference 5.

7.3.2.2.1 Single Failure Criteria

The discussion presented in Section 7.2.2.2.3 is applicable to the Engineered Safety Features Actuation System, with the following exception.

In the engineered safety features, a loss of instrument power will call for actuation of engineered safety features equipment controlled by the specific bistable that lost power (Reactor Building spray excepted). The actuated equipment must have power to comply. The power supply for the protection systems is discussed in Section 7.6 and in Chapter 8. For Reactor Building spray, the final bistables are energized to trip to avoid spurious actuation. In addition, manual Reactor Building spray requires a simultaneous actuation of 2 manual controls. This is considered acceptable because spray actuation on Hi-3 Reactor Building pressure signal provides automatic initiation of the system via protection channels meeting the criteria in Reference 4. Moreover, 2 sets (2 switches per set) of Reactor Building spray manual initiation switches are provided to meet the requirements of IEEE Standard 279-1971. Also it is possible for all engineered safety features equipment (valves, pumps, etc.) to be individually manually actuated from the control board. Hence, a third mode of Reactor Building spray initiation is available. The design meets the requirements of Criteria 21 and 23 of the 1971 General Design Criteria.

7.3.2.2.2 Equipment Qualification

Equipment qualifications are discussed in Sections 3.10 and 3.11.

7.3.2.2.3 Channel Independence

The discussion presented in Section 7.2.2.2.3 is applicable. The engineered safety features slave relay outputs from the solid-state logic protection cabinets are redundant, and the actuations associated with each train are energized up to and including the final actuators by the separate a-c power supplies which power the logic trains.

7.3.2.2.4 Control and Protection System Interaction

The discussions presented in Section 7.2.2.2.3 are applicable.

7.3.2.2.5 Capability for Sensor Checks and Equipment Test and Calibration

The discussions of system testability in Section 7.2.2.2.3 are applicable to the sensors, analog circuitry, and logic trains of the Engineered Safety Features Actuation System.

The following discussions cover those areas in which the testing provisions differ from those for the Reactor Trip System.

7.3.2.2.5.1 Testing of Engineered Safety Features Actuation Systems

The Engineered Safety Features Systems are tested to provide assurance that the systems will operate as designed and will be available to function properly in the unlikely event of an accident. The testing program meets the requirements of Criteria 21, 37, 40, and 43 of the 1971 General Design Criteria and requirements on testing of the Emergency Core Cooling System as stated in General Design Criteria-37 except for the operation of those components that will cause an adverse effect to the safety or operability of the plant per Regulatory Guide 1.22 as discussed in Section 7.1.2.5. The tests described in Section 7.2.2.2.3 and further discussed in Section 6.3.4 meet the actual safety injection. The test, as described, demonstrates the performance of the full operational sequence that brings the system into operation, the transfer between normal and emergency power sources and the operation of associated cooling water systems. The charging pumps and residual heat removal pumps are started and operated and their performance verified in a separate test discussed in Section 6.3.4. When the pump tests are considered in conjunction with the Emergency Core Cooling System test, the requirements of General Design Criteria-37 on testing of the Emergency Core Cooling System are met as close as possible without causing an actual safety injection.

Testing as described in Sections 6.3.4, 7.2.2.2.3, and 7.3.2.2.5 provides complete periodic testability during reactor operation of all logic and components associated with the Emergency Core Cooling System.

This design meets the requirements of Regulatory Guide 1.22 as discussed in the above sections. The program is as follows:

1. Prior to initial plant operations, Engineered Safety Features System tests will be conducted.

2. Subsequent to initial startup, Engineered Safety Features System tests will be conducted during each regularly scheduled refueling outage.
3. During online operation of the reactor, engineered safety features analog and logic circuitry will be fully tested. In addition, essentially all of the engineered safety features final actuators will be fully tested. The remaining few final actuators whose operation is not compatible with continued online plant operation will be checked by means of continuity testing.

7.3.2.2.5.2 Performance Test Acceptability Standard for the “S” (Safety Injection Signal) and for the “P” (the Automatic Demand Signal for Reactor Building Spray Actuation) Actuation Signals Generation

During reactor operation the basis for Engineered Safety Features Actuation Systems acceptability will be the successful completion of the overlapping tests performed on the initiating system and the Engineered Safety Features Actuation System, see Figure 7.3-2. Checks of process indications verify operability of the sensors. Analog checks and tests verify the operability of the analog circuitry from the input of these circuits through to and including the logic input relays except for the input relays associated with the Reactor Building spray function which are tested during the solid-state logic testing. Solid-State logic testing also checks the digital signal path from and including logic input relay contacts through the logic matrices and master relays and performs continuity tests on the coils of the output slave relays; final actuator testing operates the output slave relays and verifies operability of those devices which require safeguards actuation and which can be tested without causing plant upset. A continuity check is performed on the actuators of the untestable devices. Operation of the final devices is confirmed by control board indication and visual observation that the appropriate pump breakers close and automatic valves shall have completed their travel.

The basis for acceptability for the engineered safety features interlocks will be control board indication of proper receipt of the signal upon introducing the required input at the appropriate setpoint.

Routine periodic inspections of the ESF equipment and performance acceptability testing of the “S” (Safety Injection Signal) and of the “P” (Automatic Demand Signal for Reactor Building Spray Actuation) are consistent with inspections and tests of the NSSS Electrical Equipment Section 3.11.2.2.1 and the Technical Specifications.

7.3.2.2.5.3 Frequency of Performance of Engineered Safety Features Actuation Tests

During reactor operation, complete system testing (excluding sensors or those devices whose operation would cause plant upset) is performed on a periodic basis. Testing, including the sensors, is also performed during scheduled plant shutdown for refueling.

7.3.2.2.5.4 Engineered Safety Features Actuation Test Description

The following sections describe the testing circuitry and procedures for the online portion of the testing program. The guidelines used in developing the circuitry and procedures are:

1. The test procedures must not involve the potential for damage to any plant equipment.
2. The test procedures must minimize the potential for accidental tripping.
3. The provisions for online testing must minimize complication of engineered safety features actuation circuits so that their reliability is not degraded.

7.3.2.2.5.5 Description of Initiation Circuitry

Several systems comprise the total Engineered Safety Features System, the majority of which may be initiated by different process conditions and be reset independently of each other.

The remaining functions (listed in Section 7.3.1.1.1) are initiated by a common signal (safety injection) which in turn may be generated by different process conditions.

In addition, operation of all other vital auxiliary support systems, such as Emergency Feedwater, Component Cooling Water, Service Water, and Heating, Ventilating and Air Conditioning Systems listed in Section 9.4.5, is initiated by the safety injection signal.

Each function is actuated by a logic circuit which is duplicated for each of the 2 redundant trains of engineered safety features initiation circuits.

The output of each of the initiation circuits consists of a master relay which drives slave relays for contact multiplication as required. The logic, master, and slave relays are mounted in the solid-state logic protection cabinets designated Train A, and Train B, respectively, for the redundant counterparts. The master and slave relay circuits operate various pump and fan circuit breakers or starters, motor operated valve contactors, solenoid operated valves, emergency generator starting, etc.

7.3.2.2.5.6 Analog Testing

Analog testing is identical to that used for reactor trip circuitry and is described in Section 7.2.2.2.3.

An exception to this is Reactor Building spray, which is energized to actuate 2/4 and reverts to 2/3 when 1 channel is in test.

7.3.2.2.5.7 Solid-State Logic Testing

Except for Reactor Building spray channels; solid-state logic testing is the same as that discussed in Section 7.2.2.2.3. During logic testing of 1 train, the other train can initiate the required engineered safety features function. For additional details, see Reference 2.

7.3.2.2.5.8 Actuator Testing

At this point, testing of the initiation circuits through operation of the master relay and its contacts to the coils of the slave relays has been accomplished. Slave relays (K601, K602, etc.) do not operate because of reduced voltage.

The Engineered Safety Features Actuation System final actuation device or actuated equipment testing shall be performed from the engineered safety features test cabinets. These cabinets are normally located near the Solid-State Logic Protection System equipment. There is 1 test cabinet provided for each of the 2 protection Trains “A” and “B”. Each cabinet contains individual test switches necessary to actuate the slave relays. To prevent accidental actuation, test switches are of the type that must be rotated and then depressed to operate the slave relays. Assignments of contacts of the slave relays for actuation of various final devices or actuators have been made such that groups of devices or actuated equipment, can be operated individually during plant operation without causing plant upset or equipment damage. In the unlikely event that a safety injection signal is initiated during the test of the final device that is actuated by this test, the device will already be in its engineered safety feature position.

During this last procedure, close communication between the Control Room operator and the operator at the test panel is required. Prior to the energizing of a slave relay, the operator in the Control Room assures that plant conditions will permit operation of the equipment that will be actuated by the relay. After the tester has energized the slave relay, the Control Room operator observes that all equipment has operated as indicated by appropriate indicating lamps, monitor lamps and annunciators on the control board and, using a prepared check list, records all operations. After proper operation is verified, the test switch is reset at the test panel and each device is returned to its desired mode from the control board.

By means of the procedures outlined above, all engineered safety features devices actuated by engineered safety features actuation systems initiation circuits, with the exceptions noted in Section 7.1.2.5 under a discussion of Regulatory Guide 1.22 are operated by the automatic circuitry.

7.3.2.2.5.9 Actuator Blocking and Continuity Test Circuits

Those few final actuation devices that cannot be designed to be actuated during plant operation (discussed in Section 7.1.2.5) have been assigned to slave relays for which additional test circuitry has been provided to individually block actuation of a final device upon operation of the associated slave relay during testing. Operation of these slave relays, including contact operations, and continuity of the electrical circuits associated with the final devices’ control are checked in lieu of actual operation. The circuits provide for monitoring of the slave relay contacts, the devices’ control circuit cabling, control voltage and the devices’ actuation relay coils, solenoids, etc. Interlocking prevents blocking the output from more than 1 output relay in a protection train at a time. Interlocking between trains is also provided to prevent continuity testing in both trains simultaneously, therefore the redundant device associated with the protection train not under test will be available in the event protection action is required. If an accident occurs during testing, the automatic actuation circuitry will override testing as noted above. One (1)

exception to this is that if the accident occurs while testing a slave relay whose output must be blocked, those few final actuation devices associated with this slave relay will not be overridden; however, the redundant devices in the other train would be operational and would perform the required safety function. Actuation devices to be blocked are identified in Section 7.1.2.5.

The continuity test circuits for these components that cannot be actuated online are verified by proving lights on the engineered safety features test racks.

The typical schemes for blocking operation of selected engineered safety features function actuator circuits are shown in Figure 7.3-3 as details A and B. The schemes operate as explained below and are duplicated for each engineered safety features train.

Detail A shows the circuit for contact closure for protection function actuation. Under normal plant operation, and equipment not under test, the test lamps “DS *” for the various circuits will be energized. Typical circuit path will be through the normally closed test relay contact “K *” and through test lamp connections 1 to 3. Coils “X1” and “X” will be capable of being energized for protection function actuation upon closure of solid-state logic output relay contacts “K *”. Coil “X1” or “X” is typical for a breaker closing auxiliary coil, motor starter master coil, coil of a solenoid valve, auxiliary relay, etc. When the contacts “K *” are opened to block energizing of coil “X1” and “X2”, the white lamp is de-energized, and the slave relay “K *” may be energized to perform continuity testing. To verify operability of the blocking relay in both blocking and restoring normal service, open the blocking relay contact in series with lamp connections - the test lamp should be de-energized; close the blocking relay contact in series with the lamp connections - the test lamp should now be energized, which verifies that the circuit is now in its normal, i.e., operable condition.

Detail B shows the circuit for contact opening for protection function actuation. Under normal plant operation, and equipment not under test, and white test lamps “DS *” for the various circuits will be energized, and green test lamp “DS *” will be de-energized. Typical circuit path for white lamp “DS *” will be through the normally closed solid-state logic output relay contact “K *” and through test lamp connections 1 to 3. Coils “Y1” and “Y2” will be capable of being de-energized for protection function actuation upon opening of solid-state logic output relay contacts “K *”. Coil “Y2” is typical for a solenoid valve coil, auxiliary relay, etc. When the contacts “K8 *” are closed to block de-energizing of coils “Y1” and “Y2”, the green test lamp is energized, and the slave relay “K *” may be energized to verify operation (opening of its contacts). To verify operability of the blocking relay in both blocking and restoring normal service, close the blocking relay contact to the green lamp - the green test lamp should now be energized also; open this blocking relay contact - the green test lamp should be de-energized, which verifies that the circuit is now in its normal, i.e., operable condition.

7.3.2.2.5.10

The testing provisions of the engineered safety features loading sequence control panels differ from the Engineered Safety Features Actuation System. Each engineered safety features loading sequence control panel is designed to combine automatic testing with manual testing. Continuous and periodic test features are provided to test for equipment faults (e.g., open circuits, short

circuits, inoperative timers). All system accuracy and functional requirements are maintained when automatic testing is implemented. These features are provided in accordance with IEEE-420, Section 4.7 and the following:

1. Automatic Test

   The Automatic Test Feature has 3 operating modes: Continuous, Fast, and Slow. During these modes, the Automatic Test Feature monitors the engineered safety features loading sequence and upon occurrence of an improper response will display the step number of the failed test and energize a fault relay for remote annunciator. The Continuous mode provides on-line surveillance of the engineered safety features loading sequence operation by repeatedly cycling the Automatic Test circuits through their test states and monitoring the various system outputs for appropriate responses. Operation is check from the logic input signals through the logic and counter stages and up to and including the relay driven outputs. The surveillance will not interface with system requirements nor cause an undesired relay actuation during normal system operation. The Fast mode operates in the same manner as the Continuous mode except that only 1 test cycle is performed for each operation initiated test.

   The Slow mode allows manual stepping of the Automatic Test circuits through a test cycle to observe the system response via the cabinet control panel indicators. Operation is checked from the logic input signals through the logic and counter stages, the relay driver outputs, and output relays. The Slow mode actuates the output relays thereby starting or tripping plant equipment.

   Fault detection and annunciation, local and remote, are automatic in the Continuous and Fast mode while operation interpretation of the system response is required in the Slow mode. Additionally, automatic resetting of the Automatic Test circuits, in response to a True input signal, is provided in the Continuous and Fast modes. Manual reset is required in the Slow mode.

2. Manual Test

   The Manual Test Features provide the means to verify all engineered safety features loading sequence functions locally at the cabinet control panel. Input test switches enable simulation of all inputs, including operation of the input buffer relays, in any combination or time sequence. Output test switches enable actuation of each step or output individually, including operating of the final associated solid state driver stage. Blocking switches, which allow active testing of Output 1 and Output 4 without effecting associated external loads, are also provided. Indicator lamps associated with each input, system, startup, each step and each output allow the operation to visually observe the results of all tests.

7.3.2.2.5.11 Time Required for Testing

It is estimated that analog testing can be performed at a rate of several channels per hour. Logic testing of both Trains A and B can be performed in less than 30 minutes. Testing of actuated components (including those which can only be partially tested) will be a function of control

room operator availability. It is expected to require several shifts to accomplish these tests. During this procedure automatic actuation circuitry will override testing, except for those few devices associated with a single slave relay whose outputs must be blocked and then only while blocked. It is anticipated that continuity testing associated with a blocked slave relay could take several minutes. During this time the redundant devices in the other train would be functional.

7.3.2.2.5.12 Summary of Online Testing Capabilities

The procedures described provide capability for checking completely from the process signal to the logic cabinets and from there to the individual pump and fan circuit breakers or starters, valve contactors, pilot solenoid valves, etc., including all field cabling actually used in the circuitry called upon to operate for an accident condition. For those few devices whose operation could adversely affect plant or equipment operation, the same procedure provides for checking from the process signal to the logic rack. To check the final actuation device, a continuity test of the individual control circuits is performed.

The procedures require testing at various locations.

1. Analog testing and verification of bistable setpoint are accomplished at process analog racks. Verification of bistable relay operation is done at the control board status lights.
2. Logic testing through operation of the master relays and low voltage application to slave relays is done at the logic rack test panel.
3. Testing of pumps, fans and valves is done at a test panel located in the vicinity of the logic racks in combination with the control room operator.
4. Continuity testing from those circuits that cannot be operated is done at the same test panel mentioned in item 3 above.

The reactor coolant pump essential service isolation valves consist of the isolation valves on the component cooling water and the seal water return header.

The main reason for not testing these valves periodically is that the reactor coolant pumps may be damaged. Although pump damage from this type of test would not result in a situation which endangers the health and safety of the public, it could result in unnecessary shutdown of the reactor for an extended period of time while the reactor coolant pump or certain of its parts were replaced. This would place a great economic burden on South Carolina Electric and Gas Company.

Reactor Building Spray System pump tests will be performed periodically. The pump tests will be performed with the isolation valves in the spray pump discharge lines at the Reactor Building blocked closed; the Sodium Hydroxide Storage Tank valves are also blocked closed.

7.3.2.2.5.13 Testing During Shutdown

Emergency Core Cooling System tests will be performed at each major fuel reloading with the Reactor Coolant System isolated from the Emergency Core Cooling System by closing the

appropriate valves. A test safety injection signal will then be applied to initiate operation of active components (pumps and valves) of the Emergency Core Cooling System. This is in compliance with Criterion 37 of the 1971 General Design Criteria.

7.3.2.2.5.14 Periodic Maintenance Inspection

The maintenance procedures which follow may be accomplished in any order. The frequency will depend on the operating conditions and requirements of the reactor power plant. If any degradation of equipment operation is noted, either mechanically or electrically, remedial action is taken to repair, replace, or readjust the equipment.

Typical maintenance procedures include the following:

1. Check cleanliness of all exterior and interior surfaces.
2. Inspect for loose or broken control knobs and burned-out indicator lamps.
3. Inspect for moisture and condition of cables and wiring.
4. Visually or mechanically check connectors and terminal boards for looseness, poor connection, or corrosion.
5. Inspect the components of each assembly for signs of overheating or component deterioration.
6. Perform complete system operating check.

The balance of the requirements listed in Reference 4 (paragraphs 4.11 through 4.22) are discussed inSection 7.2.2.2.3. Paragraph 4.20 receives special attention in Section 7.5.4.

7.3.2.2.6 Manual Resets and Blocking Features

The manual reset feature associated with reactor building spray actuation is provided in the standard design of the Westinghouse Solid-State Protection System design for 2 basic purposes: First, the feature permits the operator to start an interruption procedure of automatic reactor building spray in the event of false initiation of an actuation signal. Second, although spray system performance is automatic, the reset feature enables the operator to start a manual takeover of the system to handle unexpected events which can be better dealt with by operator appraisal of changing conditions following an accident.

It is most important to note that manual control of the Spray System does not occur, once actuation has begun, by just resetting the associated log devices alone. Components will seal in (latch) so that removal of the actuation signal, in itself, will neither cancel or prevent completion of protective action or provide the operator with manual override of the automatic system by this single action. In order to take complete control of the system to interrupt its automatic performance, the operator must deliberately unlatch relays which have “sealed in” the initial actuation signals in the associated motor control center, in addition to tripping the pump motor circuit breakers, if stopping the pumps is desirable or necessary.

The manual reset feature associated with reactor building spray, therefore, does not perform a bypass function. It is merely the first of several manual operations required to take control from the automatic system or interrupt its completion should such an action be considered necessary.

In event that the operator anticipates system actuation and erroneously concludes that it is undesirable or unnecessary and imposes a standing reset condition in 1 train (by operating and holding the corresponding reset switch at the time the initiate signal is transmitted) the other train will automatically carry the protective action to completion. In the event that the reset condition is imposed simultaneously in both trains at the time the initiate signals are generated, the automatic sequential completion of system action is interrupted and control has been taken by the operator. Manual takeover will be maintained, even though the reset switches are released, if the original initiate signal exists. Should the initiate signal then clear and return again, automatic system actuation will repeat.

Note also that any time delays imposed on the system action are to be applied after the initiating signals are latched. Delay of actuation signals for fluid systems lineup, load sequencing, etc., does not provide the operator time to interrupt automatic completion, with manual reset alone, as would be the case if time delay were imposed prior to sealing of the initial actuation signal.

The manual block features associated with pressurizer and steam line safety injection signals provide the operator with the means to block initiation of safety injection during plant startup. These block features meet the requirements of paragraph 4.12 of IEEE Standard 279-1971 in that automatic removal of the block occurs when plant conditions require the protection system to be functional.

Safety injection actuation on low pressurizer pressure may be manually blocked when the primary pressure falls below the P-11 setpoint. Safety injection and steamline isolation actuation on low steamline pressure may also be manually blocked below the P-12 setpoint (low-low T_{avg}). Safety injection cannot be blocked on high steam line differential pressure or high-1 containment pressure, and steam line isolation cannot be blocked on either high steam line flow coincident with low-low T_{avg} or high-2 containment pressure. Thus these signals would always be available to automatically terminate a steam line rupture during cooldown or startup.

Furthermore, during heatup and cooldown and while safety injection is blocked, the operator will be in full manual control of the plant. He will be cognizant of the plant operating conditions and the expected changes in these parameters. If a serious steam line break should occur during this time, it should be apparent to the operator so that he can take the necessary action to prevent any adverse consequences in a timely fashion.

The types of instrumentation available to the operator which would indicate that a steam line break has occurred consists of alarms and indicated values. Alarms could occur on high steam flow, low steam line pressure (SI actuation, Steamline Isolation), low-low steam generator level (reactor trip), low steam generator level, high steam line differential pressure (SI actuation), high source range nuclear flux (reactor trip), and containment pressure high-1 (SI actuation) and high-2 (steam line isolation).

The instrumentation which would be indicated on the control board consists of the above channels plus T_{avg}, pressurizer level and pressurizer pressure. Since the shutdown margin during cooldown or startup is greater than that for the case analyzed in the FSAR, there will be more time for manual action to terminate the transient. Furthermore, the steam line pressure during cooldown and startup would be such that the consequences of the steam generator blowdown would be less severe than for the hot zero power case analyzed in the Final Safety Analysis Report.

Therefore, either the protection system will automatically terminate the transient or the operator will determine soon after the incident begins that a break has occurred and will take the necessary action.

7.3.2.2.7 Manual Initiation of Protective Actions (Regulatory Guide 1.62)

There are 3 individual main steam isolation valve momentary control switches (1 per loop) mounted on the control board. Each switch when actuated, will isolate its main steam line. In addition, an independent momentary control switch, mounted on the control board, will isolate all 3 main steam lines when actuated.

Manual initiation of semi-automatic switchover to recirculation following a loss of primary coolant accident is in compliance with paragraph 4.17 of IEEE Standard 279-1971 with the following comments:

1. The manual operations that are involved in this switchover are described in Section 6.3.
2. Once safety injection is initiated following a loss of primary coolant accident, the Reactor Building sump isolation valves in the Residual Heat Removal System pump suction lines will open automatically upon receipt of a lo-lo level signal from the refueling water storage tank level instrumentation.
3. Manual initiation of either 1 of 2 redundant safety injection actuation main control board mounted switches not only provides for actuation of the components required for reactor protection and mitigation of adverse consequences of the postulated accident prior to the recirculation mode associated with a loss of primary coolant accident, but also enables the Reactor Building sump isolation valves to automatically open when the lo-lo level setpoint on the refueling water storage tank is reached.

Manual operation of other components or manual verification of proper position as part of emergency procedures is not precluded nor otherwise in conflict with the above described compliance to paragraph 4.17 of IEEE Standard 279-1971.

No exception to the requirements of IEEE Standard 279-1971 has been taken in the manual initiation circuit of safety injection. Although paragraph 4.17 of IEEE Standard 279-1971 requires that a single failure within common portions of the protective system shall not defeat the protective action by manual or automatic means, the standard does not specifically preclude the sharing of initiated circuitry logic between automatic and manual functions. It is true that the manual safety injection initiation functions associated with 1 actuation train (e.g., Train A) shares portions of the automatic initiation circuitry logic of the same logic train; however, a single failure

in shared functions does not defeat the protective action of the redundant actuation train (e.g., Train B). A single failure in shared functions does not defeat the protective action of the safety functions. It is further noted that the sharing of the logic by manual and automatic initiation is consistent with the system level action requirements of IEEE Standard 279-1971, paragraph 4.17 and consistent with the minimization of complexity.

7.3.2.3 Further Considerations

In addition to the considerations given above, a loss of instrument air or loss of component cooling water to vital equipment has been considered. Neither the loss of instrument air nor the loss of component cooling water (assuming no other accident conditions) can cause safety limits as given in the Technical Specifications to be exceeded. Likewise, loss of either 1 of the 2 will not adversely affect the core or the Reactor Coolant System nor will it prevent an orderly shutdown if this is necessary. Furthermore, all pneumatically operated valves and controls will assume a preferred operating position upon loss of instrument air. It is also noted that, for conservatism during the accident analyses (Chapter 15), credit is not taken for the instrument air systems nor for any control system benefit.

In its present design, Westinghouse does not provide any circuitry which will directly trip the reactor coolant pumps on a loss of component cooling water. Normally, indication in the control room is provided whenever component cooling water is lost. The reactor coolant pumps can run about 10 minutes after a loss of component cooling water. This provides adequate time for the operator to correct the problem or trip the plant if necessary.

In regards to the Emergency Feedwater System, there are 2 motor driven pumps and one turbine driven pump. The motor driven pumps are initiated automatically by the following signals:

1. Safety injection, through the engineered safety features load sequencer.
2. Low-low level (2/3) in any steam generator (derived from the Solid-State Protection System output cabinets).
3. Manual start.
4. Trip of all main feed pumps.
5. Undervoltage on the diesel bus.

The turbine driven pump as well as the closing of blowdown and sample valves are initiated automatically by:

1. Low-low level (2/3) in 2/3 steam generators (derived from the Solid-State Protection System output cabinets).
2. Manual start.
3. Undervoltage on both diesel buses.

To assure auto-start of the component cooling water and service water pumps on the inactive loop and to prevent diesel generator overloading on a SI/LOOP signal, the circuit breaker(s) for the out of service or spare pump/chiller for systems with swing components will be racked out.

7.3.2.4 Summary

The effectiveness of the Engineered Safety Features Actuation System is evaluated in Chapter 15, based on the ability of the system to contain the effects of Condition III and IV faults, including loss of reactor coolant and steam break accidents. The Engineered Safety Features Actuation System parameters are based upon the component performance specifications which are given by the manufacturer or verified by test for each component. Appropriate factors to account for uncertainties in the data are factored into the constants characterizing the system.

The Engineered Safety Features Actuation System must detect Condition III and IV faults and generate signals which actuate the engineered safety features. The system must sense the accident condition and generate the signal actuating the protection function reliably and within a time determined by and consistent with the accident analyses in Chapter 15.

Much longer times are associated with the actuation of the mechanical and fluid system equipment associated with engineered safety features. This includes the time required for switching, bringing pumps and other equipment to speed and the time required for them to take load.

Operating procedures require that the complete Engineered Safety Features Actuation System normally be operable. However, redundancy of system components is such that the system operability assumed for the safety analyses can still be met with certain instrumentation channels out of service. Channels that are out of service are to be placed in the tripped mode, or bypass mode in the case of Reactor Building spray.

7.3.2.4.1 Loss of Coolant Protection

By analysis of loss of coolant accident and in system tests it has been verified that (except for very small coolant system breaks, which can be protected against by the charging pumps followed by an orderly shutdown), the effects of various loss of coolant accidents are reliably detected by the low pressurizer pressure signal.

For large coolant system breaks the passive accumulators inject first, because of the rapid pressure drop. This protects the reactor during the unavoidable delay associated with actuating the active Emergency Core Cooling System phase.

High Reactor Building pressure also actuates the Emergency Core Cooling System. Therefore, emergency core cooling actuation can be brought about by sensing this other direct consequence of a primary system break; that is the Engineered Safety Features Actuation System detects the leakage of the coolant into the Reactor Building. The generation time of the actuation signal of about 1.5 seconds, after detection of the consequences of the accident, is adequate.

Reactor Building spray will provide additional emergency cooling of the Reactor Building and also limit fission product release upon sensing elevated Reactor Building pressure (Hi-3) to mitigate the effects of a loss of coolant accident.

The delay time between detection of the accident condition and the generation of the actuation signal for these systems is assumed to be about 1.0 second; well within the capability of the protection system equipment. However, this time is short compared to that required for startup of the fluid systems.

The analyses in Chapter 15 show that the diverse methods of detecting the accident condition and the time for generation of the signals by the protection systems are adequate to provide reliable and timely protection against the effects of loss of coolant.

7.3.2.4.2 Steam Line Break Protection

The Emergency Core Cooling System is also actuated in order to protect against a steam line break. Table 7.3.4 gives the time between sensing high steam line differential pressure or low steam line pressure and generation of the actuation signal. Analysis of steam line break accidents, assuming this delay for signal generation, shows that safety injection is actuated for a steam line break in time to limit or prevent further core damage for steam break cases. There is a reactor trip and the core reactivity is further reduced by the borated water injected by the Emergency Core Cooling System.

Additional protection against the effects of steam line break is provided by feedwater isolation which occurs upon actuation of the Emergency Core Cooling System. Feedwater isolation is initiated in order to prevent excessive cooldown of the reactor vessel and thus protect the Reactor Coolant System boundary.

Additional protection against a steam line break accident is provided by closure of all steam line isolation valves in order to prevent uncontrolled blowdown of all steam generators. The time for generation of the protection system signal (about 2.0 seconds) is again short compared to the time to trip the fast acting steam line isolation valves which are designed to close in less than approximately 5 seconds.

In addition to actuation of the engineered safety features, the effect of a steam line break accident also generates a signal resulting in a reactor trip on overpower or following Emergency Core Cooling System actuation. The core activity is further reduced by the Emergency Core Cooling System.

The analyses in Chapter 15 of the steam line break accidents and an evaluation of the protection system instrumentation and channel design shows that the Engineered Safety Features Actuation Systems are effective in preventing or mitigating the effects of a steam line break accident.

7.3.3 Electric Hydrogen Recombiner-Description of Instrumentation

The Electric Hydrogen Recombiner System is discussed in Section 6.2.5. Two (2) redundant recombiners, which are located inside the Reactor Building, do not require any instrumentation inside the Reactor Building for proper operation after a loss of coolant accident (LOCA). Thermocouples are provided for convenience in test and periodic checkout of the recombiner; however, they are not considered necessary to assure proper operation of the recombiner.

There are provided for each recombiner a control panel and a power supply panel which are located outside the Reactor Building, as shown on Figure 6.2.54 and Figure 6.2-58. The power supply panel contains an isolation transformer plus a controller to regulate power into the recombiners. The manually operated potentiometer for this controller is on the control panel. For equipment test and periodic checkout, a thermocouple readout instrument is also provided on the control panel for monitoring temperatures in the recombiner. To control the recombination process, the correct power input which will bring the recombiner above the threshold temperature for recombination will be set on the controller. Setting of the controller is accomplished at the local control panel and power input monitored by a wattmeter, which is also mounted on the control panel. This predetermined power setting will cover variations in Reactor Building pressure and hydrogen concentration in the post-loss of coolant accident environment. The manually operated switch for energizing a recombiner is on the control panel.

7.3.3.1 Initiating Circuits

The Hydrogen Recombiner System would be operated only during periodic testing and after a loss-of-coolant accident. Operation is initiated manually from the control station, so as to allow the heating elements within the unit to be energized. A 2 position switch is provided on the control panel for this purpose.

7.3.3.2 Logic

All operation of the electric hydrogen recombiner is by operator action; there are no automatic logic functions required. A post accident hydrogen analyzer will be used to indicate when the recombiners or the venting system should be actuated.

7.3.3.3 Bypasses

The electric hydrogen recombiners are normally not operating and are not armed for automatic actuation. Following an accident the elapsed time prior to the needed start of the equipment is in terms of hours or days. The recombiners are also operated during periodic testing. Other than these times they are in a standby mode. This standby mode is not a bypass mode, which refers to the inoperative status of systems that are normally operating.

7.3.3.4 Interlocks

There are no functional interlocks associated with the electric hydrogen recombiner.

7.3.3.5 Sequence

Each electric hydrogen recombiner is capable of being supplied from an independent onsite diesel generator. Loading on the emergency electric bus is by manual means, not by sequencers.

7.3.3.6 Redundancy

To meet the requirements for redundancy and independence, 2 electric hydrogen recombiners are provided, and each recombiner is provided with a separate power panel and control panel and each is powered from a separate Class 1E bus. The operation of a single unit is intended to provide the required hydrogen removal capability.

7.3.3.7 Diversity

Diversity between the redundant portions of the Electric Hydrogen Recombiner System is not required to protect against systematic failures, such as, multiple failures resulting from a credible single event. The design and environmental and seismic qualification of the Westinghouse electric hydrogen recombiner, as reported on in topical report WCAP-7709-L (Proprietary) with Supplements 1 to 7 and WCAP-7820 (Non-Proprietary), was found acceptable for the prototype and production models by the NRC. This acceptance was reported in NRC's letters of May 1, 1975 from D. B. Vassalo to C. Eicheldinger, Manager of W Nuclear Safety Department and of June 22, 1978 from John Stolz to T. M. Anderson regarding supplements 5, 6, and 7.

7.3.3.8 Actuated Devices

A manually operated switch on the control panel is used to initiate operation of an electric hydrogen recombiner. This switch energizes a contactor in the power supply panel which applies the 3-phase electric power source to the transformer, also in the power supply panel. Electric power input to the recombiner is controlled by a controller in the power supply panel, by means of a manually operated potentiometer and a wattmeter on the control panel. Electric power is fed to the recombiner's electric resistance heaters which are used to heat a continuous flow of Reactor Building atmosphere to the hydrogen-oxygen reaction temperature. This causes hydrogen to combine with the oxygen which is in the Reactor Building.

7.3.4 Cross References

Table 7.3-7 provides cross references outlining appropriate sections that supply descriptions of initiating circuitry, logic, bypasses, interlocks, sequencing, redundancy, diversity and actuated devices for ESF and ESF supporting systems.

7.3.5 References

1. Reid, J. B., *Process Instrumentation for Westinghouse Nuclear Steam Supply System (4 Loop Plant using WCID 7300 Series Process Instrumentation)*, WCAP-7913, 1973.

2. Katz, D. N., *Solid-State Logic Protection System Description*, WCAP-7488-L (Proprietary), 1971 and WCAP-7672 (Non-Proprietary), 1971.

3. Swogger, J. W., *Testing of Engineered Safety Features Actuation System*, WCAP-7705, Revision 2, 1976.

4. The Institute of Electrical and Electronics Engineers, Inc., *IEEE Standard: Criteria for Protection System for Nuclear Power Generating Stations*, IEEE Standard 279-1971.

5. Eggleston, F. T., Rawlins, D. H., Petrow J. R., *Failure Mode and Effects Analysis (FMEA) of the Engineering Safeguard Features Actuation System*, WCAP-8584, (Proprietary) 1976, and WCAP-8760 (Non-Proprietary), 1976.

Table 7.3-1
Instrumentation Operating Condition for Engineered Safety Features

Number	Function Unit	Number of Channels	Number of Channels to Trip
1.	Safety Injection (SIS)		
	a. Manual	2	1
	b. Reactor building pressure (Hi-1)	3	2
	c. High differential pressure between steam lines	3/steam line	2 / steam line indicating that the steam line pressure is low in comparison to the two lines
	d. Pressurizer low pressure (1)	3	2
	e. Low steam line pressure	3 pressure signals	2
2.	Reactor Building Spray		
	a. Manual (2)	4	2
	b. Reactor building pressure (Hi-3) (3)	4	2

(1) Permissible bypass if reactor coolant pressure is less than 2,000 psig.
(2) Manual actuation of reactor building spray is accomplished by actuating either of two sets (two switches per set). Both switches in a set must be actuated to obtain a manually initiated spray signal.
(3) Coincident with containment isolation Phase A.

Table 7.3-2
Instrument Operating Conditions for Isolation Functions

Number	Function Unit	Number of Channels	Number of Channels to Trip
1.	Containment Isolation		
	a. Safety Injection Phase A	See Item No. 1 (a) through (e) of Table 7.3-1	
	b. Reactor Building Pressure Phase B	See Item No. 2 (b) of Table 7.3-1	
	c. Manual		
	Phase A	2	1
	Phase B	See Item No. 2 (a) of Table 7.3-1	
2.	Steam Line Isolation		
	a. High Steam Flow in 2/3 Steam Lines Coincident with Low T_{avg}	2 flow signals/steam line 3 T_{avg} signals	1 flow signal/steam line in any two lines 2
	b. Low steam line pressure	See Item No. 1 (e) of Table 7.3-1	
	c. Reactor Building Pressure (Hi-2)	3	2
	d. Manual(1)	1/loop	1/loop

(1) System level isolation also available

Table 7.3-2 (continued)
Instrument Operating Conditions for Isolation Functions

Number	Function Unit	Number of Channels	Number of Channels to Trip
3.	Feedwater Line Isolation		
	a. Safety Injection	See all signals Item No. 1 of Table 7.3-1	
	b. Steam Generator High-High Level (any loop)	3/loop	2/loop
	c. Low T_{avg} Coincident with Reactor Trip	3	2

(1) System level isolation also available

Table 7.3-3
Interlocks for Engineered Safety Features Actuation System

Designation	Input	Function Performed
P-4	Reactor tripped	Presence of P-4 signal actuates turbine trip
		Presence of P-4 signal closes main feedwater valves on T_{avg} below low T_{avg} setpoint
		Presence of P-4 signal prevents opening of main feedwater valves which were closed by safety injection or high-high steam generator water level
		Presence of P-4 signal allows manual reset/block of the automatic reactuation of safety injection
		Absence of P-4 signal defeats the manual reset/block preventing automatic reactuation of safety injection
P-11	2/3 pressurizer pressure below setpoint (Presence of P-11 signal permits functions shown. Absence of signal defeats functions shown)	Allows manual block of safety injection actuation on low pressurizer pressure and level signal
		Blocks automatic opening of the pressurizer power relief valves
P-12	2/3 (1)T_{avg} below setpoint (Presence of P-12 signal performs or permits functions shown. Absence of signal defeats function shown)	Allows manual block of safety injection actuation and steam line isolation on low steam line pressure
		Blocks steam dump except for cooldown valves
		Allows manual bypass of steam dump block for the cooldown valves only

(1) This signal in coincidence with high steam line flow actuates steam line isolation.

Table 7.3-3 (continued)
Interlocks for Engineered Safety Features Actuation System

Designation	Input	Function Performed
P-14	2/3 Steam generator water level above setpoint on any steam generator (Presence of signal performs or permits functions shown)	Closes all feedwater control valves
		Trips all main feedwater pumps which closes the pump discharge valves
		Actuates turbine trip

Table 7.3-4
Secondary System Accidents and Required Instrumentation,
Minor Secondary System Pipe Break
Major Secondary System Pipe Break

Channel	Response Time (4)	Accuracy (1)	Range
Reactor Building Pressure (2)	1.5 sec full scale	± 1.75% of	-5 to 15 psig
Steam Line Pressure(2)	1.0 sec	± 2.25% of span	0 to 1300 psig
Steam Line Differential Pressure	1.0 sec	± 3.0% of span	0 to 1200 psig
Steam Line Flow(2)	2.0 sec	± 4.5% of maximum guaranteed flow over the pressure range of 700 to 1200 psig	0 to 120% maximum calculated flow
T_{avg}(2)	8.5 sec(3)	± 3.6°F	530 to 63 °F
Pressurizer Pressure	1.0 sec	± 1.75% of span	1700 to 2500 psig

(1) See Section 7.1 for definition of ESFAS accuracy.
(2) Used for closing main steam line stop valves.
(3) RCS T_{avg} as measured at the resistance temperature detector output.
(4) That time interval from when the monitored parameter exceeds its ESF setpoint at the channel sensor until the channel bistable changes state.

Table 7.3-5
Primary System Accidents and Required Instrumentation
Ruptures in Small Pipes, Cracks in Large Pipes,
Ruptures of Large Pipes, Steam Generator Tube Rupture

Channel	Response Time(3)	Accuracy (1)	Range
Pressurizer Pressure	1.0 sec	± 1.75% of span	1700 to 2500 psig
Reactor Building Pressure (2)	1.5 sec	± 1.75% of span	-5 to 15 psig

(1) See Section 7.1 for definition of ESFAS accuracy.
(2) Not required for steam generator tube rupture.
(3) That time interval from when the monitored parameter exceeds its ESF setpoint at the channel sensor until the channel bistable changes state.

Table 7.3-6
Engineered Safety Feature Loading Sequence
Control Panels, Degree of Conformance With
Regulatory Guide 1.53 and IEEE-379-1972 (1)

Criteria	FSAR SECTION
Regulatory Guide 1.53	
C.1, IEEE 379-1972	See IEEE 379 comparison below
C.2, Continuity Checks	7.3.2.2.5.9
C.3, Interconnections	7.1.2.1.7, 7.1.2.1.8, 7.1.2.2, 7.3.2.2, 7.3.2.2.3, 7.3.2.2.7
C.4, Protection System Logic and Actuator System	7.3.2.2.5.9, 7.3.2.3
IEEE 379-1972	
3(1), Redundancy	7.1.2.2, 7.3.1.1.3. 8.3.1.4
3(2), Detectability	7.3.2.2.5.9
3(3), Nondetectability	None identified, NA
3(4), Multiple Faults	NA, included in 7.3.2.2.5.9
3(5), Completing Protective Functions	7.3.2.2, 7.3.2.2.3, 8.3.1.4
3(6), DBE and Single Failure	3.10, 3.11, 7.3.1.2.5
3(7), Operational Reliability	NA, included in design concept
5.1, Classification	NA, included in design concept
5.2, Undetectable Failures	NA, testing features are provided to detect all failures
5.3, Common Mode Failures	None identified, NA
6.1, General	7.1.2.2, 7.3.1.1, 7.3.1.1.3, 7.3.1.1.5, 7.3.2.4
6.2, Channels	NA, included in design concept
6.3, Protection System Logic	NA, redundant logic is completely separate
6.4, Actuator Circuit	NA to this equipment
6.5, Type 2 and 3 Single Failure Analysis	3.10, 3.11, 7.3.1.2.5, 7.3.2.3

Table 7.3-6 (continued)
Engineered Safety Feature Loading Sequence
Control Panels, Degree of Conformance With
Regulatory Guide 1.53 and IEEE-379-1972 (1)

Criteria	FSAR SECTION
IEEE 379-1972 (Continued)	
6.6, Overall System - Failure Analysis	NA, no interconnection between control and protective systems for this equipment

(1) Formal analyses have not been provided. However, FSAR Sections referenced indicate compliance with the concept outlined in the criteria.

Table 7.3-7
Instrument and Control Data Cross References

		Reference	Related Drawings [1]	
Category	System	FSAR Sections	FSAR Figure	Drawing Number
Engineered Safety Features System	Engineered Safety Features Actuation System (ESFAS)	7.1.2.5, 7.1.2.6, 7.3.1.1, 7.3.2.2.3, 7.3.2.2.5.5, 7.3.2.2.6, 7.5.4 Tables 7.3-1, 7.3-3	7.2-1 Sh. 8 7.3.1 thru 7.3.3 7.5-1 thru 7.5-6	- - -
			-	B-208-066 B-208-094 B-208-103 D-2544-1013 7244D38 (1MS-42-017)
	Reactor Building Heat Removal			
	Reactor Building Ventilation	6.2.2.2.2.1, 6.2.2.2.2.2, 6.2.2.5.2.2, 7.1.2.6., 7.3.1.1, 7.3.1.1.6, 7.5.4, 9.2.1.5, 9.4.7.2.5 Notes 3,6	6.2-49 7.3-1 - -	- - B-208-004 Sh AH273 thru AH276 8756D01 (1MS-51-221)
	Reactor Building Spray System	6.2.2.2.1, 6.2.2.5.1.6, 7.1.2.6, 7.3.1.1, 7.3.1.1.6, 7.5.4 Notes 3,6	6.2-46 - - -	- B-208-005 B-208-097 8756D01 (1MS-51-221)
	Reactor Building Air Purification and Cleanup	6.2.2.2.1, 6.2.2.5.1.6, 6.2.3, 7.3.1.1, 7.3.1.1.6, 7.5.4 Notes 3,6.	6.2-46 - - -	- B-208-005 B-208-097 8756D01 (1MS-51-221)
Engineered Safety Features System	Containment Isolation	6.2.4, 7.3.1.1, 7.5.4 Tables 6.2-54, 7.3-2 Notes 3,6	6.2-52	-

Table 7.3-7 (continued)
Instrument and Control Data Cross References

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number
	Combustible Gas Control	6.2.4, 6.2.5, 7.3.3 Table 6.2-54	6.2-54 6.2-58	- B-208-054
	Containment Leakage Testing	6.2.6, 6.2.6.1.5 Note 7	6.2-59 6.2-60	- -
	Safety Injection System			
	Isolation Valves - Accumulator N2 Supply (8880)	6.2.4, 6.3.2.2.7, 6.3.5.5 7.1.2.5, 6.3.2.11.1, 7.3.1.1, 7.5.4	6.3-1 Sh 2	B-208-095 Sh SI72
		Tables 7.3-1, 7.3-2, 7.3-3, 6.2-54 Notes 2, 3, 4, 6		
	Isolation Valves - Accumulator Test (8871 & 8961)	6.2.4, 6.3.2.2.7, 6.3.5.5, 7.1.2.5, 6.3.2.11.1, 7.3.1.1, 7.5.4	6.3-1 Sh 2	B-208-095, Sh SI59, SI76
		Tables 7.3-1, 7.3-2, 7.3-3, 6.2-54, Notes 2, 3, 4, 6		
	Isolation Valves - Accumulator Fill Line (8860)	6.2.4, 6.3.2.2.7, 7.1.2.5, 6.3.2.11.1, 6.3.5.5, 7.3.1.1, 7.5.4	6.3-1 Sh 2	B-208-095, Sh SI58
		Tables 6.2-54, 7.3-1, 7.3-3 Notes 2, 3, 4, 6		
Engineered Safety Features System	Sump Isolation Valves (Recirc. following SI) 8811A, B, & 8812A, B	6.2.4, 6.3.2.2.7, 6.3.5.5, 6.3.2.11.1, 7.6.7	7.6-9	B-208-095, Sh SI-21, 22, 23, 24
		Tables 6.2-54, 7.3-1, 7.3-3 Note 3		

Table 7.3-7 (continued)
Instrument and Control Data Cross References

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number
	Isolation Valves (8801A & B)	6.2.4, 6.3.2.2.7, 6.3.5.5, 7.1.2.5, 6.3.2.11, 7.3.1.1	6.3-1 Sh 1	B-208-095 Sh SI09, 10, 11, 12
		Tables 6.2-54, 7.3-1, 7.3-3, 6.3-7 Notes 2, 3, 5, 6		
	Isolation Valves - Accumulator (8808A, B, C)	6.3.2.2.7, 7.6.4, 6.3.2.11, 7.3.1.1, 6.3.2.15	7.6-2	B-208-095, Sh SI-16, 17, 18
		Tables 7.3-1, 7.3-2, 7.3-3 Notes 2,3, 5		
	RHR/LO-HEAD SI Pump	6.3.2.2.7. 6.3.2.2.4.1, 7.1.2.5, 7.3.1.1, 7.3.1.1.6, 6.3.2.11.1	6.3-1 Sh 3 7.3-1	B-208-084 Sh RH-01, 02
		Tables 7.3-1, 7.3-3, 8.3-3, 6.3-7 Notes 3, 5, 6		
	CENT. CHARGING/HI HEAD SI Pump	6.3.2.2.4.2, 6.3.2.2.7, 7.1.2.5, 7.3.1.1.5, 6.3.2.11.1, 7.3.1.1	6.3-1 Sh 3 7.3-1	B-208-021 Sh CS-04, 05, 06, 07, 08
		Tables 7.3-1, 7.3-3, 8.3-3, 6.3-7 Notes 3, 5, 6		
Engineered Safety Features System	Habitability Systems	6.4, 6.4.1.5, 7.3.1.1 7.3.1.1.5 Note 6	9.4-1	- B-208-04, Sh AH102 thru AH105

Table 7.3-7 (continued)
Instrument and Control Data Cross References

Category	System	Reference FSAR Sections	Reference FSAR Figure	Related Drawings (1) Drawing Number
	Fission Product Removal and Control Systems			
	Reactor Building Cooling Unit HEPA Filters	6.2.2.2.2, 6.2.2.5.2, 6.5.1.3, 6.5.1.5.1, 7.3.1.1, 7.5.4, Notes 3, 6	6.2-49	- B-208-004, Sh AH273 thru AH284
	Control Room Emergency Filter Plenums	6.4, 6.4.1.5, 6.5.1.3, 6.5.1.5.2, 7.3.1.1, 7.3.1.1.5, 9.4.1.2.1, 9.4.1.3 Note 6	9.4-1 -	B-208-004, Sh AH102, AH103
	Fuel Handling Building Charcoal Exhaust System	6.5.1.3, 6.5.1.5.3. 7.3.1.1, 7.3.1.1.5 9.4.3.2.1, 9.4.3.3 Notes 3, 6	7.3-1 9.4-11- -	- - B-208-004 Sh AH174, AH175 8576D01 (1MS-51-221)
	Emergency Feedwater System	7.1, 7.3.1.1 7.3.1.1.5, 7.5.4, 10.4.9.2, 10.4.9.3 10.4.9.5 Note 6	7.3-1 10.4-16 - -	- - B-208-032, 8576D01 (1MS-51-221)

Table 7.3-7 (continued)
Instrument and Control Data Cross References

		Reference		Related Drawings [1]
Category	System	FSAR Sections	FSAR Figure	Drawing Number
Engineered Safety Features Supporting Systems	Component Cooling Water System	7.1, 7.1.2.6, 7.3.1.1, 7.3.1.1.5, 7.4, 7.5.4, 9.2.2.1, 9.2.2.2, 9.2.2.3, 9.2.2.5, 11.4.2 Note 3	7.3-1 9.2-4 thru 9.2-7 - - 	- - - B-208-005 B-208-011
	Diesel Generator System	7.3.1.1, 7.4, 8.3.1.1.2 9.5.4.2, 9.5.4.3, 9.5.4.5 9.5.5.3, 9.5.5.5, 9.5.6.1, 9.5.7.3, 9.5.7.5, 9.5.8.3 Notes 3, 6	8.2-3 8.3-oh thru 8.3-oj 9.5-2 9.5-3 9.5-4 9.5-6 9.5-7 - -	- - - B-208-005 B-208-023
Engineered Safety Features System	Service Water System	7.1, 7.1.2.6, 7.3.1.1 7.3.1.1.5, 7.4, 7.5.4 9.2.1.2, 9.2.1.3 9.2.1.5 Note 3	7.3-1 9.2-1 9.2-2 (4 Sheets) - - -	- - - B-208-005 B-208-101 8756D01 (1MS-51-221)
	Chilled Water System	7.1.2.6, 7.3.1.1, 7.3.2.2.5, 7.5.4, 9.4.7.2.4, 9.4.7.3 Note 3	7.3-1 9.4-22 9.4-22 9.4-24 - - -	- - - - B-208-005 B-208-109 8756D01 (1MS-51-221)

Table 7.3-7 (continued)
Instrument and Control Data Cross References

Category	System	Reference FSAR Sections	Reference FSAR Figure	Related Drawings [1] Drawing Number
Engineered Safety Features System	Heating, Ventilating and Air Conditioning Systems			
	Auxiliary and Fuel Handling Building Ventilation Systems	6.5.1.3, 6.5.1.5.3, 7.3.1.1, 7.3.1.1.5, 9.4.2.1, 9.4.2.2, 9.4.2.3, 9.4.3.2, 9.4.3.3 Notes 3, 6	7.3-1 9.4-10 9.4-11 - - -	- - - - B-208-004 Sh AH174, AH175 B-208-108, Sh VL05 thru VL09 8756D01 (1MS-51-221)
	Control Building Ventilation Systems	6.4, 6.4.1.5, 6.5.1.3, 6.5.1.5.2, 7.3.1.1, 7.3.1.1.5, 9.4.1.2, 9.4.1.3, 12.2.4.2.1 Note 6	9.4-1 9.4-2 9.4-3 9.4-5	- - - - B-208-004, Sh AH102 thru AH105, AH107, AH108, AH147, AH148 8756D01 (1MS-51-221)
	Diesel Generator Building Ventilation System	7.3.1.1.5, 8.3.1.1.2.4, 9.4.7.2.1, 9.4.7.3 Notes 2, 3, 6	9.4-18 -	B-208-004, Sh AH 164 thru AH167

Table 7.3-7 (continued)
Instrument and Control Data Cross References

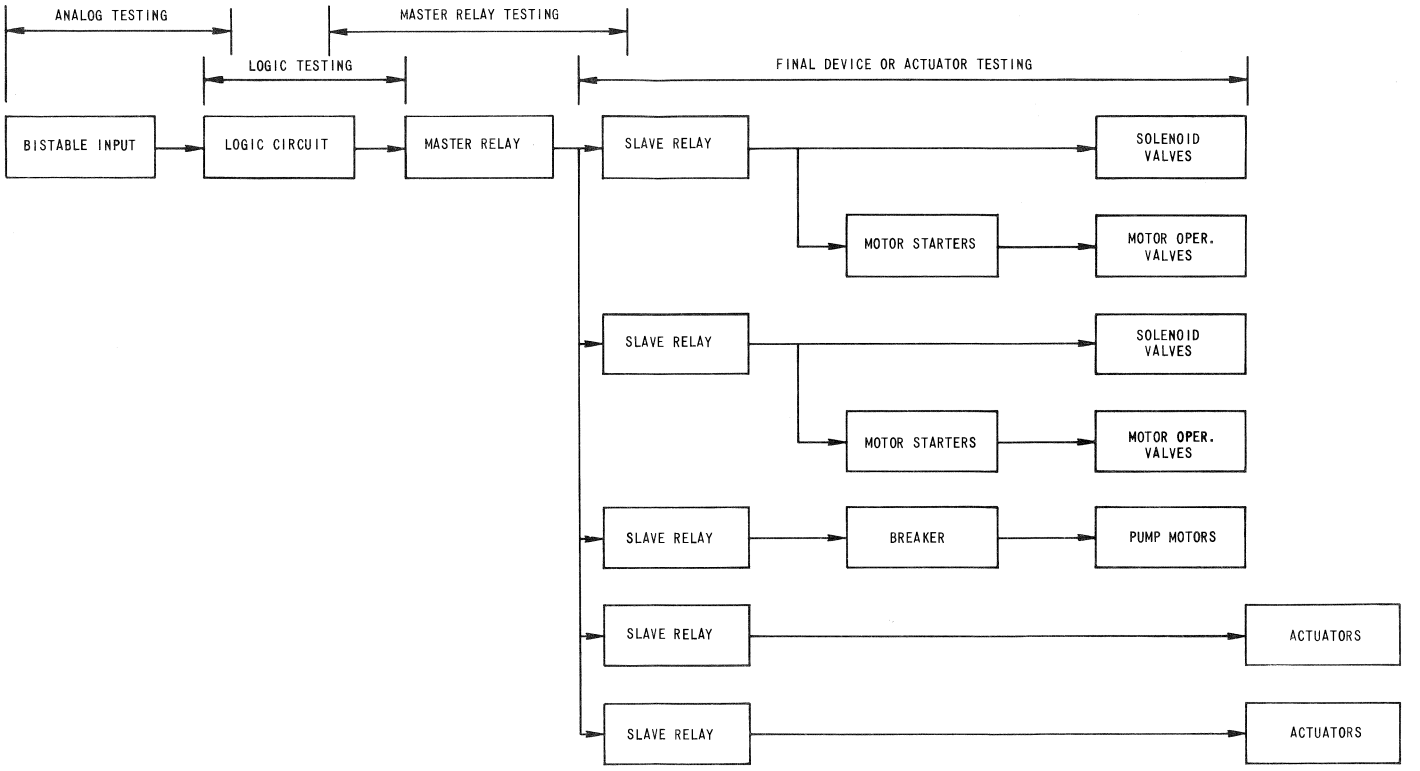
Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number
Engineered Safety Features System	Intermediate Building Ventilation System	7.3.1.1, 7.3.1.1.5, 9.4.6.2, 9.4.6.3	9.4-15 thru 9.4-17 -	- - B-208-004 Sh AH194 thru AH197 B-208-108 Sh VL18, VL19, VL22, VL24, VL26, VL27, VL30, VL31 8756D01 (1MS-51-221)
	Reactor Building Ventilation Systems	6.2.2.2.2.1, 6.2.2.2.2.2, 6.2.2.5.2.2, 7.1.2.6, 7.3.1.1, 7.3.1.1.5, 7.5.4, 9.2.1.5, 9.4.7.2.5, Notes 3, 6	6.2-49 7.3-1 -	- - - B-208-004 Sh AH273 thru AH276 8756D01 (1MS-51-221)
	Service Water Pumphouse Ventilation System	7.3.1.1.5, 9.4.7.2.2, 9.4.7.3	9.4-19 - -	B-208-004 Sh AH326 thru AH331 8756D01 (1MS-51-221)

(1) FSAR figure numbers refer to figures in the FSAR; drawing numbers refer to drawings in the Wiring Schematic Package (see Section 1.7)
(2) Not sequenced
(3) Not diverse
(4) Solenoid valve is the actuation device
(5) Motor Control Center is actuation device
(6) No Interlocks or Bypasses are provided which would inhibit ESF actuation.
(7) The containment leakage testing system is not an Engineered Safety Features System or an essential Auxiliary Supporting System. The system includes only that equipment and instrumentation required to perform the initial and periodic containment leakage testing during plant shutdown. All penetrations through containment are capped during normal plant operation.

Figure 7.3-1
DRAWING D-203-203
FSAR FIGURE REFERENCE

Figure 7.3-2

TYPICAL ENGINEERED SAFETY FEATURES TEST CIRCUITS



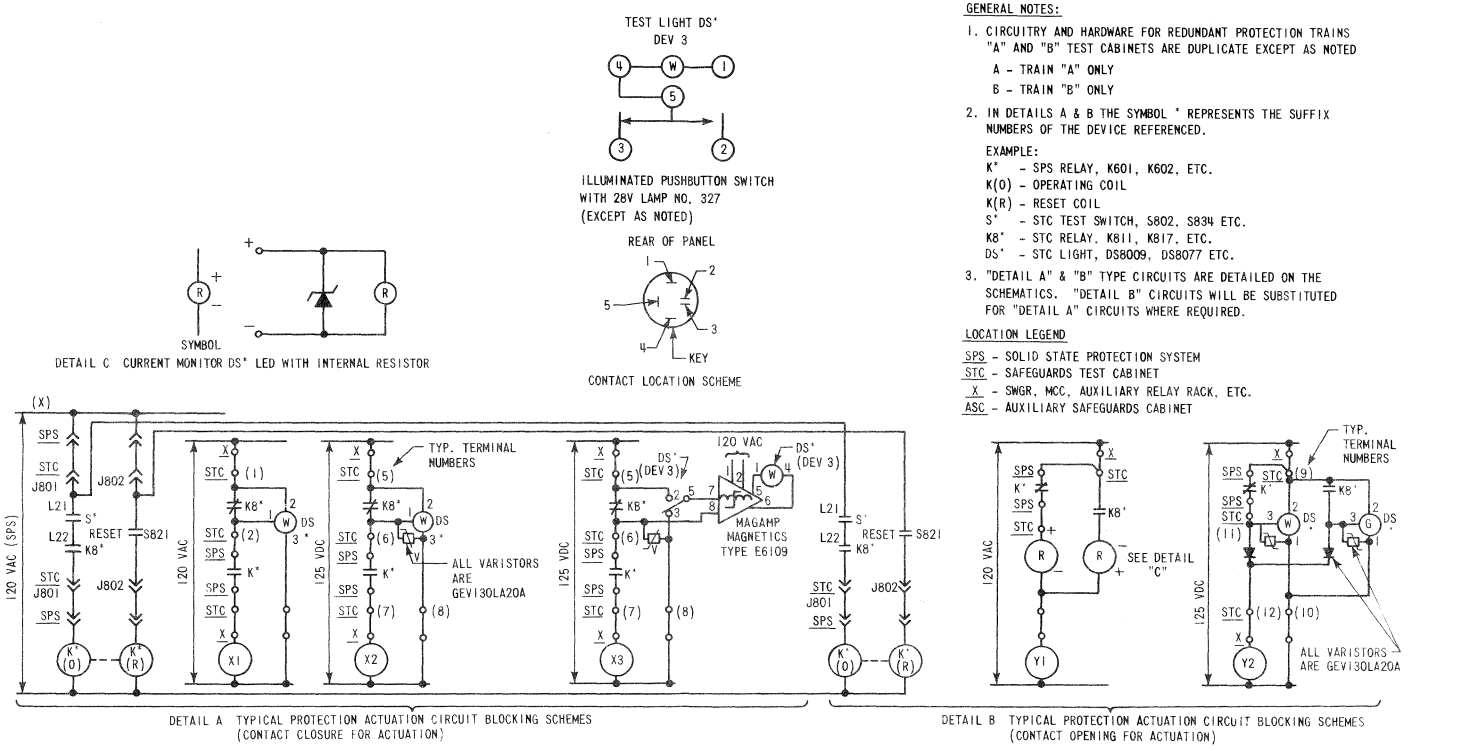
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Typical Engineered Safety Features Test Circuits

Figure 7.3-2

Figure 7.3-3

ENGINEERED SAFETY FEATURES TEST CABINET-INDEX, NOTES AND LEGEND



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Engineered Safety Features Test Cabinet - Index, Notes and Legend Figure 7.3-3

Amendment 0
August 1984

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The functions necessary for safe shutdown are available from instrumentation channels that are associated with the major systems in both the primary and secondary of the Nuclear Steam Supply System. These channels are normally aligned to serve a variety of operational functions, including startup and shutdown as well as protective functions. There are no identifiable safe shutdown systems per se. However, prescribed procedures for securing and maintaining the plant in a safe condition can be instituted by appropriate alignment of selected systems in the Nuclear Steam Supply System. The discussion of these systems together with the applicable codes, criteria and guidelines is found in other sections of this Final Safety Analysis Report. In addition, the alignment of shutdown functions associated with the engineered safety features which are invoked under postulated limiting fault situations is discussed in Chapter 6 and Section 7.3.

The instrumentation and control functions which are required to be aligned for maintaining safe shutdown of the reactor that are discussed in this section are the minimum number under nonaccident conditions. These functions will permit the necessary operations that will:

1. Prevent the reactor from achieving criticality in violation of the Technical Specifications and
2. Provide an adequate heat sink such that design and safety limits are not exceeded.

7.4.1 Description

The designation of systems that can be used for safe shutdown depends on identifying those systems which provide the following capabilities for maintaining a safe shutdown:

1. Boration (see Section 9.3.4, “Chemical and Volume Control System”).
2. Adequate supply for emergency feedwater (see Section 10.4.9, “Emergency Feedwater System”).
3. Residual heat removal (see Section 5.5.7, “Residual Heat Removal System”).

These systems are identified in the following lists together with the associated instrumentation and controls provisions. The identification of the monitoring indicators (Section 7.4.1.1) and controls (Section 7.4.1.2) are those necessary for maintaining a hot shutdown. The equipment and services available for a cold shutdown are identified in Section 7.4.1.4.

7.4.1.1 Monitoring Indicators

Safety related display instrumentation, as described in Section 7.5, is provided outside as well as inside the Control Room. The necessary indicators for maintaining a hot shutdown are as follows:

1. Water level indicator for each steam generator (1).
2. Pressure indicator for each steam generator (1).
3. Pressurizer water level indicator (1).
4. Pressurizer pressure indicator (1).

In addition, the following indicators are also provided:

1. Reactor Building temperature (1).
2. Volume control tank level (1).
3. Charging pressure and flow (1).
4. Emergency boration flow (1).
5. Condensate storage tank level (1).
6. Letdown flow (1).

7.4.1.2 Controls

7.4.1.2.1 General Considerations

1. The turbine is tripped. (Note that this can be accomplished at the turbine as well as in the Control Room.)
2. The reactor is tripped. (Note that this can be accomplished at the reactor trip switchgear as well as in the Control Room.)
3. All automatic systems continued functioning. (Discussed in Sections 7.2 and 7.7.)

(1) Indication is physically located on the Control Room Evacuation Panel (CREP).

4. For certain equipment having motor controls outside the Control Room (which duplicate the functions inside the Control Room) the controls are provided with a selector switch at the local station which transfers control of the switchgear from the Control Room to the local station(s). Placing the local selector switch in the local operating position will give an annunciating alarm in the Control Room. The transfer switches are designed so that after the transfer switch is in the local position, a failure in the Control Room or Cable Spreading Room does not cause a failure in the local control. Also, a failure in the local control circuit beyond the transfer switch does not cause a failure in the remote control circuit when the control is transferred there. The following equipment is provided with transfer switches:

   a. Pressurizer heater backup group 1 (4) (see Section 5.5.10, “Pressurizer”).

   b. Pressurizer heater backup group 2 (4) (see Section 5.5.10, “Pressurizer”).

   c. Charging flow controller (setpoint station) (see Section 9.3.4, “Chemical and Volume Control System”).

   d. Emergency borate valve (see Section 9.3.4, “Chemical and Volume Control System”).

   e. Turbine driven emergency feedwater pump flow control valves (see Section 10.4.9, “Emergency Feedwater System”).

   f. Motor driven emergency feedwater pump flow control valves (see Section 10.4.9, “Emergency Feedwater System).

   g. Letdown line isolation valves (see Section 9.3.4, “Chemical and Volume Control System”).

   h. Letdown orifice A, B, and C isolation valves (see Section 9.3.4, “Chemical and Volume Control System”).

   i. Steam supply valve to emergency feedwater pump turbine (see Section 10.4.9, “Emergency Feedwater System”).

   j. NOT USED.

   k. Service water pumps A and B (see Section 9.2.1, “Service Water System”).

   l. Service water pump C (as part of A train and as part of B train) (see Section 9.2.1, “Service Water System”).

   m. Boric acid transfer pump B (see Section 9.3.4, “Chemical and Volume Control System”).

   n. Pressurizer power operated relief valves PCV445A and PCV444B (see Section 5.5.13, “Safety and Relief Valves”).

   The backup heater groups are designed to be available during plant operations required to maintain hot shutdown or bring the plant to cold shutdown. However, this availability is not a mandatory requirement for maintaining hot shutdown or for bringing the plant to cold shutdown.

   These switches are shown by Figures 7.4-1 through 7.4-2.

Use of the transfer switch removes the automatic actuation capability for the following components (such as motors):

a. Pressurizer heater backup group 1 (see Section 5.5.10, “Pressurizer”).

b. Pressurizer heater backup group 2 (see Section 5.5.10, “Pressurizer”).

c. Service water pumps (see Section 9.2.1, “Service Water System”).

d. Boric acid transfer pump B (see Section 9.3.4, “Chemical and Volume Control System”).

e. Pressurizer power operated relief valves PCV445A and PCV444B (see Section 5.5.13, “Safety and Relief Valves”).

Removal of this automatic actuation capability does not jeopardize plant safety, since no accident is postulated to occur concurrent with the need for this transfer.

5. Certain motor operated valves, such as for service water backup water supply to the Emergency Feedwater System (see Section 10.4.9, “Emergency Feedwater System”) will have their electrical operators disconnected and the valves will be positioned manually by disconnecting the main circuit breaker at the motor control center and operating the valve by means of the handwheel after depressing a lever n the direction marked “Manual Control”.

6. Certain pumps will be controlled from their motor switchgear mechanical switches. The ability to perform the shutdown function is not jeopardized by a failure in the Control Room or Cable Spreading Room since redundant equipment could be used. In the unlikely event that a failure in the Control Room or Cable Spreading Room short circuits the switchgear trip circuit, local operation of the switchgear (without control power) would isolate this fault. Such operation can be accomplished as follows:

   a. Remove both the closing and trip fuses to isolate d-c control voltage.

   b. Manually close the circuit breaker utilizing operating mechanism located on the breaker.

   c. Manually trip the circuit breaker utilizing operating mechanism located on the breaker.

7. Certain redundant equipment (air compressors, see Section 9.3.1, “Compressed Air Systems”); heating, ventilating and air conditioning chillers (see Section 9.4.7, “Miscellaneous Building Ventilation and Cooling Systems”); and diesel generators (see Sections 8.3.1.1.2, “Onsite Standby Power Supply,” and 9.5, “Other Auxiliary Systems”) have comprehensive local control cabinets with functionally parallel start/stop controls extended to the Control Room. The ability to perform the shutdown function is not jeopardized by a failure in the Control Room or Cable Spreading Room since redundant equipment could be used. In the unlikely event that a failure in the Control Room or Cable Spreading Room prevents local control of this equipment, isolation of the fault in parallel control circuits would require removal of the external control wires at the local control cabinets.

7.4.1.2.2 Pumps and Fans

1. Emergency feedwater pumps

   In the event of a trip of all main feedwater pumps (see Section 10.4.7, “Condensate and Feedwater Systems”), feedwater pumps (see Section 10.4.9, “Emergency Feedwater System”) start automatically or can be started manually. Start/stop motor controls located locally (as well as being inside the Control Room) are provided as well as handwheel control for the valves.

2. Charging and boric acid transfer pumps

   Start/stop control for both boric acid pumps is located in the Control Room. In addition, control for one pump is located at CREP.

   The start/stop control for 3 charging pumps is located in the Control Room. In addition, controls for “B” pump and “C” pump aligned to “B” train are located at their respective switchgear. Also, all circuit breakers for the 3 pumps can be closed or tripped utilizing the operating mechanisms located on their respective breakers.

3. Service water pumps (2) (see Section 9.2.1, “Service Water System”).

   Start/stop motor controls are located outside as well as inside the Control Room.

4. Component cooling water pumps (see Section 9.2.2, “Component Cooling Water System”). The circuit breakers can be closed or tripped from operating mechanisms located on their respective breakers.
5. Instrument air compressors (see Section 9.3.1, “Compressed Air Systems”). These compressors start automatically on low air pressure.
6. Reactor building cooling units (see Section 6.2.2, “Reactor Building Heat Removal Systems”). Start/stop motor controls with a selector switch are provided for the fan motors. The controls are located outside as well as inside the Control Room.

7.4.1.2.3 Diesel Generators (see Section 8.3.1.1.2, “Onsite Standby Power Supply,” and 9.5, “Other Auxiliary Systems”)

These units start automatically following a loss of voltage on their respective buses. However, manual controls for diesel startup are also provided locally at the diesel generators (as well as inside the Control Room).

(2) Control and indication are physically located on the CREP

7.4.1.2.4 Valves and Heaters

1. Charging flow control valves[(2)] (see Section 9.3.4, “Chemical and Volume Control System”)

   Remote manual control with a selector switch for the charging line flow control valves is provided outside, as well as inside, Control Room. These controls duplicate functions that are available inside the Control Room.

2. Letdown orifice isolation valves[(2)] (see Section 9.3.4, “Chemical and Volume Control System”).

   Open/close controls with a selector switch for the letdown orifice isolation valves are grouped with the controls for the charging flow control valve. These controls duplicate functions that are inside the Control Room.

3. Emergency feedwater control valves[(2)] (see Section 10.4.9, “Emergency Feedwater System”)

   Controls for these valves are located outside as well as inside the Control Room.

4. Condenser steam dump and atmospheric steam relief valves (see Section 10.4.4, “Turbine Bypass System”)

   The condenser steam dump and atmospheric relief valves are automatically controlled. Manual control is provided locally as well as inside the Control Room for the atmospheric relief valves. Steam dump to the condenser is blocked on high condenser pressure.

5. Pressurizer heater control [(2)] (see Section 7.7.1.5, “Pressurizer Pressure Control”)

   On/off control with selector switch is provided for 2 backup heater groups. The heater groups are connected to separate buses, such that each can be connected to separate diesels in the event of loss of outside power. The controls are grouped with the charging flow controls and duplicate functions that are available inside the Control Room.

(2) Control and indication are physically located on the CREP

7.4.1.3 Control Room Evacuation

The instrumentation and controls listed in Sections 7.4.1 and 7.4.1.2 that are used to achieve and maintain a safe shutdown are available in the event an evacuation of the Control Room is required. These controls and instrumentation channels together with the equipment identified in Section 7.4.1.4 identify the potential capability for cold shutdown of the reactor subsequent to a Control Room evacuation through the use of suitable procedures. Table 7.4-1 and Figures 7.4-1 through 7.4-2 address the local control stations and the relative locations of these control stations in the plant. The design basis for Control Room evacuation does not consider a concurrent Condition II, III, or IV event, nor a single failure.

Control Room evacuation resulting from a fire in the control complex and the ability to achieve safe shutdown concurrent with the fire is demonstrated in the Fire Protection (FP) DBD.

7.4.1.4 Equipment and Systems Available for Cold Shutdown

1. Reactor coolant pumps (see Section 5.5.1, “Reactor Coolant Pumps”).
2. Emergency feedwater pumps (see Section 10.4.9, “Emergency Feedwater System”).
3. Boric acid transfer pumps (see Section 9.3.4, “Chemical and Volume Control System”).
4. Charging pumps (see Section 9.3.4, “Chemical and Volume Control System”).
5. Service water pumps (see Section 9.2.1, “Service Water System”).
6. Reactor building fans (see Section 6.2.2, “Reactor Building Heat Removal Systems,” and Section 9.4.8, “Reactor Building Cooling and Filtering Systems”).
7. Component cooling water pumps (see Section 9.2.2, “Component Cooling Water System”).
8. Residual heat removal pumps (see Section 5.5.7, “Residual Heat Removal System)[3].
9. Certain motor control center and switchgear Sections (see Section 8.3, “Onsite Power Systems”).
10. Controlled steam release and feedwater supply (see Sections 7.7.1.8, “Steam Dump Control” and 10.4.4, “Turbine Bypass System”).
11. Boration capability (see Section 9.3.4, “Chemical and Volume Control System”).

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(3) Instrumentation and controls for these systems may require some modification in order that their functions may be performed from outside the Control Room. Note that the reactor plant design does not preclude attaining the cold shutdown condition from outside the Control Room. An assessment of plant conditions can be made on the long term basis (a week or more) to establish procedures for making the necessary physical modifications to instrumentation and control equipment in order to attain cold shutdown. During such time the plant could be safely maintained at hot shutdown condition.
Detailed procedures to be followed in effecting cold shutdown from outside the Control Room are best determined by plant personnel at the time of the postulated incident.

12. Nuclear Instrumentation System source and intermediate ranges (both ranges are provided remote from the Control Room, but only source range is independent of the Control Room). (See Sections 7.2, “Reactor Trip System,” and 7.7, “Control Systems Not Required for Safety”).
13. Reactor coolant inventory control (charging and letdown) (see Section 9.3.4, “Chemical and Volume Control System”).
14. Pressurizer pressure control including opening control for pressurizer relief valves (heaters and spray) (see Section 7.7.1.5, “Pressurizer Pressure Control”). (3)

In addition, the safety injection signal trip circuit must be defeated and the accumulator isolation valves closed (3) (see Sections 6.3, “Emergency Core Cooling System,” and 7.3, “Engineered Safety Features Actuation System”).

The Fire Protection (FP) DBD identifies Virgil Summer Nuclear Station’s compliance used to achieve cold shutdown in the event of a fire in the plant.

7.4.2 Analysis

Hot shutdown is a stable plant condition, automatically reached following a plant shutdown. The hot shutdown condition can be maintained safely for an extended period of time. In the unlikely event that access to the Control Room is restricted, the plant can be safely kept at a hot shutdown until the Control Room can be re-entered by the use of the monitoring indicators and the controls listed in Sections 7.4.1.1 and 7.4.1.2. These indicators and controls are provided outside as well as inside the Control Room.

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(3) Instrumentation and controls for these systems may require some modification in order that their functions may be performed from outside the Control Room. Note that the reactor plant design does not preclude attaining the cold shutdown condition from outside the Control Room. An assessment of plant conditions can be made on the long term basis (a week or more) to establish procedures for making the necessary physical modifications to instrumentation and control equipment in order to attain cold shutdown. During such time the plant could be safely maintained at hot shutdown condition.
Detailed procedures to be followed in effecting cold shutdown from outside the Control Room are best determined by plant personnel at the time of the postulated incident.

The safety evaluation of the maintenance of a shutdown with these systems and associated instrumentation and controls has included consideration of the accident consequences that might jeopardize safe shutdown conditions. The accident consequences that are germane are those that would tend to degrade the capabilities for boration, adequate supply for emergency feedwater, and residual heat removal.

The results of the accident analysis are presented in Chapter 15. Of these the following produce the most severe consequences that are pertinent:

1. Uncontrolled Boron Dilution.
2. Loss of Normal Feedwater.
3. Loss of External Electrical Load and/or Turbine Trip.
4. Loss of Offsite Power to the Station Auxiliaries.

It is shown by these analyses that safety is not adversely affected by these incidents with the associated assumptions being that the instrumentation and controls indicated in Sections 7.4.1.1 and 7.4.1.2 are available to control and/or monitor shutdown. These available systems will allow a maintenance of hot shutdown even under the accident conditions listed above which would tend toward a return to criticality or a loss of heat sink.

The results of the analysis which determined the applicability to the Nuclear Steam Supply System safe shutdown systems of the NRC General Design Criteria, IEEE Standard 279-1971, applicable NRC Regulatory Guides and other industry standards are presented in Table 7.1-1. The functions considered and listed below include both safety-related and nonsafety-related equipment.

1. Reactor Trip System (see Section 7.2, “Reactor Trip System”).
2. Engineered Safety Features Actuation System (see Section 7.3, “Engineered Safety Features Actuation System”).
3. Safety-related display instrumentation for post accident monitoring (see Section 7.5, “Safety-Related Display Instrumentation”).
4. Main control board (see Section 7.0, “Instrumentation and Controls”).
5. Control room evacuation panel (see Sections 7.4.1.1, “Monitoring Indicators,” and 7.4.1.2, “Controls).
6. Residual heat removal (see Section 5.5.7, “Residual Heat Removal System”).
7. Instrument power supply (see Section 8.3, “Onsite Power Systems”).
8. Control systems (see Section 7.0, “Instrumentation and Controls”).

For the discussions addressing how these requirements are satisfied, the column in Table 7.1-1 entitled “Conformance Discussed In” provides the appropriate reference.

An analysis demonstrating the ability to achieve safe shutdown in the event of a fire is presented in the Fire Protection (FP) DBD.

7.4.2.1 Conformance to General Design Criterion 19

As noted in Section 7.4.1.3, equipment is provided outside the Control Room with a design capability for prompt hot shutdown of the reactor and for maintaining the unit in a safe condition during hot shutdown and with a potential capability for subsequent cold shutdown through the use of suitable procedures. For criteria relative to the control board in the Main Control Room, see Section 7.1.2.2.2.

7.4.2.2 Conformance to IEEE Standard 279-1971

The design basis information requested by Section 3 of IEEE Standard 279-1971 for protective action and pertaining to the signals for actuation of reactor trip are presented in Section 7.2.1.2. The analyses for compliance to the criteria of IEEE Standard 279-1971 for the reactor trip are addressed in Section 7.2.2. The design basis information for protective action for the Engineered Safety Features Actuation system (ESFAS) is presented Section 7.3.1.2 and the analyses for ESFAS are addressed in Section 7.3.2. For the list of references to the discussions of conformance to applicable criteria, see Tables 7.1-1 and 7.1-2.

7.4.3 Cross References

Table 7.4-2 provides cross references outlining appropriate sections that supply descriptions of initiating circuitry, logic, bypasses, interlocks, redundancy, diversity and actuated devices for systems required for safe shutdown.

Table 7.4-1
Summary of Control Stations

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Residual Heat Removal Pumps		
XPN6020 (ESF sequencer)	1.2-15	36-11
XPN6025 (ESF sequencer)	1.2-15	36-11
XSW1DA1 Unit 6A	1.2-15	63-01
XSW1DB1 Unit 5D	1.2-6	63-01
Pressurizer Relief Valves		
XPN7031 (Aux. relay rack No. 1)	1.2-15	36-11
XPN7032 (Aux. relay rack No. 2)	1.2-15	36-11
XPN7200A	1.2-12	36-03A
XPN7200B	1.2-12	36-03
Pressurizer Relief Valve Isolation Valves		
XMC1DA2X	1.2-13	63-01
XMC1DB2X	1.2-12	36-01
Pressurizer Heater Control Group		
APN4103 (Pressurizer controller)	1.2-5	36-18
XPN7008 (Process cabinet)	1.2-15	36-11
XSW1C Unit 2	1.2-18	12-01
Diesel Generators		
XCX5201 control cabinet	1.2-12	36-04
XCX5202 control cabinet	1.2-12	36-03

Table 7.4-1 (continued)
Summary of Control Stations

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Charging Flow Control Valves		
XPN7200A	1.2-12	36-03A
Letdown Orifice Isolation Valves		
XPN7200A	1.2-12	36.03A
XPN7200B	1.2-12	36-03
Emergency Feedwater Control Valves		
XPN7200A	1.2-12	36-03A
XPN7200B	1,2-12	36-03
Condenser Steam Dump and Atmospheric Relief Valves		
XPN6001 (BOP panel)	1.2-15	36-11
XPN6002 (BOP panel)	1.2-15	36-11
XPN7003 (Aux. relay rack)	1.2-15	36-11
XPN7034 (Aux. cabinet)	1.2-15	36-11
XPN7035 (Aux. cabinet)	1.2-15	36-11
XPN7115 (Termination cabinet)	1.2-16	48-02
Safety Injection Accumulator Isolation Valves		
XMC1DA2X Unit 8AE	1.2-13	63-01
XMC1DA2X Unit 8FJ	1.2-13	63-01
XMC1DB2X Unit 16IM	1.2-6	63-01

Table 7.4-1 (continued)
Summary of Control Stations

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Emergency Feedwater Pumps		
XPN7200B	1.2-12	36-03
XSW1DA Unit 13	1.2-13	63-01
XSW1DB Unit 03	1.2-12	36-01
Charging and Boric Acid Transfer Pumps		
XPN7200B	1.2-12	36-03
XMC1DA2Y Unit 4CD	1.2-4	12-28
XMC1DB2Y Unit 10GH	1.2-6	63-01
XMC1A3X Unit 6HJ	1.2-6	63-14
XMC1B3X Unit 6IK	1.2-6	63-09
Service Water Pumps		
XPN7200A	1.2-12	36-03A
XPN7200B	1.2-12	36-03
Component Cooling Water Pumps		
XSW1DA Unit 8	1.2-13	63-01
XSW1DB Unit 13	1.2-12	36-01
Instrument Air Compressors		
XPN7202	1.2-18	12-03
XPN7203	1.2-18	12-03

Table 7.4-1 (continued)
Summary of Control Stations

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Reactor Building Cooling Units		
XSW1DA1	1-2-13	63-01
XSW1DB1	1.2-6	63-01
Pressurizer Heater Backup Group 1		
APN4101 (Pressurizer Controller)	1.2-5	36-18
XPN7031 (Aux. relay rack No. 1)	1.2-15	36-11
XPN7200A	1.2-12	36-03A
XSW1DA Unit 2	1.2-13	63-01
Pressurizer Heater Backup Group 2		
APN4102 (Pressurizer controller)	1.2-5	36-18
XPN7032 (Aux. relay rack No. 2)	1.2-15	36-11
XPN7200B	1.2-12	36-03
XSW1DB Unit 5	1.2-12	36-01
Pressurizer Spray Valve		
XPN7008 (Process cabinet)	1.2-15	36-11
Nuclear Instrumentation System - Source and Intermediate Range		
XPN7051 (Computer)	1.2-15	36-10
XPN7113 (Main control board termination cabinet)	1.2-16	48-02
XPN7200A	1.2-12	36-03A

Table 7.4-1 (continued)
Summary of Control Stations

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Safety Injection Trip Circuit		
XPN7010 (Solid state protection)	1.2-15	36-11
XPN7020 (Solid state protection)	1.2-15	36-11
XPN7180 (Main control board termination cabinet)	1.2-16	48-02
Service Water to Emergency Feedwater System Valves		
XMC1DA2X Unit 4 EH	1.2-13	63-01
XMC1DA2X Unit 4 IL	1.2-13	63-01
XMC1DA2X Unit 12 AD	1.2-13	63-01
XMC1DB2X Unit 3 AD	1.2-12	36-01
XMC1DB2X Unit 3 EH	1.2-12	36-01
XMC1DB2X Unit 7 EH	1.2-12	36-01
Reactor Coolant System to Residual Heat Removal System Suction Valves		
XMC1DA2X Unit 7 FJ	1.2-13	63-01
XMC1DA2Y Unit 18 IM	1.2-4	12-28
XMC1DB2Y Unit 4 AE	1.2-6	63-01
XMC1DB2Y Unit 4 FJ	1.2-6	63-01
Borated Water to Charging Pump Valves		
XMC1DA2Y Unit 2 AD	1.2-4	12-28
XMC1DB2Y Unit 9 EH	1.2-6	63-01
XMC1DB2Y Unit 21 EH	1.2-6	63-01

Table 7.4-1 (continued)
Summary of Control Stations

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Service Water Booster Pumps		
XSW1DA1 Unit 7A	1.2-13	63-01
XSW1DB1 Unit 5A	1.2-6	63-01
Cooling Water Valves to Reactor Building Cooling Units		
XMC1DA2X Unit 12 IM	1.2-13	63-01
XMC1DA2X Unit 13 AD	1.2-13	63-01
XMC1DA2X Unit 13 EH	1.2-13	63-01
XMC1DA2X Unit 14 EH	1.2-13	63-01
XMC1DA2Y Unit 16 EH	1.2-4	12-28
XMC1DB2X Unit 18 EH	1.2-6	63-01
XMC1DB2Y Unit 19 AD	1.2-6	63-01
XMC1DB2Y Unit 19 EH	1.2-6	63-01
XMC1DB2Y Unit 20 EH	1.2-6	63-01
XMC1DB2Y Unit 22 IM	1.2-6	63-01
Chillers		
XSW1DA1 Unit 7B	1.2-13	63-01
XSW1DA1 Unit 7C	1.2-13	63-01
XSW1DB1 Unit 6A	1.2-6	63-01
XSW1DB1 Unit 7A	1.2-6	63-01
Diesel Generator Fuel Oil Transfer Pumps		
XMC1DA2Z Unit 1 CD	1.2-12	36-01
XMC1DB2Z Unit 1 CD	1.2-12	36-02

Table 7.4-1 (continued)
Summary of Control Stations

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
HVAC System Fans		
XMC1DA2X Unit 2 AB	1.2-13	63-01
XMC1DA2X Unit 2 CD	1.2-13	63-01
XMC1DA2X Unit 2 EF	1.2-13	63-01
XMC1DA2X Unit 9 IJ	1.2-13	63-01
XMC1DA2X Unit 10 EF	1.2-13	63-01
XMC1DA2X Unit 11 EF	1.2-13	63-01
XMC1DA2X Unit 15 IJ	1.2-13	63-01
XMC1DA2Y Unit 7 AB	1.2-4	12-28
XMC1DA2Y Unit 7 CD	1.2-4	12-28
XMC1DA2Y Unit 14 JK	1.2-4	12-28
XMC1DA2Z Unit 4 GI	1.2-12	36-01
XMC1DA2Z Unit 4 JL	1.2-12	36-01
XMC1DB2X Unit 2 IJ	1.2-12	36-01
XMC1DB2X Unit 3 IJ	1.2-12	36-01
XMC1DB2X Unit 6 CD	1.2-12	36-01
XMC1DB2Y Unit 4 IJ	1.2-6	63-01
XMC1DB2Y Unit 5 IJ	1.2-6	63-01
XMC1DB2Y Unit 12 GH	1.2-6	63-01
XMC1DB2Y Unit 20 AB	1.2-6	63-01
XMC1DB2Y Unit 20 CD	1.2-6	63-01
XMC1DB2Y Unit 23 KL	1.2-6	63-01
XMC1DB2Y Unit 24 CD	1.2-6	63-01
XMC1DB2Z Unit 3 AC	1.2-12	36-02
XMC1DB2Z Unit 3 DF	1.2-12	36-02
XMC1EA1X Unit 1 GI	1.2-24	25-05
XMC1EB1X Unit 4 JK	1.2-24	41-01
XPN0040 (Motor Control Panel)	1.2-3	88-13NE

Table 7.4-2
Instrument and Control Data Cross References

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number
Systems Required for Safe Shutdown				
	Component Cooling Water System	7.4, 7.1.2.6, 7.3.1.1,	7.3-1	-
		7.3.1.1.5, 7.4, 7.5.4,	9.2-4 thru	-
		9.2.2.1, 9.2.2.2,	9.2-7	-
		9.2.2.3, 9.2.2.5,	-	B-208-005
		11.4.2	-	B-208-011
		Note 3		
	Diesel Generator Systems	7.3.1.1, 7.4, 8.3.1.1.2,	8.2-3	-
		9.5.4.2, 9.5.4.3, 9.5.4.5,	8.3-0h thru	-
		9.5.5.3, 9.5.5.5, 9.5.6.1,	8.3-0j	-
		9.5.7.3, 9.5.7.5, 9.5.8.3	9.5-2	
		Notes 3, 6	9.5.3	
			9.5-4	
			9.5-6	
			9.5-7	
			-	B-208-005
			-	B-208-023
	Emergency Feedwater System	7.1, 7.3.1.1, 7.3.1.1.5,	7.3-1	-
		7.5.4, 10.4.9.2, 10.4.9.3,	10.4-16	-
		10.4.9.5	-	B-208-032
		Note 6	-	8756D01 (1MS-51-221)

Table 7.4-2 (continued)
Instrument and Control Data Cross References

Category	System	Reference FSAR Sections	Related Drawings [1] FSAR Figure	Related Drawings [1] Drawing Number
Systems Required for Safe Shutdown (Continued)	Service Water System	7.1, 7.1.2.6, 7.3.1.1,	7.3-1	-
		7.3.1.1.5, 7.4, 7.5.4,	9.2-1	-
		9.2.1.2, 9.2.1.3, 9.2.1.5	9.2-2 (4 Sheets)	-
		Note 3	-	B-208-005
			-	B-208-101
			-	8756D01 (1MS-51-221)
	Chilled Water System	7.1.2.6, 7.3.1.1, 7.3.1.1.5,	7.3-1	-
		7.5.4, 9.4.7.2.4, 9.4.7.3	9.4-22	-
			9.4-23	-
			9.4-24	-
			-	B-208-005
			-	B-208-109
			-	8756D01 (1MS-51-221)
	Main Steam System	6.2.4, 7.3.1.1, 7.5.4,	10.3-1	
		7.7.1.8, 10.3, 10.3.2.3,	10.4-3	
		10.4.9.2, 10.4.4.2,	10.4-4	
			-	B-208-063
		Table 6.2-54	-	B-208-067
			-	108D932
		Note 7	-	8756D01 (1MS-51-221)

Table 7.4-2 (continued)
Instrument and Control Data Cross References

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number
Systems Required for Safe Shutdown (Continued)	Heating Ventilation and Air Conditioning Systems			
	Auxiliary and Fuel Handling Building Ventilation Systems	6.5.1.3, 6.5.1.5.3, 7.3.1.1, 7.3.1.1.5, 9.4.2.1, 9.4.2.2, 9.4.2.3, 9.4.3.2, 9.4.3.3 Notes 3, 6	7.3-1 9-4-10 9.4-11 -	- - - B-208-004, Sh AH174, AH175 B-208-108, Sh VL05 thru VL09 8756D01 (1MS-51-221)
	Control Building Ventilation Systems	6.4, 6.4.1.5, 6.5.1.3, 6.5.1.5.2, 7.3.1.1, 7.3.1.1.5, 9.4.1.2, 9.4.1.3, 12.2.4.2.1 Note 6	9.4-1 9.4-2 9.4-3 9.4-5 - -	- - - - B-208-004, Sh AH102 thru AH105, AH107, AH108, AH147, AH148 8756D01 (1MS-51-221)
	Diesel Generator Building Ventilation System	7.3.1.1.5, 8.3.1.1.2.4, 9.4.7.2.1, 9.4.7.3 Notes 3, 6	9.4-18 -	- B-208-004, Sh AH164 thru AH167

Table 7.4-2 (continued)
Instrument and Control Data Cross References

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number
Systems Required for Safe Shutdown (Continued)	Heating Ventilation and Air Conditioning Systems (Continued)			
	Intermediate Building Ventilation System	7.3.1.1, 7.3.1.1.5, 9.4.6.2, 9.4.6.3	9.4-15 thru 9.4-17 - - -	- - B-208-004, Sh AH194 thru AH197 B-208-108, Sh VL18, VL19, VL22, VL24, VL26, VL27, VL30, VL31
	Reactor Building Ventilation System	6.2.2.2.2.1, 6.2.2.2.2.2, 6.2.2.5.2.2, 7.1.2.6, 7.3.1.1, 7.3.1.1.5, 7.5.4, 9.2.1.5, 9.4.7.2.5 Notes 3, 6	6.2-49 7.3-1 -	- - B-208-004, Sh AH273 thru AH276 8756D01 (1MS-51-221)
	Service Water Pumphouse Ventilation System	7.3.1.1.5, 9.4.7.2.2, 9.4.7.3	9.4-19 - -	B-208-004 Sh AH326 thru 331 8756D01(1MS-51-221)
	Boric Acid Transfer Pumps	7.4.1.2.2, 9.3.4.2.3. 9.3.4.2.5.3 Tables 9.3-5, 7.1-2 Notes 3, 4	9.3-16 Sh 15	B-208-021 Sh CS-01

Table 7.4-2 (continued)
Instrument and Control Data Cross References

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number
Systems Required for Safe Shutdown (Continued)	CREP Monitoring Indicators	7.4.1.1 Table 7.1-2 Notes 2, 3, 5	7.2-1 Sh 11, and 13	-
	Charging Pumps	6.3.2.2.4.2, 6.3.2.2.7, 6.3.2.11.1, 7.1.2.5, 7.3.1.1, 7.3.1.1.5 Tables 6.3-7, 7.3-1, 7.3-3, 8.3-3, 6.3-7 Note 3	6.3-1 Sh 1 7.3-1	B-208-021 Sh CS-04 thru 08

(1) FSAR figure numbers refer to figures in the FSAR; drawing numbers refer to drawings in the Wiring Schematic Package (see Section 1.7).
(2) Not redundant.
(3) Not diverse.
(4) Motor control center is the actuation device.
(5) Indicators are the actuation device.
(6) No interlocks or bypasses are provided which would inhibit ESF actuation.
(7) The Main Steam System components required for safe shutdown include only the main stream isolation valves, and valves that emit steam to the turbine driven emergency feedwater pump. The steam generator power operated relief valves are safety class, seismic, air operated, fail closed valves. The valves can be manually opened if required for safe shutdown.

Figure 7.4-1
DRAWING C-809-202
FSAR FIGURE REFERENCE

Figure 7.4-1, Sheet 2
(DELETED PER RN 99-074)

Figure 7.4-1, Sheet 3
(DELETED PER RN 99-074)

Figure 7.4-2

CONTROL ROOM EVACUATION PANEL (XPN-7200-CE (A & B)

CONTROL ROOM EVACUATION PANEL

IDENTIFICATION OF DEVICES

ITEM	DEVICE	DESCRIPTION
A	Indicator	TI-430A RCS Cold Leg Temp
B	Dual Indicator	LI-459B PZR Level/PI-455A PZR Press
C	Dual Indicator	NI-36A/Intermediate Range/NI-32A Source Range
D	Indicator	FI-150A LTDN Flow
E	Indicator	FL-122B Charging Flow
F	Indicator	PI-121A Charging Press
G	Indicator	FI-110A Emergency Borate Flow
H	Indicator	TI-433A RCS Hot Leg Temp
I	Indicator	TI-410A RCS Cold Leg Temp
J	Indicator	TI-423A RCS Hot Leg Temp
K	Dual Indicator	PI-2010A S/G B Press/LI-487B S/G B Level
L	Indicator	TI-413A RCS Hot Leg Temp
M	Dual Indicator	PI-2020A S/G C Press/LI-497B S/G C Level
N	Dual Indicator	LI-161A BA Tank Level/LI-163A BA Tank Level
O	Indicator	TI-420A RCS Cold Leg Temp
P	Dual Indicator	TI-9203B RB Temp/LI-3631B Condensate Tk Level
Q	Dual Indicator	PI-2000A S/G A Press/LI-477B S/G A Level
R	Control Switch	SS-RC08 PZR Heaters Backup Group 1
S	Control Switch	SS-RC09 PZR Heaters Backup Group 2
T	Controller	HC-122 Chg Flow - FCV 122
U	Control Switch	SS-CS09A Emer Borate – MVT 8104
V	Controller	HC-3536B TDEFP to S/GA
W	Controller	HC-3531B MDEFP to S/GA
X	Controller	HC-3546B TDEFP to S/GB
Y	Controller	HC-3551B MDEFP to S/GB
Z	Controller	HC-3556B TDEFP to S/GC
AA	Controller	HC-3541B MDEFP to S/GC
AB	XFER Switch	43-RC08 PZR Htr Group 1
AC	XFER Switch	43-RC09 PZR Htr Group 2
AD	XFER Switch	43-122 Chg Flow XFER
AE	XFER Switch	43-CS09 Emer Borate XFER
AF	XFER Switch	43-EFT TDEFP XFER
AG	XFER Switch	43-EFM MDEFP XFER
AH	Control Switch	SS-459 LCV-459 LTDN Isol
AI	Control Switch	SS-445A PZR Power Relief
AJ	Control Switch	SS-460 LCV-460 LTDN Isol

ITEM	DEVICE	DESCRIPTION
AK	Control Switch	SS-8149A LTDN Orifice Isol
AL	Control Switch	SS-8149B LTDN Orifice Isol
AM	Control Switch	SS-8149C LTDN Orifice Isol
AN	Control Switch	SS-2030 Stm Supply to EF Turb
AO	XFER Switch	43-445A PZR Power Relief
AQ	Control Switch	SS-SW01 SW Pump A
AR	Control Switch	SS-SW03 SW Pump C
AS	Control Switch	SS-SW04 SW Pump C
AT	Control Switch	SS-SW02 SW Pump B
AU	XFER Switch	43-459 LTDN Isol XFER
AV	XFER Switch	43-460 LTDN Isol XFER
AW	XFER Switch	43-8149A LTDN Orifice Isol XFER
AX	XFER Switch	43-8149B LTDN Orifice Isol XFER
AY	XFER Switch	43-8149C LTDN Orifice Isol XFER
AZ	XFER Switch	43-2030 Stm Supply to EF Turb
BB	XFER Switch	43-SW01 SW Pump A XFER
BC	XFER Switch	43-SW03 SW Pump C XFER
BD	XFER Switch	43-SW04 SW Pump C XFER
BE	XFER Switch	43-SW02 SW Pump B XFER
BF	Control Switch	SS-CS02A BA Transfer Pump B
BG	XFER Switch	43-CS02 BA Transfer Pump XFER
BH	Control Switch	SS-444B PZR Power Relief
BI	Dual Indicator	PI-403A RCS Press/PI-402D RCS Press
BJ	XFER Switch	43-444B PZR Power Relief
BK	Control Switch	SS-8152 LTDN Isol
BL	XFER Switch	43-8152 LTDN Isol
BM	Dual Indicator	LI-112 V.C.T. Level/LI-470A PZR RT Level
BN	XFER Switch	43-TSCA TSC Indicator XFER
BO	XFER Switch	43-TSCB TSC Indicator XFER
BP	XFER Switch	43-EFT02 TDEFP
BQ	XFER Switch	43-EFM02 MDEFP XFER2

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
CONTROL ROOM EVACUATION PANEL (XPN-7200-CE (A&B)) FIGURE 7.4-2 REV. 2

7.5 SAFETY RELATED DISPLAY INSTRUMENTATION

7.5.1 Description

Regulatory Guide 1.97, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident”, provides guidance for selection of readouts to monitor plant variables and systems during and following a design basis event. For VCSNS, the post-accident monitoring instrumentation provides readouts to the operator to enable him to perform manual safety functions and to determine the effect of manual actions taken following a reactor trip due to a Condition II, III, or IV event, as defined in Chapter 15. Regulatory Guide 1.97 instrumentation includes the readouts required to maintain the plant in a hot shutdown condition or to proceed to cold shutdown within the limits of the Technical Specifications. Reactivity control after Condition II and III faults will be maintained by administrative sampling of the reactor coolant for boron to ensure that the concentration is sufficient to maintain the reactor subcritical. Additional details are provided in Reference 1.

Table 7.5-2 lists the information available to the operator in addition to Regulatory Guide 1.97 instrumentation for monitoring conditions in the reactor, the Reactor Coolant System, and in the Reactor Building and process systems throughout all normal operating conditions of the plant, including anticipated operational occurrences.

7.5.2 Analysis

This section deleted by Amendment No. 94-08 in October, 1994.

7.5.3 Design Criteria

This section deleted by Amendment No. 94-08 in October, 1994.

7.5.4 ESF Monitor Lights

Certain pumps and valves, which are an integral part of or which are associated with the engineered safety features systems (used for safety injection, Reactor Building spray, and recirculation) are equipped with ESF monitor lights. These “bright/dim” lights are displayed on the main control board within easy view of the operator. When the plant is in normal full power operation, the ESF monitor lights should generally be “dim.” These lights change to the “bright” condition when the component monitored changes to an off normal operating mode. In addition to the ESF monitor lights, certain valves have an annunciator which indicates a change to an off-normal operating mode and actuates an alarm.

The ESF monitor lights are arranged on the main control board as shown by Figures 7.5-1 through 7.5-6 to permit the operator to discover easily a component that is in an off-normal operating mode. These figures also outline the components monitored. Elementary diagrams (GAI Dwg. B-208-066), submitted separately in the “Wiring Schematic Package” and listed in Table 1.7-1, outline the specific components included.

The ESF monitor lights provide supplemental information with regard to the status of ESF components.

7.5.5 Inadequate Core Cooling

The inadequate core cooling instrumentation includes the Incore Temperature Monitoring System, the core subcooling monitors, and the Reactor Vessel Level Instrumentation System (RVLIS). These systems meet the requirements of NUREG-0737 item II.F.2 for inadequate core cooling instrumentation. They are also used to provide Post Accident Monitoring Information in compliance with Regulatory Guide 1.97, Rev. 3. See Section 7.5.1.

The Incore Temperature Monitoring system is designed to provide rapid monitoring of fuel assembly outlet temperatures and to verify that the core is being adequately cooled during and after an accident. The Incore Temperature Monitoring System consists of 51 thermocouples positioned in the reactor vessel above the core to measure reactor coolant temperature at the fuel assembly outlets. After the thermocouple leads exit the reactor vessel head the circuits are divided into two electrical trains and separately routed out of the containment, through separate thermocouple penetrations, to two separate thermocouple transmitter/isolator cabinets. Outputs from the cabinets are connected to the plant computer system and Technical Support Center computer and core subcooling monitoring system. Plant computer system displays and SPDS displays, via the Technical Support Center computer, of core exit thermocouple readings are provided in the Control Room.

The core subcooling monitoring system is designed to provide information to plant personnel concerning the status of reactor core heat removal capability. This information includes a continuous display of the saturation margin to provide an early warning that core conditions are approaching saturation. Two separate core subcooling monitoring system microprocessors calculate the RCS saturation margin based on independent wide range RCS pressure input and RCS temperature inputs and display the results on four main control board analog indicators (two per channel). Temperature inputs are from both hot and cold leg wide range RTDs and Incore Temperature Monitoring System thermocouples (two per core quadrant). Only the two indicators utilizing incore thermocouple inputs are used for Post-Accident Regulatory Guide 1.97 monitoring functions.

RVLIS provides an indication of the water level in the reactor vessel when the reactor coolant pumps are not running and the relative void content of the reactor coolant when one or more of the reactor coolant pumps is running. RVLIS provides an anticipatory and unambiguous indication of an inadequate core cooling situation. The system consists of two redundant trains of instrumentation to provide three main control board indications of reactor vessel level. The indicated levels are: 1) reactor vessel upper range (water level above the penetration top of the hot leg pipe when no reactor coolant pumps are running); 2) reactor vessel full range (level from the bottom to the top of the reactor vessel when no reactor coolant pumps are operating); and 3) reactor vessel dynamic range (a measurement of the reactor core and internals pressure drop when reactor coolant pumps are operating which provides means to estimate the relative void content of the circulating fluid).

7.5.6 References

1. Virgil C. Summer Nuclear Station, *Summary Report on Regulatory Guide 1.97, Revision 3, Post Accident Monitoring System*; Enclosure II to SCE&G letter to USNRC dated April 15, 1985, Subject: Generic Letter 82-33, "Emergency Response Capability Supplement 1 to NUREG-0737."

Table 7.5-2
Control Room Indicators and/or Recorders Available to the Operator
to Monitor Significant Plant Parameters During Normal Operation

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
NUCLEAR INSTRUMENTATION						
1. Source Range						
a. Count rate	2	1 to 10^6 counts/sec -0.5 to 5.0 decades/min	± 5.3% of the linear full scale analog voltage	Both channels indicated. Either may be selected for recording.	Control board	One recorder is used to record any of the 8 nuclear channels (2 source range, 2 intermediate range, and 4 power range).
b. Startup rate	2	-0.5 to 5.0 decades/min	± 7% of the linear full scale analog voltage	Both channels indicated	Control board	
2. Power Range						
a. Uncalibrated ion chamber current (top and bottom uncompensated ion chambers)	4	0 to 120% of full power current	± 1% of full power current	All 8 current signals indicated.	NIS racks in control room	

Table 7.5-2 (continued)
Control Room Indicators and/or Recorders Available to the Operator
to Monitor Significant Plant Parameters During Normal Operation

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
NUCLEAR INSTRUMENTATION (Continued)						
2. Power Range (continued)						
b. Calibrated ion chamber current (top and bottom uncompensated ion chambers)	4	0 to 125% of full power current	± 2% of full power current	All 8 current signals recorded (four recorders) Recorder 1 upper currents for two diagonally opposed detectors Recorder 2 - upper currents for remaining detectors Recorder 3 - lower currents for two diagonally opposed detectors Recorder 4 - lower currents for remaining detectors.	Control board	

Table 7.5-2 (continued)
Control Room Indicators and/or Recorders Available to the Operator
to Monitor Significant Plant Parameters During Normal Operation

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
NUCLEAR INSTRUMENTATION (Continued)						
2. Power Range (continued)						
c. Upper and lower ion chamber current difference	4	-30 to +30%	± 3% of full power current	Diagonally opposed channels may be selected for recording at the same time using recorder in Item 1.	Control board	
d. Average flux of the top and bottom ion chamber	4	0 to 120% of full power	± 3% of full power for indication. ± 2% for recording	All 4 channels indicated. Any 2 of the four channels may be recorded using recorder in Item 1 above	Control board	
e. Average flux of the top and bottom ion chambers	4	0 to 200% of full power	± 2% of full power to 120% ± 6% of full power to 200%	All 4 channels recorded	Control board	
f. Flux difference of the top and bottom ion chambers	4	- 30 to + 30%	± 4%	All 4 channels indicated.	Control board	

Table 7.5-2 (continued)
Control Room Indicators and/or Recorders Available to the Operator
to Monitor Significant Plant Parameters During Normal Operation

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
REACTOR CONTROL SYSTEM						
1. $T_{average}$ (measured)	1/loop	530 to 350°F	± 4% F	All channels indicated.	Control board	
2. Overpower ΔT Setpoint	1/loop	0 to 150% of full power ΔT	± 4% of full power ΔT	All channels indicated. One channel is selected for recording.	Control board	
3. Overpower ΔT Setpoint	1/loop	0 to 150% of full power ΔT	± 4% of full power ΔT	All channels indicated. One channel is selected for recording.	Control board	
4. Overtemperature ΔT Setpoint	1/loop	0 to 150% of full power ΔT	± 4% of full power ΔT	All channels indicated. One channel is selected for recording.	Control board	
5. Primary Coolant Flow	3/Loop	0 to 120% of rated flow	Repeatability of ± 4.5% of full flow	All channels indicated.	Control board	

Table 7.5-2 (continued)
Control Room Indicators and/or Recorders Available to the Operator
to Monitor Significant Plant Parameters During Normal Operation

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
REACTOR CONTROL SYSTEM (Continued)						
1. Demanded Rod Speed	1	0 to 100% of rated speed	± 2%	The one channel is indicated.	Control board	
2. Median T_{avg}	1	530 to 350°F	± 40°F	The one channel is recorded.	Control board	
3. $T_{reference}$	1	540 to 5080°F	± 40°F	The one channel is recorded.	Control board	
4. Control rod Position						If system not available, borate and sample accordingly.
a. Number of steps of demanded rod withdrawal	1/group	0 to 230 steps	± 1 step	Each group is indicated during rod motion.	Control board	These signals are used in conjunction with the measured position signals (Item 4c) to detect deviation of any individual rod from the demanded position. A deviation will actuate an alarm and annunciator.
b. Demanded position of the part length rod bank	1	0 to 230 steps	± 1 step	The bank is indicated during rod motion.	Control board	

Table 7.5-2 (continued)
Control Room Indicators and/or Recorders Available to the Operator
to Monitor Significant Plant Parameters During Normal Operation

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
REACTOR CONTROL SYSTEM (Continued)						
5. Control rod Bank Demanded Position	4	0 to 230 steps	± 2.5% of total bank travel	All 4 control rod bank positions are recorded along with the low-low limit alarm for each bank.	Control board	1. One channel for each control bank. 2. An alarm and annunciator is actuated when the last rod control bank to be withdrawn reaches the withdrawal limit, when any rod control bank reaches the low-low insertion limit.
FEEDWATER AND STEAM SYSTEMS						
1. Programmed Steam Generator Level Signal	1/steam generator	0 to 100% of span	± 4%	All channels indicated.	Control board	
2. Steam Flow	2/steam generator	0 to 120% of max. calculated flow	± 5.5%	All channels indicated. The channels used for control are recorded.	Control board	Accuracy is equipment capability; however, absolute accuracy depends on applicant calibration against flow.

Table 7.5-2 (continued)
Control Room Indicators and/or Recorders Available to the Operator
to Monitor Significant Plant Parameters During Normal Operation

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
FEEDWATER AND STEAM SYSTEMS (Continued)						
3. Steam Dump Modulate Signal	1	0 to 85% max. calculated steam flow	± 1.5%d	The one channel is indicate	Control board	OPEN/SHUT indication is provided in the control room for each steam dump valve.
4. Turbine First Stage Pressure	2	0 to 120% of max. calculated turbine load	± 3.5%	Both channels indicated.	Control board	OPEN/SHUT indication is provided in the control room for each turbine stop valve.
COMPONENT COOLING WATER SYSTEM						
1. Reactor Coolant Pump Upper and Lower Bearing Cooling Water Flow	2	0 to 500 gpm	± 5.0% of calibrated span	Both channels indicated.	Control board	
2. Reactor Coolant Pump Thermal Barrier Cooling Water Flow	2	0 to 150 gpm	± 5.0% of calibrated span	Both channels indicated.	Control board	

(1) Includes channel accuracy and environmental effects.

Figure 7.5-1
DRAWING B-804-660
FSAR FIGURE REFERENCE

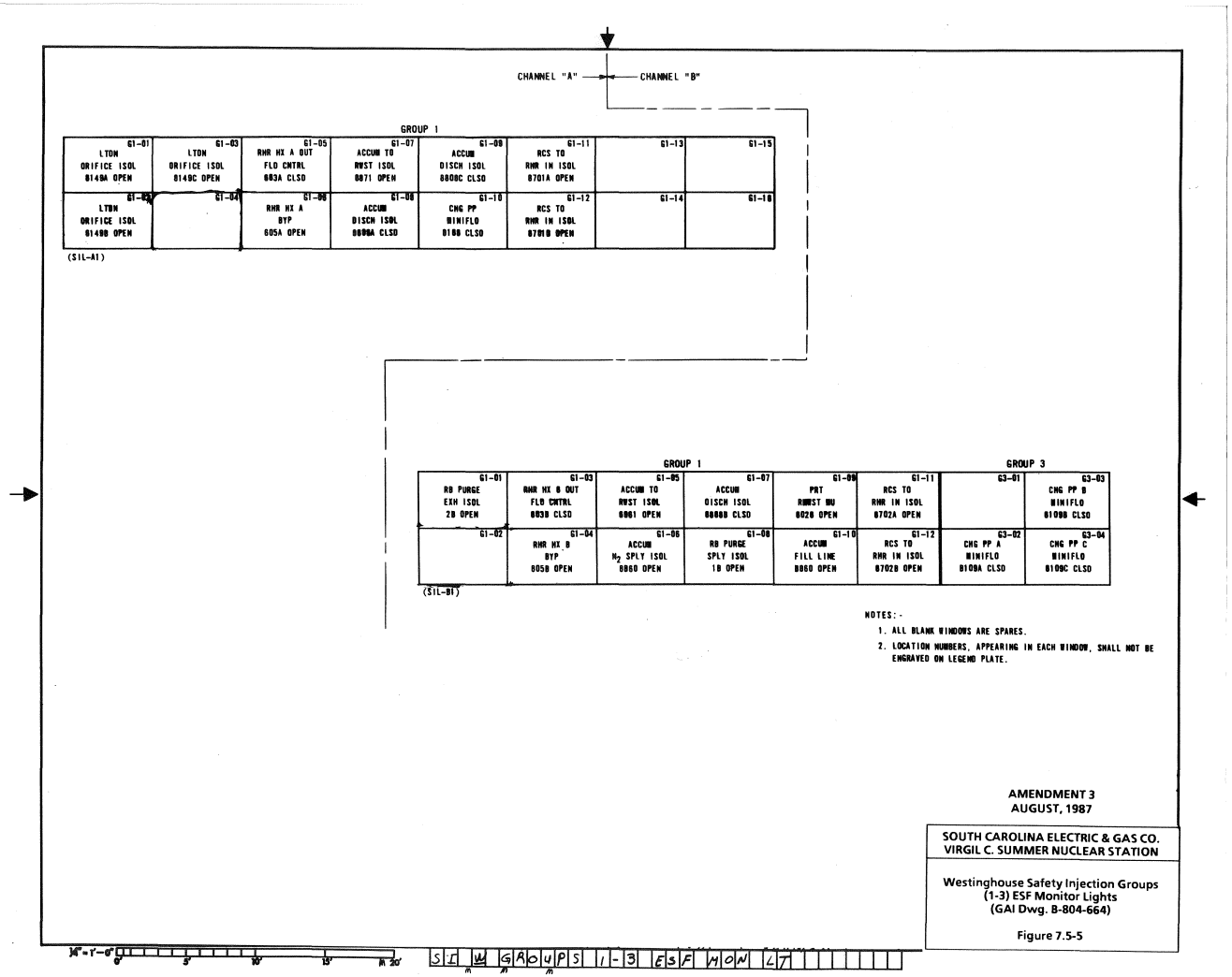
Figure 7.5-2
DRAWING B-804-661
FSAR FIGURE REFERENCE

Figure 7.5-3
DRAWING B-804-662
FSAR FIGURE REFERENCE

Figure 7.5-4
DRAWING B-804-663
FSAR FIGURE REFERENCE

Figure 7.5-5

WESTINGHOUSE SAFETY INJECTION GROUPS
(1-3) ESF MONITOR LIGHTS
(GAI DWG. B-804-664)



7.6 ALL OTHER SYSTEMS REQUIRED FOR SAFETY

7.6.1 Instrumentation and Control Power Supply System

7.6.1.1 Description

The following is a description of the Instrumentation and Control Power Supply System:

1. Refer to Figures 8.3-1, 8.3-2, 8.3-2aa, and 8.3-2ab for a single line diagram of the Instrumentation and Control Power Supply System.
2. There are 4 inverters and 6 distribution panels. Four (4) normally operating inverters are connected to 4 distribution panels. The remaining 2 panels are branch loads of the same channelized distribution panel.
3. The inverters provide a source of 120 volt 60 Hz power for the operation of the Nuclear Steam Supply System instrumentation. This power is derived from the 480 volt a-c, 3ø, 60 Hz distribution system Class 1E power supply, or the station batteries which assure continued operation of instrumentation systems in the event of loss of offsite power.
4. Each of the 4 distribution panels fed from the 4 normally operating inverters may be connected to a backup regulated source of 120 volt Class 1E a-c power. The tie is through an automatic static transfer switch or through a manual bypass switch such that the distribution panel cannot be connected to both sources simultaneously.

7.6.1.2 Analysis

There are 2 independent 480 volt a-c power sources, each serving 2 inverters. Therefore, loss of either of the two 480 volt a-c power sources affects only 2 of the 4 inverters.

There are 2 independent Class 1E batteries and battery chargers. Each battery is attached to a bus serving 2 inverters.

There is a third battery charger provided, which serves as a standby charger. This charger is provided for use during maintenance of, and backup to the normal battery chargers. The standby charger has mechanically interlocked circuit breakers on the a-c input and d-c output such that only the 2 circuit breakers associated with Channel A or the 2 circuit breakers associated with Channel B can close at one time.

Since not more than 2 inverters are connected to the same bus, a loss of a single bus can only affect 2 of the 4 inverters.

Since each of the 4 instrument channels is supplied power by independently connected inverters, the loss of an inverter cannot affect more than 1 of the 4 instrument channels.

Each distribution panel can receive power from the 120 volt Class 1E a-c backup regulated source through an automatic static transfer switch or through a manual bypass switch. The inverter power

source and the backup source are aligned such that the distribution panels cannot be connected to both sources at the same time.

Therefore no single failure in the Instrumentation and Control Power Supply System or its associated power supplies can cause a loss of power to more than one of the redundant loads.

The inverters are designed to maintain their outputs within acceptable limits. The loss of the a-c or d-c inputs is alarmed in the Control Room, as is the loss of an inverter's output. There are no inverter breaker controls on the control board, as no manual transfers are necessary in the event of loss of the 480 volt a-c preferred power source. The a-c and d-c inputs are diode isolated in the UPS.

Physical separation and provisions to protect against fire are discussed in Chapter 8.

Based on the scope definitions presented in References 1 through 3, the criteria which are applicable to the Instrumentation and Control Power Supply System are listed in IEEE Standard 308-1971. The design is in compliance with IEEE Standard 308-1971 and Regulatory Guide 1.6. Availability of this system is continuously indicated by the operational status of the systems it serves (see Figures 8.3-1 and 8.3-2) and is verified by periodic testing performed on the served systems. The inverters have been seismically qualified as discussed in Section 3.10 and shown in Table 3.10-2.

7.6.2 Residual Heat Removal Isolation Valves

7.6.2.1 Description

There are 2 motor operated gate valves in series in each of 2 inlet lines from the Reactor Coolant System to the Residual Heat Removal System. They are normally closed and are only opened for residual heat removal and Reactor Coolant System overpressure protection after system pressure is reduced below approximately 425 psig and system temperature has been reduced to approximately 350°F (see Chapter 5). They are the same type of valve and motor operator as those used for accumulator isolation (refer to Section 7.6.4), but they differ in their controls indications in the following respect (see Figures 7.6-1, 7.6-1a., and 7.6-1b):

1. Pressure interlocks are provided to prevent opening of the isolation valves whenever the Reactor Coolant System pressure is greater than approximately 425 psig. This interlock is derived from Class 1E process instrumentation channel for the isolation valves closest to the Reactor Coolant System (XVG8702A and XVG8702B) and from another independent process instrumentation channel for the 2 isolation valves closest to the Residual Heat Removal System (XVG8701A and XVG8701B). Interlock diversity is provided through the use of pressure transmitters from different manufacturers employing different measurement principles for the 2 channels of process instrumentation.
2. In addition to the open interlock, an alarm is located in the Control Room which will alert the operator if these valves are not fully closed when the Reactor Coolant System pressure increases above the 520 psig alarm setpoint.

7.6.2.2 Analyses

Based on the scope definitions presented in References 2 and 3, these criteria do not apply to the residual heat removal isolation valve interlocks; however, in order to meet NRC requirements and because of the possible severity of the consequences of loss of function, the requirements of IEEE Standard 279-1971 will be applied with the following comments:

1. For the purpose of applying IEEE Standard 279-1971, to this circuit, the following definitions will be used.

   a. Protection System

      The 2 valves in series in each line and all components of their interlocks that prevent opening of the isolation valves whenever the Reactor Coolant System pressure is greater than 425 psig.

   b. Protective Action

      The maintenance of Residual Heat Removal System isolation from the Reactor Coolant System when Reactor Coolant System pressures are above the preset value.

2. IEEE Standard 279-1971, paragraph 4.10: The above mentioned pressure interlock signals and logic will be tested on line to the maximum extent possible without adversely affecting safety. This test will include the analog signal through to the train signal which activates the relays that provide the interlocks into the valve control circuit. This is done in the best interests of safety since defeat of the interlock to permit opening the valve could potentially leave only 1 remaining valve to isolate the low pressure Residual Heat Removal System from the Reactor Coolant System.

   It is noted that the valve position lights operated from the motor operated valve limit switch on the operator are similar to the position lights (red for open and green for closed) for the accumulator isolation valves described in Section 7.6.4.

3. IEEE Standard 279-1971, paragraph 4.15: This requirement does not apply, as the setpoints are independent of mode of operation and are not changed.

Environmental qualification of the valves and wiring is discussed in Section 3.11.

7.6.3 Refueling Interlocks

Electrical interlocks (i.e., limit switches) as discussed in Section 9.1.4 are provided for minimizing the possibility of damage to the fuel during fuel handling operations.

7.6.4 Accumulator Motor Operated Valves

The design of the interconnection of signals to open the accumulator isolation valves meets the following criteria established in previous NRC positions on this matter:

1. Automatic opening of the accumulator valves when a) the primary coolant system pressure exceeds a preselected value (specified in the Technical Specifications) or b) as a safety injection signal has been initiated. Both signals shall be provided to the valves.
2. Utilization of a safety injection signal to automatically remove (override) any bypass features that are provided to allow an isolation valve to be closed for short periods of time when the Reactor Coolant System is at pressure (in accordance with the provisions of the Technical Specifications). As a result of the confirmatory "S" signal, isolation of an accumulator with the Reactor Coolant System at pressure is acceptable.

The control circuit for these valves is shown on Figure 7.6-2. The valves and control circuits are further discussed in Sections 6.3.2.15 and 6.3.5.

The Safety Injection System accumulator discharge isolation valves are motor operated normally open valves which are controlled from the main control board. These valves are interlocked such that:

1. They open automatically on receipt of an "S" signal with the main control board switch in either the "AUTO" or "CLOSE" position.
2. They open automatically whenever the Reactor Coolant System pressure is above the safety injection unblock pressure (P-11) specified in the Technical Specifications only when the main control board switch is in the "AUTO" position.
3. They cannot be closed as long as an "S" signal is present.

The main control board switches for these valves are 3 position switches which provide a "spring return to auto" from the open position and a "maintain position" from the closed position.

The "maintain closed" position is required to provide an administratively controlled manual block of the automatic opening of the valve at pressure above the safety injection unblock pressure (P-11). The manual block or "maintain closed" position is required when performing periodic check valve leakage tests when Reactor Coolant System is at pressure. The maximum permissible time that an accumulator valve can be closed when the Reactor Coolant System is at pressure is specified in the Technical Specifications.

Administrative control is required to ensure that any accumulator valve, which has been closed at pressures above the safety injection unblock pressure, is returned to the "AUTO" position. Verification that the valve automatically returns to its normal full open position would also be required.

During plant shutdown, the accumulator valves are in a closed position. To prevent an inadvertent opening of these valves during that period the accumulator valve breakers should be opened or removed. Administrative control is again required to ensure that these valve breakers are closed during the prestartup procedures.

7.6.5 Leakage Detection Systems

7.6.5.1 Description

Leakage detection is provided for the following areas and systems:

1. Reactor coolant pressure boundary (see Section 5.2.7 for a detailed description).
2. Engineered safety features systems (i.e., Reactor Building Spray, Residual Heat Removal, Safety Injection systems) in the Auxiliary Building.
3. Feedwater system (intermediate building flood protection).

7.6.5.1.1 Engineered Safety Features Systems in the Auxiliary Building

1. Level

   Undetected leaks from the Engineered Safety Features Systems in the Auxiliary Building (Reactor Building Spray, Residual Heat Removal, Safety Injection) could have adverse effects upon the safety functions of these systems. For this reason, means for detecting leakage are provided.

   Level switches are located in specifically provided alarm drains and in the building drain sumps. When leakage exceeds a flowrate of 25 gpm for the floor drains or 45 gpm the sump drains, an alarm is activated in the Control Room. Upon receipt of such an alarm, the operator takes action to isolate the leak.

   Figures 9.3-6 and 9.3-7 schematically depict the locations of alarm drains and building sumps.

2. Temperature

   Undetected leakage from the Chemical and Volume Control System letdown lines or the Auxiliary Steam System could cause the ambient temperature in the Auxiliary Building to rise. This high temperature could possibly prohibit personnel access to the area and limit the capability of equipment to function. Pipe rupture analysis has indicated the location of the most probable break areas in the system. Temperature sensors located in these break areas actuate alarms in the Control Room. Locations of these sensors are illustrated by Figures 7.6-3a through 7.6-8.

7.6.5.1.2 Feedwater System

Safety equipment and systems in the Intermediate Building are protected from flooding due to postulated pipe break or component failure resulting in leakage from the Feedwater System.

The sump level system incorporates a level switch located in each of the 3 Intermediate Building sumps. Should a high level occur in any sump, it is annunciated in the Control Room to alert the

operator to the need for investigation of the source of leakage and, if necessary, to take manual action to isolate the leak. The high-high sump level detectors are set to detect flooding which occurs at a rate which exceeds the capacity of the sump pumps. When 2 out of 3 redundant high-high sump level switches are energized, the A channel closes the feedwater pump discharge valves and the B channel trips the feedwater pumps and closes the feedwater pump suction valves. The A channel closes the feedwater isolation valves to the steam generators.

7.6.5.1.3 Leak Detection Methods Inside the Control Room

Table 7.6-1 provides a tabulation of leak detection methods inside the Control Room.

7.6.5.2 Analysis

Leak detection instrumentation is seismically qualified. These instruments are located throughout the Auxiliary Building in areas where engineered safety features equipment and piping are located. Physical separation and separate electrical power sources are used for 2 sets of redundant instruments. Calibration of the Leak Detection System instrumentation can be performed during plant operation. The instrumentation can be functionally checked by testing at any time.

7.6.6 Interlocks for RCS Pressure Control During Low Temperature Operation

This Section deleted by Amendment 1 in August, 1985.

7.6.7 Switchover From Injection to Recirculation

The details of achieving cold leg recirculation following safety injection and a postulated LOCA are given in Section 6.3.2.2.7 and on Table 6.3-3.

7.6.7.1 Description of Instrumentation Used for Switchover

As noted in Table 6.3-3, protection logic is provided to automatically open the 4 Safety Injection System (SIS), Reactor Building recirculation sump isolation valves (8811A and 8812A in Train A and 8811B and 8812B in Train B) when 2 of 4 (2/4) Refueling Water Storage Tank (RWST) level transmitters sense the Lo-Lo level setpoint in conjunction with the initiation of the engineered safety features actuation signal ("S" signal). The "S" signal is initiated by the contact of a slave relay in the Solid State Protection System output cabinet that closes on Safety Injection and remains closed until manually reset from the control board. This reset switch is separate from the main safety injection reset switch which is not associated with this circuit. The purpose of the sump valve automatic open circuit reset switch is to permit the operator to remove the actuation signal in the event the corresponding sump isolation valve must be closed and retained in a closed position following a LOCA, such as for maintenance purposes.

7.6.7.2 Initiating Circuit

The 2/4 Lo-Lo RWST level is the trip signal, which in coincidence with the "S" signal, provides the initiation function which would align the 2 residual heat removal pumps to take suction from the Reactor Building sumps and deliver directly to the RCS.

7.6.7.3 Logic

The logic function derived from the RWST level sensors and the "S" signal are depicted in Figure 7.6-9.

7.6.7.4 Bypass

The manual reset logic function is shown in Figure 7.6-10 and its purpose and action are described in Section 7.6.7.1. As noted, the "S" signal is retained by sealing it in (i.e., it is latched). This signal is not removed by action of the main safety injection reset that is used by the operator per emergency procedures to block the "S" signal to certain other equipment prior to realignment for switchover to the recirculation mode following a postulated loss of coolant accident.

7.6.7.5 Interlocks

The Trip Signal logic consists of 4 Refueling Water Storage Tank water level transmitters, each of which provides a level signal to 1 of the 4 Refueling Water Storage Tank level channel bistables. The Refueling Water Storage Tank level channel bistables are:

1. Normally de-energized
2. De-energized on loss of power
3. Energized on Lo-Lo setpoint

Each level channel bistable is assigned to a separate instrumentation and control power supply. A Trip Signal is provided from both Train A and Train B Solid State Protection System cabinets to the corresponding Reactor Building recirculation sump isolation valves logic, should 2 of the 4 water level channel bistables receive an RWST level signal lower than the Lo-Lo level setpoint, following the generation of an "S" signal.

7.6.7.6 Sequence

This circuit is energized directly from the Solid State Protection System output cabinet and is not sequenced following an accident that requires its functioning.

7.6.7.7 Redundancy

The function of this semi-automatic switchover is available from both Train A and Train B down to the actuated equipment. The function including the actuated equipment is, therefore, redundant and train separation and independence are maintained from sensor to actuated equipment.

7.6.7.8 Diversity

Diversity of components and equipment between the redundant Trains is not required to protect against systematic failures, such as multiple failures resulting from a credible single event. The associated components are environmentally and seismically qualified in accordance with the procedures described in Sections 3.10 and 3.11. It is noted that there is functional diversity provided in that manual operation is available as a backup to the semi-automatic mode.

7.6.7.9 Actuated Devices

The actuated devices are the 4 motor control center starters, 1 for each of the Motor Operated Sump Valves, 8811 A&B, and 8812 A&B.

7.6.7.10 Channel Bypass Indication

Indication is provided on the main control board to alert the operator that a Refueling Water Storage Tank water level channel is in the bypass mode and is unavailable. The indication is by status light and alarm window as shown on Figure 7.6-10.

7.6.8 Deleted

7.6.9 Deleted

7.6.10 Deleted

7.6.11 Switchover From Spray to Recirculation

The details of the Reactor Building Spray System operation following a postulated loss of coolant accident are given in Section 6.2.2.2.1.2.

7.6.11.1 Description of Instrumentation Used for Switchover

As noted in Section 6.2.2.2.1.2 logic is provided to automatically open the 4 Reactor Building Spray System, Reactor Building recirculation sump isolation valves (3004A and 3005A in Train A and 3004B and 3005B in Train B) when 2 of 4 (2/4) Refueling Water Storage Tank (RWST) level transmitters sense the Lo-Lo level setpoint in conjunction with the initiation of the engineered safety features actuation signal ("S" signal). The "S" signal is initiated by the contact of a slave relay in the Solid State Protection System output cabinet that closes on safety injection and remains closed until manually reset from the control board. This reset switch is separate from the main safety injection reset switch which is not associated with this circuit. The purpose of the sump valve automatic open circuit reset switch is to permit the operator to remove the actuation signal in the event the corresponding sump isolation valve must be closed and retained in a closed position following a loss of coolant accident, such as for maintenance purposes.

7.6.11.2 Initiation Circuit

The 2/4 Lo-Lo Refueling Water Storage Tank level is the trip signal, which in coincidence with the "S" signal, provides the initiation function which would automatically align the 2 Reactor Building spray pumps to take suction from the Reactor Building recirculation sumps and deliver directly to the Reactor Building spray nozzles.

7.6.11.3 Logic

The logic function derived from the Refueling Water Storage Tank level sensors and the "S" signal are depicted in Figures 7.6-9 and 7.6-10.

7.6.11.4 Bypass

The manual reset logic function is shown in Figure 7.6-9 and its purpose and action are described inSection 7.6.11.1. As noted, the "S" signal is retained by sealing it in (i.e., it is latched). This signal is not removed by action of the main safety injection reset that is used by the operator per emergency procedures to block the "S" signal to certain other equipment prior to realignment for switchover to the recirculation mode following a postulated loss of coolant accident.

7.6.11.5 Interlocks

The Trip Signal logic consists of 4 Refueling Water Storage Tank water level transmitters, each of which provides a level signal to 1 of the 4 Refueling Water Storage Tank level channel bistables. The Refueling Water Storage Tank level channel bistables are:

1. Normally de-energized
2. De-energized on loss of power
3. Energized on Lo-Lo setpoint

Each level channel bistable is assigned to a separate instrumentation and control power supply. A Trip Signal is provided from both Train A and Train B Solid State Protection System cabinets to the corresponding Reactor Building recirculation sump isolation valves logic, should 2 of the 4 water level channel bistables receive an Refueling Water Storage Tank level signal lower than the Lo-Lo level setpoint, following the generation of an "S" signal.

7.6.11.6 Sequence

This circuit is energized directly from the Solid State Protection System output cabinet and is not sequenced following an accident that requires its functioning.

7.6.11.7 Redundancy

The function of this switchover is available from both Train A and Train B down to the actuated equipment. The function including the actuated equipment is, therefore, redundant and train separation and independence are maintained from sensor to actuated equipment.

7.6.11.8 Diversity

Diversity of components and equipment between the redundant Trains is not required to protect against systematic failures, such as multiple failures resulting from a credible single event. The associated components are environmentally and seismically qualified in accordance with the procedures described in Sections 3.10 and 3.11. It is noted that there is functional diversity provided in that manual operation is available as a backup to the semi-automatic mode.

7.6.11.9 Actuated Devices

The actuated devices are the 4 motor control center starters, 1 for each of the Motor Operated Sump Valves, 3004 A&B and 3005 A&B.

7.6.11.10 Channel Bypass Indication

Indication is provided on the main control board to alert the operator that a Refueling Water Storage Tank water level channel is in the bypass mode and is unavailable. The indication is by status light and alarm window as shown on Figure 7.6-10.

7.6.12 References

1. The Institute of Electrical and Electronic Engineers, Inc., *IEEE Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations*, IEEE Standard 308-1971.
2. The Institute of Electrical and Electronic Engineers, Inc., *IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations,* IEEE Standard 279-1971.

Table 7.6-1
Leak Detection Methods Inside Control Room

PARAMETER	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
Refueling water storage tank level	level transmitters (LT990, LT991, LT992, LT993)	indication alarm-high level	reactor coolant leakage to ECCS
Accumulator level	level transmitters (LT920, LT922, LT924, LT926, LT928, LT930)	indication alarm-high level	reactor coolant leakage to ECCS
Accumulator pressure	pressure transmitters (PT921, PT923, PT925, PT927, PT929, PT931)	indication alarm-high level	reactor coolant leakage to ECCS
Reactor vessel flange leakoff temperature	temperature element (TE401)	indication alarm-high temperature	leakage from reactor vessel
Pressurizer safety valve discharge temperature	temperature elements (TE463, TE465, TE467, TE469)	indication alarm-high temperature	reactor coolant leakage to pressurizer relief tank
Pressurizer relief tank temperature	temperature element (TE471)	indication alarm-high temperature	reactor coolant leakage to pressurizer relief tank
Pressurizer relief tank level	level transmitters (LT470)	indication alarm-high level	reactor coolant leakage to pressurizer relief tank
Flow in pressurizer relief line	acoustic leak monitor	alarm-high flow	reactor coolant leakage to pressurizer relief tank

Table 7.6-1 (continued)
Leak Detection Methods Inside Control Room

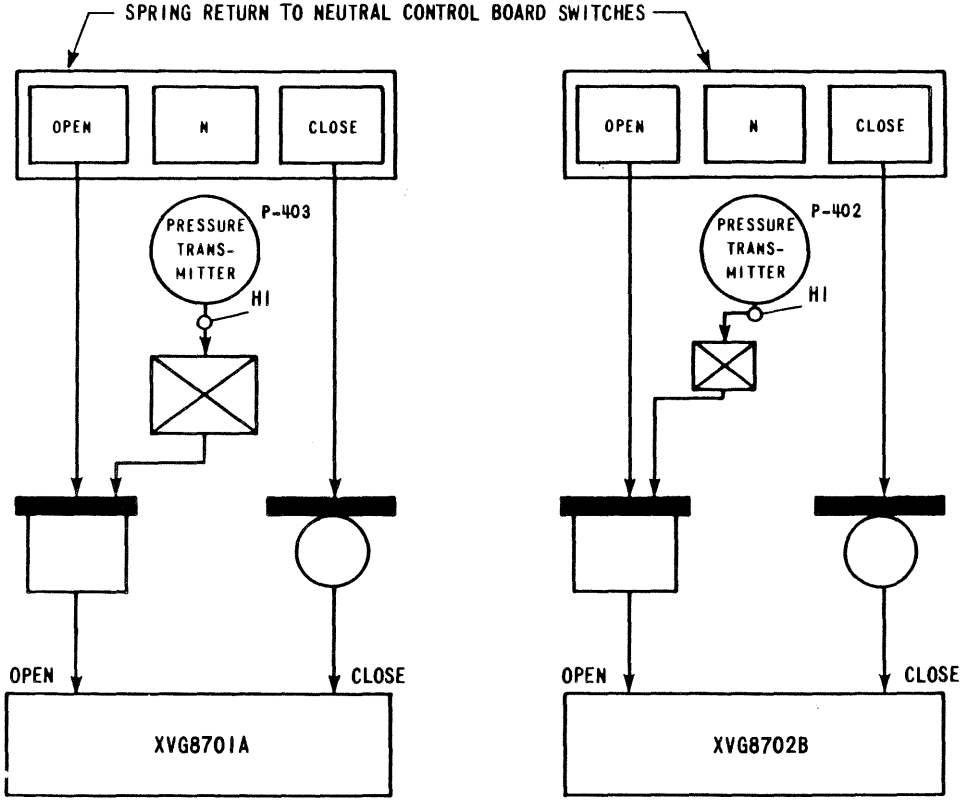
PARAMETER	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
Leak detection drains	level switches	alarm-high level	nuclear valve leak-off and miscellaneous equipment leakage
Steam generator blowdown and sampling radiation	radiation monitor (RM-L3, RM-L10)	indication alarm-high radiation	primary to secondary system leakage
Main plant vent exhaust radiation	radiation monitor (RM-A3)	indication alarm-high radiation	primary to secondary system leakage
Turbine room sump radiation	radiation monitor (RM-L8)	indication alarm-high radiation	primary to secondary system leakage
Component cooling water radiation	radiation monitor (RM-L2A, RM-L2B)	indication alarm-high radiation	intersystem leakage into component cooling water system
Component cooling water temperature from RHR heat exchanger	temperature elements (TE7037, TW7047) temperature switches (TS038, TS7048)	indication alarm-high temperature	residual heat removal heat exchanger leakage

Table 7.6-1 (continued)
Leak Detection Methods Inside Control Room

PARAMETER	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
Component cooling water temperature from reactor coolant drain tank	temperature elements (TE7118)	indication alarm-high temperature	reactor coolant drain tank heat exchanger leakage
Component cooling water flow from reactor coolant drain tank	flow transmitters (FT7116)	indication	reactor coolant drain tank heat exchanger leakage
Component cooling water temperature from reactor coolant pump thermal barrier	temperature elements (TE7140, TE7160, TE7180)	indication alarm-high temperature	reactor coolant pump thermal barrier leakage
Component cooling water flow from reactor coolant pump thermal barrier	flow transmitters (FT7138, FT7158, FT7178)	indication	reactor coolant pump thermal barrier leakage

Figure 7.6-1

LOGIC DIAGRAM - RESIDUAL HEAT REMOVAL SYSTEM ISOLATION VALVES XVG8701A AND XVG8702B

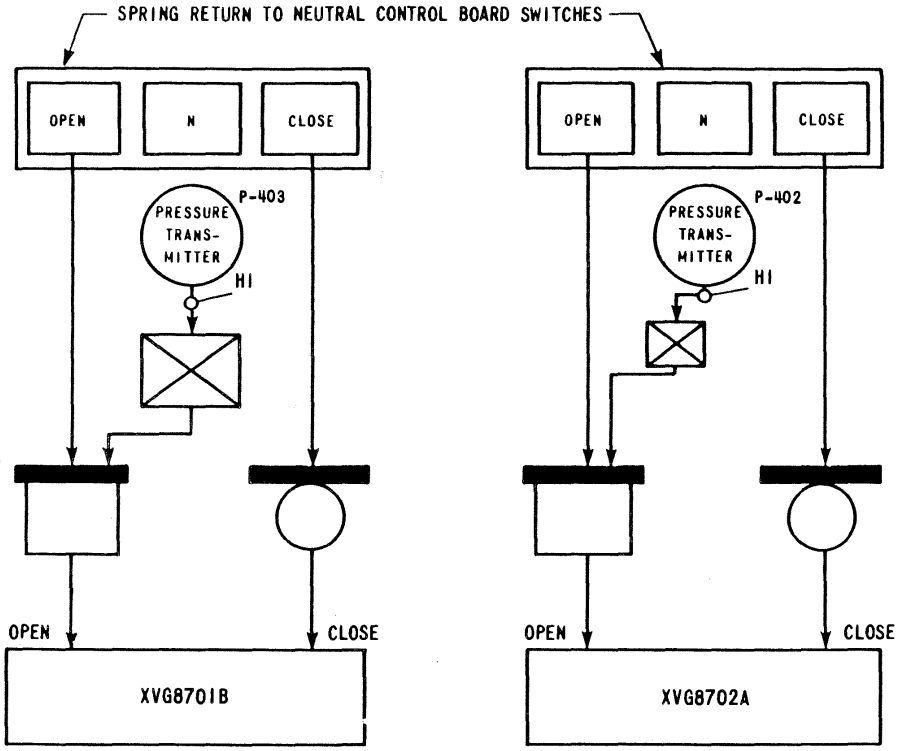


AMENDMENT 6
AUGUST, 1990

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Logic Diagram - Residual Heat Removal System Isolation Valves XVG8701A and XVG8702B Figure 7.6-1

Figure 7.6-1a

LOGIC DIAGRAM - RESIDUAL HEAT REMOVAL SYSTEM ISOLATION VALVES XVG8701B AND XVG8702A



AMENDMENT 6
AUGUST, 1990

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Logic Diagram - Residual Heat Removal System Isolation Valves XVG8701B and XVG8702A Figure 7.6-1a

Figure 7.6-1b

LOGIC DIAGRAM - RESIDUAL HEAT REMOVAL SYSTEM ISOLATION VALVES XVG 8701A, 8701B, 8702A, 8702B

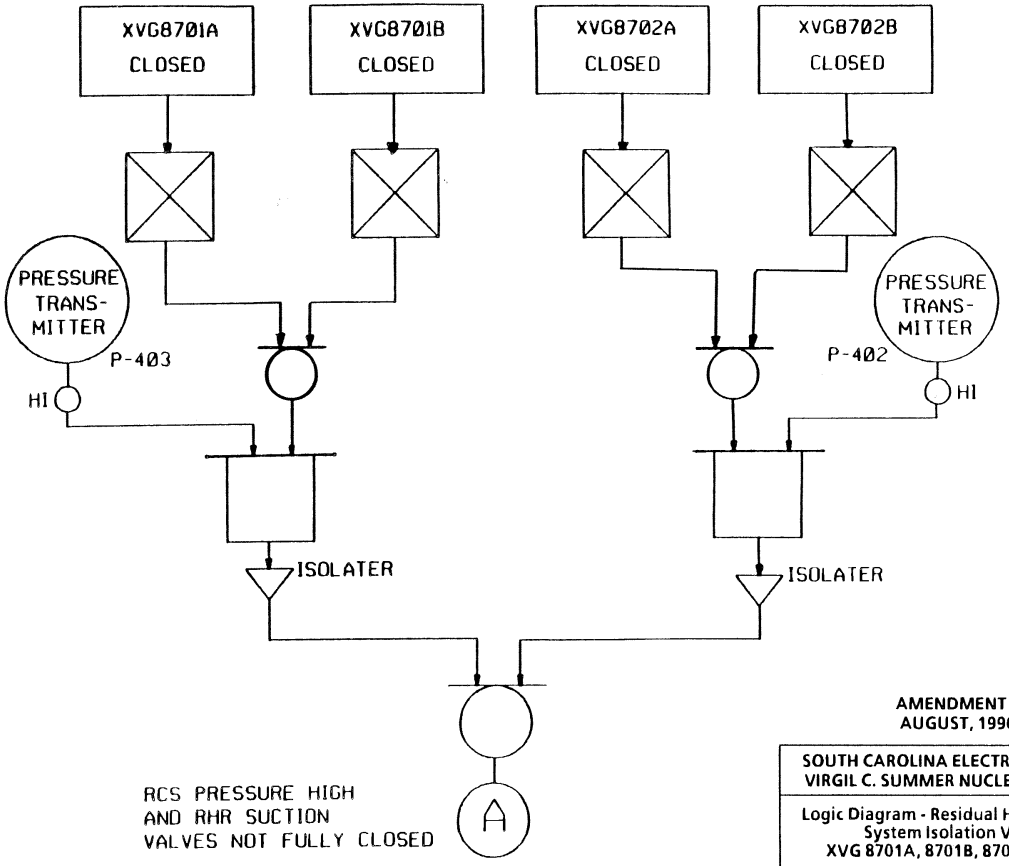


Figure 7.6-2

FUNCTIONAL BLOCK DIAGRAM OF ACCUMULATOR ISOLATION VALVE

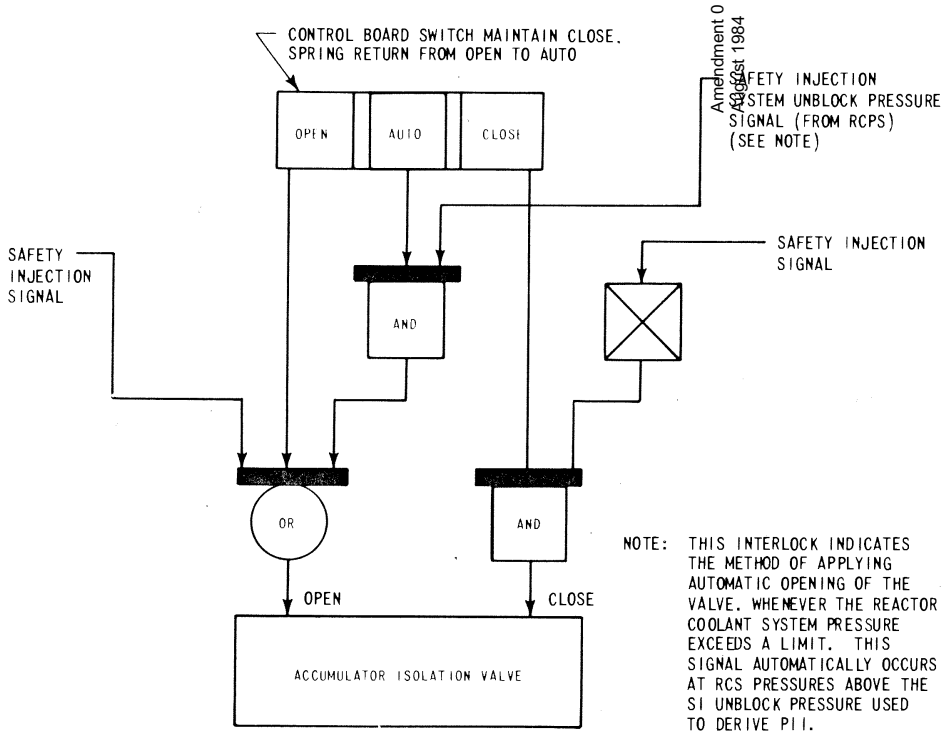


Figure 7.6-3A
DRAWING E-304-052
FSAR FIGURE REFERENCE

Figure 7.6-4
DRAWING E-304-053
FSAR FIGURE REFERENCE

Figure 7.6-5
DRAWING E-304-054
FSAR FIGURE REFERENCE

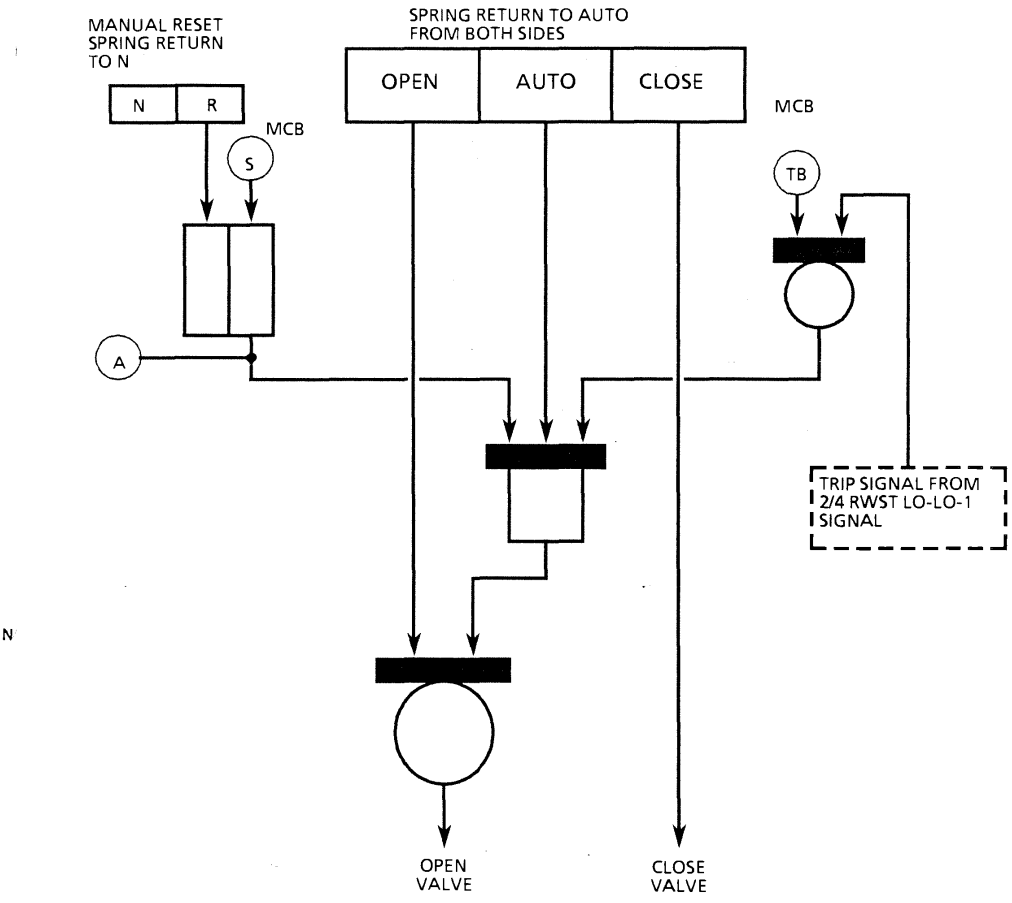
Figure 7.6-6
DRAWING E-304-674
FSAR FIGURE REFERENCE

Figure 7.6-7
DRAWING E-304-675
FSAR FIGURE REFERENCE

Figure 7.6-8
DRAWING E-304-676
FSAR FIGURE REFERENCE

Figure 7.6-9

SAFETY INJECTION SYSTEM & REACTOR BUILDING SPRAY SYSTEM RECIRCULATION ISOLATION VALVES



APPLICABLE VALVES	
DESCRIPTION	VALVE NO.
SUMP TO #1 RHR PUMP	8811A 8812A
SUMP TO #2 RHR PUMP	8811B 8812B
SUMP TO #1 SPRAY PUMP	3004A 3005A
SUMP TO #2 SPRAY PUMP	3004B 3005B

(A) ACTUATION SIGNAL LAMP

Amendment 0
August 1984

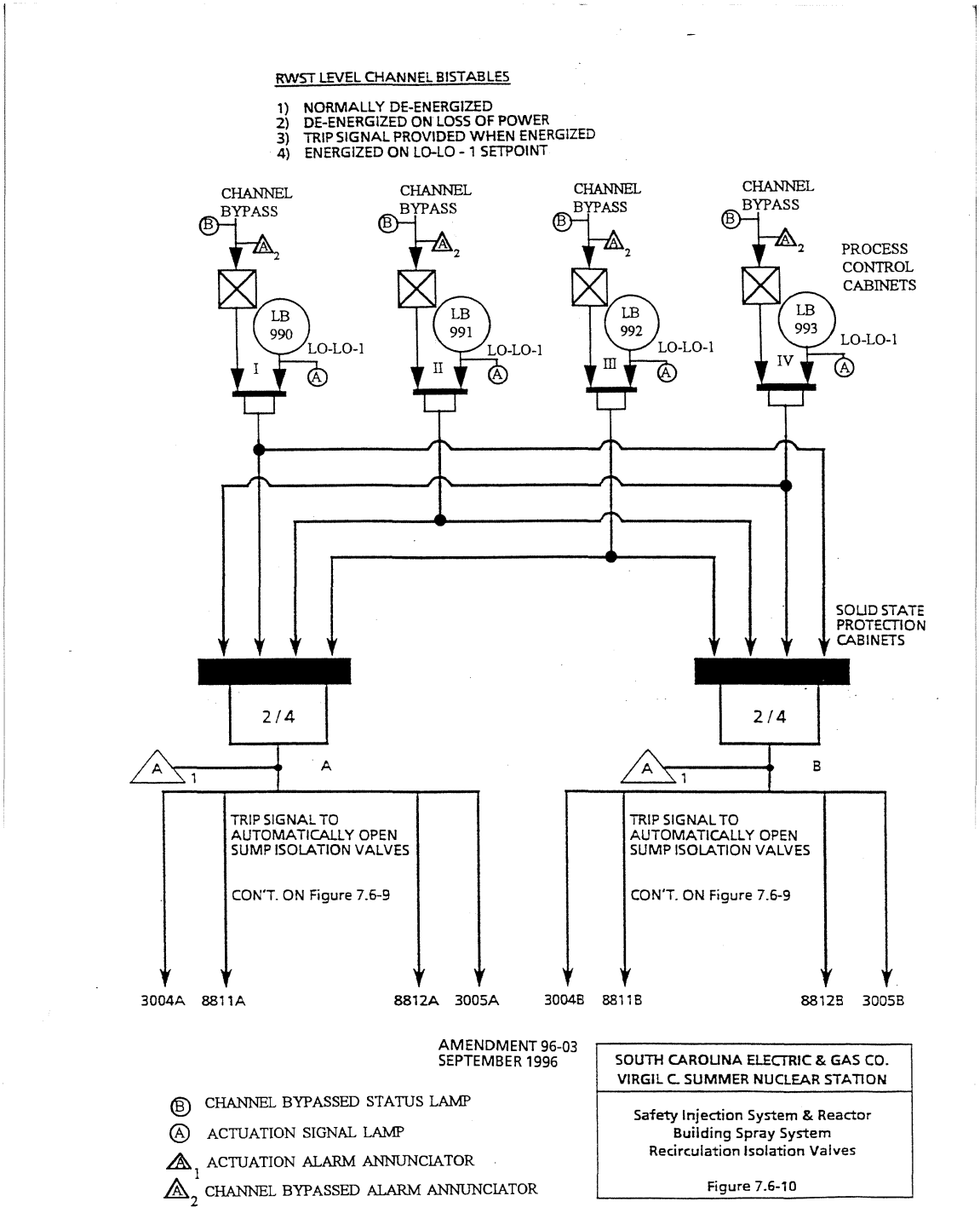
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Safety Injection System & Reactor
Building Spray System
Recirculation Isolation Valves

Figure 7.6-9

Figure 7.6-10

SAFETY INJECTION SYSTEM & REACTOR BUILDING SPRAY SYSTEM RECIRCULATION ISOLATION VALVES



7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

The general design objectives of the plant control systems are:

1. To establish and maintain power equilibrium between primary and secondary system during steady-state unit operation;
2. To constrain operational transients so as to preclude unit trip and re-establish steady-state unit operation;
3. To provide the reactor operator with monitoring instrumentation that indicates required input and output control parameters of the systems and provides the operator the capability of assuming manual control of the system.

7.7.1 Description

The plant control systems described in this section perform the following functions:

1. Reactor Control System
   a. Enables the nuclear plant to accept a step load increase or decrease of 10% and a ramp increase or decrease of 5% per minute within the load range of 15% to 100% without reactor trip, steam dump, or pressurizer relief actuation, subject to possible xenon limitations.
   b. Maintains reactor coolant average temperature (T_{avg}) within prescribed limits by creating the bank demand signals for moving groups of full length rod cluster control assemblies during normal operation and operational transients. The T_{avg} control also supplies a signal to pressurizer water level control, and steam dump control.
2. Rod Control System
   a. Provides for reactor power modulation by manual or automatic control of full length control rod banks in a preselected sequence and for manual operation of individual banks.
   b. Systems for Monitoring and Indicating
      (1) Provide alarms to alert the operator if the required core reactivity shutdown margin is not available due to excessive control rod insertion.
      (2) Display control rod position.
      (3) Provide alarms to alert the operator in the event of control rod deviation exceeding a preset limit.
3. Plant Control System Interlocks
   a. Prevent further withdrawal of the control banks when signal limits are approached that predict the approach of a departure from nucleate boiling ratio (DNBR) limit or linear power (kW/ft) limit.
   b. Inhibit automatic turbine load change as required by the Nuclear Steam Supply System.

4. Pressurizer Pressure Control

   a. Maintains or restores the pressurizer pressure to the design pressure ± 50 psi (which is well within reactor trip and relief and safety valve actuation setpoint limits) following normal operational transients that induce pressure changes by control (manual or automatic) of heaters and spray in the pressurizer. Provides steam relief by controlling the power relief valves.

5. Pressurizer Water Level Control

   a. Establishes, maintains, and restores pressurizer water level within specified limits as a function of the average coolant temperature. Changes in level are caused by coolant density changes induced by loading, operational, and unloading transients. Level changes are controlled by means of charging flow control (manual or automatic) as well as by manual selection of letdown orifices. Maintaining coolant level in the pressurizer within prescribed limits by actuating the charging and letdown system thus provides control of the reactor coolant water inventory.

6. Steam Generator Water Level Control

   a. Establishes and maintains the steam generator water level to within predetermined physical limits during normal operating transients.

   b. Restores the steam generator water level to within predetermined limits at unit trip conditions. Regulates the feedwater flowrate such that under operational transients the heat sink for the reactor coolant system does not decrease below a minimum. Steam generator water inventory control is manual or automatic through the use of feedwater control valves.

7. Steam Dump Control

   a. Permits the nuclear plant to accept a sudden loss of load without incurring reactor trip. Steam is dumped to the condenser and/or the atmosphere as necessary to accommodate excess power generation in the reactor during turbine load reduction transients.

   b. Ensures that stored energy and residual heat are removed following a reactor trip to bring the plant to equilibrium no load conditions without actuation of the steam generator safety valves.

   c. Maintains the plant at no load conditions and permits a manually controlled cooldown of the plant.

7.7.1.1 Reactor Control System

The Reactor Control System enables the nuclear plant to follow load changes automatically including the acceptance of step load increase or decreases of 10% and ramp increases or decreases of 5% per minute within the load range of 15% to 100% without reactor trip, steam dump, or pressure relief (subject to possible xenon limitations). The system is also capable of restoring coolant average temperature to within the programmed temperature deadband following a change in load. Manual control rod operation may be performed at any time.

The Reactor Control System controls the reactor coolant average temperature by regulation of control rod bank position. The reactor coolant loop average temperatures are determined from hot leg and cold leg measurements in each reactor coolant loop. There is an average coolant temperature (T_{avg}) computed for each loop, where:

$$T_{avg} = \frac{T_{hot-avg} + T_{cold}}{2}$$

The error between the programmed reference temperature (based on turbine first stage pressure) and the median of the T_{avg} measured temperatures (which is processed through a lead/lag compensation unit) from each of the reactor coolant loops constitutes the primary control signal as shown in general on Figure 7.7-1 and in more detail on the functional diagrams shown in Figure 7.2-1, Sheet 9. The system is capable of restoring coolant average temperature to the programmed value following a change in load. The programmed coolant temperature increases linearly with turbine load from zero power to the full power condition. The T_{avg} also supplies a signal to pressurizer level control and steam dump control and rod insertion limit monitoring.

The temperature channels needed to derive the temperature input signals for the Reactor Control System are fed from protection channels via isolation amplifiers.

An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transient peaks.

7.7.1.2 Rod Control System

7.7.1.2.1 Full Length Rod Control System

The full length rod control system receives rod speed and direction signals from the T_{avg} control system. The rod speed signal by design may vary over the corresponding range of 5 to 45 inches per minute (6 to 72 steps/minute) depending on the magnitude of the input signal. Manual control is provided to move a control bank in or out at a prescribed fixed speed.

When the turbine load reaches approximately 15% of rated load, the operator may select the “AUTOMATIC” mode, and rod motion is then controlled by the Reactor Control Systems. A permissive interlock C-5 (see Table 7.7-1) derived from the measurements of turbine first stage pressure prevents automatic control when the turbine load is below 15%. In the “AUTOMATIC” mode, the rods are again withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming with the control interlocks (see Table 7.7-1).

The shutdown banks are always in the fully withdrawn position during normal operation, and are moved to this position at a constant speed by manual control prior to criticality. A reactor trip signal causes them to fall by gravity into the core. There are 2 shutdown banks.

The control banks are the only rods that can be manipulated under automatic control. Each control bank is divided into 2 groups to obtain smaller incremental reactivity changes per step. All rod control cluster assemblies in a group are electrically paralleled to move simultaneously. There is individual position indication for each rod cluster control assembly.

Power to rod drive mechanisms is supplied by 2 motor generator sets operating from 2 separate 480 volt, 3-phase buses. Each generator is the synchronous type and is driven by a 200 Hp induction motor. The a-c power is distributed to the rod control power cabinets through the 2 series connected reactor trip breakers.

The variable speed rod drive programmer affords the ability to insert small amounts of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing control at high speed. A summary of the rod cluster control assembly sequencing characteristics is given below:

1. Two (2) groups within the same bank are stepped such that the relative position of the groups will not differ by more than 1 step.
2. The control banks are programmed such that withdrawal of the banks is sequenced in the following order; control bank A, control bank B, control bank C, and control bank D. The programmed insertion sequence is the opposite of the withdrawal sequence, i.e., the last control bank withdrawn (bank D) is the first control bank inserted.
3. The control bank withdrawals are programmed such that when the first bank reaches a preset position, the second bank begins to move out simultaneously with the first bank. When the first bank reaches the top of the core, it stops, while the second bank continues to move toward its fully withdrawn position. When the second bank reaches a preset position, the third bank begins to move out, and so on. This withdrawal sequence continues until the unit reaches the desired power level. The control bank insertion sequence is the opposite.
4. Overlap between successive control banks is adjustable between 0 to 50% (0 to 115 steps), with an accuracy of ± 1 step.
5. Rod speeds for either the shutdown banks or manual operation of the control banks are capable of being controlled between a minimum of 8 steps per minute and a maximum of 72 (+ 0 steps per minute, - 10 steps per minute) steps per minute.

7.7.1.2.2 Part Length Rod Control System

The part length control rods have been deleted.

7.7.1.3 Plant Control Signals for Monitoring and Indicating

7.7.1.3.1 Monitoring Functions Provided by the Nuclear Instrumentation System

The power range channels are important because of their use in monitoring power distribution in the core within specified safe limits. They are used to measure power level, axial power imbalance, and radial power imbalance. The channels are capable of recording overpower

excursions up to 200% of full power. Suitable alarms are derived from these signals as described below.

Basic power range signals are:

1. Total current from a power range detector (4 such signals from separate detectors); these detectors are vertical and have a total active length of 10 feet.
2. Current from the upper half of each power range detector (4 such signals).
3. Current from the lower half of each power range detector (4 such signals).

Derived from these basic signals are the following (including standard signal processing for calibration).

4. Indicated nuclear power (4 such signals).
5. Indicated axial flux imbalance, derived from upper half flux minus lower half flux (4 such signals).

Alarm functions derived are as follows:

6. Deviation (maximum minus minimum of 4) in indicated nuclear power.
7. Upper radial tilt (maximum to average of 4) on upper-half currents.
8. Lower radial tilt (maximum to average of 4) on lower-half currents.

Provision is made to continuously record, on the control board, the 8 ion chamber signals, i.e., upper and lower signals for each detector. Nuclear power and axial unbalance is selectable for recording as well.

The axial flux difference imbalance deviation $\Delta\Phi$ alarms are derived from the plant process computer which determines the one minute averages of the excore detector outputs to monitor $\Delta\Phi$ in the reactor core and alerts the operator where $\Delta\Phi$ alarm conditions exist. Two (2) types of alarm messages are output. Above a preset (90%) power level, an alarm message is output immediately upon determining a delta flux exceeding a preset band (usually $\pm$ 5%) about a target delta flux value. Below this preset power level, an alarm message is output if the $\Delta\Phi$ exceeded its allowable limits for a preset cumulative (usually 1 hour) amount of time in the past 24 hours.

Additional background information on the Nuclear Instrumentation System can be found in Reference 1.

7.7.1.3.2 Rod Position Monitoring of Full and Part Length Rods

Two (2) separate systems are provided to sense and display control rod position as described below:

1. Digital Rod Position Indication System

   The Digital Rod Position Indication System displays full length position. Part length rods and control are not used at V. C. Summer Nuclear Station. The Digital Rod Position Indication System senses the actual position of each full length rod using a detector which consists of discrete coils mounted concentrically with the rod drive pressure housing. The coils are located axially along the pressure housing and magnetically sense the entry and presence of the rod drive shaft through its center line. For each detector, the coils are interlaced into 2 data channels, and are connected to the containment electronics (Data A and B) by separate multi-conductor cables. By employing 2 separate channels of information, the Digital Rod Position Indication System can continue to function (at reduced accuracy) when 1 channel fails. Multiplexing is then used to transmit the digital position signals from the containment electronics to the control board display unit.

   The control board display consists of two flat panel monitors that display the control rod position in a graphical and digital format. Each rod in the control and shutdown banks has its position displayed to ±4 steps throughout its range of travel when the system is operating at full accuracy.

   Included in the system is a rod at bottom signal for each rod that operates a local alarm. Also a control room annunciator is actuated when any shutdown rod or control bank A rod is at bottom.

2. Demand Position System - The Demand Position System counts pulses generated in the Rod Drive Control System to provide a digital readout of the demanded bank position.

   The Demand Position and Digital Rod Position Indication Systems are separate systems, but safety criteria were not involved in the separation, which was a result only of operational requirements. Operating procedures require the reactor operator to compare the demand and indicated (actual) readings from the Rod Position Indication System so as to verify operation of the Rod Control System.

7.7.1.3.3 Control Bank Rod Insertion Monitoring

When the reactor is critical, the normal indication of reactivity status in the core is the position of the control bank in relation to reactor power (as indicated by the Reactor Coolant System loop ΔT) and coolant average temperature. These parameters are used to calculate insertion limits for the control banks. Two (2) alarms are provided for each control bank:

1. The “low” alarm alerts the operator of an approach to the rod insertion limits requiring boron addition by following normal procedures with the Chemical and Volume Control System.

2. The “low-low” alarm alerts the operator to take immediate action to add boron to the Reactor Coolant System by any one of several alternate methods.

The purpose of the control bank rod insertion monitor is to give warning to the operator of excessive rod insertion. The insertion limit maintains sufficient core reactivity shutdown margin following reactor trip and provides a limit on the maximum inserted rod worth in the unlikely event of a hypothetical rod ejection, and limits rod insertion such that acceptable nuclear peaking factors are maintained. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits must be decreased (the rods must be withdrawn further) with increasing power. Two (2) parameters which are proportional to power are used as inputs to the insertion monitor. These are the ΔT between the hot leg and the cold leg, which is a direct function of reactor power, and T_{avg}, which is programmed as a function of power. The rod insertion monitor uses parameters for each control rod bank as follows:

$$Z_{LL} = A(\Delta T)_{median} + B(T_{avg})_{median} + C$$

where:

Z_{LL} = Maximum permissible insertion limit for affected control bank.

$(\Delta T)_{median}$ = Median ΔT of all loops.

$T_{avg})_{median}$ = Median T_{avg} of all loops.

A,B,C= Constants chosen to maintain $Z_{LL} \geq$ actual limit based on physics calculations.

The control rod bank demand position (Z) is compared to ZLL as follows:

If $Z - Z_{LL} \leq D$ a low alarm is actuated.
If $Z - Z_{LL} \leq E$ a low-low alarm is actuated.

Actuation of the low alarm alerts the operator of an approach to a reduced shutdown reactivity situation. Administrative procedures require the operator to add boron through the Chemical and Volume Control System. Actuation of the low-low alarm requires the operator to initiate emergency boration procedures. The value for “E” is chosen such that the low-low alarm would normally be actuated before the insertion limit is reached. The value for “D” is chosen to allow the operator to follow normal boration procedures. Figure 7.7-2 shows a block diagram representation of the control rod bank insertion monitor. The monitor is shown in more detail on the functional diagrams shown in Figure 7.2-1, Sheet 9. In addition to the rod insertion monitor for the control banks, the plant computer, which monitors individual rod positions, provides an alarm that is associated with the rod deviation alarm discussed in Section 7.7.1.3.4 is provided to warn the operator if any shutdown rod cluster control assembly leaves the fully withdrawn position.

Rod insertion limits are established by:

1. Establishing the allowed rod reactivity insertion at full power consistent with the purposes given above.
2. Establishing the differential reactivity worth of the control rods when moved in normal sequence.
3. Establishing the change in reactivity with power level by relating power level to rod position.
4. Linearizing the resultant limit curve. All key nuclear parameters in this procedure are measured as part of the initial and periodic physics testing program.

Any unexpected change in the position of the control bank under automatic control, or a change in coolant temperature under manual control, provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, samples are taken periodically of coolant boron concentration. Variations in concentration during core life provide an additional check on the reactivity status of the reactor, including core depletion.

7.7.1.3.4 Rod Deviation Alarm

The demanded and measured rod position signals are also monitored by the plant computer which provides a visual printout and an audible alarm whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. The alarm can be set with appropriate allowance for instrument error and within sufficiently narrow limits to preclude exceeding core design hot channel factors.

Figure 7.7-3 is a block diagram of the rod deviation comparator and alarm system implemented by the plant computer.

7.7.1.3.5 Rod Bottom Alarms

A rod bottom signal for the full length rods in the Digital Rod Position System is used to operate control relays, which generate the “Rod Bottom” alarms.

7.7.1.4 Plant Control System Interlocks

The listing of the Plant Control System interlocks, along with the description of their derivations and functions, is presented in Table 7.7-1. It is noted that the designation numbers for these interlocks are preceded by “C”. The development of these logic functions is shown in the functional diagrams (Figure 7.2-1, Sheets 9 to 15).

7.7.1.4.1 Rod Stops

Rod stops are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by either a Control System malfunction or operator violation of administrative procedures.

Rod stops are the C_1, C_2, C_3, C_4, and C_5 control interlocks identified in Table 7.7-1. The C_3 rod stop derived from overtemperature ΔT and the C_4 rod stop, derived from overpower ΔT are also used for turbine runback, which is discussed below.

7.7.1.4.2 Automatic Turbine Load Runback

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation that might lead to an undesirable condition, which, if reached, will be protected by reactor trip.

Turbine load reference reduction is initiated by either an overtemperature or overpower ΔT signal. Two (2) out of 3 coincidence logic is used. A rod stop and turbine runback are initiated when:

$$\Delta T > \Delta T_{\text{rod stop}}$$

for both the overtemperature and the overpower condition.

For either condition in general:

$$\Delta T_{\text{rod stop}} = \Delta T_{\text{setpoint}} - B_p$$

where:

B_p = a setpoint bias.

Where $\Delta T_{\text{setpoint}}$ refers to the overtemperature ΔT reactor trip value and the overpower ΔT reactor trip value for the 2 conditions.

The turbine runback is continued until ΔT is equal to or less than $\Delta T_{\text{rod stop}}$. This function serves to maintain an essentially constant margin to trip.

7.7.1.5 Pressurizer Pressure Control

The Reactor Coolant System pressure is controlled by using either the heaters (in the water region) or the spray (in the steam region) of the pressurizer plus steam relief for large transients. The electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater group is proportionally controlled to correct small pressure variations. These variations are due to heat losses, including heat losses due to a small continuous spray. The remaining (backup) heaters are turned on automatically or manually to control pressure in conjunction with the control heaters and spray.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controller spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing spray demand signal until it reaches a maximum value.

Steam condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock and to help maintain uniform water chemistry and temperature in the pressurizer.

Power relief valves limit system pressure for large positive pressure transients. In the event of a large load reduction, not exceeding the design plant load rejection capability, the pressurizer power operated relief valves might be actuated for the most adverse conditions, e.g., the most negative Doppler coefficient, and the maximum incremental rod worth.

Diagrams of the pressurizer pressure control system are shown on Figures 7.7-4 and 7.2-1 Sheets 11 and 12.

7.7.1.6 Pressurizer Water Level Control

The pressurizer operates by maintaining a steam cushion over the reactor coolant. As the density of the reactor coolant adjusts to the various temperatures, the steam water interface moves to absorb the variations with relatively small pressure disturbances.

The water inventory in the Reactor Coolant System is maintained by the Chemical and Volume Control System. During normal plant operation, the charging flow varies to produce the flow demanded by the pressurizer water level controller. The pressurizer water level is programmed as a function of coolant average temperature, with the highest average temperature (auctioneered) being used. The pressurizer water level decreases as the load is reduced from full load. This is a result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes.

To control pressurizer water level during startup and shutdown operations, the charging flow is manually regulated from the Main Control Room.

A block diagram of the Pressurizer Water Level Control System is shown on Figure 7.7-5.

7.7.1.7 Steam Generator Water Level Control

Each steam generator is equipped with a 3 element feedwater flow controller which maintains a programmed water level which is a function of reactor flux. The 3 element feedwater controller regulates the feedwater valve by continuously comparing the feedwater flow signal, the steam generator water level signal, the programmed level and the pressure compensated steam flow signal. In addition, the feedwater pump speed is varied to maintain a programmed pressure differential between the steam header and the feed pump discharge header. The speed controller continuously compares the actual ΔP with a programmed ΔP_{ref} which is a linear function of steam flow. Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor following a reactor trip and turbine trip. An override signal closes the feedwater valves when the average coolant temperature is below a given temperature and the reactor has tripped. Manual override of the feedwater control system is available at all times. The Instrument Air system for each main feedwater control valve is equipped with the

necessary hardware to allow for local, manual control and locking of the main feedwater control valves in position with air pressure (air-gag), while maintaining the trip closed feature of the feedwater control valves.

When the plant is operating at very low power levels (as during startup), the steam and feedwater flow signals will not be usable for control. Therefore, a secondary automatic control system is provided for operation at low power. This system uses the steam generator water level and nuclear power signals in a feed forward control scheme to position a bypass valve which is in parallel with the main feedwater regulating valve. Switchover from the Bypass Feedwater Control System (low power) to the Main Feedwater Control System is initiated by the operator at approximately 25% power.

A block diagram of the Steam Generator Water Level Control System is shown in Figure 7.7-6 and 7.7-7.

7.7.1.8 Steam Dump Control

The Main Steam Supply System was originally designed to follow a full load rejection, defined as a reduction from 100% of rated turbine generator load to plant auxiliary load, without reactor trip through actuation of the steam dump to the condenser and atmosphere. With the transition to longer fuel cycles and less negative moderator temperature coefficients at the beginning of the fuel cycle, a full load rejection can no longer be sustained without a reactor trip for all times in core life and all allowable values of full power, average coolant temperature within the Reactor Coolant System.

The Automatic Steam Dump System is able to accommodate this abnormal load rejection and to reduce the effects of the transient imposed upon the Reactor Coolant System. By bypassing main steam directly to the condenser and/or the atmosphere, an artificial load is thereby maintained on the primary system. The Rod Control System can then reduce the reactor temperature to a new equilibrium value without causing a reactor trip for most allowed operating conditions (See Section 10.3.2.1). The steam dump system flow capacity was designed to be at least 85% of full load steam flow at full load steam pressure. The actual capacity is ~ 93.6%, (See Table 10.4-2).

If the difference between the reference T_{avg} (T_{ref}) based on turbine first stage pressure and the lead/lag compensated median T_{avg} exceeds a predetermined amount, and the interlock mentioned below is satisfied, a demand signal will actuate the steam dump to maintain the Reactor Coolant System temperature within control range until a new equilibrium condition is reached.

A lead/lag compensation to this T_{ref} signal is provided to improve steam dump response and provide a stable steam dump control. This allows for reducing T_{hot}, thereby opening the steam dumps at a lower temperature error.

To prevent actuation of steam dump on small load perturbations, an independent load rejection sensing circuit is provided. This circuit senses the rate of decrease in the turbine load as detected by the turbine first stage pressure. It is provided to unblock the dump valves when the rate of load

rejection exceeds a preset value corresponding to a 10% step load decrease or a sustained ramp load decrease of 5%/minute. Additional interlocks for steam dump are described in Table 7.3-3, designation P-12, and Table 7.7-1, designations C-7, C-8, C-9, C-15, and C-16.

Block diagrams of the Steam Dump Control System are shown on Figure 7.2-1, Sheet 10, and Figure 7.7-8.

7.7.1.8.1 Load Rejection Steam Dump Controller

This circuit prevents large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead/lag compensated median T_{avg} and the reference T_{avg} is based on turbine first stage pressure.

The T_{avg} signal is the same as that used in the Reactor Coolant System. The lead/lag compensation for the T_{avg} signal is to compensate for lags in the plant thermal response and in valve positioning. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating an immediate demand signal for steam dump. Since control rods are available, in this situation steam dump terminates as the error comes within the maneuvering capability of the control rods.

7.7.1.8.2 Turbine Trip Steam Dump Controller

Following a turbine trip, as monitored by the turbine trip signal, the load rejection steam dump controller is defeated and the turbine trip steam dump controller becomes active. Since control rods are not available in this situation, the demand signal is the error signal between the lead/lag compensated median T_{avg} and the no load reference T_{avg}. When the error signal exceeds a predetermined setpoint the dump valves are tripped open in a prescribed sequence. As the error signal reduces in magnitude indicating that the Reactor Coolant System T_{avg} is being reduced toward the reference no load value, the dump valves are modulated by the plant trip controller to regulate the rate of decay heat removal and thus gradually establish the equilibrium hot shutdown condition.

Following a turbine trip only sufficient steam dump capacity is necessary to maintain steam pressure below the steam generator relief valve setpoint (approximately 40% capacity to the condenser); therefore, only the first 2 groups of valves are opened. The error signal determines whether a group is to be tripped open or modulated open. The valves are modulated when the error is below the trip-open setpoints.

7.7.1.8.3 Steam Header Pressure Controller

Residual heat removal is maintained by the steam generator pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers which are used during the initial transient following a turbine and reactor trip.

7.7.1.9 Incore Instrumentation

The Incore Instrumentation System consists of Chrome-Alum-el thermocouples at fixed core outlet positions and movable miniature neutron detectors which can be positioned at the center of selected fuel assemblies, anywhere along the length of the fuel assembly vertical axis. The basic system for insertion of these detectors is shown in Figure 7.7-9.

7.7.1.9.1 Thermocouples

This section deleted by Amendment 1, August 1985.

7.7.1.9.2 Movable Neutron Flux Detector Drive System

Miniature fission chamber detectors can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. The stainless steel detector shell is welded to the leading end of helical wrap drive cable and to stainless steel sheathed coaxial cable. The retractable thimbles, into which the miniature detectors are driven, are pushed into the reactor core through conduits which extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal table. Their distribution over the core is nearly uniform with about the same number of thimbles located in each quadrant.

The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the Reactor Coolant System and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal line. During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal line is provided for the retraction operation.

The Drive System for the insertion of the miniature detectors consists basically of drive assemblies, 5 path rotary transfer assemblies, and 10 path rotary transfer assemblies, as shown in Figure 7.7-9. The Drive System pushes hollow helical wrap drive cables into the core with the miniature detectors attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly consists of a gear motor which pushes a helical wrap drive cable and detector through a selective thimble path by means of a special drive box and includes a storage device that accommodates the total drive cable length.

Manual isolation valves (1 for each thimble) are provided for closing the thimbles. When closed, the valves form a 2500 psig barrier. The manual isolation valves are not designed to isolate a thimble while a detector/drive cable is inserted into the thimble. The detector/drive cable must be retracted to a position above the isolation valve prior to closing the valve.

A small leak would probably not prevent access to the isolation valves and thus a leaking thimble could be isolated during a hot shutdown. A large leak might require cold shutdown for access to the isolation valve.

7.7.1.9.3 Control and Readout Description

The Control and Readout System provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors while plotting neutron flux versus detector position. The Control System is located in the Control Room. Limit switches in each transfer device provide feedback of path selection operation. Each gear box drives an encoder for position feedback. One (1) 5 path operation selector is provided for each drive unit to insert the detector in one of 5 functional modes of operation. One (1) 10 path operation selector is also provided for each drive unit that is used to route a detector into any 1 of up to 10 selectable paths. A common path is provided to permit cross calibration of the detectors.

The Control Room contains the necessary equipment for control, position indication, and flux recording for each detector.

A “flux-mapping” consists, briefly, of selecting (by panel switches) flux thimbles in given fuel assemblies at various core quadrant locations. The detectors are driven to the top of the core and stopped automatically. An x-y plot (position versus flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner other core locations are selected and plotted. Each detector provides axial flux distribution data along the center of a fuel assembly.

Various radial positions of detectors are then compared to obtain a flux map for a region of the core.

The number and location of these thimbles have been chosen to permit measurement of local to average peaking factors to an accuracy of ± 5% (95% confidence). Measured nuclear peaking factors will be increased by 5% to allow for this accuracy. If the measured power peaking is larger than acceptable, reduced power capability will be indicated.

Operating plant experience has demonstrated the adequacy of the incore instrumentation in meeting the design bases stated.

7.7.1.9.4 Power Distribution Monitoring System

An alternative to the Movable Incore Detector System for developing full core flux maps while above 25% power, is the BEACON Power Distribution Monitoring System (Reference 3). This system obtains data from the plant computer and processes the data into a 3-dimensional core model. The inputs into this system are core exit thermocouples, control rod bank position, Tcold, Reactor power level, and the nuclear instrumentation Power Range section signals. Per Technical Specifications, there is a minimum number of each type of input necessary to consider the system operable.

7.7.2 Analysis

The plant control systems are designed to assure high reliability in any anticipated operational occurrences. Equipment used in these systems is designed and constructed with a high level of reliability.

Proper positioning of the control rods is monitored in the Control Room by bank arrangements of the individual position columns for each rod cluster control assembly. A rod deviation alarm alerts the operator of a deviation of 1 rod cluster control assembly from the other rack in that bank position. There are also insertion limit monitors with visual and audible annunciation. A rod bottom alarm signal is provided to the Control Room for each full length rod cluster control assembly. Four (4) excore long ion chambers also detect asymmetrical flux distribution indicative of rod misalignment.

Overall reactivity control is achieved by the combination of soluble boron and rod cluster control assemblies. Long term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short term reactivity control for power changes is accomplished by the Plant Control System which automatically moves rod cluster control assemblies. This system uses input signals including neutron flux, coolant temperature, and turbine load.

The Plant Control Systems will prevent an undesirable condition in the operation of the plant that, if reached, will be protected by reactor trip. The description and analysis of this protection is covered in Section 7.2. Worst case failure modes of the Plant Control Systems are postulated in the analysis of off-design operational transients and accidents covered in Chapter 15, such as, the following:

1. Uncontrolled rod cluster control assembly withdrawal from a subcritical condition.
2. Uncontrolled rod cluster control assembly withdrawal at power.
3. Rod cluster control assembly misalignment.
4. Loss of external electrical load and/or turbine trip.
5. Loss of all a-c power to the station auxiliaries.
6. Excessive heat removal due to Feedwater System malfunctions.
7. Excessive load increase incident.
8. Accidental depressurization of the Reactor Coolant System.

These analyses show that a reactor trip setpoint is reached in time to protect the health and safety of the public under those postulated incidents and that the resulting coolant temperatures produce a departure from nucleate boiling (DNBR) well above the limiting value of 1.30. Thus, there will be no cladding damage and no release of fission products to the Reactor Coolant System under the assumption of these postulated worst case failure modes of the plant control system.

7.7.2.1 Separation of Protection and Control System

In some cases, it is advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel. As such, a failure in the control circuitry does not adversely affect the protection channel. Test results have shown that a short circuit or the application (credible fault voltage from within the cabinets) of 120 volt a-c ± 1% or 140 volt d-c on the isolated output portion of the circuit (nonprotection side of the circuit) will not affect the input (protection) side of the circuit.

Where a single random failure can cause a control system action that results in a generating station condition requiring protective action and can also prevent proper action of a protection system channel designed to protect against the condition, the remaining redundant protection channels are capable of providing the protective action even when degraded by a second random failure. The loop T_{avg} and Delta-T channel required inputs to the Steam Dump System, Reactor Control System, the Control Rod Insertion Monitor and the Pressurizer Level Control System are electrically isolated prior to being routed to the control cabinets. A median signal is then calculated for T_{avg} and Delta-T in the control cabinets utilizing a Median Signal Selection (MSS) for input to the appropriate control systems. This meets the applicable requirements of Section 4.7 of IEEE Standard 279-1971.

The pressurizer pressure channels needed to derive the control signals are electrically isolated from protection.

7.7.2.2 Response Considerations of Reactivity

Reactor shutdown with control rods is completely independent of the control functions since the trip breakers interrupt power to the full length rod drive mechanisms regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of control groups or unplanned dilution of soluble boron without exceeding acceptable fuel design limits. The design meets the requirements of the 1971 General Design Criteria 25.

No single electrical or mechanical failure in the Rod Control System could cause the accidental withdrawal of a single rod cluster control assembly from the partially inserted bank at full power operation. The operator could deliberately withdraw a single rod cluster control assembly in the control bank; this feature is necessary in order to retrieve a rod, should one be accidentally dropped. In the extremely unlikely event of simultaneous electrical failures which could result in a single rod cluster control assembly withdrawal, rod deviation would be displayed on the plant annunciator, and the individual rod position readouts would indicate the relative positions of the rods in the bank. Withdrawal of a single rod cluster control assembly by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

Each bank of control and shutdown rods in the system is divided into 2 groups (group 1 and group 2) of 4 mechanisms each. The rods comprising a group operate in parallel through multiplexing thyristors. The 2 groups in a bank move sequentially such that the first group is always within 1 step of the second group in the bank. The group 1 and group 2 power circuits are installed in

different cabinets as shown in Figure 7.7-15, which also shows that 1 group is always within 1 step (5/8 inch) of the other group. A definite schedule of actuation or deactuation of the stationary gripper, moveable gripper, and lift coils of a mechanism is required to withdraw the rod cluster control assembly attached to the mechanism. Since the 4 stationary gripper, moveable gripper, and lift coils associated with the rod cluster control assemblies of a rod group are driven in parallel, any single failure which could cause rod withdrawal would affect a minimum of 1 group of rod cluster control assemblies. Mechanical failures are in the direction of insertion, or immobility.

Figure 7.7-15 is provided for a discussion of design features that assure that no single electrical failure could cause the accidental withdrawal of a single rod cluster control assembly from the partially inserted bank at full power operation.

The Figure 7.7-15 shows the typical parallel connections on the lift, movable and stationary coils for a group of rods. Since single failures in the stationary or movable circuits will result in dropping or preventing rod (or rods) motion, the discussion of single failure will be addressed to the lift coil circuits. 1) Due to the method of wiring the pulse transformers which fire the lift coil multiplex thyristors, 3 of the 4 thyristors in a rod group could remain turned off when required to fire, if for example the gate signal lead failed open at point $\chi 1$. Upon “up” demand, 1 rod in group 1 and 4 rods in group 2 would withdraw. A second failure at point $\chi 2$ in group 2 circuit is required to withdraw 1 rod cluster control assembly; 2) Timing circuit failures will affect the 4 mechanisms of a group or the 8 mechanisms of the bank and will not cause a single rod withdrawal; 3) More than 2 simultaneous component failures are required (other than the open wire failures) to allow withdrawal of a single rod.

The identified multiple failure involving the least number of components consists of open circuit failure of the proper 2 out of 16 wires connected to the gate of the lift coil thyristors. The probability of open wire (or terminal) failure is 0.016×10^{-6} per hour by MIL-HDB217A. These wire failures would have to be accompanied by failure, or disregard, of the indications mentioned above. The probability of this occurrence is therefore too low to have any significance.

Concerning the human element, to erroneously withdraw a single rod cluster control assembly, the operator would have to improperly set the blank selector switch, the lift coil disconnect switches, and the in hold out switch. In addition, the indications would have to be disregarded or ineffective. Such series of errors would require a complete lack of understanding and administrative control. A probability number cannot be assigned to a series of errors such as these.

The Rod Position Indication System provides direct visual displays of each control rod assembly position. The plant computer alarms for deviation of rods from their banks. In addition a rod insertion limit monitor provides an audible and visual alarm to warn the operator of an approach to an abnormal condition due to dilution. The low-low insertion limit alarm alerts the operator to follow emergency boration procedures. The facility reactivity control systems are such that acceptable fuel damage limits will not be exceeded even in the event of a single malfunction of either system.

An important feature of the Control Rod System is that insertion is provided by gravity fall of the rods.

In all analyses involving reactor trip, the single, highest worth rod cluster control assembly is postulated to remain untripped in its full out position.

One means of detecting a stuck control rod assembly is available from the actual rod position information displayed on the control board. There is a control board rod position readout with one for each full length rod, to provide the plant operator actual position of the rod in steps. The indications are grouped by banks (e.g., control bank A, control bank B, etc.) to indicate to the operator the deviation of one rod with respect to other rods in a bank. This serves as a means to identify rod deviation.

The plant computer monitors the actual position of all rods. Should a rod be misaligned from the other rods in that bank by more than 15 inches, the rod deviation alarm is actuated.

Misaligned rod cluster control assemblies are also detected and alarmed in the Control Room via the Flux Tilt Monitoring System which is independent of the plant computer. Isolated signals derived from the Nuclear Instrumentation System are compared with one another to determine if a preset amount of deviation of average power level has occurred. Should such a deviation occur the comparator output will operate a bistable unit to actuate a control board annunciator. This alarm will alert the operator to a power imbalance caused by a misaligned rod. By use of individual rod position readouts, the operator can determine the deviating control rod and take corrective action. The design of the Plant Control Systems meets the requirements of the 1971 General Design Criteria 23.

Refer to Section 4.3.2.1 for additional information on response considerations due to reactivity.

7.7.2.3 Step Load Changes Without Steam Dump

The Plant Control System restores equilibrium conditions, without a trip, following a plus or minus 10% step change in load demand, over the 15 to 100% power range for automatic control. Steam dump is blocked for load decrease less than or equal to 10%. A load demand greater than full power is prohibited by the turbine control load limit devices.

The Plant Control System minimizes the reactor coolant average temperature deviation during the transient within a given value and restores average temperature to the programmed setpoint. Excessive pressurizer pressure variations are prevented by using spray and heaters and power relief valves in the pressurizer.

The control system must limit nuclear power overshoot to acceptable values following a 10% increase in load to 100%.

7.7.2.4 Loading and Unloading

Ramp loading and unloading of 5% per minute can be accepted over the 15 to 100% power range under automatic control without tripping the plant. The function of the control system is to maintain the coolant average temperature as a function of turbine generator load.

The coolant average temperature increases during loading and causes a continuous insurge to the pressurizer as a result of coolant expansion. The sprays limit the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during unloading, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The pressurizer heaters limit the resulting system pressure decrease. The pressurizer water level is programmed such that the water level is above the setpoint for heater cut out during the loading and unloading transients. The primary concern during loading is to limit the overshoot in nuclear power and to provide sufficient margin in the overtemperature ΔT setpoint.

The automatic load controls are designed to adjust the unit generation to match load requirements within the limits of the unit capability and licensed rating.

7.7.2.5 Load Rejection Furnished by Steam Dump System

When a load rejection occurs, if the difference between the required temperature setpoint of the Reactor Coolant System and the actual average temperature exceeds a predetermined amount, a signal will actuate the steam dump to maintain the Reactor Coolant System temperature within control range until a new equilibrium condition is reached.

The reactor power is reduced at a rate consistent with the capability of the Rod Control System. Reduction of the reactor power is automatic. The steam dump flow reduction is as fast as rod cluster control assemblies are capable of inserting negative reactivity.

The Rod Control System can then reduce the reactor temperature to a new equilibrium value without causing a reactor trip for most allowed operating conditions (See Section 10.3.2.1). The steam dump system flow capacity was designed to be at least 85% of full load steam flow at full load steam pressure. The actual capacity is ~ 93.6%, (See Table 10.4-2).

The steam dump flow reduces proportionally as the control rods act to reduce the average coolant temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value.

The dump valves are modulated by the reactor coolant average temperature signal. The required number of steam dump valves can be tripped quickly to stroke full open or modulate, depending upon the magnitude of the temperature error signal resulting from loss of load.

7.7.2.6 Turbine Generator Trip with Reactor Trip

Whenever the turbine generator unit trips at an operating power level above 50% power, the reactor also trips. The unit is operated with a programmed average temperature as a function of

load, with the full load average temperature significantly greater than the equivalent saturation pressure of the steam generator safety valve setpoint. The thermal capacity of the Reactor Coolant System is greater than that of the Secondary System, and because the full load average temperature is greater than the no load temperature, a heat sink is required to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for a trip from full power. This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of feedwater to the steam generators.

The Steam Dump System is controlled from the reactor coolant average temperature signal whose setpoint values are programmed as a function of turbine load. Actuation of the steam dump is rapid to prevent actuation of the steam generator safety valves. With the dump valves open, the average coolant temperature starts to reduce quickly to the no load setpoint. A direct feedback of temperature acts to proportionally close the valves to minimize the total amount of steam which is by-passed.

Following the turbine trip, the feedwater flow is cut off when the average coolant temperature decreases below a given temperature or when the steam generator water level reaches a given high level.

Additional feedwater makeup is then controlled manually to restore and maintain steam generator water level while assuring that the reactor coolant temperature is at the desired value. Residual heat removal is controlled by the steam (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers which are used during the initial transient following turbine and reactor trip.

The pressurizer pressure and level fall rapidly during the transient because of coolant contraction. The pressurizer water level is programmed so that the level following the turbine and reactor trip is above the heaters. However, if the heaters become uncovered following the trip, the Chemical and Volume Control System will provide a full charging flow to restore water level in the pressurizer. Heaters are then turned on to restore pressurizer pressure to normal.

The Steam Dump and Feedwater Control Systems are designed to prevent the average coolant temperature from falling below the programmed no load temperature following the trip to ensure adequate reactivity shutdown margin.

7.7.3 Technical Support Complex (TSC)

7.7.3.1 Description

In response to the recommendations issued post-TMI (e.g., NUREG-0578, NUREG-0585), South Carolina Electric & Gas will incorporate into the Virgil C. Summer Nuclear Power Plant a Technical Support Complex (TSC). This complex will improve the information available to operating and technical personnel. The 3 elements of the Technical Support Complex are:

1. ON-SITE Technical Support Center (OSTS).

2. Bypass and Inoperable Status Indication (BISI)
3. Safety Parameter Display System (SPDS)

The ON-SITE Technical Support Center is at a location adjacent to but separate from the Control Room. Key plant information can be displayed in and transmitted from the ON-SITE Technical Support Center to those technical personnel who are responsible for engineering support during post accident recovery. The center has the capability to receive, process, and display analog and digital signals from both the Nuclear Steam Supply System and balance of plant parts of the plant.

Bypass and Inoperable Status Indication provides the operator with a clear indication of the availability of plant safety systems. It provides the operator and OTSC personnel with a continuous systems level indication of bypasses or inoperable status of the systems comprising the Engineered Safety Features.

The purpose of the safety parameter display system (SPDS) is to assist operating personnel in evaluating the safety status of the plant. The safety parameter display system provides a continuous indication of plant parameters or derived variables which are representative of the safety status of the plant during both normal and emergency use except in the case that a seismic event results in the loss of the Integrated Plant Computer System (IPCS). The primary function of the SPDS is to aid in the rapid detection of abnormal operating conditions. Secondary functions include analyzing and diagnosing the abnormality, and providing an informational basis for corrective action execution.

The Technical Support Complex is located in the Control Building, elevation 463’0”, separate from but next to, the Control Room and is capable of accommodating a minimum of 25 persons (see Figure 1.2-15). Access to the Control Room is available through connecting doors between the Technical Support Complex and the Control Room. Print storage and plant information will be available in the Technical Support Center. The Technical Support Complex contains the following areas:

1. Data Display Room - This contains the communications and monitoring equipment necessary to provide the engineering and management support functions during an accident condition. The Communications, monitoring, and display equipment in this area includes:
   a. Communications Network including plant telephones, dedicated lines to external parties, and radio systems.
2. SCE&G Co. Technical Area - Office and communications facilities for SCE&G assigned personnel.
3. NRC Office - Office and communications for 5 NRC assigned personnel.
4. Operations Conference Room - Conference Room facilities.
5. Westinghouse Office - Office and communications facilities for plant personnel to communicate with Westinghouse.
6. GAI Office - Office and communications facilities for plant personnel to communicate with GAI.

7. Emergency Monitoring Team Office - Office facilities for the SCE&G Co. emergency monitoring team.

The Technical Support Complex is habitable to the same environmental conditions as the Control Room for postulated accident conditions. (The Technical Support Complex has the same air supply and exhaust system as the Control Room, see Section 9.4.1.2.1).

Installed radiation monitors (RM-G1 and RM-A1) will detect direct radiation and airborne radioactive contaminants for both the Control Room and the Technical Support Complex. The monitors will alarm when high radiation levels are being approached. SCE&G Co. has established in the plant's emergency procedures the necessary precautionary protective measures to be taken for high levels of radiation.

7.7.3.2 Analysis

1. The Technical Support Complex is located on elevation 463'0" of the Control Building, which is a Seismic Category I structure.
2. The environmental conditions within the Technical Support Complex are the same as those in the Control Room.
3. Installed radiation monitors (RM-G1 and RM-A1) will detect direct radiation and airborne radioactive contaminants for both the Control Room and the TSC. The monitors will alarm when high radiation levels are being approached.
4. Equipment within the Technical Support Complex is designed to assure reliability in the recovery of data.
5. The Technical Support Complex and equipment located in the Technical Support Complex are not required to initiate actuation of safety related systems. Loss of the Technical Support Complex or any equipment within the TSC will not prevent safe shutdown of the plant.

7.7.4 Critical Systems Leak Monitoring System

7.7.4.1 Description

An acoustical type leak monitoring system is provided to detect through the wall and valve seat leakage downstream of the pressurizer safety valves.

The sensors and preamps for the system are located inside the Reactor Building, with all other conditioning components located outside.

A leak through a valve seat generates metal borne acoustic waves which are detected by acoustic transducers mounted on the piping adjacent to the valves. The transducers convert the acoustic waves into electrical signals which are amplified and then transmitted to the Leak Detection System.

The Control Room is provided with indication which relates to the size of the leak and an alarm which alerts the operator of the occurrence of a leak. The system is provided with multiple sensors to enable the plant operator to determine which pressurizer safety valve is open.

7.7.4.2 Analysis

The Critical Systems Leak Monitoring System is powered from a vital instrument bus. The system will be qualified to IEEE 323-1971 and IEEE 344-1975. Seismic and environmental qualification is discussed in Section 3.10 and 3.11, respectively.

7.7.5 Reactor Vessel Level Instrumentation System

This section deleted by Amendment 4.

7.7.6 Core Subcooling Monitor

This section deleted by Amendment 1, August 1985.

7.7.7 References

1. Lipchak, J. B. and Stokes, R. A., *Nuclear Instrumentation System*, WCAP-8255, January, 1974.
2. *Calculation of Distance Factors for Power and Test Reactor Sites*, J. J. Dinunno, et al, U. S. Atomic Energy Commission, Washington, D. C., March, 1962.
3. *BEACON Core Monitoring and Operations Support System*, WCAP-12472-P-A, August, 1994.
4. WCAP-12472-P-A, Addendum 1-A, *BEACON Core Monitoring and Operations Support System*, January 2000, (W Proprietary)

Table 7.7-1
Plant Control System Interlocks

DESIGNATION	DERIVATION	FUNCTION
C-1	1/2 Neutron flux (intermediate range) above setpoint	Blocks automatic and manual control rod withdrawal
C-2	1/4 Neutron flux (power range) above setpoint	Blocks automatic and manual control rod withdrawal
C-3	2/3 Overtemperature ΔT above setpoint	Blocks automatic and manual control rod withdrawal Actuates turbine runback via load reference Defeats remote load dispatching (if remote load dispatching is used)
C-4	2/3 Overtemperature ΔT above setpoint	Blocks automatic and manual control rod withdrawal Actuates turbine runback via load reference Defeats remote load dispatching (if remote load dispatching is used)
C-5	1/1 Turbine first stage pressure below setpoint	Defeats remote load dispatching (if remote load dispatching is used) Blocks automatic control rod withdrawal
C-7	1/1 Time derivative (absolute value) of turbine first stage pressure (decrease only) above setpoint	Makes steam dump valves available for either tripping or modulation

Table 7.7-1
Plant Control System Interlocks (continued)

DESIGNATION	DERIVATION	FUNCTION
C-8	Turbine trip, 2/3 turbine emergency trip fluid pressure below setpoint or 4/4 turbine valves closed	Blocks steam dump control via load rejection T_{avg} Controller Makes steam dump valves available for either tripping or modulation
	No turbine trip, 2/3 turbine emergency trip fluid pressure above setpoint and 1/4 turbine inlet line stop valves not closed.	Blocks steam dump control via turbine trip T_{avg} controller
C-9	Any condenser pressure above setpoint, or circulation water pump breakers open	Blocks steam dump to condenser
C-11	1/1 Bank D control rod position above setpoint	Blocks automatic rod withdrawal
C-15	1/1 Generator loss of stator coolant, runback has occurred	Block steam dump to one pair of the four pairs of condenser steam dump valves (not the cooldown valves)
C-16	1/1 Condenser pressure above 4.5 inches of mercury	Block steam dump to one pair of condenser steam dump valves (not cooldown valves or valves blocked by designation C-15, above)

Table 7.7-2

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Figure 7.7-1

SIMPLIFIED BLOCK DIAGRAM OF REACTOR CONTROL SYSTEM

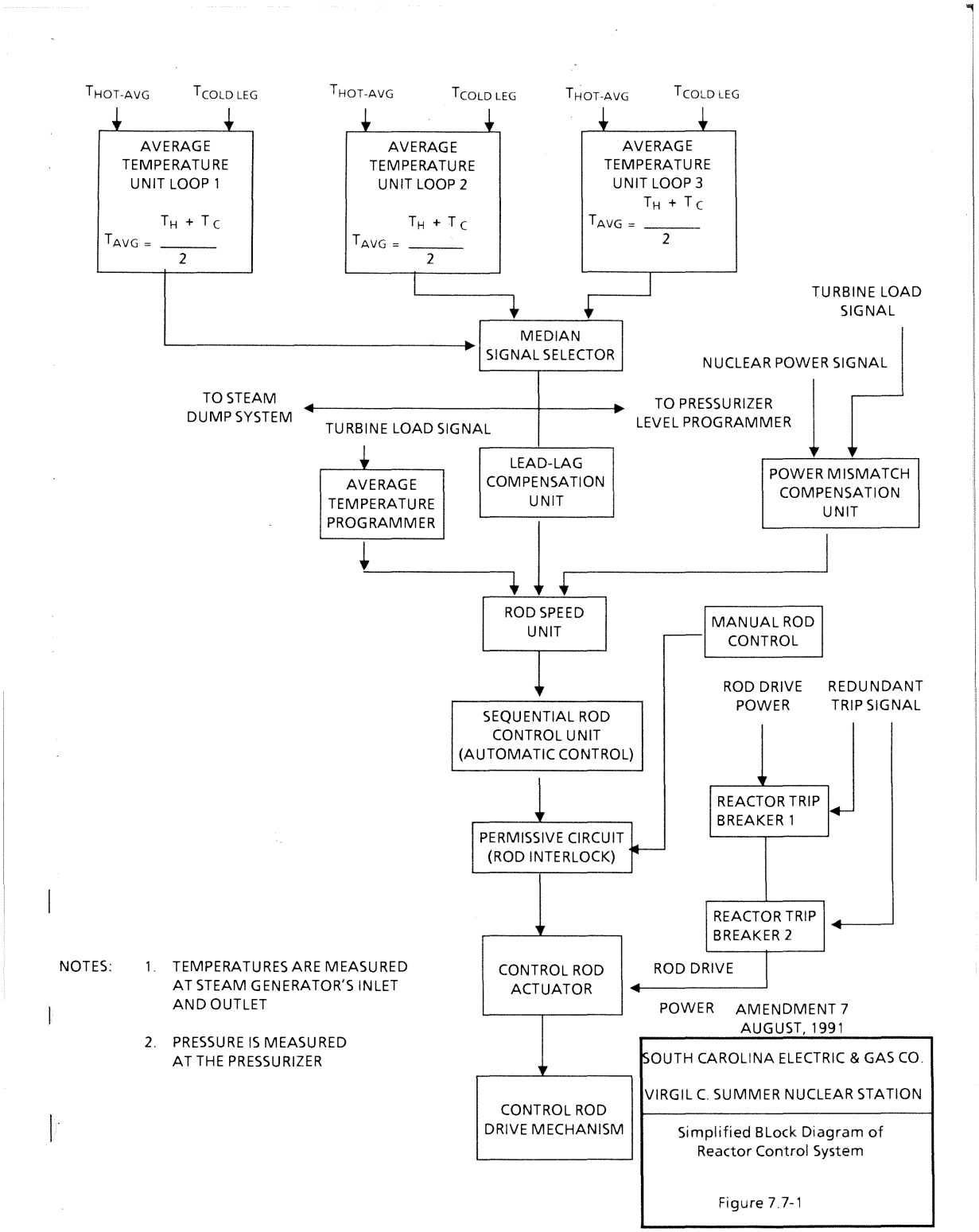
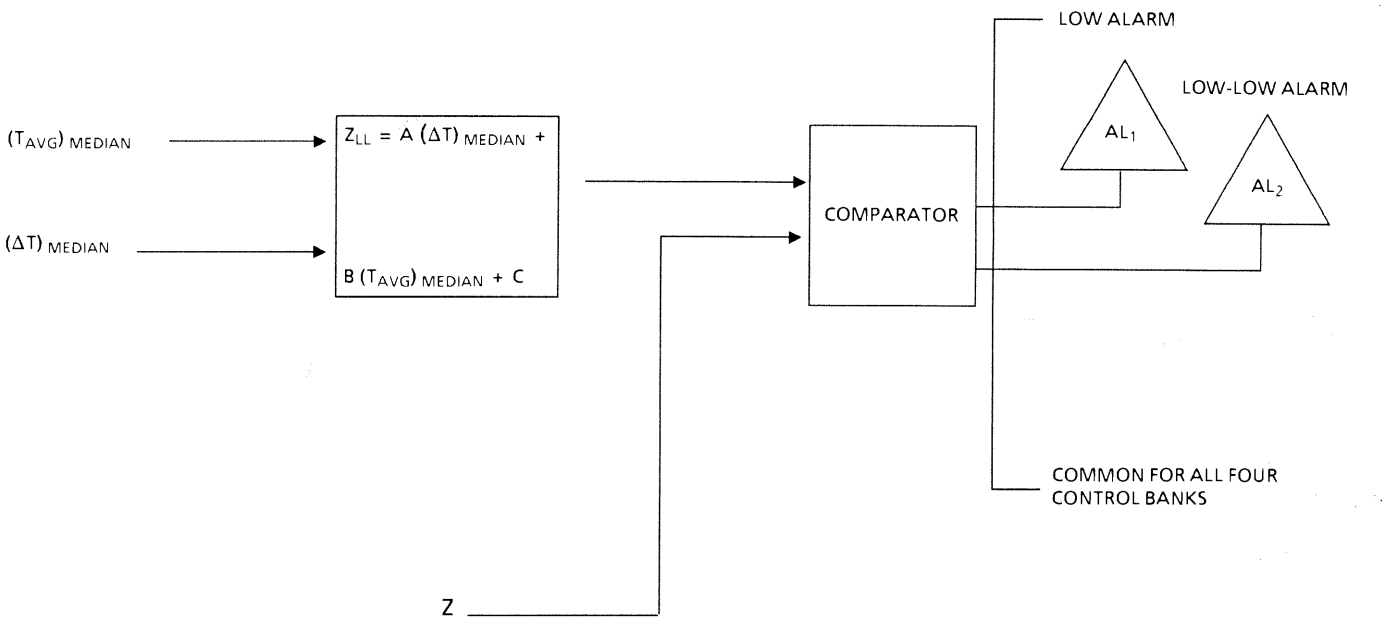


Figure 7.7-2

CONTROL BANK ROD INSERTION MONITOR



NOTE: 1. ALALOG CIRCUITRY IS USED FOR THE COMPARATOR NETWORK
2. COMPARISON IS DONE FOR ALL CONTROL BANKS

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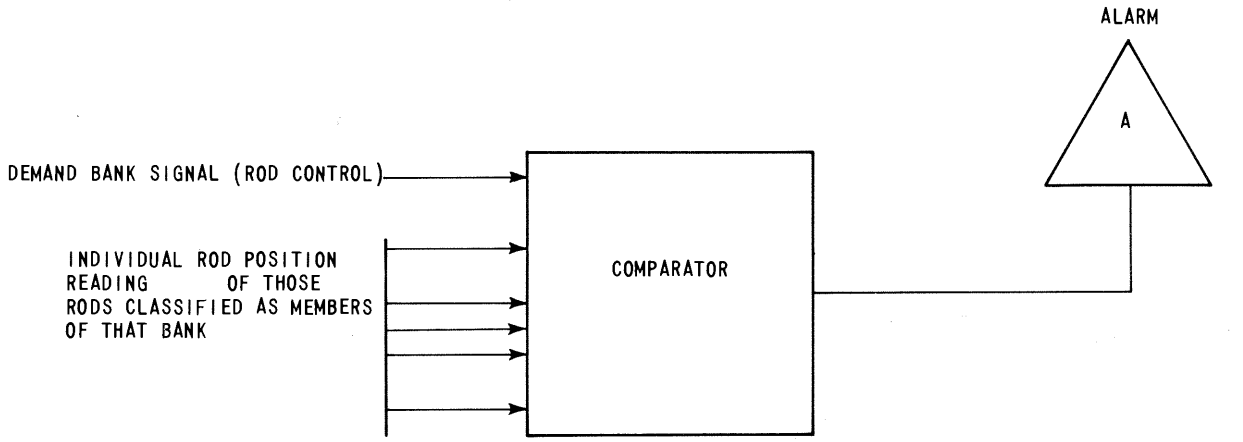
VIRGIL C. SUMMER NUCLEAR STATION

CONTROL BANK ROD INSERTION MONITOR

Figure 7.7-2

Figure 7.7-3

ROD DEVIATION COMPARATOR

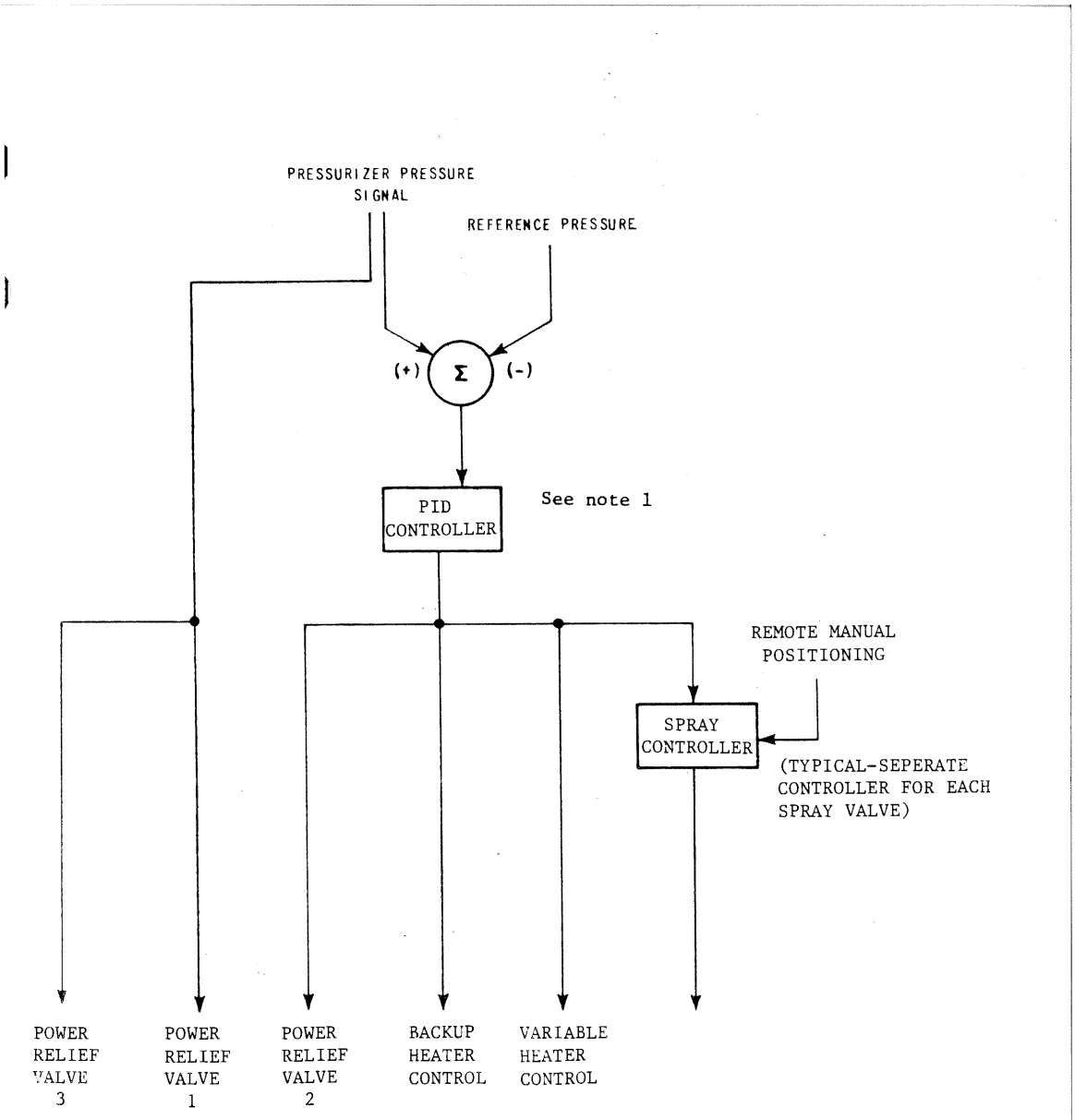


NOTE:
1. DIGITAL OR ANALOG SIGNALS MAY BE USED FOR THE COMPARATOR COMPUTER INPUTS.
2. THE COMPARATOR WILL ENERGIZE THE ALARM IF THERE EXISTS A POSITION DIFFERENCE GREATER THAN A PRESENT LIMIT BETWEEN ANY INDIVIDUAL ROD AND THE DEMAND BANK SIGNAL.
3. COMPARISON IS INDIVIDUALLY DONE FOR ALL CONTROL BANKS.

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Rod Deviation Comparator Figure 7.7-3

Figure 7.7-4

BLOCK DIAGRAM OF PRESSURIZER PRESSURE CONTROL SYSTEM



Note 1: Derivative set to Zero (Refer to NUREG-0660, II.K.3 Table C.3 Item 9)

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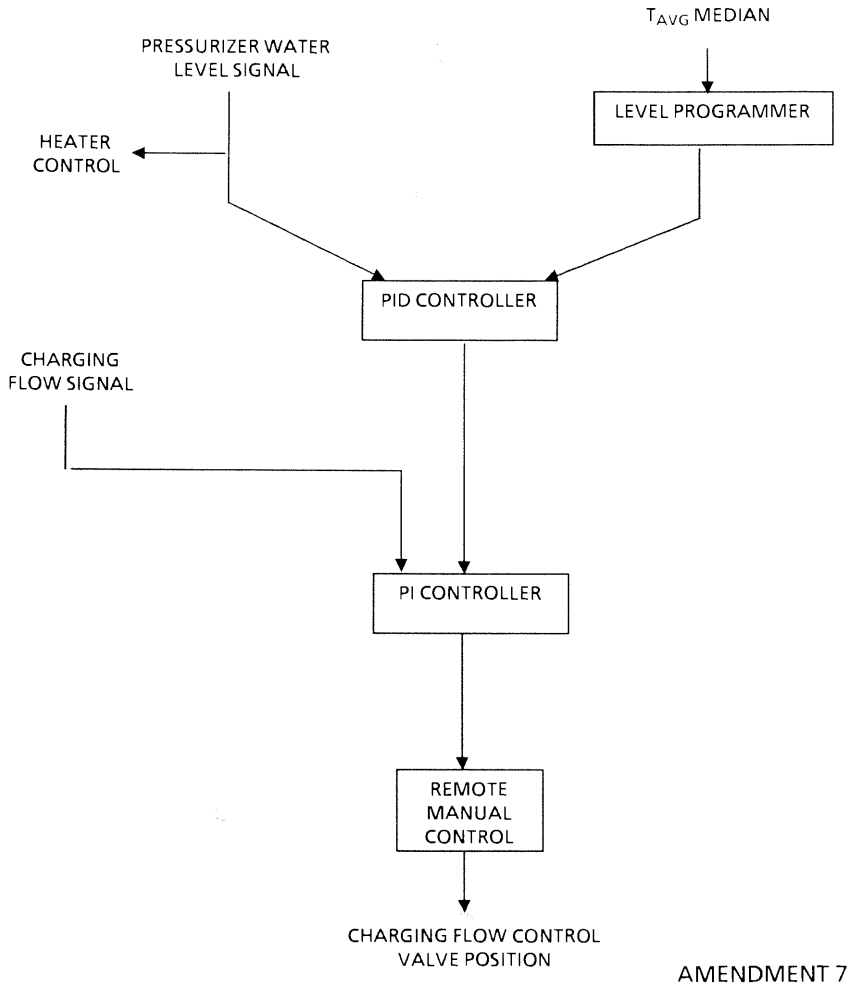
Block Diagram of Pressurizer Pressure Control System

Figure 7.7-4

Figure 7.7-5
BLOCK DIAGRAM OF PRESSURIZER LEVEL CONTROL SYSTEM



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Block Diagram of Pressurizer Level Control System

Figure 7.7-5

Figure 7.7-6
BLOCK DIAGRAM OF STEAM GENERATOR WATER LEVEL CONTROL SYSTEM

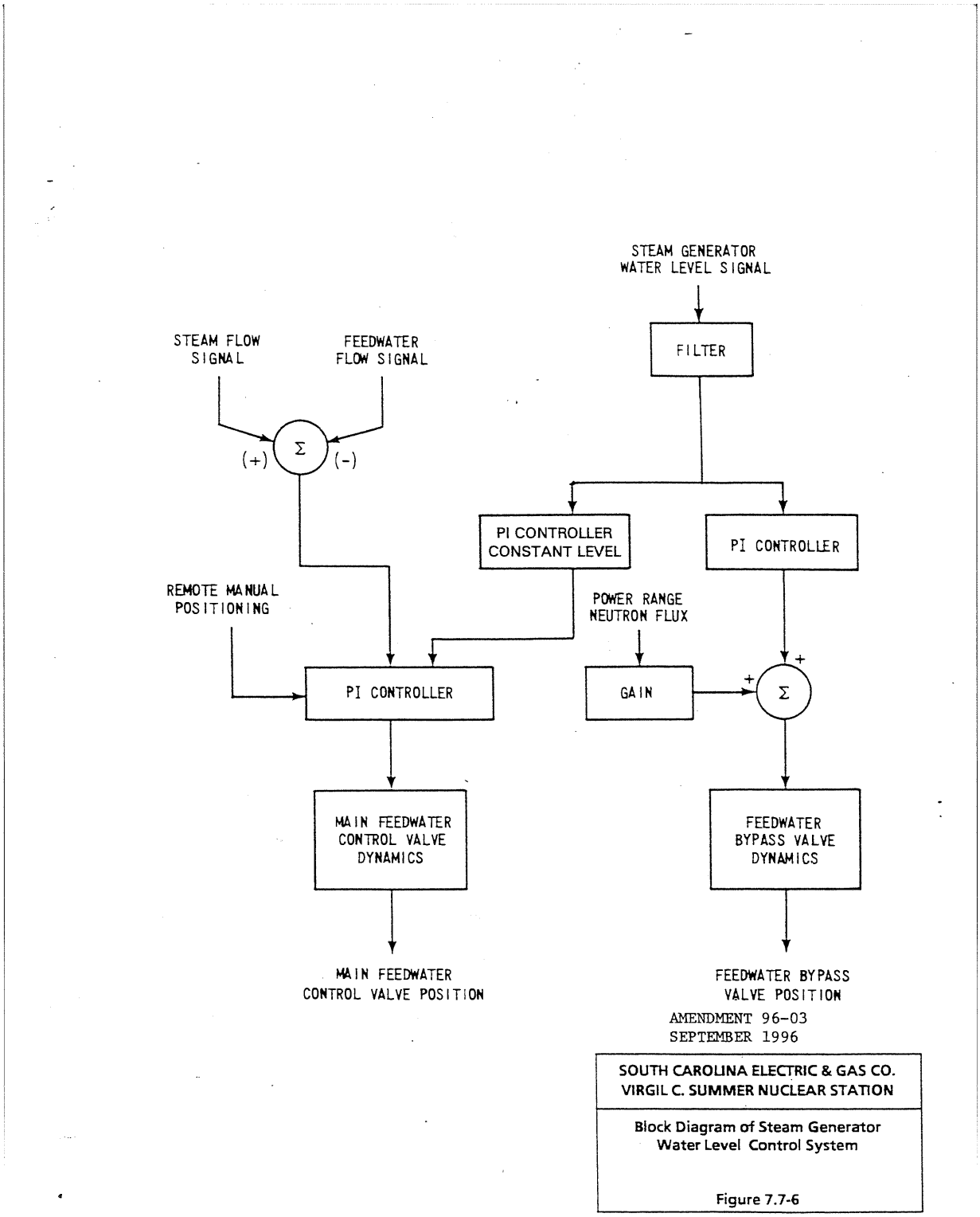
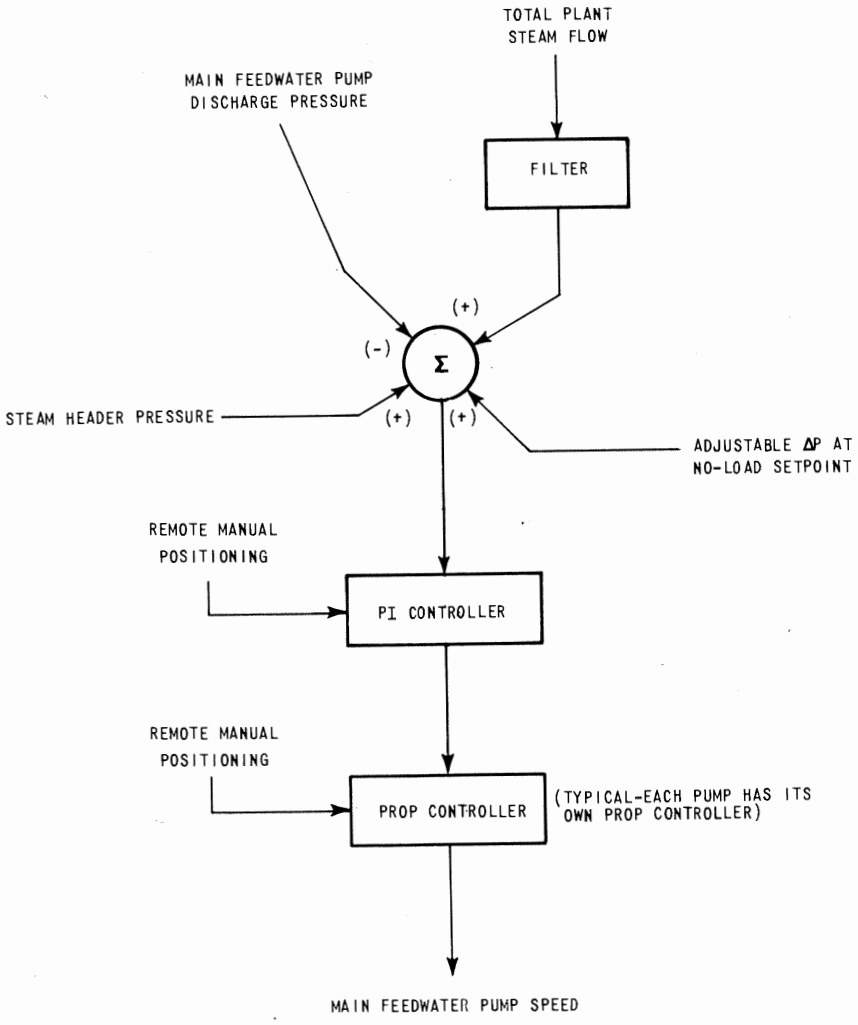


Figure 7.7-7
BLOCK DIAGRAM OF MAIN FEEDWATER PUMP SPEED CONTROL SYSTEM



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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Block Diagram of Main Feedwater Pump Speed Control System
Figure 7.7-7

Figure 7.7-8
BLOCK DIAGRAM OF STEAM DUMP CONTROL SYSTEM

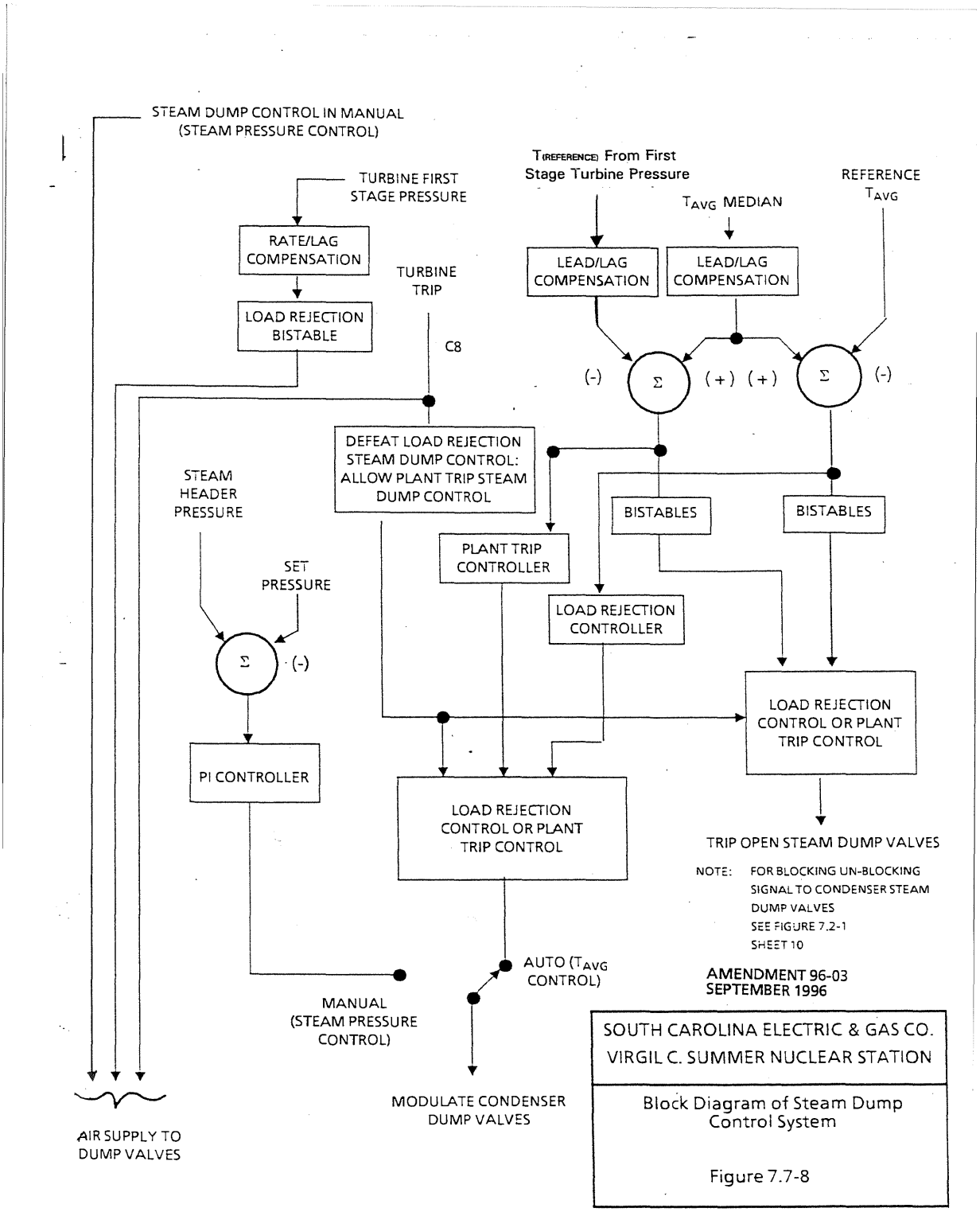
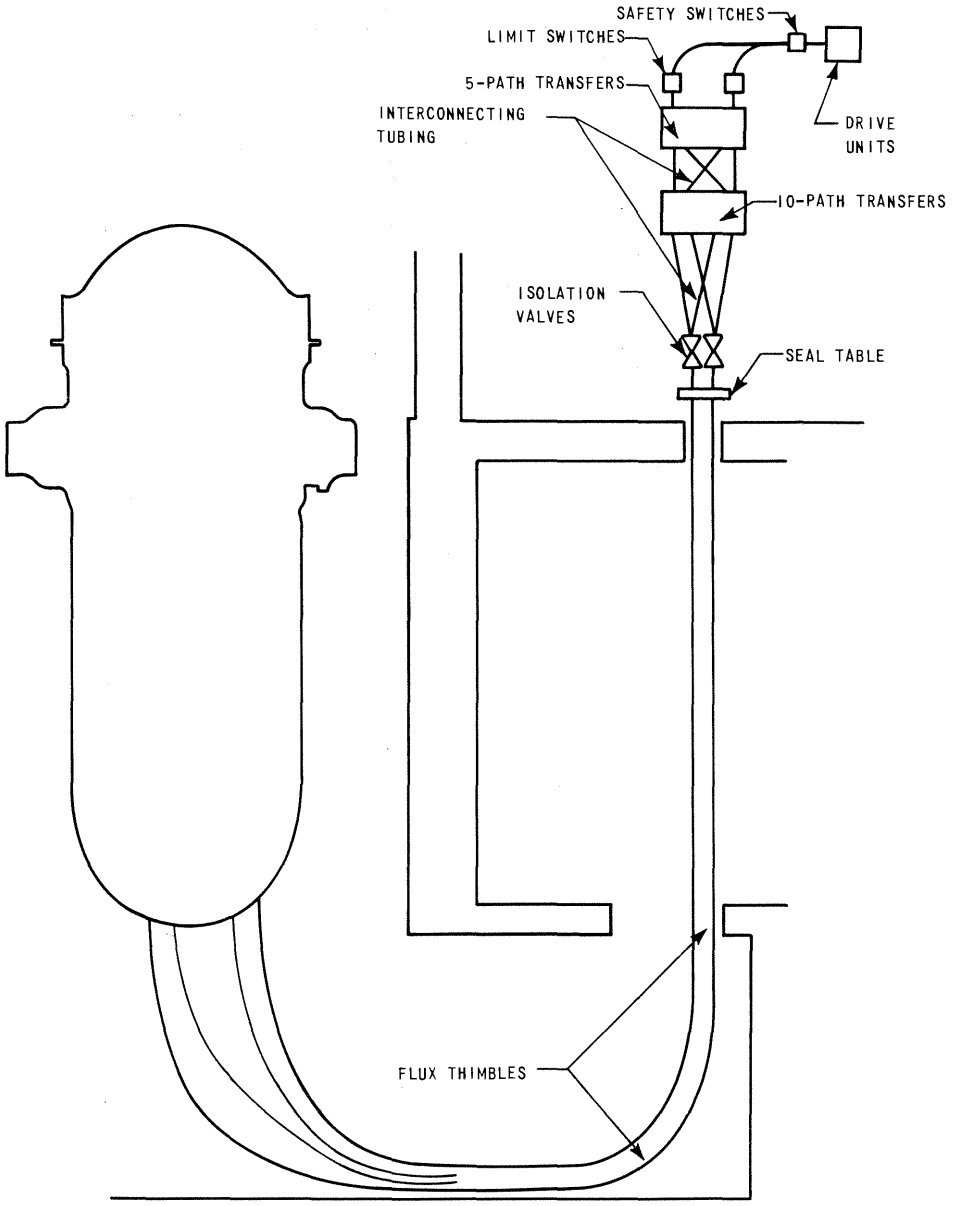


Figure 7.7-9
BASIC FLUX-MAPPING SYSTEM



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Basic Flux-Mapping System
Figure 7.7-9

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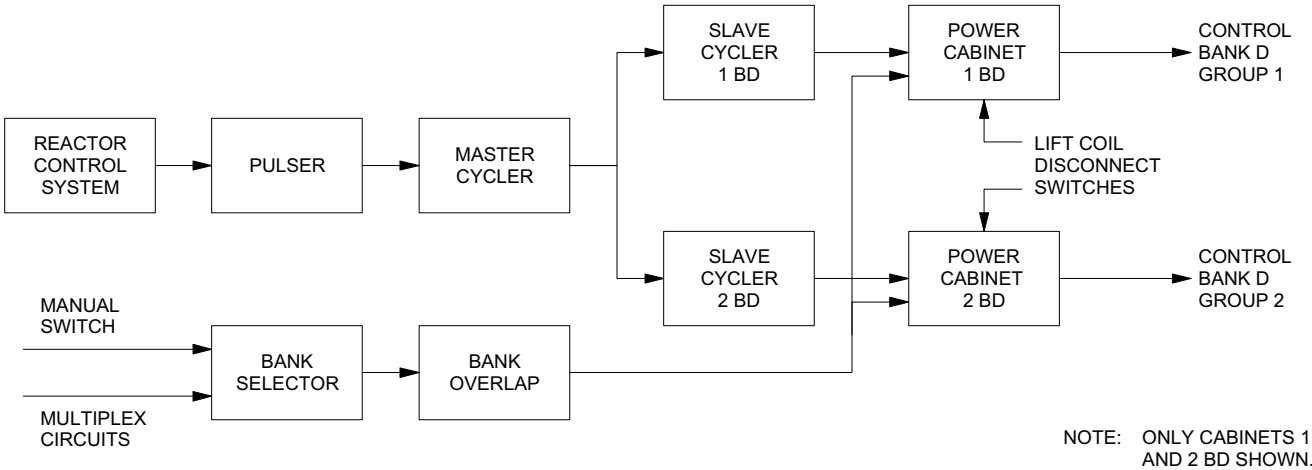
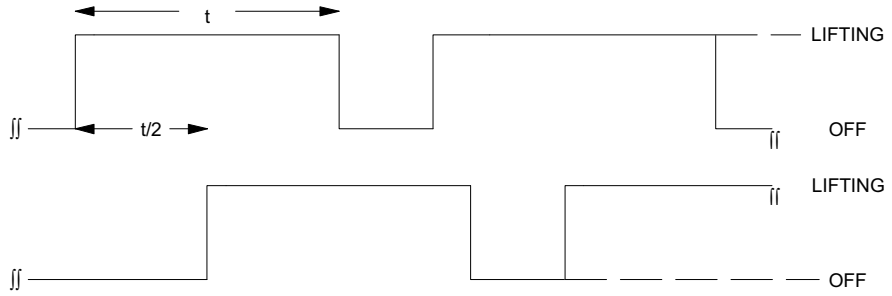
August 1984

Figure 7.7-10
(DELETED PER RN 99-085)
Figure 7.7-11
(DELETED PER RN 99-085)
Figure 7.7-12
(DELETED PER RN 99-085)
Figure 7.7-13
(DELETED PER RN 99-085)

Figure 7.7-14

SIMPLIFIED BLOCK DIAGRAM
ROD CONTROL SYSTEM

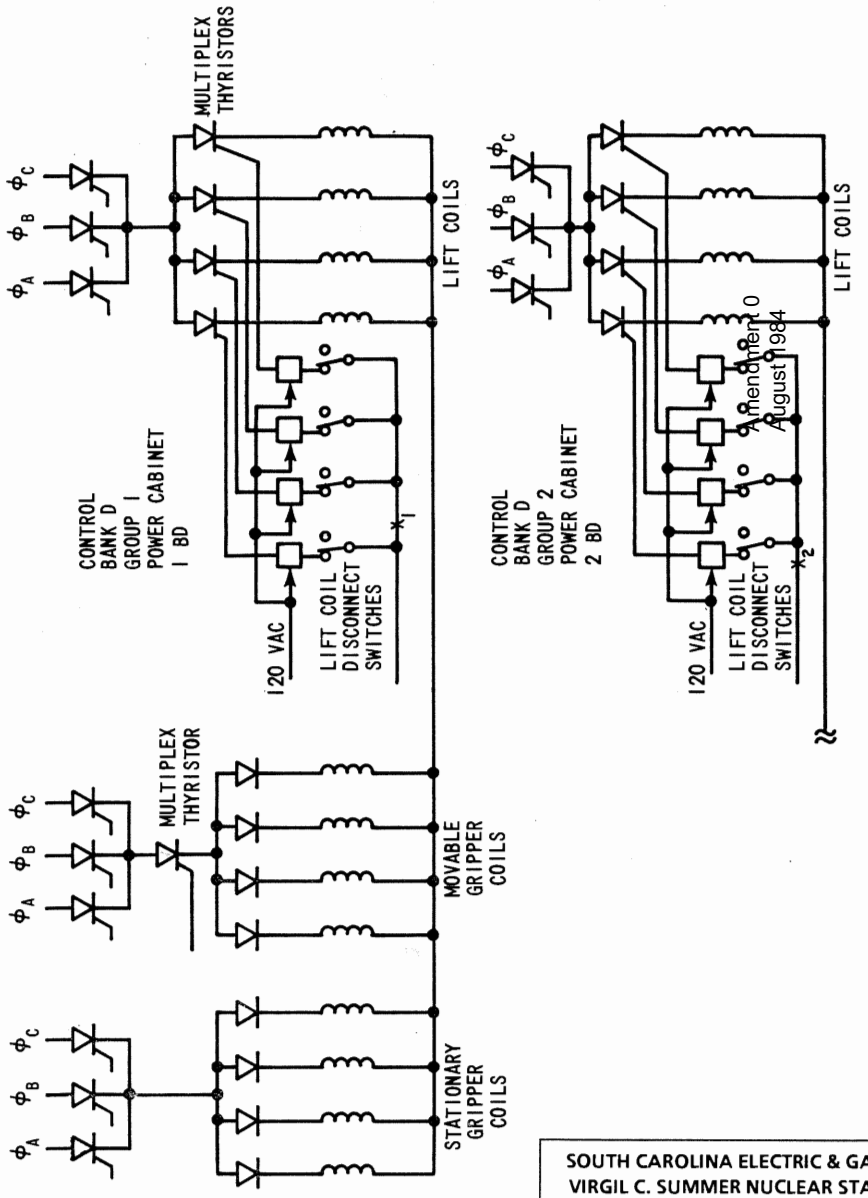




SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Simplified Block Diagram Rod Control System Figure 7.7-14

Amendment 98-01
April 1998

Figure 7.7-15
CONTROL BANK D PARTIAL SIMPLIFIED SCHEMATIC DIAGRAM POWER CABINETS 18D AND 28D



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Control Bank D Partial Simplified Schematic Diagram Power Cabinets 1BD and 2BD Figure 7.7-15

7.8 ATWS MITIGATION SYSTEM ACTUATION CIRCUITRY (AMSAC)

7.8.1 Description

7.8.1.1 System Description

The ATWS (Anticipated Transient Without Scram) Mitigation System Actuation Circuitry (AMSAC) provides a backup to the Reactor Trip System (RTS) and Engineered Safety Features Actuation System (ESFAS) for initiating turbine trip and emergency feedwater flow in the event an anticipated transient results (e.g., in the complete loss of main feedwater). The AMSAC is independent of and diverse from the Reactor Trip System and the Engineered Safety Features Actuation System with the exception of the final actuation devices and is classified as quality related equipment. It is a highly-reliable, microprocessor-based, single train system powered by a non-Class 1E source with battery backup.

The AMSAC continuously monitors level in the steam generators, which is an anticipatory indication of a loss of heat sink, and initiates certain functions when the level drops below a predetermined setpoint for at least a preselected time and for 2 of the 3 steam generator levels. These initiated functions are the tripping of the turbine, the initiation of emergency feedwater, and isolation of the steam generator blowdown and sample lines.

The AMSAC is designed to be highly reliable, resistant to inadvertent actuation, and easily maintained. Reliability is assured through the use of internal redundancy and continual self-testing by the system. Inadvertent actuations are minimized through the use of internal redundancy and majority voting at the output stage of the system. The time delay on low steam generator level and the coincidence logic used also minimize inadvertent actuations.

The AMSAC automatically performs its actuations when above a preselected power level, determined using turbine impulse chamber pressure, and remains armed sufficiently long after that pressure drops below the setpoint to ensure that its function will be performed in the event of a turbine trip.

7.8.1.2 Equipment Description

The AMSAC consists of a single train of equipment located in a seismically qualified cabinet.

The design of the AMSAC is based on the industry standard Intel multibus format, which permits the use of various readily available, widely used microprocessor cards on a common data bus for various functions.

The AMSAC consists of the following:

1. Steam Generator Level Sensing

   SG level is measured with 3 existing differential pressure-type level transmitters, for each of the main steam generators.

2. Turbine Impulse Pressure

   Turbine Impulse Pressure is measured with 2 existing pressure transmitters located in the steam supply line near the turbine.

3. System Hardware

   The system hardware consists of 2 primary systems: the Actuation Logic System (ALS) and the Test/Maintenance System (T/MS).

   Actuation Logic System

   The Actuation Logic System monitors the analog and digital inputs, performs the functional logic required, provides actuation outputs to trip the turbine and initiate emergency feedwater flow, and provides status information to the Test/Maintenance System. The Actuation Logic System consists of 3 groups of input/output (I/O) modules, 3 actuation logic processors (ALPs), 2 majority voting modules, and 2 output relay panels. The I/O modules provide signal conditioning, isolation, and test features for interfacing the Actuation Logic System and Test/Maintenance System. Conditioned signals are sent to 3 identical actuation logic processors for analog-to-digital conversion, setpoint comparison, and coincidence logic performance. Each of the actuation logic processors perform identical logic calculations using the same inputs and derive component actuation demands, which are then sent to the majority voting modules. The majority voting modules perform a 2 out of 3 vote on the actuation logic processor demand signals. These modules drive the relays providing outputs to the existing turbine trip and emergency feedwater initiation circuits. A simplified block diagram of the AMSAC Actuation Logic System architecture is presented in Figure 7.8-1.

   Test/Maintenance System

   The Test/Maintenance System provides the AMSAC with automated and manual testing as well as a maintenance mode. Automated testing is the continuously performed self-checking done by the system during normal operation. Actuation Logic System status is monitored by the T/MS and sent to the plant computer and the main control board. Manual testing of the system by the maintenance staff can be performed on-line to provide assurance that the Actuation Logic System is fully operational. The maintenance mode permits the maintenance staff, under administrative control, to modify channel setpoints, channel status and timer values, and initiate channel calibration.

   The Test/Maintenance System consists of a test/maintenance processor, a digital-to-analog conversion board, a memory board, expansion boards, a self-health board, digital output modules, a test/maintenance panel, and a portable terminal/printer.

4. Equipment Actuation

   The output relay panels provide component actuation signals through isolation relays, which then drive the final actuation circuitry for initiation of emergency feedwater and for turbine trip. Existing actuation devices of the component are used.

7.8.1.3 Functional Performance Requirements

The AMSAC automatically initiates emergency feedwater, trips the turbine, and isolates steam generator blowdown and sampling lines. Analyses have shown that the most limiting Anticipated Transient Without Scram event is a loss of feedwater event without a reactor trip. Therefore, the AMSAC performs its mitigative actuations:

1. In order to ensure a secondary heat sink following an anticipated transient (ANS Condition II) without a reactor trip.
2. In order to limit core damage following an anticipated transient without a reactor trip, and
3. To ensure that the energy generated in the core is compatible with the design limits to protect the reactor coolant pressure boundary by maintaining the reactor coolant pressure to within ASME Stress Level C.

7.8.1.4 AMSAC Interlocks

A single interlock, designated as C-20, is provided to allow for the automatic arming and blocking of the AMSAC system. The system is blocked below 40% turbine power when the actions taken by the AMSAC following an Anticipated Transient Without Scram need not be automatically initiated. Turbine impulse chamber pressure in a 2-out-of-2 logic scheme is used for this permissive. Turbine impulse chamber pressure above the setpoint will automatically defeat any block, i.e., will arm the AMSAC system. Dropping below this setpoint will automatically block the AMSAC system. Removal of the C-20 permissive is automatically delayed for a predetermined time. The operating status of the AMSAC is displayed on the main control board.

7.8.1.5 Steam Generator Level Sensor Arrangement

Steam generator level is determined by a differential pressure transmitter, measuring the level drop in the steam generator. These steam generator level signals are used as input to the AMSAC and are isolated signals from the Process Protection Cabinets.

7.8.1.6 Turbine Impulse Chamber Pressure Arrangement

Turbine impulse chamber pressure is determined by a differential pressure transmitter, measuring the pressure rise in the turbine. These pressure signals are used as input into AMSAC and are isolated signals from the Process Protection Cabinets.

7.8.1.7 Trip System

The differential pressure that is measured in the steam generator is used by the AMSAC to determine trip demand. Signal conditioning is performed on the transmitter output and used by each of the actuation logic processors to derive a component actuation demand. If 2 of the 3 steam generators have a low level at a power level greater than the C-20 permissive, then a trip demand signal is generated. This signal drives output relays for performing the necessary mitigative actions.

7.8.1.8 Isolation Devices

AMSAC is independent of the Reactor Trip and Engineered Safety Features Actuation Systems. The AMSAC inputs for measuring turbine impulse chamber pressure and narrow range steam generator water level are derived from existing transmitters and channels within the process protection system. Connections to these channels are made downstream of Class 1E isolation devices which are located within the process protection cabinets. These isolation devices ensure that the existing protection system continues to meet all applicable safety criteria by providing isolation. Buffering of the AMSAC outputs from the safety related final actuation device circuits is achieved through qualified relays. A credible fault occurring in the non-safety-related AMSAC will not propagate through and degrade the RTS and ESFAS.

7.8.1.9 AMSAC Diversity from the Reactor Protection Systems

Equipment diverse from the Reactor Trip System and Engineered Safety Features Actuation System is used in the AMSAC to prevent common mode failures that might affect the AMSAC and the Reactor Trip System or Engineered Safety Features Actuation System. The AMSAC is a digital, microprocessor-based system with the exception of the analog steam generator level and turbine impulse pressure transmitter inputs, whereas the Reactor Trip System utilizes an analog based protection system. Also where similar components are utilized for the same function in both AMSAC and the Reactor Trip System, the components used in AMSAC are provided from a different manufacturer.

Common mode failure of identical components in the analog portion of the Reactor Trip System that results in the inability to generate a reactor trip signal will not impact the ability of the digital AMSAC to generate the necessary mitigative actuations. Similarly, a postulated common mode failure affecting analog components in Engineered Safety Features Actuation System, affecting its ability to initiate emergency feedwater, will not impact the ability of the digital based AMSAC to automatically initiate emergency feedwater.

7.8.1.10 Power Supply

The AMSAC power supply is a non-Class 1E vital bus, which is independent from the RTS power supplies, and is backed by batteries which are independent from the existing batteries which supply the RTS.

7.8.1.11 Environmental Variations

AMSAC equipment is not designed as safety related equipment; therefore, it is not required to be qualified as safety related equipment. The AMSAC equipment is located in a controlled environment such that variations in the ambient conditions are minimized. No AMSAC equipment is located inside containment. The transmitters (steam generator level and turbine impulse chamber pressure) that supply the input into AMSAC are located inside containment and the Turbine Building, respectively.

7.8.1.12 Setpoints

The AMSAC makes use of 2 setpoints in the coincidence logic in order to determine if mitigative functions are required. Water level in each steam generator is sensed to determine if a loss of secondary heat sink is imminent. The low level setpoint is selected in such a manner that a true lowering of the level will be detected by the system. The normal small variations in steam generator level will not result in a spurious AMSAC signal.

The C-20 permissive setpoint is selected in order to be consistent with Anticipated Transient Without Scram investigations showing that the mitigative actions performed by the AMSAC need not be automatically actuated below a certain power level. The maximum allowable value of the C-20 permissive setpoint is defined by these investigations.

To avoid inadvertent AMSAC actuation on the loss of 1 main feedwater pump, AMSAC actuation is delayed by a defined amount of time. This will ensure the Reactor Protection System will provide the first trip signal.

To ensure that the AMSAC remains armed sufficiently long to permit its function in the event of a turbine trip, the C-20 permissive is maintained for a preset time delay after the turbine impulse chamber pressure drops below the setpoint.

The setpoints and the capability for their modification in the AMSAC are under administrative control.

7.8.2 Analysis

7.8.2.1 Safety Classification/Safety-Related Interface

The AMSAC is not safety related and therefore need not meet the requirements of IEEE 279-1971. The AMSAC has been implemented such that the Reactor Trip System and the Engineered Safety Features Actuation System continue to meet all applicable safety-related criteria. The AMSAC is independent of the Reactor Trip System and Engineered Safety Features Actuation System. The isolation provided between the Reactor Trip System and the AMSAC and between the Engineered Safety Features Actuation System and the AMSAC by the isolator modules and the isolation relays ensures that the applicable safety-related criteria are met for the Reactor Trip System and the Engineered Safety Features Actuation System.

7.8.2.2 Redundancy

System redundancy has not been provided. Since AMSAC is a backup non-safety related system to the redundant Reactor Trip System, redundancy is not required. To ensure high system reliability, portions of the AMSAC have been implemented as internally redundant, such that a single failure of an input channel or Actuation Logic Processor will neither actuate nor prevent actuation of the AMSAC.

7.8.2.3 Diversity from the Existing Trip System

Diverse equipment has been selected in order that common cause failures affecting both the Reactor Trip System and the AMSAC or both the Engineered Safety Features Actuation System and the AMSAC will not render these systems inoperable simultaneously. A more detailed discussion of the diversity between the Reactor Trip System and the AMSAC and between the Engineered Safety Features Actuation System and the AMSAC is presented in Section 7.8.1.9.

7.8.2.4 Electrical Independence

The AMSAC is electrically independent of the Reactor Trip System and Engineered Safety Features Actuation System from the sensor output up to the final actuation devices. Isolation devices are provided to isolate the non-safety AMSAC circuitry from the safety-related actuation circuits of the Emergency Feedwater System.

7.8.2.5 Physical Separation from the Reactor Trip System and Engineered Safety Features Actuation System

AMSAC needs to be and is physically separated from the existing protection system hardware. The AMSAC outputs are provided from separate relay panels within the cabinets. The 2 trains are separated within the AMSAC cabinet by a combination of metal barriers, conduit and distance.

7.8.2.6 Environmental Qualification

Equipment related to the AMSAC is qualified to operate under conditions resulting from anticipated operational occurrences for the respective equipment location. The AMSAC equipment, with the exception of the isolation devices, located outside containment in a mild environment follows the same design standard that currently exists for non-Class 1E control grade equipment.

7.8.2.7 Seismic Qualification

It is required that only the isolation devices comply with seismic qualification. The AMSAC output isolation device is qualified in accordance with a program that was developed to implement the requirements of IEEE Standard 344-1975, “IEEE Standard for Seismic Qualification of Class 1E Electrical Equipment for Nuclear Power Generating Stations.”

7.8.2.8 Test, Maintenance, and Surveillance Quality Assurance

NRC Generic Letter 85-06, “Quality Assurance Guidance for Anticipated Transient Without Scram Equipment that is not Safety Related,” requires quality assurance procedures commensurate with the quality related classification of the AMSAC. The quality controls for the AMSAC are, at a minimum, consistent with existing plant procedures or practices for non-safety-related equipment.

Design of the AMSAC followed procedures relating to equipment procurement, document control, and specification of system components, materials and services. In addition, specifications also define quality assurance practices for inspections, examinations, storage, shipping and tests as appropriate to a specific item or service.

A computer software verification program and a firmware validation program have been implemented commensurate with the quality related classification of the AMSAC to ensure that the system design requirements implemented with the use of software have been properly implemented and to ensure compliance with the system functional, performance and interface requirements.

System testing is completed prior to installation and operation of the AMSAC, as part of the normal factory acceptance testing and the validation program. Periodic testing is performed both automatically through use of the system automatic self-checking capability, and manually, under administrative control via the AMSAC test/maintenance panel.

7.8.2.9 Power Supply

Power to the AMSAC is from a battery-backed, non-Class 1E vital bus independent of the power supplies for the Reactor Trip System and Engineered Safety Features Actuation System. The station battery supplying power to the AMSAC is independent of those used for the Reactor Trip System and Engineered Safety Features Actuation System. The AMSAC is an energize-to-actuate system capable of performing its mitigative functions with a loss of offsite power.

7.8.2.10 Testability at Power

The AMSAC is testable at power. This testing is done via the system test/maintenance panel. The capability of the AMSAC to perform its mitigative actuations is bypassed at a system level while in the test mode. Total system testing is performed as a set of 3 sequential, partial, overlapping tests. The first of the tests checks the analog input portions of the AMSAC in order to verify accuracy. Each of the analog input modules is checked separately. The second test checks each of the actuation logic processors to verify that the appropriate coincidence logic is sent to the majority voter. Each actuation logic processor is tested separately. The last test exercises the majority voter and the integrity of the associated output relays. The majority voter and associated output relays are tested by exercising all possible input combinations to the majority voter. The integrity of each of the output relays is checked by confirming continuity of the relay coils without operating the relays. The capability to individually operate the output relays, confirm

integrity of the associated field wiring, and operate the corresponding isolation relays and final actuation devices at plant shutdown is provided.

7.8.2.11 Inadvertent Actuation

The AMSAC has been designed such that the frequency of inadvertent actuations is minimized. This high reliability is ensured through use of 3 redundant Actuation Logic Processors and a majority voting module. A single failure in any of these modules will not result in a spurious AMSAC actuation. In addition, a 2 out of 3 low steam generator level coincidence logic and a time delay have been selected to further minimize the potential for inadvertent actuations.

7.8.2.12 Maintenance Bypasses

The AMSAC is blocked at the system level during maintenance, repair, calibration or test. While the system is blocked, the bypass condition is continuously indicated in the Main Control Room.

7.8.2.13 Operating Bypasses

The AMSAC has been designed to allow for operational bypasses with the inclusion of the C-20 permissive. Above the C-20 setpoint, the AMSAC is automatically unblocked (i.e., armed); below the setpoint, the system is automatically blocked. The operating status of the AMSAC is continuously indicated in the Main Control Room via a status light.

7.8.2.14 Indication of Bypasses

Whenever the mitigative capabilities of the AMSAC are bypassed or deliberately rendered inoperable, this condition is continuously indicated in the Main Control Room. In addition to the operating bypass, any manual maintenance bypass is indicated via the AMSAC general warning sent to the Main Control Room.

7.8.2.15 Means for Bypassing

A permanently installed system bypass selector switch is provided to bypass the system. This is a 2-position selector switch with “NORMAL” and “BYPASS” positions. At no time is it necessary to use any temporary means, such as installing jumpers or pulling fuses, to bypass the system.

7.8.2.16 Completion of Mitigative Actions Once Initiated

The AMSAC mitigative actions go to completion as long as the coincidence logic is satisfied and the time delay requirements are met. If the flow in the feedwater lines is re-initiated before the timer expires and the steam generator water level increases to above the low setpoint, then the coincidence logic will no longer be satisfied and the actuation signal disappears. If the coincidence logic conditions are maintained for the duration of the time delay, then the mitigative actions go to completion. The emergency feedwater initiation signal is latched in at the component actuating devices and the turbine trip is latched in at the turbine electro-hydraulic control system. Deliberate operator action is then necessary to terminate emergency feedwater

flow, clear the turbine trip signal using the main control board turbine master reset, and proceed with the reopening of the turbine stop valves.

7.8.2.17 Manual Initiation

Manual initiation of the AMSAC is not provided. The capability to initiate the AMSAC mitigative functions manually, i.e., initiate emergency feedwater, trip the turbine, and isolate steam generator blowdown and sampling lines, exists at the main control board.

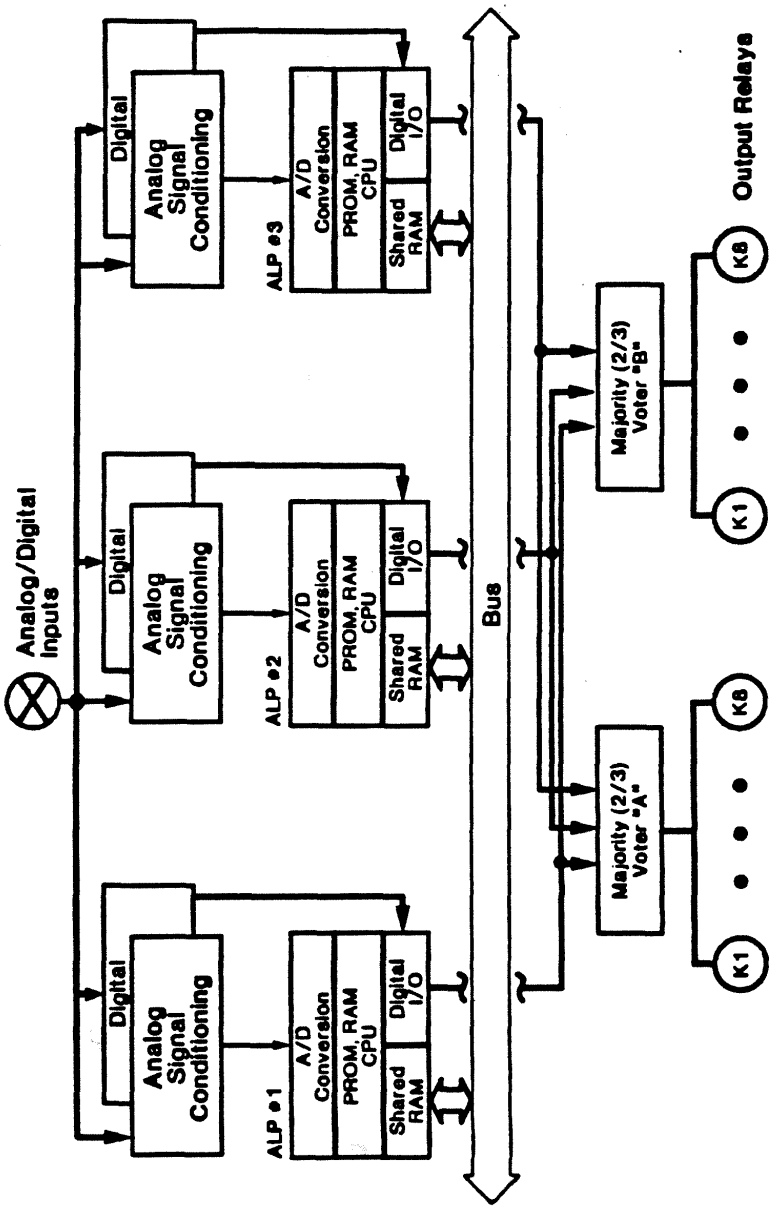
7.8.2.18 Information Readout

The AMSAC has been designed such that the operating and maintenance staffs have accurate, complete and timely information pertinent to the status of the AMSAC. A system level general warning alarm is indicated in the Control Room. Diagnostic capability exists from the test/maintenance panel to determine the cause of any unanticipated interoperability or deviation.

7.8.3 Compliance With Standards and Design Criteria

The AMSAC meets the applicable requirements of Part 50.62 of Title 10 of the Code of Federal Regulations and the quality assurance requirements of NRC Generic Letter 85-06. No other standards currently apply to the AMSAC.

Figure 7.8-1
ACTUATION LOGIC SYSTEM ARCHITECTURE



AMENDMENT 5
AUGUST, 1989

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Actuation Logic System Architecture Figure 7.8-1

V.C. Summer Power Station
Safety Analysis Report

Electric Power

Chapter 8

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 8 - ELECTRIC POWER

8.0 ELECTRIC POWER

8.1 INTRODUCTION

The Licensee's transmission system, along with points of interconnection with neighboring utilities, is shown in Figure 8.1-1. The Licensee is a member utility of the Virginia-Carolinas (VACAR) Subregion Reliability Agreement which is a part of the Southeastern Reliability Council. As a member of such a group, the Licensee can supply power to, or consume power from other members, as its system allows or demands. Transmission system ties to other utilities are as listed in Table 8.1-1. The specific interface between the transmission grid and the Virgil C. Summer Nuclear Station is discussed in Section 8.2.

The Virgil C. Summer Nuclear Station 230 kV switchyard has a single bus, single breaker arrangement, with three main bus sections. The center section is designated bus section 3, the east section designated bus section 1 and the west section designated bus section 2. A tap from bus section 2 provides a subsection of this bus with two bay positions for the Fairfield No. 1 and No. 2 lines.

The Parr 115 kV engineered safety features (ESF) line terminates in a bay in bus section 3, crosses over bus section 3 with rigid bus construction, and continues to the Virgil C. Summer Nuclear Station.

There is an Alternate AC (AAC) source of power installed that is fed from an underground 13.8kV cable to the Parr Hydro Power Station (Separate from Parr Generating Complex). This line feeds a 13.2/7.2kV weather event hardened transformer located in the VCS Substation that is connected on the low side to a non-safeguards bus in the turbine building. This source of power was designed to the requirements of NUMARC 87-00 App B and can power one entire safeguards train of equipment.

The onsite power network consists of three non-Class 1E distribution networks and two independent, redundant Class 1E distribution networks. The voltage levels of each network are 7200 volts, 480 volts and 120 volt a-c and 125 volt d-c.

The main source of power for the non-Class 1E networks is the unit auxiliary transformer which is connected to the output of the main generator between the generator circuit breaker and the low voltage bushings of the main power transformer (see Figure 8.2-3).

The emergency auxiliary transformers provide an emergency source of power for the non-Class 1E distribution network.

The normal source of power for the two independent Class 1E distribution networks are the ESF transformers and a winding of the emergency auxiliary transformers. These two sources of power also serve as an alternate source of power to each other (see Figures 8.2-3 and 8.2-4).

Two diesel generators are provided, one for each of the Class 1E buses to serve as an emergency source of power. The safety-related loads their safety functions and power requirements, supplied by the two emergency diesel generators are listed in Table 8.3-3. The ESF battery buses, inverter buses and associated loads are shown by Figures 8.3-1 and 8.3-2.

The Class 1E power network provides an adequate and reliable source of electric power for safe reactor shutdown following any design basis event, including loss of offsite power and for all normal modes of station operation.

The Virgil C. Summer Nuclear Station electrical systems are designed to comply with the scope of IEEE-308 (Reference 1) as specified in Section 1 of IEEE-308. Onsite power systems are designed to satisfy the applicable criteria of (Reference 1), as well as the criteria of Regulatory Guides 1.6 and 1.9 (see Appendix 3A).

Implementation of IEEE Standards and the extent to which any alternative approaches are used is itemized in Table 8.1-2. Applicable criteria, including: General Design Criteria, Appendix A to 10 CFR 50; Regulatory Guides; and Branch Technical Positions are listed in Table 8.1-3 with references to appropriate sections of this FSAR. Implementation of Regulatory Guides is discussed in Appendix 3A.

8.1.1 References

1. Institute of Electrical and Electronics Engineers, *Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations*, IEEE-308-1971.

Table 8.1-1
Transmission System Ties to Other Utilities

South Carolina Electric and Gas Company	South Carolina Public Service Authority	Voltages (kV)
VCS1	Blythewood	230
VCS1	Winnsboro	230
Williams	Charity	230
Lyles	Sandy Run	115
Lyles	Columbia	115
St. George	St. George	115
Faber Place	Carnes	115
Faber Place	North Charleston	115
Pepper Hill	Mateeba	230
	Southeastern Power Administration	
CLM Tap	Clark Hill	115
	Duke Energy – Carolinas	
VCS1	Newport	230
VCS2	Bush River	230
Saluda Hydro #2	Bush River (W)	115
Saluda Hydro #1	Bush River (B)	115
	Duke Energy – Progress	
Wateree	Sumter	230
St. George	Sumter	230
Eastover	Sumter	115

Table 8.1-1 (continued)
Transmission System Ties to Other Utilities

South Carolina Electric and Gas Company	South Carolina Public Service Authority	Voltages (kV)
	Georgia Power Company	
Calhoun Falls	Hart	115 (N.O.)
Okatie	McIntosh	115
	Savannah River Services	
Savannah River Plant	Vogtle	230

Table 8.1-2
Implementation of IEEE Standards

1. IEEE-279-1971, *Criteria for Protection Systems for Nuclear Power Generating Stations*, (ANSI N42.7, 1972).

   Refer to Sections 7.1, 7.2, 7.3 and 7.6.

2. IEEE-308-1971, *Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations.*

   Onsite and offsite electrical power systems are designed to satisfy the applicable criteria of IEEE-308-1971.

   Refer to Sections 7.1.2.1.3, 7.6.1.2, 8.1, and 8.2.2.1.

3. IEEE-317-1972, *Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations*.

   Electrical penetrations are designed and fabricated in accordance with the requirements of IEEE-317-1972.

   Refer to Sections 3.11.2.2.2 and 7.1.2.9 and the discussion of Regulatory Guide 1.63 in Appendix 3A.

   IEEE-323-1971, *General Guide for Qualifying Class 1E Electrical Equipment for Nuclear Power Generating Stations*.

   Environmental Qualification (EQ) of Class 1E electrical equipment is addressed in Section 3.11, which identifies the commitment to NUREG-0588, Cat. II (IEEE-323-1971) for the original plant design. NUREG-0588, Cat. I (IEEE-323-1974), 10CFR50.49, and NRC RG 1.89 requirements have also been used as the bases for environmental qualification, as described in FSAR Section 3.11 and Appendix 3A, under NRC RG 1.89.

4. IEEE-336-1971, I*nstallation, Inspection and Testing of Nuclear Power Generating Station Protection Systems*, (ANSI N45.2.4., 1972).

   Refer to Section 8.3.1.1 and Chapters 14.0 and 17.0.

5. IEEE-338-1971, *IEEE Standard Criteria for the Periodic Testing of Nuclear Power Generating Station Class 1E Power and Protection Systems*.

   Refer to Section 7.1.2.11 and Chapter 14.0.

Table 8.1-2 (continued)
Implementation of IEEE Standards

6. IEEE-344-1975, *IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations*.

   Class 1E electric equipment is tested and data is recorded to ensure that equipment satisfies design performance requirements during and following a safe shutdown earthquake (SSE). The qualification program meets the requirements of IEEE-344-1975 as discussed in Section 3.10.

7. IEEE-379-1972, *Guide for the Application of the Single Failure Criteria to Nuclear Power Generating Station Protection Systems,* (ANSI N41.2).

   Refer to Section 7.1.2.7 and the discussion of Regulatory Guide 1.53 in Appendix 3A.

8. IEEE-384-1974, *Criteria for Separation of Class 1E Equipment and Circuits*, (ANSI N41.14).

   Refer to Sections 7.1.2.2.1, 8.3.1.4 and 8.3.1.5 and the discussion of Regulatory Guide 1.75 in Appendix 3A.

9. IEEE-387-1972, *Criteria for Diesel Generator Units Applied As Standby Power Supplies for Nuclear Power Stations*.

   IEEE-387-1972 is used as the basis for design criteria for the diesel generators and accessories. Included among the referenced standards in IEEE-387-1972, Section 4.1, are IEEE-308-1971 and IEEE-323-1971. Diesel generators are designed to satisfy these standards.

10. IEEE-450-1987, *Recommended Practice for Maintenance, Testing and Replacement of Large Stationary Type Power Plant and Substation Lead Storage Batteries*.

    Refer to Section 8.3.2.2.2.

Table 8.1-3
List of Applicable Criteria

Criteria	Title	Reference FSAR Section(s)
1. General Design Criteria (GDC), Appendix A to 10 CFR 50		
GDC-1	Quality Standards and Records	3.1.2
GDC-2	Design Bases for Protection Against Natural Phenomena	3.1.2, 3.10, 3.11
GDC-3	Fire Protection	3.1.2, 7.1.2.2.3, 8.3.3.2
GDC-4	Environmental and Missile Design Bases	3.1.2
GDC-5	Sharing of Structures, Systems and Components	3.1.2
GDC-13	Instrumentation and Control	3.1.2, 7.3.1, 7.3.2
GDC-17	Electric Power Systems	3.1.2, 8.2.1, 8.2.2.2, 8.3.1.2.1, 8.3.2.2.1
GDC-18	Inspection and Testing of Electric Power Systems	3.1.2, 8.2.1, 8.3.1.2.1, 8.3.2.2.1
GDC-21	Protection System Reliability and Testability	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-22	Protection System Independence	3.1.2, 7.2
GDC-33	Reactor Coolant Makeup	3.1.2, 8.3
GDC-34	Residual Heat Removal	3.1.2, 8.3
GDC-35	Emergency Core Cooling	3.1.2, 8.3
GDC-41	Containment Atmosphere Cleanup	3.1.2, 8.3
GDC-44	Cooling Water	3.1.2, 8.3

Table 8.1-3 (continued)
List of Applicable Criteria

Criteria	Title	Reference FSAR Section(s)
2. Regulatory Guides (RG)		
RG 1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems	App. 3A, 8.1, 8.3.1.2.1, 8.3.2.2.1
RG 1.9	Selection of Diesel Generator Set Capacity for Standby Power Supplies	App. 3A, 8.1,8.3.1.1.2.4, 8.3.1.2.1
RG 1.22	Periodic Testing of Protective System Actuation Functions	App. 3A, 7.1.2.5, 7.3.2
RG 1.29	Seismic Design Classification	App. 3A
RG 1.30	Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment	App. 3A, Chapter 17.0
RG 1.32	Use of IEEE Std. 308-1971, “Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations”	App. 3A, 8.2.1, 8.3.1.2.1, 8.3.2.2.1

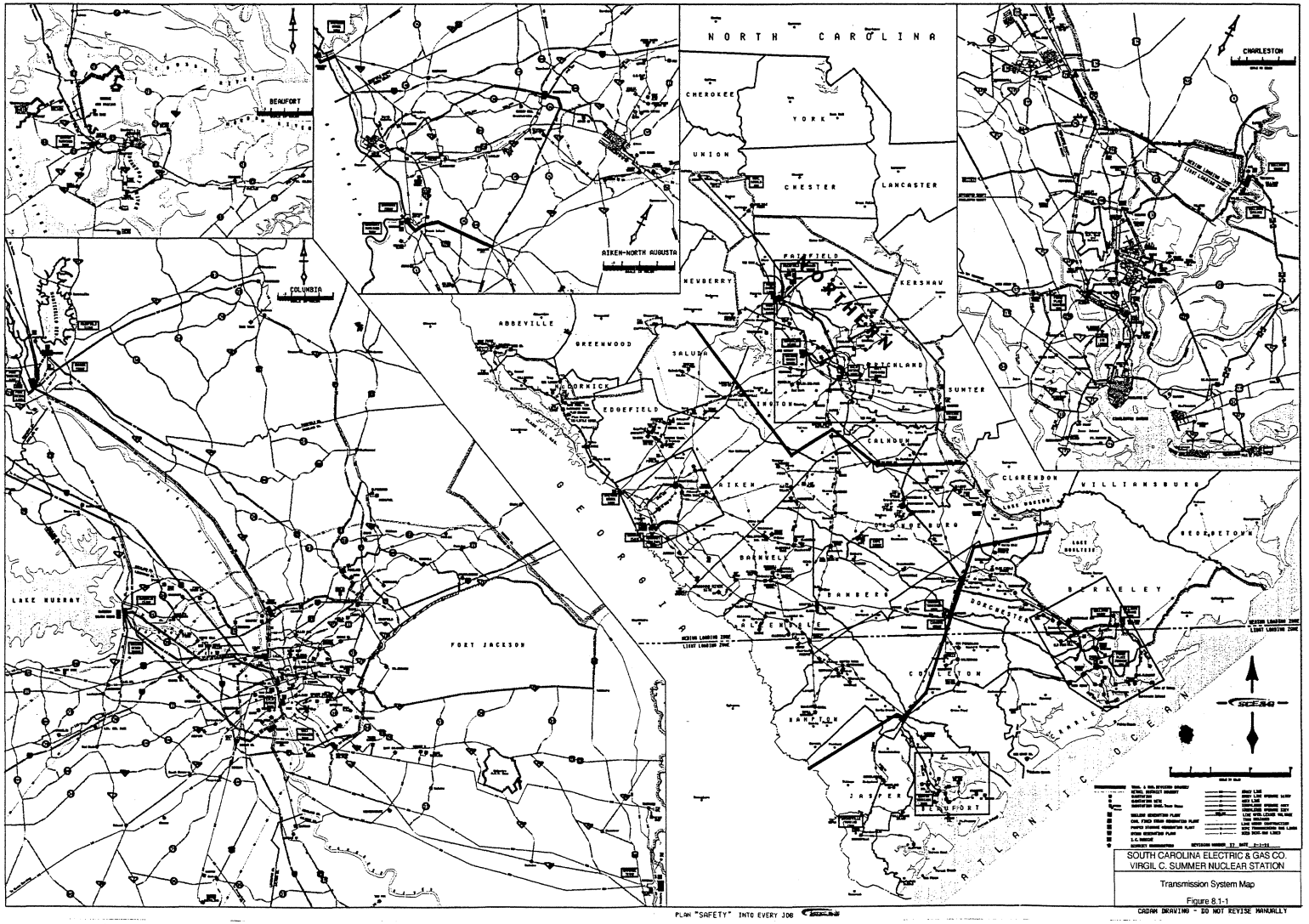
Table 8.1-3 (continued)
List of Applicable Criteria

Criteria	Title	Reference FSAR Section(s)
RG 1.41	Preoperational testing of redundant onsite Electric Power Systems to verify proper load group assignments.	App. 3A, 8.3.1.1.2.6, Chapter 14.0
RG 1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems	App. 3A, 7.1.2.6
RG 1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems	App. 3A, 7.1.2.7
RG 1.63	Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants	App. 3A, 7.1.2.8, 8.3.1.1.4
RG 1.68	Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors	App. 3A, Chapter 14.0
RG 1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants	App. 3A
RG 1.75	Physical Independence of Electric Systems	App. 3A, 7.1.2.2.1, 8.3.1.4.3
RG 1.81	Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants	App. 3A
RG 1.89	Qualification of Class IE Equipment for Nuclear Power Plants	App. 3A, 3.11, 8.3.1.2.2.1
RG 1.93	Availability of Electric Power Sources	App. 3A

Table 8.1-3 (continued)
List of Applicable Criteria

Criteria	Title	Reference FSAR Section(s)
3. Branch Technical Positions (ETCSB)		
ETCSB1	Backfitting of the Protection and Emergency Power Systems of Nuclear Reactors	Chapters 7.0 and 8.0
ETCSB2	Diesel-Generator Reliability Qualification Testing	8.3.1.1.6
ETCSB6	Capacity Test Requirements of Station Batteries-Technical Specifications	8.3.2.2.2
ETCSB8	Use of Diesel-Generator Sets for Peaking	8.3.1.1.2.4
ETCSB10	Electrical and Mechanical Equipment Seismic Qualification Program	3.10, 8.3.2.2.1
ETCSB11	Stability of Offsite Power Systems	8.2.2.2
ETCSB17	Diesel Generator Protective Trip Circuit Bypasses	8.3.1.1.2.8, Table 8.3-3 a
ETCSB21	Guidance for Applicable of Regulatory Guide 1.47	App. 3A (discussion of RG 1.47), 7.1.2.6
ETCSB27	Design Criteria for Thermal Overload Protection for Motors of Motor-Operated Valves	App. 3A (discussion of RG 1.106), 8.3.1.1.4

Figure 8.1-1
TRANSMISSION SYSTEM MAP



Amendment 98-01 April 1, 1998

8.2 OFFSITE POWER SYSTEM

8.2.1 Description

The SCE&G transmission system supplies offsite a-c power for operating the engineered safety features (ESF) buses as well as for startup and shutdown of the station. Two (2) separate sources of offsite power are provided for the Class 1E electric system, which is in compliance with General Design Criterion 17 and Regulatory Guide 1.32 (see Appendix 3A). One (1) source is the SCE&G transmission grid terminating at the Virgil C. Summer Nuclear Station 230 kV switchyard bus, which feeds the plant through a step down transformer. The second source is from the existing Parr Generating Complex over a 115 kV transmission line (see Figure 8.2-1). This source is connected to the plant through onsite step down transformers and a separate regulating transformer. These 2 sources have sufficient separation and isolation so that loss of the Virgil C. Summer Nuclear Station with the Fairfield Hydro Units offline will not degrade either of the sources below their acceptable voltage limit. Thus, loss of the station output, in conjunction with an accident, will not result in a degraded voltage condition on either source. Likewise, loss of a line or generation on the 115 kV network will not cause a degraded condition on the Emergency Auxiliary Transformer which is fed power from the 230 kV bus. Also, no single event such as an insulator or bushing failure, transformer failure, transmission line tower failure, line breakage, or similar event can cause simultaneous disruption of both sources. The offsite power system is not designed to withstand tornadoes, exceptionally severe hurricanes or ice storms. However, the circuit breakers for isolation of the 2 separate onsite power systems from the offsite power system are located within 2 separate, missile protected rooms. Therefore, any failure of the offsite power system, including the bus duct system between the offsite power system and the ESF buses, is isolated from the ESF buses before the emergency diesel generators are started (see Figure 8.2-2).

The allowable system voltage fluctuations for each of the 2 preferred offsite sources are defined in Table 8.2-2. As noted in the table, the allowable voltage range is dependent on generating unit availability, the number of buses connected to the source, and on the configuration of the transformers for the 115 kV line. The SCE&G dispatchers are provided with instructions to make every effort to maintain the system voltage fluctuations within these allowable ranges. The instructions require maintenance of the voltage limits during shutdown, as well as during operation, of Virgil C. Summer Nuclear Station. The transmission system voltage drop due to loss of the Virgil C. Summer Nuclear Station is included within the allowable voltage ranges during plant operation with the unit online. The transmission system voltage drop is not included within the allowable voltage ranges during plant operation with the unit offline because the unit is not generating. A direct communications link is provided between the SCE&G Dispatch Office in Columbia, SC, and all SCE&G generating plants. Through this communications link, the plant operators receive the instructions from the dispatch office for setting generator kilowatt, kilovar output, voltage level, and for controlling the VAR output on the Fairfield units when they are used for pumping.

The plant operators are provided with indicators for the engineered safety features (ESF) bus network as discussed in Section 8.3.1.2.1. Also, voltmeters, ammeters, kilowatt meters, kilovar meters, and frequency meters are provided for the main generator bus. If generator output differs

from that specified by the dispatch office, the operator notifies the dispatch office and receives a new set of operating levels for the generator.

Control and indication are provided locally at the substation relay house and/or the Unit 1 relay house and remotely in the system dispatcher's office for each of the incoming 230 kV transmission line circuit breakers and the 230 kV bus tie circuit breakers. Circuit breaker control consists of tripping and closing capability. Indication includes circuit breaker status (open or closed) and the amount and direction of the power being transmitted over each transmission line. Control power for the substation relay house is supplied from a 125 VDC battery, with a backup feed from the plant non-1E. Control power for the Unit 1 relay house is supplied from two (2) 125 volt d-c batteries, each sized to serve as back-up to the other.

The 230 kV buses are protected by bus differential relays. Each 230 kV line and the 115 kV line is protected by primary and backup relaying. Each 230 kV line terminal has relays that provide breaker failure protection that trips the appropriate bus lockout relay when the breaker fails to trip. Each line relays also provide a multi-shot, static reclosing function that is active in some breakers.

The 230 kV circuit breakers associated with the plant main transformer and emergency auxiliary transformers, as well as the circuit switches associated with the ESF transformers, are controlled from, and provide indication in, the control room. Also, the 230 kV circuit breakers can be tripped at the circuit breaker control panels mounted on the circuit breaker structures.

Manually operated disconnect switches are provided for the 230 kV circuit breakers to isolate each from the bus and associated lines. These manual disconnects permit testing and maintenance of each circuit breaker on an individual basis while allowing the 230 kV substation to remain energized, which satisfies General Design Criterion 18. Testing and maintenance are performed periodically in accordance with a SCE&G program.

As shown by Figure 8.2-2, the 115 kV line terminates in a rigid bus construction for the crossover of the 230 kV middle bus section. The 115 kV bus has no connection to the 230 kV bus. Therefore, any problems associated with the 230 kV bus do not affect the 115 kV bus. The rigid bus construction offers high reliability by eliminating the possibility of line dropping at this crossover point.

The preferred power source transformers, which are the emergency auxiliary transformers and the combination of the safeguard transformers and the voltage regulator are located out of doors and are physically separated from each other. Lightning arrestors are used where applicable for lightning protection. The transformers are protected by automatic water spray systems to extinguish oil fires quickly, thus preventing spreading. The transformer area is provided with a gravel filled sump pit to contain transformer oil should a rupture occur.

Power from both the emergency auxiliary transformer and from the combination of the 2 safeguard transformers and the voltage regulator is brought into the plant by independent 7200 volt buses. These buses are physically separated and independently supported throughout their length to the 2 separated, missile protected rooms which contain the separate Class 1E electric system 7200 volt buses, thus maintaining redundancy.

8.2.1.1 Unit Auxiliary, Emergency Auxiliary, and Safeguards Transformers

Normal station service power for non-Class 1E equipment, which includes that required during normal operation, startup, shutdown, and following shutdown, is provided from the unit auxiliary transformer. The primary side of the unit auxiliary transformer is connected to the generator isolated phase bus duct at a point between the generator circuit breaker and the low voltage connections to the main step up transformer as shown by Figure 8.2-3.

The unit auxiliary transformer is rated 22 kV - 7200 volts. The three 7200 volt secondaries are used to feed 3 independent 7200 volt non-Class 1E auxiliary buses. The 2 ESF system 7200 volt buses are fed independently from other sources.

Two (2) emergency auxiliary transformers are provided. The primary sides of these 2 transformers are connected in parallel to the 230 kV substation bus. The 2 secondary windings on each bank are rated 7200 volts. Three (3) of the 4 windings are used as an emergency power source for the three 7200 volt non-Class 1E auxiliary system buses. The fourth winding is a preferred offsite power source for either or both of the ESF system power trains (see Figures 8.2-3 and 8.2-4). Normally this winding is used to supply the 7200 volt ESF bus 1DB.

The primary windings of the 2 safeguard transformers, XTF-4 and 5, are connected in parallel to the 115 kV line. These 2 transformers, in combination with the regulating transformer, XTF-6, are the second preferred offsite power source for either or both of the ESF system power trains. Normally, safeguard transformer 4 is used in combination with the voltage regulator to supply 7200 volt ESF system bus 1DA. If the voltage regulator is out of service, the 2 safeguard transformers can be used in parallel to supply either or both of the 7200 volt ESF system buses; or 1 of the 2 transformers can be used to supply either or both of the buses (see Figure 8.2-4).

Connected to the same intermediate bus (1DX) as transformers XTF-4, 5 and 6 is the VC Summer Alternate AC Source (AAC). The AAC source is fed from an underground 13.8kV cable to the Parr Hydro Power Station main generator bus via Parr BKR 13123. This line feeds a 13.2/7.2 kV transformer located in the VCS Substation that feeds into the 1DX bus. All cabling and lightning protection equipment associated with this feed is weather protected. The installed cable is oversized for the potential load attached to it such that the 105º C normal rating of the cable cannot be reached with the maximum loading of a single ESF bus (750 mcm AL cable with most limiting rating of 490 amps will be loaded to a running maximum of 245 amps, 5.9MW load equivalent or 50% cable rating). Direct monitoring of underground cable temperature is not required as long as total ESF bus loading does not exceed 5.9MW (5MW calculated load with 15% conservatism). The loading of the AAC source onto either one of two ESF buses is to be done manually (sequencer Out-of-Service).

Each of the 2 principle 7200 volt ESF buses is provided with a manually initiated transfer scheme to shift the bus power supply between the 2 preferred offsite power sources.

8.2.1.2 Transmission System

The network interconnections between the Virgil C. Summer Nuclear Station and the SCE&G transmission system consist of eight 230 kV transmission lines which approach the site from 3 directions. The 230 kV transmission lines interconnect the Virgil C. Summer Nuclear Station with the major sources of generation on the SCE&G system through major transmission grid substations as shown by Figures 8.1-1 and 8.2-1. The lines are designed to meet or exceed NESC (ANSI-C2) 1973 edition, medium loading, grade B construction requirements.

Two of these eight transmission lines extend directly from the Virgil C. Summer Nuclear Station 230 kV bus section 2 to the SCE&G Fairfield Pumped Storage Facility.

In addition, two 230 kV transmission lines interconnect the Virgil C. Summer Nuclear Station with the South Carolina Public Service Authority (SCPSA) system.

One (1) 115 kV transmission line extends from the Virgil C. Summer Nuclear Station to the SCE&G Parr Generating Complex. The Parr 115kV substation and associated Transmission Grid connections serve as one of the preferred power sources for the ESF buses at the Virgil C. Summer Nuclear Station. Within the Parr 115kV substation are four gas-fired combustion turbines that with the substation form the Parr Generating Complex. The Parr Hydro station is connected to the Parr 115kV substation via a 115/13.2kV tap changing transformer, but is not considered part of the Parr Generating Complex even with its close proximity.

The 115 kV transmission line has no direct ties to the Parr Generating Complex 230 kV switchyard. This switchyard does have a tie from the Virgil C. Summer Nuclear Station 230 kV switchyard bus. The Parr Generating Complex 115 kV switchyard bus receives power from the Parr Generating Complex and from a 115 kV tie line to the Denny Terrace substation. With this arrangement, an outage at the Virgil C. Summer Nuclear Station 230 kV switchyard does not have a direct effect on the 115 kV ESF transmission line.

Figures 8.2-2 and 8.2-2a through 8.2-2d indicate the physical relationship between transmission lines entering the switchyard, between the switchyard and the plant and within the switchyard. All 230 kV transmission tie lines to other major interconnection points converge on the switchyard. All transmission line structures have a minimum of 60 feet center to center as they approach the switchyard.

Each transmission line has adequate capacity for the supply of the preferred power source emergency auxiliary transformer. The 230 kV transmission lines, 230 kV circuit breakers and 230 kV buses in the switchyard are designed to withstand and interrupt the maximum fault level at the bus.

Details of the construction of each transmission line are as follows:

1. Parr-Summer Safeguard 115 kV Line

   This line is about 2.6 miles long. Wood, H-frame construction and steel monopole structures are used. The line extends from the Parr 115 kV substation to the vicinity of the Parr 230 kV substation and then to Virgil C. Summer Nuclear Station. An approximately 600 foot segment of this line is routed from above ground to an underground duct bank and then returns to above ground routing. This underground segment eliminates the crossing of the 115 kV line over 230kV transmission lines near the Parr Substation.

   There is a switchable tie to the Parr-Winnsboro No. 1 line. It also crosses over the Norfolk-Southern Railroad at Parr and over a railroad spur at Virgil C. Summer Nuclear Station. The last 2 line structures at Virgil C. Summer Nuclear Station are steel monopole structures which raise this line above a VCS1-VCS2 tie. There are no structure or circuit conflicts since a failure of the towers would not result in loss of both sources of offsite power, as the VCS1-VCS2 tie breaker would trip leaving the other 230 kV lines intact.

2. Summer-Edenwood Line, 230 kV

   This line is about 33.02 miles long. At Virgil C. Summer Nuclear Station it is on 3 double circuit, 230 kV steel towers. The end of this line ties to the Edenwood 230 kV line about 1.2 miles from Parr. The line crosses over the Parr-Denny Terrace 230 kV line and the double circuit Parr-Denny Terrace 115 kV line. The line is of wood H-frame construction on a right-of-way with no other lines. The line continues past McMeekin Station on to Edenwood Substation.

3. Deleted

4. Summer-Pineland Line, 230 kV

   This line is on 3 double circuit, steel towers with the Summer-Denny Terrace line. These lines then are on wood H-frame structures designed for double circuits. The structures are in the center of a 240 foot wide right-of-way which extends for about 17.24 miles. In this area, the line parallels the SCPSA Summer-Blythewood 230 kV H-frame. There are structure conflicts in this area. For the next 1.62 miles, this line is on single circuit wood H-frame on a common right-of-way with the Summer-Denny Terrace line. There are no structural conflicts in this area. For the next 5.0 miles, this line is on single circuit, wood H-frame on its own right-of-way. For about the final 0.54 mile, this line is on double circuit, improved appearance, steel poles at Pineland substation. This line crosses over several transmission lines but none cross over it. Total length is about 24.4 miles.

5. Summer-Denny Terrace Line, 230 kV

   This line is attached to the same structures as the Summer-Pineland line at the Virgil C. Summer Nuclear Station and for the first 17.24 miles. From this point the Summer-Denny Terrace line is attached to single circuit H-frame structures and shares a common 240 foot right-of-way with the Summer-Pineland line for 1.62 miles. It is then on its own right-of-way for 5.91 miles. The Summer-Denny Terrace line then parallels the Denny Terrace-Rader double circuit 115 kV lines (crossing over them twice) to Denny Terrace, a distance of about 1.48 miles. Total length is 26.25 miles.

6. Deleted

7. South Carolina Public Service Authority, VCS1-Blythewood Line, 230 kV

   This line is installed on multi-pole single circuit (MPSC) structures with 1272 ACSR single conductor and is operated and owned by SCPSA. This line is located on variable width right-of-way (R/W) that extends for 20 miles from the VCS1 to SCPSA's Blythewood substation. This line is on common R/W with SCPSA's VCS1-Winnsboro 230 kV line and SCE&G's VCS1-Killian, Denny Terrace and Pineland 230 kV lines for 1.0 mile to a point referred to as Winnsboro Junction. From Winnsboro Junction, the line extends 2.8 miles to SCPSA Pomaria-Winnsboro 69 kV line. From the Pomaria-Winnsboro 69 kV line, the line extends 13.4 miles on common R/W with SCE&G's VCS1-Denny Terrace and Pineland 230 kV lines. From this point, the line veers off and extends 2.9 miles to SCPSA's Blythewood substation.

8. VCS2 Bus 2 Tie Line, 230 kV

   This line connects V. C. Summer Unit 1, Bus 2 to V. C. Summer Unit 2 switchyard. It parallels the Duke-Newport line for approximately 0.63 mile. Total length is 0.87 mile.

9. South Carolina Public Service Authority, Summer-Winnsboro Line, 230 kV

   This line is operated and owned by the SCPSA. It parallels the Summer-Blythewood line for a distance of 3.7 miles on the east side and abutting the existing right-of-way. From that point the line heads in a northeasterly direction and double circuits with the existing SCPSA Pomaria-Winnsboro 69 kV line. Total length is about 14 miles.

10. VCS1-Killian Line, 230 kV

    This line is installed on single pole single circuit (SPSC) and single pole double circuit (SPDC) steel monopole structures with bundled 1272 ACSR conductor. The line is located on variable width right-of-way (R/W) that extends for 35 miles from the VCS1 Switchyard to the Killian 230/115 kV Transmission substation. A SPSC section of this line is on common R/W with SCPSA's VCS1-Winnsboro and Blythewood 230 kV lines and SCE&G's VCS1-Denny Terrace and Pineland 230 kV lines for 1 mile to a point referred to as Winnsboro Junction. From Winnsboro Junction, the line extends 13 miles to Winnsboro and is constructed SPDC with the second circuit being the Parr-Winnsboro 115 kV Line #1. This line section is on common R/W with the Parr-Winnsboro 115 kV Line #2. From Winnsboro, the line extends 15 miles to a point referred to as Blythewood PMSS and is constructed SPDC with the second circuit being the Blythewood-Winnsboro 115 kV line. From Blythewood PMSS, the line extends 6 miles to the Killian 230/115 kV Transmission substation and is constructed SPDC with the second circuit being the Blythewood-Killian 115 kV line.

11. VCS1, Bus 1-VCS2 Tie, 230 kV

    This line is installed on single pole single circuit (SPSC) steel monopole structures with bundled 1272 ACSR conductor. This is one of three 230 kV bus ties each approximately 1 mile in length that runs between the VCS1 and VCS2 Switchyards.

Distances of all lines from the Virgil C. Summer Nuclear Station terminal to the first major substation are listed in Table 8.2-1.

8.2.2 Analysis

8.2.2.1 Introduction

The basis for design of DESC transmission facilities is such that a defined system will maintain stability with the loss of any system generator, including Virgil C. Summer Nuclear Station, or the most critical transmission line, or the loss of the largest system load. The system will also remain stable for the most severe fault condition on any transmission line or substation bus. As such, the loss of any single system generator, including Virgil C. Summer Nuclear Station, does not degrade the alternate system to where it cannot furnish shutdown power to Virgil C. Summer Nuclear Station on an uninterrupted basis. The Virgil C. Summer Nuclear Station buses and the location of the emergency auxiliary transformers and ESF transformers supplying shutdown power are such that no single permanent fault condition can prevent at least 1 of the auxiliary transformers from being available to furnish shutdown power. Table 8.2-1 lists the distances of lines from the Virgil C. Summer Nuclear Station switchyard to each first major substation.

8.2.2.2 Stability Study Results

The System Stability study was performed using power system simulator software. The dynamic simulation cases and dynamics data were updated versions of cases and data which were issued

by the NERC and which were modified to meet the specific requirements of this study. The dynamic simulation cases and data were validated using the simulator software case initialization and model testing features. This was followed by a 30 second steady state simulation in order to demonstrate that the cases and data represented non-disturbed conditions prior to simulating system contingencies. The results of the steady state simulations are not included in this report but are available for review.

Special attention was given to the analysis of disturbances in the vicinity of the V. C. Summer Nuclear Station during various system conditions. The simulations that were performed were selected as a result of discussions between V. C. Summer Design Engineering and DESC Transmission Planning.

The simulations which were performed for each contingency began with a 1 second steady state period which was followed by a sequence of contingency events and a subsequent new steady state period for a total of 30 seconds for each contingency simulation.

Both peak and light system load conditions were studied. System faults during peak load conditions are generally more challenging for offsite power voltage adequacy. System faults during light load conditions are generally more challenging for generator angular stability.

The base year chosen for summer peak and light load conditions is the year of the Study and is typically 3-4 years in the future. Since the previous study was completed, a number of changes have been made or have been planned for the DESC generating and transmission systems. All actual and planned system improvements are incorporated in the simulation models used for the current study. The base year chosen for summer peak and light load conditions is the year of the Study and is typically 3-4 years in the future. The study includes any actual system changes since the last study and any changes planned for 3-4 years beyond the base year.

The VCS FSAR required scenarios assume three MVAR levels (170, 330, and 484 MVAR). The peak load cases assume the VCS exciter provides 330 MVAR and 484 MVAR. The light load cases assume the VCS exciter provides 170 MVAR and 330 MVAR. 170 MVAR was modeled for a specific ESF bus alignment.

Use of the 484 MVAR and 330 MVAR levels for the VCS FSAR required scenarios is considered conservative for several reasons. The VCS generator exciter has a maximum momentary rating of 484 MVAR and a typical maximum continuous rating of 330 MVAR. Therefore, these values represent the maximum MVAR load the station can support for any loading scenario. These values can also represent a substantial portion of the total typical MVAR load seen on the DESC transmission system. Therefore, these values are consistent with the VCS generator exciter providing a significant portion of the voltage support for the entire DESC system. Therefore, these loadings conditions are considered extremely conservative and unlikely to occur.

V. C. Summer Balance of Plant (BOP) station loads were updated. In addition, because it is possible for Engineered Safeguard Features (ESF) bus loads to all be served from one bus, these loads were simulated as being located fully at each ESF bus (i.e., two ESF trains of equipment connected to each of the GDC 17 credited offsite sources).

For this study, the V. C. Summer generator governor model was disengaged from the simulation. A review of neighboring utilities' practices in modeling nuclear generators for transient stability simulations confirms that this is the accepted practice for representing block loaded nuclear generator governors.

The transfer of the Balance of Plant loads to the Emergency Auxiliary Transformers following a generator breaker operation has been incorporated into the study. The study models various contingencies and transmission operating scenarios. These scenarios resulted in a combined effect to lessen the available transmission voltage and angular stability support of V.C. Summer for the conditions studied. The practice of maintaining reactive power reserves in three separate areas of the Dominion Energy South Carolina system ensures that reactive power sources are available to provide voltage support to V.C. Summer.

The V. C. Summer 7.2 kV Engineered Safeguard Features (ESF) buses are supplied from the 230 kV and the 115 kV Offsite Power Supply buses. Protection from unacceptable voltage conditions is provided by Loss of Voltage and Degraded Voltage Relays that monitor the voltages of the 7.2 kV buses. The Loss of Voltage Relay scheme is modeled to operate after a 13.5 cycle (0.225 seconds) time delay at 82.00% of the nominal 7.2 kV bus voltage unless the voltage recovers to 82.75% during the time delay period of 0.225 seconds. The Degraded Voltage Relay scheme is set to operate after a 174.0 cycle (2.9 seconds) time delay at 91.75% of the nominal 7.2 kV bus voltage unless the voltage recovers to 92.328% during the 2.90 seconds time delay period. Because of the number of variables involving load tap changer settings and step change times, and ESF bus loads, no attempt has been made to report the voltages at the 7.2 kV ESF buses. Descriptions of loss of voltage and degraded voltage timer and relay operations assume that the per unit value of the 7.2 kV bus voltages are the same as those at the 230 kV and 115 kV Offsite Power Supply buses. The voltage results of the simulations are reported to V. C. Summer Design Engineering for use in calculations to determine acceptability of the voltage responses.

DESC load under frequency and generator over frequency/under frequency responses as a result of the studied conditions were also identified. The VCS generator frequency responses were monitored and evaluated in order to assess whether the VCS generator reactor coolant pump under frequency or over frequency relays would trip for frequency excursions.

CONCLUSIONS

Each of the contingencies which were simulated for this study were evaluated for generator rotor angle, generator frequency deviation, tie line flows, system under frequency load shedding, under/over frequency tripping operations, and system voltage responses. In addition, the effects of each contingency on the 230 kV and 115 kV V. C. Summer Offsite Power Supply buses were examined as well as the resulting steady state power flows on the transmission lines which are connected to the V. C. Summer transmission substation.

The generator rotor angle responses demonstrated that no conditions existed in which a generator would become unstable. None of the transmission lines connected to the V. C. Summer substation DESC system to neighboring systems remained in service throughout all conditions studied. No

conditions were found that would result in the islanding of the DESC system or neighboring systems.

Generator and system frequency responses were all within the normal operating ranges and there was no indication of system under frequency load shedding or generator under I over frequency tripping, Reactor Protection System under frequency operation, or Reactor Coolant Pump under frequency tripping.

The results of this study demonstrate that the DESC generating and transmission system is stable for the conditions that were studied. The contingencies were selected so as to test the capability and capacity of the 115 kV and 230 kV Offsite Power Supply buses at the V. C. Summer Station Unit 1 to supply the loads assigned in normal, abnormal, accident, or plant shutdown conditions. No contingency conditions were found to result in the simultaneous loss of both GDC 17 credited Offsite Power Supply buses.

Also, no conditions were found to result in under frequency load shedding operations or generator under/over frequency tripping. In addition, no System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs) were identified. Finally, there were no indications of voltage instability or stability limits. None of the contingencies that were simulated in this study indicated generator rotor angle instability would develop for generators in neighboring systems.

8.2.3 References

1. Institute of Electrical and Electronics Engineers, *Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations*, IEEE-308-1971.

Table 8.2-1
Distances of Lines to First Major Substation

First Major Substation	Distance from Virgil C. Summer Nuclear Station Terminal (miles)
Denny Terrace	26.25
Pineland No. 1	24.4
Fairfield No. 1	1.24
Fairfield No. 2	1.24
Blythewood	20.0
VCS2 Bus 2 Tie	0.87
VCS2 Bus 3 Tie	0.91
Winnsboro	14.0
Killian	38.6
VCS2 Bus 1 Tie	1.0
Newport	55.62

Table 8.2-2
Allowable Variation in Offsite System Voltage

Transformer(s)	Connected Buses	Allowable Range of Offsite Voltage (Kilo Volts)		
115 kV Source		Unit Online 330 Mvar	Unit Online 484 Mvar	Unit Offline
XTF4 with XTF6	1DA[1] or 1DB [5]	105.5 to 131.3	106.4 to 131.3	102.3 to 131.3
XTF4 with XTF6	1DA and 1DB [3]	112.8 to 131.3	113.7 to 131.3	109.5 to 131.3
XTF4 and XTF5	1DA[2] or 1DB [2, 5]	113.4 to 119.8	113.4 to 119.8	109.3 to 119.8
XTF4 and XTF5	1DA and 1DB [2 3]	114.8 to 119.8	115.7 to 119.8	111.6 to 119.8
XTF4 or XTF5	1DA[2] or 1DB [5]	114.7 to 119.8	115.6 to 119.8	111.5 to 119.8
XTF4 or XTF5	1DA and 1DB [2, 3]	119.5 to 119.8 [4]	119.5 to 119.8 [4]	117.5 to 119.8
230kV Source				
XTF31	1DB[1] or 1DA[5]	225.7 to 239.6	228.4 to 239.6	218.3 to 239.6
XTF31	1DA and 1DB [3]	233.0 to 239.6	235.8 to 239.6	225.7 to 239.6
XTF31	1DB and 1C or 1DA and 1C [5]	226.4 to 239.6	229.1 to 239.6	219.0 to 239.6
XTF31	1DA, 1DB, and 1C [3]	233.7 to 239.6	236.5 to 239.6	226.4 to 239.6

(1) Normal operating alignment
(2) Used only if regulator is out of service
(3) Maintenance only, LCO in effect, if in Modes 1-4
(4) Limit Mvar generation output to 170 Mvar
(5) Alternate operating alignment

Figure 8.2-1
DRAWING E-747-035
FSAR FIGURE REFERENCE

Figure 8.2-2
DRAWING E-229-054
FSAR FIGURE REFERENCE

Figure 8.2-2a
DRAWING E-229-001
FSAR FIGURE REFERENCE

Figure 8.2-2b
DRAWING E-229-002
FSAR FIGURE REFERENCE

Figure 8.2-2c
DRAWING E-229-003
FSAR FIGURE REFERENCE

Figure 8.2-2d
DRAWING E-229-006
FSAR FIGURE REFERENCE

Figure 8.2-3
DRAWING E-206-011
FSAR FIGURE REFERENCE

Figure 8.2-4
DRAWING E-206-012
FSAR FIGURE REFERENCE

8.3 ONSITE POWER SYSTEMS

8.3.1 A-C Power Systems

8.3.1.1 Description

The a-c power systems consist of the various auxiliary and engineered safety features electrical systems designed to provide reliable electrical power during all modes of station operation and under shutdown conditions. The a-c power systems are shown by Figures 8.2-3 and 8.2-4. The major electrical equipment is described in Table 8.3-1. Engineered safety features (ESF) auxiliaries are arranged so that loss of a single bus, for any reason, still leaves sufficient auxiliaries to safely perform required functions. In general, auxiliaries related to functions other than engineered safety features are connected to 3 auxiliary buses. A generator circuit breaker is provided to permit isolation of the generator from the system, which eliminates the necessity for a transfer from the emergency auxiliary transformer to the normal auxiliary transformer on plant startups. Engineered safety features loads are divided between 2 additional essential system buses in observance of the single failure criteria.

Controls are provided in the control room for selected 7200 volt and 480 volt switchgear units. These units are selected to provide the operator with control of the distribution network and remote control of selected loads.

8.3.1.1.1 Plant Distribution Network

1. 7200 Volt Network

   The 7200 volt network is arranged in 5 medium voltage primary bus sections. There are 2 additional medium voltage bus sections located in the Service Water Pumphouse. Each of these 2 buses is fed as a stub bus from the related ESF primary bus. Each bus consists of a separate, metal clad type, dead front construction, rated 7.2 kV nominal (8.25 kV max) volt, 500 MVA switchgear assembly. Each circuit breaker cubicle is isolated from the adjacent cubicle by metal barriers. Interrupting ratings for the switchgear breakers are 66 kA momentary, and 41 kA symmetrical at 6.6 kV, or 37.8 kA symmetrical at 7.2 kV (based on the symmetrical rating of 33 kA at 8.25 kV). These interrupting ratings are greater than any of the fault current levels on the various buses. Control power for tripping and closing the switchgear is obtained from the station batteries.

The 7200 volt buses 1A, 1B, and 1C supply power to non-safety-related auxiliaries. Each of these 3 buses supplies power to a reactor coolant pump. The normal power source for these buses is the main generator through the unit auxiliary transformer or back feed from the 230 kV bus through the main power transformer and unit auxiliary transformer. Upon tripping of the normal feeder breaker to these bus sections, the balance of plant (non-Class 1E) electrical system is automatically transferred to the emergency auxiliary transformers which are the emergency power sources. This automatic transfer is initiated when the normal feeder is tripped by main and unit transformer lockout relaying, generator differential protection relaying, generator and main transformer backup and field failure relaying, overall backup lockout relaying, and the condition of both the main transformer breaker and the generator breaker open. There is no automatic transfer when a bus over-current condition exists. Provisions are also available for manual transfer, as required.

In addition to the protective relays discussed above, there are 3 undervoltage sensing relays (1 for each phase) and 1 underfrequency sensing relay connected for each reactor coolant pump. These devices provide the reactor coolant pump undervoltage trip signal described in Section 7.2.1.1.2, Item 4.b, and the reactor coolant pump underfrequency trip signal described in Section 7.2.1.1.2, Item 4.c. These relays, together with the potential transformers from which they receive a voltage signal, are located in the reactor protection undervoltage and underfrequency relay panel. This panel is housed in the Seismic Category 1 Intermediate Building. Power feeds to the reactor coolant pumps are routed through this panel. Therefore, the voltage signal is sensed on the pump side of the supply circuit breaker.

To satisfy the single failure criteria, the panel is constructed in 3 sections, 1 section for each of the 3 reactor coolant pump power circuits. Each section is physically isolated from adjacent sections by a double, metal side sheet barrier. Any terminal blocks or fuse blocks mounted on a barrier side sheet are mounted on a polyester glass material. Polyester glass material is also placed under any wiring on a barrier side sheet. Thus, complete isolation of power cables, potential transformers and relays for each pump is maintained within the panel. The panel has been qualified to satisfy the requirements of IEEE-323 (Reference 11) and IEEE-344 (Reference 12). Electrical separation of circuits associated with the reactor protection inputs is in accordance with the criteria outlined in Section 8.3.1.4.

The 7200 volt buses 1DA and 1DB supply power to the ESF equipment. These ESF buses provide an adequate and reliable source of electrical power for safe reactor shutdown under conditions resulting from any design basis event and/or during loss of offsite power, as well as for all modes of normal station operation. The normal and preferred power source for bus 1DA is the emergency auxiliary transformer XTF-4 in conjunction with the voltage regulator XTF-6. In the event that the voltage regulator is out of service, either or both of the 2 emergency auxiliary transformers, XTF-4 and XTF-5, can be used to supply bus 1DA. When the voltage regulator is out of service, parallel operation of the 2 transformers is preferred since it provides more flexibility and a greater range of allowable offsite voltage for the 115 kV system. The normal and preferred power source for bus 1DB is also the backup power supply for 1DA. In addition to the normal power sources, each 7200 volt ESF bus has an onsite emergency power source. The AAC source ties into the same plant bus (1DX) as the ESF transformers.

The physical layout of the cable bus system for connecting the 2 power transformers (emergency auxiliary and safeguard transformers) and the voltage regulator or the AAC source to the 7.2 kV ESF buses is shown by Figures 8.3-0 through 8.3-0g. Figure 8.3-0b.1 shows the modifications to the bus shown in Figure 8.3-0b for the addition of the voltage regulator and its by-pass switches.

Each onsite power source is capable of carrying the total ESF load required for safe shutdown. The onsite standby power system consists of 2 fully equipped diesel generators which provide 7200 volt power to buses 1DA and 1DB, respectively, within 10.25 seconds after detection of a loss of the associated preferred power sources by loss of voltage relays and 13 seconds after detection of a degraded voltage condition. Buses 1DA and 1DB are provided with a manually initiated transfer to the alternate offsite power source.

Transfer switches are used to select power from 7.2 kV Channel A or Channel B sources for the C pump motors in the Service Water, Component Cooling and Safety Injection Systems. The switches are manually operated locally and are equipped with Kirk key interlock to prevent simultaneous closure of circuit breakers from both sources.

Speed switches are used to control the 2 speed, single winding motors used for the 3 component cooling water pumps.

2. 480 Volt Network

The 480 volt network distributes and controls power for all 480 volt and 120 volt a-c station demands. This network consists of 22 unit substations and 28 motor control centers. The unit substation switchgear is of metal clad, dead front construction, with 125 volt d-c operated air circuit breakers. Transformers for the 480 volt unit substations are air cooled and are directly connected to the switchgear. Except in special cases, motors rated above 50 hp to 350 hp are controlled directly by circuit breakers in the 480 volt switchgear. Motor control centers are used for control of motors 50 hp and smaller.

The maximum symmetrical interrupting capacity of the 480 volt motor control centers is 22,000 amperes. This interrupting capacity is greater than any of the fault levels on the motor control center buses. Current limiting reactors are provided in series with selected non-Class 1E motor control centers where the maximum symmetrical fault current that could otherwise occur at the motor control center would have exceeded 22,000 amperes.

The maximum symmetrical interrupting capacity of the 480 volt unit substations is dependent upon the frame size of individual unit substation cubicles. In each case the interrupting capacity of a cubicle exceeds the maximum symmetrical fault current. Frame size rating and capacity is listed in Table 8.3-2.

a. Balance of Plant 480 Volt Network

The balance of plant 480 volt network consists of 18 unit substations and 18 motor control centers. Fifteen (15) of the unit substations are 4 wire, consisting of transformers and metal clad switchgear; 3 are 3 wire, consisting of transformers and power distribution panels. The 3 wire 480 volt unit substations provide power to the pressurizer heaters. Two (2) of these unit substations are connected to redundant safety-related (Class 1E) buses. These are loaded manually from the 7.2 Kv diesel generator buses 1DA and 1DB and furnish power to the 2 groups of heaters designated as backup groups. The third unit substation is connected to a balance-of-plant bus (1C) which powers the control group of heaters which are the normally energized heaters. Main feeder breakers for the 2 backup groups have been qualified in accordance with safety-grade equipment. Safety class heater cables and trays are protected by jet spray shields in the event of a PRT diaphragm rupture. Procedures for energizing the pressurizer heaters are addressed in Emergency Operating Procedures and System Operating Procedures as appropriate. These procedures describe (1) precautions to be observed if pressurizer heaters are to be used to prevent overloading diesel generators, (2) suggested loads to trim, (3) the time required to accomplish the connection. This time shall be consistent with the timely initiation and maintenance of natural circulation conditions. This meets the requirements of NUREG-0578, Section 2.1.1, Position 3.1. All motor control centers are fed by 4 wire unit substations. The unit substations receive power from 7200 volt balance of plant buses 1A, 1B, and 1C through 7200 - 480/277 volt transformers. Each motor control center has a separate feed from the 480 volt unit substations. Selected motor control centers are provided with automatic transfer to an alternate power source.

b. Engineered Safety Features 480 Volt Network

The ESF 480 volt network consists of 6 unit substations and 9 motor control centers. The 480 volt ESF buses are fed through transformers with 7200 volt primaries and 480/277 volt secondaries which feed motor control centers, motors, and miscellaneous loads. These buses are independent from each other and there is neither automatic nor manual transfer capability. ESF 7200 - 480/277 volt transformers and switchgear are redundant and are located in separate areas of Seismic Category 1 structures to maintain isolation. ESF motor control centers are powered from the 480 volt ESF buses and have neither manual nor automatic transfer capability. The motor control centers are redundant and are located in separate areas of Seismic Category 1 structures or are separated by fire walls to maintain isolation. Under loss of offsite power conditions, power may be supplied to selected non-Class 1E 480 volt buses by the diesel generators. Equipment which is not safety-related but is considered essential for protection of the turbine or desired for convenience is manually activated by the operators.

The voltage fluctuates on the preferred sources within the limits defined in Table 8.2-2, as described in Section 8.2.1. Appendix 8D discusses the analytical method used for determining the optimum tap settings for the step down transformers in the plant distribution network. Also, included in the appendix is a tabulation of, or a referenced calculation for, the calculated voltages at the 7.2 kV and 480 volt distribution levels in the plant during light and accident load conditions with power being supplied from the offsite sources. The voltage fluctuation will be less than those given in Appendix 8E during diesel generator operation as the diesel's output is held to approximately + 0.5% of the voltage regulator's setting, and the regulator is set within the range of + 2%, - 5% of 7.2 kV. The light and accident condition loads were determined to be the worst case loads. The results indicate that with the design tap settings the motors terminal voltages will remain within the design limits of ± 10% of their rated voltages for the anticipated range of transmission system voltages.

If a degraded voltage occurs, with the established relay setting, the lowest voltage which could exist at a motor terminal is 90.0% of rated voltage (460 volts) and at a motor control center bus is 87.71% of rated voltage (480 Volts).

When the plant is at the startup stage and the design tap settings have been applied to the step down transformers, the voltages on the buses will be verified to ensure that they are not out of the range for proper equipment operation. Prior to fuel loading when the loads on the distribution system reflects the values to be expected during plant operation, the voltages and loads of the ESF system buses will be measured and the data used to verify the calculation of voltage levels. Appendix 8D discusses the calculation procedures and method of this verification of the calculation. Results were provided in a March 1, 1982 letter to the NRC. As part of the results, a tolerance study will be made and presented to show that the variations between the measured and calculated values are within the expected ranges.

The voltages on the buses are monitored during plant operation and recorded as part of operator logs to verify the proper range for equipment operation.

No load break, 480 volt a-c transfer switches are used to transfer power from 480 volt channel A or channel B sources for the motors for HVAC water chiller C and chilled water pump C. These switches are equipped with a walking beam interlock to prevent simultaneous closure of circuit breakers from both sources.

8.3.1.1.2 Onsite Standby Power Supplies

The onsite standby a-c power supplies for Virgil C. Summer Nuclear Station are 2, 12 cylinder, V configuration diesel engine driven generator sets. The generators operate at 514 rpm and provide 3 phase, 60 Hz, 7200 volt power. Each diesel generator has the following ratings:

1. Continuous, 4250 kW.
2. Short time, 4676 kW.
3. Overload (2000 hour), 4548 kW.

4. Seven (7) days, 4676 kW.
5. Thirty (30) minutes, 5100 kW.

The diesel generators are located in a building designed to satisfy Seismic Category 1 requirements and to protect the diesel generators against tornadoes, hurricanes and missiles. Within this building, the diesel generators, including associated starting equipment and other auxiliaries, are completely isolated from one another by a wall designed to withstand a safe shutdown earthquake (SSE).

Each diesel generator is provided with a separate, missile protected combustion air intake as shown by Figure 1.2-13 and a separate air discharge and engine exhaust. The diesel generators, together with associated fuel storage tanks, auxiliaries and related piping are designed to remain functional during an SSE and remain in a condition suitable for the performance of their function in shutting down and maintaining the plant in a safe condition.

Essential subsystems for each of the diesel generators and the physical arrangement of these subsystems are discussed in Sections 9.5.4 through 9.5.8.

8.3.1.1.2.1 Deleted by Amendment 98-01, April 1998

8.3.1.1.2.2 Deleted by Amendment 98-01, April 1998

8.3.1.1.2.3 Deleted by Amendment 98-01, April 1998

8.3.1.1.2.4 Diesel Generator Operation

Each 7200 volt ESF bus is continually energized from either the 230 kV or the 115 kV preferred power source transformer or from the onsite emergency diesel generators, as shown by Figures 8.2-2 and 8.2-3. The transfer from preferred power source to emergency diesel generator is accomplished automatically, when required, by the opening of the preferred power source air circuit breakers and closing of the emergency diesel generator air circuit breaker. The emergency buses and power supplies for all essential components are normally connected to the preferred offsite power sources.

The emergency diesel generators are automatically started upon receipt of an undervoltage signal from the associated bus from either the loss of voltage relays or degraded voltage relays, or upon receipt of a safety injection signal. They are also started upon receipt of a manually initiated signal from the control room. Loss of voltage on an ESF bus opens the normal or alternate supply circuit breaker (whichever is closed) and, when emergency diesel generator voltage and frequency are established, closes the emergency power source circuit breaker. In the case of a safety injection signal and/or ESF bus undervoltage, the ESF loading sequencer (see Section 7.3.1 for a detailed discussion) trips selected bus loads including all non-Class 1E loads. The bus is then reloaded in the sequence shown in Table 8.3-3, Parts A1 and B1. Items indicated by 0 second loading sequence in Table 8.3-3 are not tripped and, therefore, are immediately loaded when the emergency power source circuit breaker is closed. All other required loads are loaded in sequence by the ESF loading sequencer.

The 7.2 Kv ESF buses are each provided with 3 loss of voltage relays set at approximately 81% of the nominal bus voltage level and 3 degraded voltage relays set at approximately 91.34% of the nominal bus voltage level. Operation of a set of loss of voltage or degraded voltage relays will initiate a diesel generator start, a permissive for EFW turbine pump start, an ESF load sequence operation and a permissive for diesel generator circuit breaker close. These operations occur in a timed sequence as outlined in Table 8.3-5. The logic of the controls are illustrated in Figure 8.3-0o.

As illustrated in Table 8.3-5 the 7.2 Kv bus circuit breakers are tripped 4 seconds after the diesel generator is started on a degraded voltage condition as compared to 2 seconds for a loss of voltage condition. The delay in tripping for a degraded voltage condition allows the bus to be energized during the time the diesel generator is coming up to speed. Therefore, with the degraded voltage condition, the maximum dead bus time is 6 seconds as compared to a 10.25 seconds dead bus time allowed for a loss of voltage condition.

Appendix 8F provides a discussion of the time sequence of equipment operation with a degraded voltage condition coincident with an accident condition. When the diesel generators are started and loaded as a result of an undervoltage condition, the ESF loading sequencer logic prevents further undervoltage tripping of the safety related loads. When the buses are returned to the offsite power sources, the undervoltage tripping feature is automatically reinstated.

The emergency diesel generators and normal station service are synchronized only during periodic testing. Synchronizing capability is provided to reconnect the emergency diesel generators to the offsite power network when voltage is restored subsequent to the loss of offsite power. Synchronization is performed manually, when required. ESF equipment is duplicated on separate 7200 volt and 480 volt (as appropriate) buses as listed in Table 8.3-3, Parts A1 and B1. All equipment does not start simultaneously but is programmed to start automatically in sequenced steps. The first group, indicated by 0 load sequence seconds in Table 8.3-3, Parts A1 and B1, is connected to the ESF buses when the buses are energized. During recovery from step load increase, or from disconnection of the complete load, emergency diesel generator speed change will not exceed 75% of the difference between nominal speed and the overspeed trip setpoint or 115% of nominal speed, whichever is lower. Voltage is restored to within 10% and frequency to within 2% of the nominal values in less than 40% of each load sequence time interval. This complies with Regulatory Guide 1.9 (see Appendix 3A). Subsequent groups are each connected in sequence after short time delays.

The load profile after an accident, without offsite power, is generally outlined by Table 8.3-3, Parts A1 and B1. At no time following an accident will the load exceed the short time rating (110% of the continuous rating) of the diesel generators nor is it expected that the load will fall below 30% of the diesel generator rating.

In the event of an accident with offsite power available, the diesel generators will start and run at no load. Should a subsequent loss of offsite power occur, the diesel generators would be loaded automatically. If offsite power is not subsequently lost, the diesel generators would continue to run at no load until manually stopped by the operator.

The injection phase of a loss of coolant accident should not exceed 1 hour and the short term phase of a main steam line break accident is estimated to be 2 hours. Therefore, it is expected that both diesel generators can be stopped within 4 hours after an accident if offsite power is available. If the diesel generators are operated at no load or less than 20% load for a period of time longer than 4 hours, operating procedures will require paralleling of each machine with the bus and loading the generator to at least 50% of rated load. Only 1 diesel generator will be paralleled with a bus at a time.

Criteria discussed are conservative with respect to the manufacturer's recommendations (see Colt Industries, Fairbanks Morse Engine Division, "Operating and Maintenance Manual, South Carolina Electric and Gas Co., Virgil C. Summer Nuclear Station - Unit 1, Standby Diesel Generator Set," Colt-13-206152, Chapter 1, Tab 1, page 5-1) which, in part, are as follows:

> "In the event it is necessary to operate the engine for extended periods of time (over 24 hrs.) at from no load up to 20% of the engine rating, the engine should run at above 50% load for at least 1 hour in each 24 hour period in order to minimize the accumulation of products of combustion and lubricating products in the exhaust systems. Above 20% load rating, the engine may run continuously as required with the recommendation that the engine parameters be monitored closely and logged at least daily so as to be able to discover any problems early. (Changes in exhaust temperatures are of particular interest.)"

8.3.1.1.2.5 Diesel Generator Permissives

After the emergency diesel generator has received a starting signal, the following conditions must be satisfied before the generator is automatically connected to the ESF bus:

1. The diesel generator must be at approximately 90% of rated voltage and approximately 98% of rated frequency, based upon 2 out of 3 relaying schemes in each case.
2. The ESF bus normal and alternate power supply circuit breakers must be open.
3. There must be no electrical faults in the 7200 volt bus.

Figures 8.3-0h through 8.3-0j present diesel generator logic diagrams. Logic diagrams for the bus 1DA normal and alternate power supply circuit breakers are shown by Figures 8.3-0K and 8.3-0l. The bus 1DB normal and alternate supply circuit breakers use similar control schemes.

8.3.1.1.2.6 Diesel Generator Testing

The diesel generators are tested as follows at the manufacturer's plant prior to shipment to the plant site:

1. The diesel generators are initially started and run in accordance with the manufacturer's standard procedure which includes the following:
   a. Operation at reduced RPM for approximately 50 minutes.
   b. Operation at rated RPM and variable load for approximately 6-1/2 hours.

2. The engine overspeed setting is tested and operation at 115% overspeed is demonstrated.
3. Diesel generator starting system capacity is demonstrated.
4. Diesel generator speed governing system is tested for steady state and transient performance, including load rejection tests at 25, 50, 75, and 100% of rated load.
5. The diesel generators are started and automatically loaded with a combination of resistive and inductive loads to simulate design loading conditions for the Virgil C. Summer Nuclear Station. This test is performed 10 times on each diesel generator.
6. The ability of the diesel generators to start and accept load without service water flow and without 480 volt auxiliary power is demonstrated.
7. The starting margin of each diesel generator is demonstrated by simultaneously starting and accelerating a 1750 horsepower motor and a 500 horsepower motor with the generator carrying a resistive load of approximately 50% of rated capacity.
8. Operation of the diesel generator in parallel with a utility system is demonstrated.
9. The diesel generators are operated at variable load for a total of 11 hours, including 3 hours at 100% of rated load followed by 2 hours at 110% of rated load.

Certified evidence is supplied by the manufacturer of the diesel generators that a total of 300 start and load tests, with a maximum of 3 failures, have been performed on a diesel generator of the design supplied for Virgil C. Summer Nuclear Station.

Each start and load test consisted of starting the diesel generator and applying load within 10 seconds after the start signal, increasing load to at least 50% of the continuous rating within 30 seconds and operating under load for a minimum of 5 minutes.

Some of these tests are initiated from design cold ambient conditions (keep warm temperatures) and some from hot equilibrium temperature conditions.

Tests and inspections are performed to ensure that all components are properly mounted, connections are correct, circuits are continuous and components are operational. Tests are performed to ensure that emergency loads do not exceed diesel generator rating and that each diesel generator is suitable for starting and operating required loads.

Proper operation of the onsite standby power supply is tested periodically. An availability test is performed periodically when the plant is in operation. Only 1 diesel generator is tested at a given time. The test consists of a manually initiated start of the diesel generator, followed by manual synchronization with and connection to the station ESF buses and assumption of load by the diesel generators. Normal station operation is not affected by this test. The operational test, automatic starting, load shedding and loading of the diesel generators, initiated by a simulated loss of voltage on the ESF buses are performed normally during reactor shutdown for refueling. Preoperational testing according to Regulatory Guide 1.41 is discussed in Chapter 14 and Appendix 3A.

8.3.1.1.2.7 Deleted by Amendment 98-01, April 1998

8.3.1.1.2.8 Instrumentation and Control Systems

Control power required for operation of each diesel generator is supplied from the 125 volt d-c distribution system. Control power for the diesel generator breaker to the ESF bus is supplied from the 125 volt d-c distribution system associated with the corresponding ESF bus. Controls are provided locally and in the control room for manual start and stop of each diesel generator. An automatic control system is provided for automatic startup and adjustment of speed and voltage to a ready-to-load condition.

A start diesel signal overrides all other operating modes and immediately returns the controls for the diesel generator to the emergency mode except under the following conditions:

1. Engine tripped due to overspeed.
2. Engine tripped due to low lube oil pressure.
3. Generator tripped due to generator differential relay operation.
4. When maintenance is in progress.

A matrix arrangement is provided for tripping the diesel generator for low lube oil pressure. This matrix consists of 4 pressure relays set at 70, 65, 60, and 60 psi. To cause a diesel generator trip due to low lube oil pressure, 2 of the low pressure switches must be activated and at least 1 of the 2 activated switches must be 1 of the 2 with 60 psi setpoints.

The other protective functions for the diesel generator are able to cause a diesel generator trip only during testing. Under emergency conditions, these protective functions actuate alarms only and do not trip the diesel generator.

Table 8.3-3a is a list of the protective devices provided for the diesel generators. This list also includes the function of these devices under emergency start and test start conditions.

Also, the engine manual stop pushbutton cannot override an ESF signal.

Instrumentation is provided locally and in the control room to monitor diesel generator frequency, voltage, loading and circuit breaker position.

Alarms are provided locally for all critical variables and trip functions as shown in Figure 8.3-0n. The local annunciator provides “first out” indication to aid in determining the cause of any trips or malfunctions. Alarms and status indication are also provided in the control room as shown in Figure 8.3-0m to indicate diesel generator status and permit remote operation of the diesel generators.

Most of the instrumentation is designed and installed to permit inplace calibration.

Logic diagrams for the diesel generator starting and shutdown controls are presented by Figures 8.3-0h and 8.3-0i.

8.3.1.1.2.9 Diesel Generator Environment

Combustion air for the diesel generators is taken directly from the outside through an intake which is completely independent of the ventilation air intake. The bottom of the ventilation air intake is located 29 feet above grade, as shown in the Figures 1.2-13 and 1.2-14. This high elevation will minimize the amount of dust taken in by the ventilation system. In addition, all cabinets containing control relays and associated devices have gasketed doors and openings. Therefore, the ventilation system will introduce a minimum of dust into the building and the controls are protected from whatever dust does enter the building.

There are several elements which interact to assure the cleanliness of the Diesel Generator Room and the supportive electronic and electrical components contained therein. They are as follows:

1. All electrical and electric component cabinets are weather sealed with rubber gaskets and have filtering media provided where air is circulated through the cabinets.
2. The Diesel Generator Building is to be designated as a Cleanliness Zone IV, which requires periodic inspections, specifically for cleanliness.
3. The mandatory surveillances for assuring the diesel's ability to start are supported by a periodic preventive maintenance task which requires inspection of the electrical and electronic components to determine operability and condition. Cleanliness is one of the areas that is inspected during the performance of the preventive maintenance task.

8.3.1.1.3 120 Volt A-C Vital Bus System

Six (6) 120 volt a-c vital buses are provided. Each of 4 buses is supplied by 1 of 4 single phase static inverters. The normal feed to Panel APN5907 is from APN5901. The normal feed to Panel APN5908 is from APN 5903.

One (1) Channel A and 1 Channel D inverters are connected to ESF battery 1A, and 1 Channel B and 1 Channel E inverters are connected to ESF battery 1B.

The 120 volt a-c vital buses constitute a reliable electrical system which provides a stable power supply to vital equipment and guarantees proper action when power is required while eliminating spurious shutdowns. Controls for the backup groups of heaters, the pressurizer level transmitters and for the pressurizer relief block valve operators receive their power from this vital a-c bus source through the emergency power buses. The control power for the block valves is supplied from an emergency power bus different from that which supplies the associated PORV. Safety grade circuit breakers and fuses are used for circuit protection.

The normal source of power for the 120 volt a-c vital bus inverters is through the inverter static rectifier. These inverter rectifiers are fed from 480 volt buses 1DA2 and 1DB2. The station batteries and battery chargers constitute the standby power source. The battery chargers are fed from 480 volt buses 1DA2 and 1DB2. In the event of loss of 480 volt power, the power source for the vital bus inverters is the station batteries. These batteries are floating, on standby service. The change in power source, from normal to standby, occurs without exceeding the stated inverter

output voltage and frequency regulation. The station batteries are sized to carry this additional inverter load without being charged for no less than 4 hours. The battery chargers are sized to recharge from a design minimum charge to full charge in 12 hours while carrying the largest combined demand from the various steady-state loads.

An alternate power supply for the 120 volt a-c vital buses is provided through 480-120 volt transformers from 480 volt buses 1DA2 and 1DB2 for use when the inverters are out of service.

8.3.1.1.4 Equipment Criteria

1. Motor Size

   The criterion for motor size is that the motor develops sufficient horsepower to drive the mechanical load under maximum expected flow and pressure. Motors are sized to permit the driven equipment to develop its specified capacity without exceeding the temperature rise rating of the motor when operated at the duty cycle of the driven equipment. Motors are furnished with service factors ranging from 1.0 to 1.15. The service factor is a ratio of the safe load to the nameplate load and identifies the margin available for motor operation under overload conditions. When a motor is furnished with a service factor greater than 1.0, it is the design intent to size the motor to handle the normal operating requirements of the driven equipment without taking credit for the service factor. Motor size is determined based on the driven equipment load characteristics.

2. Engineered Safety Features Motor Starting Torque

   Motors are designed for across the line starting. ESF motors rated 6900 volts are capable of accelerating the driven equipment to rated speed at 70% of the motor nameplate voltage. ESF motors rated 460 volts are capable of accelerating the driven equipment to rated speed at 80% of rated voltage. The motors are designed to operate at ± 10% of rated voltage, ± 5% of rated frequency or a combined variation in voltage and frequency of ± 10% of absolute values, provided that frequency variation does not exceed ± 5% of rated frequency.

   Calculations based on the diesel generator factory test data indicate that the motor terminal voltage during starting will not go below 90% of the rated voltage for 6,900 volt motors or below 82% for 460 volt motors. The motor terminal voltage for the 6900 volt motors was calculated using the diesel generator voltage regulation for starting of a 1750 Hp motor. The motor terminal voltage for the 460 volt motors was calculated using the diesel generator voltage regulation for starting a 500 Hp motor and considering the voltage drop through the 7200/480 volt transformers. The actual largest system motors are 900 Hp and 350 Hp for the 7200 volt and 480 volt systems respectively (Refer to Appendix 8E). These voltage levels are well above those allowed by Regulatory Guide 1.9. The adequacy of bus voltage regulation during motor starting is confirmed during the preoperational testing program.

3. Motor Insulation

   Motor insulation is a minimum of Class B outside the Reactor Building and Class F inside the Reactor Building. The insulation temperature rating is greater than the sum of the motor temperature rise and the ambient temperature at the motor location.

   Service life is extended when necessary by 1, or a combination, of the following methods:

   a. Derating - use of a larger motor than required by the motor sizing criteria previously discussed.
   b. Insulation type - use of motor insulation with a higher temperature limit than specified for the operating conditions (e.g., specifying Class F insulation to Class B temperature limitations).
   c. Service factor - motors with 1.15 service factor are operated under normal conditions without encroaching upon the service factor.

4. Engineered Safety Features Motor Temperature Protection

   ESF motors rated 6900 volts and 600 Hp and larger are provided with 6 stator winding embedded, resistance type, 10 ohm, copper at 25°C, resistance temperature detectors (RTDs). Smaller horsepower motors are not equipped with stator RTDs due to the problems involved in embedding them in the stator. The exceptions are the 400 Hp reactor building spray pump motors which do have stator RTDs.

   Motors rated 6900 volts and selected 460 volt motors are provided with bearing thermocouples. Outputs from each of the 2 motor temperature measuring devices are routed to the plant computer which actuates an alarm and provides a printed output if the stator RTD or bearing thermocouple measured value exceeds a predetermined setpoint.

5. Interrupting Capacity

   Switchgear, unit substations, motor control centers and distribution panels are sized for interrupting capacity greater than the maximum short circuit availability at their location. The calculations to document this application take into account the fault contributions of all rotating machines and source transformers. Source impedances are selected to ensure adequate starting voltage for all motors and to limit short circuit currents at unit substation buses and motor control center buses.

6. Network Protection

   Each major motor or other major item of electrical equipment is protected by overcurrent relays that disconnect the equipment if the load current becomes excessive. Prior to plant operation protective relays are set and calibrated. Availability and proper operation of standby equipment are periodically tested during normal operation.

The protection philosophy for the 7200 volt and 480 volt systems is based upon the following considerations:

a. A faulted piece of equipment is cleared by isolating the smallest possible portion of the system.

b. A faulted piece of equipment is cleared in the minimum possible time to reduce damage to that equipment and limit the stress on the remainder of the system.

c. Protective devices are selected and set for fault sensing and overload sensing as required for applicable system/component protection.

d. Motor control centers that serve loads located inside the Reactor Building typically have starters, (with thermal overloads) magnetic molded case circuit breakers, and a current limiting circuit breaker in series. The current limiting circuit breakers have thermal and magnetic elements incorporated in their protection circuit. Loads that do not require a starter, that use a contactor without overload protection, or have overloads bypassed under accident conditions, or are mentioned in Section 8.3.1.4.1; have an additional thermal element provided in the molded case circuit breaker. This arrangement provides primary and backup protection in compliance with Regulatory Guide 1.63 (see Appendix 3A).

e. Overload elements provided for safety-related valve operators are bypassed under accident conditions by the safety injection signal contact that initiates the valve operation. This is in compliance with Regulatory Guide 1.106 (see Appendix 3A).

7. Grounding Requirements

Design criteria for grounding of safety-related systems are as follows:

a. All equipment hardware, exposed surfaces and potential induced voltage hazards are adequately grounded to assure that no danger to plant personnel exists.

b. A low impedance ground return path is provided to facilitate the operation of ground fault detection or protective devices in the event of ground fault or insulation failure on any electrical load or circuit.

The following are the methods for grounding electrical equipment:

a. A ground wire is connected to the equipment frame and the ground grid. The ground wire is run through the equipment conduit or lashed to the power cable for the equipment where no conduit is provided. The wire is either connected directly to the ground grid or to other equipment, such as a cable tray which is connected to the grounding grid.

b. Where conduit is used as the grounding path, the conduit is connected to the equipment and the grounding grid. The connection to the grounding grid is either a direct connection or is connected to other equipment such as a cable tray which is connected to the grounding grid.

The cable tray system is solidly grounded. Ground connections are made to the station grounding grid or building steel work, which is connected to the station grounding grid.

The station grounding grid is designed to maintain the station area at an effective ground potential during a worst case ground fault in any installed electrical equipment, including transmission facilities and unit main generators, as well as lightning effects. An effective ground is considered to be the maintenance of voltage potentials below a "safe touch" level for plant personnel.

8. Maintenance Program

   A maintenance program, in accordance with the recommendations of the manufacturers, is followed. This program includes periodic visual inspection and lubrication for each motor. A record is maintained for each motor indicating the date when each action is performed.

9. Starter Voltages

   Starter coils for motor control centers are designed to pull in at 85% of rated voltage and to hold in at 65% of rated voltage. The coils are energized through a 480/120 volt instrument transformer.

10. Heat tracing is provided for Nuclear Safety Related and Non-Nuclear Safety Related equipment, piping, and/or tubing for the purpose of process temperature maintenance and freeze protection of liquids and for prevention of condensation in instrument air lines.

    The heat tracing equipment protecting Safety Related systems (i.e., reactor makeup water storage tank and piping, refueling water storage tank and piping, and sodium hydroxide) includes redundant centralized control panels, temperature measuring equipment, wiring and conduit, and heat tracing cables, except for the refueling water storage tank and reactor makeup water storage tank. These tanks are monitored by redundant temperature instrumentation and are provided with 1 set of heat tracing each. Based upon the thermal capacity and insulated design of these tanks, the redundant instrumentation provides adequate operator control to prevent freezing. The centralized control panels provide power distribution, control and alarm functions from signals received from temperature measuring equipment attached to the piping systems. The primary and redundant heat trace circuits are each designed with the capability to provide the necessary freeze protection, or maintain the necessary process temperature. In the event of a failure to the primary heat trace circuit, the redundant heat trace circuit provides the necessary heat trace function. The heat tracing cables are of the parallel self-limiting type. The centralized control panels are powered from Class 1E Channel A and Channel B motor control centers. Alarms are transmitted to the control room from a local annunciator panel.

8.3.1.2 Analysis

8.3.1.2.1 Compliance Analysis

The basic design criteria are that the Class 1E electric power systems satisfy the single failure criterion and Regulatory Guide 1.32 (see Appendix 3A). The safety-related loads are assigned to 2 independent, separate 7200 volt ESF buses. Either of these buses is capable of supplying required ESF or shutdown loads. Each of these buses is continuously energized from the preferred source ESF transformer(s), 1 set of windings in emergency auxiliary transformer (XTF-31), or from 1 of the diesel generators. Each 7200 volt ESF bus serves as a power source for the safety-related loads on the 480 volt buses and for equipment which is not safety-related but is considered essential for protection of the turbine or desired for convenience. This design, including the ties to the non-ESF buses, satisfies the independence and redundancy requirements of Regulatory Guide 1.6 (see Appendix 3A) and General Design Criterion 17.

The main control board is provided with indicators to monitor the ESF bus operating levels. A voltmeter, ammeter, wattmeter, varmeter and kilowatt hour meter are provided on each of the incoming, preferred power sources. The onsite power source has a voltmeter, frequency meter, wattmeter and ammeter provided on the main control board to indicate the ESF bus operating levels. Figures 8.2-3 and 8.2-4 indicate the metering provided on the plant electrical system. Table 8.3-3b is a listing of the indicator types associated with the ESF electrical network.

The ESF buses have sufficient redundancy to allow testing of each safety-related item as a system, or in some cases as individual components to comply with General Design Criteria 17 and 18.

Two (2) diesel generators provide onsite power to the 7200 volt ESF buses. Each diesel generator is assigned exclusively to 1 bus and each is automatically started upon a loss of bus voltage, degradation of bus voltage or receipt of a safety injection actuation signal. Under conditions outlined in Section 7.3.1, normal loads, with the exception of the group indicated by 0 seconds in Table 8.3-3 Parts A1 and B1, are disconnected and the ESF loads are automatically loaded in sequence on each diesel generator in accordance with the sequence presented in Table 8.3-3.

If a loss of preferred power is not concurrent with a postulated accident, certain ESF equipment is not required. Under these conditions, other plant auxiliary equipment may be manually operated. Safety injection loads are sequenced on by the load sequencer in this case, but loads are not disconnected prior to the sequencing. Instrumentation is provided to indicate emergency diesel generator loading.

The onsite standby power supply complies with Regulatory Guide 1.9, including load limits, (see Appendix 3A). The diesel generators have a continuous rating of 4250 kw, a short time rating of 4676 kw for up to 7 days, and a 30 minute rating of 5100 kw. The limiting accident load is calculated to be 4390 kw and the maximum load under loss of offsite power conditions is calculated to be 4920 kw. These short time and continuous rating loads are verified by test during each periodically. (The largest bus connected load is calculated to be approximately 5450 kVA.)

8.3.1.2.2 Hostile Environments

8.3.1.2.2.1 Equipment Identification

The most severe environmental conditions expected to be imposed upon the equipment which would operate inside and outside the Reactor Building during normal operation and subsequent to a LOCA or main steam line break are presented in Section 3.11. Regulatory Guide 1.89 is discussed in Appendix 3A.

8.3.1.2.2.2 Loss of Ventilation

To ensure that loss of the air conditioning and/or ventilation systems does not adversely affect the operability of safety-related control and electrical equipment located throughout the plant, the environmental systems for these areas satisfy the single failure criterion. Section 9.4 presents a detailed discussion of ventilation systems. Section 3.11.4 discusses loss of ventilation.

8.3.1.2.2.3 Qualification Tests

See Section 3.11 for a discussion of the hostile environment for which electrical equipment is procured and the maximum DBA environmental conditions to which it may be subjected.

8.3.1.3 Conformance with Appropriate Quality Assurance Standards

The quality assurance procedures used during equipment design, fabrication, shipment, field storage, field installation and system and component checkout and the records pertaining to each of these during the construction and preoperational test phases are described in Chapter 17.

The Quality Assurance Program, as discussed in Chapter 17, is in conformance with IEEE-336 (Reference 1).

8.3.1.4 Independence of Redundant Systems

8.3.1.4.1 Criteria for Independence of Redundant Electric Systems

The electrical power supply, control and instrument cables for mutually redundant equipment are physically separated to preserve the redundancy and to ensure that no single, credible event will prevent operation of the associated function because of electrical conductor damage. Critical circuits and functions include power, control and instrumentation associated with reactor protection, ESF and reactor shutdown. Credible events include, but are not limited to, the effects of short circuits, pipe ruptures, fires, earthquakes, and missiles. The minimum electrical separation required for protection against design basis accidents is included in the basic plant design.

The separation of electrical circuits has been reviewed to the criteria of IEEE 384 (Reference 14) as modified by Regulatory Guide 1.75 (see Appendix 3A). The plant design complies with these criteria as described below:

1. Redundant Class 1E circuits are run in separate and independent raceways. In general plant areas, not subject to hazards, such as missiles, open ventilated cable trays for redundant circuits are separated by a minimum of 3 feet horizontally or 5 feet vertically. In cable spreading rooms open ventilated cable trays are separated by a minimum of 1 foot horizontally or 3 feet vertically. Totally enclosed raceways for redundant circuits are separated by a minimum of 1 inch. Where these separation criteria cannot be satisfied, suitable barriers are placed between the raceways. The design of these barriers is described in Appendix 8B.

2. In areas where redundant circuits are exposed to hazards, such as missiles, the minimum spacing between mutually redundant wireways is 20 feet. Where this spacing cannot be achieved, a suitable missile proof barrier is used to ensure that no common hazard could render more than 1 mutually redundant circuit inoperative. Barriers have been provided to protect trays for Class 1E circuits from the effects of jet impingement and piping is restrained to prevent pipe whip as described in Section 3.6.

3. Where non-Class 1E circuits are connected to Class 1E equipment or are routed in the same raceways with Class 1E circuits, they are designated as associated circuits. Circuits designated as associated are routed with the designated separation channel throughout their length. Where non-Class 1E circuits are connected to Class 1E equipment, an isolation device is provided to protect the Class 1E equipment. These isolation devices are further discussed in Appendix 3A under the discussion of Regulatory Guide 1.75.

4. Non-Class 1E circuits are routed in raceways independent from the raceways for Class 1E circuits. Where the separation between the raceways for non-Class 1E circuits and raceways for Class 1E circuits do not satisfy the criteria for raceways carrying redundant Class 1E circuits, as described in Item 1, above, a case by case analysis has been performed to ensure that adequate separation exists. This analysis reviewed 2 types of violations, single and multiple. Single violations are those in which a non-1E tray violates the minimum separation required at one point along its path. These cases are summarized in Appendix 8C. A multiple violation is defined as a non-Class 1E tray which violates the minimum separation required at 1 point, and then, within the same fire area, the same non-Class 1E tray violates another Class 1E tray which is of a redundant channel to the initial 1E tray. For identified multiple violations in control (4000 series) trays, tray covers have been provided between the non-Class 1E tray and one of the Class 1E trays. The remaining violation is then analyzed as a single violation (Appendix 8C). For power trays (1000, 2000 and 3000 series) which cannot be covered, periodic testing of certain cable protective devices is performed in accordance with a controlled breaker surveillance program. This testing ensures that adequate overcurrent protection exists for the cables in the non-Class 1E trays so that they cannot be a hazard to the Class 1E trays whose separation distance has been violated. The results of the analysis for identified multiple violations are summarized in the Fire Barriers Raceway Database.

   All 5000 series instrument trays are deemed as acceptable barriers for multiple violations without the use of top hats, Kaowool, or any other fire related enhancements. Because of this, multiple violations in which 1 or more of the trays involved were 5000 series were classified as single or no violations as appropriate.

5. The Class 1E circuits routed to the service water intake structure are installed in underground concrete duct banks. These duct banks are seismic Category 1 structures and, as such, are designed to protect the cables from postulated natural phenomena, including SSE. The layout of the duct banks and associated manholes is illustrated by Figures 8.3-2a through 8.3-2g.

6. Separation of safety-related circuits is maintained in the electrical penetrations of the Reactor Building. Circuits for nuclear and protection instrumentation are not mixed with other type circuits in the same penetration. The redundant circuits for the 4 nuclear and protection instrumentation channels enter containment through penetrations located around the periphery with a minimum horizontal separation of 20 feet, centerline to centerline, between any 2 channels (see Figure 8.3-3). Physical separation between penetrations containing redundant circuits, other than the 4 nuclear instrument channels, is maintained in accordance with Section 8.3.1.4.3, Item 2.

   The 4 penetrations containing the nuclear and protection instrumentation are provided with metal barriers. The metal barriers are used to separate the nuclear and protection instrumentation.

   These barriers are grounded and are arranged to provide an effective electromagnetic shield over the full length of the penetration assembly.

   Structural criteria require that penetrations be spaced on minimum horizontal and vertical centerlines as shown by Figure 8.3-3. This provides a 3 foot minimum separation between any electrical penetration and any other type of penetration. The design objective is to maintain maximum separation between safety related electrical penetrations and any large piping penetrations to minimize mechanical damage from the postulated rupture of steam or water lines. The design objective is also to maintain maximum separation between any safety-related penetrations and large power penetrations, such as those for reactor coolant pump or pressurizer heater power cables. Separation of safety-related electrical penetrations from main steam lines is maintained by a concrete floor or a minimum horizontal distance of 40 feet. One (1) exception is the penetrations for the power feeds to the Channel A Reactor Building cooling unit fans. The main steam lines and cooling unit fan power feeds both penetrate the Reactor Building above the operating floor. A 20 foot minimum separation is maintained between these penetrations. Separation from any other steam, high pressure water or large power electrical penetration is maintained by a concrete floor or by an 8 foot minimum horizontal centerline separation.

7. Cable trays, conduits and cables are marked for ready identification of the channel and to guard against violation of separation. Specific color coding is discussed in Section 8.3.1.5.

8. SP-834, “Electrical Construction Guideline for Electrical Circuit Physical Separation,” and Electrical Maintenance Procedure EMP-405.012, “Guide for Electrical Physical Separation,” identify the minimum separation guidelines for internal wiring and components within control boards, panels, relay racks, etc. A minimum separation distance of 6 inches between redundant components and/or wiring and between Class 1E and non-Class 1E components and/or wiring within the enclosures is required. Where 6 inches of air separation is not available, a suitable fire barrier is installed or an analysis is performed to demonstrate that

the separation distance is adequate. Design exceptions to the separation guidelines are addressed in Attachment 1 to SP-834.

8.3.1.4.2 Compliance with Criteria for Independence of Redundant Electric Systems

A discussion of the administrative responsibility and control provided to ensure compliance with the criteria, set forth in Section 8.3.1.4.1, during design and installation is presented in Chapter 17.

8.3.1.4.3 Criteria for Design and Installation of Electrical Cable

The recommendations of IEEE Proposed Guide P-422, (Reference 3) IEEE STD 384, (Reference 14) and Regulatory Guide 1.75 (see Appendix A) are used, except as modified by Items 1 through 6, below, as the general design criteria for the design of the power, control and instrument cable and cable tray systems related to all Class 1E electrical systems.

1. Power cable capacities are determined using derating factors listed in IPCEA P-46-426, (Reference 4) supplemented by IPCEA-NEMA P54-440. (Reference 5) Cable derating and cable tray fill are discussed in Section 8.3.3.1.
2. Cable routing in the Reactor Building, penetration areas, cable spreading room, control room, etc., is arranged following the recommendations in IEEE Proposed Guide P-422. (Reference 3) Channel separation and cable tray physical separation requirements are maintained in these areas in accordance with Section 8.3.1.4.1, item 6. Cables which must enter areas surrounded by shield walls are routed to minimize the cable length within the shields area.
3. Fire and/or smoke detection equipment is installed in areas of heavy cable concentration, as recommended by IEEE Proposed Guide P-422. (Reference 3) Fire stops are provided at cable tray penetrations through floors and fire barrier walls.
4. An exception is taken to IEEE Proposed Guide P-422 (Reference 3) recommendations for 30% cable tray fill. Experience has indicated that a design objective of 50% physical fill, including all anticipated future cables, is satisfactory. This fill calculation is based upon the summation of the cable diameter squared divided by the cross-sectional area in the tray. The tables referred to in Item 1, above, are used as the basis for ampacity rating. The allowable depth is determined from the physical fill calculations outlined above and in Section 8.3.3.1.
5. The design objective for the minimum physical vertical spacing between the power, control and instrument cable trays of the same redundant channel is 12 inches, measured from the top of the lower tray to the bottom of the upper tray and a 9 inch clearance between the top of a tray and beams, piping, etc., to facilitate installation of cables in the tray. However, in areas where physical limitations govern, the physical separation may be less than the 12 inches and 9 inches, respectively.
6. The same basic design considerations are incorporated for tray and conduit supports as for the structures to which they are attached. Therefore, the same supports can be used for redundant raceways or for a redundant and non-safety raceway.

8.3.1.5 Physical Identification of Safety-Related Equipment

Identification of cable and raceways is readily apparent in the design and installation stages and is such that any safety-related cable can be readily identified. Raceways and cables (particularly for redundant systems) are adequately identified to prevent violation of separation criteria. Channel identification for safety-related and associated circuits is based upon the 4 reactor protection process control channel colors: red, orange, blue, and yellow. In addition, green is used for C train and tan is used for non-safety-related circuits. Cable trays and cables for these circuits, as well as for power, control and instrumentation circuits for ESF Channels A and B are identified relative to the 6 colors as indicated in Table 8.3-4.

Cable identification is as follows:

1. Color coding

   Cables are marked at 5 foot intervals. The circumference of the cable is marked such that the marking is visible no matter how the cable is turned.

2. Tagging

   Tags are placed at each end of the cable. These tags are marked to indicate the circuit and channel. Any nonengineered safety feature cables in a safety-related tray are marked to distinguish them from the safety-related cables.

3. Conduits

   Conduits are marked with identification markers. Color coding is done with colored tape at 15 foot intervals. Tags for embedded conduit are attached to the concrete above the conduit.

4. Cable Trays

   Cable trays for safety-related cables are identified with tags. The color coded tags are located on the trays so they are visible from easily accessible vantage points, such as walkways, etc.

5. Equipment Identification

   Each piece of equipment has an identification (ID) tag attached which identifies the equipment. Channel designation for safety related and associated equipment is identified by a strip of color coded tape.

   Tags mounted on equipment inside the Reactor Building are of stainless steel and have the required information engraved. Where there is not room to mount the tag to the equipment, it will be attached by wire. In these cases, the color coded tape will be attached to the back of the tag. Stainless steel ID tags are also used outside the Reactor Building. Tags for associated equipment have 2 colors.

8.3.1.6 Electrical Penetration Areas

Electrical penetration areas are located as follows:

1. Fuel Handling Building penetration area (penetration access area - North). Number of penetrations is 7.
2. Intermediate Building penetration area (penetration access area - East). Number of penetrations is 5.
3. Intermediate and Auxiliary Building penetration area (penetration access area - West). Number of penetrations is 33.

No special designations have been assigned areas where penetrations enter the Reactor Building.

Redundant circuits are spatially separated by 40 feet or a concrete floor, except for nuclear instrumentation penetrations, which are spatially separated by 20 feet.

Provisions for fire detection and protection in the penetration access areas consist of the following:

1. An early warning fire detection system comprised of smoke detectors.
2. A fire hose/standpipe system.
3. Manual fire extinguishers.

Protection to ensure that missiles inside the Reactor Building will not jeopardize plant safety are discussed in Section 3.5.1.

All containment penetration seal assemblies are protected against major incidents, such as missiles and rupture of high energy piping. Additionally safety related penetrations are protected on both sides of the nozzle. Therefore, based upon good design practice, a separation of 3 feet from other penetrations, the failure of which could inflict only minor or insignificant damage to an electrical penetration, was provided.

8.3.2 D-C Power Systems

8.3.2.1 Description

Separate Class 1E and non-Class 1E d-c power systems are provided. Two (2) Class 1E 125 volt d-c systems provide sources of reliable, uninterruptible d-c power for control and instrumentation for normal operation and orderly shutdown of ESF equipment. A separate non-Class 1E 125 volt d-c system is provided to supply non-ESF d-c loads, including large power non-ESF loads. This system is also a manually switched backup d-c source for the Substation Relay House d-c system. The 125 volt d-c battery systems, located in the Substation Relay House and in the Unit 1 Relay House, are provided for 230 kV substation protection and control. These systems are shown in Figures 8.3-1, 8.3-2, 8.3-4, 8.3-5 and 8.3-5a.

The Class 1E d-c system for control and instrumentation consists of 2 full capacity, 125 volt d-c, lead calcium, 60 cell batteries, 2 125 volt d-c battery buses and 3 static battery chargers. Two (2) of the 3 battery chargers are supplied from separate, redundant motor control centers. One (1) of these 3 chargers serves as a standby charger and is provided for use during maintenance of, and to backup, either of the normal power supply chargers. The standby battery charger, 1A-1B, is provided with a set of 2 transfer switches which consist of mechanically interlocked circuit breakers on the a-c input and d-c output. These circuit breakers, as shown by Figures 8.3-6 and 8.3-7, are interlocked to allow only the 2 breakers associated with Channel A or the 2 breakers associated with Channel B to close at the same time. The battery chargers remain connected to the respective a-c source buses upon loss of offsite power. Each battery charger is protected by the molded case circuit breakers in the input and output circuits. The d-c circuit has a voltage adjustment of 100 to 145 volts d-c. During an equalizing charge, d-c voltage may be set at 140 volts. All Class 1E d-c loads can operate at 140 volts d-c without damage. An overvoltage alarm is provided to annunciate in the control room upon detection of voltages greater than 140 volts d-c.

The non-Class 1E 230 kV Substation d-c systems provided for the 230 kV substation control and relaying consists of the following:

1. For the Substation Relay House, the d-c system consists of a 125 volt battery with a main battery bus, two battery changers and two separate distribution panels for 230 kV circuit breaker tripping. Backup for non-1E loads is also provided by this system.
2. For the Unit 1 Relay House, the d-c system consists of two independent d-c systems. Each system is comprised of a 125 volt battery with two distribution panels, a battery charger and common bus-tie fuse-disconnect switch. One d-c system supplies the 230 kV substation system primary protection and control. The second d-c system supplies backup protection and control. Other 230 kV substation systems and relay house d-c loads and can be supplied from either d-c system.

The second non-Class 1E d-c system provided for the 230 kV substation control and relaying in the substation relay house consists of a 125 volt battery with a battery bus, 2 static battery chargers and 2 separate distribution panels for power circuit breaker tripping. Backup for large power non-ESF loads is also provided by the system.

The non-Class 1E d-c system in the Unit 1 relay house consists of two 125 volt d-c batteries, each with its battery charger, feeding 2 separate distribution panels for power circuit breaker tripping.

The non-Class 1E battery has adequate storage capacity to power the following loads for a period of 1 hour:

1. Main generator emergency seal oil pump.
2. Circuit breaker closing and tripping (non-ESF buses).
3. Miscellaneous non-ESF loads.
4. Non-ESF instrumentation inverter and computer inverter.

5. D-C turbine bearing oil pump.
6. Feedwater pump d-c oil pump (3 pumps).
7. Reactor and Diesel Generator Building emergency panels.

A 1 hour period is considered to be the minimum time for use in sizing the batteries. Complete loss of offsite and onsite a-c power for such a period of time is considered highly unlikely. Loss of both diesel generators during an assumed prolonged loss of offsite power is not postulated nor is complete loss of all battery chargers postulated. Battery chargers are considered to be available to sustain the bulk of the battery loads well within the 1 hour period of time.

The non-Class 1E battery supplying power to the d-c turbine bearing oil pumps is of sufficient capacity to power the pumps during turbine coastdown to avoid turbine bearing damage.

Battery capacity in addition to that which is absolutely essential is provided.

8.3.2.1.1 Uninterruptible Non-Class 1E System

The uninterruptible non-Class 1E 125 volt d-c system is an ungrounded system. The system is operated ungrounded with the battery floating on the system. Dual input inverter No. 5 (450 volt a-c normal input, 125 volt d-c backup input) provides uninterruptible 120 volt a-c power for the AMSAC system, secondary plant digital control systems, the station computer and other non-Class 1E loads. No Class 1E loads are supplied from this system. The secondary plant digital control system can also be powered by the ISFSI Electrical Building uninterruptible power supply.

The dual input inverter No. 5 provides continuous power to non-Class 1E 120 volt vital secondary digital control system and computer loads. Transfer from one input to the other is accomplished without interruption to the load. The inverter is protected by circuit breakers on the 480 volt a-c input side and the 125 volt d-c input side. Abnormal conditions in the dual input inverter cause alarms to occur in the control room.

The output of inverter No. 5 is connected to a distribution panel through an automatic static transfer switch. An alternate backup 480-120 volt transformer non-Class 1E power source is provided through the automatic static transfer switch. The feed to the transformer is from a 480 volt motor control center as indicated by Figures 8.3-4 and 8.3-4b.

All metering and monitoring is performed by a digital control system that includes a microprocessor. The operation of the microprocessor has no impact on the ability of inverter No. 5 to perform its function.

Inverter No. 6 is also powered from the non-Class 1E 125 volt d-c bus. A static switch is provided on the output of this inverter to switch the feed to the inverter distribution panel from the inverter output to a 120 volt ac supply upon detection of loss of inverter output.

8.3.2.1.2 Uninterruptible Class 1E Systems

Each uninterruptible Class 1E system contains a separate 125 volt d-c and 120 volt ac system.

The 125 volt d-c system is a 2 wire, ungrounded system centered around a full capacity 125 volt, lead calcium battery, 125 volt d-c main distribution panel and solid state battery chargers. Figures 8.3-2aa and 8.3-2ab show connection of the battery, battery charger and main distribution panel of each redundant Class 1E power system. No ties are provided between the redundant Class 1E 125 volt d-c systems. All non-Class 1E loads connected to the Class 1E d-c system are identified by Figure 8.3-1 (see Note 4, Figure 8.3-1). Connection of non-Class 1E loads to the Class 1E d-c system is discussed in the statement concerning Regulatory Guide 1.75 in Appendix 3A.

Eight (8) separate 125 volt d-c distribution panels including the 2 main distribution panels are provided. Each panel provides d-c instrumentation and control power as necessary for proper functioning of the plant.

The battery, battery charger and main distribution panel of each system are located in protected areas of the Intermediate Building, separate from the location of redundant channel equipment. The protected areas are separated by a fire resistant barrier. The inverters and other distribution panels are also located in protected areas.

Each ESF battery has a rated capacity of 2175 ampere hours (with an 8 hour discharge cycle to 1.75 volts per cell). This capacity is sufficient to power essential loads and normally connected non-essential loads for a 4 hour duty cycle following loss of all a-c power. The 4 hour duty cycle is based on coping requirements for Station Blackout (Reference 15) defined by NUMARC 87-00 (Reference 17) and endorsed by NRC Regulatory Guide 1.155 (Reference 16). The 4 hour duty cycle with loss of all a-c power envelopes the previous 2 hour duty cycle based on a LOCA in conjunction with the loss of all a-c. The 2 hour duty cycle represents standard industry practice for sizing batteries for generating stations and does not reflect V. C. Summer design basis requirements for demonstrating d-c system operability. Essential loads include the following:

1. Instrumentation inverters - with ESF and non-ESF loads.
2. Engineered safety features control.
3. Diesel generator control and field flashing.
4. Circuit breaker closing and tripping (ESF buses).
5. Controls and alarms, including Auxiliary Relay Racks, Isolator Cabinets, Main Control Boards, HVAC Boards and Control Room Annunciators.
6. Control Room emergency lighting.

During normal operation, the 125 volt d-c load is supplied from the battery chargers with the batteries floating on the system. Upon loss of station a-c power, the entire d-c load is supplied from the batteries until the a-c power to the chargers is restored by the emergency diesel generator or the preferred power source. The function of the battery is to provide sufficient stored energy to operate necessary d-c loads for as long as each load is required during the loss of a-c power. The

time duration for the loss of a-c power is the time required for the diesel generator to start and accept load. For the V. C. Summer Station, the diesel generator breaker will close and energize the battery charger within 10.25 seconds after a loss of a-c power. Failure of a battery charger or failure of a diesel generator to start would be a single failure for which there is a redundant train of electrical systems that will be used to achieve safe shutdown and mitigate design basis events. A failure of a battery charger would not prevent either start of the diesel generator or closure of the necessary breakers to re-establish a-c power to the auxiliary a-c system. In the event of a charger failure, a backup charger has been provided and can be connected well within the battery's 4 hour duty cycle. Thus, the minimum 4 hour battery capacity provides considerable margin for the battery to perform its intended function.

Separate evaluations were performed to demonstrate sufficient battery capacity and to demonstrate system operability based on sufficient voltage at d-c equipment/device terminals.

The evaluation to demonstrate sufficient Class 1E battery capacity was based on ampere loads associated with Class 1E and non-Class 1E equipment as shown on Figures 8.3-1, 8.3-2, 8.3-2aa, and 8.3-2ab.

The evaluation to demonstrate d-c equipment/device operability was based on ensuring that the available operating voltage (or current) for required equipment was equal to or greater than the minimum operating voltage recommended by the applicable vendor or by actual tests to demonstrate component operability with margin. Available operating voltages (or currents in the case of D.G. field flashing) were evaluated to ensure operability of Class 1E devices based on the required time of operation and the applicable system losses resulting from voltage drop. Operability of non-Class 1E loads which are supplied from the 1A and 1B batteries was not evaluated.

System operating voltages were determined based on the battery as the sole source during the first 10.25 seconds following LOOP with only 59 cells or 58 cells connected. System operating voltages after 10.25 seconds were determined based on the battery at float voltage following restoration of a-c power to the battery charger.

The evaluation conservatively determined voltage drop based on the d-c load currents established by the battery capacity evaluation, as modified to include design margins, and the equivalent circuit resistance, as modified to compensate for worst case conductor temperatures.

Although there is no accident analysis that requires d-c system operability with the battery as the sole source after 10.25 seconds, the design objective was to ensure the ESF 125 v d-c system is capable of supporting/operating normal and required emergency d-c loads in the event of a DBA, or required SBO loads in the event of a 4 hour station blackout. Required SBO loads are normal (non-accident) loads necessary to ensure the reactor core is cooled and containment integrity is maintained in the event all a-c power is lost for a 4 hour period.

8.3.2.1.3 Capacity

The ampere demand of each ESF battery was calculated for the loads listed in the preceding Items 1 through 6, as well as for other connected d-c loads, to establish the worst case 4 hour duty cycle. This calculation resulted in the following 4 hour load profile.

1. Battery 1A - 376.9 amperes for the first minute, 200.3 amperes for the next 238 minutes, and 246.3 amperes for the last minute.
2. Battery 1B - 392.4 amperes for the first minute, 215.8 amperes for the next 238 minutes, and 261.8 amperes for the last minute.

The capacity of each ESF battery was then checked to ensure that the batteries are capable of supplying required d-c loads for the duty cycle. In addition the battery capacity includes design margin, accounts for battery degradation with age, and considers the reduction of battery capacity due to temperature variations. The capacity evaluation was based on a final (end of discharge) battery terminal voltage of 108 V d-c (or greater), which provides sufficient margin to ensure device operability with a reduction of up to 2 cells (58 cells connected) on either battery.

The calculated ampere demand includes normally connected devices with no distinction as to whether devices are required to operate or are desirable loads. The inclusion of the latter precludes the need for any load shedding and no operator action is required to maintain power to essential safety related loads during the 4 hour duty cycle. However, any load shedding performed during the battery duty cycle adds to the existing capacity margin and results in a higher battery voltage at the end of the duty cycle.

The d-c system is designed so that the loads with common a-c and d-c power supplies, such as inverters, are powered by the batteries during blackout, but are automatically returned to the a-c system upon ac bus voltage restoration. As a result, the battery chargers are required to have a minimum capacity of 150 amperes to provide the necessary 12 hour recharge. This is well within the system’s 300 ampere battery charger rating.

8.3.2.1.4 Ventilation

The battery rooms and battery charger rooms are located in the Intermediate Building and are provided (as a group) with a once through ventilation system consisting of two (2) 100% capacity supply fans and two (2) 100% capacity exhaust fans as shown in Figure 9.4-16. The ventilation system is designed for continuous operation. Therefore, the chance of producing an explosive atmosphere due to evolution of hydrogen during the process of battery charging is minimized. The system is provided with high and low temperature alarm inputs to the HVAC control board annunciator system. The battery room ventilation system is discussed further in Section 9.4.6.

8.3.2.1.5 Equipment

8.3.2.1.5.1 Batteries and Battery Racks

All batteries are of the central station, lead calcium type and are designed for continuous float duty. Each cell is of the sealed type, assembled in a shock absorbing clear plastic container, with covers bonded in place to form a leakproof seal. The batteries are mounted on protected, corrosion resistant, steel racks for security and to facilitate maintenance. The Class 1E batteries and racks are designed to remain functional during a safe shutdown earthquake and remain in a satisfactory condition to perform their function in shutting down the reactor and maintaining the station in a safe condition.

8.3.2.1.5.2 Battery Chargers

Each solid state battery charger has an output for float and equalize modes with an input of 480 volt 3-phase, a-c power. Each charger is equipped with a d-c voltmeter, d-c ammeter, a-c failure relay, a ground detection annunciator alarm, low battery voltage alarm relay and fan failure alarm. A battery charger malfunction activates an alarm in the control room. Each battery charger is designed to prevent the 480 volt a-c system from becoming a load on the battery as a result of loss of 480 volt a-c input.

Tests have verified that battery charger stability is not load dependent.

There is no annunciator to alarm when the battery charger goes into a current limiting condition.

In addition to the charger output ammeter, a 0 center scale ammeter is connected to a shunt in the leads between the battery and the battery bus to indicate current flow to and from the battery. These 2 ammeters show the status of battery charging or discharging currents and d-c system loads at all times. Main breakers, as shown on Figures 8.3-1, 8.3-2, and 8.3-4 are equipped with auxiliary switches to operate indicator lights in the control room for an off normal position. Thus, the operator is provided with system status information. Following a loss of normal station power, the battery chargers are energized from the diesel generators.

Additional monitoring is provided by a special, narrow band, d-c voltage relay to monitor Class 1E battery voltage. The relay initiates an alarm in the control room if battery voltage falls slightly below normal float voltage.

Voltage monitoring in this manner provides a backup alarm if a charger fails since a fully charged battery suffers a rapid drop in voltage if its floating charge fails. Such a rapid voltage drop causes the voltage monitoring relay to initiate the associated alarm. Battery ground detection annunciation is provided on the main control board for both Class 1E and non-Class 1E Plant d-c systems.

The ratings for each battery charger continuous output are as follows:

1. Charger 1A - 300 amperes
2. Charger 1B - 300 amperes
3. Charger 1A-B - 300 amperes
4. Charger 1X - 400 amperes
5. Charger 1X-2X - 400 amperes

Each battery charger has capacity adequate to restore its associated battery to full charge while providing power to the largest combination of the various steady-state loads. The charging capacity is based upon restoring the battery to full charge from the design minimum charge within 12 hours after discharge regardless of the status of the station.

8.3.2.1.5.3 Main D-C Distribution Panels

Each battery distribution switchboard consists of a metal clad structure with 125 volt d-c, 2 wire, ungrounded main bus. Two (2) pole, manually operated, air circuit breakers protect each feed.

8.3.2.1.5.4 Class 1E Dual Input Inverters

The dual input inverter in each system provides continuous power to the 120 volt vital a-c buses. The output of the inverter is a regulated supply. Transfer from 1 input to the other is accomplished without interruption of the output. Each inverter is protected by circuit breakers on the 480 volt a-c input side, 120 volt vital a-c output side and 125 volt d-c input side. Each dual input inverter is provided with an a-c and a d-c ammeter. Abnormal conditions in the dual input inverter, including loss of a-c input, loss of d-c input, and loss of a-c output voltage cause alarms to occur in the control room.

The output of each inverter is connected to a distribution cabinet through an automatic static transfer switch and a normally closed circuit breaker. An alternate backup 480-120 volt transformer Class 1E power source is provided through the automatic static transfer switch. The feed to the transformers is from a 480 volt motor control center as indicated by Figures 8.3-1 and 8.3-2. The distribution cabinets have appropriately sized branch circuit breakers to feed reactor protection and other vital instrument channels. Most reactor protective schemes have 3 or 4 channels. Redundant instrument channels are fed from redundant vital buses.

Because of the preferred failure mode defined for the reactor protective instrumentation, failure of an instrument channel power source results in a reactor trip signal from the affected channel. Multiple power supplies are provided to prevent a single power supply failure from initiating a false reactor trip.

The vital bus rectifiers and inverters are assembled from high quality components, conservatively designed for long life and continuous operation.

By avoiding the use of electromechanical devices, routine maintenance downtime is greatly reduced. There are no vacuum tubes or moving parts in the completely static vital bus supply systems.

The ratings of each inverter are as follows:

1. Inverter No. 1 - 10 kVA.
2. Inverter No. 2 - 10 kVA.
3. Inverter No. 3 - 10 kVA.
4. Inverter No. 4 - 10 kVA.

8.3.2.1.5.5 Non-Class 1E Inverters

There are 2 non-Class 1E (balance of plant) inverters. Inverter No. 5 is a dual input inverter. The dual input inverter No. 5 provides continuous power to non-Class 1E 120 volt vital digital control systems and computer loads. Transfer from one input to the other is accomplished without interruption to the load. The output of inverter No. 5 is connected to a distribution panel through an automatic static transfer switch. An alternate backup 120 volt non-Class 1E power source is provided through the automatic static transfer switch. The AMSAC system, secondary plant digital control systems and the station computer constitutes the primary loads on this inverter. The secondary plant digital control system can also be powered by the ISFSI Electrical Building uninterruptible power supply.

Inverter No. 6 is a single input inverter supplied from the 125 volt d-c non-ESF system. Output from this inverter is paralleled with a supply from a 480-120 volt transformer which is connected, through a static transfer switch to the inverter main distribution panel. The transformer source serves as an alternate supply to the inverter main distribution panel. Upon loss of inverter output, automatic transfer of the inverter main distribution panel to the alternate supply is initiated. The primary load on inverter No. 6 is non-ESF instrumentation.

An alternate power source circuit breaker is provided in the distribution cabinet to permit manual transfer from the inverter or transformer power source to a backup power source as indicated by Figure 8.3-4.

Inverter ratings are as follows:

1. Inverter No. 5 - 10.0 kVA.
2. Inverter No. 6 - 10.0 kVA.

8.3.2.1.5.6 480-120 Transformer and Static Transfer Switch

An alternate source of power to each of the 120 volt vital a-c buses is provided by a 480-120 volt Class 1E, single phase transformer. The 480-120 volt transformer in each system is designed to supply the total 120 volt vital a-c bus load when the dual input inverter is out of service.

A static transfer switch is provided for inverter No. 6 to switch the 120 volt vital a-c bus loads from the single input inverter to the 480-120 volt transformer. The static transfer switch is a solid state device. Its operation is unaffected by load and power factor variations. Transfer of the 120 volt vital a-c bus loads from the single input inverter to the 480-120 volt transformer causes an alarm to occur in the control room. Transfer back to the inverter is performed manually at the discretion of the operator.

8.3.2.1.5.7 Nominal 120 Volt Vital A-C Bus System

The nominal 120 volt a-c vital bus system consists of 6 panels and 4 inverters which provide power to 4 independent channels of ESF instrumentations. Channels A and B consist of 2 panels and 1 inverter each while Channels D and E consist of 1 panel and 1 inverter each. Figures 8.3-1, 8.3-2, 8.3-2aa, and 8.3-2ab depict the system.

The vital bus system is a very reliable electrical system. It provides a stable supply to vital equipment and guarantees proper action when power is required, while eliminating spurious shutdowns.

The normal power source for each vital bus inverter is through the inverter static rectifier from a 480 volt ESF bus. Should the normal power source fail completely or be subject to transient voltage or frequency variations, the vital bus inverter power source becomes the battery charger or battery which is floating on standby service. This transition from static rectifier to battery power supply takes place without disturbing vital bus voltage or frequency. The station batteries are sized to carry this additional inverter load without chargers for no less than 4 hours. The chargers are sized to bring a fully discharged battery up to equalize charge voltage with the inverter load connected in 12 hours.

8.3.2.2 Analysis

8.3.2.2.1 Compliance

The Class 1E uninterruptible systems satisfy the criteria of Regulatory Guides 1.6 and 1.32 (see Appendix 3A), and General Design Criteria 17 and 18. The uninterruptible systems are designed so no action, automatic or manual, needs to be taken to make d-c or vital a-c power available to the equipment required immediately following LOCA or after a loss of a-c power. No operator action is required to maintain d-c or vital a-c power availability, based on single failure criteria, for safe shutdown or accident mitigation following a loss of a-c power.

Class 1E system components are identified and seismically qualified as described in Section 3.10. The battery was connected to a resistive load of approximately 20 amperes during seismic testing.

Class 1E equipment and the hostile environment to which it is subjected are discussed in Section 3.11.

Each uninterruptible system includes power sources and a distribution system arranged to provide power to associated system loads. No ties exist between Class 1E systems. Figures 8.3-1, 8.3-2,

8.3-2aa, and 8.3-2ab illustrate the independence of the Class 1E uninterruptible systems. Equipment, cables and other components are designed, identified and located in accordance with the criteria given herein. Sections 8.3.1.4 and 8.3.1.5 discuss general design criteria applicable to the uninterruptible systems as well as to the a-c systems.

8.3.2.2.2 Maintenance and Testing

The uninterruptible systems are subjected to periodic maintenance tests to determine the condition of each individual component. Batteries are checked for electrolyte level, specific gravity, cell voltage and visual signs of deterioration. A battery performance discharge test is performed according to IEEE-450 (Reference 7). Battery chargers, and inverters are checked by visual inspection weekly and performance tests are conducted periodically.

Maintenance and testing procedures for batteries are in accordance with IEEE-450 (Reference 7). Testing and inspection are performed according to the following:

1. General inspections and recording of data are performed in accordance with IEEE-450 (Reference 7).
2. Quarterly tests, inspections, and recording of data are performed in accordance with IEEE-450 (Reference 7).
3. Yearly inspections are performed in accordance with IEEE-450 (Reference 7).
4. Battery service tests are performed in accordance with IEEE-450 (Reference 7). The time interval between tests is based on a nominal 18 month refueling outage schedule. Service tests are not performed during outages that require performance of a capacity (performance discharge) test. (See Regulatory Guide 1.32 discussion in Appendix 3A.)
5. Battery capacity tests are performed in accordance with IEEE-450 (Reference 7) and IEEE-308 (Reference 8).

8.3.2.3 Physical Identification of Safety-Related Equipment

The physical identification of safety-related equipment is discussed in Section 8.3.1.5.

8.3.3 Fire Protection for Cable Systems

The 15,000 volt rated power cable, the 8,000 volt rated power cable, 600 volt rated power cable for 480 volt and 120 volt a-c systems and 125 volt d-c systems, 600 volt rated control cable for 120 volt a-c and 125 volt d-c controls and 300 volt instrument cable are constructed with an overall fire retardant outer jacket.

Cable for external circuits is type tested in accordance with Section 2.5 (Flame Tests) of IEEE-383 (Reference 9) and the cables are certified to be of fire retardant construction.

8.3.3.1 Cable Derating, Cable Tray Fill, and Cable Construction

Cables are derated to compensate for ambient temperatures and for the presence of adjacent power cables. Power cables are sized and derated on the basis of IPCEA P-46-426 (Reference 4), supplemented by IPCEA-NEMA P54-440 (Reference 5).

Motor feeders, power panel feeds and small lighting and receptacle panel transformer feeds are sized for 125% of full load current. Large power transformer feeders are sized for 140% of full load current at maximum rating. Motor control center feeders are sized for 140% of the calculated normal diversified load current. Feeders to resistive loads are sized on the basis of 110% of rated current at rated voltage.

In selecting IPCEA ampacity tables, a load factor of 100% is assumed.

Ampacities of 7200 volt power cables are in accordance with IPCEA P-46-426 (Reference 4) in air ratings, derated by factors of 0.70 in 40°C areas and 0.63 in 50°C areas.

Ampacities of 480 volt cables or large d-c cables in single layer power trays are in accordance with IPCEA P-46-426 (Reference 4) in air ratings and are derated by factors of 0.70 in 40°C areas and 0.63 in 50°C areas.

Ampacities of 480 volt cables or d-c cables in a random lay power tray are in accordance with IPCEA-NEMA P-54-440 (Reference 5). Derating factors for 3 inch depth are used.

Ampacities of small 480 volt cables or small 125 volt d-c cables (#10 AWG and smaller), when run in control trays, are in accordance with IPCEA P-46-426 (Reference 4) in air ratings derated by a factor of 0.50.

Ampacities for 7.2 kV and 480 V 3 conductor cables in conduit wrapped in Kaowool at 40°C ambient temperature are calculated to ensure a maximum copper surface temperature of 90°C. Basis for these calculations are data obtained from IPCEA P-46-426. The application ampacities of the cables are determined by applying a 1.25 derating factor to the design ampacities. The cable sizes are then selected so that the cable application ampacity is equal to or greater than the design current value determined from the cable sizing criteria.

No ampacity derating factors are applied to control and instrument cables.

Ampacities are determined on the basis of 90°C tables at 40°C ambient in all interior areas except containment. Containment or ESF motors in areas requiring forced ventilation of the motor are determined on the basis of 50°C ambient.

Pressurizer heater cables are sized by special ratings due to the operating environment.

The Reactor Building cooling unit fan motor power cables and the post accident hydrogen recombiner unit power cables (Reference 10) require special consideration since these motors must operate in the post accident containment environment. These cables are sized to carry the

required current during the post accident temperature and pressure transient without exceeding the recommended emergency operating temperature rating for the cable and to continue to operate for a minimum of 6 months after the accident.

A preventive maintenance program to test the insulation values of circuits and equipment is followed.

Ladder type tray systems are used for power and control trays. Instrument trays are solid bottom trays with top cover plates.

The 5 basic tray systems are as follows:

1. The 7200 volt power trays.
2. The 480 volt and below, single layer power trays.
3. The 480 volt and below, random lay power trays.
4. Control trays.
5. Instrument trays.

In vertical stacking the 7200 volt power trays are on top, 480 volt power trays next lower, control trays next lower, and instrument trays on the bottom.

8.3.3.1.1 7200 Volt Power Trays

No other type cable is mixed in the same tray with 7200 volt power cable. These trays are 4 inches deep (inside dimension). There is 1 layer of cable with no spacing between cables.

8.3.3.1.2 480 Volt and Below, Single Layer Power Trays

The 480 volt and below, single layer power tray system is exclusively for 480 volt, 3-conductor power cables or d-c power cables. This tray system is 4 inches deep (inside dimensions) and contains only large (MCM sizes) and 4/0 cables. There is 1 layer of cables with no spacing between cables.

8.3.3.1.3 480 Volt and Below, Random Lay Power Trays

The 480 volt and below, random lay power cable tray is for 480 volt power cables 4/0 and smaller. The tray is 6 inches deep (inside dimensions).

$$\text{Percent fill} = \frac{\left(d_1^2+d_2^2+\ldots.+d_n^2\right) x\, 100}{\text{Tray Depth x Tray Width}}$$

where: $d_1, d_2, \ldots . d_n$ = Diameters of all cables in the tray presently planned plus all known future cables.

Small 480 volt power cables (#10 AWG and smaller) may be run either in the random lay power cable tray or the control tray. Circumstances may dictate running an MCM size power cable in a random lay power tray. The cable is then derated with the derating factor appropriate to the random lay trays.

8.3.3.1.4 Control Trays

The control trays contain control cables, small 480 volt power cables (#10 AWG and smaller, except for selected motor operated valves which use larger sized cables) and small d-c power cables (#10 AWG and smaller). All of these cables carry either intermittent current or continuous current of 5 Amps or less. Single phase, 120 volt a-c circuits (#10 AWG and smaller) carrying 5 amps or less may also be run in the control trays. The amount of heat generated from cables which carry intermittent current is negligible based on the large majority of time the load is not operating.

The control trays are 6 inches deep (inside dimensions). The design limit for control tray fill is based on verifying that the weight of new and existing cable is within the tray and tray support weight capability.

8.3.3.1.5 Instrument Trays

Instrument trays contain low level analog signals cables. These trays are 6 inches deep (inside dimensions). The design limit for instrument tray fill is based on verifying that the weight of new and existing cable is within the tray and tray support weight capability. In addition to all low level analog signal cables, the instrument trays are used for digital contact (breaker contact) cables where the source of power is the reactor protection or computer packages, otherwise all digital circuits are in the control trays.

8.3.3.1.6 Cable Tray Fill Criteria

The 50% cable tray fill criteria is the design objective that applies only to random lay power trays. Random lay power trays contain 480 volt power cables smaller than MCM sizes. Power cables, No. 10 and smaller, may be run either in random lay power tray or in control tray.

The 30% fill criteria recommendation in IEEE Propose Guide P-422 (Reference 3) is based upon the summation of cross sectional areas of cables. The 50% fill noted in Section 8.3.1.4.3 is based upon the summation of the cable diameter squared areas. Fill of 50% on this basis is equivalent to 39% fill on the IEEE Propose Guide P-422 (Reference 3) basis (i.e., 3.1416/4.0 times 50%). Through experience, it has been found that approximately 40% fill on the basis of cross sectional area or 50% fill on the basis of diameter squared area is satisfactory with respect to physical tray loading and uses the tray more efficiently.

Power cables are rated on the basis of this 3 inch physical depth, using the derating factors of IPCEA-NEMA P-54-440 (Reference 5).

These derating factors are in agreement with the 50% or 3 inch depth physical loading. Control and instrument cables require no derating.

Where random lay power tray fill exceeds 50%, worst case conditions have been analyzed to assure the capability of the tray hangers to support the additional weight and, that sufficient margin exists in the cable sizing to account for the heating effects (Reference IEEE Transaction Paper 70TP557PWR “Ampacities for Cables in Randomly Filled Trays”, also, see FSAR Section 8A.1.2). For each random lay power tray, a calculation was performed to address the additional heat loading from the new power cable and its effect on the ampacity (heat loading) of other power cables in that tray. The existing and new power cables were derated if the total heat loading of the cables in the tray was not within the allowable heat loading based on the percent fill. In addition, this calculation determined the weight of the new and existing cables to ensure that their combined weight was less than the maximum weight that the tray support can carry. For trays filled to the maximum weight allowed by the tray supports, the maximum allowable cable sidewall pressures will not be exceeded (Reference FSAR Section 8A.1.3). In the event overfill occurs at tray intersections, protection will be provided to preclude cable damage.

The cable tray fill criteria for control and instrument trays is controlled by the cable management system computer program. This program contains an alarm limit for the maximum weight allowed for each tray size used. Therefore, manual calculations to monitor cable weight are not required since this calculation is done by the cable management system and an alarm is provided if the tray or tray support weight capability is exceeded. Heat loading is not a concern for control and instrumentation cables due to their small currents and/or intermittent operation.

For expanded cable and tray design considerations, see Appendix 8A.

8.3.3.1.7 Cable Construction

Feeder and motor cables in 7200 volt service are insulated cables rated at a minimum of 8000 volts. Single conductor cables or each conductor of multi-conductor cables in 7200 volt service are shielded.

Power cables for 480 volt service are insulated cable rated at a minimum of 600 volts. Single conductor cables and multi-conductor cables are provided with an overall flame retardant jacket.

Control cables are of single or multi-conductor construction with a 600 volt (minimum) insulation, total coverage electrostatic shield and overall flame retardant jacket.

Low voltage instrument cables are insulated cables rated at 300 volts, minimum. Where required, these cables are provided with a total coverage electrostatic shield and with an overall flame retardant jacket.

8.3.3.2 Fire Detection and Protection Devices

Fire detection and protection systems, either automatically or manually initiated, are provided in those areas required to preserve the integrity of circuits for redundant safety-related systems. A

fixed, low pressure carbon dioxide fire extinguishing system is installed in the relay room and computer room at elevation 436’ of the Control Building. A preaction sprinkler system is installed in the following areas of the Control Building:

1. Cable spreading room - elevation 425’.
2. Cable spreading room - elevation 448’.
3. Cable chase areas.

Smoke detection systems are installed in the switchgear rooms and penetration access areas. Section 9.5.1 provides greater detail concerning fire detection and protection.

The fire hazard to cables is reduced by cable construction as described in Section 8.3.3.1.7.

8.3.3.3 Fire Barriers and Separation Between Redundant Cable Trays

Criteria used for the separation between different Class 1E system trays and between Class 1E and non-Class 1E trays are given in Section 8.3.1.4. Where the required separation cannot be maintained, fire barriers are installed in accordance with IEEE P-422 (Reference 3), Section 8.3.2. The fire barriers are qualified in accordance with criteria given in Section 9.5.1.

In cases of multiple separation violations between non-safety related trays and redundant safety related trays in the same fire area, tray covers or circuit breaker surveillance has been provided as a resolution. Refer to FSAR Section 8.3.1.4.1, item 4 for details.

8.3.3.4 Fire Stops

Openings in walls, floors, and ceilings, which are provided for the routing of raceways, are protected by fire stops. Fire stops are designed with a fire rating equivalent to that required for the wall, floor or ceiling with which it is associated. The materials used in fabricating fire stops are rated in accordance with ASTM E 119. In addition to preventing the spread of fire, fire stops are designed to be reasonably leaktight, thereby limiting the propagation of smoke and gases from one area to another.

8.3.4 Safety Related Cable

No natural polyethylene materials are used in safety related inter-connecting circuits between equipment in the Virgil C. Summer Nuclear Station. Cables which have cross linked polyethylene are used for various plant applications.

8.3.5 References

1. Institute of Electrical and Electronic Engineers, *Installation Inspection, and Testing Requirements for Instrumentation and Electric Equipment during the Construction of Nuclear Power Generating Stations*, IEEE-336-1971.
2. Deleted (RN 99-037)
3. Institute of Electrical and Electronics Engineers, *Design and Installation of Cable Systems in Power Generation Stations,* IEEE Proposed Guide P-422, prepared by the Working Group on Wire and Cable Systems Station Design Subcommittee, Power Generation Committee.
4. Insulated Power Cable Engineers Association, *Power Cable Ampacities,* IPCEA P-46-426-1962.
5. Insulated Power Cable Engineers Association - National Electrical Manufacturers Association, *Ampacities of Cables in Open-Top Cable Trays*, IPCEA-NEMA P-54-440.
6. Institute of Electrical and Electronics Engineers, *Guide for Class 1E Control Switch Boards for Nuclear Power Generating Stations*, IEEE-420-1973.
7. Institute of Electrical and Electronics Engineers, *Recommended Practice for Maintenance, Testing, and Replacement of Large Stationary Type Power Plant and Substation Lead Storage Batteries*, IEEE-450-1987.
8. Institute of Electrical and Electronics Engineers, *Criteria for Class 1E Electric Systems for Nuclear Power Generating Systems*, IEEE-308-1971.
9. Institute of Electrical and Electronics Engineers, *Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations*, IEEE-383-1974.
10. *Electric Hydrogen Recombiner for PWR Containments,* WCAP-7709-L, Supplement 7, (Proprietary) and WCAP-7820, Supplement 7 (non-Proprietary), August, 1977.
11. Institute of Electrical and Electronics Engineers, *Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations, General Guide*, IEEE-323-1971.
12. Institute of Electrical and Electronics Engineers, *Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations*,
13. Fire Protection (FP) DBD
14. Institute of Electrical and Electronics Engineers, *Criteria for Separation of Class 1E Equipment and Circuits*, IEEE-384, 1974.
15. 10 CFR Part 50, Section 50.63, *Loss of all Alternating Current Power*.
16. U. S. Nuclear Regulatory Commission Regulatory Guide 1.155, *Station Blackout*.
17. NUMARC 87-00, Nuclear Management and Resources Council, Inc., *Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactor.*
18. Calculation No. DC08500-022, *Determination of Maximum Sidewall Pressure Imposed on Cable in Cable Tray as a Result of Cable Weight*.

Table 8.3-1
Major Electrical Equipment

Equipment	Tag Numbers	Description and Ratings
Unit Generator	XGN1-EG	1,137,680 kVA, 0.905 pf, 22 kV, 1800 rpm, 3ϕ, 60 Hz
Standby Diesel Generator	XEG0001A, B-E (Engine) XEG0001A, B-G (Generator)	4250 kW, 7.2 kV, 0.8 pf, 3ϕ, 60 Hz
Main Transformer	XTF1-EG	940/1052.8 MVA, 55C/65C, FOA, 242-22 kV, 3ϕ, 60 Hz
Unit Auxiliary Transformer	XTF2-ES	48/64 MVA, 55C, 22-7.2/7.2/7.2 kV
Emergency Auxiliary Transformer	XTF31-ES XTF32-ES	24/32/40/44.8 MVA, 55/55/55/65 with nominal 8.0% impedance from HV to LV, based upon 24 MVA base, 230-7.2/7.2 kV
Engineered Safety Transformer	XTF4-ES XTF5-ES	10/12.5/14 MVA, 115/7.2 kV
7.2 kV Line Voltage Regulator	XTF6-ES	1500 kVA, 55° C rise, Class OA, 7.2 kV ± 10% in 32 - 5/8% steps, 1200 Amps, 1.12% based on 15 MVA, 3ϕ, 60 Hz
Generator Circuit Breaker	XCB0010-EG	1ϕ, 60 Hz, 22 kV (nominal) 36 kV (max), interrupting rating of 210 kA (Sym System Source) and 150 kA (Sym Gen Source).

Table 8.3-2
Symmetrical Interrupting Capacity For
480 Volt Unit Substation Cubicles

	Symmetrical Interrupting Capacity	
Frame Size (amps)	Instantaneous Trip (amps)	Delayed Trip (amps)
600	30,000	22,000
1600	50,000	50,000
2000	65,000	55,000
3000	65,000	65,000

FSAR TABLE REFERENCE

Table 8.3-3
Part A1
FSAR Table Reference
Design Calculation DCO8360-006

FSAR TABLE REFERENCE

Table 8.3-3
Part A2
FSAR Table Reference
Design Calculation DCO8360-006

FSAR TABLE REFERENCE

Table 8.3-3
Part B1
FSAR Table Reference
Design Calculation DCO8360-006

FSAR TABLE REFERENCE

Table 8.3-3
Part B2
FSAR Table Reference
Design Calculation DCO8360-006

Table 8.3-3a
Diesel Generator Protective Devices

Device	Protective Relay Function if Diesel Start is Initiated By: ESF OR Undervoltage	Protective Relay Function if Diesel Start is Initiated By: Test Start Switch
67 DG Motoring - reverse power flow	Alarm	Trip (2)
51 DG Ground Overcurrent	Alarm	Trip (2)
51VDG Time overcurrent - voltage controlled	Alarm	Trip (2)
46 DG Negative phase sequence	Alarm	Trip (2)
64 FDG Field ground relay	Alarm	Alarm
87 DG Generator differential	Trip (3)	Trip (3)
40 DG Field failure relay	Alarm	Trip (2)
Lube oil pressure low (4 switches)	Trip (1)(3)	Trip (3)
Engine overspeed	Trip (3)	Trip (3)
Crankcase pressure high	Alarm	Trip (3)
Lube Oil temperature high	Alarm	Trip (3)
Jacket coolant temperature high	Alarm	Trip (3)
59 Overvoltage	Alarm	Alarm
Fuel Oil Pressure Low	Alarm	Alarm
Start failure	Alarm	Alarm
Barring Device Engaged	Prevent Start	Prevent start

(1) Trip occurs on actuation of 2 of 4 switches if at least 1 of the 2 actuated switches has setpoint of 60 psi. Setpoints are at 70, 65, 60, and 60 psi.
(2) Trips Diesel Generator Breaker only.
(3) Trips Diesel Generator Breaker and Diesel Generator Engine.

Table 8.3-3b
Engineered Safety Features Bus Indicators

Indicator Type	Function	Location
GE Type AB-40, Frequency Meter	Diesel generator A, frequency	Main Control Board (MCB) panel XCP6117
GE Type AB-40, A-C Wattmeter	Diesel generator A, watts	MCB panel XCP6117
GE Type AB-40, A-C Voltmeter	Diesel generator A, volts	MCB panel XCP6117
GE Type AB-40, A-C Wattmeter	ESF transformer, watts	MCB panel XCP6117
GE Type AB-40, A-C Voltmeter	ESF bus 1DA, volts	MCB panel XCP6117
GE Type AB-40, A-C Varmeter	ESF transformer, vars	MCB panel XCP6117
GE Type 180, A-C Ammeter	Diesel generator A, amperes	MCB panel XCP6117
GE Type 180, A-C Ammeter	ESF transformer, amperes	MCB panel XCP6117
GE Type 180, A-C Ammeter	7.2 kV bus 1DA feeder, amperes	MCB panel XCP6117
GE Type AB-40, Frequency Meter	Diesel generator B, frequency	MCB panel XCP6117
GE Type AB-40, A-C Wattmeter	Diesel generator B, watts	MCB panel XCP6117
GE Type AB-40, A-C Voltmeter	Diesel generator B, volts	MCB panel XCP6117
GE Type AB-40, A-C Voltmeter	7.2 kV bus 1DB, volts	MCB panel XCP6117
GE Type 180, A-C Ammeter	Diesel generator B, amperes	MCB panel XCP6117
GE Type 180, A-C Ammeter	7.2 kV bus 1DB feeder, amperes	MCB panel XCP6117
GE Type AB-40, A-C Ammeter	7.2 kV bus tie 1DX2DX, amperes	MCB panel XCP6117
Red Lion PAX, A-C Voltmeter	115 kV incoming, volts	MCB panel XCP6117

Table 8.3-4
Identification of Safety-Related Cable Trays and Cables

Color	Reactor Protection Channel	Process Control Channel	Engineered Safety Features Actuation & Equipment Channel
Red	I	1	A, J
Orange	II	2	D, L
Blue	III	3	B, K
Yellow	IV	4	E, M
Green	-	-	C
Tan, plus Channel color	Associated	-	X, plus channel
Tan or no color	Non-Safety-Related	-	X

Table 8.3-5
Sequence of Operation Following a Loss
or Degraded Voltage Condition

Items of Operation	Loss of Voltage (Time in Seconds)	Degraded Voltage (Time in Seconds)
Loss or Degraded Voltage Condition	0	0
Diesel Generator Start	0.25	3
Permissive to EFW Pump Start	0.25	3
Initiate ESFLS Operation	2.25	7
7.2Kv Bus Circuit Breaker Trip	2.25	7
Permissive to Close Diesel Generator Circuit Breaker	5.25	10
Diesel Generator Ready to Load (Initiate Block Loading)	10.25	13

FSAR FIGURE REFERENCE

Figure 8.3-0
FSAR FIGURE REFERENCE
DRAWING 1MS-33-007

FSAR FIGURE REFERENCE

Figure 8.3-0a
FSAR FIGURE REFERENCE
DRAWING 1MS-33-008

FSAR FIGURE REFERENCE

Figure 8.3-0b
FSAR FIGURE REFERENCE
DRAWING 1MS-33-009

FSAR FIGURE REFERENCE

Figure 8.3-0b.1
FSAR FIGURE REFERENCE
DRAWING 1MS-33-191

FSAR FIGURE REFERENCE

Figure 8.3-0c
FSAR FIGURE REFERENCE
DRAWING 1MS-33-028

FSAR FIGURE REFERENCE

Figure 8.3-0d
FSAR FIGURE REFERENCE
DRAWING 1MS-33-029

FSAR FIGURE REFERENCE

Figure 8.3-0e
FSAR FIGURE REFERENCE
DRAWING 1MS-33-030

FSAR FIGURE REFERENCE

Figure 8.3-0f
FSAR FIGURE REFERENCE
DRAWING 1MS-33-033

FSAR FIGURE REFERENCE

Figure 8.3-0g
FSAR FIGURE REFERENCE
DRAWING 1MS-33-034

FSAR FIGURE REFERENCE

Figure 8.3-0h
FSAR FIGURE REFERENCE
DRAWING C-203-005

FSAR FIGURE REFERENCE

Figure 8.3-0I
FSAR FIGURE REFERENCE
DRAWING C-203-006

FSAR FIGURE REFERENCE

Figure 8.3-0j
FSAR FIGURE REFERENCE
DRAWING C-203-007

FSAR FIGURE REFERENCE

Figure 8.3-0k
FSAR FIGURE REFERENCE
DRAWING C-203-008

FSAR FIGURE REFERENCE

Figure 8.3-0l
FSAR FIGURE REFERENCE
DRAWING C-203-009

Figure 8.3-0m

MAIN CONTROL BOARD ANNUNCIATOR STATION
B-804-636 SH.1 & 637 SH.1 REV. 9

	1	2	3	4	5	6
1	DG LOW LUBE OIL PRESSURE	DG OVERSPEED TRIP	DG FUEL OIL STORAGE TANK LOW/LOW LEVEL	DG FUEL OIL DAY TANK LOW/LOW LEVEL	NOTE 5	DG ENGINE FAILED START
2	DG NOT READY FOR AUTO START (NOTE 1)	DG AUX NOT IN AUTO POSITION	DG FUEL OIL STORAGE TANK HI/LOW LEVEL	DG FUEL OIL DAY TANK LOW LEVEL	NOTE 5	DG ENGINE RUNNING TROUBLE (NOTE 2)
3	DG STARTING AIR LOW PRESSURE	DG MANUAL VLVS NOT ALIGNED PROPERLY	DG FUEL OIL LOW PRESSURE	DG LOSS OF DC POWER	NOTE 5	DG ENGINE TEMPERATURE TROUBLE (NOTE 3)
4	SPARE	DG DIFF LOCKOUT ENERGIZED	DG GENERATOR TROUBLE (NOTE 4)	NOTE 5	NOTE 5	NOTE 5
5	NOTE 5	DG ENGINE TROUBLE SHUTDOWN	DG SELECT SWITCH IN MAINTENANCE	NOTE 5	SPARE	NOTE 5
6	NOTE 5	DG BARRING DEVICE ENGAGED	DG ANNUNCIATOR GROUND/POWER FAILURE	NOTE 5	NOTE 5	NOTE 5

(SHOWN TYPICAL FOR BOTH ANNUNCIATOR STATIONS XCP0636 & XCP0637.)

NOTE 1 - INCLUDES:

A) STARTING AIR LOW PRESSURE; B) DIFFERENTIAL LOCKOUT ENERGIZED; C) LOW LUBE OIL PRESSURE; D) BARRING DEVICE ENGAGED; E) DIESEL GENERATOR AUXILIARIES NOT IN AUTO POSITION; F) MANUAL VALVES NOT ALIGNED PROPERLY; G) SELECTOR SWITCH 43 IN MAINTENANCE; H) LOSS OF DC POWER; I) ENGINE TROUBLE SHUTDOWN; J) START FAILURE RELAY; K) EXCITER NOT RESET.

NOTE 2 INCLUDES:

A) LOW COOLANT PRESSURE; B) FUEL OIL PUMP RUNNING; C) WATER IN AIR TANKS; D) HIGH AFTER COOLING TEMPERATURE; E) CRANKCASE PRESSURE HIGH; F) ROCKER ARM LUBE OIL LEVEL HIGH; G) ROCKER ARM LUBE OIL PRESSURE LOW; H) LUBE OIL LEVEL LOW; I) COOLANT SYSTEM LEVEL LOW; J) FUEL OIL DAY TANK LEVEL HIGH; K) AIR INTAKE DIFFERENTIAL PRESSURE HIGH.

NOTE 3 INCLUDES:

A) LUBE OIL TEMPERATURE LOW; B) COOLING SYSTEM TEMPERATURE LOW; C) LUBE OIL TEMPERATURE HIGH; D) COOLING SYSTEM TEMPERATURE HIGH

NOTE 4 INCLUDES:

A) OVERVOLTAGE; B) OVERCURRENT 51VDG; C) REVERSE POWER 67DG; D) GEN. STATOR HIGH TEMPERATURE; E) NEG. PHASE SEQUENCE 46DG; F) FIELD GROUND 64DG; G) FIELD FAILURE 40DG; H) SYSTEM GROUND 51DG.

NOTE 5 - ALARMS ASSOCIATED WITH OTHER SYSTEMS

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

MAIN CONTROL BOARD
ANNUNCIATOR STATION
B-804-636 SH.1 & 637 SH. 1
REV. 9
Figure 8.3-0m

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Figure 8.3-0n

DIESEL GENERATOR LOCAL ANNUNCIATOR STATIONS
DWG. NO. 1MS-32-120 REV. 0

	1	2	3	4	5	6	7	8
1	LOW LUBE OIL PRESSURE	LOW COOLANT PRESSURE	LOW FUEL OIL PRESSURE	LOW ROCKER ARM LUBE OIL PRESSURE	LOW START-AIR PRESSURE	START FAILURE	ROCKER ARM LUBE PUMP OVERRUN OR CONTACTOR FAILURE	DIFFERENTIAL GENERATOR LOCKOUT
2	HIGH LUBE OIL TEMPERATURE	HIGH COOLANT TEMPERATURE	DC FUEL OIL PUMP RUNNING	HIGH ROCKER ARM LUBE OIL LEVEL	WATER IN AIR TANKS	OVERSPEED TRIP	OVERCURRENT 51 VDG	SYSTEM GROUND 51 DG
3	LOW LUBE OIL TEMPERATURE	LOW COOLANT TEMPERATURE	HIGH FUEL OIL LEVEL	HIGH CRANKCASE PRESSURE	HIGH AFTERCOOLER TEMPERATURE	ENGINE TROUBLE SHUTDOWN	REVERSE POWER 67 DG	NEGATIVE PHASE SEQUENCE 46 DG
4	LOW LUBE OIL LEVEL	LOW COOLANT LEVEL	LOW FUEL OIL LEVEL	HIGH AIR INTAKE FILTER DIFF. PRESSURE	OVERVOLTAGE	EMERGENCY SHUTDOWN	GENERATOR STATOR HIGH TEMPERATURE	FIELD GROUND 64 DG
5	LOSS OF DC POWER	BARRING DEVICE ENGAGED	LOW-LOW FUEL OIL LEVEL	SELECTOR SWITCH IN MAINTENANCE	VALVE IMPROPER POSITION	LOCAL CONTROL	AUX. SWITCH NOT IN AUTO	FIELD FAILURE 40 DG

(SHOWN TYPICAL FOR BOTH ANNUNCIATOR STATIONS XCX5201 & XCX5202.)

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

DIESEL GENERATOR LOCAL
ANNUNCIATOR STATIONS
DWG. NO. 1MS-32-120
REV. 0
Figure 8.3-0n

Amendment 98-01
April 1998

m:mf3026.jpf (4325) JH14325(6)pf14325. Thu Sep 18 14:15:16 EDT 1997

FSAR FIGURE REFERENCE

Figure 8.3-0o
FSAR FIGURE REFERENCE
DRAWING C-203-010

FSAR FIGURE REFERENCE

Figure 8.3-1
FSAR FIGURE REFERENCE
DRAWING E-206-062

FSAR FIGURE REFERENCE

Figure 8.3-2
FSAR FIGURE REFERENCE
DRAWING E-206-062

FSAR FIGURE REFERENCE

Figure 8.3-2a, Sheet 1
FSAR FIGURE REFERENCE
DRAWING E-216-011

FSAR FIGURE REFERENCE

Figure 8.3-2aa
FSAR FIGURE REFERENCE
DRAWING E-206-062

FSAR FIGURE REFERENCE

Figure 8.3-2ab
FSAR FIGURE REFERENCE
DRAWING E-206-062

FSAR FIGURE REFERENCE

Figure 8.3-2b
FSAR FIGURE REFERENCE
DRAWING E-216-012

FSAR FIGURE REFERENCE

Figure 8.3-2c
FSAR FIGURE REFERENCE
DRAWING E-216-013

FSAR FIGURE REFERENCE

Figure 8.3-2d
FSAR FIGURE REFERENCE
DRAWING E-216-014

FSAR FIGURE REFERENCE

Figure 8.3-2e
FSAR FIGURE REFERENCE
DRAWING E-434-006

FSAR FIGURE REFERENCE

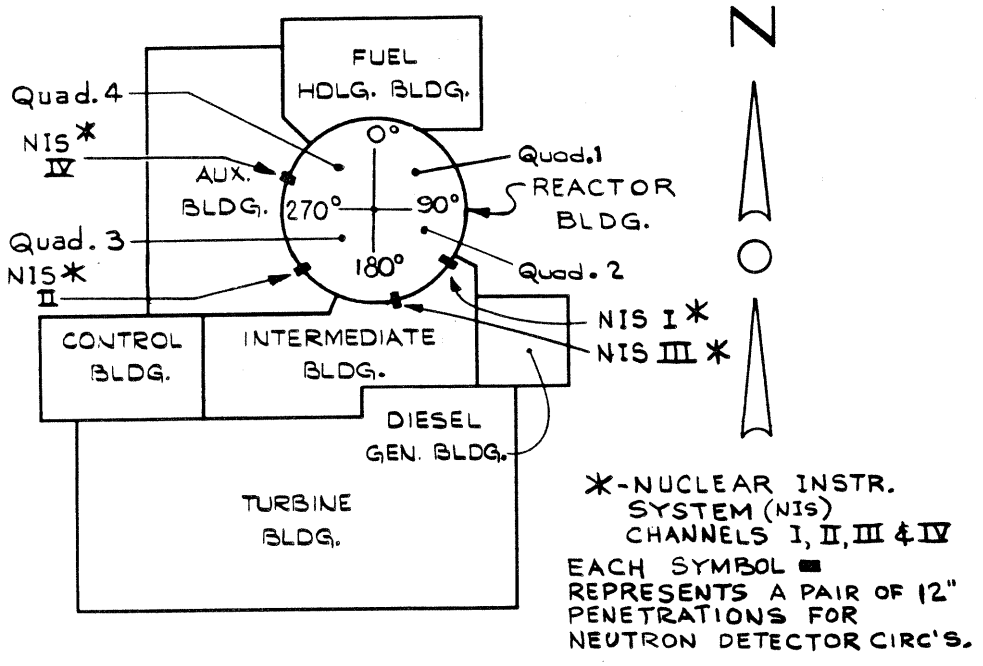
Figure 8.3-2f
FSAR FIGURE REFERENCE
DRAWING E-434-007

FSAR FIGURE REFERENCE

Figure 8.3-2g
FSAR FIGURE REFERENCE
DRAWING E-441-001

Figure 8.3-3

CONTAINMENT PENETRATION SEPARATION



SEPARATION CRITERIA (DISTANCES ARE CENTER LINE TO CENTER LINE)

ABOVE MEZZANINE ELEVATION 436'-0".

A 4'-0" HORIZONTAL AND VERTICAL SPACING MAY BE USED BETWEEN ANY 2 ADJACENT PENETRATIONS IF THE COMBINED RADII OF THE PENETRATIONS DO NOT EXCEED 18".

IF A MINIMUM OF 18" CANNOT BE USED THEN THE SPACINGS MUST GO TO AT LEAST 8'-0".

BELOW MEZZANINE ELEVATION 436'-0".

VERTICAL SPACINGS - SAME AS ABOVE.

HORIZONTAL SPACINGS - SAME AS ABOVE - EXCEPT THAT THE COMBINED RADII OF THE PENETRATIONS MUST NOT EXCEED 10".

IF A MINIMUM OF 10" CANNOT BE USED THEN THE SPACINGS MUST GO TO 8'-0".

AMENDMENT 0
AUGUST 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Containment Penetration Separation Figure 8.3-3

FSAR FIGURE REFERENCE

Figure 8.3-4, Sheet 1
FSAR FIGURE REFERENCE
DRAWING E-206-061

FSAR FIGURE REFERENCE

Figure 8.3-4a, Sheet 2
FSAR FIGURE REFERENCE
DRAWING E-206-061

FSAR FIGURE REFERENCE

Figure 8.3-4b, Sheet 3
FSAR FIGURE REFERENCE
DRAWING E-206-061

FSAR FIGURE REFERENCE

Figure 8.3-5
FSAR FIGURE REFERENCE
DRAWING E-229-025

FSAR FIGURE REFERENCE

Figure 8.3-5a
FSAR FIGURE REFERENCE
DRAWING E-229-152

FSAR FIGURE REFERENCE

Figure 8.3-6
FSAR FIGURE REFERENCE
DRAWING 1MS-37-043

FSAR FIGURE REFERENCE

Figure 8.3-7
FSAR FIGURE REFERENCE
DRAWING 1MS-37-041

FSAR FIGURE REFERENCE

Figure 8.3-8
FSAR FIGURE REFERENCE
DRAWING E-203-201

8.4 STATION BLACKOUT

V. C. Summer Nuclear Station Unit No. 1 conforms to 10CFR50.63 entitled “Loss of All Alternating Current Power” (Station Blackout). V. C. Summer's program meets the guidance provided by Regulatory Guide (RG) 1.155, Station Blackout; Nuclear Management and Resources Council, Inc. (NUMARC) 87-00, Guidelines and Technical Bases for NUMARC Initiatives addressing Station Blackout at Light Water Reactors; and NUMARC 87-00 Supplemental Questions/Answers and Major Assumptions dated December 27, 1989. Virgil C. Summer Technical Report TR08200-003 entitled “Compliance to NRC Rule 10CFR50.63” (Station Blackout), documents VCSNS compliance. Additional details are provided in the NRC issued Safety Evaluations References 1 and 2.

8.4.1 Station Blackout Duration

NUMARC 87-00 was used to determine an SBO duration of four hours.

The following plant factors were identified in determining the proposed Station Blackout duration:

1. AC Power Design Characteristic Group is P1 based on:
   a. Independence of offsite power classification of Group “1 1/2”
   b. Severe weather (SW) classification of Group “1”
   c. An extreme severe weather (ESW) classification of Group “3”
2. The emergency AC power configuration group is C based on:
   a. There are two EDGs credited as AC power supplies
   b. One emergency AC power supply is necessary to operate safe shutdown equipment following a loss of offsite power.
3. The target EDG reliability is 0.95.
   a. A target EDG reliability of 0.95 was based on the Virgil C. Summer Station having an average EDG greater than 0.95 over the last 100 demands.
   b. EDG failure statistics for the last 20 and 50 demands, in accordance with the requirements of RG 1.155 was provided, which confirms that the target selection is appropriate.

8.4.2 Coping Method

The V. C. Summer Nuclear Station coping method is in accordance with the “AC-Independent Approach” delineated in NUMARC 87-00 for the required coping duration of four hours and recovery therefrom. In this approach for VCSNS, DC power is required to be available for the coping duration to operate equipment necessary to achieve safe shutdown conditions until offsite or emergency AC power is restored. The following plant systems and components are required to have the availability, adequacy, and capability to achieve and maintain a safe shutdown and to recover from an SBO for a four-hour coping duration.

8.4.2.1 Class 1E Battery Capacity

The V. C. Summer Nuclear Station has sufficient battery capacity and size to support decay heat removal during a Station Blackout for the required four-hour coping duration in accordance with NUMARC 87-00 without load stripping, as discussed in Section 8.3.2.1.2. The battery analysis is documented/maintained in SCE&G Calculation DC08320-005.

8.4.2.2 Condensate Inventory For Decay Heat Removal

The V. C. Summer plant has adequate condensate inventory for decay heat removal during a Station Blackout for a required duration of four hours. The necessary condensate inventory is assessed by a bounding analysis based on the NUMARC 87-00 Equation. The minimum permissible condensate storage tank level per technical specification requirements provides 172,700 gallons, which exceeds the required quantity for coping with a four-hour Station Blackout per SCE&G Technical Report TR08200-003.

8.4.2.3 Compressed Air

The V. C. Summer air operated valves required for decay heat removal have been evaluated and accepted for manual operation under Station Blackout conditions for the four-hour duration.

8.4.2.4 Effects of Loss of Ventilation

The effects of loss of ventilation within areas of the plant containing equipment necessary to achieve and maintain safe shutdown during a Station Blackout is evaluated per NUMARC 87-00. The dominant areas of concern (DACs) and analysis are documented in SCE&G Technical Report TR08200-003.

8.4.2.5 Containment Isolation

Containment isolation valves that must be operated under SBO conditions must have the ability to be positioned, with indication, independent of the preferred and Class 1E AC power supplies and that no modifications or procedure changes are necessary to ensure containment integrity can be obtained if it is needed under SBO conditions. Containment isolation valve design and operation at VCSNS meet the intent of the guidance described in RG 1.155.

8.4.2.6 Reactor Coolant Inventory

The ability to maintain adequate reactor coolant system (RCS) inventory to ensure that the core is cooled has been assessed for four hours. The generic analysis listed in NUMARC 87-00 was used in this assessment. The expected rates of RCS inventory loss under SBO conditions do not result in core uncovery.

8.4.3 References

1. USNRC Letter to SCE&G dated January 30, 1992, Subject: Safety Evaluation Regarding Station Blackout Analysis, Virgil C. Summer Nuclear Station, Unit No. 1 (TAC No. M68610).
2. USNRC Letter to SCE&G dated June 1, 1992, Subject: Supplemental Safety Evaluation Regarding Station Blackout, Virgil C. Summer Nuclear Station, Unit No. 1 (TAC No. M68610).
3. U. S. Nuclear Commission Regulatory Guide 1.155, *Station Blackout*.
4. NUMARC 87-00, Nuclear Management and Resources Council, *Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors*.

Appendix 8A
Additional Cable and Tray Design Considerations

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APPENDIX 8A
ADDITIONAL CABLE AND TRAY DESIGN CONSIDERATIONS

8A.1 METHODS EMPLOYED

Sections 8A.1.1 through 8A.1.3 describe methods employed to show sufficient conservatism in the cable and tray design to assure that adequate cable tray hanger strength exists, that cables are sufficiently sized, and that the weight of upper cables in trays does not damage bottom layer cables.

8A.1.1 Weight on Hangar

Cables are routed in tray in two different configurations (e.g., single lay and random lay). The weight of the cables, tray, tray covers, fire barrier materials on the tray, and any conduits and pipes hung from the tray supports were used to establish the tray support capability. The allowable cable weight limit is based on the capability of the cable tray (e.g., 35 lbs/ft^2 of tray bottom area for single lay 4" deep trays and 45 lbs/ft^2 of tray bottom area for random lay 6" deep trays).

For single lay cable tray, percent fill and cable heating were not the deciding factors for limiting tray fill. Engineering determined that the maximum number of cables that a single lay tray can accommodate is based on the cable diameters versus the width of the tray.

The initial design criteria for random lay tray was based on a maximum of 50% fill. Engineering performed calculations to ensure that cable heating and cable weight were acceptable whenever the tray fill was less than 50%. Because the tray fill was conservatively calculated based on the square of the cable diameter in lieu of the cross sectional area of the cable, the actual tray fill is less than the calculated tray fill. The cable management system computer program was used to monitor tray fill. The 50% limit originally established was found to be inadequate as cables were added over the life of the plant. Therefore, calculations were performed whenever a random lay cable tray fill exceeded 50%. Subsequently the criteria for random lay power cable trays was changed to weight per tray support with an alarm point of either 50% fill for trays presently less than 50% filled or the last calculated allowable % fill for trays whose fill exceeded 50%. In addition, the criteria and alarm point for instrument and control tray were changed to weight only per tray support only, since heat loading was not a concern.

Whenever a power cable is added to a random lay power tray and the associated tray fill exceeds the previously accepted percent tray fill limit, a calculation is performed. The calculation addresses additional loading from the new power cables to ensure that the combined weight of the new and existing cables is less than the allowable design weight capability of the tray support. Heat loading is also evaluated to ensure that the existing ampacity derating factors are still applicable.

Engineering determined that cable heating was not a concern for the small currents and intermittent operating conditions associated with control and instrument cables and therefore only total cable weight needed to be considered. The design limit for control and instrumentation cable tray fill is based on verifying that the weight of the new and existing cable does not exceed the tray and tray support weight capability. The cable tray fill criteria for control and instrument trays is controlled by the cable management system computer program. This program contains an alarm limit for the maximum weight allowed for each tray size used. Therefore, manual calculations to monitor cable weight are not required because this calculation is performed by the cable management system and an alarm is provided if the tray or tray support weight capability is exceeded.

8A.1.2 Cable Heating

Single layer kV and 480 volt cable trays need not be considered with respect to possible cable overheating since, inherently, the fill is limited to the single layer of cable with appropriate derating factors applied. Rated ampacities are in accordance with ICEA P-46-426 (Reference 1); the free air ratings for the applicable ambient temperatures were derated for the presence of adjacent power cables. In addition, a load factor of 100 percent was assumed and feeders are sized for 110, 125, or 140 percent of rated current, depending upon type of service (resistive loads; motors, power panels and small transformers; and large power transformers, respectively).

No ampacity derating factors are applied to control and instrument cables due to the type of service and low current levels.

For random lay power trays (Reference 2, Table 12), a 3 inch depth was used to determine cable ampacity. Therefore, derating due to tray fill need only be considered for trays with fill greater than 50 percent design objective, since the 50 percent design fill is equivalent to a 3 inch depth. The 100 percent load factor feeder sizing considerations previously noted were also applied, along with appropriate derating where required for higher ambient temperatures.

In selected cases fill above 50% was authorized to larger values after specific evaluation of heat dissipation and weight loading. Heat dissipation was evaluated using the methods described in Reference 3.

From Figure 4 of Reference 3 the following linear approximation can be made for the allowable heat generation versus tray fill:

$$Q_d = \frac{6.5}{d^{1.47}} \quad (1)$$

Where:

Q_d = Allowable heat generation per unit area of cable cross-section to limit conductor temperature to 90°C

d = Depth of tray fill in inches

Since heat generation in a given cable at a fixed temperature is proportional to the square of the current, the following relationships can be established:

$$Q_d = KI_d^2 \quad (2)$$

Where:

I_d = Ampacity of cable for tray fill depth d

K = Constant

Combining into equation (1) and developing a ratio:

$$\frac{Q_{d'}}{Q_d} = \frac{KI_{d'}^2}{KI_d^2} = \frac{(d)^{1.47}}{(d')^{1.47}}$$

Using the relationship, the curve of Figure 4 in Reference 3 was extended to cover larger fills of six inch deep tray. Because Reference 3 was developed for three inch deep tray, the tray fill permitted is one-half the value shown in Figure 4. As long as the tray fill meets this criterion, the cable ampacities of Reference 2 are still permissible.

There is an additional margin of conservatism in the heat dissipation calculation. Tray fill is calculated using diameter squared to represent cable cross-sectional area instead of actual cable area. This represents a margin of 27.3 percent above actual tray fill. In addition, non-continuous current carrying cables are not included in heat density calculations but are included in tray fill and weight calculations, which ensures conservatism.

No ampacity derating of cables has been necessary because of heat dissipation.

8A.1.3 Cable Side Wall Pressure

In accordance with manufacture’s published information the maximum allowable side wall pressure of typical cables used is considerably higher than the pressure that cables on the bottom of a tray will experience from cables above, even for fills in excess of 50 percent. The minimum

allowable side wall pressure is 50 lb/ft, while the maximum loading per cable in a tray filled to the tray support limit, or 100% physical fill, will be less than 7 lb/ft [18] *.

8A.2 CONCLUSIONS

Tray fill is monitored by computer. Any tray that exceeds the design fill is reported on a separate printout. This printout is used in routing design, and cables are routed through other, less full trays. Late in construction other trays may exceed the maximum values justified in Sections 8A.1.1 through 8A.1.3. When this occurs, the situation will be evaluated and action will be taken to relieve such a condition. Alternatives are to calculate the actual tray load and verify that the load does not exceed the design capacity, enlarge the existing tray, strengthen the existing hangers, or in the case of random lay power trays where the concern is ampacity, each individual circuit application can be evaluated and the total ampacity calculated.

8A.3 REFERENCES

1. Insulated Cable Engineers Association, *Power Cable Ampacities,* ICEA P-46-426-1962.
2. Insulated Cable Engineers Association, *Ampacities of Cables in Open-Top Cable Trays*, ICEA P-54-440.
3. Stolpe, J. *Ampacities for Cables in Randomly Filled Trays*, Institute of Electrical and Electronics Engineers Transaction Paper 70TP557PWR.

* Refers to Section 8.3, Reference [18], Calculation No. DC08500-022, “Determination of Maximum Sidewall Pressure Imposed on Cable in Cable Tray as a Result of Cable Weight.” See Amendment 00-01, Revision Notice 99-14.

Appendix 8B
Cable Raceway Fire Barriers Design

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NOTE: Appendix 8B is being retained for historical purposes only.

APPENDIX 8B
CABLE RACEWAY FIRE BARRIERS DESIGN

8B.1 PURPOSE

This report describes the criteria, assumptions and design used by Gilbert Associates, Inc. (GAI) to locate and construct cable raceway fire barriers on the Virgil C. Summer Nuclear Station for the South Carolina Electric and Gas Company.

8B.2 CRITERIA

Fire barriers were designed to comply with IEEE Standard 384-1977 "Criteria for Independence of Class 1E Equipment and Circuits."

Fire barriers are required to prevent propagation of a fire between two, or more, raceways of redundant divisions or non-class 1E to Class 1E cable trays which do not maintain minimum physical separation. This minimum physical separation is specified in IEEE-384, and in SP-834 – "Electrical Construction Guideline for Electrical Circuit Physical Separation." In summary, the minimum separation distances are based on open ventilated cable trays and are as follows:

1. Cable spreading area - one foot horizontally and three feet vertically.
2. General plant area - three feet horizontally and five feet vertically.

Where the above separation is not provided the following specified criteria extracted from IEEE-384 are used:

1. The use of physical barriers or enclosed raceways, which qualify as barriers, shall be separated by a minimum distance of one inch.
2. Vertical barriers, separating redundant horizontal tray running parallel requiring horizontal separation will have a minimum of one foot (or to ceiling) extension above the top of the tray at the highest elevation in a stack.
3. Horizontal barriers, separating redundant horizontal trays crossing requiring vertical separation will have a minimum of three feet extension beyond each side of the widest tray (one foot in the cable spreading area).
4. Horizontal barriers, separating redundant horizontal trays running parallel requiring vertical separation will have a minimum of six inches extension beyond each side of the widest tray.

These barriers are intended to prevent redundant raceway-to raceway fires which are self-initiated only.

Based on the above, the following was extrapolated:

1. Solid tray covers and bottoms, referred to in this report as fire shields, may be added to open ladder tray to qualify it as an enclosed raceway. Trays containing power cables (480 volt and higher) may require barriers in lieu of fire shields since fire shields may inhibit ventilation.
2. Channel tray (4 inch open top, solid bottom) will be considered an enclosed, open top tray and may require covers only.
3. Instrument trays, in this plant are installed with solid covers and bottoms and constitute an enclosed raceway.
4. Conduit alone constitutes an enclosed raceway.
5. Conduit installed beneath or alongside of an open tray of a redundant division does not require a barrier.
6. Conduit installed less than five feet (three feet in a cable spreading area) above a tray of a redundant division requires a barrier.
7. Conduits may be wrapped with a flexible fireproof material which will suffice as a barrier. This may be used where space permits installation.

8B.3 MATERIALS AND INSTALLATION

8B.3.1 Fire Shields

Tray covers and bottoms will be made of 18 gauge steel. They will be attached to the tray by one of several methods described in detail by the tray vendor for other applications in the plant. Basically, the covers are strapped or clamped to the tray. Covers will be peaked to 1 inch, except for covers for fittings which will be flat; bottoms will be flat.

8B.3.2 Barriers

Board barriers will be made from Babcock and Wilcox M-Board in one inch thickness. Installation techniques are under development.

8B.3.3 Conduit Wrapping

Conduit wrapping will be done with Johns-Manville Cerablanket, or Babcock and Wilcox Kaowool blanket materials. These are high-temperature fiber blankets in a thickness of one inch and, typically, a width of 24 inches. The blanket will be wrapped around the conduit and fastened with fire resistant tape or by other similar method.

8B.4 ACTUAL CASES

Detailed in Figures 8.B-1 through 8.B-12 are representatives cases found in the Virgil C. Summer Nuclear Station where physical separation of redundant channels could not be maintained. The type of fire barrier designed for each case and the installation methods are described below. Options are provided for each case and an option may be selected, for individual cases, based on economics, available space and complexity (e.g., it may be more advantageous to use one board barrier rather than many covers and bottoms where several trays are involved).

1. Detail 1 - Redundant Horizontal Trays Crossing, Requiring Vertical separation.
   a. Option A - shows the use of fire shields on each tray.
   b. Option B - shows the use of a horizontal board barrier.
2. Detail 2 - Redundant Horizontal Trays Running Parallel Requiring Vertical Separation.
   a. Option A - shows the use of fire shields on each tray.
   b. Option B - shows the use of a horizontal board barrier.
3. Detail 3 - Redundant Horizontal Trays Running Parallel Requiring Horizontal Separation
   a. Option A - shows the use of fire shields on each tray.
   b. Option B - shows the use of a vertical board barrier.
4. Detail 4 - Horizontal Tray Crossing Redundant Vertical Tray Requiring Horizontal Separation.
   a. Option A - shows the use of a fire shield on each tray.
   b. Option B - shows the use of a vertical board barrier.
5. Detail 5 - Horizontal Conduit Crossing Over Redundant Horizontal Tray Requiring Vertical Separation.
   a. Option A - shows the use of a fire shield on each tray.
   b. Option B - shows the wrapping of conduit.
   c. Option C - shows the use of a horizontal board barrier.
6. Detail 6 - Horizontal Conduit Above Redundant Horizontal Tray Running Parallel Requiring Vertical Separation.
   a. Option A - shows the use of a fire shield on each tray.
   b. Option B - shows wrapping of the conduit.
   c. Option C - shows the use of a horizontal board barrier.
7. Detail 7 - Vertical Conduit Crossing Redundant Horizontal Tray Requiring Horizontal Separation.

a. Option A - shows the use of a fire shield on each tray.

b. Option B - shows wrapping of the conduit.

c. Option C - shows the use of a vertical board barrier.

8. Detail 8 - Horizontal Conduit Crossing Redundant Vertical Tray Requiring Horizontal Separation.

a. Option A - shows the use of a fire shield on each tray.

b. Option B - shows wrapping of the conduit.

c. Option C - shows the use of a vertical board barrier.

Figure 8.B-1

ELECTRICAL FIRE BARRIER DETAILS

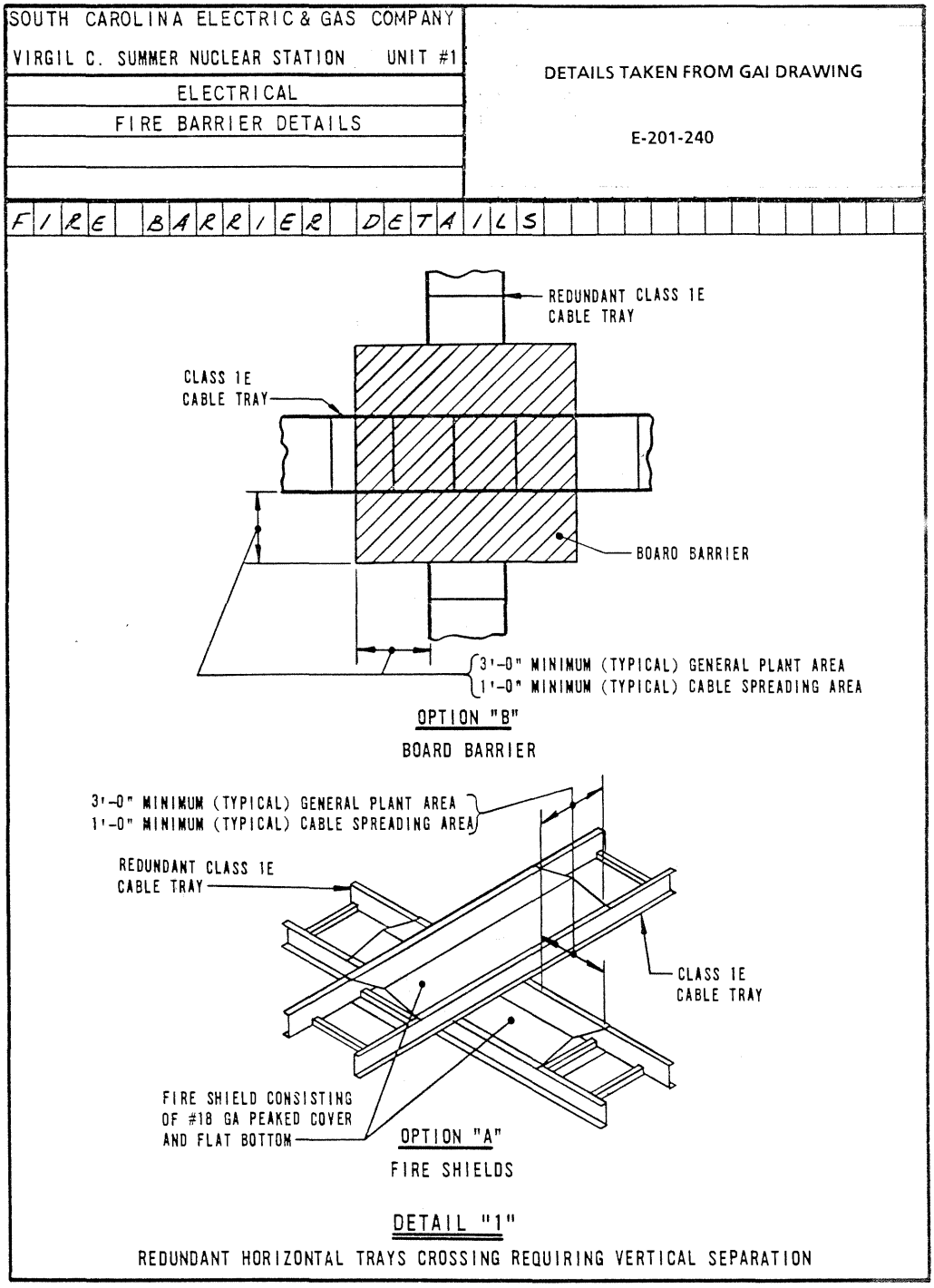

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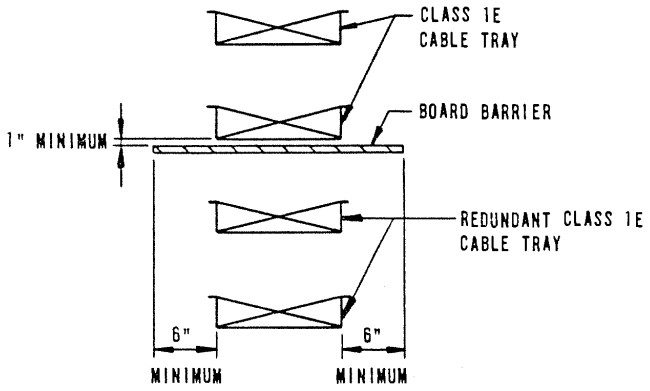
Figure 8B-1

Figure 8.B-2
ELECTRICAL FIRE BARRIER DETAILS

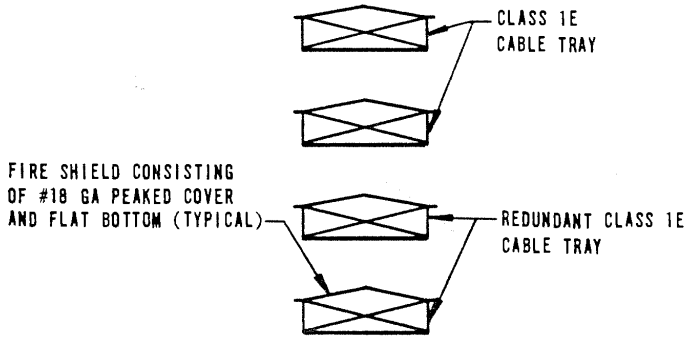
SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
FIRE BARRIER DETAILS

DETAILS TAKEN FROM GAI DRAWING
E-201-240

FIRE BARRIER DETAILS



OPTION "B"
BOARD BARRIER



OPTION "A"
FIRE SHIELDS

DETAIL "2"
REDUNDANT HORIZONTAL TRAYS RUNNING
PARALLEL REQUIRING VERTICAL SEPARATION

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Figure 8.B-3
ELECTRICAL FIRE BARRIER DETAILS

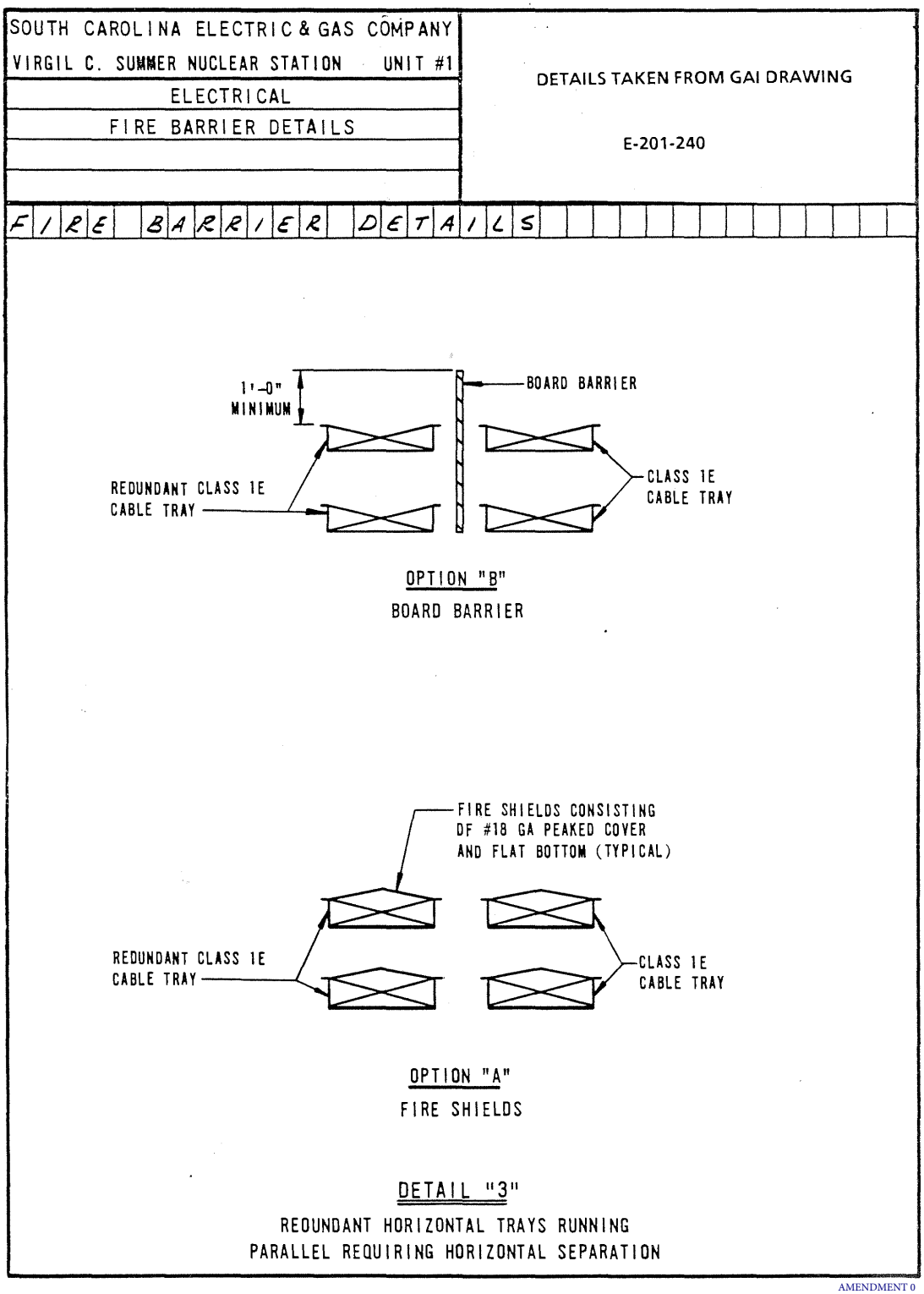

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Figure 8B-3

Figure 8.B-4
ELECTRICAL FIRE BARRIER DETAILS

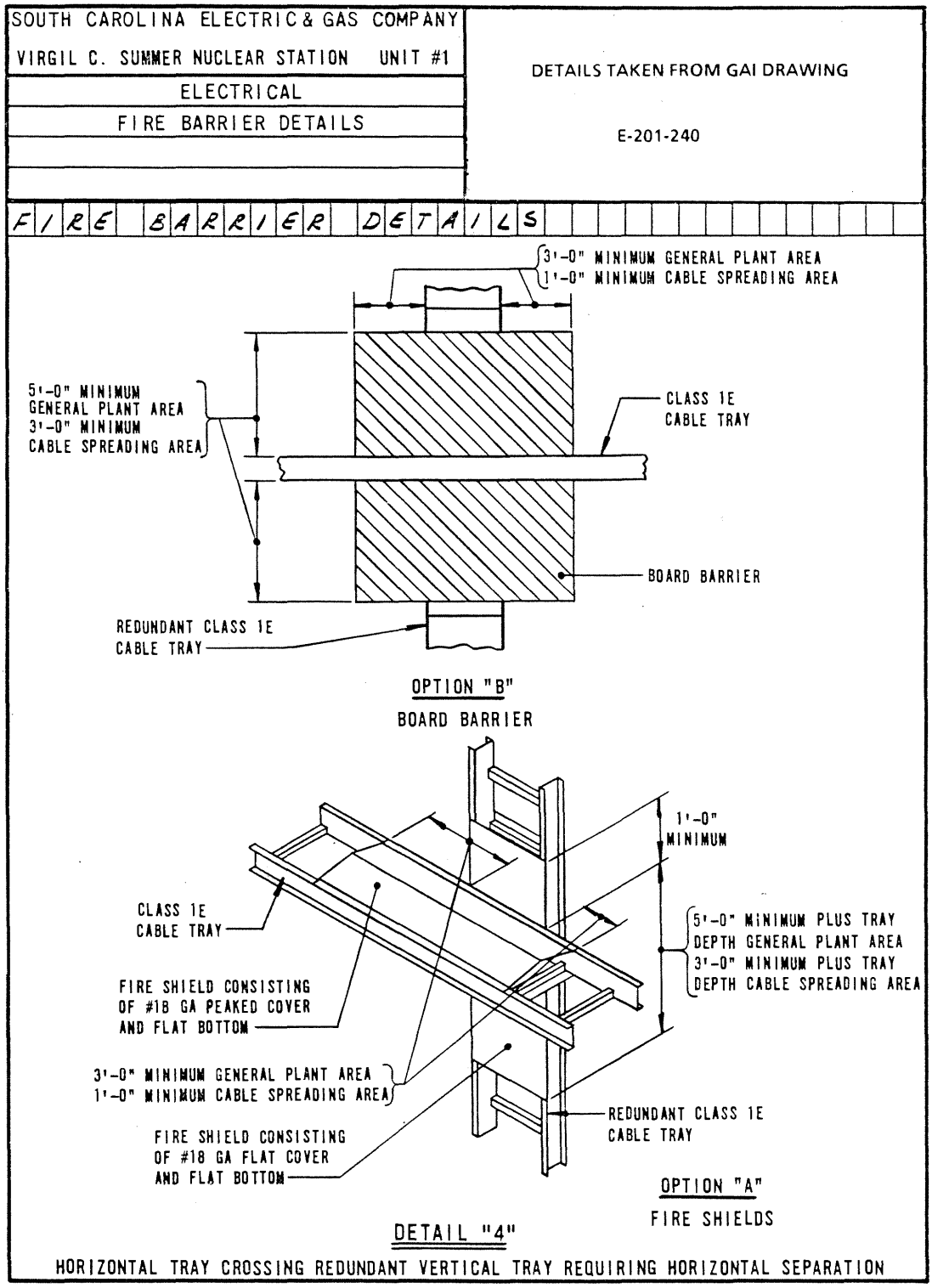

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Figure 8B-4

Figure 8.B-5

ELECTRICAL FIRE BARRIER DETAILS

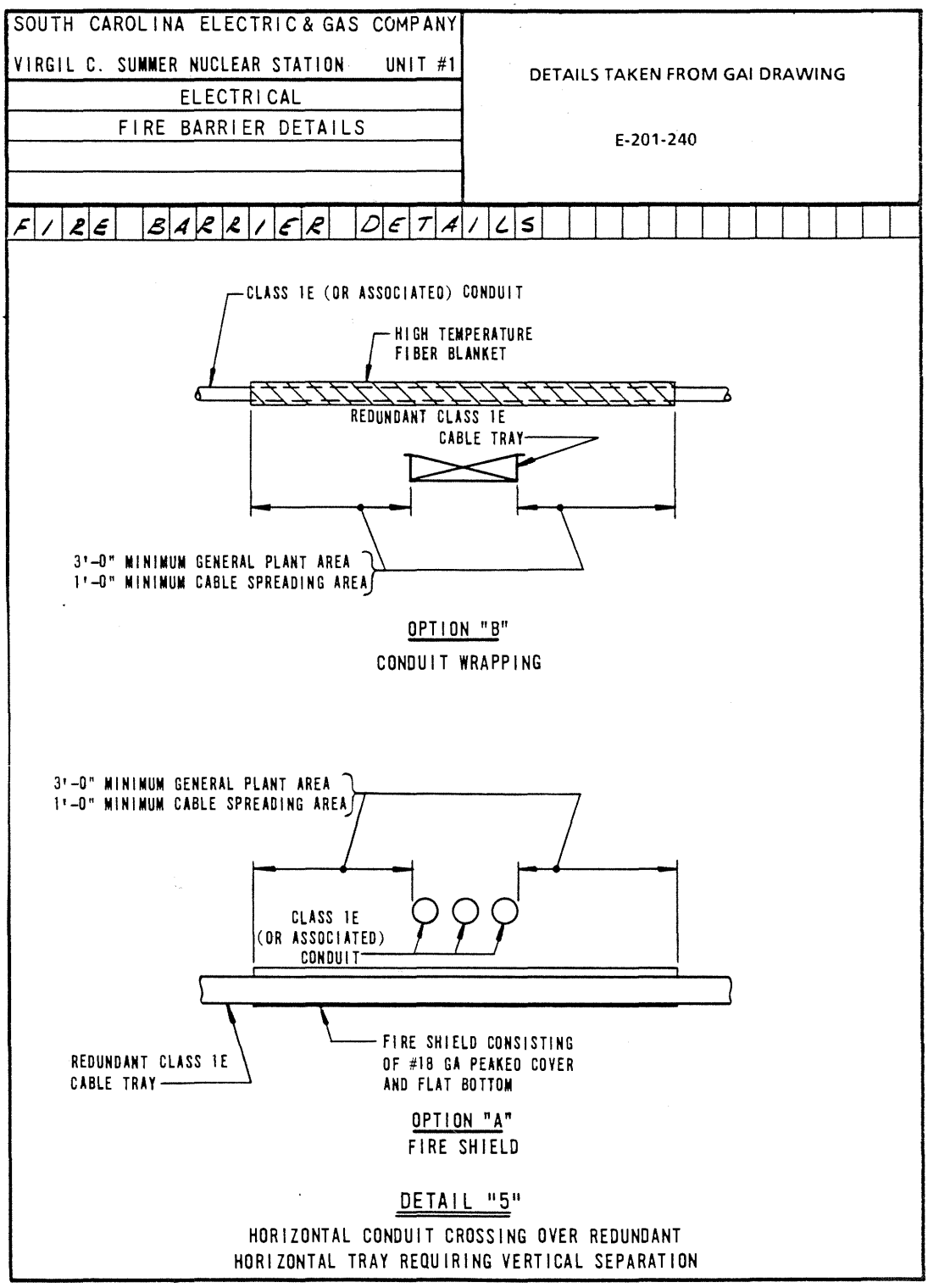

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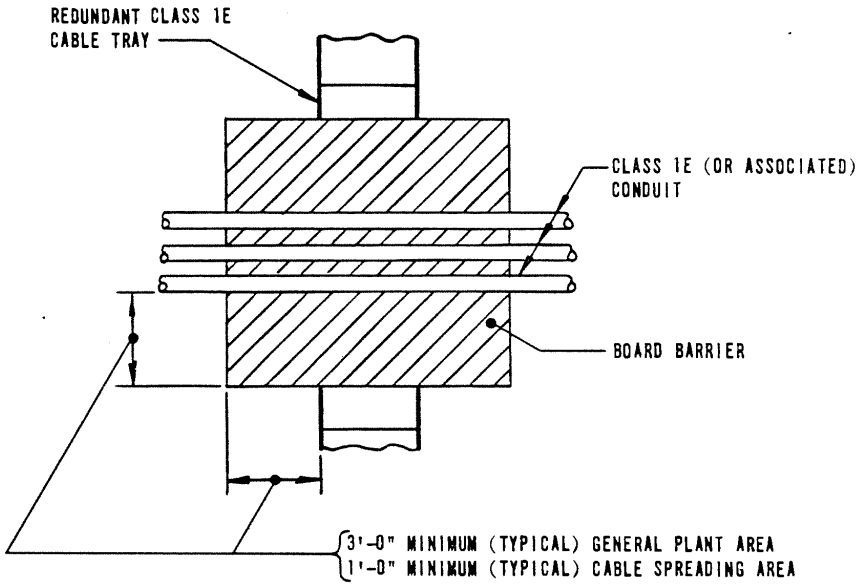
Figure 8B-5

Figure 8.B-6
ELECTRICAL FIRE BARRIER DETAILS

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
FIRE BARRIER DETAILS

DETAILS TAKEN FROM GAI DRAWING
E-201-240

FIRE BARRIER DETAILS



OPTION "C"
BOARD BARRIER

DETAIL "5"
HORIZONTAL CONDUIT CROSSING OVER REDUNDANT
HORIZONTAL TRAY REQUIRING VERTICAL SEPARATION

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Figure 8.B-7
ELECTRICAL FIRE BARRIER DETAILS

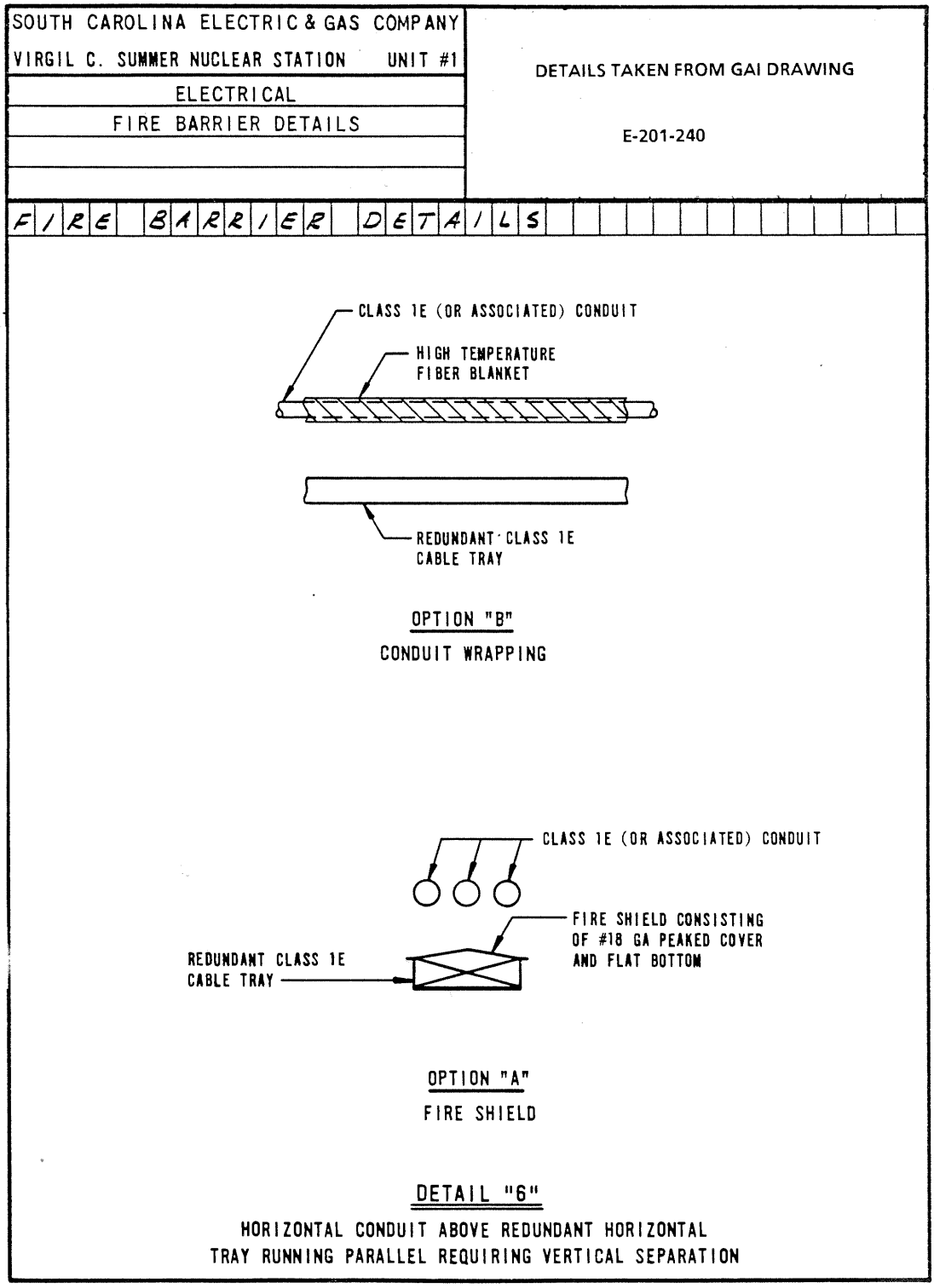

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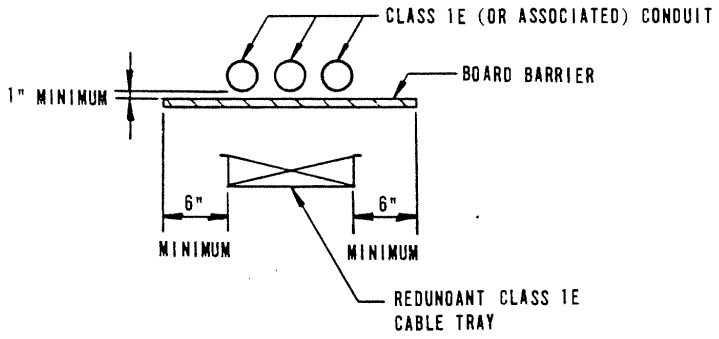
Figure 8B-7

Figure 8.B-8

ELECTRICAL FIRE BARRIER DETAILS

SOUTH CAROLINA ELECTRIC & GAS COMPANY VIRGIL C. SUMMER NUCLEAR STATION UNIT #1 ELECTRICAL FIRE BARRIER DETAILS	DETAILS TAKEN FROM GAI DRAWING E-201-240

FIRE BARRIER DETAILS



OPTION "C"

BOARD BARRIER

DETAIL "6"

HORIZONTAL CONDUIT ABOVE REDUNDANT HORIZONTAL TRAY RUNNING PARALLEL REQUIRING VERTICAL SEPARATION

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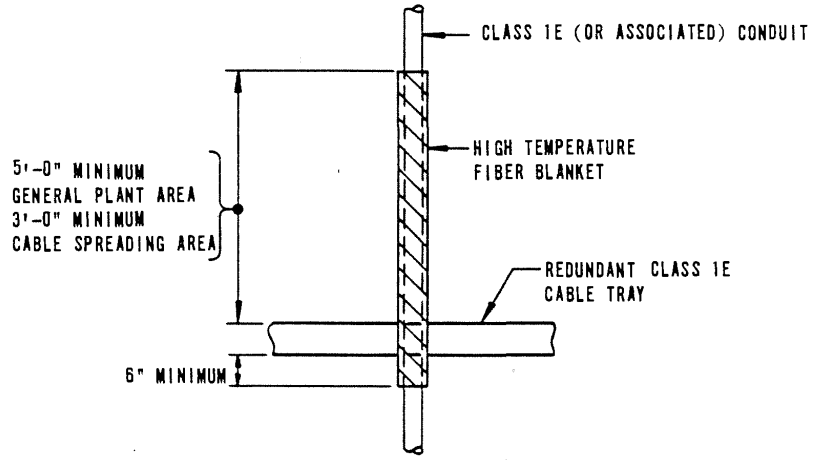
Figure 8.B-9

ELECTRICAL FIRE BARRIER DETAILS

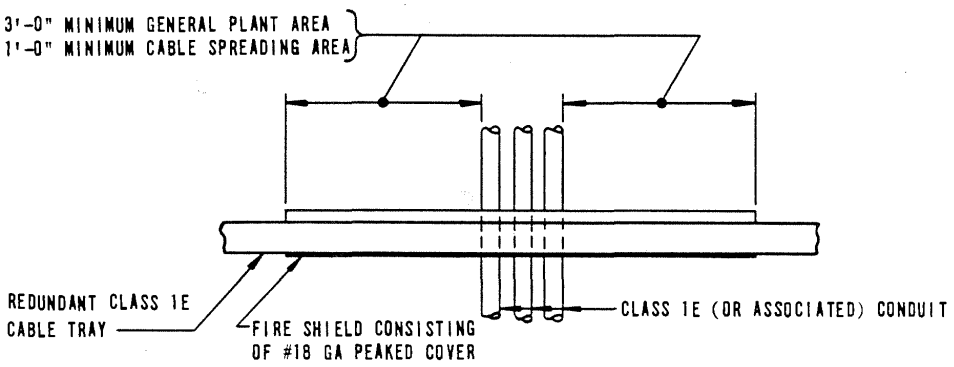
SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
FIRE BARRIER DETAILS

DETAILS TAKEN FROM GAI DRAWING
E-201-240

FIRE BARRIER DETAILS



OPTION "B"
CONDUIT WRAPPING



OPTION "A"
FIRE SHIELD

DETAIL "7"
VERTICAL CONDUIT CROSSING REDUNDANT HORIZONTAL TRAY REQUIRING HORIZONTAL SEPARATION

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Figure 8B-9

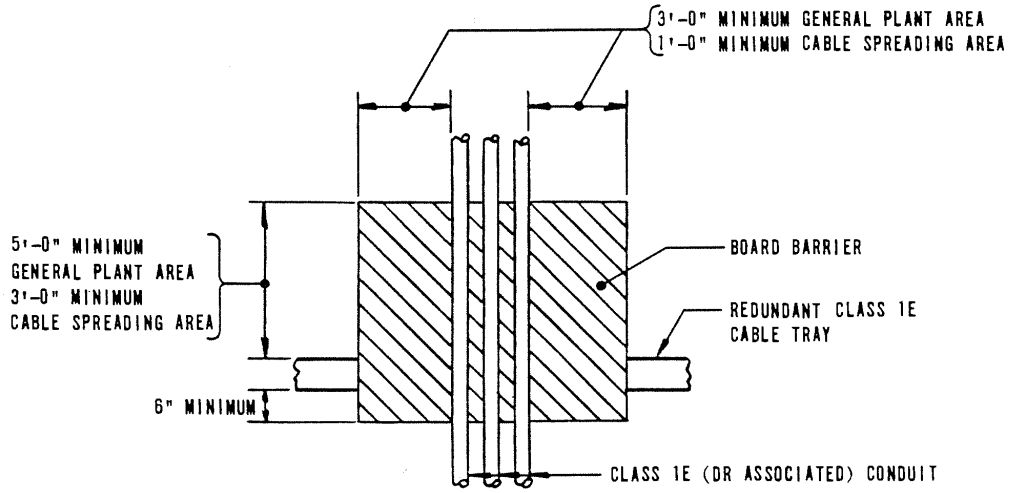
Figure 8.B-10

ELECTRICAL FIRE BARRIER DETAILS

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
FIRE BARRIER DETAILS

DETAILS TAKEN FROM GAI DRAWING
E-201-240

FIRE BARRIER DETAILS



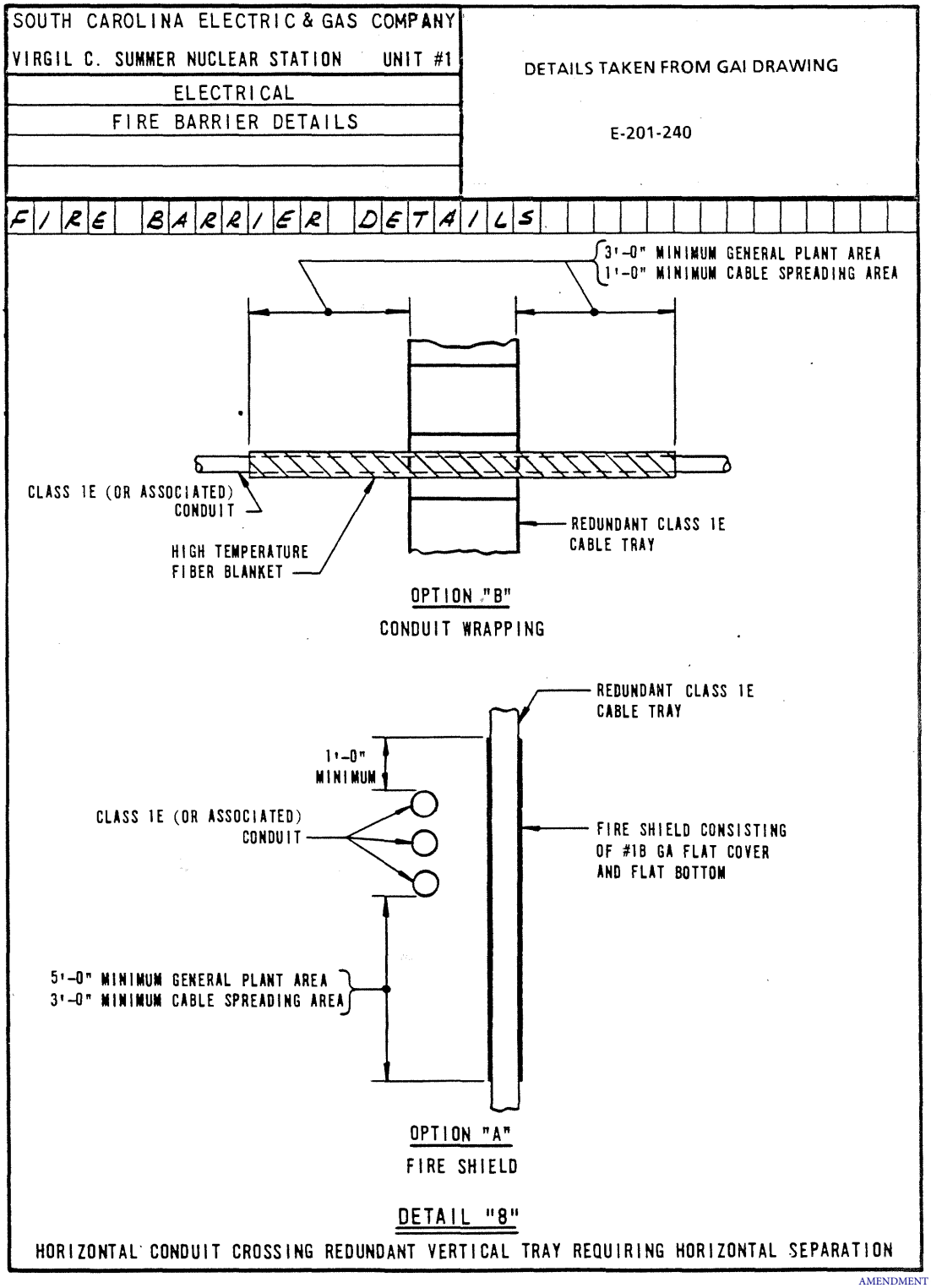
OPTION "C"
BOARD BARRIER

DETAIL "7"
VERTICAL CONDUIT CROSSING REDUNDANT HORIZONTAL
TRAY REQUIRING HORIZONTAL SEPARATION

AMENDMENT 0

Figure 8.B-11

ELECTRICAL FIRE BARRIER DETAILS



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AUGUST 1984

Figure 8B-11

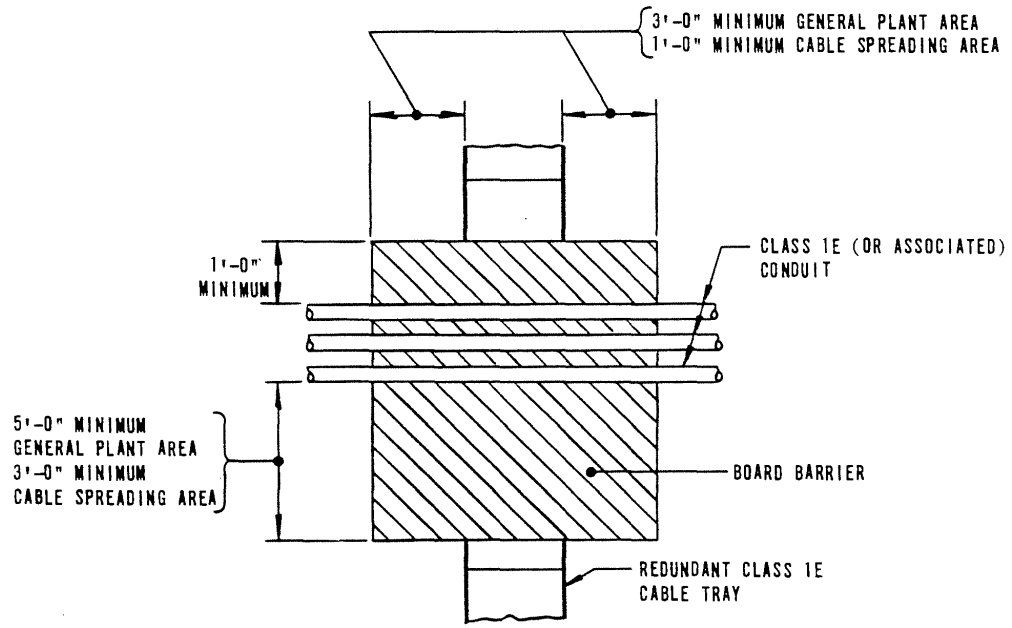
Figure 8.B-12

ELECTRICAL FIRE BARRIER DETAILS

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
FIRE BARRIER DETAILS

DETAILS TAKEN FROM GAI DRAWING
E-201-240

FIRE BARRIER DETAILS



OPTION "C"
BOARD BARRIER

DETAIL "8"
HORIZONTAL CONDUIT CROSSING REDUNDANT VERTICAL TRAY REQUIRING HORIZONTAL SEPARATION

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AUGUST 1984

Figure 8B-12

Appendix 8C
Summary of Analysis of Separation Between Tray for Non-Class 1E Circuits and Tray for Class 1E Circuits

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APPENDIX 8C
SUMMARY OF ANALYSIS OF SEPARATION BETWEEN TRAY FOR NON-CLASS 1E CIRCUITS AND TRAY FOR CLASS 1E CIRCUITS

8C.1 OBJECTIVE

Perform an analysis in accordance with IEEE 384-1974, Section 5.1.1.2, to ensure acceptable separation between trays for non-class 1E circuits and trays for Class 1E circuits.

8C.2 CRITERIA

Separation shall be sufficient that no single electrically initiated fire can result in the loss of a safety system function.

8C.3 BASIS

The Fire Protection Research Program tests performed at Sandia Laboratories for the U.S. Nuclear Regulatory Commission (NRC) were used as a source of data on the characteristics of cable fires. The following conclusions drawn from the reports were used in the analysis of individual situations:

1. It is difficult to initiate a fire from an electrical fault or overload in trays with cables which satisfy the flame retardant criteria of IEEE 384-1974.
2. If a fire can be started and propagated, it spreads through a stack of trays with an angle of spread of approximately 35 degrees from vertical.
3. In horizontal trays, the fire does not propagate horizontally within a given tray.
4. Fire does not propagate downward from one tray to the tray below.

The results of the IEEE 383 flammability tests for cable actually used at Virgil C. Summer Nuclear Station were also used to determine that the flammability of the cable used at Virgil C. Summer Nuclear Station is less than that used for the full scale tests at Sandia Laboratories.

8C.4 METHOD

The tray drawings for plant areas containing trays for Class 1E circuits are reviewed and each case where a tray for non-Class 1E circuits approaches a tray for Class 1E circuits is noted and given an identification number. Each case is then clarified with sections and details as necessary to determine separation distances and to categorize the situation. The cases are then individually reviewed using the basis given above to determine the adequacy of the separation. If

the criteria stated above are not satisfied by the existing design, suitable barriers are added to the raceway system design so that the final design satisfies the criteria.

1. Tray for non-Class 1E circuits parallel to tray for Class 1E circuits. Subcategories include: above, below, beside, and between.
2. Tray for non-Class 1E circuits crossing tray for Class 1E circuits. Subcategories include: above, below, and between.
3. Tray for non-Class 1E circuits bridging between routes of trays for redundant Class 1E circuits. Subcategories include: above, below, and between.
4. Trays for non-Class 1E circuits diagonally parallel trays for Class 1E circuits. Subcategories include: above and below.
5. Trays for non-Class 1E circuits vertical. Subcategories include: parallel to or crossing tray for class 1E circuits.

8C.5 ANALYSIS

A listing of cases analyzed is provided by Section 8C.6. In addition, detailed analyses for three typical cases are presented in Sections 8C.5.1 through 8C.5.3.

8C.5.1 CASE NO. 041-C

8C.5.1.1 Description

1. Location

   Control Building, Elevation 425’-0

2. Figure

   Figure 8C-1

3. Type of Area

   Cable spreading room

4. General Description

   A tray for non-Class 1E (channel X) control circuits passes over a vertical stack of trays for Class 1E, channel A circuits and further north passes over a vertical stack of trays for Class 1E, channel B circuits.

5. Category

   Bridging - above

6. Types of Trays

   All trays shown in Figure 8C-1 are open ventilated ladder type, except tray 5144 (A) which is the totally metal enclosed type.

7. Number of Circuits

   Tray 4290 (x) - 316 control circuits

   Tray 4351 (x) - 103 control circuits

   Tray 4650 (x) - 38 control circuits

   Tray 4314 (A) - 337 control circuits

   Tray 4284 (A) - 182 control circuits

   Tray 5144 (A) - 124 instrument circuits

   Tray 4326 (B) - 435 control circuits

   Tray 4325 (B) - 209 control circuits

8. Significant Circuits

   Both the channel A and B trays contain a number of circuits for the component cooling water, emergency feedwater, safety injection, and service water systems; as well as circuits for other safety systems.

8C.5.1.2 Analysis

All circuits are for control or instrumentation and have very low internal energy levels. Therefore, energy is not available to initiate a fire.

Any fire which might start in the trays for non-class 1E circuits will not propagate to either of the stacks of trays for the Class 1E circuits since tests have demonstrated that cable fires do not propagate downward. In addition, the tests have shown that a cable fire will not propagate horizontally over the 5 foot-8 inch distance between the stacks of trays for the Class 1E circuits.

A fire which might start in the trays for the Class 1E circuits could propagate to trays for the non-Class 1E circuits but, as stated above, tests have shown that the fire would not propagate

horizontally to the trays for the redundant Class 1E circuits nor would the fire propagate downward to the other stack.

Although the preceding analysis documents that a fire barrier is not required, a barrier was installed in the Channel B control trays in compliance with the licensing commitment to provide barriers for multiple separation violations as described in paragraph 8.3.1.4.1, Item 4.

8C.5.2 Case No. 102-A

8C.5.2.1 Description

1. Location

   Reactor Building Elevation, 436'-0"

2. Figure

   Figure 8C-2

3. Type of Area

   General plant area

4. General Description

   Trays for Class 1E circuits, channels A and D, run parallel to trays for non-Class 1E (channel X) circuits throughout this elevation of the Reactor Building. No trays of other channels are present.

5. Category

   Parallel – beside

6. Types of Trays

   The trays, as shown by Figure 8C-2, consist of both open ventilated ladder trays and totally metal enclosed trays.

7. Number of Circuits

   Tray 3098 (X) - 13 480 volt random layed power circuits

   Tray 4168 (X) - 33 control circuits

   Tray 5063 (X) - 22 instrument circuits

Tray 4174 (A) - 62 control circuits

Tray 5069 (A) - 3 instrument circuits

Tray 5077 (D) - 3 instrument circuits

8. Significant Circuits

Tray 4174 contains a number of circuits from the chemical and volume control system, reactor coolant system, and safety injection system; as well as from other systems.

8C.5.2.2 Analysis

The Class 1E, channel D circuits are in a totally metal enclosed raceway at the bottom of the stack. Therefore they are adequately separated from other trays.

The lower of the two trays for Class 1E channel A circuits is totally metal enclosed and therefore, is adequately separated. Any fires which might start in the upper of the two trays for Class 1E channel A circuits would not propagate to the tray for the channel D circuits nor to the trays for non-Class 1E circuits.

The bottom tray for non-Class 1E circuits is totally metal enclosed and therefore, is adequately separated from other trays.

The middle tray for non-Class 1E circuits contains control circuits which do not have adequate energy to initiate a fire. Should a fire occur, it could propagate to the top tray for the Class 1E, channel A circuits and to the top tray for non-Class 1E circuits. However, this is acceptable because only one channel of Class 1E circuits would be affected and, therefore, system safety functions would be maintained.

The top tray for non-Class 1E circuits contains power circuits which potentially could initiate a fire. However, the tests have shown that such a fire is very unlikely and should such a fire occur, it would not propagate to any other trays in this configuration.

Although the preceding analysis documents that a fire barrier is not required, a barrier was installed in the Channel D control trays in compliance with the licensing commitment to provide barriers for multiple separation violations as described in paragraph 8.3.1.4.1, Item 4.

8C.5.3 Case No. 073-A

8C.5.3.1 Description

1. Location

Auxiliary Building Elevation, 388'-0"

2. Figure

   Figure 8C-3

3. Type of Area

   General plant area

4. General Description

   Trays for Class 1E circuits, channels A and B, run parallel to trays for non-Class 1E circuits, channel X. This situation exists for a distance of 20 feet.

5. Category

   Parallel - above and beside

6. Types of Trays

   Both trays for Class 1E circuits contain control circuits. Trays for non-Class 1E circuits include instrument, control, and random layed power circuits.

7. Number of Circuits

   Tray 4062 (A) - 28 control circuits

   Tray 4064 (B) - 27 control circuits

   Tray 5022 (X) - 38 instrument circuits

   Tray 4059 (X) - 106 control circuits

   Tray 3033 (X) - 49 random layed power circuits

8. Significant Circuits

   Both trays 4062 and 4064 contain circuits for the chemical and volume control system and the leak detection system, as well other systems.

8C.5.3.2 Analysis

Tray 4064 for Class 1E, channel B circuits is separated by considerably more than 5 feet vertically and 3 feet horizontally from all other trays and, therefore, is adequately separated.

Tray 4062 for Class 1E, channel A circuits is 14 inches away from tray 5022 for non-Class 1E, channel X circuits. However, tray 5022 is totally metal enclosed and, therefore, is not a hazard to tray 4062. Tray 4062 is more than 5 feet horizontally and 3 feet vertically from all other trays and therefore, is adequately separated.

8C.6 CASES ANALYZED

The following pages list the cases analyzed.

Figure 8C-1

CASE 041-C

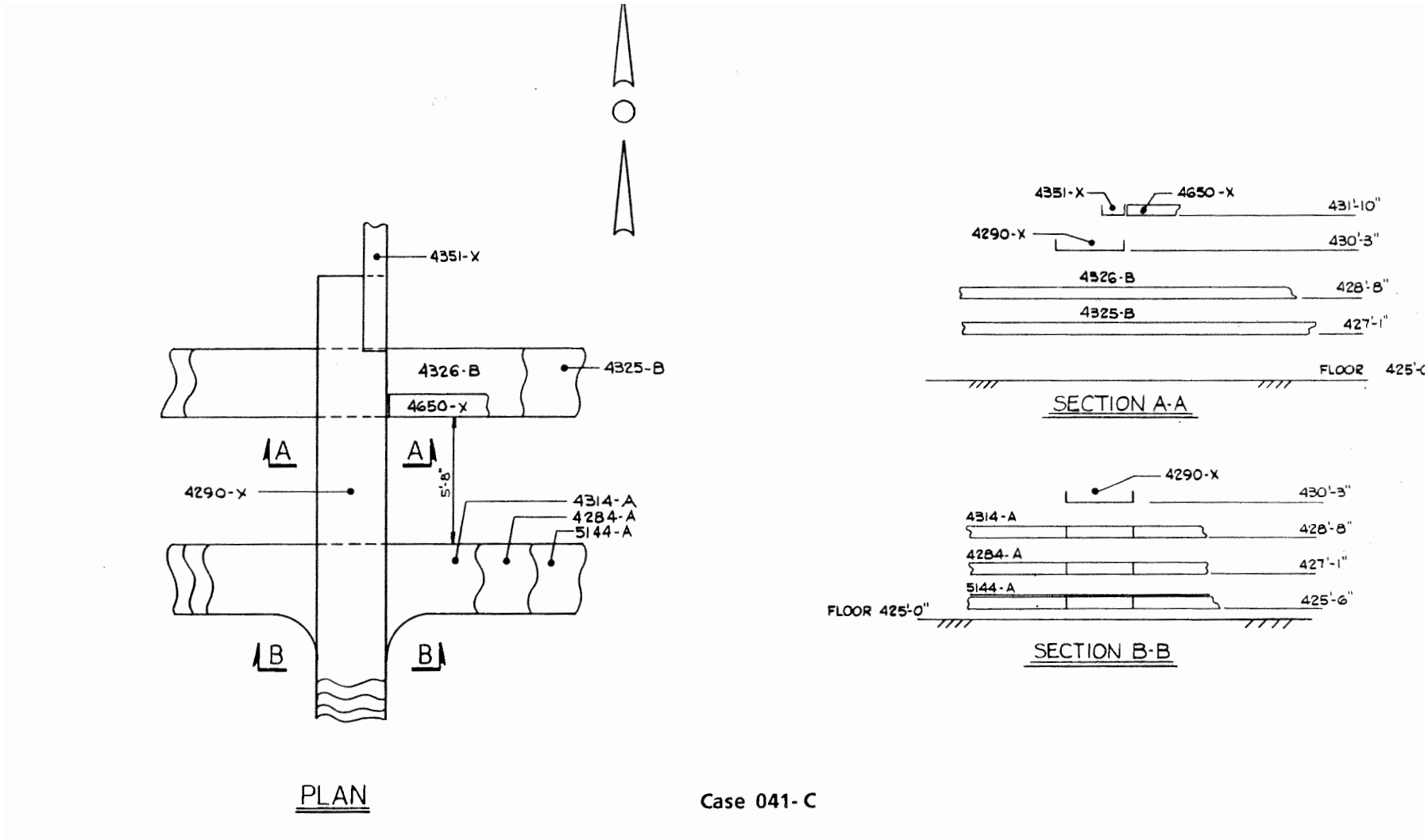


Figure 8C-2
CASE 102-A

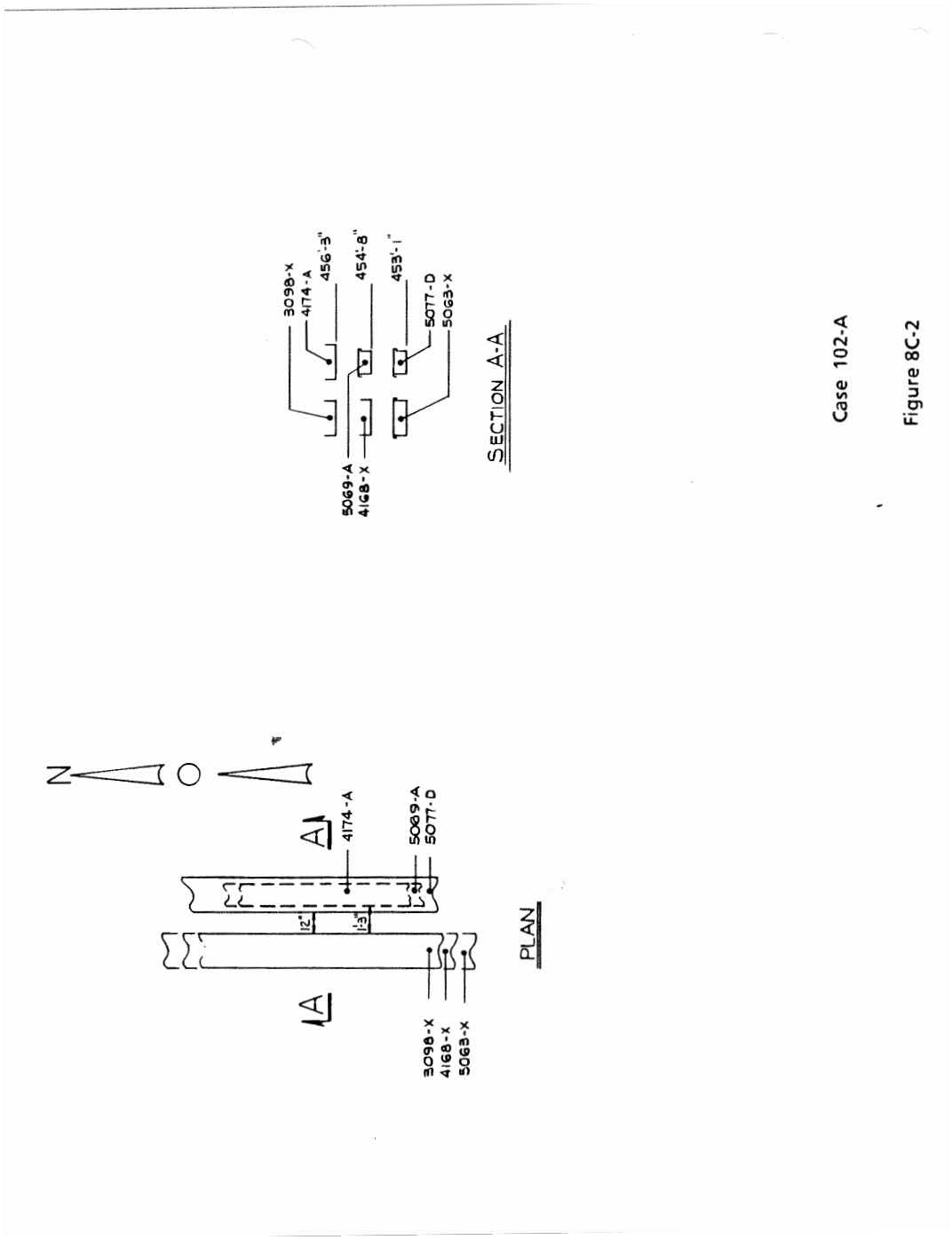


Figure 8C-2

Figure 8C-3

CASE 073-A

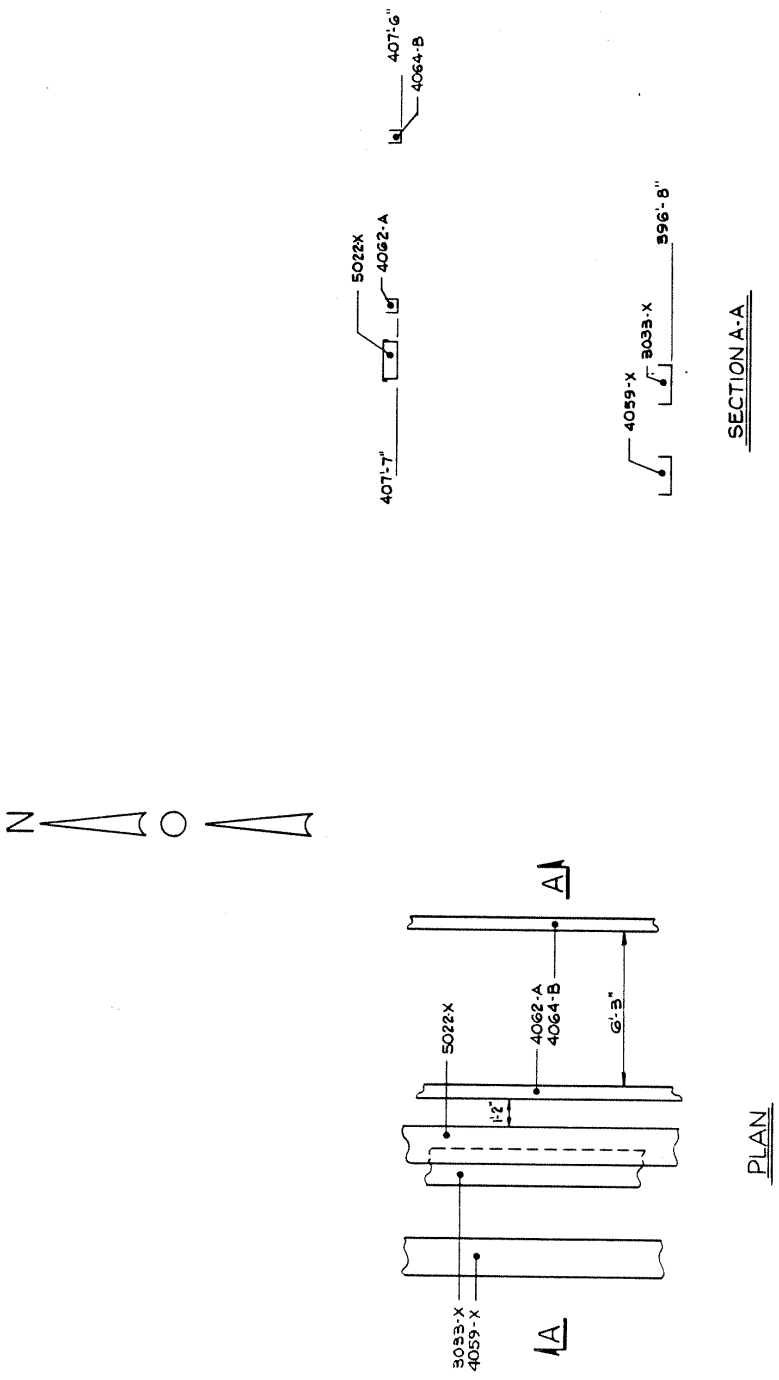


Figure 8C-3

Tables 8C-8 through 8C-39
CONSTRUCTION BIDDING PURPOSES

see next pages

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX.
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 425'-0"

MADE ROB | CHKD MWS | DRAWING NO. 04 446 ISS-200-941 | SH. NO. 041-1 | REV D
SQ LOC RWP | END INTERF | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE | JOB 04446-020 | ENGINEER APPROVAL | DEPT | DATE

REV	MADE	CH	SQL	APP	DATE	REV	MADE	CH	SQL	APP	DATE
C	RH	-	-	JE	7/96	D	TF				

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
041-A	E-11	P	M ABOVE B	2'-7"	-	YES*	
041-B	G-11	P	L ABOVE A	2'-7"	-	YES*	
041-C	F-6	P C	B BELOW X	12"	-	NO	① ⑥ D
041-D	H-7	C	D ABOVE X	12"	-	NO	②
		C	D ABOVE A	2'-7"	-	YES*	
041-E	E-5	P	B ABOVE E	12"	-	NO	E TOTALLY ENCLOSED
		D	B BELOW E	1'-1"	12"	NO	B TOTALLY ENCLOSED
		C	B BELOW E	1'-11"	-	YES*	
041-F	D-3	P	B BELOW X	12"	-	NO	①
041-G	H-8	P	D NEXT TO X	-	6"	NO	①
		P	D ABOVE X	12"	-	NO	②
041-H	H-12	C	B BELOW X	12"	-	NO	①
041-I	E-8	P	E BELOW X	12"	-	NO	①
041-K	C-3	P	B ABOVE X	12"	-	NO	②, (3) ⑩ D
041-L	E-3	P	B ABOVE E	1'-2"	-	NO	E TOTALLY ENCLOSED
041-M	H-6	P,V	D NEXT TO X	-	6"	NO	② D TOTALLY ENCLOSED
041-N	E-10	C	B BELOW X	4'-2"	-	NO	①
041-P	E-9	C	M ABOVE B	2'-7"	-	YES*	

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER SERIES E-214 XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS SEE FSAR TABLE 8.3.4
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. ○ INDICATES SPECIAL NOTES - SEE SHEET SN 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 425'-0"

DRAWING NO. 04 446 SS-200 941 | SH. NO. 041-2 | REV D

GILBERT ASSOCIATES, INC.
ENGINEERS AND CONSULTANTS
READING, PA.

W.O. 04446-870 ENGINEER APPROVAL — DEPT — DATE

REV	MADE	CH	SQL	APP	DATE
C	DH	-	-	JC	9/1/97

REV	MADE	CH	SQL	APP	DATE
D	PF				

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR

ENGR.
DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
041-Q	G-9	P	L ABOVE J	12"	-	NO	③
		C	L ABOVE A	2'-7"	-	NO	② L TOTALLY ENCLOSED
		C	J ABOVE A	12"	-	NO	② J TOTALLY ENCLOSED
041-R	D-11	P V	B NEXT TO X	-	6"	NO	②, ①
041-S	D-7	P	E BELOW X	2'-7"	-	NO	①
041-T	C-5	P	A NEXT TO X	-	6"	NO	①
041-U	E-4	P	A ABOVE X	8"	-	NO	②
041-V	C-5	P	B ABOVE X	12"	-	NO	② ③ ⑥
041-W	G-5	C	B NEXT TO A	-	2'-8"	YES*	
041-X	C-4	D	B BELOW A	1'-7"	-	NO	③

D

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX.
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 436' 0"

MADE: EDB | CHKD: MS | DRAWING NO.: 0 1 | 4461 | SS-200-941 | SH. NO.: 002-1 | REV: C
SQ LOG: RWP | ENG INTENT: | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE | D. Kelly 0421 4/25/77 ENGINEER APPROVAL DEPT DATE
W.O. 04446-020

REV	MADE	CH	SQL	APP	DATE	REV	MADE	CH	SQL	APP	DATE
C	DH	-	-	RC	10 NOV	B					

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
042-A	C-14	P	B ABOVE X	10"	-	NO	② X TOTALLY ENCLOSED
042-B	D-11	P V	B NEXT TO X	-	6"	NO	②.①
042-C	C-5	P	A NEXT TO X	-	6"	NO	①.②
042-D	E-4	P	A ABOVE X	8"	-	NO	②
042-E	C-5	P	A ABOVE X	8"	-	NO	②
042-F	H-6	P V	D NEXT TO X	-	6"	NO	①
042-G	D-4	C	A ABOVE X	1'-8"	-	NO	②

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR

ENGR.
DATE

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER, SERIES E-214-XXX.
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SH 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 448'-0"

MADE: DJH | CHKD: [illegible] | DRAWING NO.: 0H 446 1 SS-200 911 | SH. NO.: 043 1 | REV.: C
SQ LOR: R4P | ENG INTERP: | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE: | W.O. 04446-020 | ENGINEER APPROVAL: [signature] (043) 2/23/87 DEPT DATE
REV C | MADE [illegible] | CH | SQL | APP | DATE 10 21 86 | REV B | MADE | CH | SQL | APP | DATE 2/23/87

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
043-A	D-12	C	A ABOVE B	8"	-	YES*	
043-B	F-4	C	A NEXT TO D	-	6"	NO	②.③
043-C	E-11	P.C	A ABOVE X	1'-3"	-	NO	②
043-D	E-8	P.C	A ABOVE X	1'-3"	-	NO	②
043-E	E-14	P	B ABOVE X	12"	-	NO	② X TOTALLY ENCLOSED
		P	B NEXT TO X	-	2'-0"	NO	① ②
		P	B NEXT TO A	-	4'-0"	NO	④
		P	A NEXT TO X	-	1'-8"	NO	①. ②.
043-F	G-4	P.C	A ABOVE D	4'-5"	-	NO	D TOTALLY ENCLOSED
043-G	G-5	C	A ABOVE X	12"	-	NO	②
		P.D	A ABOVE D	4'-5"	3'-0"	NO	③ ④
		C	A BELOW X	9"	-	NO	① ②
043-H	H-5	C	A ABOVE D	4'-5"	-	NO	③. ④
043-J	C-5	P	A BELOW X	11"	-	NO	①. ②
		P	A NEXT TO X	-	6"	NO	①. ②
043-K	D-11	P.V	B NEXT TO X	-	6"	NO	①. ②

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES

1 FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER, SERIES E 214 XXX
2 FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8 3-4
3 * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4 ( ) INDICATES SPECIAL NOTES SEE SHEET SN 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 463'-0"

MADE	CHKD	DRAWING NO.	SH. NO.	REV
KOB	11/4/5	0H 1NG1SS-200 9HH	0HH 1	C

SO LOR KWP — ENG INTERF — SCALE — GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.

W O 044461-070

ENGINEER APPROVAL REV	MADE	CH	SQL	APP	DATE	DEPT REV	MADE	CH	SQL	APP	DATE
C	KOB					B					

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
044-A	B-4	C	A ABOVE D	12"	-	NO	(1), (2) D TOTALLY ENCLOSED
		P	A BELOW D	2'-3"	-	NO	(3), (2)
044-B	F-4	P	A BELOW D	2'-3"	-	NO	(3), (2)
		P,V	A NEXT TO D	-	12"	NO	(3), (2)
044-C	G-5	C	A ABOVE X	2'-6"	-	NO	(2)
		P	A BELOW X	12"	-	NO	(1) (2) A TOTALLY ENCLOSED
044-D	E-10	C	B NEXT TO X (X VERTICAL)	-	6"	NO	(1)
		P	B ABOVE X	12"	-	NO	(1)
		P	B BELOW X	2'-7"	-	NO	(1)

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-714-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE B 3-4
3. * THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. ( ) INDICATES SPECIAL NOTES - SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 482' 0"

MADE: [illegible] CHKD: [illegible]
SO LOR: [illegible] ENG INTERF: [illegible]
SCALE:

DRAWING NO. 0H 446 ISS-200 911 | SH. NO 015-1 | REV C

GILBERT ASSOCIATES, INC.
ENGINEERS AND CONSULTANTS
READING, PA.

W O 04446 020 ENGINEER APPROVAL [illegible] DEPT [illegible] DATE 9/25/97

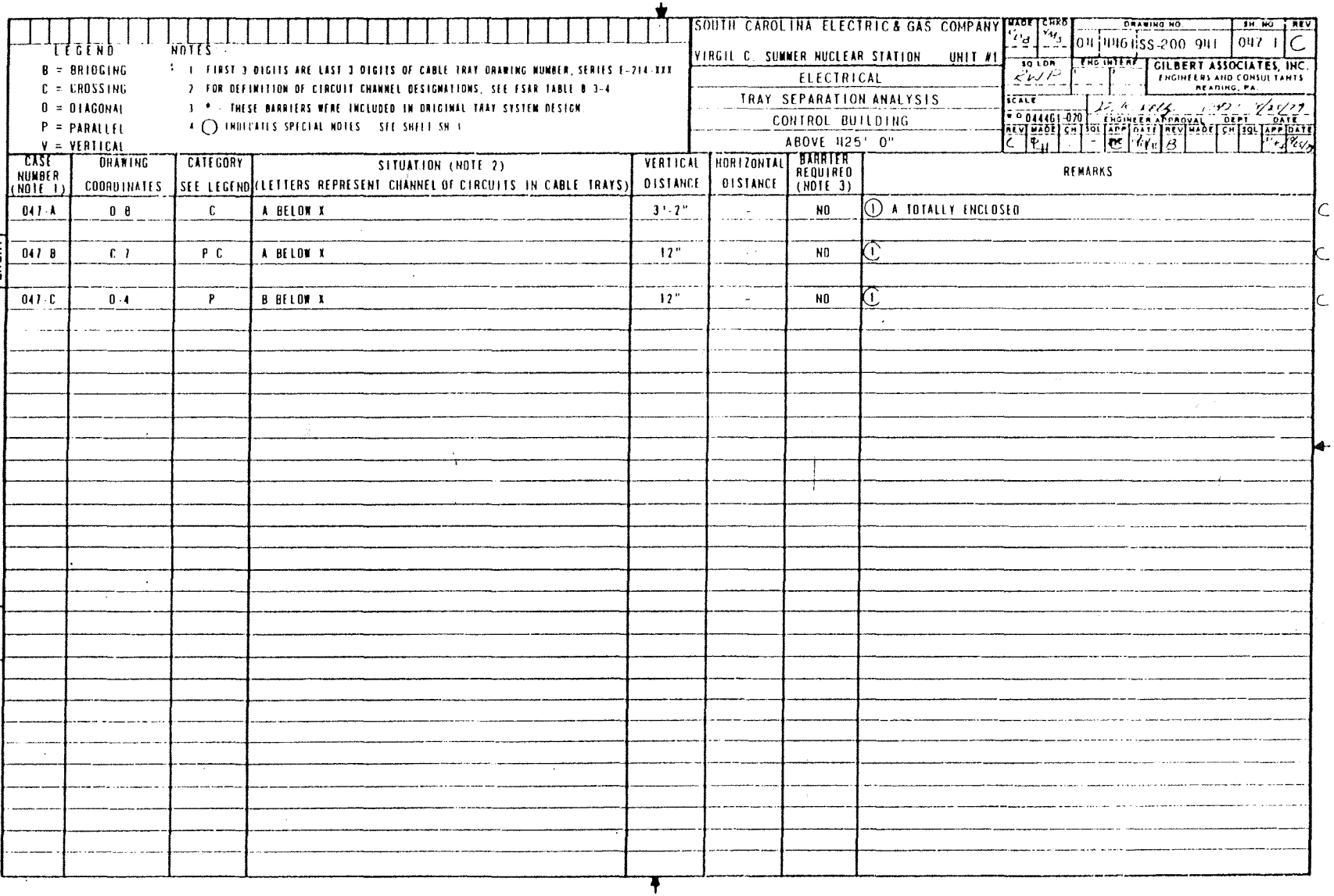
REV	MADE	CH	SQL	APP	DATE
C	[illegible]			[illegible]	9/11

REV	MADE	CH	SQL	APP	DATE
B					9/25

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR

ENGR.
DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
045-A	E 8	C	A BELOW X	5'-0"	-	NO	(1)
045-B	C-14	C	B BELOW X	3'-4"	-	NO	(1)



LEGEND
B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

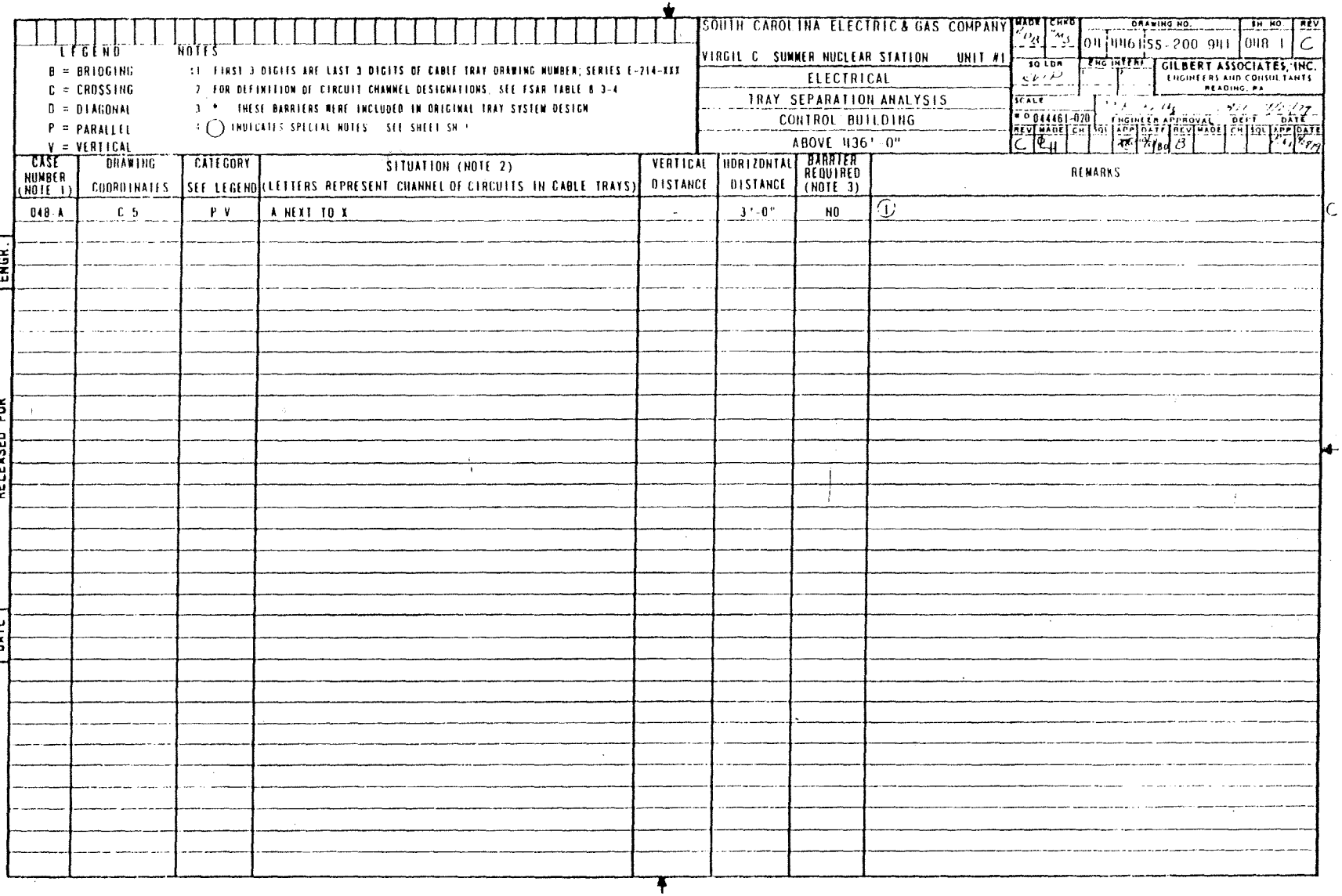
NOTES:
1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER, SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8 3-4
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SH 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 425' 0"

MADE CHKD | DRAWING NO. 04 0446 SS-200 911 | SH NO 047 1 | REV C
SQ LDR | ENG INTERP | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE | ENGINEER APPROVAL | DEPT | DATE
REV | MADE | CH | SQL | APP | DATE | REV | MADE | CH | SQL | APP | DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
047-A	D 8	C	A BELOW X	3'-2"	-	NO	(1) A TOTALLY ENCLOSED
047 B	C 7	P C	A BELOW X	12"	-	NO	(1)
047-C	D-4	P	B BELOW X	12"	-	NO	(1)

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE



LEGEND
B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES
1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4
3. * THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. ◯ INDICATES SPECIAL NOTES SEE SHEET SH 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 436' 0"

MADE 2/28 CHKD 3/5
DRAWING NO. 0H 2166SS-200 9H1
SH. NO 0H8 1
REV C
SQ LDR
ENG INTRF
GILBERT ASSOCIATES, INC.
ENGINEERS AND CONSULTANTS
READING, PA
SCALE
W.O 044461-020
ENGINEER APPROVAL DEPT DATE
REV MADE CH SQL APP DATE REV MADE CH SQL APP DATE
C 2/28 3/5 3/20 3/27

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
048.A	C 5	P V	A NEXT TO X	-	3'-0"	NO	(1)

RELEASED FOR
BIDDING PURPOSES
CONSTRUCTION

ENGR.
DATE

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES :

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER, SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4
3. * THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. ◯ INDICATES SPECIAL NOTES SEE SHEET SN 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 418' 0"

MADE: [illegible] CHKD: [illegible]
DRAWING NO.: 01 NNG ISS-200 941
SH. NO.: 009 1
REV: C
SQ LDR: EWP
ENG INSTR:
GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE:
W.O. 044461-020
ENGINEER APPROVAL: [illegible] 4/21 4/22/97
DEPT:
DATE:

REV	MADE	CH	SQL	APP	DATE
C	[illegible]	-	-	[illegible]	4/10

REV	MADE	CH	SQL	APP	DATE
B				[illegible]	[illegible]

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
049-A	D-13	P	B NEXT TO X	-	1'-4"	NO	(1)
049-B	F-13	P	B NEXT TO X	-	1' 6"	NO	(1)

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR

ENGR.	DATE

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES

1 FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2 FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4
3 * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4 ◯ INDICATES SPECIAL NOTES - SEE SHEET SH 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE ψ18'-0"

MADE 4-23 CHKD 4-25
DRAWING NO. 01 0061SS-200 911
SH NO. 051 1
REV C
SQ LOG 5225
ENG INTENT
GILBERT ASSOCIATES, INC.
ENGINEERS AND CONSULTANTS
READING, PA
SCALE
W.O. 04446-070
ENGINEER APPROVAL DEPT DATE
REV C MADE 4-11 CH - SQL APP DATE 4/28/94 REV 3 MADE CH SQL APP DATE 5/2/94

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEE OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS	
051-A	E-12	P	A NEXT TO X	-	12"	NO	(1)	C
		P	A NEXT TO B	-	4'-0"	NO	(4) (1)	C
		P	B NEXT TO X	-	2'-0"	NO	(1)	C

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

SOUTH CAROLINA ELECTRIC & GAS COMPANY

VIRGIL C. SUMMER NUCLEAR STATION UNIT #1

ELECTRICAL

TRAY SEPARATION ANALYSIS

AUXILIARY BUILDING

ABOVE 374'-0"

MADE CHKD | DRAWING NO. | SH. NO. | REV

GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.

SCALE | ENGINEER APPROVAL | DEPT. | DATE

W.O. 8444461-020

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. ◯ INDICATES SPECIAL NOTES SEE SHEET SW 1

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
071-A	I-7	P	A ABOVE X	3'-5"	-	NO	(2)
071 B	F 9	P	B BELOW X	1'-11"	-	NO	(1) (4) (2)
071-C	E-9	P	B NEXT TO X	-	6"	NO	(1) (6) D
071-D	F-12	P	D NEXT TO X	-	6"	NO	(3) (6) D
071-E	G-12	C	B ABOVE X	4'-5"	-	NO	(2)

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

8C-18

AMENDMENT 97-01

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. (C) INDICATES SPECIAL NOTES SEE SHEET SH 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
AUXILIARY BUILDING
ABOVE 388'-0"

MADE RDB 9/21 CHKD
DRAWING NO. 04 | 4461 | SS-200 | 011
SH. NO. 073 1
REV C
SQ LDR RWP
ENG INTERF
GILBERT ASSOCIATES, INC.
ENGINEERS AND CONSULTANTS
READING, PA.
SCALE
W O 04446 | 020
ENGINEER APPROVAL DEPT DATE
REV C | MADE RDB 9/21 | CH | SQL | APP | DATE 9/21/79 | REV 3 | MADE | CH | SQL | APP | DATE 9/29/79

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
073-A	H-9	P	A NEXT TO X	-	12"	NO	(1) (2) C

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-274-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE H.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. ◯ INDICATES SPECIAL NOTES SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
AUXILIARY BUILDING
ABOVE 397'-0"

MADE: BOB CHKD: MMS
DRAWING NO.: 04 NN61 SS-200 911
SH. NO.: 074 1
REV: D
SO LOR: RWP
ENG INTERF:
GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE:
P.O. 84461-020
ENGINEER APPROVAL / DEPT / DATE

REV	MADE	CH	SQL	APP	DATE
C	KH	-	-		4/1/96

REV	MADE	CH	SQL	APP	DATE
D	PF				

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
074-A	D-9	P	A NEXT TO X	-	1'-2"	NO	(1)
074-B	F-12	D	B ABOVE X	1'-2"	12"	NO	(2) (6)

CONSTRUCTION / BIDDING PURPOSES RELEASED FOR

DATE	ENGR.

D

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-714-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
AUXILIARY BUILDING
ABOVE 412'-0"

MADE RDB CHKD MMS — DRAWING NO. 011 4461 SS-200 911 — SH. NO. 076-1 — REV D
SQ LOR 2W P — ENG INTENT — GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE — P.O. 84446-020 — ENGINEER APPROVAL — DEPT — DATE

REV	MADE	CH	SQL	APP	DATE	REV	MADE	CH	SQL	APP	DATE
C	PH	-	-	[illegible]	11/1/10	D	PP				

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
076-A	F-9	P	A NEXT TO X	-	2'-4"	NO	(1)
		D	A BELOW X	9"	1'-10"	NO	(1)
076-B	D 6	P	A NEXT TO X	-	2'-9"	NO	(1) (6)
076-C	J-9	P	A NEXT TO X	-	3'-9"	NO	(1)
		P	A BELOW X	12"	-	NO	(1)
076-D	G-9	P	A NEXT TO X	-	2'-4"	NO	(1)
		P	A BELOW X	12"	-	NO	(1)
076-E	J-4	P	B NEXT TO X	-	1'-6"	NO	(1)
076-F	G-5	P	B BELOW X	9"	-	NO	(1)

D

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
AUXILIARY BUILDING
ABOVE 412'-0"

MADE EDB CHKD HMJ | DRAWING NO. 04 1116 SS-200 911 | SH. NO 077 | REV C
SO LOR RWP | ENG INTERF | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE | W O 044401-020 | ENGINEER APPROVAL | DEPT | DATE 4/5/79

REV	MADE	CH	SQL	APP	DATE
C	EH	-	-	[illegible]	9/4/78

REV	MADE	CH	SQL	APP	DATE
B				[illegible]	9/4/79

CONSTRUCTION BIDDING PURPOSES RELEASED FOR ENGR. DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
077-A	H-9	P	A NEXT TO X	-	6"	NO	(1)
077 B	G-9	P	A NEXT TO X	-	3'-3"	NO	(1), (4
077-C	B-8	P	A BELOW X	12"	-	NO	(1)
077-D	B-8	P	A BELOW X	7'-10"	-	NO	1, 4
077-E	B-6	C	A BELOW X	1'-2"	-	NO	1
077-F	B-5	P	B NEXT TO X	-	1'-6"	NO	(1)
077-G	E-5	P	B NEXT TO X	-	1'-9"	NO	(1)
		B	X ABOVE A AND B	5"	-	NO	(1) X GOES THROUGH FIRE STOP IN WALL
077-H	H-5	P	B NEXT TO X	-	6"	NO	(1)
077-J	H-2	P	B NEXT TO E	-	1'-2"	YES*	
		D	B BELOW E	12"	1'-2"	YES*	
077-K	G-2	P	B NEXT TO E	-	2'-6"	YES*	

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:-

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX.
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
AUXILIARY BUILDING
ABOVE 436'-0"

DRAWING NO.	SH. NO.	REV
04 1146 SS-200-941	078-1	D

GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.

SCALE

W.O. 04446-070

ENGINEER APPROVAL				DEPT	DATE				
REV	MADE	CH	SQL	APP	DATE	REV	MADE	CH	SQL	APP	DATE
C	[illegible]	-	-	[illegible]	7/1/96	D	PE				

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS	
078-A	H-9	P	A BELOW X	1'-2"	-	NO	(1)	
078-B	J-5	P	A ABOVE X	6'-2"	-	NO	(4)	
078-C	H-6	C	A ABOVE B	5'-2"	-	NO	(4)	
		C,P	B ABOVE X	3'-0"	-	NO	(5) (6)	D
078-D	J-6	C	A ABOVE X	5'-2"	-	NO	(4)	
		C,P	A BELOW X	3'-0"	-	NO	(1) (6)	D
078-E	G-6	C,P	A ABOVE B	6'-2"	-	NO	(4)	
078-F	J-6	P	A ABOVE X	6'-2"	-	NO	(4)	
078-G	H-6	P	A ABOVE B	6'-2"	-	NO	(4)	
078-H	F-3	P	A BELOW X	12"	-	NO	(1)	
078-J	G-5	P	A BELOW X	12"	-	NO	(1)	
078-K	G-7	C	A BELOW X	6"	-	NO	(1)	
		P	A BELOW X	6'-3"	-	NO	(1)	

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER, SERIES E-214 XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. (n) INDICATES SPECIAL NOTES - SEE SHEET SH 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
AUXILIARY BUILDING
ABOVE 436'-0"

MADE KOB CHKD VMS | DRAWING NO. 0U 446 SS-200-911 | SH. NO. 079-1 | REV D
SQ LOR KNP | ENG INTENT | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE | W.O. 04446-020 | ENGINEER APPROVAL | DEPT | DATE 4/30/98
REV C | MADE PH | CH - | SQL - | APP | DATE | REV D | MADE PF | CH | SQL | APP | DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS	
079-A	G-12	C	B NEXT TO X (B VERTICAL)	-	3'-9"	NO	(1), (4)	
079-B	E-12	C	B NEXT TO X (B VERTICAL)	-	3'-9"	NO	(1), (4)	
079-C	D-9	P	A BELOW X	1'-10"	-	NO	(1)	
		P	A NEXT TO X	-	6"	NO	(3)	
079-D	B-9	P	A BELOW X	1'-2"	-	NO	(1)	
079-E	G-9	P	A BELOW X	11"	-	NO	(1)	
		P	A NEXT TO X	-	8"	NO	(3) (6)	D
079-I	F-6	C	A ABOVE X	10"	-	NO	(5)	
079-G	D-6	P	A NEXT TO X	-	2'-0"	NO	(1)	
079-H	D-6	C	A ABOVE X	2'-1"	-	NO	(5) (6)	D
079-J	C-6	D	A ABOVE X	5"	6"	NO	(5) (6)	D

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR

DATE	ENGR.

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:-

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-714-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
AUXILIARY BUILDING
ABOVE 463'-0"

MADE: BOB CHKD: MS | DRAWING NO.: 04 1461 SS-200-941 | SH. NO.: 080-1 | REV: D
SQ LOR: EWP | ENG INTERF: | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE: | W.O. 84446-070 | ENGINEER APPROVAL: DEPT: DATE: 4/25/77

REV	MADE	CH	SQL	APP	DATE
L	TH	-	-	[illegible]	4/11

REV	MADE	CH	SQL	APP	DATE
D	PF				

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
080-A	J-12	P	B BELOW X	12"	-	NO	(1)
		P	B ABOVE X	8"	-	NO	(5)
		P	B NEXT TO X	-	3'-3"	NO	(1) (4)
080-B	F-12	P	B ABOVE X	8"	-	NO	(5)
		P	B BELOW X	12"	-	NO	(1)
080-C	E-10	P	B ABOVE X	8"	-	NO	(5)
		P	B BELOW X	12"	-	NO	(1)
		O	B NEXT TO X	2'-1"	4'-6"	NO	(1) (4)
080-D	D-6	P	B ABOVE X	8"	-	NO	(5)
		P	B BELOW X	12"	-	NO	(1) (6)
080-E	K-8	P	O NEXT TO L	-	8"	NO	(3) (6)

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

D
D

LEGEND
B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:
1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
AUXILIARY BUILDING
ABOVE 463' 0"

MADE CDB CHKD MM 2
DRAWING NO. 01 1461 SS-200-911
SH. NO. 081-1
REV D
SQ LOG 2WP
ENG INTERF
SCALE
W.O. 94446-070
ENGINEER APPROVAL DEPT DATE
GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.

REV	MADE	CH	TQL	APP	DATE
C	[illegible]	-	-	[illegible]	9/1/0

REV	MADE	CH	TQL	APP	DATE
D	PE				1.

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
081-A	H-13	P	D NEXT TO X	-	3"	NO	(1). (2) D TOTALLY ENCLOSED
		P	D ABOVE A	11"	-	NO	(3)
		P	A NEXT TO X	-	3"	NO	(1). (2). (3) (6)
081-B	G-16	P	B ABOVE X	8"	-	NO	(5)
		P	B NEXT TO X	-	1"	NO	(1)
		P	B BELOW X	1'-1"	-	NO	(1)
081-C	F-14	P	B ABOVE X	8"	-	NO	(5)
		P	B BELOW X	12"	-	NO	(1)
081-D	D-12	P	B BELOW X	12"	-	NO	(1)
		P	B ABOVE X	11"	-	NO	(5)
		P	D BELOW X	12"	-	NO	(1). (2). D TOTALLY ENCLOSED
081-E	E-12	P	B BELOW X	12"	-	NO	(1)
		P	B ABOVE X	8"	-	NO	(5)
		P	D BELOW X	12"	-	NO	(1) (2) D TOTALLY ENCLOSED
081-F	B-12	C	B BELOW X	3"	-	NO	(1) (2)
			B ABOVE X	10"	-	NO	(5)
			D BELOW X	12"	-	NO	(1). (2) D TOTALLY ENCLOSED
081-G	B-12	P	B BELOW X	12"	-	NO	(1)
		P	B ABOVE X	10"	-	NO	(5)
081-H	B-10	P	D BELOW X	12"	-	NO	(1)
		P	D NEXT TO X	-	6"	NO	(3) (6)
081-I	B-8	P	D NEXT TO X	-	6"	NO	(3) (6)

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

D
D
D

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX.
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
AUXILIARY BUILDING
ABOVE 463' 0"

MADE EDB CHKD MAS | DRAWING NO. OH 446 SS-200 911 | SH. NO. 081 2 | REV C
EQ LOR RWP | ENG INTERF | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE | W.O. 04446-020 | ENGINEER APPROVAL | DEPT | DATE
REV C MADE EW CH SQL APP DATE 7/11/10 | REV B MADE CH SQL APP DATE 8/15/97

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS	
081-K	G-9	P V	A NEXT TO X	-	3"	NO	(1)	C
081-L	G-10	P	A NEXT TO X	-	3'-2"	NO	(1)	C
		C	A BELOW X	1'-5"	-	NO	(1)	C
081-M	D 8	V	A ABOVE X	4'-0"	-	NO	(5)	C
081-N	G-12	C	B ABOVE X	10"	-	NO	(5)	C
		D	B ABOVE D	2'-1"	3"	NO	(1), (2). D TOTALLY ENCLOSED	C
		D	D ABOVE A	11"	2'-0"	NO	BOTH TRAYS TOTALLY ENCLOSED	

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SH-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
REACTOR BUILDING
ABOVE 412'-0"

MADE RDD CHKD WMS | DRAWING NO. 01 1161 SS-200 941 | SH. NO. 101-1 | REV D
SQ LOG SWP | ENG INTERF | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE | W O 044461-020
REV C MADE TPH CH - SQL - APP'D ENGINEER APPROVAL DATE 4/10/96
REV D MADE PK CH SQL APP'D DEPT DATE 5/1/97

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
101-A	O-7	P	B ABOVE E	12"	-	NO	(3)
		P	E NEXT TO X	-	8"	NO	(1) (2) (6)
		P	B NEXT TO X	-	6"	NO	(1) (2)
		P	B ABOVE X	12"	-	NO	(2)
101-B	K-9	P	B ABOVE E	1'-7"	-	NO	(3)
		C	B BELOW X	1'-3"	-	NO	(1) (2)
		P	E NEXT TO X	-	6"	NO	(1) (2)
		P	B NEXT TO X	-	6"	NO	(1) (2)
		P	B ABOVE X	1'-7"	-	NO	(2)
101-C	K-10	P	B ABOVE E	6"	-	NO	(3)
		P	E NEXT TO X	-	6"	NO	(1) (2)
		C	B ABOVE X	6"	-	NO	(2)
		P	B ABOVE X	1'-7"	-	NO	(2)
		P	B NEXT TO X	-	6"	NO	(1)
101-D	K-12	C	B ABOVE X	6"	-	NO	(3) (6)
		P	B ABOVE E	1'-7"	-	NO	(3) (6)
		C	E BELOW X	6"	-	NO	(3) (6)
		P	E NEXT TO X	-	8"	NO	(1) (2) (6)
		P	B ABOVE X	1'-7"	-	NO	(2)
		P	B NEXT TO X	-	6"	NO	(1)
101-E	H-14	P	B ABOVE E	1'-7"	-	NO	(3) (6)
		P	E NEXT TO X	-	8"	NO	(1) (2) (6)
		P	B ABOVE X	1'-7"	-	NO	(2)
		P	B NEXT TO X	-	6"	NO	(1) (2)

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX.
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ( ) INDICATES SPECIAL NOTES - SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
REACTOR BUILDING
ABOVE 412'-0"

MADE KDB 4/25/97 CHKD NMS
DRAWING NO. 04 4461 SS-200-911 SH. NO. 101 2 REV D
SO LOM RWP
ENG INVERT
SCALE
GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
W O 04446-070
ENGINEER APPROVAL DEPT. DATE
REV C MADE LD 11 CH - SQL - APP DATE 4/25/97 REV D MADE PF CH SQL APP DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS	
101-F	F-15	P	E BELOW X	12"	-	NO	(1)	(6)
		P	E NEXT TO X	-	1'-3"	NO	(3)	(6)
		P	B NEXT TO E	-	1'-8"	NO	(3)	
		P	B NEXT TO X	-	12"	NO	(1) (2)	
		C	B BELOW X	1'-10"	-	NO	(1)	(6)
101-G	C-15	P	B BELOW X	10"	-	NO	(1)	(6)
		P	B NEXT TO E	-	9"	NO	(3)	
		P	E NEXT TO X	-	1'-8"	NO	(1)	(6)
		P	E BELOW X	2'-5"	-	NO	(1)	(6)

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

SOUTH CAROLINA ELECTRIC & GAS COMPANY

VIRGIL C. SUMMER NUCLEAR STATION UNIT #1

ELECTRICAL

TRAY SEPARATION ANALYSIS

REACTOR BUILDING

ABOVE 436'-0"

DRAWING NO. 04 0461 SS-200 911 | SH. NO. 102 1 | REV D.

GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.

LEGEND

B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX.
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
102-A	F-7	P	A NEXT TO X	-	12"	NO	(1)
		P	A ABOVE D	12"	-	NO	(3)
		P	D NEXT TO X	-	1'-3"	NO	(3) (6)
102-B	C-14	P	A NEXT TO X	-	6"	NO	(1)
		P	A ABOVE D	1'-2"	-	NO	(3)
		P	D NEXT TO X	-	6"	NO	(3) (6)
102-C	F-15	C	D ABOVE X	1'-2"	-	NO	(3) (6)
		C	D BELOW X	1'-5"	-	NO	(1) (2) (6)
		C	A ABOVE D	2'-6".	-	NO	(3)
		P	A NEXT TO X	-	2'-9"	NO	(1)
102-D	H-15	P	A BELOW X	8"	-	NO	(1) (2)
		P	A ABOVE D	8"	-	NO	(2). D TOTALLY ENCLOSED
		P	A NEXT TO D	-	6"	NO	(3)
102-E	K-10	P	A NEXT TO X	-	1'-2"	NO	(1)
		P	A ABOVE D	12"	-	NO	(3)
		P	D NEXT TO X	-	1'-5"	NO	(3)

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR

ENGR.
DATE

LEGEND

B = BRIDGING
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P = PARALLEL
V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
INTERMEDIATE BUILDING
ABOVE 412'-0"

MADE DJB CHKD MJS | DRAWING NO. 04 4461 SS-200-941 | SH. NO. 131-1 | REV C
SQ LOR RWP | ENG INTERF | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE | ENGINEER APPROVAL | DEPT | DATE
P.O. 044461-070

REV	MADE	CH	SQL	APP	DATE	REV	MADE	CH	SQL	APP	DATE
C	DJB	-	-	KT	7/14/97	3					

CONSTRUCTION
BIDDING PURPOSES
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ENGR.
DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
131-A	D-16	P	B ABOVE X	12"	-	NO	(3)
		P	B NEXT TO X	-	6"	NO	(1) (2)
		P	B BELOW X	12"	-	NO	(1) (2)
131-B	E-15	P	B ABOVE E	1'-2"	-	NO	E TOTALLY ENCLOSED
		P	B NEXT TO E	-	1'-3"	NO	E TOTALLY ENCLOSED
131-C	D-14	P	B ABOVE E	1'-2"	-	NO	E TOTALLY ENCLOSED
		P	B NEXT TO E	-	1'-3"	NO	E TOTALLY ENCLOSED
		P	B ABOVE X	1'-7"	-	NO	(3)
		P	B NEXT TO X	-	6"	NO	(1) (2)
131-D	C-13	P	B NEXT TO X	-	6"	NO	(1)
		D	B ABOVE X	12"	6"	NO	(5)
		D	B BELOW X	12"	6"	NO	(1)
131-E	C-11	P	B NEXT TO E	-	1'-3"	NO	E TOTALLY ENCLOSED
		D	B BELOW E	12"	1'-3"	NO	E TOTALLY ENCLOSED
131-F	E-12	P	B ABOVE E	1'-2"	-	NO	E TOTALLY ENCLOSED
		P	B NEXT TO E	-	1'-2"	NO	E TOTALLY ENCLOSED
131-G	E-10	P	B ABOVE E	3'-3"	-	NO	E TOTALLY ENCLOSED
		C	B ABOVE E	12"	-	NO	E TOTALLY ENCLOSED
131-H	D-7	P	B ABOVE X	2'-5"	-	NO	X TOTALLY ENCLOSED
		P	B NEXT TO X	-	6"	NO	(1), X TOTALLY ENCLOSED
131-J	F-13	C	B BELOW X	3"	-	NO	
		C	B ABOVE X	4"	-	NO	

LEGEND

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NOTES:

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2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMNER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
INTERMEDIATE BUILDING
ABOVE 412'-0"

MADE RDB CHKD MMS | DRAWING NO. 04 0061 SS-200-911 | SH. NO. 131 2 | REV D
SQ LDR RWP | ENG INVEST | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE | W.O. 04446-020 | ENGINEER APPROVAL DEPT DATE
REV C | MADE PH | CH - | SQL - | APP PE | DATE 9/1/10 | REV D | MADE PE | CH | SQL | APP | DATE

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
131-K	G-11	C	B ABOVE X	5"	-	NO	⑤
131-L	G-7	P	A ABOVE X	10"	-	NO	⑤
		P	A NEXT TO X	-	0"	NO	①
		D	A ABOVE X	10"	8"	NO	⑤ ⑥
131-M	J-10	C,D	A BELOW C	6"	2'-3"	YES*	
131-N	J-7	C,V	A BELOW X (X VERTICAL)	6"	-	NO	①
		P	A NEXT TO X	-	6"	NO	①

CONSTRUCTION
BIDDING PURPOSES
RELEASED FOR
ENGR.
DATE

D

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P = PARALLEL
V = VERTICAL

NOTES:

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2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.

/ ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
INTERMEDIATE BUILDING
ABOVE 412'-0"

MADE: RDB CHKD: MMS
DRAWING NO.: 04 4461 SS-200-911
SH. NO.: 132 1
REV: C
SQ LOA: RWP
ENG INTENT:
GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE:
W.O. 044461-020
ENGINEER APPROVAL: H. K. Keck 0021 9/25/97

REV	MADE	CH	SQL	APP	DATE
C	RH			[illegible]	9/11/10

REV	MADE	CH	SQL	APP	DATE
B				RH	8/1/97

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS	
132-A	J-11	C	A BELOW X	4"	-	NO	(1)	C
		C	A ABOVE X	10"	-	NO	(5)	C
132-B	F-11	P	B ABOVE X	1'-10"	-	NO	(2). X TOTALLY ENCLOSED	C
		P	B NEXT TO X	-	6"	NO	(1). (2)	C

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NOTES:

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2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN 1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
INTERMEDIATE BUILDING
ABOVE 436' 0"

MADE: ROB CHKD: MS
DRAWING NO.: 0H 446 ISS 200 911
SH. NO.: 133-1
REV: C
SQ LOG: RWP
ENGINEER:
GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE:
W O 04446 020
ENGINEER APPROVAL: P. A. Kelly 0921 DEPT 3/21/79 DATE
REV C MADE PH CH SQL APP DATE
REV B MADE CH SQL APP DATE 3/19/79

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS	
133-A	H-10	C V	A NEXT TO X (A VERTICAL)	-	2'-6"	NO	(1)	C
		C	A BELOW X	10"	-	NO	(1)	C
133-B	H-13	C V	A NEXT TO X (A VERTICAL)	-	1'-2"	NO	X TOTALLY ENCLOSED	
133-C	E-14	C	A ABOVE X	7"	-	NO	(5)	C

CONSTRUCTION
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V = VERTICAL

NOTES
1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
INTERMEDIATE BUILDING
ABOVE 463'-0"

DRAWING NO. 04 | 0461 | SS-200 941 | SH. NO. 135-1 | REV C

GILBERT ASSOCIATES, INC.
ENGINEERS AND CONSULTANTS
READING, PA.

SCALE

W.O. 044461-020

ENGINEER APPROVAL DEPT DATE 7/24/79

REV	MADE	CH	SQL	APP	DATE
C	PH			JE	7/11/79

REV	MADE	CH	SQL	APP	DATE

CASE NUMBER (NOTE 1)	DRAWING CODRDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
135-A	J-14	P	A BELOW X	12"	-	NO	(1)
		C	A BELOW X	12"	-	NO	(1)
135-B	G 14	P	A ABOVE X	12'	-	NO	(5)
		P	A BELOW X	1'-3"	-	NO	(1)

CONSTRUCTION
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ENGR.
DATE

LEGEND

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V = VERTICAL

NOTES:

1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
PENETRATION ACCESS AREA
ABOVE 412' 0"

MADE: RDB CHKD: MJ2
DRAWING NO.: 04 NN6 SS-200 911
SH. NO.: 141 1
REV: C
SQ LOR: R W P
END INTERF:
GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.
SCALE:
W.O. 04446-070

REV	MADE	CH	ENGINEER APPROVAL SQL	APP	DATE	DEPT REV	MADE	CH	SQL	APP	DATE
C	[illegible]	-	-	[illegible]	4/11/97	B				[illegible]	4/11/97

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
141-A	G-11	D	B ABOVE X	1'-9"	3'-6"	NO	④. X TOTALLY ENCLOSED

C

CONSTRUCTION
BIDDING PURPOSES
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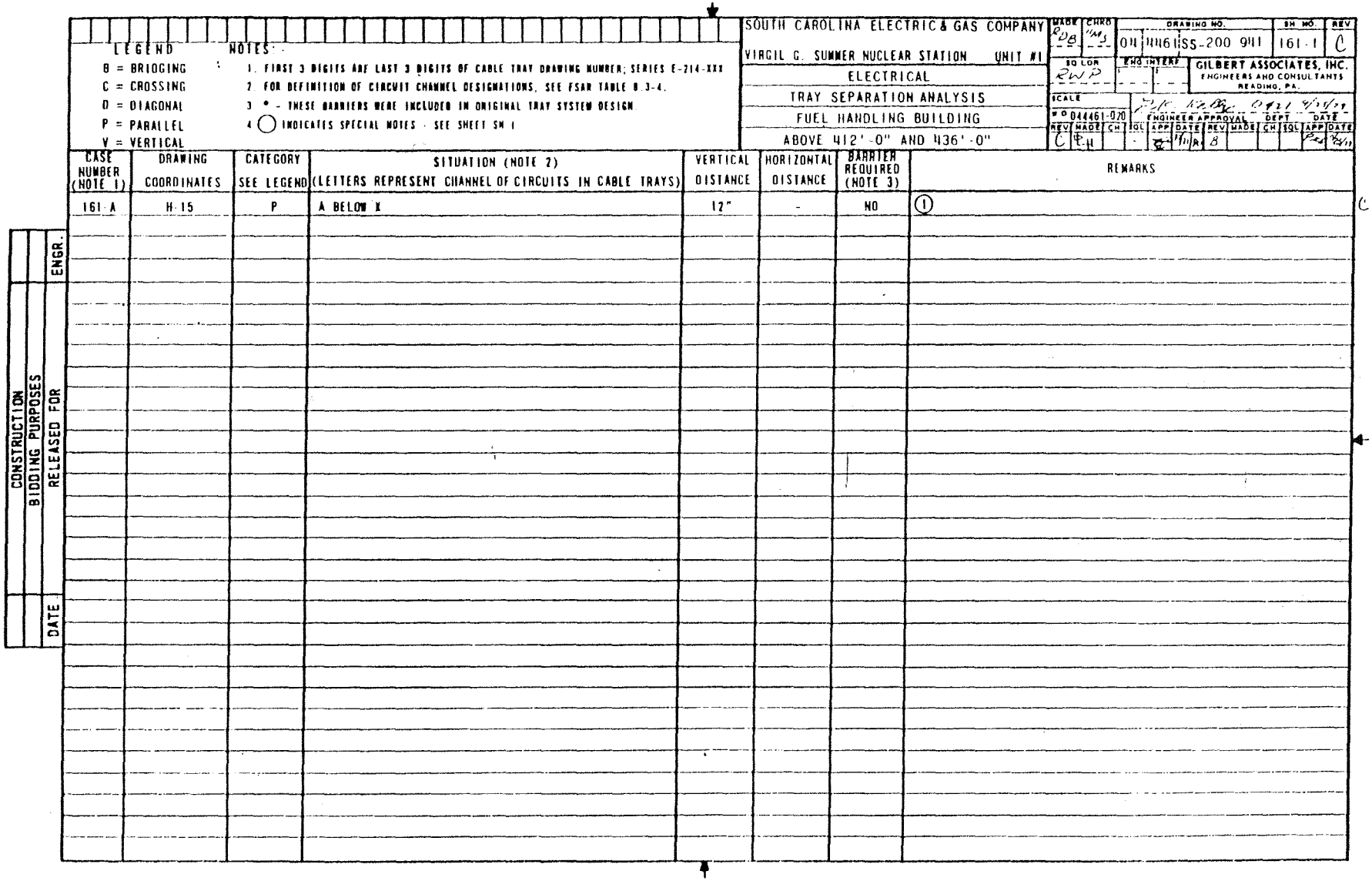
DATE



SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
FUEL HANDLING BUILDING
ABOVE 412'-0" AND 436'-0"

DRAWING NO. 01 NN61SS-200 911 | SH NO. 161-1 | REV C
GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.

LEGEND
B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:
1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. • - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN 1

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
161-A	H-15	P	A BELOW X	12"	-	NO	(1)

CONSTRUCTION
BIDDING PURPOSES
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DATE

SOUTH CAROLINA ELECTRIC & GAS COMPANY

VIRGIL C. SUMMER NUCLEAR STATION UNIT #1

ELECTRICAL

TRAY SEPARATION ANALYSIS

FUEL HANDLING BUILDING

ABOVE 463'-0"

MADE BY: EDB CHKD: MJS

DRAWING NO.: 04 N461 SS-200-911 | SH. NO.: 162-1 | REV: C

SQ LOR: RWP | ENG INTERP: | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.

SCALE: | W.O. 04446-020 | ENGINEER APPROVAL: R.K. Kelly 0421 DEPT 7/25/97 DATE

REV	MADE	CH	SQL	APP	DATE	REV	MADE	CH	SQL	APP	DATE
C	EDB				4/11/97	B					7/25/97

LEGEND

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NOTES:

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2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SH-1

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
162-A	G-15	P	B ABOVE X	8"	-	NO	(5)
		P	B BELOW X	12"	-	NO	(1)
	G-13	P	B NEXT TO X	-	12"	NO	(1)
		P	B BELOW X	12"	-	NO	(1) (2)

CONSTRUCTION
BIDDING PURPOSES
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DATE

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C SUMMER NUCLEAR STATION UNIT #1
ELECTRICAL
TRAY SEPARATION ANALYSIS
SPECIAL NOTES

DRAWING NO. 04 1166 SS-200-941 | SH. NO. SN-1 | REV B

GILBERT ASSOCIATES, INC.
ENGINEERS AND CONSULTANTS
READING, PA.

SCALE | P.O. 044461 070 | ENGINEER APPROVAL | DEPT | DATE

REV	MADE	CH	SQL	APP	DATE	REV	MADE	CH	SQL	APP	DATE
B	PF										

CONSTRUCTION
BIDDING PURPOSES
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ENGR.
DATE

NOTES FOR SN-1

1 FIRE WILL NOT PROPAGATE DOWN OR HORIZONTAL

2 CONTROL OR INSTRUMENT TRAY HAVE VERY LOW INTERNAL ENERGY LEVELS THEREFORE, ENERGY IS NOT AVAILABLE TO INITIATE A FIRE

3 TRAYS ARE TOTALLY ENCLOSED

4 ADEQUATE SPACIAL SEPARATIONS MAINTAINED

5 ONLY ONE CHANNEL OF CLASS 1E CIRCUITS AFFECTED THEREFORE, SYSTEM SAFETY FUNCTIONS MAINTAINED

6. This analysis concluded a barrier was not required. However, a barrier was subsequently installed in compliance with the licensing commitment to provide barriers for multiple separation violations as described in paragraph 8.3.1.4.1, Item 4.

Appendix 8D
Analysis of the Acceptable Voltage Range to be Applied to the ESF System

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APPENDIX 8D
ANALYSIS OF THE ACCEPTABLE VOLTAGE RANGE TO BE APPLIED TO THE ESF SYSTEM

8D.1 CRITERIA

This calculation was based on two criteria:

- The voltage at each piece of safety related equipment must be within the safe operating range for that piece of equipment.
- The voltage of the offsite sources must be sufficient to operate the required loads in the event of an accident without actuating the degraded voltage relays.

NOTE: This section is being retained for historical purposes only.

8D.2 METHOD

In preparation for the development of the calculations, a “Feeder/Load Data Base” was developed and verified. This data base contains information on the characteristics of the safety related loads and their feeder circuits, including the demand load for various plant operating conditions. The characteristics for the system equipment and materials, such as transformers and cables, were taken from the “as-built” data for the specific equipment and materials.

The system calculations were performed using electrical analysis software. The first calculation established a base case model of the electrical power distribution system. This model includes the existing transformer tap settings which include a 2.5% boost for the 480 volt unit substation transformers 1DA1, 1DA2, 1DB1, and 1DB2. For unit substations, 1EA1 and 1EB1 and for the emergency auxiliary and safeguards transformers, the taps are set at the nominal position. Throughout the calculation process, the transformer tap settings were reviewed to determine if revised settings could improve the overall performance of the system. (Reference Calculation DC-820-001.)

The next calculation modified the base case system model to evaluate the system under the worst case loading conditions. This condition results from the large break LOCA accident during the injection phase. The source voltage in this model was manually reduced and the system was repeatedly analyzed in an iterative process until the worst case motor terminal voltage was reduced to 90% of its rated voltage. The motors in V. C. Summer Station were specified and designed for steady state operation with a terminal voltage in the range of ± 10% of their rated voltage. The voltage at the motor control center (MCC) buses was also checked and found to exceed 420 volts.

This ensures that there is sufficient voltage for the pick-up of the MCC contactors. The resulting system model established that a voltage equal to or greater than 90.2% on 7.2 kV buses 1DA and 1DB is sufficient to ensure adequate voltage at the terminals of the safety related motors. Since the purpose of this part of the evaluation is to determine the minimum 7.2 kV bus voltage to provide adequate terminal voltage for all Class 1E loads, the number of buses connected to the offsite source and the voltage of the offsite source are not significant. The results of this model are summarized in Table 7.3.3 of Calculation DC-820-001.

With the minimum 7.2 kV bus voltage established, the next effort determined the minimum setpoint for the degraded voltage relays. Since these relays have a tolerance on both their calibration and operation, a detailed evaluation of the total tolerance band was performed. This determined a total tolerance band of ± 0.328%. Since the relay must operate before the 7.2 kV buses reach the minimum acceptable voltage, the setpoint value must exceed the minimum value by an amount at least equal to the tolerance. To provide both a margin and consistency with the previous settings, the setpoint was established at 91.34% of rated voltage. (Reference Calculation DC-820-001.)

Based on the degraded voltage relay setting, the tolerance on the relay calibration and operation, and the response of the SCE&G transmission system to a trip of the V. C. Summer Nuclear Station, the next part of the effort determined the minimum acceptable offsite source voltages during normal plant operation.

Studies of the transmission system under extreme loading and system configuration conditions have determined that 230 kV system voltage will dip to 95.5% of the pre-trip voltage in the event of a unit trip. After less than 3 seconds, the system voltage will recover to 97.1% of the pre-trip voltage. Similarly, the 115kV system voltage will dip to 95.6% of the pre-trip voltage in the event of a unit trip and will recover in less than 3 seconds to 97.3% of the pre-trip voltage.

Electrical analysis software was used to model the effects of motor starting conditions due to an accident loading sequence on the 230 kV and 115 kV offsite sources. Based on the tolerance band of the relays and the motor inrush conditions, the 7.2 kV bus voltage must be at least 93.9% of rated voltage prior to motor starting to avoid relay actuation (including a 1% margin which was determined to be unnecessary subsequent to the completion of the calculation). The minimum pre-accident voltage is also dependent on the number of plant buses connected to each offsite source. In a further evaluation, the capabilities of the various combinations of safeguard transformers and the voltage regulating transformer were determined and combined with the worst case voltage dip resulting from a unit trip. The results of these evaluations are summarized in Table 8.2-2. (Reference Calculation DC-820-001.)

The final part of the analysis determined the maximum allowable offsite system voltages. Additional system models were developed with electrical analysis software for plant operation in modes 5 or 6, cold shutdown or refueling. One model evaluated the system using the emergency

auxiliary transformer, XTF-31, as the source and the second model used the safeguard transformers, XTF-4 and 5, as the source. The loading consisted of the minimum set of equipment that would be expected to be operational during plant shutdown and only one of the two trains of ESF equipment was supplied from each offsite source. The models were repeatedly analyzed with increased source voltages until the worst case motor terminal voltage reached 110% of motor rated voltage. The results of these models are summarized in Table 8.D-2, and the maximum voltage limits are included in Table 8.2-2.

8D.3 CONCLUSION

As described above, the 7.2 kV bus voltage must be at least 90.2% of rated voltage to ensure the voltage at motor terminals exceeds the rated minimum motor voltage for steady state operation. This voltage is also sufficient to ensure MCC contactor pick-up. (Reference Calculation DC-876-007.)

The setpoint for the degraded voltage relays must be at least 90.528% of rated voltage to ensure that the relays actuate when the 7.2 kV bus voltage reaches the minimum defined above. The actual relay setpoint is 91.34% of rated voltage.

The offsite system voltages must exceed the minimum values listed in Table 8.2-2 (Reference Calculation DC-820-001) in order to ensure that the degraded voltage relays will reset after the first loading step and will not (inadvertently) drop-out on subsequent steps in the event of an accident. These minimum voltages are dependent on the number of buses connected to each offsite source, the arrangement of transformers, and on whether the voltage regulator is in service.

The voltage of the offsite sources must not exceed 104.2% of rated in order to avoid excessive voltage on motor terminals. The 115 kV line voltage can be higher than this if the voltage regulator is in service.

No improvement in overall system performance can be obtained with alternative transformer tap settings.

Table 8.D-2
CALCULATED MOTOR VOLTAGES FOR MAXIMUM OFFSITE VOLTAGE

Two (2) cases, BLLXTF45 (115 kV source) and BLLXTF31 (230 kV source), were created to determine the maximum offsite system voltage allowable without producing excessive voltages at the motor terminals. Since "A" train was chosen as the worst case bus (heaviest load), "B" train was chosen as the bus to study under light load conditions (Mode 6). The criterion for evaluating worst case conditions was a running motor reaching 110% of rated terminal voltage (NEMA standard maximum).

The source used for the evaluation of the 230 kV system was an emergency auxiliary transformer, XTF-31. The source used for the evaluation of the 115 kV system was 2 ESF transformers, XTF-4 and 5, in parallel.

The offsite voltage was decreased by small increments of voltage from 1.0 per unit until the worst case motor was found.

			Maximum Offsite Voltage	
Dapper Bus #	Operating "B" Train Motors	Maximum Allowable Voltage	115kV Source Case BLLXTF45 120 kV (1.042 pu)	230kV Source Case BLLXTF31 240 kV (1.042 pu)
55	XPP1B	7590	7477	7476
72	XPP39B	7590	7472	7471
502	XHX1B	506	506 *	506 *
504	XPP31B	506	504	504
509	MFN97B	506	501	501
601	XPP48B	506	497	497
602	XFN23B	506	495	495
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9013	XFN83B	506	498	498

* Worst Case Motor

Appendix 8E
Analysis of the Voltage Drops on the ESF System When Starting a 6900 or 460 Volt Motor With the Diesel Generator as the Source

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APPENDIX 8E
ANALYSIS OF THE VOLTAGE DROPS ON THE ESF SYSTEM WHEN STARTING A 6900 OR 460 VOLT MOTOR WITH THE DIESEL GENERATOR AS THE SOURCE

8E.1 CRITERIA

The criteria was to determine (1) the voltage at the terminals of the largest safety related 6900 and 460 volt motors when they are started and (2) the voltage at the other Safety Related buses during the same period. The power source was considered to be the diesel generator with the safety injection signal loads operating on the buses.

8E.2 BACKGROUND

The 6900 volt charging/safety injection (CH/SI) pump motors and the 460 volt service water booster pump (SWBP) motors are the largest safety related motors for their respected voltages. Therefore, their characteristics were used in the calculations.

Electrical analysis software was used to simulate the restart of the largest motors and to determine the effect on system voltages. The diesel generator can be modeled as “an infinite source” with zero impedance when modeling the system under steady state conditions since the generator voltage regulator will hold the terminal voltage to within ± 1/2% of the setting. However, for transient conditions, the diesel generator model needs to include an internal impedance since the voltage regulator can not respond immediately to changes in loading. The source impedance for the transient model was based on the short circuit impedance of the generator as described below in section 8E.3. To obtain the internal source voltage, the source voltage of the model was manually adjusted to produce a machine terminal voltage of 0.945 per unit (under steady state conditions) with the generator load equal to the maximum system load, minus the load of the motor to be restarted. A terminal voltage of 0.945 per unit was used because the lower administrative limit for setting the voltage regulator is 95% and the regulator has a tolerance of ± 1/2%. To find the voltage levels during the initial inrush for motor starting, the source voltage was held constant and the starting load of the motor was added to the system. The system voltages were then calculated.

As described in Section 8D.2, the safety injection signal load is the largest load to be applied to the ESF system buses at any one time. Thus, this load was used as the running load on the buses.

8E.3 METHOD

An analytical software model (from calculation DC-836-008, case DSTEP8S) of the diesel generator steady state full load condition was used as a base case for developing the large motor restart model (Reference calculation DC-8360-012). This DSTEP8S case model determines the voltage at the "A" train buses when the Safety Injection loads are operating and when the Diesel Generator is supplying the load.

To evaluate the restart of large motors on the diesel generator, the steady state analytical software model was modified to incorporate a source impedance and to create two new cases. The first analytical software model, case DS825R, simulates the restart of the 6900 Volt Charging/SI pump (XPP43, 900 HP) and the second, case DS8101R, simulates the restart of the 480 volt service water booster pump (XPP45, 350 HP).

The source impedance was taken as equal to the short circuit impedance of the generator. This short circuit impedance was based on the generator test data which includes the following information:

Generator rating:	5845 KVA
Generator X/R ratio:	16
Short circuit reactance:	0.13 per unit

The steady state analytical software model was copied and modified by adding the source impedance and turning pumps XPP43A and XPP45A off-line in order to simulate the pumps tripping. The source voltage for the model was manually adjusted until the generator terminal voltage was equal to 0.945 per unit. This is the lowest value allowed by the combination of the regulator setting limit of 95% and the ± 1/2% tolerance of the regulator. The resulting source voltage was then held constant and the starting load for each of the two motors was added into each of the two respective models. The following are the load values used:

Model Bus	TAG	KW	KVAR
25	XPP43A	485	2992
101	XPP45A	231	1074

The resulting bus voltage from the two new model cases DS825R and DS8101R were then evaluated to determine the following:

a. Acceptance of the motor starting voltage by comparing the model case voltage with the motor's minimum required starting voltage.

b. Verification that the motor control center (MCC) contactors do not drop out during large motor restart.

The 6900 volt safety related motors were designed to start at 70% of rated voltage and, therefore, have a minimum starting voltage of 4830 volts. The 460 volt safety related motors were designed to start at 80% of rated voltage and, therefore, have a minimum starting voltage of 368 volts.

The contactors in the SQUARE D motor control centers have a dropout of 65% of nominal voltage. A value of 5% was added to account for voltage drop within the control circuit. Since the 480/120 Volt power transformers are wound to produce 120 volts on the secondary when fully loaded, a value of 70% of 480 volts (336V) on the MCC busses was used in the evaluation.

8E.4 CONCLUSION

Considering the diesel generator as the power source, the calculated voltage at the terminals of the 6900 volt CH/SI pump motor and 460 volt SWBP motor is above the minimum design starting voltage as mentioned in Section 8.3.1.1.4.2 and listed below:

		VOLTAGE		
Model Bus	TAG	MIN Start	Calculated	Margin
25	XPP43A	4830	6323	31%
101	XPP45A	368	415	13%

Since other safety related motors are smaller than the CH/SI pump motor and the SWBP motor for their respective voltage levels, the motor terminal voltage during the starting of all safety related motors will be above the design starting voltage for these motors.

The following table lists the voltages at each MCC bus for each of the two restart conditions. The table shows that all voltages are substantially above the 336 volt criteria and, therefore, verifies that the energized contactors will not drop out during large motor restart.

Model Bus	TAG	START XPP43A	START XPP45A
1000	XMC1DA1X-P	410	431
1500	XMC1DA2X-S	409	430
2000	XMC1DA2Y-P	408	429
2500	XMC1DA2Y-S	409	430
3000	XMC1DA2Z	407	428
4000	XMC1EA1X	418	438
8000	XMC1EC1X*	418	438

* Loads on this MCC are not energized. Therefore, the voltages are the same as for bus 4000.

Tables 8.E-1 and 8.E-2 list the calculated voltages of the ESF system buses and the motor terminals.

Table 8.E-1
CALCULATED VOLTAGE LEVEL OF ESF SYSTEM BUSES AND
MOTOR TERMINALS WITH A DIESEL GENERATOR AS A SOURCE AND
STARTING THE 6900 VOLT CHARGING/SAFETY INJECTION PUMP MOTOR

Condition:

Initial voltage:	6804 (94.5% of 7200 volts at diesel generator terminals prior to starting motor)
Initial Load:	3505 KW
Power Source:	Diesel Generator
Motor:	Charging/Safety Injection Pump Mtr. (6900 Volt)

Resulting Voltages:

ESF System Points	Voltages	Percent of Nominal Bus Voltage
Diesel Generator	6339	88.04
7200 Volt Bus 1DA	6328	87.88
6900 Volt CH/SI Pump	6323	91.63 of motor nominal rating
480 Volt Bus 1DA1	418	87.08
480 Volt Bus 1DA2	410	85.41
480 Volt MCC 1DA2Z	407	84.79
7200 Volt Bus 1EA	6322	87.8
480 Volt MCC 1EA1X	418	87.08

Table 8.E-2
CALCULATED VOLTAGE LEVEL OF ESF SYSTEM BUSES AND
MOTOR TERMINALS WITH A DIESEL GENERATOR AS A SOURCE AND
STARTING THE 460 VOLT SERVICE WATER PUMP MOTOR

Condition:

Initial voltage:	6804 (94.5% of 7200 volts at diesel generator terminals prior to starting motor)
Initial Load:	4087 kW
Power Source:	Diesel Generator
Motor:	Service Water Booster Pump Motor (460 Volt)

Resulting Voltages:

ESF System Points	Voltages	Percent of Nominal Bus Voltage
Diesel Generator	6627	92.04
7200 Volt Bus 1DA	6618	91.92
460 Volt SWBP Pump	415	90.21 of motor nominal rating
480 Volt Bus 1DA1	423	88.12
480 Volt Bus 1DA2	431	89.79
480 Volt MCC 1DA2Z	428	89.16
7200 Volt Bus 1EA	6612	91.83
480 Volt MCC 1EA1X	438	91.25

Appendix 8F
Starting Sequence of ESF Equipment Following an Accident Coincident With a Degraded Voltage Condition

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APPENDIX 8F
STARTING SEQUENCE OF ESF EQUIPMENT FOLLOWING AN ACCIDENT COINCIDENT WITH A DEGRADED VOLTAGE CONDITION

8F.1 INTRODUCTION

The following study identifies the timed sequence of starting the ESF system equipment for an accident coincident with degraded voltage on the offsite power system. The accidents considered are (1) Loss of Coolant Accident (LOCA) and (2) Main Steam Line Break (MSLB). The study compares the equipment starting times during accident conditions, with a degraded voltage to the starting times assumed in the accident analyses with total loss of voltage. See Tables 8.F-1 and 8.F-2.

8F.2 DISCUSSION

During these two accident scenarios, the diesel generator will start when safety injection is initiated at time zero. A maximum of 10 seconds is then required for the generator to reach the speed and voltage necessary to connect to the ESF buses.

The degraded voltage relays are set to actuate at 91.34% of nominal voltage. If the voltage drops below 80% of nominal, the undervoltage relays will actuate. A time delay of 3 seconds is provided before the degraded voltage relays signal a start to the diesel to allow for voltage dips caused by a large motor starting. However, it should be noted that for these accidents the diesel was started at time zero by safety injection; therefore the signal to start the diesel generated by the degraded voltage relay is duplicative. If the degraded voltage condition persists for 4 more seconds (now a total of 7 seconds), the 7.2 kV ESF buses are cleared. An additional time delay of 3 seconds is then provided to allow residual motor voltage to decay.

8F.3 CONCLUSION

Under the accidents discussed here, a maximum of 10 seconds is required before the diesel generator can be connected to the ESF buses. However, if there is no accident and a degraded voltage condition exists, a maximum of 13 seconds would be required before the diesel is connected.

Table 8.F-1
DEGRADED GRID VOLTAGE COINCIDENT WITH LOCA

Time (Seconds)	Description of Event
0	Degraded voltage condition on 7.2 kV ESF Buses Loss of Coolant Accident (SI Signal - Start Diesel Generator signal).
3	Degraded voltage detection signal.
7	Clear 7.2 kV ESF bus (Trip incoming and feeder breakers).
10	Close Diesel Generator breaker. Start load block #1(Start SI/Charging Pump, Start opening valves).
12 Note 1	SI/Charging Pump at full speed (~ 2 sec starting time).
15	Start RHR Pump.
19 Note 1	RHR Pump at full speed (~ 4 sec starting time).
20	Start SW Pump. Start Chilled Water Pump.
24.5 Note 2	SW Pump at full speed (~ 4.5 sec starting time).
25	Start Component Cooling Pump. Component Cooling Pump at full speed (~ 4 sec starting time).
27 Note 1	Safety Injection related valves at their final position (27 sec. includes EDG start time, valve stroke time, and signal processing time).
30	Start Emergency Feedwater Pump.
35	Start Reactor Building Cooling Units. Start Fuel Handling Building Exhaust Fan.
40	Start SW Booster Pump.
42	Emergency Feedwater Pump at Full Speed. (~ 12 sec starting time).

Table 8.F-1 (continued)
DEGRADED GRID VOLTAGE COINCIDENT WITH LOCA

Time (Seconds)	Description of Event
43 Note 4	Reactor Building Cooling Units at full speed and air flow has reached operating values (8 sec delay from time of starting the fans to the time of having reached operating values of air flow per FSAR, Section 6.2.2.2.2.2).
45	Start HVAC Chiller. SW Booster Pump at full speed (5 sec starting time per FSAR, Section 6.2.2.2.2.2).

(1) Refer to Section15.4 for discussions on LBLOCA.
(2) Critical case is the requirement to provide cooling water to the Diesel Generator within 1 minute from the time of starting.
(3) See FSAR, Section 15.4.2.2.2.1.
(4) See FSAR, Section 6.2.1.3.4.3.

Table 8.F-2
DEGRADED GRID VOLTAGE COINCIDENT WITH MSLB

Time (Seconds)	Description of Event
0	Degraded voltage condition on 7.2 kV ESF Bus on Main Steam Line Break Accident (SI Signal - Start Diesel Generator signal).
3	Degraded voltage detection signal.
7	Clear 7.2 kV ESF bus (Trip incoming and feeder breakers).
10	Close Diesel Generator breaker. Start load block #1 (Start SI/Charging Pump, Start opening valves).
12 Note 1	SI/Charging Pump at full speed (~ 2 sec starting time).
15	Start RHR Pump.
19 Note 1	RHR Pump at full speed (~ 4 sec starting time).
20	Start SW Pump. Start Chilled Water Pump.
24.5 Note 2	SW Pump at full speed (~ 4.5 sec starting time).
25	Start Component Cooling Pump.
27 Note 1	Safety Injection related valves at their final position (27 sec. includes EDG start time, valve stroke time, and signal processing time).
29	Component Cooling Pump at full speed (~ 4 sec starting time).
30	Start Emergency Feedwater Pump.
35	Start Reactor Building Cooling Units. Start Fuel Handling Building Exhaust Fan.
40	Start SW Booster Pump.

Table 8.F-2 (continued)
DEGRADED GRID VOLTAGE COINCIDENT WITH MSLB

Time (Seconds)	Description of Event
42 (60) Note 3	Emergency Feedwater Pump at Full Speed. (~ 12 sec starting time).
43 Note 4	Reactor Building Cooling Units at full speed and air flow has reached operating values (8 sec delay from time of starting the fans to the time of having reached operating values of air flow per FSAR, Section 6.2.2.2.2.2).
45	Start HVAC Chiller. SW Booster Pump at full speed (5 sec starting time per FSAR, Section 6.2.2.2.2.2).

(1) See FSAR Section 15.4.2.1.2.1.
(2) Critical case is the requirement to provide cooling water to the Diesel Generator within 1 minute from the time of starting.
(3) See FSAR, Section 15.4.2.2.2.1.
(4) See FSAR, Section 6.2.1.3.4.3.

Appendix 8G
Electrical Containment Penetration
Conductor Overcurrent Protection Devices

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Electrical Containment Penetration
Conductor Overcurrent Protection Devices

The following drawings identify overcurrent protection devices required to protect containment penetration assembly conductors in accordance with the requirements of Regulatory Guide 1.63. Regulatory Guide 1.63 is discussed in further detail in Appendix 3A.

Figure 8G-1, Sheet 1
DRAWING E-224-532
FSAR FIGURE REFERENCE

Figure 8G-2, Sheet 2
DRAWING E-224-532
FSAR FIGURE REFERENCE

Figure 8G-3, Sheet 3
DRAWING E-224-532
FSAR FIGURE REFERENCE

Figure 8G-4, Sheet 4
DRAWING E-224-532
FSAR FIGURE REFERENCE

Figure 8G-5, Sheet 5
DRAWING E-224-532
FSAR FIGURE REFERENCE

Figure 8G-6, Sheet 6
DRAWING E-224-532
FSAR FIGURE REFERENCE

Figure 8G-7, Sheet 7
DRAWING E-224-532
FSAR FIGURE REFERENCE

Figure 8G-8, Sheet 8
DRAWING E-224-532
FSAR FIGURE REFERENCE

Figure 8G-9, Sheet 9
DRAWING E-224-532
FSAR FIGURE REFERENCE

Figure 8G-10, Sheet 10
DRAWING E-224-532
FSAR FIGURE REFERENCE

V.C. Summer Power Station
Safety Analysis Report

Auxiliary Systems

Chapter 9

Revision 26---06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 9 - AUXILIARY SYSTEMS

9.0 AUXILIARY SYSTEMS

9.1 FUEL STORAGE AND HANDLING

9.1.1 New Fuel Storage

9.1.1.1 Design Bases

New fuel is stored in racks (see Figure 9.1-1). Each rack is composed of individual vertical cells which are fastened together in any number to form a module that is firmly bolted to anchors in the floor of the new fuel storage area. The racks consist of two arrays of storage cells, each containing 30 cells in a 2 x 15 pattern. The new fuel storage racks are designed to include storage for 60 assemblies at a center to center spacing of 21 inches. The new fuel storage rack cells are 14 ft-4 in. high and 0.078 inches thick. This spacing provides a minimum separation between adjacent fuel assemblies of 12 inches which is sufficient to maintain a subcritical array even in the event the building is flooded with unborated water. Surfaces that come into contact with the fuel assemblies are made of annealed austenitic stainless steel, whereas the supporting structure may be painted carbon steel.

The racks are designed to withstand nominal operating loads as well as safe shutdown earthquake (SSE) and operating basis earthquake (OBE) seismic loads. The racks are Safety Class 2b and meet the allowable stresses in the ASME Code, Section III, Appendix 17. The new fuel racks are designed to withstand a maximum uplift force of 5000 pounds.

The new fuel storage racks are designed to accommodate Westinghouse 17x17 fuel assemblies (STANDARD, VANTAGE 5, and VANTAGE+) with a maximum nominal enrichment of 5.0 weight percent U-235.

9.1.1.2 Facilities Description

The new fuel storage facility is located in the eastern end of the fuel handling building (see Figure 1.2-6). The facility consists of a concrete pit 27 feet deep by 15 feet wide by 28 feet long, covered by a removable grating. The new fuel storage racks are anchored to the floor of the facility and are designed to store fuel assemblies for 1/3 of a core.

9.1.1.3 Safety Evaluation

The design of normally dry new fuel storage racks is such that the effective multiplication factor does not exceed 0.98 with fuel of the highest anticipated enrichment in place, assuming optimum moderation (under dry, fogged, or flooded conditions). Credit is taken for the inherent neutron-absorbing effect of the materials of construction.

The new fuel assemblies are stored dry and the 21 inch center to center spacing ensures an eversafe geometric array. Space between storage positions is blocked to prevent insertion of fuel. Under these conditions, a critically accident during refueling and storage is precluded.

An exemption from the requirements of 10CFR70.24, “Criticality Accident Requirements”, has been granted to VCSNS based on the design and administrative controls associated with new and spent fuel storage. In response to two VCSNS letters to the NRC requesting the 10 CFR 70.24 exemption (Reference 1 and Reference 2), the NRC granted an exemption listing seven criteria to maintain the exemption valid (Reference 3).

1. Plant procedures do not permit more than one PWR fuel assembly to be in storage or in transit between its associated shipping cask or storage rack at one time.
2. The k-effective of the fresh fuel storage racks filled with fuel of the maximum permissible U-235 enrichment and flooded with pure water does not exceed 0.95 at a 95% probability, 95% confidence level.
3. If optimum moderation of fuel in the fresh fuel storage racks occurs when the fresh fuel storage racks are not flooded, the k-effective corresponding to this optimum moderation does not exceed 0.98 at a 95% probability, 95% confidence level.
4. The k-effective of spent fuel storage racks filled with fuel of the maximum permissible U-235 enrichment and flooded with pure water does not exceed 0.95 at 95% probability, 95% confidence level.
5. The quantity of forms of special nuclear material, other than nuclear fuel, that are stored on site in any given area is less than the quantity necessary for critical mass.
6. Radiation monitors, as required by GDC 63, are provided in the fuel storage and handling areas to detect excessive radiation levels and to initiate appropriate safety actions.
7. The maximum nominal U-235 enrichment is 5 wt%.

9.1.2 Spent Fuel Pool Storage

9.1.2.1 Design Bases

Spent fuel is stored in racks (see Figure 9.1-2). The high density spent fuel racks consist of individual cells with 8.85" x 8.85" (nominal) square cross section, each of which accommodates a single fuel assembly. The cells are arranged in modules of varying size. A total of 1712 cells are arranged in 12 distinct modules in 2 regions. Figure 9.1-2a shows the arrangement of the rack modules in the spent fuel pool. Figure 9.1-2a and Figure 9.1-2b show the typical Region 1 rack structure and cell assemblage detail. Figure 9.1-2c and Figure 9.1-2d show the typical Region 2 rack structure and cell assemblage detail. Table 911-2 provides relevant design data on each region. The modules in the 2 regions are of 3 different types. Table 9.1-3 summarizes the physical data for each module type.

Region 1 is designated for storage of new or freshly discharged fuel assemblies with a maximum nominal enrichment of 4.95 weight percent U-235.

Region 2 is designed to accommodate the storage of fuel assemblies with a maximum nominal initial enrichment of 4.95 weight percent U-235 with a minimum burnup and up to 5.0 weight percent U 235 with a minimum burnup of 41,611 MWD/MTU or fuel of initial enrichment and burnup combinations within the acceptable domain depicted in Figure 4.3-44. The above limits are applicable to Westinghouse 17x17 fuel assemblies (STANDARD, VANTAGE 5, and VANTAGE+).

The modules are not anchored to the pool floor, to each other, or to the pool walls. A minimum gap of 1" is provided between the modules to ensure that kinematic movements of the modules during the plant design basis earthquake will not cause inter-module impact. Adequate clearance with other pool hardware, e.g., light fixtures, etc. is also provided.

The spent fuel storage rack design ensures the separation between spent fuel assemblies. Space between storage positions is sufficient to permit insertion of a fuel assembly. All rack surfaces that come into contact with fuel assemblies consist of austenitic stainless steel. These materials are resistant to corrosion during normal and emergency water quality conditions.

Spent fuel racks are designed to withstand shipping, handling, normal operating loads (impact and dead loads of fuel assemblies) as well as SSE loads. The racks are Safety Class 2b and meet the American Institute of Steel Construction (AISC) requirements. The spent fuel racks are also designed to meet the Seismic Category 1 requirements of Regulatory Guide 1.13 (see Appendix 3A).

The spent fuel storage racks are designed with adequate energy absorption capabilities to withstand the impact of a dropped spent fuel assembly from the maximum lift height of the fuel handing machine. Cranes capable of carrying loads heavier than that incurred in handling a failed fuel assembly are prevented by design from traveling over the spent fuel pool.

The spent fuel racks can withstand an uplift force greater than the uplift force of the fuel handling machine.

Shielding requirements are discussed in Section 9.1.4.3.4. Radiological considerations are discussed in Chapter 12.

9.1.2.2 Facilities Description

The spent fuel pool is located in the western end of the fuel handling building (see Figure 1.2-6). The pool is a stainless steel lined pit 39 feet long by 28 feet wide by 39 feet deep. The normal water level at elevation 461.5 feet provides approximately 24 feet of water shielding over the stored spent fuel assemblies.

During normal operation, the spent fuel pool is isolated from the fuel transfer canal by a removable stainless steel gate.

The stainless steel liner welds are equipped with a leak detection system to monitor and locate liner weld leaks.

9.1.2.3 Safety Evaluation

Design of this storage facility ensures a safe condition under normal and postulated accident conditions. Consideration of criticality safety analysis is discussed in Section 4.3.2.7. Compliance with Regulatory Guide 1.13 is discussed in Appendix 3A.

The spent fuel cooling system is discussed in Section 9.1.3.

9.1.3 Spent Fuel Cooling System

The spent fuel cooling system cools spent fuel pool water to remove decay heat from the spent fuel elements. It also provides for purification of the water in the spent fuel pool and refueling water storage tank (RWST), provides for transfer of water between the RWST and spent fuel pool, maintains boron concentrations, monitors radiation levels and monitors and maintains spent fuel pool water level to ensure adequate cooling and shielding.

9.1.3.1 Design Bases

The spent fuel cooling system is designed to perform the following functions:

1. While performing a core shuffle (72 assemblies off-loaded), maintain the Spent Fuel Pool Water temperature to less than 152.53°F using 1 Spent Fuel Cooling (SFC) heat exchange. This peak temperature is due to a heat load based on decay heat generation from 72 assemblies with an exposure of 55 GWD/MTU, cooled for 72 hours, and moved to the Spent Fuel Pool in exactly 20 hours; plus 1709 spent fuel assemblies with exposures up to 55 GWD/MTU and cooled for 18 months or more. All fuel assemblies discharged through 1996 are assumed to have been burnt at 2775 MWt. All Fuel assemblies discharged after 1996 are assumed to have been burnt at 2900 MWt. The maximum net heat load for this case is 20.71 MBTU/HR, considering passive heat losses (including evaporative cooling effects) of 1.01 MBTU/HR.
2. For a full core off-load (157 assemblies off-loaded), maintain the Spent Fuel Pool Water temperature to less than 150.97°F using 2 SFC heat exchangers. This peak temperature is due to a heat load based on decay heat generation from 157 assemblies with exposures of 30.25 GWD/MTU (13 assemblies), 52.25 GWD/MTU (72 assemblies) and 55 GWD/MTU (72 assemblies) cooled for 72 hours, and moved to the SFP in exactly 20 hours; plus 1565 assemblies with exposures up to 55 GWD/MTU and cooled for 18 months, or more. All fuel assemblies discharged through 1996 are assumed to have been burnt at 2775 MWt. All fuel assemblies discharged after 1996 are assumed to have been burnt at 2900 MWt. The maximum net heat load coincident with peak bulk temperature for this case is 40.16 MBTU/HR, considering passive heat losses (including evaporative cooling effects) of 0.95 MBTU/HR.
3. For a full core off-load (157 assemblies off-loaded), maintain the Spent Fuel Pool Water temperature to less than 170°F using 1 SFC heat exchanger with an augmented Spent Fuel cooling system water flow rate of 2400 gpm. This peak temperature is due to a heat load based on decay heat generation from 157 assemblies with exposures of 30.25 GWD/MTU

(13 assemblies), 52.25 GWD/MTU (72 assemblies) and 55 GWD/MTU (72 assemblies). Cooling times are calculated as a function of the component cooling water temperature into the SFC heat exchanger, which is varied from 85°F to 105°F, and range from 58 hours (85°F cooling water) to 146 hours (105°F cooling water). The full core off-load is moved into the SFP in exactly 20 hours; with the SFP already containing 1565 assemblies with exposures up to 55 GWD/MTU and cooled for 18 months or more. All fuel assemblies discharged through 1996 are assumed to have been burnt at 2775 MWt. All fuel assemblies discharged after 1996 are assumed to have been burnt at 2900 MWt. The maximum net heat load coincident with peak bulk temperature for this case is 40.74 MBTU/HR, considering passive losses (including credit for evaporative cooling effects of 1.77 MBTU/HR.

4. An abnormal fuel off-load is one where a full core is off-loaded 36 days after 72 assemblies were placed in the spent fuel pool. For an abnormal off-load, maintain the SFP water temperature to less than 149.53°F using 2 SFC heat exchangers. This peak temperature is due to a heat load based on decay heat generation from 157 assemblies with exposures of 2778 MWD/MTU (72 assemblies), 31884 MWD/MTU (72 assemblies) and 53884 MWD/MTU (13 assemblies), cooled for 72 hours and moved to the SFP in exactly 20 hours; plus 1565 assemblies with exposures up to 55 GWD/MTU and cooled for 19 months or more. The maximum net heat load coincident with peak bulk temperature for this case is 38.84 MBTU/HR, considering passive losses (including evaporative cooling effects) of 0.90 MBTU/HR, and single failure does not have to be considered.
5. Transfer water between the RWST and the refueling cavity.
6. Maintain the purity and clarity of water in the spent fuel pool and/or the refueling cavity at acceptable levels by means of skimming, filtering and/or demineralizing the water to remove corrosion and fission products.
7. Provide means for adding boric acid to the spent fuel pool to maintain the boron concentrations at a nominal 2000 ppm.
8. Provide means to add demineralized water to the spent fuel pool to make up for evaporation losses.
9. Monitor spent fuel coolant for excessive radioactivity due to defective fuel elements.
10. Provide for filtering and/or demineralization to clean the water in the RWST.
11. Maintain a water shield above the spent fuel elements to limit radiation levels in the area of the pool to less than 2.5 mr/hr.

The components of the system are classified as Safety Class 2b, except for equipment and piping associated with the spent fuel purification pump, spent fuel cooling demineralizer and spent fuel purification filters; and radiation monitor, RM-L4. These components are not safety-related. The RWST is Safety Class 2a.

Safety Class 2a piping, valves and equipment are designed, fabricated, tested and inspected in accordance with the ASME Code, Section III, Class 2.

Safety Class 2b piping, valves and equipment are designed, fabricated, tested and inspected in accordance with the ASME Code, Section III, Class 3.

Isolation of nonessential portions of the spent fuel cooling system is provided.

9.1.3.2 System Description

A spent fuel cooling system diagram is included as Figure 9.1-3.

The spent fuel cooling system consists of three basic loops: The spent fuel cooling loop; the spent fuel cooling and transfer loop; and the spent fuel purification loop.

The spent fuel cooling loop provides for cooling of the spent fuel pool. Cooling water is removed from the pool through four 6 inch lines, is pumped by the spent fuel cooling pump through spent fuel heat exchanger A and is returned to the pool through four 6 inch lines.

The spent fuel cooling and transfer loop serves as an alternate or supplement to the spent fuel cooling loop when required. It also serves to transfer water between the several storage volumes associated with the fuel handling and storage systems, including the RWST, fuel transfer canal, refueling cavity, and the cask loading area. The loop consists of the spent fuel cooling and transfer pump, spent fuel heat exchanger B, and interconnecting piping as shown on Figure 9.1-3.

Loop seal piping is installed to ensure the minimum required Technical Specification RWST volume is protected from potential line breaks in the non-safety portion of the purification loop.

The major components of the purification loop are the spent fuel purification pump, spent fuel cooling demineralizer, and two spent fuel purification filters in parallel. Normally the purification loop takes suction from the spent fuel pool skimmers, pumps the water through the spent fuel cooling demineralizer and the spent fuel purification filters, and returns the water to the spent fuel pool. This loop can also take suction from the spent fuel pool, RWST, cask loading area skimmer, refueling cavity, fuel transfer canal drain or cask loading area drain. The purification loop can also discharge to the RWST, fuel transfer canal, refueling cavity, and the return line to the cask loading area.

The RWST is included in the spent fuel cooling system. It is an atmospheric storage tank in an open Seismic Category 1 structure. It is equipped with an overflow line, one vent line to the Auxiliary Building plant vent, and heat tracing. Outdoor system piping connecting to the tank is equipped with separate, redundant heat tracing circuits.

The RWST vent is piped directly to the auxiliary building charcoal exhaust system. The vent line is of 8 inch, schedule 40 pipe with runs of approximately 2 feet vertically, 25 feet horizontally and 4 feet sloping higher by 2-1/2 feet where it enters the auxiliary building. This vent piping is designed to Quality Related Standards to ensure that the vent piping remains functional following design wind and seismic loading. Since normally there is no air flow in the RWST vent line, it has been concluded that no appreciable amount of moisture could accumulate in the line. Therefore, the probability of blockage due to freezing is considered negligible.

Component data are presented in Table 9.1-1.

9.1.3.3 Safety Evaluation

Equipment, piping and components of the spent fuel cooling system are housed in Seismic Category 1 structures. Piping lines entering and exiting from the spent fuel pool are located at elevation 460’-3" and are provided with anti-siphoning holes to preclude draining the pool below this level. This low water level was established to satisfy the requirements of the following criteria:

1. Minimize the dose rate at the pool surface during spent fuel transfer in the unlikely event of a coincident pipe break in a line entering or exiting the spent fuel pool.
2. Assure that the Technical Specification requirement of 23 feet of water is maintained over the top of irradiated fuel assemblies located in the spent fuel pool storage racks.
3. Not to exceed the 10 CFR 71.73 cask drop design criterion for the spent fuel cask, a minimum water height above the cask loading area is required so that a cask drop through air and water will not generate a calculated impact velocity greater than 44 ft/sec.

   At the start of fuel handling operations, the water level in the cask load area is the same as and is controlled by the spent fuel pool water level. Therefore, at the design low water level of the pool, a minimum water level of 40.5 feet above the bottom of the cask load area is available to satisfy the cask drop design criterion. It has been determined that the cask drop through 3.75 feet of air plus 40.5 feet through water will generate an impact velocity of less than 44 ft/sec at the cask load area floor.

The suction lines inside the spent fuel pool are positioned to take suction approximately 4 feet below the normal water level to minimize vortexing and the possibility of floating debris entering the system. The return cooling lines from the spent fuel heat exchangers are located inside the pool such that cooled water is discharged downward. This ensures adequate dispersion of the cold water around the stored spent fuel assemblies. Each suction and return line in the pool is provided with a small anti-siphoning hole (approximately 1/2 inch) located 1 foot, three inches below the normal water level (460'3") to prevent draining the pool below the design low water level in the event of a postulated pipe break occurring outside the pool below the low water level.

Also, there are no drain lines connected to the spent fuel pool. The suction and return lines are located on opposite sides of the pool to prevent channeling and to obtain maximum circulation of the pool water. During fuel handling operations with the pool at the normal water level, about 10 feet of water shielding is available during the transfer of spent fuel elements.

Normal makeup water to the pool is available from the demineralized water storage tank. Emergency makeup water to the pool is available from the RWST, which is Safety Class 2a, or from the reactor makeup water storage tank (RMWST), which is Safety Class 2b. Pumps from three separate systems: spent fuel cooling and purification pumps, Reactor Makeup Water pumps, and demineralized water transfer pumps are available for the transfer of water.

The spent fuel pool water is cooled by either one of two redundant spent fuel cooling water loops. Each loop contains a pump, heat exchanger, piping, valves and instrumentation. The pumps can be powered from separate emergency (diesel) power sources.

Typical refueling practice is to perform a full core off-load with two spent fuel cooling pumps in operation. For a full core offload, the spent fuel cooling system is required to maintain the spent fuel pool water below a temperature of 170°F (which is the limit of the structural integrity analysis) during normal operation with one spent fuel cooling loop in operation and at or below the bulk boiling temperature during an emergency (i.e., abnormal full core offload with both spent fuel cooling loops in operations). The design assumptions and peak SF Pool water temperatures are described in Section 9.1.3.1 and preserved through plant procedures that require the following:

1. Prior to the start of core offload, both SFC loops be available with a minimum of one loop in operation.
2. If the indicated pool temperature is ≥ 120°F,
   a. Both spent fuel cooling loops be in operation, or
   b. In the event of a spent fuel pump is unavailable, flow in the operating cooling loop is increased to ≥ 2400 gpm.
3. Multiple reliable sources of electric power be maintained to the SF pumps, including at least one diesel generator backed, safety related electrical bus for spent fuel pool cooling at all times that spent fuel is being moved and while the full core is off-loaded.

Although two SFP cooling loops are typically functional and are supplied by 1E electrical buses, administrative controls provide for an ESF bus outage when spent fuel is being moved or while the full core is offloaded. If 1E power is not available to one of the cooling loops, contingency plans allow for one of the spent fuel cooling pumps to be quickly connected to a reliable source of offsite power. In the unlikely case that all SF cooling is lost, sufficient time exists to provide makeup water to the pool to preclude the fuel from becoming uncovered.

The degree of conformance of the design of the spent fuel cooling system and the fuel handling system with the recommendations of Regulatory Guide 1.13 is addressed in Appendix 3A.

9.1.3.4 Inspection and Testing Requirements

Testing requirements of this system are satisfied through system operation. The spent fuel cooling pump and spent fuel cooling and transfer pump are alternated during normal cooling to equalize wear. Routine inspections of system piping and components are made during system operation.

9.1.3.5 Instrumentation Requirements

Measurement and monitoring of radiation, pressure, level, flow rate, and temperature are performed for purposes of indication, alarm, control, and record maintenance. A leakage

detection system is provided to detect leakage from the spent fuel pool and determine the location of the leakage.

9.1.3.5.1 Radiation Measurement

See Section 11.4 for details.

9.1.3.5.2 Pressure Measurement

Pressure gages provide local indication for the following points in the system: inlets to suction strainers, suctions and discharges of spent fuel cooling and transfer pump and spent fuel cooling pump, suction and discharge of spent fuel purification pump, and inlet and outlet of spent fuel purification filters.

Pressure test connections are provided on the outlet of each spent fuel heat exchanger.

9.1.3.5.3 Level Measurement

During transfer of spent resin to the spent resin storage tank from the spent fuel cooling demineralizer, Health Physics verifies that all resin has been flushed to the spent resin storage tank using radiation surveys.

RWST level measurement consists of four independent level channels, each having control room indication. These loops perform a post accident monitoring function (see Section 7.5 for more detail); provide annunciator inputs of maximum fill, minimum fill, low-low, and empty liquid levels; and analog input to the plant computer. Each loop is independent and physically separated from the other.

Safety classification of these loops is Class 1E for equipment which provides the post accident monitoring function.

The spent fuel pool has two level measurement loops, each having control room indication and one loop inputting to the plant computer. High and low pool levels are annunciated in the control room and locally. These level loops are physically separated.

The fuel transfer canal, refueling cavity, and cask loading area each have a level loop providing control room indication and control room annunciation of high and low water levels. Additionally, the fuel transfer canal and cask loading area level inputs are sent to the plant computer.

9.1.3.5.4 Flow Rate Measurement

The spent fuel cooling and the spent fuel cooling transfer piping loops each have flow rate measurement instrumentation providing control room indication, low flow annunciation in the control room (not actuated unless spent fuel cooling or transfer pump breaker is closed) and analog input to the plant computer. These flow loops are physically separated.

The purification piping loop has a local flow indicator which is located downstream of the purification filters.

9.1.3.5.5 Temperature Measurement

RWST temperature measurement consists of two temperature loops. Each loop provides control room indication and one loop provides analog input to the TSC computer.

The spent fuel pool has two temperature measurement loops, each providing control room indication and annunciation of high temperature. In addition, one of the loops provides analog inputs to the plant and TSC computers. These channels are physically separate and redundant.

The refueling cavity has a temperature loop which provides control room indication and high temperature annunciation in the control room.

Spent fuel heat exchangers A and B both have local temperature indicators on the inlet and outlet.

In the spent fuel purification demineralizer inlet piping there is a temperature switch with input to the control room annunciator for high temperature.

9.1.4 Fuel Handling System

9.1.4.1 Design Bases

The Fuel Handling System (FHS) consists of equipment and structures utilized for the refueling operation in a safe manner meeting General Design Criteria 61 and 62 of 10 CFR 50, Appendix A.

The following design bases apply to the FHS.

1. Fuel handling devices have provisions to avoid dropping or jamming of fuel assemblies during transfer operation.
2. Handling equipment has provisions to avoid dropping of fuel handling devices during the fuel transfer operation.
3. Handling equipment used to raise and lower spent fuel have a limited maximum lift height so that the minimum required depth of water shielding is maintained.
4. The Fuel Transfer System (FTS), where it penetrates the containment, has provisions to preserve the integrity of the containment pressure boundary.
5. Criticality during fuel handling operations is prevented by geometrically safe configuration of the fuel handling equipment.
6. Handling equipment will not fail in such a manner as to preclude the safety function of Seismic Category 1 equipment in the event of a SSE.

7. The inertial loads imparted to the fuel assemblies or core components during handling operations are less than the loads which could cause damage.
8. Physical safety features are provided for personnel operating fuel handling equipment.

9.1.4.2 System Description

The FHS consists of the equipment needed for transporting and handling fuel from the time it reaches the station until it leaves the station. Basically this equipment is comprised of fuel assemblies, core component and reactor component hoisting equipment, fuel handling equipment, and the FTS. The structures associated with the fuel handling equipment are the refueling cavity, the refueling canal, the fuel transfer canal, the spent fuel pool, and the new fuel storage area.

New fuel assemblies received for initial fuel loading are removed one at a time from the shipping container and stored in both the new and spent fuel storage racks. Normally, new fuel assemblies received after the initial fuel loading are stored in the new fuel storage racks located in the new fuel storage area.

A new fuel assembly is delivered to the reactor by removing a new fuel assembly from the storage rack, placing it into the new fuel elevator, lowering it into the fuel transfer canal, rotating to horizontal and transferring it through the FTS.

The fuel handling equipment is designed to handle the spent fuel assemblies underwater from the time they leave the reactor vessel until they are placed in a cask for removal from the Fuel Handling Building (for either transfer to the ISFSI for dry cask storage or for shipment from the site). Underwater transfer of spent fuel assemblies provides an effective, economic, and transparent radiation shield, as well as a reliable cooling medium for removal of decay heat. The boric acid concentration in the water provides an additional margin to preclude criticality.

The associated fuel handling structures may be generally divided into: the refueling cavity, the refueling canal and fuel transfer canal which are flooded during plant shutdown for refueling, the spent fuel pool which is kept full of water and is accessible to operating personnel, and the new fuel storage area. The refueling canal and the fuel transfer canal are connected by a fuel transfer tube. This tube is fitted with a blind flange on the refueling canal end and a gate valve on the fuel transfer canal end. The blind flange is in place except during refueling to ensure containment integrity. Fuel is carried through the fuel transfer tube on an underwater transfer car.

During Dry Cask Storage operations in the Fuel Handling Building, the fuel transfer canal and the cask loading pit are flooded for cask loading and unloading.

Fuel is moved between the reactor vessel and the refueling canal by the refueling machine. A rod cluster control changing fixture is located in the refueling canal for transferring control elements from one fuel assembly to another fuel assembly. The FTS is used to move fuel assemblies between the reactor building and the fuel handling building. After a fuel assembly is placed in the fuel container, the lifting arm pivots the fuel assembly to the horizontal position for passage through the fuel transfer tube. After the transfer car transports the fuel assembly through the fuel

transfer tube, the lifting arm at that end of the tube pivots the assembly to a vertical position so that the assembly can be lifted out of the fuel container.

In the spent fuel pool and the fuel transfer canal, fuel assemblies are moved about by the fuel handling machine. When lifting spent fuel assemblies, the hoist uses a long handled tool to assure that sufficient radiation shielding is maintained. A shorter tool is used to handle new fuel assemblies initially, but the new fuel elevator must be used to lower the assembly to a depth at which the fuel handling machine, using the long handled tool, can place the new fuel assemblies into or out of the fuel storage racks.

Decay heat, generated by the spent fuel assemblies in the spent fuel pool, is removed by the spent fuel cooling system. After a sufficient decay period, the spent fuel assemblies are removed from the spent fuel racks and loaded into casks for removal from the Fuel Handling Building.

9.1.4.2.1 Refueling Procedure

The refueling operation follows a detailed procedure which provides a safe and efficient refueling operation. Before refueling operations the reactor coolant system is borated and cooled down to refueling shutdown conditions as specified in the Technical Specifications. Criticality protection for refueling operations, including a requirement for checks of boron concentration, at least once per 72 hours is specified in the Technical Specifications. The following significant points are assured by the refueling procedure:

1. The refueling water and the reactor coolant contain over 2000 ppm boron. This concentration, together with the negative reactivity of control rods, is sufficient to keep the core reactivity less than or equal to 0.95 K_{eff} during the refueling operations. A reactivity penalty for the withdrawal of the highest worth rod is included in the reactivity calculation.
2. The water level in the refueling cavity is high enough to keep the radiation levels within acceptable limits when the fuel assemblies are being removed from the core.

The refueling operation is divided into four major phases: 1) preparation, 2) reactor disassembly, 3) fuel handling, and 4) reactor assembly. A general description of a typical refueling operation through the four phases is given below:

1. Phase I Preparation

   The reactor is shutdown and cooled to cold shutdown conditions with a final $K_{eff} \leq 0.95$ (all rods in minus 1). Following a radiation survey, the reactor building is entered. At this time, the coolant level in the reactor vessel is lowered to a point slightly below the vessel flange. Checking of the fuel transfer equipment and refueling machine for proper operation is begun in this phase.

2. Phase II - Reactor Disassembly

   All cables, air ducts, and insulation are removed from the vessel head. The refueling cavity is then prepared for flooding by sealing off the reactor cavity; checking of the underwater lights, tools, and finishing checks of the fuel transfer system and continuing checks of the refueling machine; closing the refueling canal drain holes; and removing the blind flange from the fuel transfer tube. With the refueling cavity prepared for flooding, the vessel head is taken to its storage pedestal. Water from the refueling water storage tank is pumped either into the fuel transfer canal and the refueling cavity by the Spent Fuel Cooling system, or into the reactor coolant system by the residual heat removal pumps causing the water to overflow into the refueling cavity. When the water reaches a safe shielding depth, (see Section 9.1.4.3.4) the control rod drive shafts are disconnected and, with the upper internals, are removed from the vessel. The fuel assemblies and rod cluster control assemblies are now free from obstructions and the core is ready for refueling. Checking of the refueling machine is completed at this time.

3. Phase III - Fuel Handling

   The refueling is accomplished by either a full core off-load and re-load to and from the Spent Fuel Pool or a core shuffle. The full core off-load removes all of the fuel from the reactor vessel to the spent fuel pool. There, the rod cluster control assemblies are shifted between fuel assemblies as necessary, by a portable rod cluster control changing tool suspended from the fuel handling machine. When ready, the fuel assemblies are loaded into the vessel in the designed pattern. New fuel assemblies are usually pre-staged in the spent fuel pool to expedite the reload, but can be moved from the new fuel pit into the fuel container with the new fuel elevator and fuel handling machine. The core shuffle moves fuel assemblies within the reactor vessel, only removing those most depleted to the spent fuel pool and replacing them with new or only partially depleted fuel assemblies brought from the spent fuel pool or new fuel pit. The rod cluster control assemblies are shifted between fuel assemblies as necessary by the rod cluster control changing fixture, which is in the refueling canal of the reactor building.

   The following describes the steps of a core shuffle:

   a. The refueling machine is positioned over a fuel assembly in the core.
   b. The fuel assembly is lifted by the refueling machine to a predetermined height sufficient to clear the reactor vessel and still leave sufficient water covering the fuel assembly to eliminate any radiation hazard to the operating personnel.
   c. If the removed assembly contains a rod cluster control assembly, the assembly is placed in the rod cluster control changing fixture by the refueling machine. The rod cluster control assembly is removed from the spent fuel assembly and put in a new fuel assembly or in a partially spent fuel assembly previously placed in the changing fixture.
   d. The fuel transfer car is moved into the refueling canal from the fuel transfer canal.
   e. The fuel assembly container is pivoted to the vertical position by the lifting arm.

f. The refueling machine is moved to line up the spent fuel assembly with the FTS.

g. The refueling machine loads a spent fuel assembly into the fuel assembly container of the transfer car.

h. The fuel assembly container is pivoted to the horizontal position by the lifting arm.

i. The fuel assembly container is moved through the fuel transfer tube to the fuel transfer canal by the transfer car.

j. The fuel assembly container is pivoted to the vertical position. The spent fuel assembly is unloaded by the spent fuel handling tool attached to the fuel handling machine.

k. The spent fuel assembly is moved into the spent fuel pool and placed in a spent fuel storage rack by the fuel handling machine.

l. The new fuel assembly is taken from the new fuel storage rack and loaded into the new fuel elevator by the fuel handling building crane. The fuel handling machine takes the fuel from the new fuel elevator and places it in the fuel assembly container. Alternatively the new fuel is pre-staged in the spent fuel pool and is moved to the fuel assembly container by the fuel handling machine.

m. The fuel assembly container is pivoted to the horizontal position and the transfer car is moved back into the refueling canal.

n. Partially spent fuel assemblies are relocated in the reactor core, and new fuel assemblies are added to the core.

o. Any new assembly or transferred fuel assembly that is placed in a control position is first placed in the rod cluster control changing fixture to receive a rod cluster control from a spent fuel assembly.

p. This procedure is continued until refueling is completed.

4. Phase IV - Reactor Assembly

   Reactor assembly, following refueling, is essentially achieved by reversing the operations given in Phase II - Reactor Disassembly.

9.1.4.2.2 Component Description

9.1.4.2.2.1 Refueling Machine

The refueling machine (see Figure 9.1-4) is a rectilinear bridge and trolley system with a vertical mast extending down into the refueling water. The bridge spans the refueling cavity and the refueling canal and runs on rails. The bridge and trolley motions are used to position the vertical mast over a fuel assembly in the core. A long tube with a pneumatic gripper on the end is lowered down out of the mast to grip the fuel assembly. The gripper tube is long enough so that the upper end is still contained in the mast when the gripper end contacts the fuel. A winch mounted on the trolley raises the gripper tube and fuel assembly up into the mast tube. The fuel is transported while inside the mast tube to its new position.

The refueling machine uses a single variable frequency drive mounted in the motor control console to control the speeds of the bridge, trolley and main hoist motors. This is an electronic device that provides step-less variable speeds from zero to full speed.

All controls for the refueling machine are mounted on a console in the trolley. The bridge is positioned on a coordinate system laid out on one rail. The trolley is positioned with the aid of a scale on the bridge structure. The drive for the bridge, trolley and main hoist provides for variable speeds and includes the ability for setting separate frequencies for setting jogging (inching) speeds for the bridge, trolley and main hoist. The maximum speed for the bridge is 65 fpm, 45 fpm for the trolley and 21 fpm for the main hoist. The auxiliary monorail hoist on the refueling machine has a two step magnetic controller to give hoisting speeds of approximately 7 and 20 fpm.

Refueling machine interlocks and permissives are provided by a Programmable Logic Controller (PLC) that is mounted inside the Control Console on the trolley. PLC interlocks and limit switches prevent damage to the fuel assemblies. The PLC tracks the inner mast position in order to stop the hoist from being raised above a safe shielding depth; this function is backed up with a physical limit switch. In an emergency, the bridge, trolley and main hoist can be operated manually using handwheels on the respective motors.

The refueling machine mast is equipped with hardware to support in-mast sipping - a failed fuel detection process.

9.1.4.2.2.2 Fuel Handling Machine

The fuel handling machine (see Figure 9.1-5) is a wheel-mounted walkway, spanning the spent fuel pool, the fuel transfer canal, and cask loading pit, which carries an electric monorail hoist on an overhead structure. The fuel handling machine is used for handling fuel assemblies within the spent fuel pool, the fuel transfer canal and the cask loading pit by means of a long handled tool suspended from the hoist. The hoist travel and tool length are designed to limit the maximum lift of a fuel assembly to a safe shielding depth.

The fuel handling machine has a 2 step magnetic controller for the bridge and hoist. The bridge speeds are 11 and 33 fpm and the hoist speeds are 7 and 20 fpm. A hydraulic coupling is used in the bridge drive to limit starting acceleration.

The hoist trolley is hand operated by a chain drive.

9.1.4.2.2.3 New Fuel Elevator

The new fuel elevator (see Figure 9.1-6) consists of a box-shaped assembly with its top end open, sized to house one fuel assembly that is raised and lowered by a winch and cable.

The new fuel elevator is normally used to lower a new fuel assembly to an elevation where it can be handled by the fuel handling machine with a long-handled spent fuel handling tool. The new

fuel assembly can then be moved to the fuel basket of the transfer system during core loading or to the spent fuel pool to stage the assembly for core loading at a later date.

The new fuel elevator is also used as a work platform for holding an irradiated fuel assembly. An example of this would be fuel assembly top nozzle reconstitution referred to in FSAR chapter 4. In this process, the irradiated fuel assembly is loaded into the New Fuel Elevator with the spent fuel handling tool and fuel handling machine and the elevator at the bottom of its travel. The elevator is then raised to a level with about 10 feet of water shielding available above the fuel. The New Fuel Elevator controls have been modified and administrative controls are also used to control the process to ensure that radiation dose rates to personnel remain within acceptable limits.

9.1.4.2.2.4 Fuel Transfer System

The FTS (see Figure 9.1-7) is a transfer car that runs on tracks extending from the refueling canal through the fuel transfer tube and into the fuel transfer canal. The car is moved along the track via a cable/winch system. A hydraulically actuated lifting arm is at each end of the fuel transfer tube. The fuel container in the refueling canal receives a fuel assembly in the vertical position from the refueling machine. The fuel assembly is then lowered to a horizontal position for passage through the fuel transfer tube. After passing through the tube, the fuel assembly is raised to a vertical position for removal by a tool suspended from a hoist mounted on the fuel handling machine. The fuel handling machine them moves to a storage loading position and places the spent fuel assembly in the spent fuel storage racks.

During reactor operation, the transfer car is stored in the fuel transfer canal. A blind flange is bolted on the refueling canal end of the fuel transfer tube to seal the containment. The terminus of the tube outside the reactor building is closed by a gate valve.

9.1.4.2.2.5 Rod Cluster Control Changing Fixture

The rod cluster control changing fixture is supplied for periodic rod cluster control element inspections and for transfer of rod cluster control elements from one fuel assembly to another (see Figure 9.1-8). The major subassemblies which comprise the changing fixture are the frame and track structure, the carriage, the guide tube, the gripper, and the drive mechanism. The carriage is a moveable container supported by the frame and track structure. The tracks provide a guide for the 4 flanged carriage wheels and allow horizontal movement of the carriage during changing operation. The positioning stops on both the carriage and frame, locate each of the three carriage compartments directly below the guide tube. Two (2) of these compartments are designed to hold individual fuel assemblies and the third is made to support a single rod cluster control element. Situated above the carriage and mounted on the refueling canal wall is the guide tube. The guide tube provides for the guidance and proper orientation of the gripper and rod cluster control element as they are being raised and lowered. The gripper is a pneumatically actuated mechanism responsible for engaging the rod cluster control element. It has two flexure fingers which can be inserted into the top of the rod cluster control element when air pressure is applied to the gripper piston. Normally the fingers are locked in a radially extended position. Mounted on the operating deck is the drive mechanism assembly which consists of the manual carriage drive mechanism,

the revolving stop operating handle, the pneumatic selector valve for actuating the gripper piston, and the electric hoist for elevation control of the gripper.

9.1.4.2.2.6 Spent Fuel Assembly Handling Tool

The spent fuel assembly handling tool (see Figure 9.1-9) is used to handle new and spent fuel assemblies in the fuel transfer canal and the spent fuel pool. It is a manually actuated tool, suspended from the fuel handling machine, which uses four cam actuated latching fingers to grip the underside of the fuel assembly top nozzle. The operating handle to actuate the fingers is located at the top of the tool. When the fingers are latched a pin is inserted into the operating handle, which prevents the fingers from being accidentally unlatched during fuel handling operations.

9.1.4.2.2.7 New Fuel Assembly Handling Fixture

The new fuel assembly handling fixture (see Figure 9.1-10) is used to lift and transfer new fuel assemblies from the new fuel storage area to the new fuel elevator. It is a manually actuated tool suspended from the fuel handling building crane, which uses 4 cam actuated latching fingers to grip the underside of the fuel assembly top nozzle. The operating handles to actuate the fingers are located on the side of the tool. When the fingers are latched, the safety screw is turned in to prevent the accidental unlatching of the fingers.

9.1.4.2.2.8 Reactor Vessel Head Lifting Rig

The original Reactor Vessel Head lifting rig has been replaced with a special lifting device integrated into the Integrated Head Assembly (IHA), typically referred to as the reactor head service structure. This lifting rig assembly is part of the IHA and stays installed on the IHA during both refueling activities and normal power operations. This device complies with ANSI 14.6-1978 design requirements as documented in the IHA Design Report.

9.1.4.2.2.9 Cranes

1. Polar Crane

   The reactor building polar crane is a single trolley, electric, overhead crane with a main hoist capacity of 360 tons and an auxiliary hoist capacity of 25 tons. The polar crane is used to lift the reactor vessel head and reactor internals prior to refueling operations.

   The Polar Crane has two loading conditions, a “Construction” load, and a “Normal Operation” load. The “Construction” loading is 360 ton and does not consider seismic interaction. The “Normal Operation” loading is 157.5 ton and does consider seismic forces (i.e., crane will continue to hold a suspended load during and after a seismic event). During normal plant shutdown for refueling, seismic interaction is considered when loads, such as the reactor vessel head assembly, are suspended above irradiated fuel in the reactor vessel.

2. Fuel Handling Building Crane

   The fuel handling building crane is a single trolley, electric, overhead crane with a main hoist capacity of 125 tons and an auxiliary hoist capacity of 15 tons. The fuel handling building crane is used to remove and replace the spent fuel pool gate; unload and transfer new fuel assemblies; and move, load, and unload casks during spent fuel transfer operations.

   The Fuel Handling Building overhead bridge crane is a single-failure-proof crane with a capacity of 125 tons as described in Section 3.12.4.3. The crane is designed to hold the full rated capacity during and after a postulated seismic event.

9.1.4.2.2.10 Reactor Vessel Internals Lifting Device

The reactor vessel internals lifting device (see Figure 9.1-11) is a structural frame positioned by the polar crane. The frame is lowered onto the guide tube support plate at the internals, and is mechanically connected to the support plate by 3 breech lock type connectors. Bushings on the frame engage guide studs in the vessel flange to provide guidance during removal and replacement of the internals package.

9.1.4.2.2.11 Reactor Vessel Stud Tensioner

The stud tensioners are employed to secure the head closure joint at every refueling. The stud tensioner is a hydraulically operated device that uses oil as the working fluid.

9.1.4.3 Safety Evaluation

9.1.4.3.1 Safe Handling

9.1.4.3.1.1 Design Criteria for the Fuel Handling System

1. The primary design requirement of the equipment is reliability. A conservative design approach was used for all load bearing parts. Where possible, components are used that have a proven record of reliable service. Throughout the design, consideration was given to the fact that the equipment will spend long idle periods stored in an atmosphere of 80°F and high humidity.
2. Except as otherwise specified the refueling machine and fuel handling machine are designed and constructed in accordance with Crane Manufacturer Association of America (CMAA) Specification 70.
3. The design load for the refueling machine and fuel handling machine was the normal dead and live loads plus the maximum hoist load.
4. The allowable stresses for the refueling machine and fuel handling machine structures supporting the weight of the fuel, are as specified in Subarticle XVII-2200 of Appendix XVII of the ASME Code, Section III, 1974 Edition.

Hoisting components loaded in simple tension have an allowable stress of 0.20 ultimate stress maximum.

5. All components critical to the operation of the equipment or located so that parts can fall into the reactor are assembled with the fasteners positively restrained from loosening under vibration. Spring or tooth type lock washers are not considered as positive restraints. If positive restraint cannot be achieved on fasteners on purchased components above the water line, then the fasteners must be lockwired, tack welded or backed out, coated with locking compound and retightened.

9.1.4.3.1.2 Industrial Codes and Standards Used in the Design of the Fuel Handling Equipment

1. Refueling Machine and Fuel Handling Machine: Applicable sections of CMAA Specification 70.
2. Structural: ASME Code, Section III, Appendix XVII, Subarticle XVII-2200, 1974 Edition.
3. Electrical: Applicable standards and requirements of IEEE Standard 279, National Electric Code, NFPA #70, and NEMA Standards MGI and ICS are used in the design, installation, and manufacturing of all electrical equipment.
4. Materials: Materials conform to the specifications of the ASTM standard.
5. Safety: OSHA Standards 29 CFR 1910, and 29 CFR 1926 including load testing requirements, the requirements of ANSI N18.2, Regulatory Guide 1.29 (see Appendix 3A) and General Design Criteria 61 and 62.

9.1.4.3.1.3 Refueling Machine

The refueling machine design includes the following provisions to ensure safe handling of fuel assemblies:

1. Electrical Interlocks

   a. Bridge, Trolley and Hoist Drive Mutual Interlocks

      The bridge, trolley, and hoist are interlocked such that only one motor can be operated at any one time either by the master or jog switches. If any one of the master or jog switches are actuated, all others are inactivated and have no effect on the current operating mode of the machine. The logic checks for actual motor operation and motor control relay status, and thus can stand a single failure.

   b. Bridge Trolley Drive - Gripper Tube Up

      With a fuel assembly attached, bridge and trolley motions are prevented except when the Gripper Tube Up interlock is actuated. The interlock is redundant and can withstand a single failure.

c. Gripper Interlock

Interlocks exists that prevent the solenoid valve that supplies air to the gripper actuator for disengagement to open except if both the mast is at the elevation that corresponds to Gripper Tube Down and a Slack Cable condition exists.

As backup protection for this interlock the mechanical weight actuated lock in the gripper prevents operation of the gripper under load, even if air pressure is applied to the operating cylinder. This interlock is redundant and can withstand a single failure.

d. Excessive Suspended Weight

The load control system (integral to the PLC) will stop the hoist when overloads or underloads occur. A six way selector switch on the Control Console allows the operator to select between light and heavy assemblies and varying levels of overload. A master overload is programmable, yet non-bypassable and is set at a value to ensure fuel is protected. For underload, each of the positions on the selector switch has one value for hoist cut-out.

e. Hoist-Gripper Position Interlock

An interlock in the hoist drive circuit in the up direction, permits the hoist to be operated only when either the open or closed indicating switch on the gripper is actuated. The hoist-gripper position interlock consists of two logic paths that work parallel such that one path must be closed for the hoist to operate. If neither one of the gripper position limit switches are actuated, audible and visual alarms on the console will actuate. The interlock, therefore, is not redundant but can withstand a single failure since both an interlocking path and the monitoring path must fail to cause a hazardous condition.

2. Bridge and Trolley Hold-Down Devices

Both the refueling machine bridge and trolley are horizontally restrained on the rails by two pairs of guide rollers, one pair at each wheel location on one truck only. The rollers are attached to the bridge truck and contact the vertical faces on either side of the rail to prevent horizontal movement. Vertical restraint is accomplished by anti-rotation bars located at each of the four wheels for both the bridge and trolley. The anti-rotation bars are bolted to the trucks and, for the bridge restraints, extended under the rail flange, while for the trolley restraints, extended beneath the top flange of the bridge girder which supports the trolley rail. Both horizontal and vertical restraints are adequately designed to withstand the forces and overturning moments resulting from the SSE.

3. Design Load

The design load for structural components supporting the fuel assembly is the dead weight plus 4800 pounds (3 times the fuel assembly weight).

4. Main Hoist Braking System

   The main hoists are equipped with 2 independent braking systems. A solenoid release-spring set electric brake is mounted on the motor shaft. This brake operates in the normal manner to release upon application of current to the motor and set when current is interrupted. The second brake is a mechanically actuated load brake internal to the hoist gear box that sets if the load starts to overhaul the hoist. It is necessary to apply torque from the motor to raise or lower the load. In raising, this motor cams the brake open. In lowering, the motor slips the brake allowing the load to lower. This brake actuates upon loss of torque from the motor for any reason and is not dependent on any electrical circuits.

5. Fuel Assembly Support System

   The main hoist system is supplied with redundant paths of load support such that failure of any one component will not result in free fall of the fuel assembly. Two wire ropes are anchored to the winch drum and carried over independent sheaves to a load equalizing mechanism on the top of the gripper tube. In addition, supports for the sheaves and equalizing mechanism are backed up by passive restraints to pick up the load in the event of failure of this primary support. Each cable system is designed to support 13,750 pounds or 27,500 pounds acting together.

   The working load of a fuel assembly, with a Rod Cluster Control Assembling (RCCA) plus gripper is approximately 2000 pounds.

   The gripper itself has four fingers gripping the fuel, any two of which will support the fuel assembly weight.

   The gripper mechanism contains a spring actuated mechanical lock which prevents the gripper from opening unless the gripper is under a compressive load.

   During each refueling outage and prior to removing fuel, the gripper and hoist system is routinely load tested to at least 3250 pounds.

9.1.4.3.1.4 Fuel Transfer System

The following safety features are provided for in the FTS.

1. Transfer Car Permissive Switch

   The transfer car controls are located in the fuel handling building and conditions in the reactor building are, therefore, not visible to the operator. The transfer car permissive switch allows a second operator in the reactor building to exercise some control over car movement if conditions visible to him warrant such control. Transfer car operation is possible only when both lifting arms are in the down position as indicated by the limit switches. The permissive switch is a backup for the transfer car lifting arm interlock. Assuming the fuel assembly container is in the upright position in the reactor building and the lifting arm interlock circuit fails in the permissive condition, the operator in the fuel handling building still cannot operate the car because of the permissive switch interlock. The interlock, therefore, can withstand a single failure.

2. Lifting Arm - Transfer Car Position

   Two redundant interlocks allow lifting arm operation only when the transfer car is at the respective end of its travel and therefore can withstand a single failure.

   Of the two redundant interlocks which allow lifting arm operation only when the transfer car is at the end of its travel, one interlock is a position limit switch in the control circuit. The backup interlock is a frame down limit switch which not allow the car to traverse until both frame down limits are closed. Additionally, the lifting arm will not operate while the car is traversing.

3. Transfer Car - Valve Open

   A remote panel has been installed at the valve operator location which is equipped with lights which show the position of the valve. When the valve is full open only the red light is illuminated. While the valve is changing position (open - closed or closed - open) the red and green lights are illuminated. When fully closed the green light is illuminated. Tied to the red light only illumination (valve full open) is the traverse permissive. The carriage will not traverse with the valve not full open. In addition to the remote light indicating panel XPN5556, the control panel is equipped with a red light - valve open.

4. Transfer Car - Lifting Arm

   The transfer car lifting arm is primarily designed to protect the equipment from overload and possible damage if an attempt is made to move the car when the fuel assembly container is in the vertical position. This interlock is redundant and can withstand a single failure.

The basic interlock is a position limit switch in the control circuit. The backup interlock is a mechanical latch device that is opened by the weight of the fuel assembly container when in the horizontal position.

5. Lifting Arm - Refueling Machine

   The refueling canal lifting arm is interlocked with the refueling machine. Whenever the transfer car is located in the refueling canal, the lifting arm cannot be operated unless the refueling machine mast is in the fully retracted position or the refueling machine is over the core.

   The circuits which interlock the refueling canal lifting arm with the refueling machine are redundant.

6. Lifting Arm - Fuel Handling Machine

   The lifting arm is interlocked with the fuel handling machine. The lifting arm cannot be operated unless the fuel handling machine is not over the lifting arm area. The interlocks are redundant.

7. Additional protective devices designed into the Raytheon modification:
   1. Load sensitive bases which open circuits if an underloaded or overload torque is sensed on the car.
   2. Overcurrent protection on the winch motors.
   3. Overtravel programmed limits to backup primary limits in case of failures. Additionally, hard stops are provided to create overtorque in case limit controls fail.

9.1.4.3.1.5 Fuel Handling Machine

The fuel handling machine includes the following safety features.

1. The fuel handling machine controls are interlocked to prevent simultaneous operation of the bridge drive and hoist.
2. Bridge drive operation in the normal 2 speeds is permitted only when the hoist is in the full up position. The bridge can be jogged in increments of less than one inch, at low speed, in timed intervals when the hoist is in other than the full up position.
3. An overload protection device is included on the hoist to limit the uplift force which could be applied to the fuel storage racks. The protection device limits the hoist load to 125 percent of the rated hoist capacity.
4. The design load on the hoist is the weight of one fuel assembly (1600 lbs), the weight of one failed fuel container (1000 lbs), and the weight of the tool which gives it a total weight of approximately 3000 lbs.
5. Restraining bars are provided on each truck to prevent the bridge from overturning.

9.1.4.3.1.6 Fuel Handling Tools and Equipment

All fuel handling tools and equipment handled over an open reactor vessel are designed to prevent inadvertent decoupling from machine hooks (i.e., lifting rigs are pinned to the machine hook and safety latches are provided on hooks supporting tools).

Tools required for handling internal reactor components are designed with fail safe features that prevent disengagement of the component in the event of an operating mechanism malfunction. These safety features apply to the following tools.

1. Control rod drive shaft unlatching tool: The air cylinders actuating the gripper mechanism are equipped with backup springs which close the gripper in the event of loss of air to the cylinder. Air operated valves are equipped with safety locking rings to prevent inadvertent actuation.
2. Spent fuel assembly handling tool: When the fingers are latched a pin is inserted into the operating handle and prevents inadvertent actuation. The tool weighs approximately 385 pounds and is preoperationally tested at 125 percent the weight of one fuel assembly (1600 lbs).
3. New fuel assembly handling fixture: When the fingers are latched a safety screw is screwed in preventing inadvertent actuations. The tool weighs approximately 100 pounds and is preoperationally tested at 125 percent the weight of one fuel assembly (1600 lbs).

9.1.4.3.1.7 Polar Crane

The reactor building polar crane is safety-related and is designed to Seismic Category 1 requirements. This crane is equipped with two completely independent and automatically operated brake systems. Each brake system is capable of stopping the rated crane load at any speed up to 150 percent of the rated speed.

9.1.4.3.1.8 Fuel Handling Building Crane

The fuel handling building crane is safety-related and is designed to Seismic Category 1 requirements. This crane is equipped with two completely independent and automatically operated brake systems. Each brake system has a minimum capacity of 125 percent of that required to hold the design rated loads. The fuel handling building crane rail installation allows operation over the cask loading pit, decontamination and new fuel storage area, but excludes operation over the spent fuel pool. Structural stops are provided at each end of the rails.

9.1.4.3.2 Seismic Considerations

The safety classifications for all fuel handling and storage equipment are listed in Table 3.2-1. These safety classes provide criteria for the seismic design of the various components. Safety Class 1 and 2a equipment is designed to withstand the forces of the OBE and SSE. For normal conditions plus OBE loadings, the resulting stresses are limited to allowable working stresses as defined in the ASME Code, Section III, Appendix XVII, Subarticle XVII-2200 for normal and

upset conditions. For normal conditions plus SSE loadings, the stresses are limited to within the allowable values given by Subarticle XVII-2110 for critical parts of the equipment which are required to maintain the capability of the equipment to perform its safety function. Permanent deformation is allowed for the loading combination which includes the SSE to the extent that there is no loss of safety function.

The Safety Class 2b and 3 fuel handling and storage equipment satisfies the Safety Class 1 and 2a criteria given above for the SSE. Consideration is given to the OBE only in so far as failure of the Safety Class 2b and 3 equipment might adversely affect Safety Class 1 or 2a equipment.

For Non-Nuclear Safety equipment, design for the SSE is considered if failure might adversely affect a Safety Class 1, 2a, 2b, or 3 component.

Design for the OBE is considered if failure of the Non-Nuclear Safety component might adversely affect a Safety Class 1 or 2a component.

9.1.4.3.3 Containment Pressure Boundary Integrity

The fuel transfer tube which connects the refueling canal (inside the reactor building) and the fuel transfer canal (outside the reactor building) is closed on the refueling canal side by a blind flange at all times except during refueling operations. Two seals are located around the periphery of the blind flange with leak-check provisions between them.

9.1.4.3.4 Radiation Shielding

During all phases of spent fuel transfer, the gamma dose rate at the surface of the water is 2.5 mr/hr or less. This is accomplished by maintaining the spent fuel pool level at the normal elevation of 461’-6", thus providing a nominal 10 feet of water shielding above the active fuel assembly during all handling operations.

The two fuel handling devices used to lift spent fuel assemblies are the refueling machine and the fuel handling machine. The refueling machine contains positive stops which prevent the top of a fuel assembly from being raised to within a nominal 10 feet of the normal water level in the refueling cavity. The hoist on the fuel handling machine moves spent fuel assemblies with a long handled tool. Hoist travel and tool length likewise limit the maximum lift of a fuel assembly to within a nominal 10 feet of the normal water level in the spent fuel pool.

9.1.4.3.5 Spent Fuel Shipping Cask Handling

The spent fuel shipping cask is designed to withstand a drop, in air, of 30 feet without release of the solid contents of the cask. Restrictive administrative procedures are followed during cask handling operations to minimize cask impact loadings in the event of a cask drop. The only area where the drop height exceeds 30 feet is above the cask loading pit. However, as discussed in Section 9.1.3.3, a cask drop into the flooded cask loading pit does not violate the 30 foot drop criteria since the calculated impact velocity of the cask at the floor of the cask loading pit is less than 44 ft/sec. The velocity of 44 ft/sec is the impact velocity generated by a 30 foot cask drop in

air onto an unyielding surface. Water level in the cask loading pit is continuously controlled whenever the cask is placed in or removed from the pit. Therefore, for a cask drop into the flooded cask loading pit, there is no release of the solid contents of the cask.

To minimize the consequences of a cask drop, the cask is moved at a height of 1 foot above the operating floor by the fuel handling building crane. Handling of the cask in the plant proper is performed with the bottom impact limiter removed from the cask.

Since handling of the cask in the plant does not violate the 30 foot drop criterion, cask integrity is maintained and there is no release of the contents of the cask. Therefore, a design basis analysis of the radiological consequences of a spent fuel cask drop accident is not required.

The area of fuel handling building crane coverage precludes damage to safety-related equipment should a cask drop occur. There are no safety related systems or components located under the travel path of the fuel transfer cask. In addition, cask handling in this limited area will not violate the 30 foot drop criteria.

9.1.4.4 Tests and Inspections

As part of normal plant operations, the fuel handling equipment is inspected for operating conditions prior to each refueling operation. During the operational testing of this equipment, procedures are followed that will affirm the correct performance of the FHS interlocks.

9.1.5 Spent Fuel Dry Cask Storage

9.1.5.1 System Description

The Virgil C. Summer Nuclear Station (VCSNS) has established an Independent Spent Fuel Storage Installation (ISFSI) located approximately 500 feet west of the Unit 1 Fuel Handling Building (FHB) and northeast of warehouses A and B in the plant Protected Area as shown on Figure 1.2-1. The ISFSI concrete pad has a capacity for 98 vertical spent fuel storage casks.

Spent Fuel Dry Cask Storage operations at the VCSNS are conducted under a general license in accordance with Subpart K of 10 CFR Part 72. The general license issued by 10 CFR 72.210 authorizes a 10 CFR Part 50 nuclear power plant licensee to store spent fuel at an onsite ISFSI. Subpart K of 10 CFR Part 72 also includes 10 CFR 72.212, “Conditions of general license issued under §72.210,” which requires the use of a dry cask storage system that is pre-approved by the Nuclear Regulatory Commission, as evidenced by its listing in 10 CFR 72.214.

The VCSNS ISFSI uses the Holtec HI-STORM Flood and Wind (FW) vertical cask storage overpack, the Holtec MPC-37 multi-purpose canister (MPC), and the HI-TRAC Variable Weight (VW) transfer cask as described in the HI-STORM FW MPC Storage System FSAR and approved by the Nuclear Regulatory Commission in HI-STORM FW Certificate of Compliance No. 1032, which includes the Technical Specifications for the HI-STORM FW MPC Storage System.

The MPC provides the confinement boundary for the stored fuel. The MPC is a welded, cylindrical canister with a honeycombed cell fuel basket to contain the spent fuel assemblies. All MPC confinement boundary components are made entirely of stainless steel. The honeycombed cell fuel basket construction includes the neutron absorbing material that provides criticality control. The MPC also provides axial shielding at the top and bottom ends.

The HI-STORM FW storage overpack provides additional radiation shielding and structural protection of the MPC during storage. The HI-STORM FW overpack design includes a lid which incorporates the air outlet duct. The overpack is a heavy-walled steel and concrete, cylindrical vessel whose side wall consists of non-reinforced concrete enclosed between inner and outer carbon steel shells. The carbon steel shells are coated on the exposed surfaces for corrosion protection. The overpack has eight air inlets at the bottom and a near 360 degree (excluding the support plates) air outlet at the top to allow air to circulate naturally through the cavity to cool the MPC inside. The inner shell has guide tubes attached to its interior surface to guide the MPC during insertion and removal and allow cooling air to circulate through the overpack.

The HI-TRAC VW is a metal transfer cask that provides a means to lift and handle the MPC. The Hi-TRAC VW provides shielding of the spent fuel assemblies in the MPC and structural protection of the MPC during loading, unloading, and movement of the MPC from the cask loading area to the storage overpack. The HI-TRAC VW is a multi-walled (carbon steel/lead/carbon steel) cylindrical vessel which utilizes a neutron shielding water jacket and a removable bottom lid used during MPC transfer operations.

9.1.5.2 Operations in the Fuel Handling Building

Loading the MPC-37 canisters with spent fuel assemblies takes place in the FHB. An empty MPC-37 canister is brought into the FHB rail bay in a HI-STORM FW overpack situated on top of a Low Profile Transporter (LPT). The empty MPC is loaded into the HI-TRAC VW transfer cask that is supported in the decontamination area by a Cask Support Pedestal. The HI-TRAC VW containing the empty MPC is lifted by the FHB single-failure-proof overhead crane, using a HI-TRAC lift yoke, from the decontamination area and placed in the cask loading pit of the spent fuel pool for spent fuel loading operations. A Variable Elevation Cask Staging Pedestal (VECASP) assembly is located on the floor of the cask loading pit. Using the lift yoke and a lift yoke extension, the HI-TRAC VW containing the empty MPC is moved to the lower position inside the VECASP in the cask loading pit.

The MPC is then loaded with spent fuel assemblies utilizing the fuel handling machine. The HI-TRAC VW and loaded MPC are transferred by the FHB crane to the stainless steel lined decontamination area, where the MPC is decontaminated, welded shut, drained, dried, and backfilled with helium. The HI-TRAC VW containing the MPC is then lifted and placed on top of the HI-STORM FW overpack inside the FHB rail bay so that the MPC can be transferred from the HI-TRAC to the HI-STORM. After the MPC has been placed in the HI-STORM, the loaded HI-STORM is transported out of the FHB on the LPT, where the loaded HI-STORM is lifted from the LPT by a vertical cask transporter (VCT), moved along the haul path by the VCT to the ISFSI pad, and placed in its storage location.

Critical load handling operations in the FHB associated with dry cask loading or unloading activities are conducted using single-failure-proof handling systems, which include the main hoist on the FHB overhead crane and lifting devices meeting the enhanced safety factors of ANSI N14.6 or ASME B30.9. These lifting devices and other cask handling system components meet the applicable requirements of ANSI N14.6, NUREG-0554, and applicable guidelines of NUREG-0612 per the VCSNS heavy loads program described in FSAR Section 3.12.

9.1.6 References

1. Taylor, G. J., *Virgil C. Summer Nuclear Station (VCSNS), Docket No. 50/395, Operating License No, NPF-12, Exemption from the Requirements of 10 CFR 70.24*, RC-97-0128, July 17, 1997.
2. Taylor, G. J., *Virgil C. Summer Nuclear Station (VCSNS), Docket No. 50/395, Operating License No, NPF-12, Exemption from the Requirements of 10 CFR 70.24 Supplement 1*, RC-97-0162, August 6, 1997.
3. Johnson, A. R. (NRC) to Taylor, G. J. (SCE&G), *Issuance of Exemption from the Requirements of 10 CFR 70.24 Virgil C. Summer Nuclear Station – (TAC NO. M99278)*, September 9, 1997.
4. Final Safety Analysis Report for the HI-STORM FW MPC Storage System, Holtec Report HI-2114830, Docket 72-1032.
5. 10 CFR 72 Certificate of Compliance No. 1032, HI-STORM FW MPC Storage System, Effective Date June 13, 2011; including Appendix A - Technical Specifications for the HI-STORM FW MPC Storage System, and Appendix B - Approved Contents and Design Features for the HI-STORM FW MPC Storage System.

Table 9.1-1
Spent Fuel Cooling System Component Data

Spent Fuel Cooling Pump and Spent Fuel Cooling and Transfer Pump	
Type	Centrifugal, electric motor driven, horizontal shaft
Safety Class	2b
Code	ASME Code, Section III, Class 3
Materials of Wetted Parts	Austenitic stainless seal
Seal Type	Mechanical Seal
Motor, hp	75
Power Supply	460V, 3 phase, 60Hz
Design Flow, gpm	1800
Design Head (TDH), ft	100
Connections	Flanged: 8 inch Discharge 10 inch Suction
Operating Speed, rpm	1750
Spent Fuel Heat Exchangers	
Quantity	2
Type	U-Tube
Material of Wetted Parts	Tube: Austenitic stainless steel Shell: Carbon steel
Heat Transfer Rate (Per Cooler)	
Normal (original), BTU/hr	14.02×10^6
Peak (original), BTU/hr	19.23×10^6
Partial Offload (Uprate)	20.71×10^6
Full Core Offload (Uprate)	40.74×10^6 (85°F shell side inlet) 31.16×10^6 (105°F shell side inlet)
Abnormal Offload (Uprate)	38.84×10^6

Table 9.1-1 (continued)
Spent Fuel Cooling System Component Data

Inlet temperature	Shell Side	Tube Side
Normal (original), °F	105	135
Peak (original), °F	105	146
Partial Offload (Uprate) °F	105	150
Full Core Offload (Uprate) °F	105	186
Abnormal Offload (Uprate) °F	105	200
Flow Rate, lb/hr	8.9×10^5	8.9×10^5
Pressure Drop, Total, psi	<15	<10
Design Pressure, psig	150	150
Design Temperature, °F	250	250
Safety Class	2b	2b
Design Code	ASME Code, Section III, Class 3	ASME Code, Section III, Class 3

Spent Fuel Purification Pump	
Type	Centrifugal, electric motor driven, vertical shaft
Materials of Wetted Parts	Austenitic stainless steel
Seal Type	Packing gland
Motor, hp	75
Power Supply	460V, 3 phases, 60 HZ
Design Flow, gpm	180
Design Head, ft	200
Connections	Flanged, 4” suction, 3” discharge
Safety Class	NNS

Table 9.1-1 (continued)
Spent Fuel Cooling System Component Data

Spent Fuel Cooling Demineralizer	
Purification Media	Anion and/or cation exchange resins as required
Operating temp, max. °F	140
Flow, gpm	180
Safety Class	NNS
Spent Fuel Purification Filters	
Quantity	2
Type	Removable cartridge
Removal Rating, microns abs.	≤ 30
Flow, gpm, each	180
Safety Class	NNS
Refueling Water Storage Tank	
Type	Cylindrical, vertical
Normal Operating Capacity	
Minimum Contained Volume, gal	453,800
Maximum Contained Volume, gal	514,665
Material	Stainless steel
Design Pressure, psig	+3, -0.5
Safety Class	2a

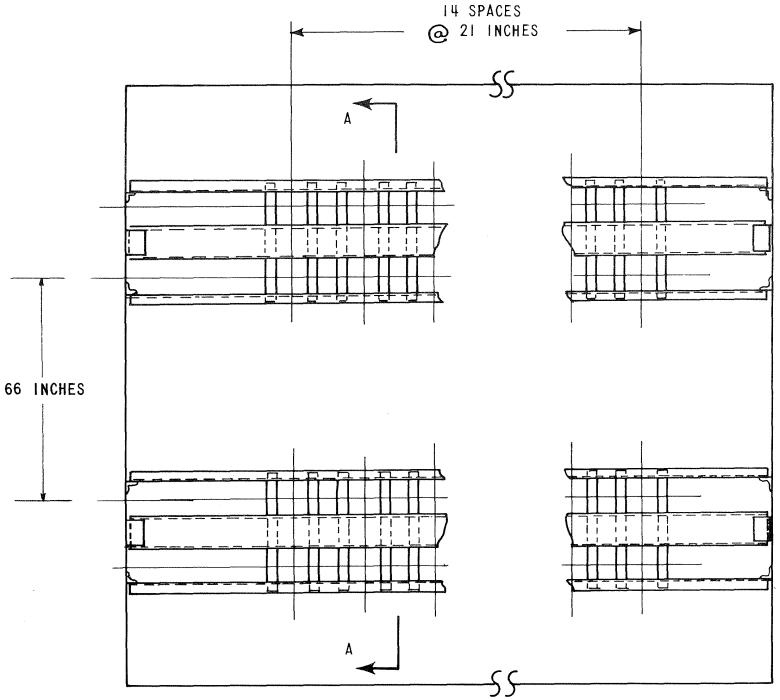
Table 9.1-2
Spent Fuel Storage Racks - Design Data

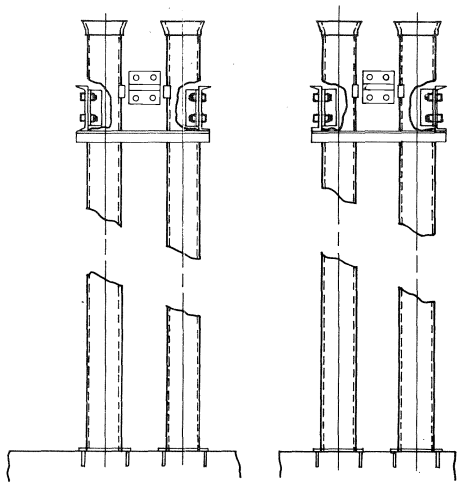
Region	Cell Pitch (nominal)	B_{10} Loading (nominal)	Flux Trap Gap (nominal)
1	10.867 in.	0.0324 gm/cm^2	1.6 in.
2	9.070 in.	0.0324 gm/cm^2	0.0 in.

Table 9.1-3
Spent Fuel Storage Racks - Module Data

Region No.	Module Type	Quantity	Cells per module	Array Size	Approximate Weight (lb/module)
1	C	1	100	10 x 10	25300
1	C	1	100	10 x 10	24900
2	A	4	156	13 x 12	23300
2	A	2	156	13 x 12	22800
2	B	2	144	12 x 12	21600
2	B	2	144	12 x 12	21200

Figure 9.1-1
NEW FUEL STORAGE RACK ASSEMBLY





AMENDMENT 2
AUGUST, 1986

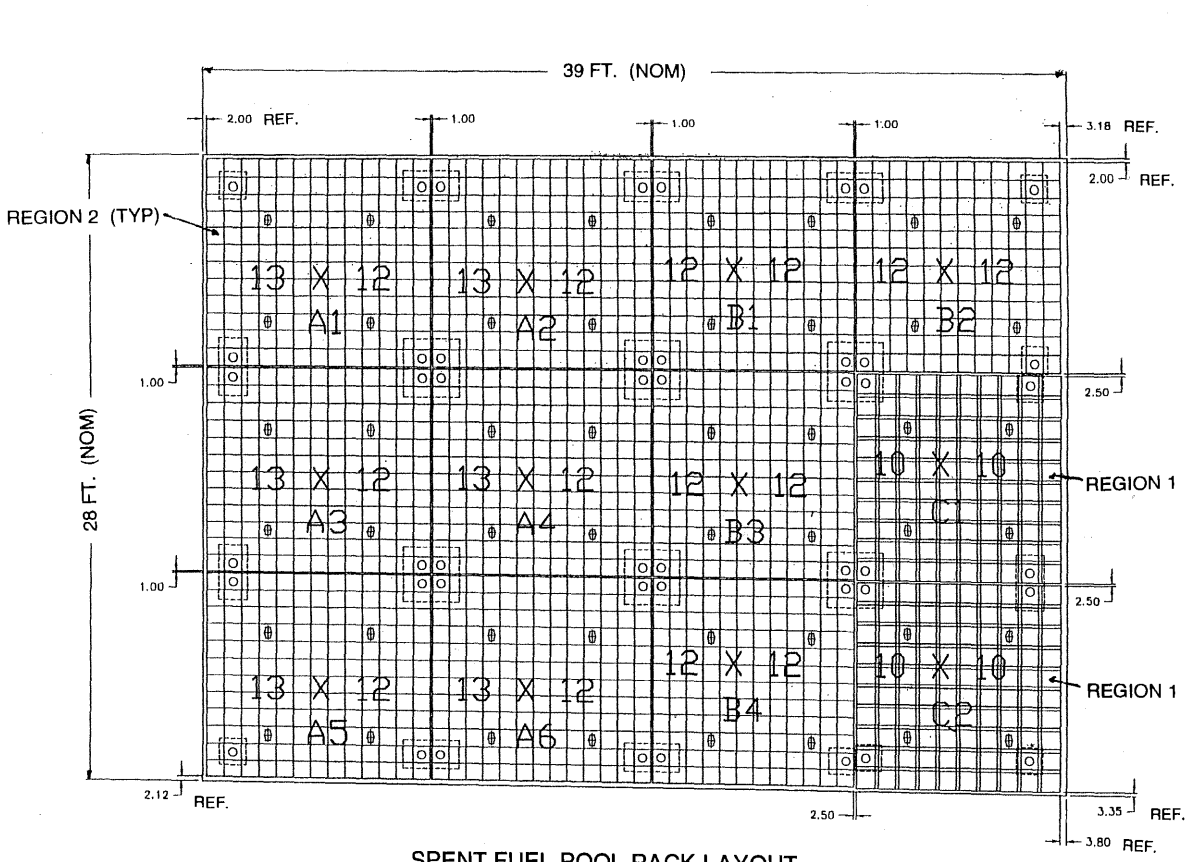
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

New Fuel Storage Rack
Assembly

Figure 9.1-1

Figure 9.1-2

SPENT FUEL STORAGE RACKS - MODULE LAYOUT



SPENT FUEL POOL RACK LAYOUT

NOTE: Clearance dimensions between racks are nominal design gaps in inches.

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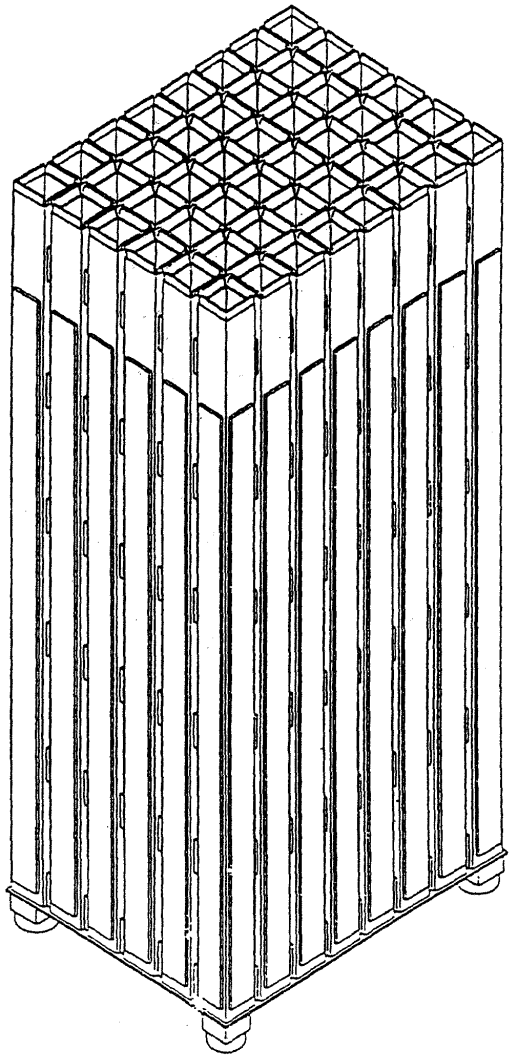
Spent Fuel Storage Racks - Module Layout Figure 9.1-2

Figure 9.1-2a

HIGH DENSITY SPENT FUEL STORAGE RACK
SCHEMATIC VIEW - REGION 1 RACK STRUCTURE



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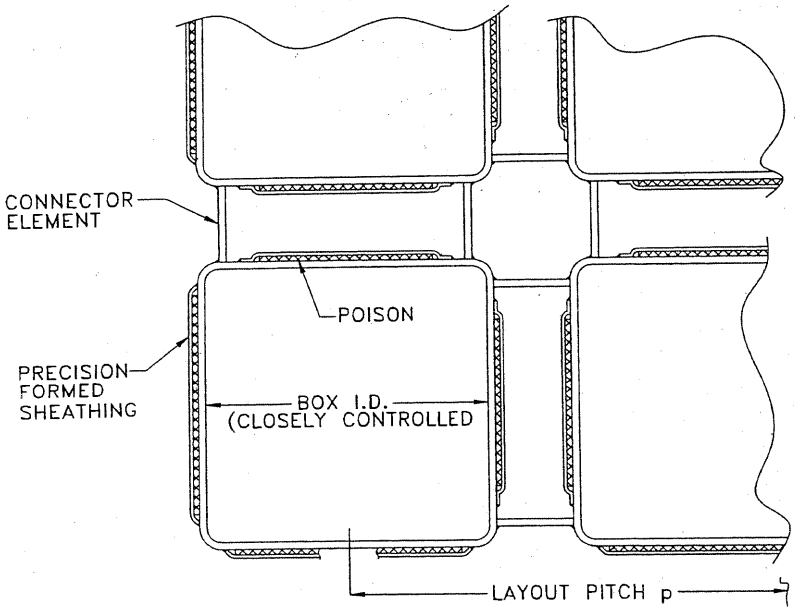
High Density Spent Fuel Storage Rack Schematic View - Region 1 Rack Structure Figure 9.1-2a

Figure 9.1-2b

HIGH DENSITY SPENT FUEL STORAGE RACK
REGION 1 STORAGE CELL ASSEMBLAGE



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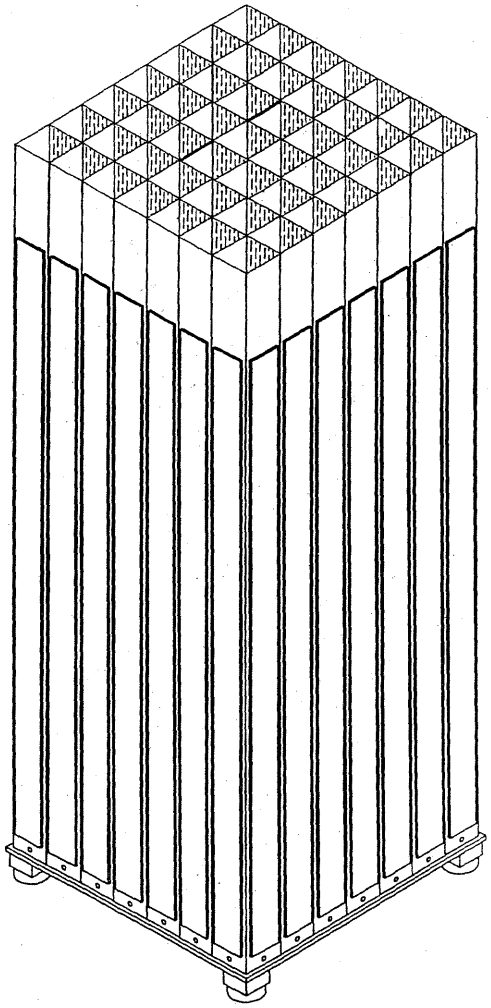
High Density Spent Fuel Storage Rack Region 1 Storage Cell Assemblage Figure 9.1-2b

Figure 9.1-2c

HIGH DENSITY SPENT FUEL STORAGE RACK
SCHEMATIC VIEW - REGION 2 RACK STRUCTURE



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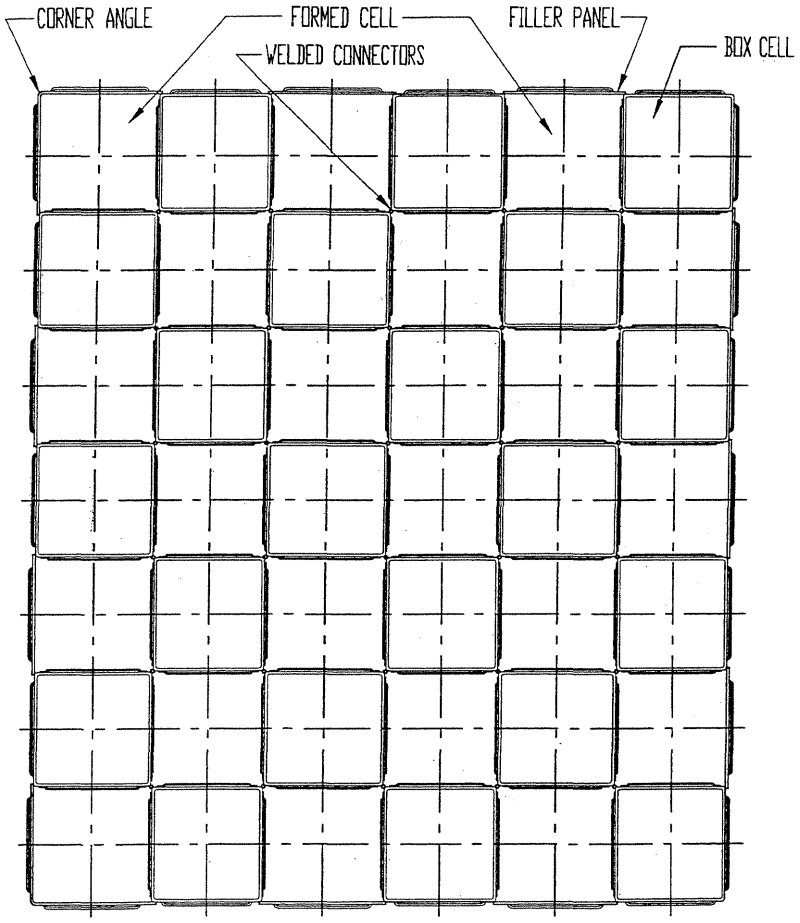
High Density Spent Fuel Storage Rack Schematic View - Region 2 Rack Structure Figure 9.1-2c

Figure 9.1-2d

HIGH DENSITY SPENT FUEL STORAGE RACK
REGION 2 STORAGE CELL ASSEMBLAGE



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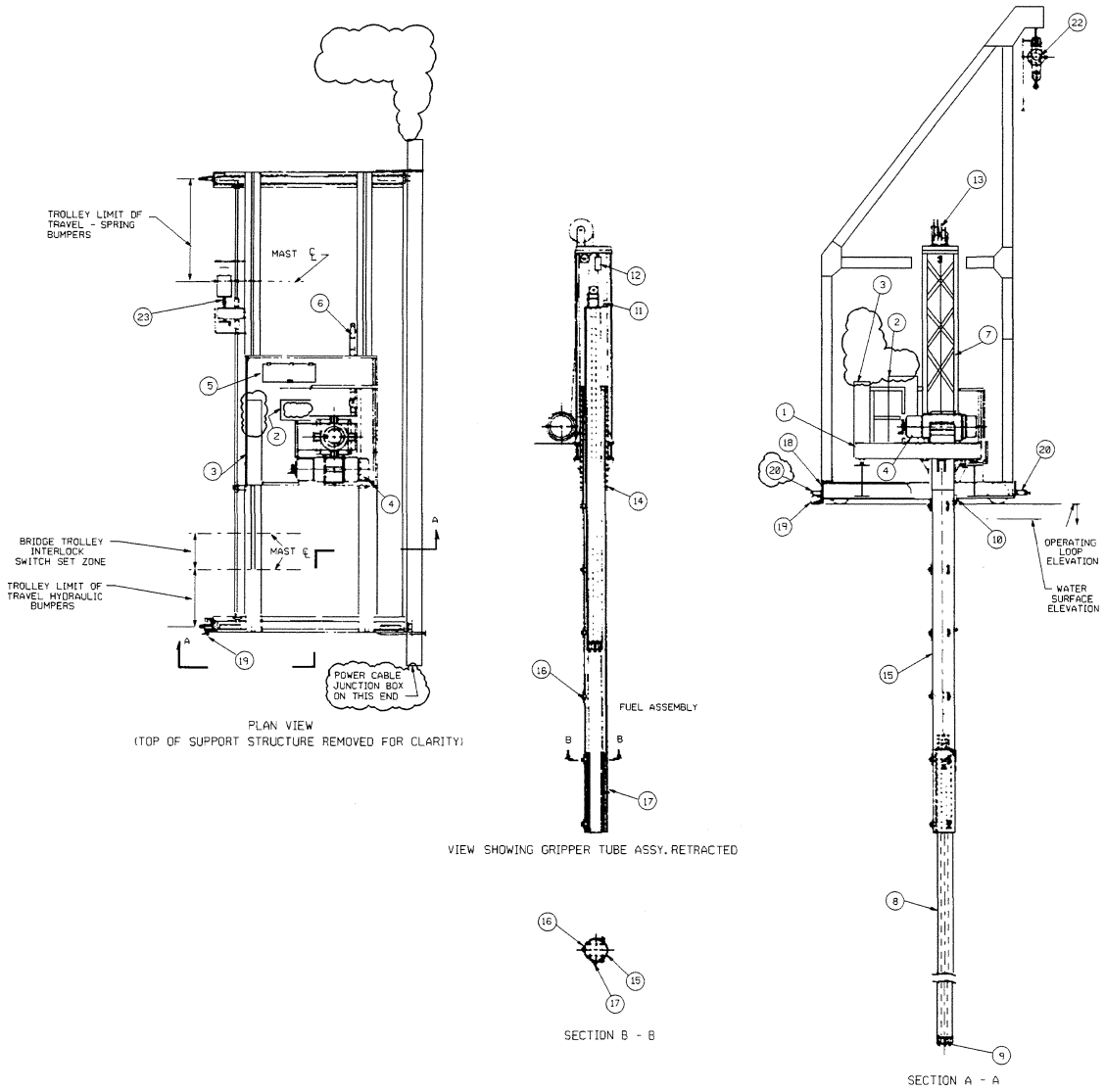
SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
High Density Spent Fuel Storage Rack Region 2 Storage Cell Assemblage Figure 9.1-2d

Figure 9.1-3
DRAWING D-302-651

Figure 9.1-4

REFUELING MACHINE



1. TROLLEY
2. CONTROL CONSOLE
3. MOTOR CONTROL CABINET
4. MAIN HOIST
5. TROLLEY DRIVE ACCESS HATCH
6. TROLLEY POSITION SCALE
7. SUPPORT STRUCTURE
8. GRIPPER TUBE
9. GRIPPER
10. GRIPPER TUBE DOWN POSITION SWITCH
11. GRIPPER TUBE UP POSITION SWITCH
12. LOAD CELL
13. AIR HOSE AND ELECTRIC CABLE REELS
14. MAST SUPPORT TUBE
15. OUTER MAST TUBE
16. GUIDE ROLLERS
17. FUEL ASSY. GUIDE BARS
18. BRIDGE
19. BRIDGE POSITION TRANSMITTER
20. HYDRAULIC BUMPER
22. MONORAIL HOIST
23. BRIDGE DRIVE

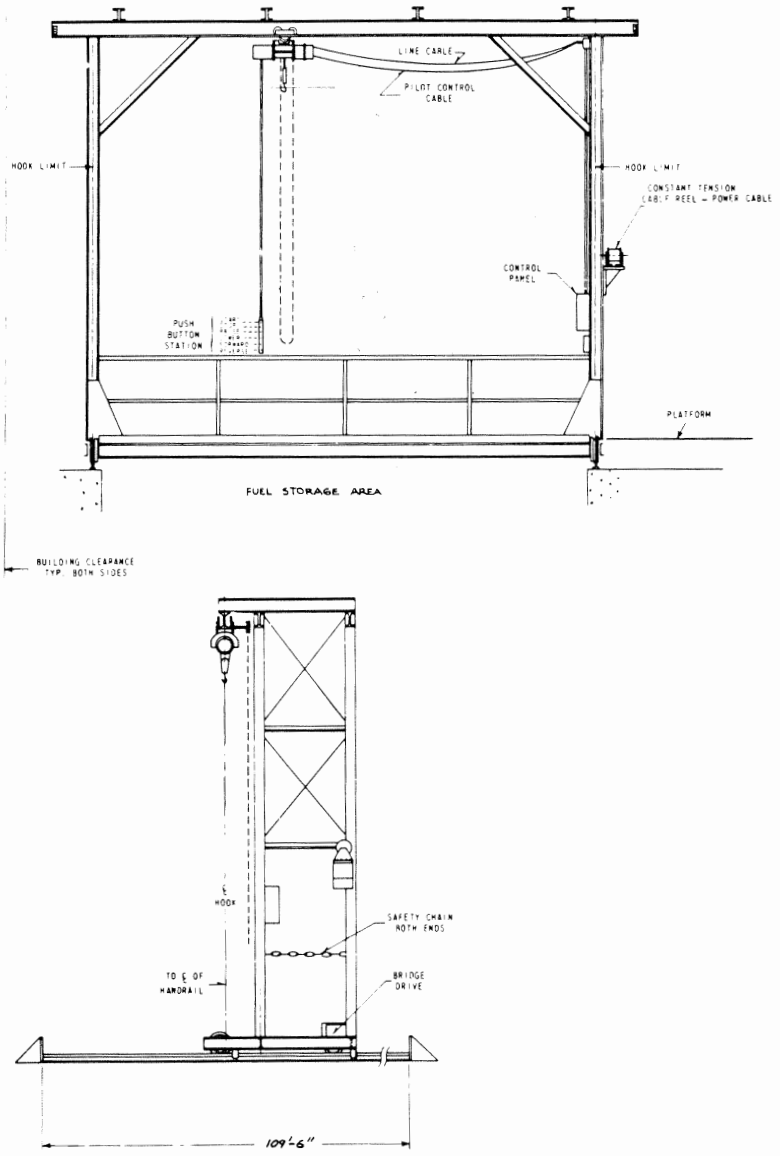
NOTE: THE MAST IS EQUIPPED WITH HARDWARE TO SUPPORT IN-MAST SIPPING - A FAILED FUEL DETECTION PROCESS.

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

REFUELING MACHINE

Figure 9.1-4 Rev. 0

Figure 9.1-5
FUEL HANDLING MACHINE



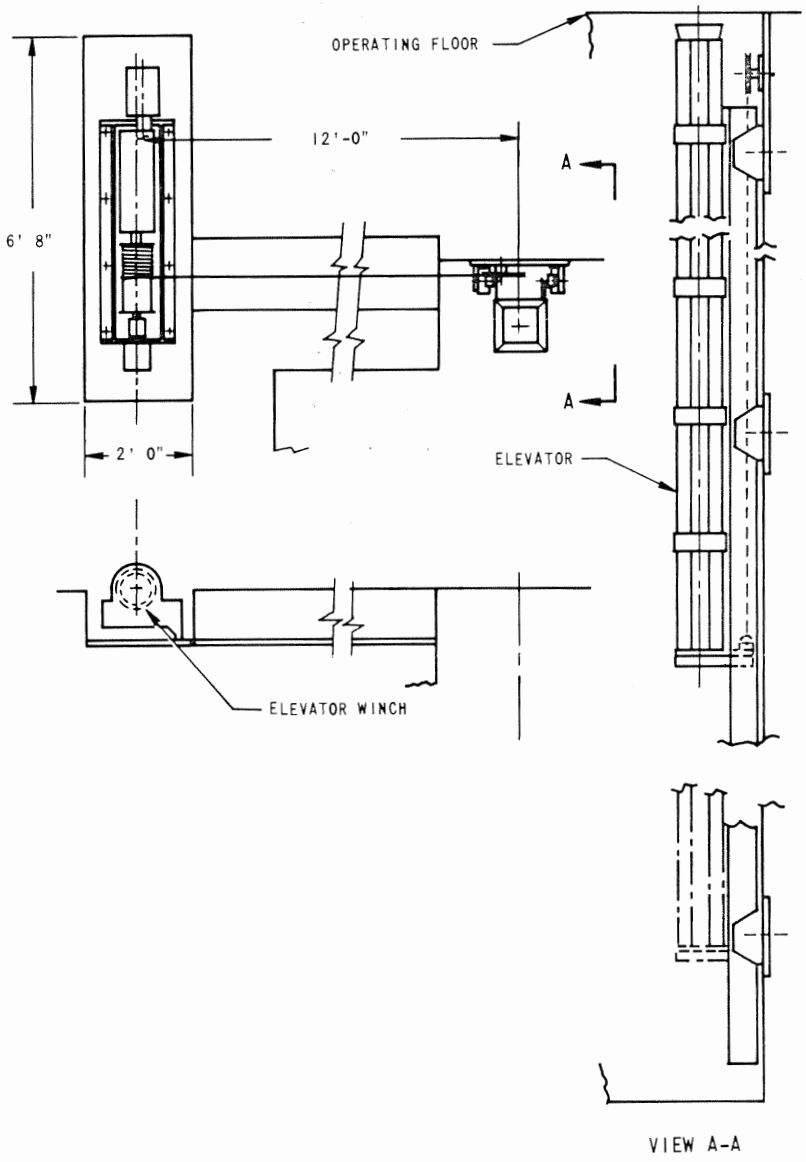
AMENDMENT 0
AUGUST 1984

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Fuel Handling Machine

Figure 9.1-5

Figure 9.1-6
NEW FUEL ELEVATOR



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VIRGIL C. SUMMER NUCLEAR STATION

New Fuel
Elevator

Figure 9.1-6

Figure 9.1-7

FUEL TRANSFER SYSTEM REV. 0

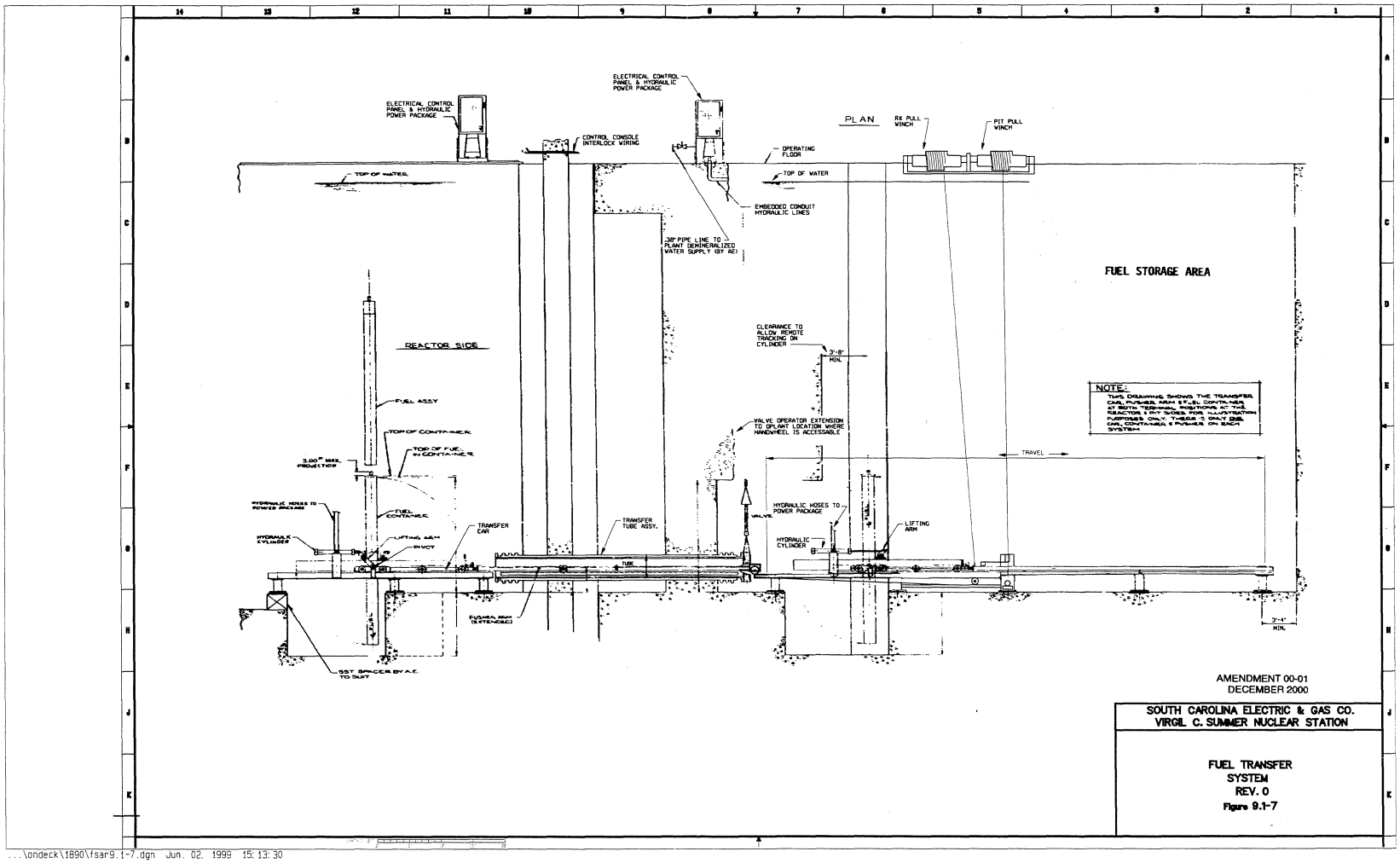
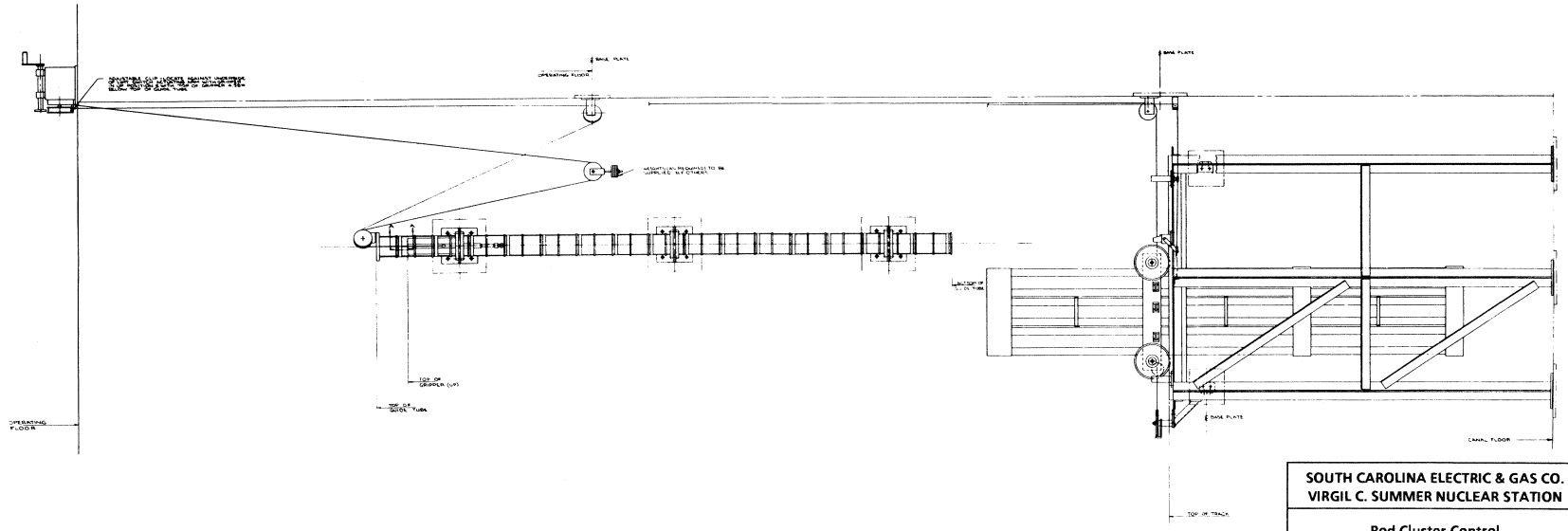


Figure 9.1-8

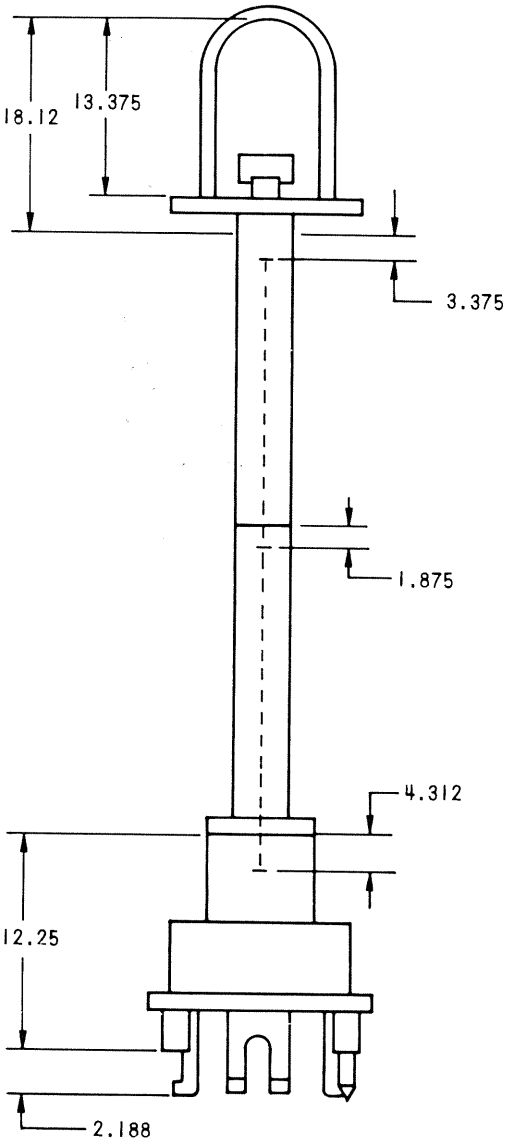
ROD CLUSTER CONTROL CHANGING FIXTURE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Rod Cluster Control Changing Fixture
Figure 9.1-8

AMENDMENT 0
AUGUST 1984

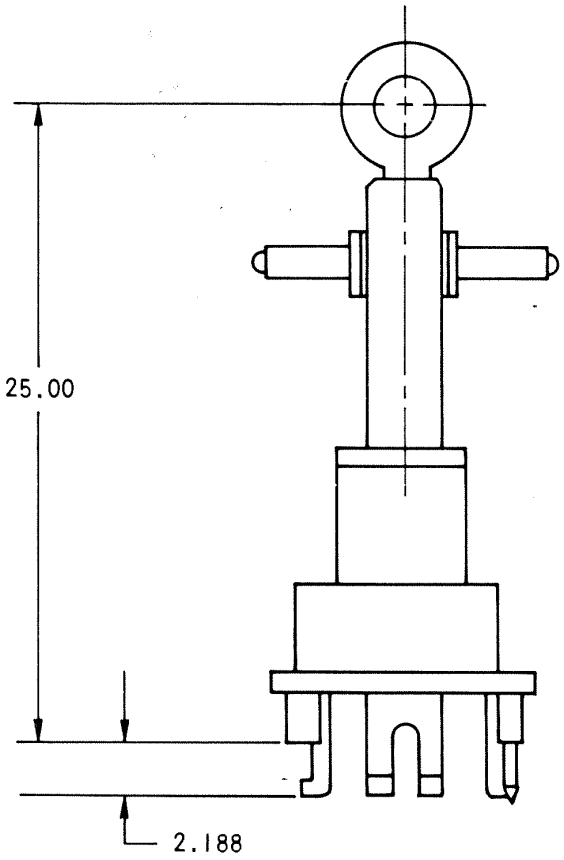
Figure 9.1-9
SPENT FUEL HANDLING TOOL



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Spent Fuel Handling Tool
Figure 9.1-9

AMENDMENT 0
AUGUST 1984

Figure 9.1-10
NEW FUEL HANDLING TOOL



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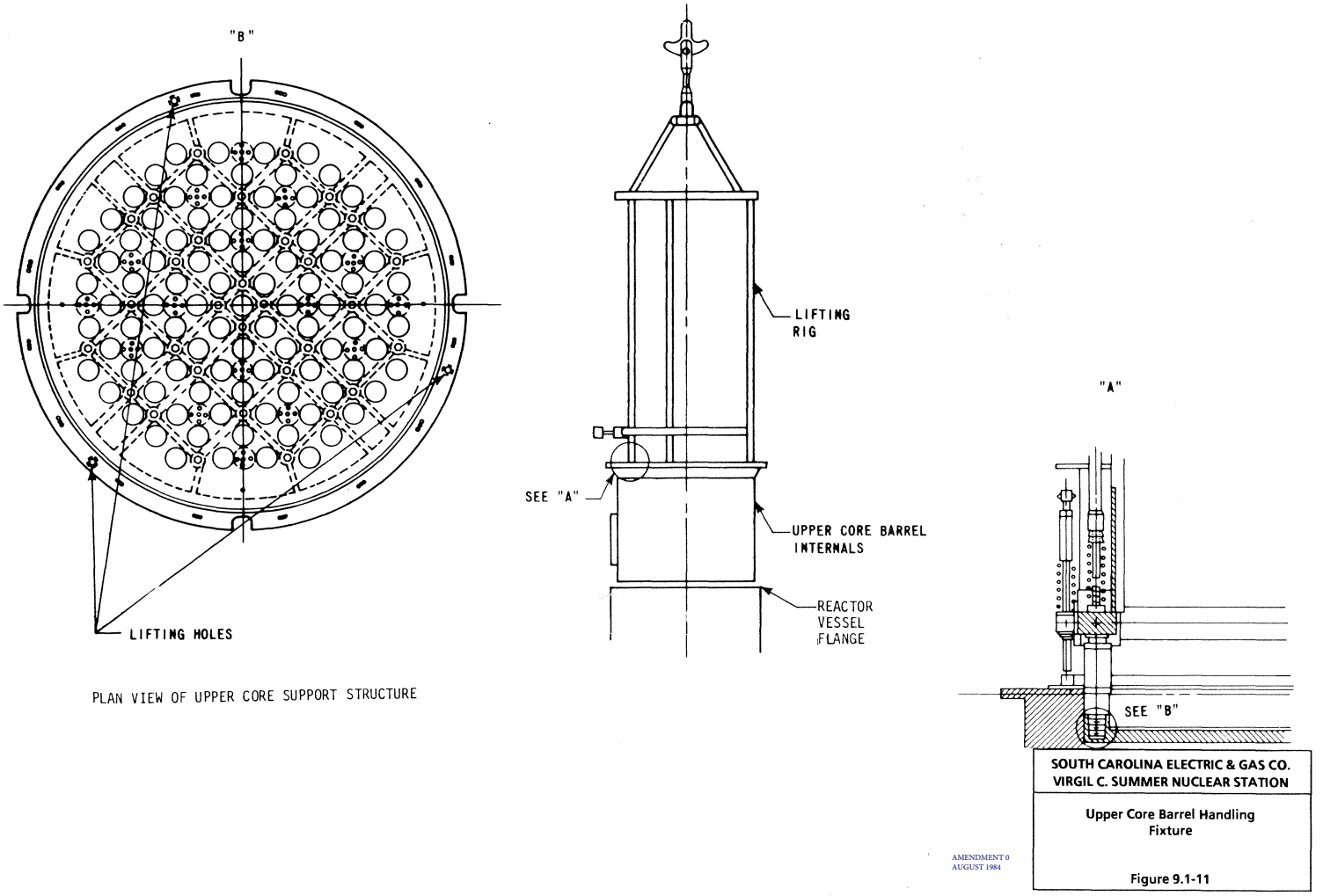
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
New Fuel Handling Tool
Figure 9.1-10

Figure 9.1-11

UPPER CORE BARREL HANDLING FIXTURE



9.2 WATER SYSTEMS

9.2.1 Service Water System

The Service Water System (SWS) provides water from the Service Water pond, a Seismic Category 1 impoundment adjacent to Monticello Reservoir, for cooling of the emergency diesel generators, Component Cooling heat exchangers, HVAC (Heating Ventilating and Air conditioning) mechanical water chiller condensers and the Service Water pump house cooling coils. The system also cools the reactor building cooling units (RBCUs) under: post accident or high containment pressure conditions, loss of non-Class 1E power; loss of industrial cooling water or during testing. In addition, this system is the backup water source for the Emergency Feedwater System and Component Cooling Water System. The system consists of two independent (A and B) full capacity loops with the capability of valving a third swing Service Water pump into either loop. The system is safety-related and is designed so that a single failure denies cooling to only 1 of the redundant loops.

9.2.1.1 Design Bases

The SWS is designed in accordance with the requirements of General Design Criterion 44, to provide sufficient redundant and independent capacity to ensure that cooling water is available to safety systems and components necessary to achieve and maintain a safe shutdown from normal plant operation or following a design basis accident.

SWS redundancy is protected through physical separation of equipment, barriers and double valving at interconnections of redundant loops. Physical separation is provided wherever possible to eliminate the potential for damage to both SWS headers by a missile which could be generated by equipment in the vicinity of the headers. Where physical separation is not feasible missile protection walls are employed where necessary.

SWS piping and components are classified as Safety Class 2b, except those portions of SWS piping conveying cooling water to the Digital Rod Position Indication System cooling unit, Service Water pump house cooling coils, and water jet air exhausters used to remove air from the line interconnecting the Circulating Water pumphouse and the Service Water pumphouse. Reactor Building penetrations, isolation valves and intermediate piping are classified as Safety Class 2a. The portions of SWS piping conveying cooling water to the Digital Rod Position Indication System cooling units and water jet air exhausters are classified as non-nuclear safety class and non-Seismic Category 1. The remaining system components are classified as Seismic Category 1.

The capacity of the SWS, with both redundant loops in operation, is adequate during a normal plant shutdown to reduce the RCS temperature to 140°F within 24 hours after reactor shutdown following an extended full power run at the current licensed RTP of 2900 MWt. With 1 of the 2 SWS loops inoperable (single failure), satisfactory cooldown can be achieved, except that the time to reduce the RCS temperature to 140°F will be extended. The SWS is capable of limiting the CCWS temperature to 105°F at the end of the 24 hour cooldown period is achieved through operation of both loops, the SWS is capable of limiting the CCWS temperature to 120°F with a

single failure of the SWS. At no time during the cooldown does the CCWS temperature exceed 120°F.

The system is capable of satisfying these performance requirements with Service Water temperature at the design maximum of 95°F.

The control room operator is able to monitor the cooling performance of system components by means of instrumentation which indicates flows, temperatures and pressures or actuates alarms. Should the operating equipment fail to satisfy cooling requirements, the operator is able to place a redundant loop in service. Instrumentation for each heat exchanger and pump loop is applied so that abnormal operating conditions are identifiable by the operator.

Piping and pressure retaining components for this system satisfy the requirements of the ASME Code, Section III, Class 2 or 3, as applicable, except the non-nuclear safety class portions.

Piping and pressure retaining components of non-nuclear safety class portions of the SWS satisfy the requirements of ANSI B16.5 and ANSI B31.1.

9.2.1.2 System Description

System diagrams for the SWS are provided as Figures 9.2-1 and 9.2-2 (Sheets 1 through 4). Service water is supplied to the system by three, 100% capacity, vertical, wet pit pumps, each equipped with a two-speed motor which is permanently locked in the high speed position. Three (3) traveling water screens, each with independent controls, screen wash system and associated piping, valves, instrumentation and controls as shown by Figure 9.2-1 are also provided. The Service Water pumps can be controlled manually from the control room, the control room evacuation panel, locally or automatically as described in Section 9.2.1.3.

During normal plant operation, 1 of 3 Service Water pumps is in service at all times. A second SW pump may be run to limit biofouling in the inactive loop and is available for emergency use. The third Service Water pump is provided as an installed spare and its circuit breaker(s) is racked out. The spare pump can be aligned in parallel with the running Service Water pump in either loop through crossover connections. In the event of malfunction of the running Service Water pump, the spare pump is manually started to replace the running pump. The automatic start capability of the Service Water pumps is not used.

If 1 pump is out of service for maintenance, its circuit breaker must be placed in the test/maintenance position. The third pump must be aligned electrically and mechanically to replace the out of service pump.

Piping of the Service Water pump C is arranged so that it can be manually valved into either the A or B loop in place of Service Water pump A or B, as required. The interconnecting piping between Service Water pump C discharge and both A and B loops contains double manual valves to ensure the required double isolation between A and B loops.

Each Service Water pump has a corresponding traveling screen, screen wash system, and screen control system. The screen wash system take their water supply from the corresponding Service Water pump discharge header. Screen wash is provided using only the Service Water pumps discharge. This has been found to provide adequate screen wash force.

The diesel generator cooler in the operating SWS loop receive cooling water flow continuously, even though the diesel is not in operation. The plant Fire Protection System serves as a standby means of cooling the diesel generators. This includes automatic opening of the cross connect valves on high lube oil temperature or high jacket water temperature when the diesel is operating in the emergency mode.

Provision is made to supply Service Water to the Emergency Feedwater System through remotely operated valves if required. The 8” SW lines that provide backup flow to the Emergency Feedwater System are lined with a cured-in-place pipe lining to prevent MIC and general corrosion. Also, upon receipt of a “lo-lo” Component Cooling water surge tank level signal, Service Water is automatically provided for Component Cooling water makeup (see Sections 9.2.2 and 10.4.9).

SWS piping at the Component Cooling heat exchangers is arranged to allow back flushing of the heat exchangers, if required, by manual positioning of the valves.

A portion of the Service Water flow from each loop goes to a water jet exhauster. These air exhausters remove air that may be released from solution in the 36 inch pipe which interconnects the circulating water pumphouse and the Service Water Pumphouse.

Cooling water flow to the HVAC mechanical water chiller condensers is provided when the chiller is operating. The motor operated inlet valves open when their associated chillers are operating. Manual valves are available at the chiller outlets for isolation of these heat exchangers if required.

The RBCUs receive water from the Service Water booster pumps and the Digital Rod Position Indication System cooling unit is isolated from the Reactor Building cooling units by closing the isolation valves under safety injection, loss of non-Class 1E power, or test conditions. Upon receipt of a safety injection signal, the ESFLS starts the inactive loop at high speed. A description of safety injection actuation signals is presented in Section 7.3. The Service Water booster pumps, with throttling orifices in the discharge piping, maintain system pressure inside the Reactor Building above peak post accident pressure when Service Water flow is maintained to 2 RBCUs.

During normal operation, cooling water flow to the RBCUs and the Digital Rod Position Indication System cooling unit is provided by an industrial cooling system.

Valves XVB-3107A(B)-SW and XVB-3106A(B)-SW have been designed and interlocked to other equipment controls to mitigate two scenarios in which a pipe water hammer could occur. The first water hammer scenario was postulated to occur when the RBCUs are operating in their normal lineup where they are being cooled by the nonsafety Industrial Cooling Water System and the Service Water booster pumps (SWBP) are started during normal swap over to the SW system

for or after a Loss Of Offsite Power (LOOP). The second water hammer scenario is postulated to occur when the SW system is aligned to provide cooling for the RBCUs and a LOOP occurs.

To minimize the effects of the first water hammer scenario vacuum relief valves XVV-13143A(B)-SW downstream of valve XVB-3107A(B)-SW will replace, with air, any vacuum void downstream of closed valves XVB-3107A(B)-SW that may be formed due to gravity drain down of water to the SW pond. Upon the start of the SWBPs and opening of valves XVB-3107A(B)-SW, the air in the piping will act as a cushion to minimize any water hammer affects that could occur downstream of XVB-3107A(B)-SW. The opening logic of valves XVB-3107A(B)-SW has a delayed opening after valve XVB-3106A(B)-SW begins to open. The delay allows fluid flow momentum to build to assure that additional void formation in the RBCU piping inside containment will not occur during swap over to the SW system.

To minimize the effects of the second water hammer scenario XVB-3107A(B)-SW, fast closing air operated butterfly valves, close in seven seconds upon de-energizing of the SWBPs. During times that the RBCUs are aligned with the SW system, if a LOOP were to occur, the fast valve closure will trap water in the high points above the valve and prevent void formation due to gravity drain down of the water to the SW pond. Interface logic is provided to equipment controls that tie the start of the respective SWBP to the closed position of the respective valve XVB-3107A(B)-SW. The controls prevent a SWBP start if the respective valve XVB-3107A(B)SW failed to close within 10±1 seconds, allowing drain down of the water to the SW Pond.

A check valve with controlled closing speed is installed at the Service Water booster pump discharge to minimize water hammer in the event that electrical power to the pump and associated motorized discharge valve is momentarily interrupted.

Effluent from the SWS is returned to the Service Water pond by the 2 independent (A and B) loops. Motorized valves at the pump discharge and check valves at the system discharge prevent siphoning of the Service Water pond back into the system in the event of a major line rupture within the plant.

A biocide injection system was installed in the Service Water System for organic fouling control.

A chemical injection system was installed to treat the Service Water System for corrosion and silt disposition.

Information concerning major SWS components is presented in Table 9.2-1.

9.2.1.3 Safety Evaluation

The Service Water System is safety-related and is used to remove heat released during the postulated loss of coolant accident (LOCA).

Three (3) 100% capacity Service Water pumps, located in the Service Water intake structure, take suction from the Seismic Category 1 Service Water pond. Thus, a positive supply of cooling water is assured.

Under emergency conditions, power is supplied to loop A and B Service Water pumps by emergency diesel generators A and B, respectively.

The Service Water pumps are vertical, wet pit pumps housed in the Service Water intake structure and are supplied with water from the Service Water pond. The Service Water pond is connected to Monticello Reservoir through an interconnecting pipe system between the circulating water intake structure and the Service Water intake structure. Piping is installed so that the flow path is interrupted if Monticello Reservoir is drawn down below elevation 415' coincident with the isolation valve being open for some unforeseen reason. The minimum required submergence, to the bottom of the suction bells, for the Service Water pumps is 5 feet. At minimum Service Water pond level, the available submergence to the bottom of the suction bell, is approximately 21 feet. A discussion of low Service Water pond level considerations is presented in Section 2.4.11.

The Service Water intake structure also has a weir to ensure that the water level in the intake structure does not drop below elevation 399', the bottom of the Service Water pump suction bell is at elevation 394'. Water may be supplied to the Service Water intake structure from Monticello Reservoir through the interconnecting pipe and thereby maintain the minimum 5 foot submergence requirement.

The Service Water pumps are valved to discharge into either of the 2 main headers supplying cooling water to the nuclear portion of the station. System design assures that a single failure does not result in loss of more than 1 of the redundant Service Water loops. Table 9.2-2 presents a SWS failure analysis. The 2 Service Water loops are designed so that all cross connections between the loops are double valved. At least 2 valves in series are closed during normal operation.

During a postulated LOCA, the 2 Service Water booster pumps supplying Service Water to the RBCUs are started. Throttling orifices in the return lines control back pressure to maintain Service Water pressure above long term post accident Reactor Building ambient pressure. This favorable pressure differentiated in conjunction with the leak-tight integrity of the RBCU coils and associated SWS piping, minimize the potential for transport of radioactive materials outside of containment in a postulated post-accident situation.

The RBCUs are normally used for Reactor Building temperature control. Normal cooling water supply to the RBCUs is provided by cooled water from the Industrial Cooling Water System.

In the event of a safety injection signal, both A and B Service Water loops, including the Service Water booster pumps are started to satisfy redundancy requirements. Each Service Water booster pump is supplied with power from the appropriate (A or B) emergency diesel generator.

During normal operation, and a postulated LOCA, 1 Service Water pump operates to supply up to 16,800 gpm of water at temperatures up to 95°F. This flow is adequate to provide sufficient cooling to one SWS loop. A second SW pump may be run to limit biofouling of the inactive loop.

During the postulated LOCA or upon receipt of a safety injection signal, the Digital Rod Position Indication System cooling unit is isolated from the RBCUs by closing the isolation valves.

Missile protection is discussed in Section 3.5. Pipe rupture considerations are discussed in Section 3.6.

The SWS is generally protected from radioactive contamination by 2 physical boundaries. Systems which contain radioactive materials are cooled by the Component Cooling Water System which is, in turn, cooled by the SWS. The SWS also cools the HVAC mechanical water chiller condensers where Service Water is separated from the potentially radioactive fluid by at least 3 physical barriers. The single application where Service Water is separated from radioactive fluid by only 1 physical barrier is post accident Reactor Building cooling. However, in this case, the Service Water booster pumps maintain Service Water pressure inside the Reactor Building above long term Reactor Building pressure. Reactor Building pressure exceeds SWS pressure for only a short time interval in the post accident case in the event that an individual RBCU is isolated in one or both trains.

The RBCU cooling coils, and associated SWS piping are classified as moderate energy components, in accordance with applicable pipe rupture rules. Therefore, only through wall leakage cracks may be postulated, in the long term, following a design basis accident. However, SWS pressure remains above Reactor Building pressure in the long term following a design basis accident.

The Service Water pumps can be manually controlled from the control room or from the control room evacuation panel.

The Service Water booster pumps can be manually controlled from the control room. The Service Water booster pumps automatically start upon receipt of a safety injection signal via the ESFLS. During an undervoltage condition on bus 1DA or 1DB the respective Service Water booster pumps are tripped and then loaded on the emergency diesel generator by the ESFLS. The low suction pressure trip is blocked when the booster pump starts in response to a safety injection signal.

Service water pump discharge valves are automatically driven open when their respective pumps start and are driven closed when their respective pump is shutoff. There are no operator controls provided for these valves on the main control board. The Service Water booster pump discharge valves, are automatically driven open when their respective pumps start, and close when the Service Water Booster Pump stops.

Differential pressure across each traveling screen is measured by 2 bubbler probes. Upon receipt of a high differential pressure signal from either bubbler probe (indicating dirty screens), the screen wash system is started and the screen wash isolation valve is opened. This provides high pressure water to the screen wash spray nozzles. Pressure in the spray nozzle header is sensed and provides a starting signal to the screen drive motor. This control scheme ensures that the screen wash systems do not start unless sufficient suction pressure is available and the screen is not driven unless sufficient pressure exists at the spray nozzles to ensure complete washing.

A timer ensures that the screen is washed and driven for a period corresponding to a minimum of 1-1/3 revolutions of the screen.

Capacity for local manual operation using a jog button is provided. Flow to the screens is not interrupted during the self-cleaning cycle. Upon receipt of a safety injection or loss of non-Class 1E power signal via the ESFLS, the normal screen controls are isolated and the screens cease rotation.

9.2.1.4 Tests and Inspections

The SWS is operated during all plant operating phases. Operation is alternated between the 2 loops during normal power operation; although a SW pump may be run to provide flow to the inactive loop to limit biofouling. Thus, normal operation verifies the operability and performance of the Service Water pumps. Therefore, no periodic testing of the pumps is necessary. Automatic startup of the system in response to a safety injection or loss of non-Class 1E power signal is verified periodically.

System actuation tests are performed during the refueling period when a loop is inactive. These tests check the automatic startup circuitry and operation of the actuation relays and associated components. One of the SWS loops is in operation throughout the refueling period.

Other system verifications are also performed periodically. Closure of the industrial cooler containment isolation valves in response to the applicable ESF signals during each refueling shutdown. Also, these valves are checked to verify their leak tightness (see Section 6.2.6).

9.2.1.5 Instrumentation Requirements

SWS instrumentation provides the necessary inputs for control, operation and performance/status monitoring of the system. This instrumentation is shown on Figures 9.2-1 and 9.2-2 (Sheets 1 through 4). In addition, indicators and/or controls are located on the control room evacuation panel, on local panels and near the components.

9.2.1.5.1 Pressure Measurement

1. Pressure Indicators

   Direct reading pressure indicators are provided on the discharge side of the Service Water pumps, on the suction side of the Service Water booster pumps, and on the discharge side of the Service Water screen wash system.

2. Pressure Transmitters

   Pressure transmitters located on the discharge side of the Service Water and Service Water booster pumps and in the exit of the RBCUs provide signals for control room indication and low pressure alarms. In addition, the transmitters on the discharge side of the Service Water pumps provide auto-start signals for the Service Water pumps; however, auto-start on low pressure is no longer used because the standby concept has been replaced by an installed spare concept.

3. Pressure Switches

   Switches located at the spray nozzle header provide contacts for the traveling screen start signal. Switches located on the suction side of the Service Water booster pumps provide contacts for an alarm. One switch is located on the suction side at the DRPI cooling unit booster pump providing interlock contacts which prevent the pump from starting and which trip the pump if suction pressure is not sufficient.

4. Pressure Test Connections

   Pressure test connections are located throughout the system for use during performance testing.

5. Differential Pressure Switches

   Two (2) independent differential pressure switches located across each traveling screen provide contacts for the respective screen wash isolation valve opening.

9.2.1.5.2 Liquid Level Measurement

Two (2) level transmitters located in the Service Water pond provide signals for control room indication and low level alarm.

9.2.1.5.3 Flow Rate Measurement

Direct reading flow indicators (locally mounted) are provided for cooling water flow to the upper and lower motor bearings for each Service Water pump A, B, and C. A flow element is provided on both the A and B 30" diameter Service Water pump discharge headers (IFE-4586 for A pump discharge; IFE-4587 for B pump discharge). The flow elements are mounted downstream of the tee in each respective discharge header which connects the header with the C pump discharge pipe. A locally mounted flow indictor (IFI-4586 or IFI-4587) is provided for flow indication for each flow element.

Flow transmitters located on the outlet side of the diesel generator coolers, Component Cooling heat exchangers and HVAC mechanical water chiller condensers provide signals to the Yokogawa units on the main control board (see Section 9.2.1.5.5), which provide both component low flow alarms and indication.

Flow transmitters located on the discharge side of the Service Water booster pumps and in the discharge loop headers from the RBCUs provide signals for control room indication and low flow alarms.

9.2.1.5.4 Temperature Measurement

1. Temperature Indicators

   Direct reading temperature indicators are provided on the outlet side of the diesel generator coolers, Component Cooling heat exchangers, Digital Rod Position Indication System cooling unit, HVAC mechanical water chiller condensers, and Service Water pump house cooling coils.

2. Temperature Elements

   Temperature elements (thermocouples) located on the outlet side of the diesel generator coolers, Component Cooling heat exchangers and HVAC mechanical water chiller condensers provide signals to the control room Yokogawa Recorders (see Section 9.2.1.5.5) which provide both high temperature alarms and indication. Temperature elements which provide input through signal converters to control room indicators are located in each loop header from the reactor building cooling units and in each loop supply header. Temperature elements providing computer input are located at the motor inboard, outboard, thrust bearings and motor stators of each Service Water pump.

3. Temperature Test Connections

   Test wells are conveniently located throughout the system for use during performance testing.

9.2.1.5.5 Monitors

For those cooling heat exchangers which do not have individual flow and/or temperature indicators, Yokogawa Recorders are provided. These recorders, mounted on the main control board, accept analog signals from the individually measured temperatures and flows. For every measured variable there is an individual alarm condition window with capability provided to set an alarm condition signal limit from the measured variable. For every 20 measured temperature or flow signals, an indicator is provided in temperature degrees or flow gallons per minute (GPM). Abnormal conditions are annunciated. If, at a sensor location, the temperature exceeds its maximum setpoint limit, or if the flow drops below its minimum setpoint limit, the event is alarmed. The operator checks the actual reading and takes appropriate action. To prevent unnecessary alarm attendance by the operator, the variable signals are grouped so that when one Service Water loop is inactive, all of the temperature and flow variable alarms on that loop can be defeated together. Since HVAC mechanical water chiller C can be used with either Service Water loop A or loop B, flow readings appear on both A and B Yokogawa Recorders units to satisfy separation criteria.

9.2.1.5.6 Special Instrumentation

The main control board ESF monitor lights (see Section 7.5 for a more detailed explanation) provide an easily recognizable indication of the status of essential components and equipment.

Included among the monitor lights for this system are status (position) indication of the containment isolation valves, the Service Water pump discharge valves and the valves in the return paths.

An audible and visual alarm is annunciated on the main control board if manual action by the operator deliberately bypasses the operation of the SWS.

The Service Water booster pump discharge flow and Service Water temperature in and out of the Reactor Building are part of the post accident monitoring instrumentation (see Section 7.5 for a more detailed explanation).

9.2.1.5.7 Instrumentation Qualifications

Sections 3.10, 3.11, and 7.1 outline the qualifications and diversity of the instrumentation utilized in this system.

9.2.2 Component Cooling Water System

The Component Cooling Water System (CCWS) serves as an intermediate, closed loop cooling system to transfer heat from components important to safety including those which may contain radioactive or potentially radioactive fluids to the Service Water System. These components are the residual heat removal (RHR) pumps, RHR heat exchangers, charging pump gear/oil coolers and Component Cooling water pump motors.

The CCWS is also utilized during normal plant operation to transfer heat from various systems and components that are not important to safety. This latter service is subsequently referred to as “nonessential”. Use of the CCWS precludes release of radioactivity in the event of malfunction of one of the nonessential components. Nonessential recipients of Component Cooling water supply are as follows:

1. Reactor coolant drain tank heat exchanger.
2. Excess letdown heat exchanger.
3. Reactor coolant pumps (bearings and thermal barrier cooler).
4. Spent fuel heat exchangers.
5. Letdown heat exchanger.
6. Seal water heat exchanger.
7. Recycle evaporator package.
8. Waste evaporator package.
9. Waste gas compressors.
10. Sample heat exchangers.
11. Waste Process System recombiners.

Operation of the CCWS is required during all phases of normal plant operation, including startup through cold shutdown and refueling, as well as during emergency operation following a LOCA. Significant heat removal functions of the system are as follows:

1. Remove the excess heat generated during a plant startup.
2. Provide cooling of the letdown flow during normal power operation.
3. Remove residual and sensible heat from the Reactor Coolant System (RCS) during and after a plant shutdown.
4. Remove the residual heat released in the reactor during refueling operations and from the stored spent fuel.
5. Provide cooling to the components important to safety following a LOCA to achieve a safe shutdown or maintain a safe reactor operating condition.

9.2.2.1 Design Bases

The CCWS is designed to satisfy the requirements of General Design Criterion 44. Sufficient redundant and independent capacity ensures that cooling water is available to achieve and maintain a safe shutdown from normal plant operation, following an accident combined with a loss of offsite power and any single failure (including failure of one diesel generator). The redundancy within the CCWS is consistent with redundancies within other safety-related systems.

The basic CCWS is classified as Safety Class 2b except for the following:

1. The chemical injection system, portions of the surge tank makeup water systems and piping downstream of system relief vent and drain valves are non-nuclear safety class.
2. Penetration isolation valves and associated intermediate piping are classified as Safety Class 2a.

The basic CCWS is classified as Seismic Category 1, except for the following:

1. Radiation monitor instrument lines downstream of the seismic isolation root valves.
2. The Recycle Evaporator Package Sample Cooler and the Waste Evaporator Package Sample Cooler flow indicator’s instrument lines downstream of the seismic isolation root valves.

The various systems supplied with Component Cooling water, corresponding required flow rates and heat loads associated with various plant operational modes are listed in Tables 9.2-3 through 9.2-10.

With both loops in operation, the CCWS capacity is adequate during a normal plant shutdown to reduce the RCS temperature to 140°F within 24 hours after reactor shutdown following an extended full power run at the current licensed RTP of 2900 MWt. With a single failure within the CCWS, satisfactory cooldown can be achieved, except that the time to reduce the RCS temperature to 140°F may be extended depending upon the failure. During the cooldown, the

system is capable of limiting the CCWS temperature to 105°F at the end of the 24 hour cooldown period with both loops in operation. After an RCS temperature of 140°F at the end of the 24 hour cooldown period is achieved with both loops, the CCWS is capable of limiting the CCWS temperature to 120°F with a complete failure of either loop. At no time during the cooldown does the CCWS temperature exceed 120°F. The system is capable of meeting these performance requirements when provided with Service Water at a maximum temperature of 95°F.

The pressure on the Component Cooling water side of the CCWS heat exchanger is maintained at a pressure less than the pressure on the Service Water side to prevent CCW leakage into the Service Water pond should a tube leak develop within the heat exchanger. This is a non-safety related requirement.

CCWS components are accessible for necessary manual operations and maintenance. The post LOCA situation will render some of the CCWS inaccessible but will not neutralize the safety function of the system. The CCWS installation is removed or shielded from possibly radioactive process systems to preclude unacceptable personnel exposure.

CCWS components satisfy the intent of Regulatory Guide 1.48 (see Appendix 3A) and are seismically qualified.

Single failure incidents within the CCWS have been analyzed and analytical results demonstrate that no single failure precludes performance of the safety function of the system. Table 9.2-11 presents the single failure analysis.

9.2.2.2 System Description

The CCWS consists of 2 independent loops, providing 100% redundancy in the supply of cooling water for the safety-related systems, and a common supply for the nonessential systems.

System diagrams for the CCWS are included as Figures 9.2-4 through 9.2-7.

The ECCS components supplied with cooling water by the CCWS are as follows:

1. Residual heat removal pumps.
2. Residual heat removal heat exchangers.
3. Centrifugal charging pumps.

These components are parts of redundant, independent systems served by redundant, independent CCWS loops. Thus, upon loss of 1 CCWS cooling loop, or portion thereof, cooling water remains available to the redundant component in each of the safety-related systems.

As required by General Design Criterion 44, the same emergency power bus delivers power to essential components and essential elements in the same CCWS loop. Should a loss of offsite power, combined with failure of 1 onsite emergency power supply occur, the CCWS loop

supplying cooling water to safety-related components receiving power from the operating emergency power supply remains operable.

The common circuit for the nonessential systems is connected to both CCWS loops through crossover connections and can be supplied from either CCWS loop. Normally, isolation valves (2 valves in series) in the crossover connections to 1 loop are closed and the circuit is aligned to receive Component Cooling water only from the operating loop. This alignment provides complete isolation between the 2 loops. Valve position status lights are provided in the control room. The crossover connections to both loops are open simultaneously only during a normal switchover operation. The crossover connections to both loops can be closed at the main control board by operator action for isolation of the nonessential circuit from both CCWS loops during safety injection or recirculation operating modes if cooling water is not required for the spent fuel pool cooling heat exchanger.

A third CCWS pump is provided which is aligned in parallel with the running pump in either loop through crossover connections. Two (2) valves in series are provided in each crossover header to maintain isolation and independence between the 2 loops. Incorrect valve alignment is alarmed in the control room. This third pump is normally aligned with the running loop and serves as a standby to the running pump. Should pressure decrease below a certain level due to a malfunction of the running pump, the standby pump is automatically started to maintain operation of the loop. The standby pump does not start as a result of a safety injection signal without loss of offsite power but remains as a backup to the running pump during subsequent operations.

If there is a loss of offsite power, the standby pump is locked out to ensure against its inadvertent startup during the restarting of the running pump by the engineered safety features load sequencer (ESFLS). It does not provide automatic backup to the running pump during subsequent operation. A manual electrical circuit realignment is performed if standby pump operation is required.

If one pump is out of service for maintenance, its circuit breaker must be placed in the test/maintenance position. The third pump must be aligned electrically and mechanically to replace the out of service pump.

Redundant valves (2 valves in series) are used in all cross connections between the two CCWS loops to ensure isolation or the capability for isolation of 1 loop from the other. Use of 2 valves ensures against loss of isolation in the event of valve pressure boundary failure or a line failure between valves combined with a valve functional failure.

The Component Cooling pumps have 2 speed capability. Operation of the pump at high speed is initiated only by manual operator action and is administratively permitted only when the nonessential circuit is connected to the loop and the RHR heat exchanger circuit is open. Only the low speed pump operating mode is associated with the CCWS safety function. One pump operating in the high speed mode satisfies normal shutdown criteria under design conditions but the capability of achieving a safe shutdown for normal operation or following an accident is not contingent upon availability of the high speed mode. Operation of a CCWS loop with the pump at high speed is an option available to the operator at any time subject to the previously noted restrictions.

The CCWS is operated during all phases of plant operation:

1. Startup.
2. Normal power operation.
3. Shutdown.
4. Refueling.
5. Under hot standby conditions.
6. Following an accident (including a LOCA).

The 2 loops are operated independently and can be operated singly or simultaneously. One (1) loop has the flow capacity to satisfy cooling water requirements under normal plant operating conditions except during normal shutdown. During normal shutdown, operation of the second loop is necessary to support operation of the second RHR pump and RHR heat exchanger to cool the reactor coolant system from 350°F to 140°F within 24 hours after reactor shutdown. A satisfactory cooldown of the Reactor Coolant System can be achieved with only 1 loop operating; however, this would extend the cooldown time.

Upon the occurrence of an accident resulting in a safety injection signal, both CCWS loops are activated. The active loop continues to operate in the normal mode. The pump in the inactive loop is automatically started in the low speed mode to provide cooling water flow through the RHR heat exchanger circuit and to its assigned safety-related pumps. If 1 loop does not operate in response to the safety injection signal, the other loop provides cooling water to the safety-related systems necessary to achieve a safe shutdown.

If 1 Component Cooling pump is out of service for repair or maintenance, its breaker must be placed in the test/maintenance position and each of the 2 remaining pumps is connected to a different loop. This maintains redundant, independent capacity for supplying cooling water to safety-related components. The valves in the crossover connections between the nonessential circuit and the inactive loop are closed.

A surge tank maintains adequate net positive suction head (NPSH) to each Component Cooling pump, provides makeup water to each loop as needed and provides compensation for fluid thermal expansion. The bottom half of the tank is partitioned such that each half serves 1 CCWS loop. Thus, a loss of water in 1 loop does not affect the other loop. Isolation and independency of the loops is thereby maintained.

Cooling water is demineralized and treated with corrosion inhibiting chemicals and an alkaline agent. Demineralized makeup water is automatically supplied to each compartment of the surge tank. An operator actuated chemical injection system prepares and injects chemical additives into the CCWS water as needed.

A connection to the pump suction piping for each loop is provided from the SWS for emergency makeup water supply to the CCWS. Emergency makeup is provided when leakage is in excess of the maximum demineralized water makeup rate of 50 gpm, or when normal makeup is not

available. Breaks in miscellaneous non-nuclear safety related instrument lines as a result of seismic event would result in a maximum leakage rate of 153 gpm. A signal resulting from a lo-lo level in 1 of the baffled surge tank compartments would automatically open the Service Water isolation valve connected to that compartment.

Radiation monitors, located in each CCWS loop, detect leakage into the loop from those components containing radioactive fluid and initiate an alarm in the control room. The source of the leakage is identified by analyzing cooling water samples from the heat exchanger of each served component. The source of leakage is then isolated by closing the valves in the cooling water supply and return lines to that particular heat exchanger.

Excessive leakage of Component Cooling water is detected by pressure changes, flow rate changes, an increase in the frequency and/or duration of surge tank water makeup cycles or visual inspection of the system.

Valves are provided in the CCWS distribution circuits so that a particular circuit can be isolated from the CCWS in case of leakage or for maintenance of the heat exchanger supplied by that circuit. Also, manual shutoff valves are provided in each CCWS loop to permit isolation of a pump or Component Cooling heat exchanger for maintenance.

The CCWS loop and heat exchanger for the reactor coolant pump thermal barriers create a pressure head significantly greater than the other cooling circuits. To provide adequate pressure head for this circuit, booster pumps are utilized to create the additional pressure head required. Three (3) booster pumps are provided in a parallel arrangement. During normal operation, 1 of the pumps is operating. A second pump is in a standby condition to back up the operating pump and is started automatically if the discharge pressure decreases below a predetermined limit. The third pump is provided to maintain backup capability should 1 pump be out of service for repair or maintenance.

Since operation of the booster pumps is not a CCWS safety function requirement and the thermal barrier cooler serves only as a backup to flow from the charging pumps for reactor coolant pump seal cooling, the booster pumps receive electric power from the non-Class 1E supply buses. In the event of a safety injection signal, the operating booster pump continues to operate and the backup booster pump remains in a standby condition. However, in the event of a loss of offsite power, the operating booster pump stops and the booster pumps remain inoperable. (The reactor coolant pumps also stop if a loss of offsite power occurs.)

Flow rates, pressure and temperatures are measured in each of the CCWS circuits. At the Component Cooling heat exchangers, residual heat removal heat exchangers, RHR pumps and components necessary for normal operation, high temperature and low flow alarms are activated in the control room by the measurement systems. An alarm is also activated if a high RHR heat exchanger flow rate occurs to provide protection against excessive tube vibration. An excessive RHR heat exchanger flow can be reduced by throttling the manual valve in the CC system outlet line from the heat exchanger (XVB-9507A, B-CC).

Motor operated valves are located in the discharge lines from the reactor coolant pump thermal barrier coolers. These valves close in response to a high flow rate from the coolers and, in conjunction with a check valve upstream of the cooler, provide isolation of the CCWS from over pressurization in the event of a tube failure in the thermal barrier cooler. Corresponding isolation elements are provided in the CCWS circuit serving the excess letdown heat exchanger to isolate the balance of the CCWS from the effects of a failure in this heat exchanger.

Throttling and balancing capability is provided within each loop and within each CCWS supply circuit to balance loop flow characteristics to pump characteristics for either pump operating speed and to balance each parallel flow circuit so that it receives the required cooling flow. Likewise, if a circuit is removed from service, the other circuits and the loop balances must be adjusted accordingly. Pressure reducing orifices are used where throttling of a circuit is required under all operating conditions. Where the requirement for throttling depends upon the plant (or CCWS) operating mode, various valves in the circuits are used for temporary trim throttling.

The CCWS loops are each capable, with the pump operating at high speed, of supplying peak flow rate of approximately 11,700 gpm of water. At the beginning of plant cooldown with a maximum temperature of 120°F, the CCWS (with both loops operating) transfers a peak heat load of 251.8 x 10^6 BTU/hr (includes spent fuel pool load) to Service Water with a maximum temperature of 95°F. At a maximum CCWS temperature of 120°F and total flowrate of 7325 gpm, one CCWS Heat Exchanger can transfer 140.7 x 10^6 BTU/hr to the SWS assuming 95°F SW and 7680 gpm SWS flow. During the recirculation phase, the heat load on one CCWS loop is estimated to be 72.8 x 10^6 BTU/hr and 59.5 x 10^6 BTU/hr on the other.

Information concerning major CCWS components is presented by Table 9.2-12.

9.2.2.3 Safety Evaluation

Those portions of the CCWS required to ensure performance of safety-related functions are designed to satisfy Safety Class 2a or 2b and Seismic Category 1 requirements. All Safety Class 2a components are built in accordance with the ASME Code, Section III, Subsection NC. All Safety Class 2b components are built in accordance with the ASME Code, Section III, Subsection ND.

A single failure analysis is presented by Table 9.2-11. This analysis demonstrates that sufficient redundancy is provided with the system to ensure that safety-related functions are performed.

Protection of the CCWS from the dynamic effects of pipe rupture is discussed in Section 3.6.

Sections 9.2.2.3.1 through 9.2.2.3.3 describe CCWS operation during safety injection, recirculation and shutdown, respectively.

9.2.2.3.1 Safety Injection

Following the occurrence of a safety injection signal, the CCWS provides cooling water to both centrifugal charging pumps and RHR pumps. In subsequent phases, removal of heat from the RHR heat exchanger may be accomplished through operator action which depends upon the accident or event causing the safety injection signal.

Both CCWS loops operate during safety injection. This provides Component Cooling water to the centrifugal charging pumps and RHR pumps which ensures that the minimum safety function of these pumps is available under any accident condition, including loss of offsite power and any single failure.

Upon receipt of a safety injection signal (without loss of offsite power), the active CCWS loop continues to operate. The safety injection signal does not start the standby Component Cooling pump. However, the standby pump continues to remain active and starts automatically if there is a malfunction of the running Component Cooling pump resulting in a decrease in the loop pressure.

The inactive CCWS loop is activated in response to the safety injection signal. The supply and return lines to the RHR heat exchanger are normally open in this loop. The non-running Component Cooling pump is started automatically by the ESFLS. The loop operates to circulate cooling water through the RHR heat exchanger circuit, charging pump oil coolers, and to the RHR pump aligned with the loop.

If there is a loss of offsite power in conjunction with or subsequent to the safety injection signal, the running loop pump stops and is then restarted by the ESFLS. The pump in the non-running loop likewise stops and is restarted by the ESFLS if the loss of offsite power was preceded by a safety injection signal. The standby pump is locked out when a loss of offsite power occurs and does not start automatically if there is a subsequent malfunction of the running pump. The operating booster pump stops and the booster pumps remain inoperable.

The supply of Component Cooling water to the nonessential systems continues (unless terminated by the operators) except, if a containment, phase B isolation signal occurs, the CCWS containment isolation valves in the lines to and from the Reactor Building are closed terminating the cooling water supply to the reactor coolant pumps, the reactor coolant drain tank heat exchanger and the excess letdown heat exchanger.

The RHR heat exchanger circuit remains closed on the active loop during the injection phase. When operation of the heat exchanger is necessary for reactor cooldown or for recirculation, the RHR heat exchanger circuit is activated by the operator. The valves in the crossover connections to the nonessential circuit can be closed as the RHR heat exchanger circuit is activated and pump operation may be continued at low speed. However, if the nonessential circuit is not shut off when the RHR heat exchanger circuit is activated, the pump is switched to the high speed mode by the operator. An alternate arrangement is to isolate all of the components on the nonessential circuit except the spent fuel pool cooling heat exchanger and operate the pump at low speed. In anticipation of switchover, during the injection phase, the CC flow to the RHR Hx may be initiated in the active loop with the CC pump in slow speed; however, subsequent to completion

of the switchover procedure (Table 6.3-3), the CC pump in the active loop will be placed in fast speed provided that the swing pump is available.

No operator action is required for normal operation of the CCWS during safety injection. Alarms are actuated in the event of an abnormal condition within either of the two loops. Following the occurrence of a safety injection signal, the operator may modify the operation of the system.

9.2.2.3.2 Recirculation

The post LOCA safety injection phase is followed by the recirculation phase during which the water collected in the Reactor Building from the accident and the safety injection phase is recirculated through the RHR heat exchanger and the Reactor Coolant System by the RHR pumps. During this phase the CCWS loops must transfer the heat load from the RHR heat exchangers, as well as provide cooling to the respective RHR and charging pumps.

The normally inactive loop operates during the safety injection phase with the RHR heat exchanger circuit open. Therefore, no change is necessary in the operation of this loop when recirculation is initiated. In the active loop, the RHR heat exchanger circuit is normally shut off throughout safety injection. The shutoff valve must be opened by manual operator action to activate the RHR heat exchanger for the recirculation phase. When the RHR heat exchanger circuit is opened, the operator either shuts off the nonessential supply circuit, switches the pump to the high speed mode or manually isolates the individual components on the nonessential circuit except for the spent fuel pool cooling heat exchangers. If required, the spent fuel heat exchanger may be temporarily removed from service. In anticipation of switchover, during the injection phase, the CC flow to the RHR Hx may be initiated in the active loop with the CC pump in slow speed; however, subsequent to completion of the switchover procedure (Table 6.3-3), the CC pump in the active loop will be placed in fast speed provided that the swing pump is available.

9.2.2.3.3 Shutdown

Shutdown is a transient condition which takes the plant from the hot, critical, minimum load condition to cold shutdown. During the initial shutdown period residual and sensible reactor heat are removed from the Reactor Coolant System through the steam generators. CCWS operation is continued through this initial period with no change from the normal power operation mode. After approximately 4 hours (when reactor coolant temperature and pressure are reduced to approximately 350°F and 400 psig) the cooldown heat removal function is transferred to the CCWS through the RHR heat exchangers.

Maximum heat removal demand is placed on the CCWS at this time. After maximum core operating life, the peak heat load of approximately 107 x 106 BTU/hr is transferred to the CCWS through each RHR heat exchanger to maintain the normal reactor cooldown rate. An additional heat load of approximately 38 x 106 BTU/hr is added from the RHR pumps and the nonessential systems. To handle this heat load, operation of both CCWS loops is necessary. The RHR heat exchanger circuit is opened on the operating loop and the pump is switched to the high speed mode. This loop supplies cooling water for the nonessential systems, assigned RHR pump and 1 RHR heat exchanger. Operation of the other loop in the low speed mode is initiated to supply

cooling water to one RHR heat exchanger and the assigned RHR pump. Trim throttling of the high speed loop may be necessary to rebalance flows and meet temperature limits of components in the circuits for the high speed operating mode.

9.2.2.4 Tests and Inspections

The CCWS is operated during all plant operating phases. Operation is alternated between the two loops during normal power operation. In addition, the low speed mode is tested in accordance with ASME Code, Section XI. The operability and performance of the 2 Component Cooling pumps at low speed is therefore verified. Automatic startup of the system in response to a safety injection signal is verified periodically. Satisfactory startup and operation of each pump at low speed is verified prior to plant startup after each refueling period.

System tests are performed as required by Tech Specs. These tests check the automatic startup circuitry and operation of the actuation relays and associated components. One (1) of the loops is in operation throughout the refueling period.

Other system verifications are also performed periodically. Closure of the containment isolation valves in response to a "high-high" containment pressure signal is checked during each refueling shutdown. Also, these valves are checked to verify their leak tightness (see Section 6.2.6). Closure of the isolation valves in the thermal barrier discharge lines in response to a high flow signal from the downstream flow meter is verified periodically.

9.2.2.5 Instrumentation Requirements

Measurement and monitoring of radiation, pressure, liquid level, flow rate and temperature are performed for purposes of indication, alarm, control and record maintenance as required by the CCWS.

9.2.2.5.1 Radiation Measurement

A radiation monitor in each CCWS loop provides control room indication if either CCWS loop has become contaminated from the following:

1. Thermal barrier cooler leakage.
2. Tube leakage from heat exchangers with contaminated fluid served by the CCWS.

An excessive radiation level actuates control room alarms and closure of the valve in the surge tank vent line. The radiation monitoring system which performs these measurements is discussed in Section 11.4.

9.2.2.5.2 Pressure Measurement

Pressure measuring devices monitor the discharge header pressure from the Component Cooling pumps and Component Cooling booster pumps. These devices provide control room indication,

alarms and automatic start of the backup Component Cooling pump when there is a decrease in discharge header pressure. Local pressure gages are used to indicate suction and discharge pressure for all CCWS pumps and the pressure in the surge tank vapor space.

9.2.2.5.3 Liquid Level Measurement

Surge tank liquid level is monitored on both sides of the baffle. High, low and low-low levels cause alarms in the control room. The low level indication causes the demineralized water makeup valve to the affected side of the tank to open. A low-low level indication causes the emergency Service Water makeup valve to the affected side of the tank to open. Clearing of low level indication causes the demineralized water makeup valve to close. Operator action is required to close the Service Water valve.

9.2.2.5.4 Flow Rate Measurement

Flow rate measurement is performed in both the essential and nonessential loops.

Identical instrumentation measures Component Cooling water flow rates in CCWS essential loops A and B. Flow rate measurements are made in the Component Cooling pump discharge headers, RHR heat exchanger inlet lines and the discharge lines from the RHR pump seals. The essential CCWS measurements provide control room indication of Component Cooling water flow to essential components.

Redundant safety related flow transmitters are provided in the supply header to the upper and lower reactor coolant pump bearings. These transmitters provide signals for flow indication and actuation of low flow alarms in the control room should CCWS flow to the pump bearings decrease to less than that required to serve three reactor coolant pumps. Redundant safety related flow transmitters are also provided in the supply header from the CCWS booster pumps to the reactor coolant pump thermal barriers. These transmitters provide signals for flow indication and actuation of low flow alarms in the control room should flow to the thermal barriers decrease to less than that required to serve three reactor coolant pumps.

Nonessential CCWS flow measurements provide the operator with flow information for each reactor coolant pump thermal barrier and bearing cooler outlet line, the waste evaporator heat exchanger package, the recycle evaporator package and the individual nonessential heat exchangers (except sample coolers) served by the CCWS. For the monitored nonessential components, an alarm is initiated when the cooling water flow rate falls below a preset limit.

9.2.2.5.5 Temperature Measurement

Temperature measurements are backup indications for control of flow measurements for both the essential and nonessential CCWS loops. For each analog flow signal transmitted to the control room (and its associated low flow limit alarm), there is a corresponding analog temperature signal transmitted to the control room and a corresponding high temperature limit alarm. Additional high temperature alarms from temperature switches are also provided. For certain analog temperature transmitting devices, there is either a local thermometer or a locally indicating temperature switch

which permits local indication for checking and, in some cases, remote alarms or computer logging. By removing the adjacent thermometer or temperature switch from its thermal well, the well can be used as a reference to check the calibration of the adjacent analog temperature transmitting device. In addition, test wells are located throughout the system to allow checking of heat exchanger efficiencies.

9.2.2.5.6 Special Instrumentation

The main control board ESF monitor lights (see Section 7.5 for more detailed explanation) provide an easily recognizable indication of the status of essential components and equipment. Included among the monitor lights for this system are status (position) indication of the containment isolation valves.

An audible and visual alarm is annunciated on the main control board if manual action by the operator deliberately bypasses the operation of the CCWS.

9.2.2.5.7 Instrumentation Qualification

Sections 3.10, 3.11 and 7.1 outline the qualification and diversity of instrumentation utilized in this system.

9.2.3 Demineralized Water Makeup System

The Demineralized Water System is composed of the cycle makeup pretreatment system, which clarifies and filters raw water from Monticello Reservoir, and the cycle makeup demineralization system which demineralizes water from the cycle makeup pretreatment system for distribution to the Nuclear Steam Supply System (NSSS), the secondary (turbine) cycle, and for other miscellaneous uses.

9.2.3.1 Design Bases

The Demineralized Water System is designed to satisfy the makeup water requirements of the Reactor Coolant System and secondary (turbine) cycle systems.

The system is nonsafety-related. Piping and equipment is designed and fabricated in accordance with applicable American National Standards Institute, American Society of Testing and Materials and American Water Works Association codes and standards and the ASME Code, Section VIII.

9.2.3.2 System Description

Figures 9.2-8 and 9.2-9 show the Demineralized Water Makeup System.

In the cycle makeup pretreatment system, raw water from Monticello Reservoir is treated with a suitable flocculant and chlorine to precipitate suspended matter, remove color and adjust pH. The clarified water is filtered through automatic gravity filters and is force fed into a 1,000,000 gallon

filtered water storage tank. The filtered water is then pumped to miscellaneous pump seals, industrial cooler makeup, and through carbon filters to cycle makeup demineralization system. The carbon filters remove organic matter and excess chlorine as well as objectionable taste and odor. A portion of the carbon filter effluent used to serve as sterile water makeup for potable water service. The sterile water system includes provision for chemical treatment to disinfect and control the alkalinity of the system. Sterile water supply is modified to be fed from the same OWS source as potable water, see Section 1.2.3.8.4.

The cycle makeup demineralization system purifies water from the cycle makeup pretreatment system. Rated capacity of the cycle makeup demineralization system is 375 gpm (per train) and is based upon 1.5% of rated steam flow.

Two trains of plant installed demineralizer units and a vendor supplied portable demineralizer system are used. Each train includes a cation unit, anion unit and a mixed bed polishing unit. Since experiencing a sulfuric acid leak that damaged the discharge nozzle of the sulfuric acid tank, it has not been possible to regenerate the resin beds in the installed cycle makeup demineralization system. Therefore, the vendor supplied portable demineralizer system operates normally. The equipment associated with the cycle makeup demineralization system remains installed in the plant, isolated from the Filtered Water System and the Demineralized Water Storage Tank. The vendor supplied system is aligned in parallel with the original two trains. The portable equipment consists of a demineralizer trailer, a carbon activated skid, and a resin polishing skid. The trailer includes a series of a cation and an anion unit. The demineralized water produced is stored in the 500,000 gallon Demineralized Water Storage Tank and pumped to the following major use points:

1. To a vacuum degasifier for primary plant cycle makeup (recycle makeup water system).
2. To miscellaneous nuclear related uses, such as resin sluicing and Component Cooling water makeup.
3. To the main condenser for secondary cycle makeup.
4. To laboratories and sampling rooms.
5. To Auxiliary Steam (AS) System Condensate Return Unit.

When the resin is spent in the vendor supplied system, the trailer and skids are unhooked and replaced with a new system with the same specifications. If the cycle makeup demineralization system equipment is used, regeneration of the installed plant demineralizer units is accomplished automatically after pushbutton initiation, using dilute sulfuric acid and dilute sodium hydroxide solution. Regenerant wastes are discharged to the neutralization waste basin for neutralization with sulfuric acid and sodium hydroxide. Neutralized wastes are pumped to Monticello Reservoir through the circulating water discharge.

9.2.3.3 Safety Evaluation

The Demineralized Water System is nonsafety-related and, therefore, is not required to operate under accident conditions.

Proper precautions are taken in the handling, storage and mixing of chemicals used in the cycle makeup pretreatment and demineralization systems. Leaks and accidental spills are confined and treated prior to disposal.

9.2.3.4 Testing and Inspection Requirements

The Demineralized Water System is tested and inspected in accordance with applicable codes and standards and vendor recommendations. Periodic monitoring of equipment controls, periodic inspection of system piping and components and testing and adjustment of equipment as suggested by the manufacturers are performed during normal operation.

9.2.3.5 Instrumentation Requirements

Measurement and monitoring of conductivity, silica, dissolved oxygen, sodium, pressures, levels, flow rates and temperatures are performed for purposes of indication, alarm, control and record maintenance at the equipment and at the local control panel.

9.2.4 Potable and Sanitary Water Systems

The original potable water source and its treatment are described in Section 9.2.3: from the pressurized sterile water tank, potable water is distributed to plumbing fixtures, showers, laboratory units, laundry and emergency shower and eyewash facilities throughout the plant. The modified source of potable water is obtained from the Off Site Water Treatment System (OWS); see Section 1.2.3.8.4. No potable water is provided to potentially radioactive equipment. No radiological contamination of this system is expected during normal operation or during an accident.

9.2.5 Ultimate Heat Sink

A safety class impoundment, referred to as the Service Water pond, is constructed in a small arm of Monticello Reservoir to perform ultimate heat sink functions under various conditions. The Service Water pond is created by three earth dams and the site embankment areas (see Figure 1.2-1) which are designed and constructed to meet the most severe natural phenomena as described in Chapter 2. The volume of water stored within the impoundment and the surface area related to water elevation are shown in Figure 2.4-13.

9.2.5.1 Design Bases

A description of the design bases for the ultimate heat sink is presented in Section 2.4.8.

9.2.5.2 System Description

The Service Water pond supplies water for the Service Water System under normal and emergency operating conditions. The intake for the Service Water System is located along the northwest shoreline of the pond on the west embankment. A discharge structure for this system is provided along the southwest edge of the pond and also on the west embankment.

The Service Water intake structure, as shown schematically in Figure 2.4-11, provides adequate water from either the Service Water pond or Monticello Reservoir through an interconnecting pipe and isolation valve. It is possible to safely shut down the plant using only the Service Water pond without reliance upon Monticello Reservoir. Hydraulic performance of the Service Water pond is described in Section 2.4-8.

9.2.5.3 Safety Evaluation

9.2.5.3.1 Analytical Model

A time dependent computer model developed to predict the thermal performance of the ultimate heat sink (Service Water Pond). The model used to describe the temporal and spatial thermal distribution within the Service Water pond (SWP) contained three coupled major components:

- Heat transfer between the pond and the atmosphere
- Transport of heated water discharged near the pond's surface
- Internal movement of heat within the pond (vertical transport)

Field studies of the thermal and flow characteristics of the SWP were conducted in October 1997, before and after Refueling Outage #10, the results of which were used in validating the computer model methodology. These studies included top to bottom temperature measurements to evaluate thermal stratification and dye studies to characterize the circulation patterns within the SWP.

9.2.5.3.2 Design Bases for Safety Evaluation

The Service Water pond is designed to satisfy the following requirements:

1. Service Water Flow Requirements
   a. For normal operation - 12,000 - 24,000 gpm.
   b. Under loss of coolant accident (LOCA) conditions - 32,000 gpm.
   c. For normal shutdown - 12,000 - 26,000 gpm.

   The normal operation and normal shutdown design basis SWP thermal study assumed two trains of Service Water in operation since this results in the limiting SWP temperatures for these modes.
2. Service Water System Heat Rejection
   a. During normal operation - 57.35 x 10^6 BTU/hour.
   b. Under LOCA conditions - (see Figure 9.2-10).
   c. During normal shut down - (see Figure 9.2-11).
3. Service Water Pond Levels
   a. Normal operation (mean level) - elevation 422.0’.

b. Under LOCA conditions - elevation 414.75' - 415.0’.

c. Normal shutdown - elevation 414.75' - 415.0’.

4. Service Water Pond Area and Capacity
See Figure 2.4-13.

9.2.5.3.3 Analyses

The Service Water pond serves as the ultimate heat sink for the Virgil C. Summer Nuclear Station. The method used to determine the calculated heat loads for the ultimate heat sink was to sum the heat loads served by the Service Water System for the design basis LOCA. These heat loads are transferred to the Service Water System from other cooling systems as follows:

1. Component Cooling Water System

   The Component Cooling Water System (CCWS) provides cooling for the residual heat removal (RHR) heat exchangers, spent fuel cooling and other NSSS auxiliaries. The RHR heat exchangers remove decay heat and sensible heat from the NSSS during the recirculation mode of Emergency Core Cooling System operation. The RHR heat duty following a LOCA is shown by Figure 9.2-10. Spent fuel cooling heat loads are included in the CCWS heat load transferred to the Service Water System following a LOCA and are listed in Table 9.2-9.

2. Reactor Building Cooling Units

   The reactor building cooling units remove heat from the Reactor Building atmosphere following a LOCA and transfer it to the Service Water system. This heat load is shown by Figure 9.2-10.

3. Diesel Generator Coolers

   The heat rejected from the diesel generators to the Service Water System is 21.36 x 106 BTU/hr, based upon two diesel generators operating at the 7 day load rated capacity. This heat load is assumed to remain constant over the 30 day period.

4. HVAC Mechanical Water Chillers

   The Chilled Water System provides cooling for numerous safety related cooling coils. The HVAC mechanical water chillers reject the total heat load from the refrigeration system to the Service Water System. The heat load from two HVAC chillers plus compressor heat rejection is 9.9 x 106 BTU/hr assumed to remain constant throughout the 30 day period.

The analysis of the thermal performance of the Service Water pond is based upon the heat loads described in items 1 through 4, above, with added design margins, and the meteorological conditions described in Section 9.2.5.3.1. The analytical results indicate that the Service Water pond provides sufficient heat dissipation to limit Service Water intake temperature to a maximum

value of less than 95°F under the most adverse conditions by restricting the pre-incident Service Water intake structure temperature to 90.5°F and the SWP level to 416.5' (Reference 6).

9.2.5.3.3.1 Normal Operation

For the initial condition in the LOCA studies, it was considered appropriate to evaluate the thermal performance of the Service Water pond for normal meteorological and plant operating conditions.

Average monthly climatological data for a 32 year period of record (1965 through 1996) at Columbia, S. C., provided the bases for the generation of daily meteorological data for normal operation. The data included dry bulb temperatures, dewpoint temperatures and wind speeds. There are two other climatological recording stations in the vicinity of the site: Parr and Little Mountain. These stations are closer to the site than Columbia Station but do not have complete data. The nearest source of consistent and sufficiently complete data for analytical purposes is Columbia. For the parameters measured at Parr and Little Mountain, there is little difference from the Columbia data. Therefore, the Columbia data was used for the analysis. The operational conditions existing prior to RF-10 were used in the SWP computer model to estimate the SWP temperatures for the entire 32 year period. Rolling averages, over periods of 1 hour and 1 hour to 50 days, of the intake temperatures from the SWP were calculated for the 32 year period. The results indicated that the meteorological conditions from the time periods July to August 1968, 1986, and 1993 will provide the most restrictive intake temperatures.

9.2.5.3.3.2 Loss of Coolant Accident and Normal Shutdown Conditions

To study the effects of LOCA and normal shutdown heat rejection rates on the thermal performance of the Service Water pond, it is hypothesized that the most critical cases would occur if Monticello Reservoir failed completely, coincident with the interconnecting pipe isolation valve in the open position. This would cause the Service Water pond water surface elevation to drop to a minimum of elevation 415.0’. To establish the operating characteristics necessary to evaluate the thermal performance of the Service Water pond, it is further assumed that the reservoir failed instantaneously and the Service Water pond surface elevation dropped from its normal mean level at elevation 422.0’ to elevation 415.0’ instantaneously. An additional loss of 0.25' is included to account for seepage from the SWP.

The ultimate heat sink has been analyzed for a minimum water surface elevation of 414.75’. The volume evaporated from the surface of the SWP during the 10 day and 30 day period following the postulated LOCA initiation was determined to be $4.96X10^5$ ft^3 and $1.56X10^6$ ft^3, respectively. There are no drift losses from the pond.

The meteorological data described in Section 9.2.5.3.3.1 was used as input for LOCA cases.

9.2.5.3.4 Summary of Analytical Results

Based upon generated meteorological data and the proposed operating conditions, the analytical results show that the Service Water pond is an adequate heat sink and source of cooling water

under the most adverse conditions with the pre-incident Service Water intake structure temperature limited to 90.5°F and the SWP level limited to 416.5' (Reference 6). The maximum Service Water intake temperatures are summarized in Table 9.2-15. Vertical temperature distributions for the LOCA studies are provided on Figure 9.2-22.

Figure 2.4-1 shows the location of Service Water intake and discharge structures. The topography of the pond is also shown by this figure.

In the analysis it is assumed that the discharge to the Service Water pond is completely mixed with an equal flowrate of pond water. However, the Service Water discharge structure is designed to limit entrance mixing and encourage hot surface layer development. Figure 3.8-64 presents details of the discharge structures. This should improve the actual thermal structure by developing more satisfaction and reducing the extent of the epilimnium. It should also result in the withdrawal of cooler water at the level of the Service Water intake structure.

9.2.5.4 Testing and Inspection Requirements

Ultimate heat sink testing and inspection requirements include only periodic visual inspection of riprap.

9.2.5.5 Instrumentation Requirements

The instrumentation associated with the ultimate heat sink is described in Section 9.2.1.

9.2.6 Condensate Storage Facilities

9.2.6.1 Design Bases

The condensate storage system is designed to provide and store sufficient demineralized water to satisfy secondary cycle makeup requirements.

The condensate storage system is designed to ensure that a reserve of condensate quality water is dedicated for use by the emergency feedwater system (EF). To accomplish this function, the condensate storage tank (CST) is designed to provide the EF a sufficient amount of water to refill the steam generators to no load program level plus the amount required to replenish the steam released from the steam generators through the MSSVs and PORVs. Under the uprated plant conditions with the Model Δ75 Steam Generators, the required CST volume to maintain Hot Standby for 2 hours followed by a 4 hour cooldown to RHR operation is 152,550 gallons; the required volume to maintain Hot Standby for an 11 hour period is 158,570 gallons. Therefore, 158,570 gallons is the minimum required CST inventory that is dedicated and available to the EF. The actual CST volume that is dedicated and available to the EF based on the physical configuration of the tank from the bottom of the condensate to condenser nozzle to the top of the emergency feedwater suction nozzle is 160,054 gallons. There is an additional unusable volume of 19,794 gallons below the top of the emergency feedwater suction nozzle.

Since the condensate storage tank is the primary source of emergency feedwater, it is a safety-related component. Therefore, this tank is designed, fabricated, inspected, tested and stamped in accordance with the requirements of the ASME Code, Section III, for Class 3 tanks.

9.2.6.2 System Description

The condensate storage tank and cycle makeup scheme are shown on the system diagram, Figure 10.4-8. The emergency feedwater supply is shown by Figure 10.4-16.

The system consists of one condensate storage tank, with a capacity of 500,000 gallons of condensate, and the associated makeup and distribution systems. The condensate storage tank is located outside, adjacent to the Water Treatment Building. Of the condensate storage tank capacity, 160,054 gallons is reserved for use by the emergency feedwater system. This reserve is the volume between the bottom of the condensate to condenser nozzle and the top of the emergency feedwater suction nozzle. It is maintained by having the tank connections, except those required for instrumentation, emergency feedwater pump suction, chemical analysis and tank drainage, above the level providing 160,054 gallons to the EF system. The tank is field fabricated of carbon steel, lined with an inert material. Table 9.2-16 presents tank physical details. A check valve in the drain line of the tank is provided to allow for nitrogen sparging as a method of controlling CST water oxygen levels; the sparging operation is not allowed in modes 1 - 3.

Makeup to the condensate storage tank is supplied from the 500,000 gallon demineralized water storage tank. The makeup water is routed through the main condenser for deaeration. As the makeup water enters the condenser, it increases the hotwell level. A level control valve then opens to permit condensate, from the discharge of the condensate pumps, to flow into the condensate storage tank. Makeup is cyclical in nature. The makeup control valve opens when the low tank level is reached, and closes at the high tank level.

Emergency feedwater pump recirculation lines also return water to the condensate storage tank when the emergency feedwater system is used during startup or any time an emergency feedwater pump is in a recirculating mode.

9.2.6.3 Safety Evaluation

The water contained in the condensate storage tank is normally supplied from the demineralized water storage tank through the main condenser. Radiological considerations are not a factor in design or tank location.

To assure the availability of the condensate storage tank contents, it is constructed in accordance with the ASME Code, Section III. The tank foundation is designed to satisfy Seismic Category 1 requirements. The location of the condensate storage tank ensures that releases of the stored water due to any unforeseen failure does not affect any safety-related equipment.

Freeze protection is not required for the condensate storage tank. During normal plant operation, recirculation between the condensate storage tank and the condenser hotwell may be

accomplished. This technique may be used to maintain the temperature of the condensate storage tank contents well above freezing.

Freeze protection is provided, by means of electric heat tracing, for safety-related piping and instrument lines connected to the condensate storage tank, including the suction line to the emergency feedwater pumps. This line is heat traced at all exposed locations.

9.2.6.4 Tests and Inspections

Testing of this system includes operability tests associated with the tank level monitoring instrumentation that initiates the automatic transfer of the suctions of the emergency feedwater pumps on low suction pressure. Inspections are limited to periodic visual examinations of welds and connections to the tank.

9.2.6.5 Instrumentation Requirements

The condensate storage tank is provided with level instrumentation necessary for control of makeup to maintain an adequate tank operating level. Level switches initiate alarms in the control room upon detection of high level and if level decreases below that required for use by the Emergency Feedwater System. Level instrumentation associated with the Emergency Feedwater System is discussed in Section 10.4.9.

9.2.7 Reactor Makeup Water Supply System

The reactor makeup system provides for storage of tritiated but not aerated, recycled primary coolant grade water.

9.2.7.1 Design Bases

The Reactor Makeup Water Supply System is designed to perform the following functions:

1. Supply water to the Chemical and Volume Control System (CVCS).
2. Supply makeup water to the spent fuel pool at a rate of 150 gpm.
3. Provide a backup water supply for spray cooling in the pressurizer relief tank, capable of supplying 150 gpm.
4. Provide a water supply for makeup to and flushing of reactor auxiliary systems.
5. Provide storage capacity equal to or greater than the total 84,000 gallon capacity of the recycle holdup tanks for recycle primary coolant grade water produced in the boron recovery system and Liquid Waste Processing system.

The portion of the Reactor Makeup Water Supply System between the reactor makeup water storage tank and the CVCS and Spent Fuel Cooling System is safety related and is classified as Safety Class 2b. The remainder of the system is not safety related.

Two (2) isolation valves in series and monitor and control instrumentation ensure that flow related failures in nonsafety related portions of the system do not jeopardize the functional capability of the safety related portions.

Safety Class 2b piping, valves and equipment are designed, fabricated, tested and inspected in accordance with the ASME Code, Section III, Class 3. Nonsafety related piping and equipment satisfy the requirements of ANSI B31.1.0 and the ASME Code, Section VIII, as applicable.

9.2.7.2 System Description

Figure 9.2-24 is the Reactor Makeup Water Supply System flow diagram. Data for major system components is presented in Table 9.2-17.

The initial supply of primary coolant grade water is provided by the demineralized makeup water system. Subsequent primary grade makeup water requirements are satisfied from the 100,000 gallon capacity reactor makeup water storage tank. The principal source of makeup water in the reactor makeup water storage tank is the demineralized water system using the system vacuum degasifier transfer pumps. The boron recovery system evaporators and the liquid waste processing system evaporators are a secondary source of makeup water in the reactor makeup water storage tank when in operation. This water contains tritium. Therefore, its use is limited to reactor auxiliary systems containing radioactive fluid.

Water supplied to the boric acid blender for reactor coolant makeup is automatically controlled by the reactor coolant makeup control system, a part of the CVCS. Water is provided for the following upon demand by manually starting one of the two reactor makeup water pumps:

1. Makeup for evaporative losses from the spent fuel pool.
2. Flushing of boric acid and waste evaporator units, drumming station, demineralizers, resin fill hopper, reagent tanks, catalytic recombiner packages and gas decay tanks.
3. Transport of resin to and from the spent resin storage tank.
4. Dilution in the chemical mixing tank and boric acid batching tank.
5. Makeup for seal water losses in the waste gas compressors.
6. Cooling water to the pressurizer relief tank in the event of safety valve discharge.

The reactor makeup water storage tank is located outside the plant in the tank area adjacent to the Auxiliary Building. This tank and all outdoor system piping connecting to the tank are insulated and heat traced to maintain a minimum temperature at 40°F. The reactor makeup water pumps and most system piping are located in the Auxiliary Building.

9.2.7.3 Safety Evaluation

The portion of the reactor makeup water storage system that supplies water to the CVCS and the Spent Fuel Cooling System is Safety Class 2b since it supplies reactor coolant makeup required

for normal plant shutdown, as well as makeup to the spent fuel pool. System operation is not required for ANS 18.2 (Reference 4) Condition III and IV events.

Two (2) valves in series are provided to isolate the safety-related portion of the system from the nonsafety related portion. A flow switch and a low pressure alarm provide means for detection of malfunction or operation of the nonsafety related portion of the system that could jeopardize the functional capability of the safety-related portion.

Two (2) 100% capacity reactor makeup water pumps assure that an adequate supply of water is available when required.

9.2.7.4 Inspection and Testing Requirements

Major components of the reactor makeup water system are in use during normal plant operation. The two reactor makeup water pumps are alternated during normal system operation to equalize wear. Routine observations of system piping and components are made during normal operation. Periodic tests are not required.

9.2.7.5 Instrumentation Requirements

Measurement and monitoring of pressure, temperature, level and flow are performed for purposes of indication, alarm, control and record maintenance.

9.2.7.5.1 Pressure Instrumentation

Pressure transmitters with local indicating meters are located on the discharge of each reactor makeup water pump. These transmitters provide control room indication for monitoring pump operation. A pressure transmitter with local indicating meter is also located in the supply line from the demineralized water makeup system for purposes of control and indication.

A pressure switch located in the supply line to nonsafety related portions of the reactor makeup water system actuates an alarm in the control room should a pipe break or other malfunction occur which could cause loss of pressure. This alarm is interlocked with a low flow switch to preclude this alarm function when there is no flow in this line.

Test connections on the suction side of each pump are provided for measurement, in conjunction with the pressure transmitters, of differential pressure to check pump performance.

9.2.7.5.2 Temperature Instrumentation

Direct reading local temperature indicators are provided to permit monitoring of pump motor coolers. Redundant temperature elements in the reactor makeup water storage tank provide indication and actuate a low temperature alarm in the control room. Heat tracing circuits on the tank are automatically energized to maintain a minimum temperature of 40°F.

9.2.7.5.3 Level Instrumentation

Redundant level transmitters with local indicating meters are provided on the reactor makeup water storage tank to provide indication and high, low, and lo-lo level alarms in the control room.

9.2.7.5.4 Flow Instrumentation

A high/low flow switch with local indicating meter is provided in the supply line to the nonsafety related portions of the reactor makeup water system. The high flow switch actuates the two isolation valves in series whenever flow exceeds 150 gpm, the capacity of one reactor makeup water pump. The low flow switch provides an interlock to the low pressure switch in the non-safety related supply line to preclude the low pressure alarm when there is no flow in that line (i.e., when the header is isolated). A flow element with local indicating meter is located in the pump recirculation line from the common discharge header to the reactor makeup water storage tank to permit checking of pump performance.

9.2.8 References

1. Deleted per RN 01-098
2. Deleted per RN 01-098
3. Deleted per RN 01-098
4. American Nuclear Society, *Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants*, ANS 18.2, 1970.
5. Seckler, J. G., *Hydraulic Analysis of Interconnecting Pipe System for V. C. Summer Nuclear Station*, Civil Engineering Department, Gilbert Associates, Inc., Reading, Pennsylvania, Internal Report, January, 1973.
6. Byrne, S. A., *Virgil C. Summer Nuclear Station, Docket No. 501395, Operating License No. NPF-12, Technical Specification Change Request, Ultimate Heat Sink - TSP 99-0280*, RC-00-0249, June 12, 2000.

Table 9.2-1
Major Service Water System Components

Service Water Pumps	
Quantity	3
Type	Vertical, turbine
Location	Service water intake structure
Safety Class	2b
Speed (low/high), rpm*	880/1167
Capacity, gpm	16,800
Total Dynamic Head, ft	100
Shutoff Head, ft	233
Motor	
Two Speed	
Voltage Rating, volts a-c	6900
Rated Brake Horsepower, bhp*	
Low Speed	300
High Speed	700
Traveling Screens	
Quantity	3
Type	Through flow, single speed, platform supported
Location	Service water intake structure
Safety Class	2b
Screen Width, ft	3
Screen material	304 stainless steel
Screen mesh Opening, in	1/4
Screen Speed, ft/min	10

* Motor locked in high speed position permanently.

Table 9.2-1 (continued)
Major Service Water System Components

Design Water Velocity, ft/min	0.75 approach; 2.25 through, max
Shaft Center Distance, ft	47
Capacity, gpm	16,800
Service Water Booster Pumps	
Quantity	2
Type	Single stage, double suction, horizontal, split case centrifugal, oil lubricated
Location	Service water intake structure
Safety Class	2b
Speed, rpm	1780
Capacity, gpm	4000
Total Dynamic Head, ft	235
Shutoff Head, ft	280
Motor	
Voltage Rating, volts a-c	460
Horsepower	350

Table 9.2-2
Service Water System Failure Analysis

Component	Malfunction	Comment
Service Water Pump	Pump trips or fails to start	Service water pump in redundant loop operates to cool plant.
Service Water Booster Pump	Pump trips or fails to start	Service water booster pump in redundant loop operates to cool plant.
Traveling Screen	Jams or fails to run	Affected loop can operate for indefinite time period. Redundant loop operates to cool plant.
Electrical Channel A	Electrical malfunction	Alternate Service Water loop on B Channel operates to cool plant.
Electrical Channel B	Electrical malfunction	Alternate Service Water loop on A Channel operates to cool plant.

Table 9.2-3
CCWS Cooling Water Supply and Heat Removal Requirements
Plant Startup to Hot Critical Minimum Load

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Head Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
RHR Heat Exchangers	1	10.17×10^6	10.17×10^6 [(1) (6) (8)]	5600	5600
Spent Fuel Heat Exchanger	1	13.32×10^6	13.32×10^6 (2)	1800	1800
Letdown Heat Exchanger	1	16.10×10^6	16.10×10^6 (3)	1100	1100
Excess Letdown Heat Exchanger	1	5.17×10^6	5.17×10^6 (3)	262	262
Reactor Coolant Pumps	3	1.20×10^6	3.60×10^6 (3)	216	648
Seal Water Heat Exchanger	1	1.50×10^6	1.50×10^6	250	250
Recycle Evaporator Package	1	8.80×10^6	8.80×10^6	780	780
Recycle Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10
Reactor Coolant Drain Tank Heat Exchanger	1	0.64×10^6	0.64×10^6	240	240
Waste Evaporator	1	8.80×10^6	8.80×10^6	780	780
Waste Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10
Waste Gas Compressors	1 (2)	0.135×10^6	0.135×10^6 (4)	50	50
Sample Heat Exchangers	7	0.212×10^6	1.5×10^6	14	98

Table 9.2-3 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Plant Startup to Hot Critical Minimum Load

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Head Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
RHR Pumps	1	0.05×10^6	0.05×10^6 (1) (6)	5	5
Waste Process System Recombiner	1 (2)	0.07×10^6	0.07×10^6 (4)	10	20
Radiation Monitors	1	-	-	3	3 (9)
Charging Pump oil Coolers	1	0.028×10^6	0.028×10^6 (6)	5 (5)	5 (5)
Charging Pump gear oil coolers	1	0.0225×10^6	0.0225×10^6 (6)	5 (5)	5 (5)
Charging Pump Bypass	1	-	-	60 (5)	60 (5)
Component Cooling Water Pump Motor	1	0.17×10^6	0.17×10^6 (6)	50	50

Table 9.2-3(Continued)

Totals	Single CCWS Loop in Operation	Both CCWS Loops in Operation	
		Loop 1	Loop 2
Heat load before reactor coolant pumps started, BTU/hr	45.43×10^6	35.21×10^6	10.39×10^6
Heat load after reactor coolant pumps started, BTU/hr	60.13×10^6	60.13×10^6	-
Flow, gpm, before reactor coolant pumps started	11826	6226	5658
Flow, gpm, after reactor coolant pumps started	6226	6226	0

(1) Discontinued after reactor coolant pumps started.
(2) Based on 72 assemblies at 21 days and 1709 cooled for more than 18 months.
(3) No heat load until reactor coolant pumps started.
(4) CCWS water supplied to both units, however only one in operation.
(5) The total flow of Component Cooling water to the branch serving the Charging pump is 70 GPM. The 70 GPM flow includes the 5 GPM used for lube oil cooling, 5 GPM for gear oil cooling, and the remainder passes through a flow balancing bypass at the inlet to the pump cooling water piping. The flow totals are based on the 70 GPM flow required to the branch.
(6) Essential Load
(7) During startup, the running charging pump is typically in the loop carrying the non-essentials (Loop 1).
(8) Based on 85 assembles at 21 days.
(9) Flow exists per loop if respective CCWS pump is operating.

{ } Units receiving CCWS flow

Table 9.2-4
CCWS Cooling Water Supply and Heat Removal Requirements
Normal Power Operation

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
RHR Heat Exchangers	-	-	-	-	-
Spent Fuel Heat Exchangers	1	13.32×10^6	13.32×10^6 (3)	1800	1800
Letdown Heat Exchanger	1	11.05×10^6 (1)) 5.21×10^6 (2)	11.05×10^6 (1) 5.21×10^6 (2)	575 (1) 155 (2)	575 (1) 155 (2)
Excess Letdown Heat Exchanger	-	-	-	-	-
Reactor Coolant Pumps	3	1.2×10^6	3.6×10^6	216	648
Seal Water Heat Exchanger	1	1.5×10^6	1.5×10^6	250	250
Recycle Evaporator Package	1	8.8×10^6	8.8×10^6	780	780
Recycle Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10
Reactor Coolant Drain Tank Heat Exchanger	1	2.23×10^6	2.23×10^6	240	240
Waste Evaporator	1	8.8×10^6	8.8×10^6	780	780

Table 9.2-4 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Normal Power Operation

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
Waste Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10
Waste Gas Compressors	1(2)	0.135×10^6	0.135×10^6	50	100 (6)
Sample Heat Exchangers	7	0.212×10^6	1.5×10^6	14	98
RHR Pumps (5)	- (1)	-	-	5	5
Waste Process System Recombiner	1 (2)	0.07×10^6	0.07×10^6	10	20 (6)
Radiation Monitors	1	-	-	3	3 (7)
Charging Pump oil cooler	1	0.028×10^6	0.028×10^6 (5)	5 (4)	5 (4)
Charging Pump gear oil cooler	1	0.0225×10^6	0.0225×10^6 (5)	5 (4)	5 (4)
Charging Pump Bypass	1	-	-	60 (4)	60 (4)
Component Cooling Water Pump Motor	1	0.17×10^6	0.17×10^6 (5)	50	50

Table 9.2-4 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Normal Power Operation

Totals	Maximum (1)	Normal (2)
Heat Load, BTU/hr	51.5×10^6	45.6×10^6
Flow, gpm	5439	5019

(1) Maximum letdown (load following or purification),
(2) Normal letdown
(3) Based on 72 assemblies at 21 days and 1709 cooled for more than 18 months.
(4) The total flow of Component Cooling water to the branch serving the Charging pump is 70 GPM. The 70 GPM flow includes the 5 GPM used for lube oil cooling, 5 GPM for gear oil cooling, and the remainder passes through a flow balancing bypass at the inlet to the pump cooling water piping. The flow totals are based on the 70 GPM flow required to the branch.
(5) Essential Load.
(6) CCWS water supplied to both units; however, only one is in operation.
(7) Flow exists per loop if respective CCWS pump is operating
{ } Units receiving CCWS flow.

Table 9.2-5
CCWS Cooling Water Supply and Heat Removal Requirements
Normal Plant Shutdown at 4 Hours

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
RHR Heat Exchangers	1 2	122.53×10^6 1074×10^6 (2)	122.53×10^6 (1) 214×10^6 (2)	5600	11,200
Spent Fuel Heat Exchangers	1	-	13.32×10^6 (3) (6)	1800 (3)	1800 (3)
Letdown Heat Exchanger	1	1.88×10^6	1.88×10^6 (4)	700	700
Excess Letdown Heat Exchanger	-	-	-	-	-
Reactor Coolant Pumps	1 (3)	1.2×10^6	1.2×10^6	216	648
Seal Water Heat Exchanger	1	1.5×10^6	1.5×10^6	250	250
Recycle Evaporator Package	1	8.8×10^6	8.8×10^6	780	780
Recycle Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10
Reactor Coolant Drain Tank Heat Exchanger	1	-	-	240	240
Waste Evaporator	1	8.8×10^6	8.8×10^6	780	780
Waste Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10

Table 9.2-5 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Normal Plant Shutdown at 4 Hours

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
Waste Gas Compressors	1 (2)	0.135×10^6	0.135×10^6	50	100
Sample Heat Exchangers	7	0.2×10^6	1.4×10^6	14	98
RHR Pumps	2	0.05×10^6	0.1×10^6	5	10
Waste Process System Recombiner	1 (2)	0.07×10^6	0.07×10^6	10	20
Radiation Monitors	2	-	-	3	6 (9)
Charging Pump oil cooler	1	0.028×10^6	0.028×10^6	5 (5)	5 (5)
Charging Pump gear oil cooler	1	0.0225×10^6	0.0225×10^6	5 (5)	5 (5)
Charging Pump Bypass	1	-	-	60 (5)	60 (5)
Component Cooling Water Pump Motor	2	0.17×10^6	0.34×10^6	50	100

Table 9.2-5 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Normal Plant Shutdown at 4 Hours

Totals		CCWS Loop 1 (4) (8)	CCWS Loop 2 (4)
Two loops operating	Heat Load, BTU/hr	144.6×10^6	107.22×10^6
	Flow, gpm	11164	5658
One loop operating	Heat Load, BTU/hr	138.23	
	Flow, gpm	9364 (10)	

(1) Includes one RCP, decay heat at 4 hours, and a 0° F/hr cooldown.
(2) Includes one RCP, decay heat at 4 hours, and sensible heat from a 50° F/hr cooldown rate of the RCS.
(3) Normally not required during cooldown but included for system design purposes.
(4) Both loops in operation.
(5) The total flow of Component Cooling water to the branch serving the Charging pump is 70 GPM. The 70 GPM flow includes the 5 GPM used for lube oil cooling, 5 GPM for gear oil cooling, and the remainder passes through a flow balancing bypass at the inlet to the pump cooling water piping. The flow totals are based on the 70 GPM flow required to the branch.
(6) Based on 72 assemblies at 21 days and 1709 cooled for more than 18 months.
(7) Essential Load.
(8) The running charging pump is in the loop carrying the non-essential loads (Loop 1).
(9) Flow exits per loop if respective CCWS pump is operating.
(10) Assumes no flow to spent fuel heat exchanger.
{ } Units receiving CCWS flow.

Table 9.2-6
CCWS Cooling Water Supply and Heat Removal Requirements
Normal Plant Shutdown at 24 Hours

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
RHR Heat Exchangers	1	30.33×10^6 (1)	60.6×10^6	5600	11,200
Spent Fuel Heat Exchangers	1	-	13.32×10^6 (6)	1800	1800 (2)
Letdown Heat Exchanger	-	-	-	700	700 (8)
Excess Letdown Heat Exchanger	-	-	-	-	-
Reactor Coolant Pumps	(3)	-	-	216	648 (8)
Seal Water Heat Exchanger	-	-	-	250	250 (8)
Recycle Evaporator Package	1	8.8×10^6	8.8×10^6	780	780
Recycle Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10
Reactor Coolant Drain Tank Heat Exchanger	1	-	-	240	240
Waste Evaporator	1	8.8×10^6	8.8×10^6	780	780
Waste Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10

Table 9.2-6 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Normal Plant Shutdown at 24 Hours

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
Waste Gas Compressors	1 (2)	0.135×10^6	0.135×10^6	50	100
Sample Heat Exchangers	7	0.2×10^6	1.4×10^6	14	98
RHR Pumps	2	0.05×10^6	$0.10 \times 10^{6(5)}$	5	10
Waste Process System Recombiner	1 (2)	0.07×10^6	0.07×10^6	10	20
Radiation Monitors	2	-	-	3	6 (7)
Charging Pump oil cooler	1	0.028×10^6	$0.028 \times 10^{6(5)}$	5 (4)	5 (4)
Charging Pump gear oil cooler	1	0.0225×10^6	$0.0225 \times 10^{6(5)}$	5 (4)	5 (4)
Charging Pump Bypass	1	-	-	60 (4)	60 (4)
Component Cooling Water Pump Motor	2	0.17×10^6	$0.34 \times 10^{6(5)}$	50	100

Table 9.2-6 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Normal Plant Shutdown at 24 Hours

Totals	CCWS (3) Loop 1	CCWS (3) Loop 2
Heat Load, BTU/hr	63.32×10^6	107.22×10^6
Flow, gpm	11164	5658

(1) Design heat load (core residual heat only)
(2) Normally not required during cooldown but included for system design purposes.
(3) Both loops in operation.
(4) The total flow of Component Cooling water to the branch serving the Charging pump is 70 GPM. The 70 GPM flow includes the 5 GPM used for lube oil cooling, 5 GPM for gear oil cooling, and the remainder passes through a flow balancing bypass at the inlet to the pump cooling water piping. The flow totals are based on the 70 GPM flow required to the branch.
(5) Essential Load.
(6) Based on 72 assemblies at 21 days and 1709 cooled for more than 18 months.
(7) Flow exists per loop when respective CCWS pump is running.
(8) Flow continues to components not in service.
{ } Units receiving CCWS flow.

Table 9.2-7
CCWS Cooling Water Supply and Heat Removal Requirements
Refueling

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
RHR Heat Exchangers	2	21.05×10^6	42.09×10^6 [(6) (2)]	5600	11,200 (2)
	1	20.65×10^6	20.65×10^6 [(6) (1) (5)]	5600	5600 (1)
Spent Fuel Heat Exchangers	1	5.52×10^6	5.52×10^6 [(3) (2)]	1800	1800
	1	20.71×10^6	20.71×10^6 [(5) (1)]	1800	1800
Letdown Heat Exchanger	-	-	-	700	700
Excess Letdown Heat Exchanger	-	-	-	-	-
Reactor Coolant Pumps	-	-	-	216	648
Seal Water Heat Exchanger	-	-	-	250	250
Recycle Evaporator Package	1	8.8×10^6	8.8×10^6	780	780
Recycle Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10
Reactor Coolant Drain Tank Heat Exchanger	-	-	-	240	240
Waste Evaporator	1	8.8×10^6	8.8×10^6	780	780
Waste Evaporator Sample Cooler	1	0.11×10^6	0.11×10^6	10	10

Table 9.2-7 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Refueling

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
Waste Gas Compressors	1 (2)	0.135×10^6	0.135×10^6	50	100
Sample Heat Exchangers	-	-	-	14	98
RHR Pumps	2	0.05×10^6	0.10×10^6 (2) (6)	5	10
Waste Process System Recombiner	1 (2)	-	-	10	20
Radiation Monitors	2	-	-	3	6 (7)
Charging Pump oil cooler	1 (8)	0.028×10^6	0.028×10^6 (6)	5 (4)	5 (4)
Charging Pump gear oil cooler	1 (8)	0.0225×10^6	0.0225×10^6 (6)	5 (4)	5 (4)
Charging Pump Bypass	1	-	-	60 (4)	60 (4)
Component Cooling Water Pump Motor	2	0.17×10^6	0.34×10^6 (6)	50	100

Table 9.2-7 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Refueling

Totals	Both Loops in Operation (2)		Single CCWS Loop in Operation (1)
	CCWS Loop 1	CCWS Loop 2	
Heat Load, BTU/hr	44.79×10^6	63.32×10^6	59.58×10^6
Flow, gpm	11164	5658	

(1) Subsequent to transfer of spent fuel to spent fuel pool.
(2) Spent fuel still in core at 72 hours after shutdown.
(3) Heat load based on 1709 assemblies cooled for > 18 months.
(4) The total flow of Component Cooling water to the branch serving the Charging pump is 70 GPM. The 70 GPM flow includes the 5 GPM used for lube oil cooling, 5 GPM for gear oil cooling, and the remainder passes through a flow balancing bypass at the inlet to the pump cooling water piping. The flow totals are based on the 70 GPM flow required to the branch.
(5) Based on 1709 assemblies cooled for > 18 months plus 72 assemblies @ 103 hours after shutdown.
(6) Essential Load.
(7) Flow exists if respective CCWS pump is operating.
(8) Normally one charging pump is operated during refueling to prevent backflushing of cavity water through the reactor coolant pump seals.
{ } Units receiving CCWS flow.

Table 9.2-8
CCWS Cooling Water Supply and Heat Removal Requirements
Safety Injection

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
RHR Heat Exchangers	- (1)	-	-	5600 (1)	5600 (1)
Spent Fuel Heat Exchangers	1	13.32×10^6	$13.32 \times 10^{6(5)}$	1800	1800
Letdown Heat Exchanger	-	-	-	-	-
Excess Letdown Heat Exchanger	-	-	-	-	-
Reactor Coolant Pumps	- (3)	-	-	216 (2)	648 (2)
Seal Water Heat Exchanger	- (1)	-	-	250	250
Recycle Evaporator Package	- (1)	-	-	780	780
Recycle Evaporator Sample Cooler	- (1)	-	-	10	10
Reactor Coolant Drain Tank Heat Exchanger	- (1)	-	-	240 (2)	240 (1) (2)
Waste Evaporator	- (1)	-	-	780	780
Waste Evaporator Sample Cooler	- (1)	-	-	10	10

Table 9.2-8 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Safety Injection

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
Waste Gas Compressors	1 {2}	-	-	50	100
Sample Heat Exchangers	- {7}	-	-	14	98
RHR Pumps	2	0.05×10^6	0.10×10^6 (7)	5	10
Waste Process System Recombiner	1 {2}	-	-	10	20
Radiation Monitors	2	-	-	3	6 (6)
Charging Pump oil cooler	2	0.028×10^6	0.056×10^6 (7)	5 (4)	10 (4)
Charging Pump gear oil cooler	2	0.0225×10^6	0.045×10^6 (7)	5 (4)	10 (4)
Charging Pump Bypass	1	-	-	60 (4)	60 (4)
Component Cooling Water Pump Motor	2	0.17×10^6	0.34×10^6 (7)	50	100

Table 9.2-8 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Safety Injection

Totals	CCWS (1) Loop 1	CCWS (1) Loop 2
Heat Load, BTU/hr	13.59×10^6	0.27×10^6
Flow, gpm	4864 (3)	5728

(1) No change in operating loop. Inactive loop started to low speed with RHR heat exchanger on line.
(2) CCW flow terminated on containment, Phase B isolation signal.
(3) If containment, Phase B isolation signal occurs, flow required is 3976 gpm.
(4) The total flow of Component Cooling water to the branch serving the Charging pump is 70 GPM. The 70 GPM flow includes the 5 GPM used for lube oil cooling, 5 GPM for gear oil cooling, and the remainder passes through a flow balancing bypass at the inlet to the pump cooling water piping. The flow totals are based on the 70 GPM flow required to the branch.
(5) Based on 72 assemblies at 21 days and 1709 cooled for > 18 months.
(6) Flow exists if respective CCWS pump is operating.
(7) Essential Load.
{ } Units receiving CCWS flow.

Table 9.2-9
CCWS Cooling Water Supply and Heat Removal Requirements
Recirculation

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
RHR Heat Exchangers	2	59.244×10^6	118.488×10^6	5600	11,200
Spent Fuel Heat Exchangers	1	$13.32 \times 10^{6(4)}$	-	1600 (2)	1600 (2)
Letdown Heat Exchanger	-	-		-	- (7)
Excess Letdown Heat Exchanger	-	-	-	-	- (7)
Reactor Coolant Pumps	-	-	-	-	(1)
Seal Water Heat Exchanger	-	-	-	-	(1)
Recycle Evaporator Package	-	-	-	-	(1)
Recycle Evaporator Sample Cooler	-	-	-	-	(1)
Reactor Coolant Drain Tank Heat Exchanger	-	-	-	-	(1)
Waste Evaporator	-	-	-	-	(1)
Waste Evaporator Sample Cooler	-	-	-	-	(1)

Table 9.2-9 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Recirculation

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
Waste Gas Compressors	-	-	-	-	(1)
Sample Heat Exchangers	-	-	-	-	(1)
RHR Pumps	2	0.05×10^6	0.1×10^6 (6)	5	10
Waste Process System Recombiner	-	-	-	-	(1)
Radiation Monitors	2	-	-	3	6 (5)
Charging Pump oil cooler	2	0.028×10^6	0.056×10^6 (6)	5 (3)	10 (3)
Charging Pump gear oil cooler	2	0.0225×10^6	0.045×10^6 (6)	5 (3)	10 (3)
Charging Pump Bypass	1	-	-	60 (3)	60 (3)
Component Cooling Water Pump Motor	2	0.17×10^6	0.34×10^6 (6)	50	100

Table 9.2-9 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Recirculation

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
Totals					
		CCWS Loop 1		CCWS Loop 2	
Heat Load, BTU/hr		72.83×10^6		59.51×10^6	
Flow, gpm		7328		5728	

(1) CCW flow assumed to be shut off, for slow speed operation in the active loop.
(2) Flow reduced from the normal 1800 gpm, to allow slow speed operation of the CC pump in the active loop.
(3) The total flow of Component Cooling water to the branch serving the Charging pump is 70 GPM. The 70 GPM flow includes the 5 GPM used for lube oil cooling, 5 GPM for gear oil cooling, and the remainder passes through a flow balancing bypass at the inlet to the pump cooling water piping. The flow totals are based on the 70 GPM flow required to the branch.
(4) Based on 72 assemblies at 21 days and 1709 assemblies cooled for > 18 months.
(5) Flow exists if respective CCWS pump is running.
(6) Essential Load
(7) Excess letdown valve must be closed by operator if it was not closed. Letdown flow is shut by letdown temperature control.
{ } Units receiving CCWS flow.

Table 9.2-10
CCWS Cooling Water Supply and Heat Removal Requirements
Hot Standby, Loss of Offsite Power

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
RHR Heat Exchangers	-	-	-	-	-
Spent Fuel Heat Exchangers	1	13.32×10^6	13.32×10^6 (3)	1800	1800
Letdown Heat Exchanger	1	5.21×10^6	5.21×10^6	155	155
Excess Letdown Heat Exchanger	-	-	-	-	-
Reactor Coolant Pumps	-	-	-	216	648
Seal Water Heat Exchanger	1	1.5×10^6	1.5×10^6	250	250
Recycle Evaporator Package	(1)	-	-	780(1)	780 (1)
Recycle Evaporator Sample Cooler	(1)	-	-	10(1)	10 (1)
Reactor Coolant Drain Tank Heat Exchanger	1	-	-	240	240
Waste Evaporator	(1)	-	-	780(1)	780 (1)
Waste Gas Compressors	(2)	-	-	50(1)	100 (1)

Table 9.2-10 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Hot Standby, Loss of Offsite Power

Equipment	Units in Service	Heat Load (BTU/hr, each)	Total Heat Load (BTU/hr)	Required Flow (gpm, each)	Total Flow (gpm)
Waste Evaporator Sample Cooler	(1)	-	-	10 (1)	10 (1)
Sample Heat Exchangers	7	0.212×10^6	1.5×10^6	-	(1)
RHR Pumps	(1)	-	-	5	10
Waste Process System Recombiner	1(2)	0.07×10^6	0.07×10^6	10	20
Radiation Monitors	1	-	-	3	3 (4)
Charging Pump oil coolers	1	0.028×10^6	0.056×10^6 (5)	5 (2)	5 (2)
Charging Pump gear oil cooler	1	0.0225×10^6	0.045×10^6 (5)	5 (2)	50 (2)
Charging Pump Bypass	1	-	-	60 (2)	60 (2)
Component Cooling Water Pump Motor	1	0.17×10^6	0.17×10^6 (5)	50	50

Table 9.2-10 (continued)
CCWS Cooling Water Supply and Heat Removal Requirements
Hot Standby, Loss of Offsite Power

Totals	
Heat Load, BTU/hr	21.82×10^6
Flow, gpm	5019

(1) Flows can be shut off.
(2) The total flow of Component Cooling water to the branch serving the Charging pump is 70 GPM. The 70 GPM flow includes the 5 GPM used for lube oil cooling, 5 GPM for gear oil cooling, and the remainder passes through a flow balancing bypass at the inlet to the pump cooling water piping. The flow totals are based on the 70 GPM flow required to the branch.
(3) Based on 72 assemblies at 21 days and 1709 assemblies cooled for > 18 months.
(4) Flow exists if respective CCWS pump is operating.
(5) Essential Load
{ } Units receiving CCWS flow.

Table 9.2-11
Component Cooling Water System Single Failure Analysis

	Component	Malfunction	Components and Consequences
1.	Component Cooling Pumps	Rupture of Pump casing	The casing is designed for 200 psig and 200° F. The pump is protected from over pressurization by a relief valve in the discharge line. The pumps are inspectable and are located in the Intermediate Building, protected against credible missiles. All pumps can be isolated from the system.
2.	Component Cooling Pump	Standby pump fails to start	The pump in the inactive loop is started to ensure that required safety functions of the system are satisfied.
3.	Component Cooling Heat Exchanger	Shell or tube rupture	A very unlikely event. However, the heat exchanger can be isolated from the system.
4.	Piping	Pipe Crack	Since this system is low energy, only through wall leakage cracks are postulated. The maximum postulated pipe crack size would require isolation of one CCW loop. The other loop will remain operable to provide cooling water to system heat loads. (Per BTPAPCSB3-1, a failure in the redundant train need not be postulated.)

Table 9.2-12
Major Component Cooling Water System Components

Component Cooling Pumps	
Quantity	3
Type	Horizontal, single stage, centrifugal
Location	Intermediate Building, elevation 412’
Safety Class	2b
Rated Operating Speed (low/high), rpm	880/1170
Rated Capacity (low speed/high speed), gpm	7200/11,700
Rated Total Dynamic Head (low speed/high speed), ft	100/165 (1)
Materials	
Casing	Cast steel
Impeller	Cast steel
Shaft	Stainless steel
Motor	
Two Speed	
Voltage Rating	6900 volts a-c
Rated Horsepower	
Low Speed	Approximately 340
High Speed	Approximately 600
Component Cooling Heat Exchangers	
Quantity	2
Type	Horizontal, shell and tube
Location	Intermediate Building elevation 412’
Safety Class	2b

(1) Design Requirements are performance conditions specified for heat exchanger design and may not match specific operating conditions.

Table 9.2-12 (continued)
Major Component Cooling Water System Components

Material		
Shell	Carbon steel	
Tube	Stainless steel	
Size (approx.) ft	50 x 7-1/2	
Design Requirements (Peak Heat Load) (1)	Shell	Tube
Flow, gpm	11,700	9,000
Pressure Drop, max, psi	15	10
Pressure, psig	150	65
Heat Transfer, BTU/hr	130×10^6	
Water Inlet Temp., °F	-	95
Water Outlet Temp., max, °F	120	-
Component Cooling Heat Exchangers		
Alternate Design Requirements (Normal Heat Load) (1)	Shell	Tube
Flow, gpm	7185/5320	9,000
Heat Transfer, BTU/hr	44.5×10^6	
Surge Tank		
Quantity	1	
Type	Cylindrical, bottom half divided into two compartments	
Location	Auxiliary Building elevation 463’	
Safety Class	2b	

(1) Design Requirements are performance conditions specified for heat exchanger design and may not match specific operating conditions.

Table 9.2-12 (continued)
Major Component Cooling Water System Components

Capacity	
Total, gal	2300
Each Compartment, gas usable	Usable Surge Capacity Available to Accommodate Inleakage and Thermal Expansion (total), gallons 567
	Usable Surge Capacity Available Below Divider Plate to Accommodate Out-leakage (per compartment), gallons 626
Material	Carbon steel
Overpressure Protection, psig	+3
Component Cooling Water Booster Pumps	
Quantity	3
Type	Horizontal, single stage centrifugal
Location	Intermediate Bldg., Elev. 412’
Safety Class	2b
Rated Operating Speed, RPM	3450
Rated Capacity, gpm	120
Rated Total Dynamic Head, ft	106
Materials	
Casing	SA-351 Gr CF8M
Impeller	A-351 Gr 316SS
Shaft	A-479 Gr 316SS
Motor	
Voltage Rating, Volts a-c	460
Rated Horsepower	9.5

Table 9.2-15
Maximum SWP Intake Temperature During a LOCA(1)

SWP Surface Elevation Feet	Maximum Intake Temperature °F	Intake Temperature at LOCA Initiation °F
414.75	95.12	90.92
415	95.06	90.88
417.5	94.44	90.49

Maximum Intake Temperature During Normal Shutdown(1)

SWP Surface Elevation Feet	Maximum Intake Temperature °F	Intake Temperature at LOCA Initiation °F
414.75	95.04	90.90
415	94.97	90.86
417.5	94.33	90.48

(1) Maximum calculated values without taking into account Technical Specification limits established in Reference [6]. Under the most adverse conditions with the service water intake structure temperature and the SWP level limited to the Technical Specification values of 90.5°F and 416.5', respectively, the design basis maximum service water intake structure temperature of 95°F is not exceeded.

Table 9.2-16
Condensate Storage Tank Data

Capacity, gal	500,000
Diameter, ft	47
Height, ft	41
Material	Carbon steel
Internal Coating	Inert plastic

Table 9.2-17
Reactor Makeup Water System Component Data

Reactor Makeup Water Pumps	
Quantity	2
Type	Canned, end suction, centrifugal
Design Flow, gpm	150
Design Head, ft	400
Speed, rpm	3450
Power required, full load kW	51
Power supply, volts	460, 3 Ø
Materials	Wetted parts, austenitic stainless steel
Connections	Flanged; 2 inch discharge, 3 inch suction
Safety Class	2b
Code	ASME III, Class 3
Reactor Makeup Water Storage Tank	
Type	Cylindrical, vertical
Capacity, gal	100,000
Design Pressure	Atmospheric
Safety Class	2b

Figure 9.2-1
DRAWING D-302-221
FSAR FIGURE REFERENCE

Figure 9.2-2, Sheet 1
DRAWING D-302-222
FSAR FIGURE REFERENCE

Figure 9.2-2, Sheet 2
DRAWING D-302-222
FSAR FIGURE REFERENCE

Figure 9.2-2, Sheet 3
DRAWING D-302-222
FSAR FIGURE REFERENCE

Figure 9.2-2, Sheet 4
DRAWING D-302-222
FSAR FIGURE REFERENCE

Figure 9.2-3
DELETED BY AMENDMENT 95-04

Figure 9.2-4
DRAWING D-302-611
FSAR FIGURE REFERENCE

Figure 9.2-5
DRAWING D-302-612
FSAR FIGURE REFERENCE

Figure 9.2-6
DRAWING D-302-613
FSAR FIGURE REFERENCE

Figure 9.2-7
DRAWING D-302-614
FSAR FIGURE REFERENCE

Figure 9.2-8
DRAWING D-302-161
FSAR FIGURE REFERENCE

Figure 9.2-9
DRAWING D-302-163
FSAR FIGURE REFERENCE

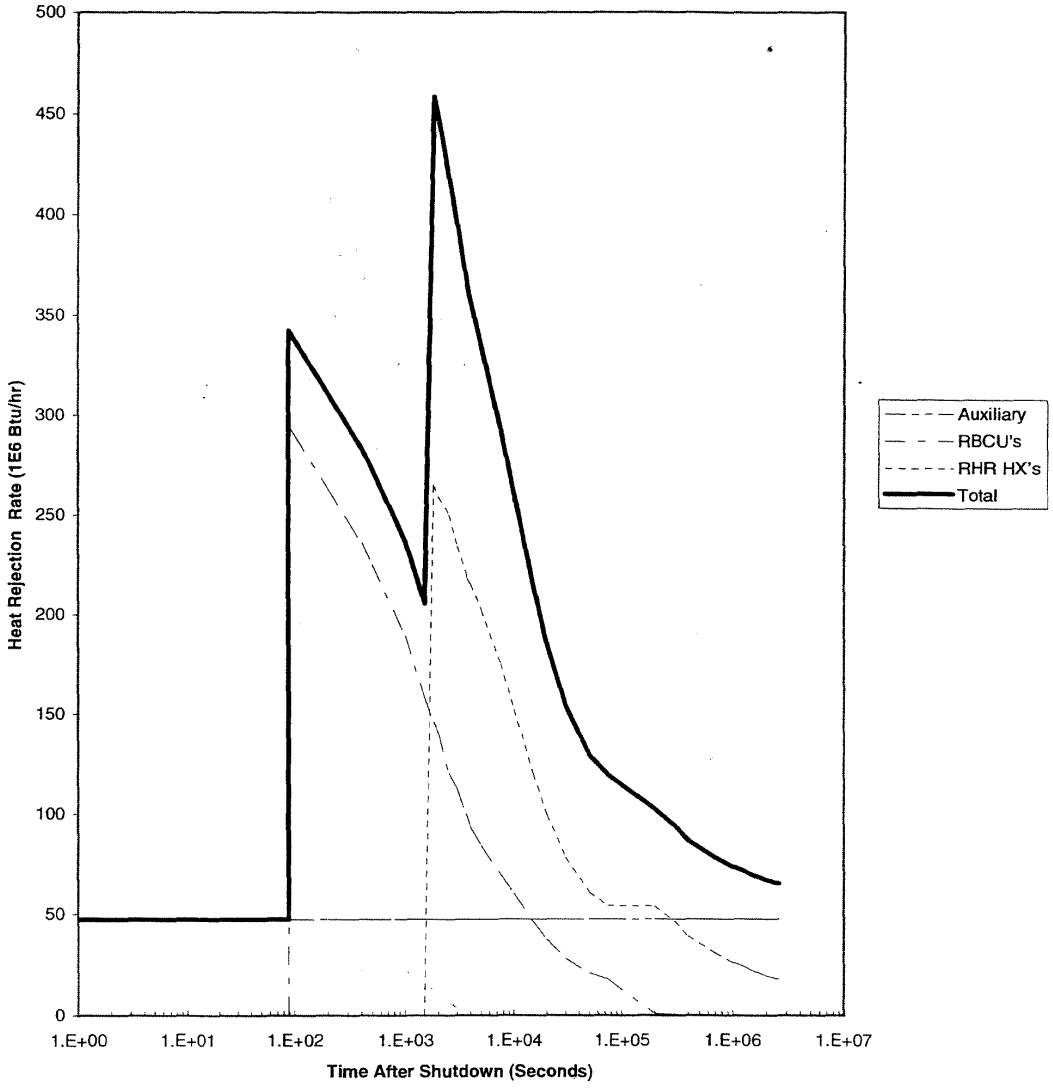
Figure 9.2-9a
DRAWING D-302-162
FSAR FIGURE REFERENCE

Figure 9.2-9b
DRAWING D-302-164
FSAR FIGURE REFERENCE

Figure 9.2-9c
DRAWING D-302-167
FSAR FIGURE REFERENCE

Figure 9.2-10

HEAT REJECTION TO SERVICE WATER POND UNDER LOCA CONDITIONS



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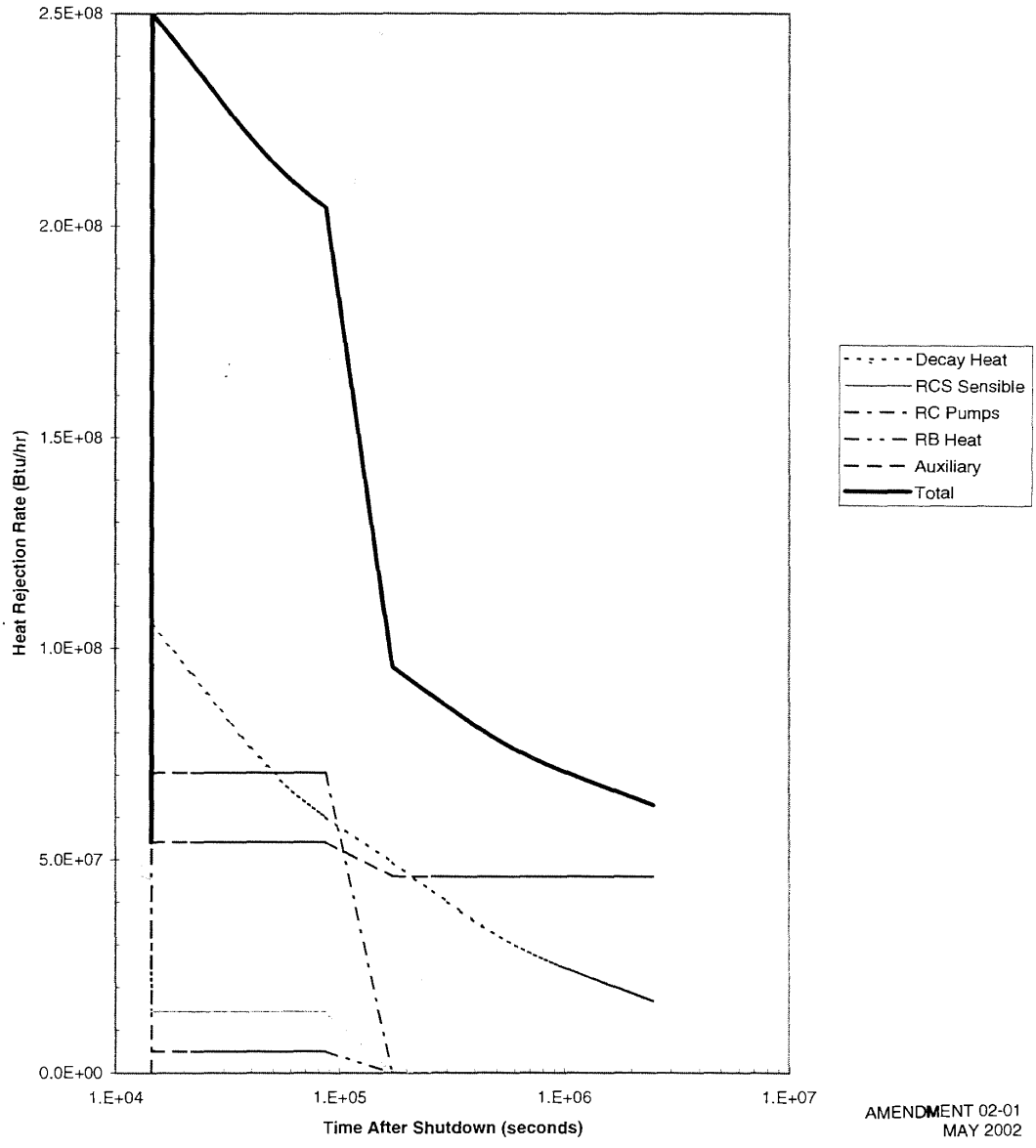
MAY 2002

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Heat Rejection to Service Water Pond Under LOCA Conditions Figure 9.2-10

Figure 9.2-11

HEAT REJECTION TO SERVICE WATER POND UNDER NORMAL SHUTDOWN CONDITIONS

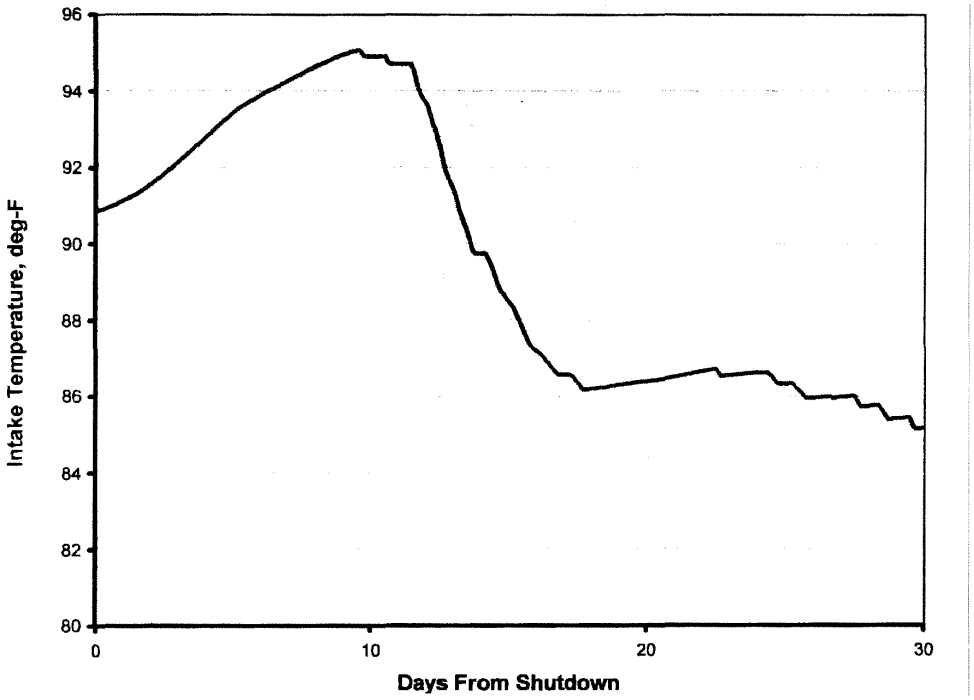


AMENDMENT 02-01
MAY 2002

SOUTH CAROLINA GAS & ELECTRIC CO VIRGIL C. SUMMER NUCLEAR STATION
Heat Rejection to Service Water Pond Under Normal Shutdown Conditions Figure 9.2-11

Figures 9.2-12 - 9.2-15
DELETED PER RN01-098

Figure 9.2-16
SERVICE WATER INTAKE TEMPERATURES
DURING LOCA SHUTDOWN



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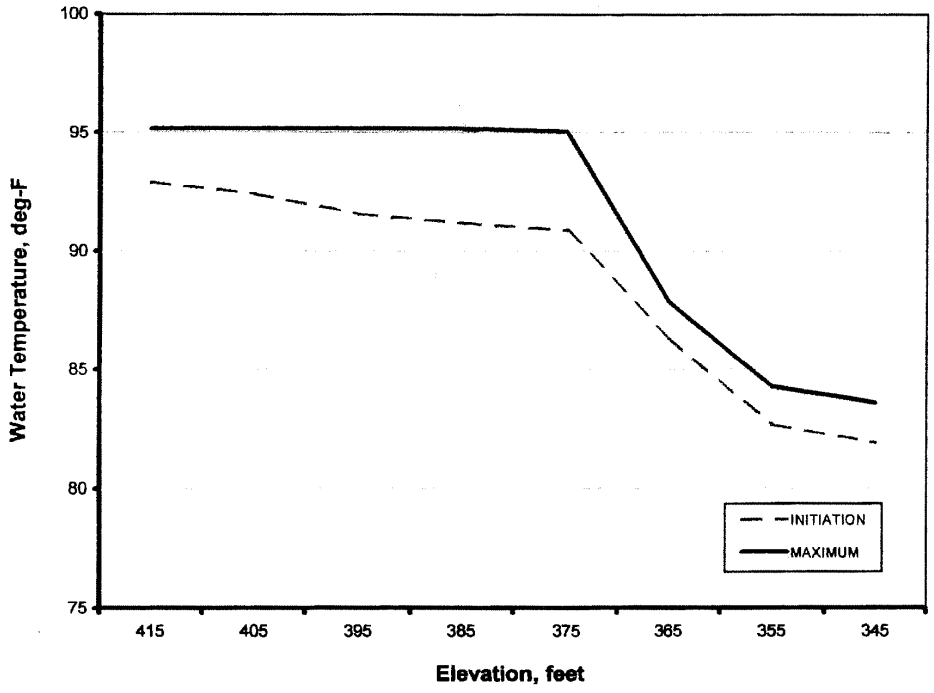
MAY 2002

SOUTH CAROLINA ELECTRIC AND GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Service Water Intake Temperatures During LOCA Shutdown Figure 9.2-16

Figures 9.2-17 - 9.2-21
DELETED PER RN 01-098

Figure 9.2-22
VERTICAL TEMPERATURE DISTRIBUTION DURING LOCA



AMENDMENT 02-01
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SOUTH CAROLINA ELECTRIC AND GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Vertical Temperature Distribution During LOCA Figure 9.2-22

Figure 9.2-23
DELETED PER RN 01-098

Figure 9.2-24
DRAWING D-302-791
FSAR FIGURE REFERENCE

9.3 PROCESS AUXILIARIES

9.3.1 Compressed Air Systems

The compressed air systems include the Station Service Air System, Instrument Air System, the condensate polisher compressed air system (see Section 10.4.6) and Reactor Building Instrument Air System. The Station Service Air System provides air for general plant use. The Instrument Air System provides air for instruments and controls. The Reactor Building Instrument Air System provides clean, dry air for Nuclear Steam Supply System (NSSS) instruments and valves inside the Reactor Building. Breathing air, when required, is obtained from the backup instrument air compressor.

9.3.1.1 Design Bases

The compressed air systems are designed to satisfy NSSS and balance of plant (BOP) requirements for compressed air. Piping and valves associated with the compressed air systems, except for Reactor Building penetrations, are designed, fabricated, inspected and erected in accordance with ANSI B16.5 (Reference 1) and ANSI B31.1 (Reference 2). Piping and valves between and including containment isolation valves are designed, fabricated, inspected and erected in accordance with the requirements of the ASME Code, Section III, Class 2. Receiver tanks are designed, fabricated, inspected and erected in accordance with ASME Code, Section VIII, Division 1, requirements.

Seismic classification of compressed air system components is as follows:

1. Seismic Category 1

   Reactor Building piping penetrations and process piping between and including containment isolation valves.

2. Nonseismic Category

   Remaining Service Air System piping and Instrument Air System piping.

Containment isolation valves are provided on each Reactor Building penetration for isolation during a postulated loss of coolant accident (LOCA). Isolation valves are provided on equipment and components for maintenance purposes.

Air compressors are supplied with electric power from 480 volt buses.

9.3.1.2 System Description

Figures 9.3-1 through 9.3-3a provide compressed air system diagrams. Design parameters for major system components are presented in Table 9.3-1.

Two (2) electric motor driven, full capacity, oil-free rotary screw compressors located in the turbine room supply compressed air to the Station Service Air System and Instrument Air System. The air compressors take suction locally and discharge to the common air receiver. Each air compressor motor receives electric power from a different non-safety related 480 volt bus and is controlled locally or from the control room. Control switches permit placing 1 air compressor in operation and the other in standby. The standby air compressor is activated by a pressure switch mounted on the air receiver if air receiver pressure decreases to less than a predetermined value.

A normally open valve (with limit switches) interconnects the Instrument Air System with the instrument air system backup compressor, including its air receiver, filter and dryer. This provides the Instrument Air System with a third compressor, and each is a standby to the other with similar controls.

When required, the instrument air backup compressor is isolated from the system and its output is totally dedicated to breathing air.

The instrument air backup compressor receives electric power from a 480 volt diesel bus which is isolated in the event of loss of offsite power or safety injection. In the event of a loss of offsite power, this compressor can be manually loaded onto the diesel bus after the operator has determined that all automatically sequenced loads have started. The instrument air backup compressor is an air cooled unit.

A diesel driven, full capacity, oil-free rotary screw compressor located outside of the Turbine Building is provided with an underground pipe connection to the main air receiver discharge. A moisture separator is installed inside the Turbine Building to protect the air system from moisture slugs. This connection allows the diesel driven compressor to supply the Station Service Air or Instrument Air System and provides an additional back-up air supply. The line from the compressor is provided with a check valve to prevent air loss if the compressor fails. The diesel driven compressor is activated by a pressure switch mounted downstream of the check valve if instrument air pressure decreases to less than a predetermined value.

Station Service Air is distributed to quick disconnect hose connections for use throughout the plant. A backpressure regulated valve is provided in the line supplying station service air to isolate the Station Service Air System in the event of low pressure in the Instrument Air System. Reactor Building service air is supplied by the Station Service Air System through a removable spool piece. The only anticipated need for service air within the Reactor Building is for the performance of maintenance during outages. During normal operation, the Reactor Building service air line is disconnected from the service air piping by closing the containment isolation valve and removing the spool piece.

Instrument air is filtered to remove particles larger than 5 microns and dried to a dew point of -40°F at 100 psig. Each of the two dryers have a prefilter and afterfilter which are provided for ease of maintenance. The dryer is of the electrically heated, dual chamber, desiccant type with full flow automatic bypass piping. The Instrument Air System serves as a backup for the Reactor Building Instrument Air Services.

Two (2) electric motor driven, full capacity, nonlubricated, reciprocating type air compressors located in the penetration access area supply air for the Reactor Building Instrument Air System. The air compressors take suction from the Reactor Building and discharge to air receivers.

Each Reactor Building instrument air compressor receives electric power from a different 480 volt, nonessential bus and is controlled locally or from the control room. Switches are provided which allow either constant speed control or automatic start/stop air compressor operation. Under constant speed control, when demand decreases, the air compressor continues to operate but is unloaded. When automatic start/stop is selected, the air compressor stops when demand decreases and starts when demand increases.

Reactor Building instrument air is filtered to remove particles larger than 5 microns and dried to a dew point of 35°F at 100 psig. Two (2) full capacity, refrigerated type dryers with integral moisture separators are provided for this service. Condensate drains from the dryers, moisture separators and air receivers are piped to the nuclear drain system for sampling and disposal, due to the possibility of radioactive contamination of the system. If Reactor Building instrument air system pressure decreases to less than 90 psig, the backup instrument air valve automatically opens to supply air from the Instrument Air System.

Cooling water required for the station service and instrument air compressor water jackets and interstage coolers is supplied from the turbine building closed cycle cooling water system. Cooling water required for the reactor building instrument air compressor water jackets and aftercoolers is supplied from the Industrial Cooling Water System.

9.3.1.3 Safety Evaluation

Neither the Station Service Air System, the Instrument Air System, Instrument Air Backup System nor the Reactor Building Instrument Air System is required to mitigate the consequences of a LOCA or to achieve safe shutdown. Instruments and controls served by the Instrument Air System and the Reactor Building Instrument Air System are: 1) non-nuclear safety class and are either not required to function during a LOCA or to achieve safe shutdown; 2) nuclear safety class and fail in a safe position after loss of air supply. The only air operated devices which do not fall into one of the 2 categories described above are the feedwater isolation valves, the control room outside air dampers, the emergency feedwater system control valves and the turbine driven steam isolation valve. These air operated devices are equipped with safety related air volume tanks or accumulators.

The fire service to diesel generator cooling water isolation valves are equipped with quality related air accumulators.

Reactor building instrument air system containment isolation valves are normally open. Status lights are provided in the control room to indicate the position of these valves. Automatic closure of these containment isolation valves is initiated by receipt of a containment isolation Phase A signal.

The reactor building service air line is normally disconnected from the service air piping by a closed isolation valve and removal of the spool piece. No outleakage through the reactor building service air line is anticipated during a LOCA or under other emergency conditions.

The breathing air system containment isolation valves are normally locked closed. They will be permitted to be opened under administrative control during refueling and maintenance shutdown periods.

9.3.1.4 Testing and Inspection

Operability and performance of the air compressors is verified during normal operation of the systems.

Air compressors are subjected to manufacturer's performance testing. In addition, the completed compressed air systems are subjected to preoperational testing under design conditions.

9.3.1.5 Instrumentation Requirements

Instrumentation and controls for the compressed air systems are provided, as shown by Figures 9.3-1 through 9.3-3a to control and monitor system operation and the performance of equipment.

Local control panels are provided in the Turbine Building for the station service and instrument air compressors and in the penetration access area for the reactor building instrument air compressors. Operational control devices and monitoring instruments, as well as numerous alarms are provided on these control panels. In addition, air pressure and air flow rate are continuously monitored by local pressure indicators and flow elements mounted on the system piping. The presence of any alarm condition at one of the local panels or switches results in annunciation at a common alarm in the control room. The Breathing Air System has a carbon monoxide monitor to monitor the breathing air for carbon monoxide concentration when breathing air is in use. An alarm results in a local alarm, a remote alarm in the Health Physics Laboratory and a compressor trip and subsequent alarm in the control room.

A local control panel is provided in the yard beside the diesel driven compressor. An operational control switch for the auto-start of the compressor is provided on this panel.

An additional panel is provided on the compressor skid. This panel provides additional operational control devices and alarms.

A control switch for each compressor except the diesel driven compressor is provided in the control room to permit remote operation.

9.3.2 Process Sampling System

Fluid system sampling capabilities are available at numerous local sampling points located throughout the plant. Samples requiring cooling and depressurization and which are, or may be, radioactive (and therefore require frequent monitoring) are piped to the nuclear sample room

through the Nuclear Sampling System. This system also provides continuous, automatic analysis of steam generator secondary side water (see Section 10.3.5 for details). In addition, the Nuclear Sampling System provides centralized sampling of vital process fluids. For turbine cycle sampling, see Section 10.3.5. The system also has the capability to sample the Reactor Coolant System during post-accident conditions.

9.3.2.1 Design Bases

The design bases for the nuclear sampling system are as follows:

1. Cool and depressurize liquid samples.
2. Provide a minimum delay of 60 seconds for reactor coolant samples, thus allowing sufficient time for N16 to decay to acceptable levels prior to leaving the Reactor Building.
3. Provide a hooded sample sink suitable for sample collection and disposition of wastes to the waste holdup tank.
4. Provide ample ventilation to protect personnel from inhalation of radioactive gases and vapors.
5. Provide demineralized rinse water.
6. Provide sufficiently high fluid velocity during purging of the lines and during sampling to retain solid particles in suspension.
7. Use lines as small as possible to control purge volumes.
8. Provide for obtaining all samples manually in accordance with a specified schedule.
9. Provide capability for purging sample lines and equipment so that representative samples are obtained. Plateout of samples is reduced by maintaining sample velocities of 2.0 ft/sec.
10. Provide for measurement of temperature, pressure and purge flow rate for each sample point.
11. Provide passive flow restriction by use of 3/8 inch OD (0.245 inch ID) tubing which restricts flow sufficiently that a passive failure of a downstream component does not prevent a safety system function required for a Condition III or Condition IV event.
12. Provide a special sampling panel for reactor coolant and RHR systems which allows for post accident sampling of these systems.
13. Provide shielding for personnel protection consistent with GDC-19.

System equipment and components are classified in accordance with the safety classifications discussed in Section 3.2. Construction of safety class equipment and components is in accordance with the ASME Code, Section III. Seismic design and safety classification of sampling lines and components conform to the classification of the system to which each sampling line is connected. The degree of compliance with Regulatory Guides 1.26 and 1.29 is discussed in Appendix 3A. Components and piping downstream of the second isolation valve are designed to non-nuclear safety class and non-Seismic Category 1 requirements. Radiation shielding is provided to protect personnel from exposure to lines or equipment containing radioactive fluids for all types of sampling (See FSAR Appendix 12A for radiation exposure and shielding discussion).

Provision is made for continuous flow through the sample lines from the steam generator secondary sides. Shutoff valves, which close upon receipt of a containment isolation signal (Phase A), are provided. These valves are also interlocked such that they close upon receipt of an emergency feedwater start signal, but these interlocks may be overridden by operation of a switch located at the sampling rack. This switch does not, however, override the containment isolation signal (Phase A).

9.3.2.2 System Description

The Nuclear Sampling System diagram is presented by Figures 9.3-4 and 9.3-20. Points sampled by the system are tabulated in Table 9.3-2.

Tubing from each of the nuclear sampling system sample points is routed to the nuclear sample room, located at the northwest corner of the nuclear control access area at elevation 412'. Shielding is provided for these lines where required to minimize personnel exposure.

The sampling system for obtaining a reactor coolant sample following a TMI-2 type accident will have sufficient shielding to limit general plant personnel whole body exposure to significantly less than 70 mr/hr during use of the system.

Operators of the sampling system will be protected from excessive radiation by the use of lead shielding as for example, the on-line monitors will have a 4 inch thick lead brick wall to limit whole body exposure to significantly less than 70 mr/hr. Transportable sample bombs containing the diluted liquid sample and the containment air sample may be shielded to minimize exposure to radiation during transport to the Radio-Chem Laboratory or count room for the required analyses. Slightly higher exposure may be experienced by the operators at the hands and fingers when the sample bombs are removed from their attachment point.

Dilution of the sample will minimize exposure of laboratory personnel to radiation during analysis of the samples.

System isolation valves, penetration isolation valves, test connections and reactor coolant N16 delay coils are located in the Reactor Building. Residual heat removal system isolation valves, the chemical and volume control system N16 delay coils, test vent connections and penetration isolation valves are located in the Auxiliary Building. The majority of the balance of valves and equipment are located in the nuclear sample room in the Control Building. Samples from the following extraction points are cooled using heat exchangers served by the Component Cooling Water System:

1. Residual heat removal loops (2 points).
2. Pressurizer liquid and steam spaces (2 points).
3. Reactor coolant loop B (hot leg).
4. Reactor coolant loop C (hot leg).
5. Steam generator A, secondary water (shell and blowdown).

6. Steam generator B, secondary water (shell and blowdown).
7. Steam generator C, secondary water (shell and blowdown).

An auxiliary cooler is provided for points 1 through 4 to assure samples are at required temperatures during periods of high sample flow rates.

Samples from points 5 through 7 and from accumulators A, B and C are depressurized by use of globe type throttle valves located where flashing of the sample fluid to steam does not occur.

Samples from the reactor coolant loops pass through a delay coil designed to allow sufficient time for decay of N16 prior to leaving the Reactor Building. Sample lines from extraction points 5 through 7, above, provide continuous flow of secondary fluid from the steam generators (see Section 10.3.5).

All liquids are routed to the sample sinks where purging samples can be individually collected. Mixing of primary and secondary fluids is prevented by the use of separate subsystems without interties as shown by Figures 9.3-4 and 9.3-20. Purge volumes from primary extraction points are routed to the volume control tank or waste holdup tank and for the accident case, to the pressurizer relief tank. Upon completion of purging, samples can be routed to the sample sink. Sufficient volume is drawn into the sink prior to taking the sample to purge the line from the normal purge path to the sink to assure a representative sample. The liquid in the sample sink from purging and sampling is routed to the waste holdup tank. Purge volumes from secondary system extraction points are routed to a separate sink and thence to the nuclear blowdown holdup tank.

Extraction points 1 through 4 are directed through a special sampling panel which is designed to be used for both normal and post-accident sampling. Liquid can be analyzed for dissolved solids and isotopes. Dilution of the liquid sample can be accomplished.

In addition to the sample points which require cooling and depressurization, as previously described, there are numerous local sample points throughout the plant. Local sample points on tanks are either on the discharge side of the corresponding pump or the tank has the capability of being recirculated to ensure that samples are representative. Sample lines are purged for a sufficient period of time prior to sample extraction to remove sediment deposits and air and gas pockets.

Remote manual, fail closed, solenoid valves are the primary functional valves used during sampling and for shutoff of sample lines leaving the Reactor Building and certain other high pressure, high temperature extraction points. These valves are located close to the point where the process system is tapped. Air operated valves, located in the nuclear sample room are used for throttling, shutoff and sample routing. All containment isolation valves fail closed and are closed upon receipt of a containment isolation signal (Phase A). Test connections and test vents are provided in appropriate locations to permit leak testing of the containment isolation valves.

The special sampling panel has pneumatically operated valves for control of the sampling flow path.

For sampling of gases, refer to ANSI N13.1(Reference 3).

Component data are presented in Table 9.3-3.

9.3.2.3 Safety Evaluation

Those portions of the Nuclear Sampling System which interface with safety class systems or perform a containment isolation function are designated as Safety Class 3 or 2a. These portions of the system are designed in accordance with appropriate codes and standards as discussed in Section 3.2. The Nuclear Sampling System performs no additional safety related functions.

The seismic design and safety classification of sampling lines and components conform to the classification of the system to which each sampling line is connected. The degree of compliance with Regulatory Guides 1.26 and 1.29 is discussed in Appendix 3A. Components and piping downstream of the second isolation valve are designed to non-nuclear safety class and non-Seismic Category 1 requirements.

The system is designed to provide radiological protection consistent with GDC-19 and protection from industrial safety risks which could result from the high temperatures and pressures of some samples.

9.3.2.4 Testing and Inspection Requirements

Containment isolation valves are tested and inspected as described in Sections 6.2.4 and 6.2.6. Inservice inspection of ASME Class 2 and 3 components is discussed in Section 5.7.

Routine preventive maintenance requirements are stated in the station maintenance procedures.

9.3.2.5 Instrumentation Requirements

Nuclear sampling system instrumentation provides the signals required for reliable operation, control and performance/status monitoring of the system. Functional descriptions of system instrumentation are as follows:

1. Pressure Indicators

   Pressure indicators located throughout the system permit monitoring of the sample lines.

2. Temperature Indicators

   Temperature indicators located throughout the system permit monitoring of sample lines.

3. Flow Indicators

   Flow indicators permit monitoring of sample flow.

4. Radiation Monitor

   The radiation monitor, RM-L1, shown in Figure 9.3-4, measures gross gamma activity from the reactor coolant letdown line. An increase in the activity level in this line may be indicative of a fuel clad failure. This condition also causes an alarm in the control room.

   The radiation monitor RE 6992 shown in Figure 9.3-20 measures gross gamma activity from extraction points 1 through 4, as described in Section 9.3.2.2.

9.3.3 Equipment and Floor Drainage System

9.3.3.1 Design Bases

To preclude backflooding as a cause of degradation of any safety related equipment or piping, an extensive network of 4 inch floor drains is provided in all buildings. Drain headers terminate in a series of sumps or tanks which are equipped with high level alarms. All sumps except the east penetration access, waste holdup tank room, chemical feed equipment drains and IB sump D-battery room sumps have automatic, redundant sump pumps. Engineered safety features equipment and piping areas are provided with floor drain sumps which are instrumented to actuate alarms in the control room when flow into the sumps exceeds the maximum expected flow of 45 to 50 gpm (alarm drains). All such alarms are audible at the main control board. Measurements, such as reactor building sump level, are displayed on the main control board. Separate drain systems are provided for reactor grade and low level waste depending upon the location served. These separate systems distribute drain flow to the proper sump or tank. Exact locations of equipment and piping and associated drain systems are shown by Figures 9.3-5 through 9.3-15 and are described in Section 9.3.3.2. Portions of the system which contain additional safety features are also discussed in Section 9.3.3.2. Reactor coolant leakage detection is discussed in Section 5.2.7.

Technical Requirements for steam propagation barriers/components (SPB) in the equipment and floor drainage system required to maintain area environmental conditions for equipment qualification (EQ) purposes are provided in plant procedures. These procedures specify the technical criteria for design, procurement, installation /maintenance and inspection of these QR components. Components may include orifice plates, check valves, or loop seals designed to segregate EQ zones to ensure that the conditions for which the equipment qualification were based on are not exceeded.

9.3.3.2 System Description

The equipment and floor drainage system and related sump pumping systems are shown by Figures 9.3-5 through 9.3-15.

1. Reactor Building

Reactor grade or low activity leakage may originate from equipment inside the Reactor Building. All floors above the basement, inside the Reactor Building, are interconnected by grating or are individual structural platforms which support equipment. Consequently, safety related equipment located at these levels cannot be backflooded during normal operation. In addition, floor drains and equipment drains are installed to isolate any leakage to the local floor area concerned. These drain headers, in addition to the ones in the basement, terminate inside and below the floor opening of the reactor building sump. The refueling cavity liner seepage detection trough is part of this system.

The incore instrument sump at elevation 387’-6" collects any leakage that occurs directly around the reactor vessel and instrument chase. This affords protection for the bottom of the hot reactor vessel and instrument cable bundles.

A removable spool piece is installed in the discharge line from the incore instrumentation sump to facilitate removal of reactor cavity leakage to the reactor coolant drain tanks during refueling outages.

The accumulated drainage or leakage flows in the Reactor Building or incore instrument sump are normally sent to the floor drain tank. If increased activity is detected, the flow is aligned to the waste holdup tank.

2. Fuel Handling Building

Four inch floor drains in the Fuel Handling Building discharge to a header in the Auxiliary Building. Normal low level effluent from this header flows to the Auxiliary Building sump. The spent fuel pool liner seepage detection trough is part of this system.

The Excess Liquid Waste System, located in a separate area of the Fuel Handling Building, has its own sump system which collects floor and equipment drains. No safety class equipment is contained in this area. The sump system includes three sumps, one for each of the decontamination pit collecting tank and excess waste holdup tank cubicles and one for the general area. All sump pumps discharge to the 10,000 gallon decontamination pit collecting tank or the 10,000 gallon excess waste holdup tank, both integral to the system. The sump system also collects low level effluent from the hot machine shop decontamination room trench drain.

3. Penetration Access Area

Floor and equipment drains in the penetration access areas flow to the 10,000 gallon floor drain tank located at the lowest level (elevation 374’-0") in the Auxiliary Building. This system contains alarm drains.

The component cooling surge tank, the reactor building instrument air compressors and dryers are all on the operating floor. The component cooling surge tank and the reactor building instrument air compressors are located in the personnel access area. The air dryers are in an area monitored by alarm drains. Main steam relief valve compartments on the mezzanine have floor drains. The basement penetration access area has floor drains and several alarm drains for leakage detection. Floor drains in the east penetration access area flow to a common sump in the basement. The sump pump discharges to the floor drain tank.

4. Auxiliary Building

   a. Drains to Waste Holdup Tank

      Reactor grade equipment drains and tank overflows in the Auxiliary Building flow to the 10,000 gallon waste holdup tank at the lowest level in the building. There are no floor drains or alarms associated with this system. Equipment drains in the sub-basement flow to the 1000 gallon miscellaneous waste drain tank. A small centrifugal pump empties this tank to the waste holdup tank at the same floor elevation.

   b. Drains to Floor Drain Tank

      Low activity floor and equipment drains above the mezzanine and approximately one-half of all floor and equipment drains at or below the mezzanine flow directly to the 10,000 gallon floor drain tank. Alarm drains for this portion of the system alert the operator to leakage from piping above shield slabs at elevations 426’-6" and 400’-0", residual heat removal heat exchangers at elevation 412’-0" and Safety Injection System low head piping and valve chambers at floor elevation 397’-0".

   c. Drains to Auxiliary Building Sump

      The balance of floor and equipment drains at or below the mezzanine flow to the 1,945 gallon Auxiliary Building sump at elevation 374’-0". Alarm drains for this portion of the system protect the gas decay tank valve gallery and the charging pumps at elevation 388’-0" and the reactor building spray pumps at elevation 374’-0". Sump pumps discharge to the floor drain tank.

   d. Other Auxiliary Building Sumps

      The boron recycle holdup tank room sump pumps at elevation 388’-0" discharge to the liquid waste holdup tank. The liquid waste holdup tank room area sump at elevation 374’-0" is pumped to the floor drain tank.

      Residual heat removal pump room sump B sump pumps at elevation 374’-0" normally discharge to the floor drain tank. Pump flow may be aligned to the waste holdup tank if necessary. Residual heat removal pump room sump A and the waste evaporator feed pump room sump contain no sump pumps. They drain to the residual heat removal pump room sump B.

      The Nuclear Blowdown System reservoir, at elevation 374’-0", collects effluent from the system demineralizers and floor drains at elevation 452’-6".

      Blowdown monitor and holdup tanks with demineralizers and pumps at elevation 436’-0", along with basement equipment and floor drains for this system also flow to the reservoir. Steam generator blowdown samples from the nuclear sampling room are drained to this reservoir. Reservoir sump pumps discharge to the blowdown holdup tank at elevation 436’-0".

5. Outside

The refueling water storage tank and reactor makeup water storage tank, located in an enclosure outside the Auxiliary Building at elevation 412’-0", are protected by sump pumps which discharge to a waste monitor tank.

The refueling water storage pit drain tank, installed on elevation 436’-0" northwest of refueling water storage tank sump, discharges the contents to a waste monitor tank if contents show unacceptable level of radioactivity, or to yard drainage system if contents show acceptable for release.

The sodium hydroxide storage tank is located in a cubicle outside the Auxiliary Building at elevation 412’-0". It is protected by sump pumps which discharge to the 10,000 gallon neutralization waste tank trench.

6. Intermediate Building

   The alarm drains from the shield slab which run between the penetration access areas at elevation 422’-3" flow to the east penetration access area sump. The contents of this sump are pumped to the floor drain tank.

   Three (3) Intermediate Building basement sumps contain a total of 6 pumps, each rated at 75 gpm. These sumps protect the component cooling water pumps and heat exchangers at the same level by discharging to the Turbine Building sump. Two (2) out of 3 sump high level alarms cause the main feedwater isolation valves and other valves to close and eliminate the most probable cause of flooding in this area (see Section 7.6).

7. Control Building

   Lavatories within the normal radiation control area, hot showers, hot laundry and the floor drains in these areas flow to the laundry and hot shower tank at elevation 374’-0" in the Auxiliary Building. Fume hood sinks in the radiochemical laboratory flow to the chemical drain tank, also at elevation 374’-0" in the Auxiliary Building. The sample sink and panel drains for steam generator blowdown empty into the nuclear blowdown reservoir. The primary sample sink drainage flows to the waste holdup tank. Floor and equipment drains for the 482’-0" elevation, (except the charcoal filter plenum drains) drain via the Turbine Building sump system. The charcoal plenums, most of the floor drains, sinks in the health physics laboratory and equipment drains in the radiochemical laboratory flow to the floor drain tank.

8. Tendon Access Gallery

   The tendon access gallery is provided with floor sumps which drain to a building sump. This building sump is equipped with sump pumps to pump sump contents to the Turbine Building sump.

9. Turbine Building Drains

The 250 gpm turbine room sump pumps discharge to the 6000 gallon (normal operating capacity) industrial and sanitary waste collection sump. This sump is located north of the substation fence. Releases to this system, associated with the remote possibility of low level activity spillage in the Turbine Building, are discussed in Section 11.2.7. Figure 9.3-15 illustrates this connection.

10. Valve Packing Box Leakage

    Valve packing box leakage is monitored by directing any leakage from 12 groups of packing boxes to level switches. The valve groups are illustrated by Figures 9.3-13 and 9.3-13a. Each of the 12 level switches actuates a local alarm annunciator and causes a common alarm in the control room if leakage from any valve in the associated group is detected.

11. Service Water Pump House

    Wall drains are provided in the piping pits on the 425’ level of the Service Water Pump House to allow the relief of internal flooding. A total of three drains, one in each piping pit, are at an elevation of 426’-11” and limit the height of internal flooding to below the height of any essential equipment in the pits. The drains release into the Service Water Bay and can be plugged in case of an external flooding event.

9.3.3.3 Safety Evaluation

The equipment and floor drain system has no active valves except for the Reactor Building sump drain system which is provided with containment isolation valves. These valves close automatically upon receipt of a Phase A containment isolation signal rendering the Reactor Building sump drains essentially inoperable.

Leakage detection floor alarm drains are provided to identify the most probable location of a leaking component or pipe line. These are located in those areas which contain safety class equipment and systems which are most important to safe plant operation. Alarm response time for leakage in excess of the maximum expected (i.e., 45 to 50 gpm) ranges from a few seconds for the alarm drains to less than 4 minutes for residual heat removal pump room B sump.

Alarm systems for greater than 1 gpm and greater than 10 gpm flow to the Reactor Building sump and an unidentified leakage indication alarm for the Incore Instrument Sump are provided. Level instruments are provided for the Reactor Building sump. The residual heat removal pump room sumps and the waste evaporator feed pump room sump are each equipped with alarms actuated by a flow of greater than 45 gpm to the sump. The residual heat removal pump rooms have a 1 foot high curb at the access openings and thus have the capacity to contain a 50 gpm leak in either room for greater than 30 minutes, without flooding equipment, if the sump pumps should fail. If the contents of either the recycle holdup tank or waste holdup tank should flood either tank compartment, the spillage into the recycle holdup tank compartment is pumped to the waste holdup tank and spillage into the waste holdup tank compartment is pumped to the floor drain tank. If sump pumps are inoperative, each compartment is designed to hold the tank contents.

The plant drain system assures that spillage is collected and can be processed before being recycled or released to the environment.

9.3.3.4 Testing and Inspection Requirements

The drain system is given an extensive check for leakage and proper routing prior to actual operation. Pumps are checked for level switch control and operation. Valves in sump pump systems are aligned as shown on various system flow diagrams. Systems can be checked periodically by utilizing local control switches. Alarms are calibrated locally and checked in the control room.

9.3.3.5 Instrumentation Requirements

Display instrumentation in the control room which is related to the reactor coolant pressure boundary leakage detection system is described in Section 5.2.7 as are the information displayed and allowance for operator action. Section 7.6 discusses system instrumentation in further detail.

9.3.4 Chemical and Volume Control System

The Chemical and Volume Control System (CVCS) is shown in Figure 9.3-16 (Sheets 1 through 5). It is designed to provide the following services to the reactor coolant system (RCS):

1. Maintenance of programmed water level in the pressurizer, i.e., maintain required water inventory in the RCS.
2. Maintenance of seal-water injection flow to the reactor coolant pumps.
3. Control of reactor coolant water chemistry conditions, activity level, soluble chemical neutron absorber concentration and makeup.
4. Emergency core cooling (part of the system is shared with the Emergency Core Cooling System).
5. Provide means for filling, draining and pressure testing of the RCS.

9.3.4.1 Design Bases

Quantitative design bases are given in Table 9.3-4 with qualitative descriptions given below.

9.3.4.1.1 Reactivity Control

The CVCS regulates the concentration of chemical neutron absorber (boron) in the reactor coolant to control reactivity changes resulting from the change in reactor coolant temperature between cold shutdown and hot full power operation, burnup of fuel and burnable poisons, buildup of fission products in the fuel, and xenon transients.

9.3.4.1.1.1 Reactor Makeup Control

1. The CVCS is capable of borating the RCS through either 1 of 2 flow paths and from either 1 of 2 boric acid sources.
2. The amount of boric acid stored in the CVCS always exceeds that amount required to borate the RCS to cold shutdown concentration assuming that the control assembly with the highest reactivity worth is stuck in its fully withdrawn position. This amount of boric acid also exceeds the amount required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

9.3.4.1.1.2 Boron Thermal Regeneration

The load following capabilities of the Boron Thermal Regeneration System were removed by plant modification MRF 21511. The system continues to be used as deborating demineralizers to reduce reactor coolant boron concentration towards the end of core life. The Boron Thermal Regeneration System (BTRS) also is used to cool the letdown flow for enhanced RCP seal performance and to clean up the RCS before shutting down the reactor.

9.3.4.1.2 Regulation of Reactor Coolant Inventory

The CVCS maintains the coolant inventory in the RCS within the allowable pressurizer level range for normal modes of operation including startup from cold shutdown, full power operation and plant cooldown. This system also has sufficient makeup capacity to maintain the minimum required inventory in the event of minor RCS leaks (see Technical Specifications for a discussion of maximum allowable RCS leakage).

9.3.4.1.3 Reactor Coolant Purification

The CVCS is capable of removing fission and activation products, in ionic form or as particulates, from the reactor coolant in order to provide access to those process lines carrying reactor coolant during operation and to reduce activity releases due to leaks.

9.3.4.1.4 Chemical Additions for Corrosion Control

The CVCS provides a means for adding chemicals to the RCS which control the pH of the coolant during initial startup and subsequent operation, scavenge oxygen from the coolant during startup, and counteract the production of oxygen in the reactor coolant due to radiolysis of water in the core region.

The CVCS is capable of maintaining the oxygen content and pH of the reactor coolant within limits specified in Table 5.2-10.

9.3.4.1.5 Seal Water Injection

The CVCS is able to continuously supply filtered water to each reactor coolant pump seal, as required by the reactor coolant pump design. In situations where the charging pumps are not available, the seals can be supplied by the Alternate Seal Injection Pump.

9.3.4.1.6 Emergency Core Cooling

The centrifugal charging pumps in the CVCS also serve as the high-head safety injection pumps in the Emergency Core Cooling System. Other than the centrifugal charging pumps and associated piping and valves, the CVCS is not required to function during a loss of coolant accident (LOCA). During a LOCA, the CVCS is isolated except for the centrifugal charging pumps and the piping in the safety injection path and the reactor coolant pump seal injection path. Also, at strategically identified local high points, the CVCS is provided with indicating air-traps to ensure that the ECCS portions of the CVCS remain void free (reference NRC GL 2008-01).

9.3.4.2 System Description

The CVCS is shown in Figure 9.3-16 (Sheets 1 through 5) with system design parameters listed in Table 9.3-4. The CVCS consists of several subsystems: the charging, letdown and seal water system; the reactor coolant purification and chemistry control system; the reactor makeup control system; and the boron thermal regeneration system.

9.3.4.2.1 Charging, Letdown and Seal Water System

The charging and letdown functions of the CVCS are employed to maintain a programmed water level in the RCS pressurizer, thus maintaining proper reactor coolant inventory during plant operation. This is achieved by means of continuous feed and bleed process during which the feed rate is automatically controlled based on pressurizer water level. The bleed rate can be chosen to suit various plant operational requirements by selecting the proper combination of letdown orifices in the letdown flow path. Normal letdown flow consists of the flow from a single 60 gpm letdown orifice or any combination of two orifices aligned in parallel.

Reactor coolant is discharged to the CVCS from a reactor coolant loop crossover leg; it then flows through the shell side of the regenerative heat exchanger where its temperature is reduced by heat transfer to the charging flow passing through the tubes. The coolant then experiences a large pressure reduction as it passes through the letdown orifice(s) and flows through the tube side of the letdown heat exchanger where its temperature is further reduced. Downstream of the letdown heat exchanger a second pressure reduction occurs. This second pressure reduction is performed by the low pressure letdown valve, the function of which is to maintain upstream pressure thus preventing flashing downstream of the letdown orifices.

The coolant then flows through one of the mixed bed demineralizers. The flow may then pass through the cation bed demineralizer which is used intermittently when additional purification of the reactor coolant is required.

The letdown flow leaving the demineralizers may be directed to the Boron Thermal Regeneration System. The coolant then flows through the reactor coolant filter and into the volume control tank through a spray nozzle in the top of the tank. Hydrogen (from the gaseous waste processing system) is continuously supplied to the volume control tank where it mixes with fission gases which are stripped from the reactor coolant into the tank gas space. The contaminated hydrogen is vented back to the Gaseous Waste Processing System. The partial pressure of hydrogen in the volume control tank determines the concentration of hydrogen dissolved in the reactor coolant for control of oxygen produced by radiolysis of water in the core.

Three (3) centrifugal charging pumps are provided to take suction from the volume control tank and return the cooled, purified reactor coolant to the RCS. Normal charging flow is handled by 1 of the 3 charging pumps. This charging flow splits into 2 paths. The bulk of the charging flow is pumped back to the RCS through the tube side of the regenerative heat exchanger. The letdown flow in the shell side of the regenerative heat exchanger raises the charging flow to a temperature approaching the reactor coolant temperature. The flow is then injected into a cold leg of the RCS. Two (2) charging paths are provided from a point downstream of the regenerative heat exchanger. A flow path is also provided from the regenerative heat exchanger outlet to the pressurizer spray line. An air operated valve in the spray line is employed to provide auxiliary spray to the vapor space of the pressurizer during plant cooldown. This provides a means of cooling the pressurizer near the end of plant cooldown, when the reactor coolant pumps, which normally provide the driving head for the pressurizer spray, are not operating.

A portion of the charging flow is directed to the reactor coolant pumps (nominally 8 gpm per pump) through a seal water injection filter. It is directed down to a point between the pump shaft bearing and the thermal barrier cooling coil. Here the flow splits and a portion (nominally 5.5 gpm per pump) enters the RCS through the labyrinth seals and thermal barrier. The remainder of the flow is directed up the pump shaft, cooling the lower bearing, and to the RCP seal. The seal controlled bleed-off flow discharges to a common manifold, exits from the containment, and then passes through the seal water return filter and the seal water heat exchanger to the suction side of the charging pumps, or by alternate path to the volume control tank. A very small portion of the seal flow leaks through the seal faces. A number 3 seal provides a final barrier to leakage of reactor coolant to the Reactor Building atmosphere. The number 3 leakoff flow is discharged to the reactor coolant drain tank in the liquid waste processing system. In situations where the charging pumps are not available, the seals can be supplied by the positive-displacement Alternate Seal Injection (ASI) Pump, which provides a total of 20 gpm (approximately 7 gpm per RCP seal) directly from the RWST. The ASI pump is powered by a dedicated NNS diesel generator and is designed to operate continuously for no less than 24 hours following a station black-out event (SBO). The ASI system is a sub-system of CVCS (Figure 9.3-16, Sheet 3) and is designed as an ASME III, Code Class 2 system (safety-related for pressure boundary integrity). The Alternate Seal Injection pump was conservatively designed and procured as an active pump, although it is not credited in station analysis which would require its function to be active.

The excess letdown path is provided as an alternate letdown path from the RCS in the event that the normal letdown path is inoperable. Reactor coolant can be discharged from a crossover leg to flow through the tube side of the excess letdown heat exchanger where it is cooled by component cooling water. Downstream of the heat exchanger a remote-manual control valve controls the

letdown flow. The flow normally joins the RCP seal controlled bleed-off discharge manifold and passes through the seal water return filter and heat exchanger to the suction side of the charging pumps. The excess letdown flow can also be directed to the reactor coolant drain tank or directly into the volume control tank via a spray nozzle. When the normal letdown line is not available, the normal purification path is also not in operation. Therefore, this alternate condition would allow continued power operation for a limited period of time, dependent on RCS chemistry and activity. The excess letdown flow path is also used to provide additional letdown capability during the final stages of plant heatup. This path removes some of the excess reactor coolant due to expansion of the system as a result of the RCS temperature increase.

Surges in RCS inventory due to load changes are accommodated for the most part in the pressurizer. The volume control tank provides surge capacity for reactor coolant expansion not accommodated by the pressurizer. If the water level in the volume control tank exceeds the normal operating range, a proportional controller modulates a three-way valve downstream of the reactor coolant filter to divert a portion of the letdown to the Boron Recycle System. If the high-level limit in the volume control tank is reached, an alarm is actuated in the control room and the letdown flow is completely diverted to the Boron Recycle System.

The Boron Recycle System (Section 9.3.6) receives and processes reactor coolant effluent prior to discharge to the environment or alternatively for reuse in the plant. The system decontaminates the effluent by means of demineralization and gas stripping.

Low level in the volume control tank initiates makeup from the reactor makeup control system. If the reactor makeup control system does not supply sufficient makeup to keep the volume control tank level from falling to a lower level, a low alarm is actuated. Manual action may correct the situation or, if the level continues to decrease, an emergency low level signal from both level channels causes the suction of the charging pumps to be transferred to the refueling water storage tank.

9.3.4.2.2 Reactor Coolant Purification and Chemistry Control System

9.3.4.2.2.1 pH Control

The pH control chemical employed is lithium hydroxide. This chemical is chosen for its compatibility with the materials and water chemistry of borated water/stainless steel/zirconium/inconel systems. In addition, Lithium-7 is produced in the core region due to irradiation of the dissolved boron in the coolant.

The concentration of Lithium-7 in the RCS is coordinated with boron concentration for RCS pH control (Table 5.2-10). If the concentration is too high, as it may be during the early stages of a core cycle, the cation bed demineralizer may be employed in the letdown line in series operation with a mixed bed demineralizer. Lithium may also be removed via a mixed bed demineralizer which has not had its cation resin converted to the lithium form. If the concentration of Lithium-7 is too low, lithium hydroxide can be introduced into the RCS via the charging flow. The solution is prepared in the laboratory and poured into the chemical mixing tank. Reactor makeup water is then used to flush the solution to the suction manifold of the charging pumps.

9.3.4.2.2.2 Oxygen Control

During reactor startup from the cold condition, hydrazine is employed as an oxygen scavenging agent. The hydrazine solution is introduced into the RCS in the same manner as described above for the pH control agent. Hydrazine is not employed at any time other than startup from the cold shutdown state.

Dissolved hydrogen is employed to control and scavenge oxygen produced due to radiolysis of water in the core region. Sufficient partial pressure of hydrogen is maintained in the volume control tank such that the specified equilibrium concentration of hydrogen is maintained in the reactor coolant. A pressure control valve maintains a minimum pressure in the vapor space of the volume control tank. This valve can be adjusted to provide the correct equilibrium hydrogen concentration (25 to 50 cc hydrogen at STP per kilogram of water). Hydrogen is supplied from the hydrogen manifold in the gaseous processing system.

9.3.4.2.2.3 Reactor Coolant Purification

Mixed bed demineralizers are provided in the letdown line to provide cleanup of the letdown flow. The demineralizers remove ionic corrosion products and certain fission products. One demineralizer is in continuous service and can be supplemented intermittently by the cation bed demineralizer, if necessary, for additional purification. The cation resin removes principally cesium and lithium isotopes from the purification flow. The second mixed bed demineralizer serves as a standby unit for use if the operating demineralizer becomes exhausted during operation.

A further cleanup feature is provided for use during residual heat removal. A remote operated valve admits a bypass flow from the Residual Heat Removal System (RHRS) into the letdown line upstream of the letdown heat exchanger. In addition, all 3 letdown orifice isolation valves may be opened at this time. The flow passes through the heat exchanger, through a mixed bed demineralizer and the reactor coolant filter to the volume control tank. The fluid is then returned to the RCS via the normal charging route.

Filters are provided at various locations to ensure filtration of particulate and resin fines and to protect the seals on the reactor coolant pumps.

Fission gases are removed from the reactor coolant by continuous purging of the volume control tank to the gaseous waste processing system.

9.3.4.2.3 Reactor Makeup Control System

The soluble neutron absorber (boric acid) concentration is controlled by the Boron Thermal Regeneration System and by the reactor makeup control system. The reactor makeup control system is also used to maintain proper reactor coolant inventory. In addition, for emergency boration and makeup, the capability exists to provide refueling water or 4 weight percent boric acid directly to the suction of the charging pump.

The reactor makeup control system provides a manually preselected makeup composition to the charging pump suction header or to the volume control tank. The makeup control functions are those of maintaining desired operating fluid inventory in the volume control tank and adjusting reactor coolant boron concentration for reactivity control. Reactor makeup water and boric acid solution (4 weight percent) are blended together at the reactor coolant boron concentration for use as makeup to maintain volume control tank inventory or they can be used separately to change the reactor coolant boron concentration.

The boric acid is stored in two boric acid tanks. Two (2) boric acid transfer pumps are provided with 1 pump normally aligned to provide boric acid to the suction header of the charging pumps, and the second pump in reserve. On a demand signal by the reactor makeup controller, the pump starts and delivers boric acid to the suction header of the charging pumps. The pump can also be used to recirculate the boric acid tank fluid.

All portions of the CVCS which normally contain concentrated boric acid solution (4 weight percent boric acid) are located within a heated area in order to maintain solution temperature at ≥ 65°F. If a portion of the system which normally contains concentrated boric acid solution is not located in a heated area, it is provided with some other means (e.g., heat tracing) to maintain solution temperature at ≥ 65°F.

The reactor makeup water pumps, taking suction from the reactor makeup water storage tank, are employed for various makeup and flushing operations throughout the systems. One of these pumps also starts on demand from the reactor makeup controller and provides flow to the suction header of the charging pumps or the volume control tank through the letdown line or spray nozzle, respectively.

During reactor operation, changes are made in the reactor coolant boron concentration for the following conditions:

1. Reactor startup - boron concentration must be decreased from shutdown concentration to achieve criticality.
2. Load follow - boron concentration must be either increased or decreased to compensate for the xenon transient following a change in load.
3. Fuel burnup - boron concentration must be decreased to compensate for fuel burnup and the buildup of fission products in the fuel.
4. Cold shutdown - boron concentration must be increased to the cold shutdown concentration.

The Boron Thermal Regeneration System can be used in conjunction with dilution operations of the reactor makeup control system to reduce the amount of effluent to be processed by the Boron Recycle System.

The reactor makeup control system can be set up for the following modes of operation:

1. Automatic Makeup

The "automatic makeup" mode of operation of the reactor makeup control system provides blended boric acid solution, preset to match the boron concentration in the RCS. Automatic makeup compensates for minor leakage of reactor coolant without causing significant changes in the reactor coolant boron concentration.

Under normal plant operating conditions, the mode selector switch is set in the "automatic makeup" position. This switch position establishes a preset control signal to the total makeup flow controller and establishes positions for the makeup stop valves for automatic makeup. The boric acid flow controller is set to blend to the same concentration of borated water as is contained in the RCS. A preset low level signal from the volume control tank level controller causes the automatic makeup control action to start a reactor makeup water pump, start a boric acid transfer pump, open the makeup stop valve to the charging pump suction, and position the boric acid flow control valve and the reactor makeup water flow control valve. The flow controllers then blend the makeup stream according to the preset concentration. Makeup addition to the charging pump suction header causes the water level in the volume control tank to rise. At a preset high level point, the makeup is stopped. This operation may be terminated manually at any time.

If the automatic makeup fails or is not aligned for operation and the tank level continues to decrease, a low level alarm is actuated. Manual action may correct the situation or, if the level continues to decrease, an emergency low level signal opens the stop valves in the refueling water supply line to the charging pumps, and closes the stop valves in the volume control tank outlet line.

2. Dilution

The "dilute" mode of operation permits the addition of a preselected quantity of reactor makeup water at a preselected flowrate to the RCS. The operator sets the mode selector switch to "dilute," the total makeup flow controller setpoint to the desired flowrate, the total makeup batch integrator to the desired quantity and initiates system start. This opens the reactor makeup water flow control valve, opens the makeup stop valve to the volume control tank inlet, and starts a reactor makeup water pump. Excessive rise of the volume control tank water level is prevented by automatic actuation (by the tank level controller) of a three-way diversion valve which routes the reactor coolant letdown flow to the boron recycle system. When the present quantity of water has been added, the batch integrator causes makeup to stop. Also, the operation may be terminated manually at any time.

Dilution can also be accomplished by operating the boron thermal regeneration system in the boron storage mode.

3. Alternate Dilution

   The "alternate dilute" mode of operation is similar to the dilute mode except a portion of the dilution water flows directly to the charging pump suction and a portion flows into the volume control tank via the spray nozzle and then flows to the charging pump suction. This decreases the delay in diluting the RCS caused by directing dilution water to the volume control tank.

4. Boration

   The "borate" mode of operation permits the addition of a preselected quantity of concentrated boric acid solution at a preselected flowrate to the RCS. The operator sets the mode selection switch to "borate," the concentrated boric acid flow controller setpoint to the desired flowrate, the concentrated boric acid batch integrator to the desired quantity, and initiates system start. This opens the makeup stop valve to the charging pumps suction, positions the boric acid flow control valve, and starts the selected boric acid transfer pump, which delivers a 4 weight percent boric acid solution to the charging pumps suction header. The total quantity added in most cases is so small that it has only a minor effect on the volume control tank level. When the preset quantity of concentrated boric acid solution is added, the batch integrator causes makeup to stop. Also, the operation may be terminated manually at any time.

5. Manual

   The "manual" mode of operation permits the addition of a preselected quantity and blend of boric acid solution to the refueling water storage tank, to the recycle holdup tanks in the Boron Recycle System, or to some other location via a temporary connection. While in the manual mode of operation, automatic makeup to the RCS is precluded. The discharge flow path must be prepared by opening manual valves in the desired path.

   The operator sets the mode selector switch to "manual," the boric acid and total makeup flow controllers to the desired flowrates, the boric acid and total makeup batch integrators to the desired quantities, and actuates the makeup start switch.

   The start switch actuates the boric acid flow control valve and the reactor makeup water flow control valve and starts the preselected reactor makeup water pump and boric acid transfer pump.

   When the preset quantities of boric acid and reactor makeup water have been added, the batch integrators cause makeup to stop. This operation may be stopped manually by actuating the makeup stop switch.

If either batch integrator is satisfied before the other has recorded its required total, the pump and valve associated with the integrator which has been satisfied will terminate flow. The flow controlled by the other integrator will continue until the integrator is satisfied. In the manual mode, the boric acid flow is terminated first to prevent piping systems from remaining filled with 4 weight percent boric acid solution.

The quantities of boric acid and reactor makeup water injected are totalized by the batch counters and the flowrates are recorded on recorders. Deviation alarms sound for both boric acid and reactor makeup water if flowrates deviate from setpoints.

9.3.4.2.4 Boron Thermal Regeneration System

Downstream of the mixed bed demineralizers, the letdown flow can be diverted to the Boron Thermal Regeneration System (BTRS) for processing when boron concentration reductions are desired. The BRTS can process any letdown flow rate up to the maximum design flow rate of 120 gpm. Part or all of the letdown flow can be directed through the thermal regeneration demineralizers for processing. After processing, the flow is returned to a point upstream of the reactor coolant filter.

Storage of boron is determined by the temperature of fluid entering the thermal regeneration demineralizers. A chiller unit and a group of heat exchangers are employed to provide the desired fluid temperatures at the demineralizer inlets.

During boron storage, the letdown stream enters the moderating heat exchanger and from there it passes through the letdown chiller heat exchanger. These two heat exchangers cool the letdown stream prior to its entering the demineralizers. The letdown reheat heat exchanger is permanently piped out of service on the tube side and performs no function. The temperatures of the letdown stream at the point of entry to the demineralizers is controlled automatically by the temperature control valve which controls the shell side flow to the letdown chiller heat exchanger. After passing through the demineralizers, the letdown enters the moderating heat exchanger shell side, where it is heated by the incoming letdown stream before going to the volume control tank.

Therefore, for boron storage, a decrease in the boric acid concentration in the reactor coolant is accomplished by sending the letdown flow at relatively low temperatures to the thermal regeneration demineralizers. Reactor coolant with a decreased concentration of boric acid leaves the demineralizers and is directed to the RCS via the charging system.

As an additional function, a thermal regeneration demineralizer can be used as a deborating demineralizer, which would be used to dilute the RCS down to very low boron concentrations towards the end of a core cycle. To make such a bed effective, the effluent concentration from the bed must be kept very low, close to zero ppm boron. This low effluent concentration can be achieved by using fresh resin. Use of fresh resin can be coupled with the normal replacement cycle of the resin; one resin bed being replaced during each core cycle.

9.3.4.2.5 Component Description

A summary of principal component design parameters is given in Table 9.3-5, and safety classifications and design codes are given in Section 3.2.

In addition, portions of the system that are required to carry ECCS fluid outside containment during the recirculation phase of ECCS operation are designed to minimize leakage to the atmosphere as described in Section 6.3.2.11.3.

9.3.4.2.5.1 Piping

CVCS piping that handles radioactive liquid is austenitic stainless steel. Piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing.

9.3.4.2.5.2 Charging Pumps

Three (3) charging pumps of the single speed, horizontal, centrifugal type are supplied to inject coolant into the RCS. One (1) pump is normally running, 1 is a non running pump and the third is a spare with its breaker(s) normally racked out. The third pump can be used as a replacement if 1 of the other pumps is out of service. Parts in contact with the reactor coolant are fabricated of austenitic stainless steel or other material of adequate corrosion resistance. There is a minimum flow recirculation line to protect the centrifugal charging pumps from a closed discharge valve condition. The component cooling water cooling flow to the charging pump lube oil system is established through the air operated component cooling water valves which open when the charging pumps start.

Charging flowrate is determined from a pressurizer level signal. When operating a centrifugal charging pump, charging flow control is accomplished by a modulating valve on the discharge side of the centrifugal pumps. The centrifugal charging pumps also serve as high-head safety injection pumps in the Emergency Core Cooling System.

9.3.4.2.5.3 Boric Acid Transfer Pumps

Two (2) canned motor pumps are supplied. One (1) pump is normally aligned to supply boric acid to the suction header of the charging pumps while the second serves as a standby. Manual or automatic initiation of the reactor coolant makeup system will start the aligned pump to provide normal makeup of boric acid solution to the suction header of the charging pumps. Miniflow from this pump flows back to the associated boric acid tank and helps maintain thermal equilibrium. The standby pump can be used intermittently to circulate boric acid solution through the other tank to maintain thermal equilibrium in this part of the system. Emergency boration, supplying 4 weight percent boric acid solution directly to the suction of the charging pumps, can be accomplished by manually starting either or both pumps. The transfer pumps also function to transfer boric acid solution from the batching tank to the boric acid tanks.

The pumps are located in a heated area to prevent crystallization of the boric acid solutions. Parts in contact with the solution are of austenitic stainless steel.

9.3.4.2.5.4 BTRS Chiller Pumps

These centrifugal pumps circulate the water through the chilled water loop in the Boron Thermal Regeneration System. One (1) pump is normally operated, with the second serving as a standby.

9.3.4.2.5.5 Regenerative Heat Exchanger

The regenerative heat exchanger is designed to recover heat from the letdown flow by reheating the charging flow, which reduces thermal effects on the charging penetrations into the reactor coolant loop piping.

The letdown stream flows through the shell of the regenerative heat exchanger and the charging stream flow through the tubes. The unit is constructed of austenitic stainless steel, and is of all welded construction.

The temperatures of both outlet streams from the heat exchanger are monitored with indication given in the control room. A high temperature alarm is actuated on the main control board if the temperature of the letdown stream exceeds desired limits.

9.3.4.2.5.6 Letdown Heat Exchanger

The letdown heat exchanger cools the letdown stream to the operating temperature of the mixed bed demineralizers. Reactor coolant flows through the tube side of the exchanger while component cooling water flows through the shell side. Surfaces in contact with the reactor coolant are austenitic stainless steel, and the shell is carbon steel.

The low pressure letdown valve, located downstream of the heat exchanger, maintains the pressure of the letdown flow upstream of the heat exchanger in a range sufficiently high to prevent two phase flow. Pressure indication and high pressure alarm are provided on the main control board.

The letdown temperature control indicates and controls the temperature of the letdown flow exiting from the letdown heat exchanger. A temperature sensor, which is part of the CVCS, provides input to the controller in the Component Cooling Water System. The exit temperature of the letdown stream is thus controlled by regulating the component cooling water flow through the letdown heat exchanger. Temperature indication is provided on the main control board. If the outlet temperature from the heat exchanger is excessive, a high temperature alarm is actuated and a temperature controlled valve diverts the letdown directly to the volume control tank.

9.3.4.2.5.7 Excess Let Down Heat Exchanger

The excess letdown heat exchanger cools reactor coolant letdown flow at a rate which is equivalent to the portion of the nominal seal injection flow which flows into the RCS through the reactor coolant pump labyrinth seals.

The excess letdown heat exchanger can be employed either when normal letdown is temporarily out of service to maintain inventory control in the RCS or it can be used to supplement maximum letdown during heatup. The letdown flows through the tube side of the unit and component cooling water is circulated through the shell. Surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel. Tube joints are welded. A temperature detector measures the temperature of the excess letdown flow downstream of the excess letdown heat exchanger. Temperature indication and high temperature alarm are provided on the main control board.

A pressure sensor indicates the pressure of the excess letdown flow downstream of the excess letdown heat exchanger and excess letdown control valve. Pressure indication is provided on the main control board.

9.3.4.2.5.8 Seal Water Heat Exchanger

The seal water heat exchanger is designed to cool fluid from 3 sources: reactor coolant pump controlled bleed-off flow, reactor coolant discharged from the excess letdown heat exchanger, and miniflow from a centrifugal charging pump. Reactor coolant flows through the tube side of the heat exchanger and component cooling water is circulated through the shell. The seal water heat exchanger is sized for a design basis case, for which the flowrate through the tube side is equal to maximum design reactor coolant pump seal leakage and miniflow from two centrifugal charging pumps. The heat exchanger is also sized for an alternate case, for which the flowrate through the tube side is equal to the sum of the nominal excess letdown flow, maximum design reactor coolant pump seal leakage, and miniflow from one centrifugal charging pump. The unit is designed to cool the above flows to the temperature normally maintained in the volume control tank. Surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

9.3.4.2.5.9 Moderating Heat Exchanger

The moderating heat exchanger operates as a regenerative heat exchanger between incoming and outgoing streams to and from the thermal regeneration demineralizers.

The incoming flow enters the tube side of the moderating heat exchanger. The shell side fluid, which comes directly from the demineralizers, enters at low temperature during boron storage. The unit is constructed of austenitic stainless steel.

9.3.4.2.5.10 Letdown Chiller Heat Exchanger

During the boron storage operation, the process stream enters the tube side of the letdown chiller heat exchanger after leaving the tube side of the moderating heat exchanger. The letdown chiller

heat exchanger cools the process stream to allow the thermal regeneration demineralizers to remove boron from the coolant. The desired cooling capacity is adjusted by controlling the chilled water flowrate passed through the shell side of the heat exchanger.

The letdown chiller heat exchanger surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

9.3.4.2.5.11 Letdown Reheat Heat Exchanger

The letdown reheat heat exchanger is no longer used.

9.3.4.2.5.12 Volume Control Tank

The volume control tank provides surge capacity for part of the reactor coolant expansion volume not accommodated by the pressurizer. When the level in the tank reaches the high level setpoint, the remainder of the expansion volume is accommodated by diversion of the letdown stream to the Boron Recycle System. The tank also provides a means for introducing hydrogen into the coolant to maintain the required equilibrium concentration and is used for degassing the reactor coolant. It also serves as a head tank for the charging pumps.

A spray nozzle located inside the tank on the letdown line provides liquid to gas contact between the incoming fluid and the hydrogen atmosphere in the tank.

The tank is constructed of austenitic stainless steel.

Hydrogen (from the hydrogen manifold in the gaseous waste processing system) is continuously supplied to the volume control tank while a remotely operated vent valve, discharging to the gaseous waste processing system, permits continuous removal of gaseous fission products which are stripped from the reactor coolant and collected in this tank. Relief protection, gas space sampling, and nitrogen purge connections are also provided. The tank also accepts the seal water return flow from the reactor coolant pumps; this flow can be routed directly to the suction of the charging pumps.

Volume control tank pressure is monitored with indication given in the control room. Alarm is actuated in the control room for high and low pressure conditions.

Two (2) level channels govern the water inventory in the volume control tank. Level indication with high and low alarms is provided on the main control board for one channel and local level indication is provided for the other channel.

If the volume control tank level rises above the normal operating range, 1 level channel provides an analog signal to the proportional controller which modulates the three-way valve downstream of the reactor coolant filter to maintain the volume control tank level within the normal operating band. The three-way valve can split letdown flow so that a portion goes to the Boron Recycle System and a portion to the volume control tank. The controller would operate in this fashion

during a dilution operation when reactor makeup water is being fed to the volume control tank from the reactor makeup control system.

If the modulating function of the channel fails and the volume control tank level continues to rise, the high level alarm will alert the operator to the malfunction and the full letdown flow will be automatically diverted by the backup level channel.

During normal power operation, a low level in the volume control tank initiates auto makeup which injects a preselected blend of boric acid solution and reactor makeup water into the charging pump suction header. When the volume control tank level is restored to normal, auto makeup stops.

If the automatic makeup fails and the tank level continues to decrease, a low level alarm is actuated. Manual action may correct the situation or, if the level continues to decrease, a low-low signal from both level channels opens the stop valves in the refueling water supply line, and closes the stop valves in the volume control tank outlet line.

9.3.4.2.5.13 Boric Acid Tanks

The combined boric acid tank capacity is sized to store sufficient boric acid solution for refueling plus enough for a cold shutdown from full power operation immediately following refueling with the most reactive control rod not inserted.

The concentration of boric acid solution in storage is maintained between 7000 and 7700 ppm. Periodic manual sampling and corrective action, if necessary, assure that these limits are maintained. As a consequence, measured amounts of boric acid solution can be delivered to the reactor coolant to control the boron concentration.

A temperature sensor provides temperature measurement of each tank’s contents. Temperature indication as well as high and low temperature alarms are provided locally.

Three (3) level detectors indicate the level in each boric acid tank. Redundant level indication with high, low, low-low and empty level alarms is provided on the main control board for each tank. The high alarm indicates that the tank may soon overflow. The low alarm warns the operator to start makeup to the tank. The low-low alarm is set to indicate the minimum level of boric acid in the tank to ensure sufficient boric acid is available for a cold shutdown with one stuck rod. The empty level alarm is set to give warning of loss of pump suction.

9.3.4.2.5.14 Batching Tank

The batching tank is used for mixing a makeup supply of boric acid solution for transfer to the boric acid tanks.

A local sampling point is provided for verifying the solution concentration prior to transferring it out of the tank. The tank is provided with an agitator to improve mixing during batching operations and a steam jacket for heating the boric acid solution.

9.3.4.2.5.15 Chemical Mixing Tank

The primary use of the chemical mixing tank is in the preparation of caustic solutions for pH control and hydrazine solution for oxygen scavenging.

9.3.4.2.5.16 BTRS Chiller Surge Tank

The BTRS chiller surge tank handles the thermal expansion and contraction of the water in the chiller loop. The surge volume in the tank also acts as a thermal buffer for the chiller. The fluid level in the tank is monitored with level indication and high and low level alarms provided on the main control board.

9.3.4.2.5.17 Mixed Bed Demineralizers

Two (2) flushable mixed bed demineralizers assist in maintaining reactor coolant purity. A hydrogen-form cation resin and a hydroxyl-form anion resin are charged into the demineralizers. The cation resin is converted to lithium-form and the anion resin is converted to the borate form in operation. Both types of resin remove fission and corrosion products. The resin bed is designed to reduce the concentration of ionic isotopes in the purification stream, except for cesium, yttrium and molybdenum, by a minimum factor of 10.

Each demineralizer has more than sufficient capacity for 1 core cycle with 1% of the rated core thermal power being generated by failed fuel. One (1) demineralizer is normally in service with the other in standby.

A temperature sensor monitors the temperature of the letdown flow downstream of the letdown heat exchanger and if the letdown temperature exceeds the maximum allowable resin operating temperature (approximately 140°F), a three-way valve is automatically actuated to bypass the flow around the demineralizers. Temperature indication and high alarm are provided on the main control board. The air operated three-way valve failure mode directs flow to the volume control tank.

9.3.4.2.5.18 Cation Bed Demineralizer

A flushable demineralizer with cation resin in the hydrogen form is located downstream of the mixed bed demineralizers and is used intermittently to control the concentration of Li^7 which builds up in the coolant from the B^{10} (n, α) Li^7 reaction. The demineralizer also has sufficient capacity to maintain the Cesium-137 concentration in the coolant below the value listed in Table 11.1-2. The resin bed is designed to reduce the concentration of ionic isotopes, particularly cesium, yttrium, and molybdenum by a minimum factor of 10. The demineralizer is sized to accommodate a letdown flow rate of 60 gpm when in service, which is more than adequate to control Li^7 or cesium in the RCS. Any letdown flow in excess of 60 gpm is diverted through the bypass line around the cation bed demineralizer.

The demineralizer has more than sufficient capacity for 1 core cycle with 1% of the rated core thermal power being generated by failed fuel.

9.3.4.2.5.19 Thermal Regeneration Demineralizers

The function of the thermal regeneration demineralizers was to store the total amount of boron that must be removed from the RCS to accomplish the required dilution during a load cycle in order to compensate for xenon buildup resulting from a decreased power level. Furthermore, the demineralizers were able to release the previously stored boron to accomplish the required boration of the reactor coolant during the load cycle in order to compensate for a decrease in xenon concentration resulting from an increased power level. The load following capabilities of the thermal regeneration demineralizers was removed by plant modification MRF 21511. The resins continue to be used to store boron. However, the boron release feature of the system has been disabled.

The thermal regeneration demineralizer resin capacity is directly proportional to the solution boron concentration and inversely proportional to the temperature. Further, the differences in capacity as a function of both boron concentration and temperature are reversible.

Temperature instrumentation is provided upstream of the thermal regeneration demineralizers to control the temperature of the process flow. During boron storage operations, it controls the flow through the shell side of the letdown chiller heat exchanger to maintain the process flow at 50°F as it enters the demineralizers. Temperature indication and a high temperature alarm are provided on the main control board.

An additional temperature instrument is provided to protect the demineralizer resins from a high temperature condition. On reaching the high temperature setpoint, an alarm is sounded on the main control board and the letdown flow is diverted to the volume control tank from a point upstream of the mixed bed demineralizers.

Failure of the temperature controls resulting in hot water flow to the demineralizers would result in a release of boron stored on the resin with a resulting increase in reactor coolant boron concentration and increased margin for shutdown. If the temperature of the resin rises significantly above 140°F, the number of ion storage sites will gradually decrease, thus reducing the capability of the resin to remove boron from the process stream. Degradation of ion removal capability will occur for temperatures of approximately 160°F and above. The extent of the degradation and rate at which it will occur depend upon the temperature experienced by the resin and the length of time that the resin experiences this elevated temperature.

Failure of the temperature control system resulting in cold water flow to the demineralizers would result in storage of boron on the resin and reduction of the reactor coolant boron concentration. The amount of reduction in reactor coolant boron concentration is limited by the capacity of the resin to remove boron from the water. As the boron concentration is reduced, the control rods would be driven into the core to maintain power level. If the rods were to reach the shutdown limit setpoint, an alarm would be actuated informing the operator that emergency boration of the RCS is necessary in order to maintain capability of shutting the reactor down with control rods alone.

9.3.4.2.5.20 Reactor Coolant Filter

The reactor coolant filter is located in the letdown line upstream of the volume control tank. The filter collects resin fines and particulates from the letdown stream. The flow capacity of the filter is designed to accept the maximum purification flowrate.

Two (2) local pressure indicators are provided to show the pressures upstream and downstream of the reactor coolant filter and thus provide filter differential pressure.

9.3.4.2.5.21 Seal Water Injection Filters

Two (2) seal water injection filters are located in parallel in a common line to the reactor coolant pump seals; they collect particulate matter that could be harmful to the seal faces. Each filter is sized to accept flow in excess of the normal seal water flow requirements.

A differential pressure indicator monitors the pressure drop across each seal water injection filter and gives local indication with high differential pressure alarm on the main control board.

9.3.4.2.5.22 Seal Water Return Filter

This filter collects particulates from the reactor coolant pump seal water return and from the excess letdown flow. The filter is designed to pass the sum of the excess letdown flow and the maximum design seal leakage from all reactor coolant pumps.

Two (2) local pressure indicators are provided to show the pressures upstream and downstream of the filter and thus provide differential pressure across the filter.

9.3.4.2.5.23 Boric Acid Filter

The boric acid filter collects particulates from the boric acid solution being pumped from the boric acid tanks by the boric acid transfer pumps. The filter is designed to pass the design flow of 2 boric acid transfer pumps operating simultaneously.

Local pressure indicators indicate the pressure upstream and downstream of the boric acid filter and thus provide filter differential pressure.

9.3.4.2.5.24 Letdown Orifices

Three (3) letdown orifices are provided to reduce the letdown pressure from reactor conditions and to control the flow of reactor coolant leaving the RCS. The orifices are placed into or out of service by remote operation of their respective isolation valves. Normal letdown ranges from 60 to 120 gpm and is obtained by placing one 60 gpm orifice or any combination of two orifices aligned in parallel. All 3 orifices may be used in parallel for either flow control when the RCS pressure is less than normal or greater letdown flow during maximum purification or heatup. Each orifice consists of an assembly which provides for permanent pressure loss without recovery, and is made of austenitic stainless steel or other adequate corrosion resistant material.

A flow monitor provides indication in the control room of the letdown flowrate, and a high alarm to indicate unusually high flow.

A low pressure letdown controller located downstream of the letdown heat exchanger controls the pressure upstream of the letdown heat exchanger to prevent flashing of the letdown liquid. Pressure indication and high pressure alarm are provided on the main control board.

9.3.4.2.5.25 Number 1 Seal Bypass Orifices

Number 1 Seal bypass flow was necessary for Westinghouse RCP seal to ensure adequate flow for cooling of the pump's lower radial bearing and to limit the temperature rise of the water cooling the number 1 seal during startup or shutdown when the RCS pressure was low. The number 1 seal bypass orifice is constructed of austenitic stainless steel and designed to pass adequate flow for the differential pressure existing at the lowest allowable RCS pressure for reactor coolant pump operation. The Westinghouse RCP seals were replaced with N-9000 seals which have sufficient cooling flow at low RCS pressure. Therefore the bypass flow is no longer required. The number 1 seal bypass orifices remain in the piping system but the downstream piping is capped.

9.3.4.2.5.26 Boric Acid Blender

The boric acid blender, made of austenitic stainless steel, is provided to ensure thorough mixing of the 4 weight percent solution of boric acid and reactor makeup water when required. The blender is designed to pass the maximum letdown flow.

9.3.4.2.5.27 DELETED.

9.3.4.2.5.28 BTRS Chiller

The BTRS chiller is located in a chilled water loop containing a surge tank, chiller pumps, the letdown chiller heat exchanger, piping, valves and controls.

The purpose of the chiller is to cool down the process stream during storage of boron on the resin.

9.3.4.2.5.29 Valves

Where pressure and temperature conditions permit, diaphragm type valves are used to essentially eliminate leakage to the atmosphere. Packed valves which are larger than 2 inches and which are designated for radioactive services are provided with a stuffing box and lantern leakoff connections. Design requirements for zero-leakage valves and dual vent and drain isolation, described in Section 6.3.2.11.3 apply to valves 2 inches and smaller located in portions of the system designed to carry ECCS fluid outside containment during post-LOCA recirculation. Control (modulating) and three-way valves are either provided with stuffing box and leakoff connections or are totally enclosed. Leakage to the atmosphere is essentially 0 for these valves. Basic material of construction is stainless steel for valves which handle radioactive liquid or boric acid solutions.

Relief valves are provided for lines and components that might be pressurized above design pressure by improper operation or component malfunction.

1. Charging Line Downstream of Regenerative Heat Exchanger

   If the charging side of the regenerative heat exchanger is isolated while the hot letdown flow continues at its maximum rate, the volumetric expansion of coolant on the charging side of the heat exchanger is relieved to the RCS through a spring loaded check valve.

2. Letdown Line Downstream of Letdown Orifices

   The pressure relief valve downstream of the letdown orifices protects the low pressure piping and the letdown heat exchanger from overpressure when the low pressure piping is isolated. The capacity of the relief valve is equal to the maximum flowrate through all letdown orifices. The valve set pressure is equal to the design pressure of the letdown heat exchanger tube side.

3. Letdown Line Downstream of Low Pressure Letdown Valve

   The pressure relief valve downstream of the low pressure letdown valve protects the low pressure piping and equipment from overpressure when this section of the system is isolated. The overpressure may result from leakage through the low pressure letdown valve. The capacity of the relief valve exceeds the maximum flowrate through all letdown orifices. The valve set pressure is equal to the design pressure of the demineralizers.

4. Volume Control Tank

   The relief valve on the volume control tank permits the tank to be designed for a lower pressure than the upstream equipment. This valve has a capacity equal to the summation of the following items: maximum letdown, normal seal water return, excess letdown and nominal flow from one reactor makeup water pump. The valve set pressure equals the design pressure of the volume control tank.

5. Charging Pump Suction

   A relief valve on the charging pump suction header relieves pressure that may build up if the suction line isolation valves are closed or if the system is overpressurized. The valve set pressure is equal to the design pressure of the associated piping and equipment.

6. Seal Water Return Line (Inside Reactor Building)

   This relief valve is designed to relieve overpressurization in the seal water return piping inside the Reactor Building if the motor operated isolation valve is closed. The valve is designed to relieve the total controlled bleed-off flow of the reactor coolant pump seals plus the design excess letdown flow. The valve is set to relieve at the design pressure of the piping.

7. Seal Water Return Line (Charging Pumps Bypass Flow)

   This relief valve protects the seal water heat exchanger and its associated piping from overpressurization. If either of the isolation valves for the heat exchanger are closed and if the bypass line is closed, the piping would be overpressurized by the miniflow from the centrifugal charging pumps. The valve is sized to handle the design basis flowrate of the Excess Letdown Heat Exchanger, the fluid from the reactor coolant pump seals returning to the volume control tank, and the miniflow from two operating centrifugal charging pumps, which bounds that of the Seal Water Heat Exchanger. The valve is set to relieve at the design pressure of the heat exchanger.

8. Letdown Reheat Heat Exchanger

   The relief valve is located on the piping leading from the shell side of the heat exchanger. If the shell side were filled with cold water and isolated, overpressurization could occur when the water warms to room temperature. The valve is set to relieve at the design pressure of the heat exchanger shell side.

9. Letdown Chiller Heat Exchanger

   The relief valve is located on the piping leading from the shell side of the heat exchanger. If the shell side were isolated while flow was maintained in the tube side, overpressurization could occur. The valve is set to relieve at the design pressure of the heat exchanger shell side.

10. Steam Line to Batching Tank

    The relief valve on the steam line to the batching tank protects the low pressure piping and batching tank heating jacket from overpressure when the condensate return line is isolated. The capacity of the relief valve equals the maximum expected steam inlet flow. The set pressure equals the design pressure of the heating jacket.

9.3.4.2.6 System Operation

9.3.4.2.6.1 Reactor Startup

Reactor startup is defined as the operations which bring the reactor from cold shutdown to normal operating temperature and pressure.

It is assumed that:

1. Normal residual heat removal is in progress.
2. RCS boron concentration is at the cold shutdown concentration.
3. Reactor makeup control system is set to provide makeup at the cold shutdown concentration.
4. RCS is either water solid or drained to minimum level for the purpose of refueling or maintenance. If the RCS is water solid, system pressure is maintained by operation of a

charging pump and controlled by the low pressure letdown valve in the letdown line (letdown is achieved via the low pressure letdown connection from the residual heat removal system, as well as one or more letdown orifices).

5. The charging and letdown lines of the CVCS are filled with coolant at the cold shutdown boron concentration. The letdown orifice isolation valves are closed.

If the RCS requires filling and venting, the procedure is as follows:

1. One (1) charging pump is started, which provides blended flow from the reactor makeup control system at the cold shutdown boron concentration.
2. The vents on the head of the reactor vessel and pressurizer are opened.
3. The RCS is filled and the vents closed.

The system pressure is raised by using the charging pump and controlled by the low pressure letdown valve. When the system pressure is adequate for operation of the reactor coolant pumps, seal water flow to the pumps is established and the pumps are operated and vented sequentially until all gases are cleared from the system. Final venting takes place at the pressurizer.

After the filling and venting operations are completed, charging and letdown flows are established. All pressurizer heaters are energized and the reactor coolant pumps are employed to heatup the system. After the reactor coolant pumps are started, the residual heat removal pumps are stopped but pressure control via the Residual Heat Removal System (RHRS) and the low pressure letdown line is continued as the pressurizer steam bubble is formed. At this point, steam formation in the pressurizer is accomplished by manual control of the charging flow and low pressure letdown valve with all letdown orifices open. When the pressurizer water level reaches the no-load programmed setpoint, the pressurizer level control is shifted to control the charging flow to maintain programmed level. The RHRS is then isolated from the RCS and the normal letdown path is established. The pressurizer heaters are used to increase RCS pressure.

The reactor coolant boron concentration is now reduced by operating the reactor makeup control system in the "dilute" mode. The reactor coolant boron concentration is corrected to the point where the control rods may be withdrawn and criticality achieved. Nuclear heatup may then proceed with corresponding manual adjustment of the reactor coolant boron concentration to balance the temperature coefficient effects and maintain the control rods within their operating range. During heatup, the appropriate combination of letdown orifices is used to provide necessary letdown flow.

Prior to or during the heating process, the CVCS is employed to obtain the correct chemical properties in the RCS. The reactor makeup control system is operated on a continuing basis to ensure correct control rod position. Chemicals are added through the chemical mixing tank as required to control reactor coolant chemistry such as pH and dissolved oxygen content. Hydrogen overpressure is established in the volume control tank to assure the appropriate hydrogen concentration in the reactor coolant.

9.3.4.2.6.2 Power Generation and Hot Standby Operation

1. Base Load

   At a constant power level, the rates of charging and letdown are dictated by the requirements for seal water to the reactor coolant pumps and the normal purification of the RCS. One (1) charging pump is employed and charging flow is controlled automatically from pressurizer level. The only adjustments in boron concentration necessary are those to compensate for core burnup. These adjustments are made at infrequent intervals to maintain the control groups within their allowable limits. Rapid variations in power demand are accommodated automatically by control rod movement. If variations in power level occur, and the new power level is sustained for long periods, some adjustment in boron concentration may be necessary to maintain the control groups within their maneuvering band.

   During normal operation, normal letdown flow (60 to 120 gpm) is maintained and 1 mixed bed demineralizer is in service. Reactor coolant samples are taken periodically to check boron concentration, water quality, pH and activity level. The charging flow to the RCS is controlled automatically by the pressurizer level control signal through the discharge header flow control valve.

2. Load Follow

   A power reduction will initially cause a xenon buildup followed by xenon decay to a new, lower equilibrium value. The reverse occurs if the power level increases; initially, the xenon level decreases and then it increases to a new and higher equilibrium value associated with the amount of the power level change.

   The reactor makeup control system is used to vary the boron concentration in the reactor coolant to compensate for xenon transients occurring when reactor power is changed.

   The most important intelligence available to the plant operator, enabling him to determine whether dilution or boration of the RCS is necessary, is the position of the control rods. For example, if the control rods are below their desired position, the operator must borate the reactor coolant to bring the rods outward. If, on the other hand, the control rods are above their desired position, the operator must dilute the reactor coolant to bring the rods inward.

   During periods of plant loading, the reactor coolant expands as its temperature rises. The pressurizer absorbs this expansion as the level controller raises the level setpoint to the increased level associated with the new power level. The excess coolant due to RCS expansion is letdown and stored in the volume control tank. During this period, the flow through the letdown orifice remains constant and the charging flow is reduced by the pressurizer level control signal, resulting in an increased temperature at the regenerative heat exchanger outlet. The temperature controller downstream from the letdown heat exchanger increases the component cooling water flow to maintain the desired letdown temperature.

During periods of plant unloading, the charging flow is increased to make up for the coolant contraction not accommodated by the programmed reduction in pressurizer level.

3. Hot Standby

   If required, for periods of maintenance, or following spurious reactor trips, the reactor can be held subcritical, but with the capability to return to full power within the period of time it takes to withdraw control rods. During this hot standby period, temperature is maintained at no-load T_{avg} by initially dumping steam to remove core residual heat, or at later stages, by running reactor coolant pumps to maintain system temperature.

   Following shutdown, xenon buildup occurs and increases the degree of shutdown; i.e., initially, with initial xenon concentration and all control rods inserted, the core is maintained at a minimum of 1% $\Delta k/k$ subcritical. The effect of xenon buildup is to increase this value to a maximum of about 3% $\Delta k/k$ at about 8 hours following shutdown from equilibrium full power conditions. If hot standby is maintained past this point, xenon decay results in a decrease in degree of shutdown. Since the value of the initial xenon concentration is about 3% $\Delta k/k$ (assuming that an equilibrium concentration had been reached during operation), boration of the reactor coolant is necessary to counteract the xenon decay and maintain shutdown.

   If a rapid recovery is required, dilution of the system may be performed to counteract this xenon buildup. However, after the xenon concentration reaches a peak, boration must be performed to maintain the reactor subcritical as the xenon decays out.

4. Cold Shutdown

   Cold shutdown is the operation which takes the reactor from hot shutdown conditions to cold shutdown conditions (reactor is subcritical by at least 1% $\Delta k/k$ and $T_{avg} \leq 200$ °F

   Before initiating a cold shutdown, the RCS hydrogen concentration is lowered by reducing the volume control tank overpressure, by replacing the volume control tank hydrogen atmosphere with nitrogen, and by continuous purging to the gaseous waste processing system.

   Before cooldown and depressurization of the reactor plant is initiated, the reactor coolant boron concentration is increased to the cold shutdown value. After the boration is completed and reactor coolant samples verify that the concentration is correct, the operator resets the reactor makeup control system for leakage makeup and system contraction at the shutdown reactor coolant boron concentration.

   Contraction of the coolant during cooldown of the RCS results in actuation of the pressurizer level control to maintain normal pressurizer water level. The charging flow is increased, relative to letdown flow, and results in a decreasing volume control tank level. The volume control tank level controller automatically initiates makeup to maintain the inventory.

After the RHRS is placed in service and the reactor coolant pumps are shutdown, further cooling of the pressurizer liquid is accomplished by charging through the auxiliary spray line. Coincident with plant cooldown, a portion of the reactor coolant flow is diverted from the RHRS to the CVCS for cleanup. Demineralization of ionic radioactive impurities and stripping of fission gases reduce the reactor coolant activity level sufficiently to permit personnel access for refueling or maintenance operations.

9.3.4.3 Safety Evaluation

9.3.4.3.1 Reactivity Control

Any time that the plant is at power, the quantity of boric acid retained and ready for injection always exceeds that quantity required for the normal cold shutdown assuming that the control assembly of greatest worth is in its fully withdrawn position. This quantity always exceeds the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay. An adequate quantity of boric acid is also available in the refueling water storage tank to achieve cold shutdown.

When the reactor is subcritical; i.e., during cold or hot shutdown, refueling and approach to criticality, the neutron source multiplication is continuously monitored and indicated. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate, is slow enough to give ample time to start a corrective action to prevent the core from becoming critical. The rate of boration, with a single boric acid transfer pump operating, is sufficient to take the reactor from full power operation to 1% shutdown in the hot condition, with no rods inserted, in less than 90 minutes. In less than 90 additional minutes, enough boric acid can be injected to compensate for xenon decay, although xenon decay below the equilibrium operating level will not begin until approximately 25 hours after shutdown. Additional boric acid is employed if it is desired to bring the reactor to cold shutdown conditions.

Two (2) separate and independent flow paths are available for reactor coolant boration; i.e., the charging line and the reactor coolant pump seal injection line. Solution temperature requirements are maintained. A single failure does not result in the inability to borate the RCS. Two (2) separate high head safety injection flow paths are also available.

If the normal charging line is not available, charging to the RCS is continued via reactor coolant pump seal injection at the rate of approximately 5 gpm per pump. At the charging rate of 15 gpm (5 gpm per reactor coolant pump), approximately 6 hours are required to add enough boric acid solution from the Boric Acid Tank to counteract xenon decay, although xenon decay below the full power equilibrium operating level will not begin until approximately 25 hours after the reactor is shutdown.

As backup to the normal boric acid supply, the operator can align the refueling water storage tank outlet to the suction of the charging pumps.

Since inoperability of a single component does not impair ability to meet boron injection requirements, plant operating procedures allow components to be temporarily out of service for

repairs. However, with an inoperable component, the ability to tolerate additional component failure is limited. Therefore, operating procedures require immediate action to effect repairs of an inoperable component, restrict permissible repair time, and require demonstration of the operability of the redundant component.

9.3.4.3.2 Reactor Coolant Purification

The CVCS is capable of reducing the concentration of ionic isotopes in the purification stream as required in the design basis. This is accomplished by passing the letdown flow through 1 of the mixed bed demineralizers which removes ionic isotopes, except those of cesium, molybdenum and yttrium, with a minimum decontamination factor of 10. Through occasional use of the cation bed demineralizer the concentration of cesium can be maintained below the Cs-137 value listed in Table 11.1-2.

The maximum temperature that will be allowed for the mixed bed and cation bed demineralizers is approximately 140°F. If the temperature of the letdown stream approaches this level, the flow will be automatically diverted so as to bypass the demineralizers. If the letdown is not diverted, the only consequence would be a decrease in ion removal capability. Ion removal capability starts to decrease when the temperature of the resin goes above approximately 160°F for anion resin or above approximately 250°F for cation resin. The resins do not lose their exchange capability immediately. Ion exchange still takes place (at a faster rate) when temperature is increased. However, with increasing temperature, the resin loses some of its ion exchange sites along with the ions that are held at the lost sites. The ions lost from the sites may be re-exchanged farther down the bed. The number of sites lost is a function of the temperature reached in the bed and of the time the bed remains at the high temperature. Capability for ion exchange will not be lost until a significant portion of the exchange sites are lost from the resin.

There would be no safety problem associated with over-heating of the demineralizer resins. The only effect on reactor operating conditions would be the possibility of an increase in the reactor coolant activity level. If the activity level in the reactor coolant were to exceed the limit given in the Technical Specifications, reactor operation would be restricted as required by the Technical Specifications.

9.3.4.3.3 Seal Water Injection

Flow to the reactor coolant pumps' seals is assured by the fact that there are 3 charging pumps, any 1 of which is capable of supplying the normal charging line flow plus the nominal seal water flow.

9.3.4.3.4 Leakage Provisions

CVCS components, valves, and piping which see radioactive service are designed to limit leakage to the atmosphere. Leakage to the atmosphere is limited through:

1. Welding of all piping joints and connections except where flanged connections are provided to facilitate maintenance and hydrostatic testing,

2. Extensive use of leakoffs to collect leakage, and
3. Use of diaphragm valves where conditions permit.

The volume control tank in the CVCS provides an inferential measurement of leakage from the CVCS as well as the RCS. Low level in the volume control tank actuates makeup at the prevailing reactor coolant boron concentration. The amount of leakage can be inferred from the amount of makeup added by the reactor makeup control system.

9.3.4.3.5 Ability to Meet the Engineered Safety Features Function

A failure analysis of the portion of the CVCS which is safety-related (used as part of the emergency core cooling system) is included as part of the emergency core cooling system failure analysis resented in Tables 6.3-6 and 6.3-7.

9.3.4.4 Tests and Inspections

As part of plant operation, periodic tests, surveillance inspections and instrument calibrations are made to monitor equipment condition and performance. Most components are in use regularly; therefore, assurance of the availability and performance of the systems and equipment is provided by control room and/or local indication.

9.3.4.5 Instrumentation Application

Process control instrumentation is provided to acquire data concerning key parameters about the CVCS. The location of the instrumentation is shown on Figure 9.3-16. The instrumentation furnishes input signals for monitoring and/or alarming purposes. Indications and/or alarms are provided for the following parameters:

1. Temperature.
2. Pressure.
3. Flow.
4. Water level.

The instrumentation also supplies input signals for control purposes. Some specific control functions are:

1. Letdown flow is diverted to the volume control tank upon high temperature indication upstream of the mixed bed demineralizers.
2. Pressure upstream of the letdown heat exchanger is controlled to prevent flashing of the letdown liquid.
3. Charging flowrate is controlled during charging pump operation.
4. Water level is controlled in the volume control tank.

5. Temperature of the boric acid solution in the batching tank is maintained.
6. Reactor makeup is controlled.
7. Temperature of letdown flow to the Boron Thermal Regeneration System is controlled.
8. Temperature of the chilled water flow to the letdown chiller heat exchanger is controlled.
9. Temperature of letdown flow return from the boron thermal regeneration demineralizers is controlled.

9.3.5 Failed Fuel Detection System

The Virgil C. Summer Nuclear Station does not employ a specific failed fuel detection system. However, provision is made for detection of failed fuel by utilization of the process sampling system and the Radiation Monitoring System, discussed in Sections 9.3.2 and 11.4, respectively. In addition, the refueling machine mast is equipped with hardware to support in-mast sipping - a failed fuel detection process that can be used during refueling.

Radiation monitor, RM-L1, provides indication of the gross gamma activity in the reactor coolant. Alarms are provided in the control room to alert the operator to an excessive increase in reactor coolant activity. Laboratory analysis of a reactor coolant sample is used to establish that fission products are present and, if so, the concentration. In this manner information for the determination of fuel failure is obtained.

9.3.6 Boron Recycle System

This section describes the design and operating features of the Boron Recycle System (BRS) which includes the Reactor Grade Water System (RGWS) demineralizers.

9.3.6.1 Design Bases

9.3.6.2 Collection Requirements

The BRS primarily collects and processes water from the recycle holdup tank. Provisions are made to sample and analyze fluids before they are discharged. Based on the laboratory analysis, these wastes are either released under controlled conditions via the penstocks of the Fairfield Pumped Storage Facility or retained for further processing. Permanent records of liquid releases are provided by analyses of known volumes of waste. Alternatively, the liquid may be reused in the plant. For the most part, this effluent is the deaerated, tritiated, borated, and radioactive water from the letdown and drains.

The BRS is designed to collect, via the letdown line in the Chemical and Volume Control System (CVCS), the excess reactor coolant that results from the following plant operations during 1 core cycle:

1. Dilution for core burnup from approximately 1800 ppm boron at the beginning of an 18 month core cycle to approximately 10 ppm near the end of the core cycle.

2. Hot shutdowns and startups. Four (4) hot shutdowns are assumed to take place during an 18 month core cycle.
3. Cold shutdowns and startups. Three (3) cold shutdowns are assumed to take place during an 18 month core cycle.
4. Refueling shutdown and startup.

The BRS also collects water from the following sources:

1. Reactor coolant drain tank (liquid waste processing system) - collects leakoff type drains from equipment inside the containment.
2. Volume control tank and charging pump suction pressure reliefs (CVCS) and residual heat removal pumps pressure reliefs (Emergency Core Cooling System).
3. Boric acid blender (CVCS) - provides storage of boric acid if a boric acid tank must be emptied for maintenance. The boric acid solution is stored in a recycle holdup tank after first being diluted with reactor makeup water by the blender to ensure against precipitation of the boric acid in the unheated recycle holdup tank.
4. Spent fuel pool pumps (Spent Fuel Cooling System) - provides a means of storing the fuel transfer canal water in case maintenance is required on the transfer equipment.
5. Valve leakoffs and equipment drains.

9.3.6.2.1 Capacity Requirement

The BRS is designed to process the total volume of water collected during a core cycle as well as short term surges. The design surge is that produced by a cold shutdown and subsequent startup during the latter part of a core cycle or by a refueling shutdown and startup.

9.3.6.2.2 Purification Requirement

The water collected by the BRS contains dissolved gases, boric acid, and suspended solids. Based on reactor operations with 1% of the rated core thermal power being generated by failed fuel, the BRS is designed to provide sufficient cleanup of the water to allow discharge to the environment within regulatory limits.

The maximum radioactivity concentration buildup in the BRS components is based on operation of the reactor at its engineered safeguards design rating with failed fuel generating 1% of the rated core thermal power. For each component, the shielding design considers the maximum buildup on an isotopic basis including only those isotopes which are present in significant amounts. Filtration and demineralization are the means by which the activity concentrations are controlled.

9.3.6.3 System Description

The BRS is shown in Figure 9.3-18 (piping and instrumentation diagram). When water is directed to the BRS, the flow passes first through the recycle evaporator feed demineralizers and filters and then into the recycle holdup tanks.

The recycle evaporator feed pumps can be used to transfer liquid from one recycle holdup tank to the other if desired. When sufficient water is accumulated to warrant cleanup operation, the recycle evaporator feed pumps take suction from the selected recycle holdup tank. The fluid then flows through the RGWS demineralizers after which it normally is transferred to one of the waste monitor tanks for eventual release from the plant. Alternatively, the water may be sent back to the other monitor tank or to the excess liquid waste system for further processing.

9.3.6.3.1 Component Description

A summary of principal component data is given in Table 9.3-6 and the code requirements are given in Section 3.2.

9.3.6.3.1.1 Recycle Evaporator Feed Pumps

Two (2) centrifugal, canned pumps supply feed to the RGWS demineralizers from the recycle holdup tanks. The pumps can also be used to recirculate water from the recycle holdup tanks through the recycle evaporator feed demineralizers for cleanup if desired. An auxiliary discharge connection is provided to return water to the transfer canal from the recycle holdup tanks, if those tanks were used for storage of transfer canal water during refueling equipment maintenance. Another auxiliary discharge connection is provided to supply water to the suction of the charging pumps (CVCS) for refilling the RCS after loop or system drain.

9.3.6.3.1.2 Recycle Holdup Tanks

Two (2) recycle holdup tanks provide storage of radioactive fluid which is discharged from the RCS during startup, shutdown, load changes and boron dilution. The sizing criteria for the tanks is based on the design surge cold shutdown and startup. The tanks are constructed of austenitic stainless steel.

Each tank has a diaphragm which prevents air from dissolving in the water and prevents the hydrogen and fission gases in the water from mixing with the air. The volume in the tank above the diaphragm is continuously ventilated with building supply air, and the volume of gas below the diaphragm is vented to the gaseous waste processing system.

In addition to the collection of effluent the recycle holdup tanks provide the following functions:

1. Serve as a head tank for the recycle evaporator feed pumps.
2. Provide holdup for draining the RCS to the centerline of the reactor vessel nozzles, including the pressurizer and steam generators.

3. Provide storage for refueling transfer canal water during refueling equipment maintenance.
4. Collect discharge from the relief valve which bypasses the recycle evaporator feed demineralizers.

9.3.6.3.1.3 Recycle Evaporator Feed Demineralizers

Two (2) sluiceable demineralizers remove fission products from the fluid directed to the recycle holdup tanks. The demineralizers also provide a means of cleaning the recycle holdup tank contents via recirculation.

9.3.6.3.1.4 Recycle Evaporator Condensate Demineralizer

A flushable demineralizer is provided as a polishing demineralizer and provides a means of cleanup of the reactor makeup water storage tank contents.

9.3.6.3.1.5 Recycle Evaporator Feed Filter

This filter collects resin fines and particulates from the fluid entering the recycle holdup tanks.

9.3.6.3.1.6 Recycle Evaporator Condensate Filter

This filter collects resin fines and particulate and may be used in conjunction with the recycle evaporator condensate demineralizer.

9.3.6.3.1.7 Recycle Evaporator Concentrates Filter

This filter removes particulates and may be used during certain fluid transfer operations.

9.3.6.3.1.8 Reactor Grade Water System Demineralizers

The Reactor Grade Water System demineralizers are provided to process radioactive waste prior to release to the environment. The demineralizers are located on the 447’ elevation of the Auxiliary Building.

The liquid waste stream enters the demineralizers through a booster pump, a mechanical filter, and an Influent Control Leg which monitors waste stream parameters and provides attachments for service air and water. From the Influent Control Leg, the waste may enter one of the three pressure vessels that contain media for cleanup of the liquid waste. The media normally include:

- Cation resin to remove metals and transition metals.
- Mixed bed resin that reduces undesired positive and negative ions.
- Charcoal media for cleanup as a prefilter providing mechanical filtration capability to protect the other demineralizer beds.

A typical lineup for the three Duratek demineralizers in series could be charcoal, cation and mixed bed with cation.

The actual required vessel lineup during normal plant operation is determined prior to processing by sampling the recycle holdup tank to be processed and determining the parameter(s) that are out of specification. Selection of the appropriate vessels is made by a quick-disconnect logic arrangement. After processing, decontaminated effluent passes through an Effluent Control Leg which records waste volume.

9.3.6.3.1.9 Recycle Holdup Tank Vent Ejector

The ejector is designed to pull gases from under the diaphragm in a recycle holdup tank and deliver them to the gaseous waste processing system. Nitrogen, provided by the standby waste gas compressor, provides the motive force.

9.3.6.3.1.10 Valves

The basic material of construction for most valves is stainless steel. All valves are welded to the piping except the three-way and relief valves, which are flanged. All three-way valves are provided with a stuffing box and lantern leakoff connections. The relief valve upstream of the recycle evaporator feed demineralizers protects the piping which feeds these demineralizers.

9.3.6.3.1.11 Piping

Piping that handles radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing. Stainless steel flex hose is used in a portion of the system.

9.3.6.3.2 System Operation

The BRS is manually operated with the exception of a few automatic protection functions. These automatic functions protect the recycle evaporator feed demineralizers from a high inlet temperature and a high differential pressure, prevent a high vacuum from being drawn on the recycle holdup tank diaphragm and protect the recycle evaporator feed pumps from low net positive suction head. The BRS has sufficient instrumentation readouts and alarms to provide the operator information to assure proper system operation.

9.3.6.3.2.1 Demineralization

Water is accumulated in the recycle holdup tank until sufficient quantity exists to warrant processing through the Reactor Grade Demineralizer System demineralizers. Prior to cleanup operation the contents of the recycle holdup tank are analyzed and if required the demineralizer sequence or resin mix adjusted. Following processing by the demineralizers the flow is sent to the waste monitor tank for discharge to the environment. When the water has been sufficiently processed, it is discharged via the waste monitor tank into the penstocks of the Fairfield Pumped Storage Facility at a rate so as not to exceed a small fraction of the 10 CFR 20 limits. Water leaving this system is monitored for radiation. This radiation monitor, RM-L5, is described in

Section 11.4. Should the radiation monitor close the discharge valve, it must be reset/bypassed before the valve can be reopened.

9.3.6.3.2.2 Recycle Holdup Tank Venting

Because hydrogen is dissolved in the reactor coolant at approximately 1 atmosphere overpressure, a portion of the hydrogen along with fission gases will come out of solution in the recycle holdup tank under the diaphragm. The hydrogen and fission gases are vented to the gaseous waste processing system as required. The total integrated flow from the letdown line and the reactor coolant drain tank to the recycle holdup tanks is monitored. An alarm indicates when a sufficient amount of water has passed to the recycle holdup tanks to require venting of the accumulated gases. A recycle holdup tank should also be vented before and after a RCS loop drain or a drain from the spent fuel pool (or fuel transfer canal).

When venting of either recycle holdup tank is required, the following steps are observed:

1. All inlets to the recycle holdup tank are closed.
2. The recycle holdup tank is lowered to less than or equal to 15%.
3. Both waste gas compressors are lined up to the recycle holdup tank vent ejector.
4. The compressors are started up and the vent from the holdup tank is opened. The vent flow is throttled to approximately 1.2 scfm. At this time, a sample of the vent gases can be taken to check the composition.
5. When the gases have been vented from the recycle holdup tank, the pressure in the vent line decreases, which automatically trips the recycle holdup tank vent isolation valve closed.
6. After the vent isolation valve closes, the manual vent valve is closed, the gas compressor is shut down, and the recycle holdup tank inlets and outlets are lined up for normal use.

9.3.6.3.2.3 Maintenance Drains

When large amounts of water must be drained from the RCS or the spent fuel pool (or fuel transfer canal) to the BRS, a recycle holdup tank is drained of water and vented to the gaseous waste processing system. The water can then be stored in this tank until maintenance is completed and, after checking the chemistry, returned. After returning the water, the recycle holdup tank is again vented to the gaseous waste processing system where it is directed to a shutdown gas decay tank to prevent accumulation of air (i.e., nitrogen) in the high activity gas decay tanks during the venting.

9.3.6.3.2.4 Reactor Makeup Water Cleanup

If the reactor makeup water requires purification, it can be recirculated through the recycle evaporator condensate demineralizer until its chemistry is within specifications. If further processing is necessary, water from the reactor makeup water storage tank can be directed through the recycle evaporator condensate demineralizer and into the recycle holdup tanks for processing via the RGWS demineralizers.

9.3.6.4 Safety Evaluation

Malfunctions in the BRS do not affect the safety of station operations. The BRS is designed to tolerate equipment faults with critical functions being met by the use of 2 pieces of equipment so that the failure of 1 will, at most, reduce the capacity of the BRS but not completely shut it down. Because of the large surge capacity of the BRS, the nonavailability of the RGWS demineralizers can be tolerated for periods of time.

9.3.6.5 Tests and Inspections

The BRS is in intermittent use throughout normal reactor operation. Periodic visual inspection and preventive maintenance are conducted using normal industry practice.

9.3.6.6 Instrumentation Application

The instrumentation available for the BRS is discussed below. Alarms are provided as noted. There is also a common alarm on the main control board which indicates any alarms on the BRS panel.

9.3.6.6.1 Temperature at Inlet to the Recycle Evaporator Feed Demineralizer

Instrumentation is provided to measure the temperature of the inlet flow to the recycle evaporator feed demineralizers and to control a three-way bypass valve. If the inlet temperature becomes too high, the instrumentation aligns the valve to bypass the demineralizers. Local temperature indication and a high temperature alarm on the BRS panel are provided by this instrumentation.

9.3.6.6.2 Pressure

1. Pressure Differential Across the Recycle Evaporator Feed Demineralizers

   Instrumentation is provided to measure the pressure differential across the recycle evaporator feed demineralizers and to control the same three-way valve as discussed above (but independently of the temperature control). If the pressure drop through the demineralizers is too high, this instrumentation aligns the valve to divert flow directly to the recycle evaporator feed filters. Local pressure differential indication and a high alarm on the BRS panel are provided by this instrumentation.

2. Pressure at Inlet and Outlet of Filters

   Instrumentation is provided to measure the pressure differential across each recycle evaporator feed filter, the recycle evaporator concentrates filter, and the recycle evaporator condensate filter. Local indication of the pressure in each inlet and outlet line is provided.

3. Pressure at Discharge of Recycle Evaporator Feed Pump

Instrumentation is provided to measure and give local indication of the discharge pressure of each recycle evaporator feed pump.

4. Pressure in Vent Line from the Recycle Holdup Tanks

   Instrumentation is provided to measure the pressure in the recycle holdup tank vent line and to control a shutoff valve in the vent line. This instrumentation is used during holdup tank venting operations. When the pressure in this line becomes too low, the valve will be automatically closed to protect the holdup tank diaphragm from an excessive differential pressure across it. Local pressure indication and low pressure alarm on the BRS panel are provided.

9.3.6.6.3 Flow

1. Boron Recycle System Flow Totalizer

   Instrumentation is provided to monitor the total integrated flow received by the BRS from the letdown line (CVCS) and the reactor coolant drain tank (waste processing system). Indication of integrated flow and high alarm are given on the BRS panel. Actuation of the high alarm indicates that the integrated flow has reached a value at which the volume of gases (hydrogen and fission gases) which have come out of solution should be vented from the recycle holdup tanks.

2. Flow in Vent Line from Recycle Holdup Tanks

   Instrumentation is provided which gives local indication of the recycle holdup tank vent purge flow.

3. Flow in Feed Line to the RGWS Demineralizers

   Instrumentation is provided which gives local indication of RGWS demineralizers feed flow.

9.3.6.6.4 Level in the Recycle Holdup Tanks

Instrumentation is provided to give an indication of the water level of each recycle holdup tank. Both high level and low level alarms are provided by this instrumentation at the BRS panel. If, after reaching the low level alarm setpoint, the recycle evaporator feed pumps are not stopped, the holdup tank level will continue to decrease until a second low level point is reached and a level actuated control circuit stops the pumps.

9.3.7 References

1. American National Standards Institute, *Steel Pipe, Flanges, Flanged Valves and Fittings*, ANSI B16.5, 1968.

2. American National Standards Institute, *Power Pipin*g, ANSI B31.1, 1967, Addenda through 1972.

3. American National Standards Institute, *American National Standard Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities*, ANSI N13.1, 1969.

Table 9.3-1
Major Compressed Air System Components

Instrument and Service Air Compressors	
Quantity	2
Type	Oil-free rotary screw, two stage, water cooled
Location	Turbine Building
Safety Class	NNS
Capacity, scfm	990
Discharge Pressure, psig	125
Main Motor	
Horsepower	250
Speed, rpm	1800
Electrical Characteristics	460V, 3Φ 60 Hz
Reactor Building Instrument Air Compressors	
Quantity	2
Type	Reciprocating, single stage, single cylinder, water cooled, nonlubricated
Location	Penetration Access Area
Safety Class	NNS
Capacity, scfm	154
Discharge Pressure, psig	90 - 125
Main Motor	
Horsepower	50
Speed, rpm	1800
Electrical Characteristics	460V, 3Φ 60 Hz

Table 9.3-1 (continued)
Major Compressed Air System Components

Instrument Air Dryer	
Quantity	2
Type	Dual chamber, heated, activated alumina desiccant
Location	Turbine Building
Safety Class	NNS
Guaranteed Capacity, scfm	750
Dew point, °F at 100 psig	-40
Pressure Drop, psi	5
Reactor Building Instrument Air Dryers	
Quantity	2
Type	Refrigerated
Location	Penetration Access Area
Safety Class	NNS
Capacity, scfm	150
Dew point, °F at 100 psig	35
Pressure Drop, psi	<5
Backup Instrument Air Compressor	
Quantity	1
Type	Single Stage, Rotary screw
Location	Auxiliary Building
Safety Class	NNS
Capacity, scfm	636
Discharge Pressure, psig	120
Main Motor	
Horsepower	150

Table 9.3-1 (continued)
Major Compressed Air System Components

Speed, rpm	1800
Electrical Characteristics	460V, 3Φ 60 Hz
Diesel Driven Air Compressor	
Quantity	1
Type	Oil-free, rotary screw, two-stage
Location	Yard
Safety Class	NNS
Capacity, scfm	1500
Discharge Pressure, psig	150
Main Motor	
Horsepower	600
Speed, rpm	1800

Table 9.3-2
Nuclear Sampling System Sample Points

Points of Extraction	Number of Points
Residual Heat Removal Loops	2
Pressurizer Steam Space	1
Pressurizer Liquid Space	1
Reactor Coolant Loop B (hot leg)	1
Reactor Coolant Loop C (hot leg)	1
Steam Generator A, Secondary Water	2 (shell and blowdown)
Steam Generator B, Secondary Water	2 (shell and blowdown)
Steam Generator C, Secondary Water	2 (shell and blowdown)
Accumulators A, B, C	3 (one each accumulator)
Chemical and Volume Control System	
Downstream of Letdown Heat Exchanger	1
Downstream of Mixed Bed Demineralizer No. 1	1
Downstream of Mixed Bed Demineralizer No. 2	1
Downstream of Demineralizers and Upstream of Reactor Coolant Filter	1
Volume Control Tank, Gas Space	1
Reactor Coolant Drain Tank	1
Thermal Regeneration Demineralizer Outlet	1

Table 9.3-3
Nuclear Sampling System Major Components

Sample Heat Exchangers	Service (1)			
	(a)	(b)	(c)	(d)
Quantity	1	2	1	3
Cooling Water (shell)				
Inlet Temperature, max., °F	105	105	105	105
Inlet Temperature, normal range, °F	54-98	54-98	54-98	54-98
Flow, gpm	14	14	14	14
Pressure, max., psig	150	150	150	150
Pressure Drop, psi	<10	<10	<10	<10
Cooled Water (tube)				
Inlet Temperature, °F	680	650	400	540
Outlet Temperature, °F	<100	<100	<100	<100
Outlet Temperature, max., °F	120	120	120	120
Flow, gpm	0.3	0.68	0.47	0.64
Design Pressure, psig	2485	2485	600	1185
Pressure Drop, psi	<50	<50	<50	<50
Velocity, min., ft/sec	2.0	4.7	3.2	4.4
Delay Coils				
Design Pressure, psig	2485			
Size, inches	1/2 OD; 0.188 wall			
Length, ft				
Reactor Coolant Loop Sample Sample Downstream Letdown	142			
Heat Exchanger (two coils)	240,120			
Orientation	Vertical runs connected by 180° bends			
Material	Type 304 stainless steel			

Table 9.3-3 (continued)
Nuclear Sampling System Major Components

Sample Heat Exchangers	Service (1)
Code	ASME Code, Section III Class 2

(1) Service
Pressurizer Steam and Liquid Space (a)
Reactor Coolant Loops B and C (b)
Residual Heat Removal Loop (c)
Steam Generators A, B, and C (d)

Table 9.3-4
Chemical and Volume Control System Design Parameters

General	
Seal Water supply flowrate, for three reactor coolant pumps nominal, gpm	24
Seal Water return flowrate, for three reactor coolant pumps, nominal, gpm	7.5
Letdown Flow, gpm	60-120
Charging flow (excludes seal water), gpm	45-105
Temperature of letdown reactor coolant entering system maximum, °F	557
Temperature of charging flow directed to reactor coolant system min. @ 105 gpm charging, °F	438
Temperature of effluent directed to boron recycle system, °F	115
Centrifugal charging pump bypass Flow (each), gpm	60
Alternate Seal Injection Pump Flow, gpm	20

Table 9.3-5
Principal Component Data Summary
Chemical and Volume Control System

Centrifugal Charging Pumps	
Number	3
Design pressure, psig	2900
Design temperature, °F	300
Design flow, gpm	150
Design head, ft	5800
Material	Austenitic Stainless Steel
Boric Acid Transfer Pumps	
Number	2
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	75
Design head, ft	235
Material	Austenitic Stainless Steel
BTRS Chiller Pumps	
Number	2
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	400
Design head, ft	150
Material	Carbon Steel
Regenerative Heat Exchanger	
Number	1
Heat transfer rate at 60 gpm letdown, BTU/hr	8.62×10^6

Table 9.3-5 (continued)
Principal Component Data Summary
Chemical and Volume Control System

Regenerative Heat Exchanger (Continued)	
Shell Side	
Design pressure, psig	2485
Design temperature, °F	650
Fluid	Borated Reactor Coolant
Material	Austenitic Stainless Steel
Alternate Seal Injection Pump	
Number	1
Design pressure, psig	3107
Design temperature, °F	120
Design flow, gpm	20
Design head, ft	7120
Material	Austenitic Stainless Steel
Tube Side	
Design pressure, psig	3100
Design temperature, °F	650
Fluid	Borated Reactor Coolant
Material	Austenitic Stainless Steel
Shell Side (@ 60 gpm Letdown)	
Flow, lb/hr (Normal)	29,800
Inlet temperature, °F	554
Outlet temperature, °F	290
Tube Side (@ 45 gpm Charging)	
Flow, lb/hr (Normal)	22,400
Inlet temperature, °F	130
Outlet temperature, °F	501

Table 9.3-5 (continued)
Principal Component Data Summary
Chemical and Volume Control System

Letdown Heat Exchanger		
Number	1	
Heat transfer rate at 120 gpm letdown, BTU/hr	16.1×10^6	
Shell Side		
Design pressure, psig	150	
Design temperature, °F	250	
Fluid	Component Cooling Water	
Material	Carbon Steel	
Tube Side		
Design pressure, psig	600	
Design temperature, °F	400	
Fluid	Borated Reactor Coolant	
Material	Austenitic Stainless Steel	
Shell Side	@ 120 gpm Letdown	@ 60 gpm Letdown
Flow, lb/hr	551,100	76,500
Inlet temperature, °F	105	105
Outlet temperature, °F	134	173
Tube Side (Letdown)		
Flow, lb/hr	59,600	29,800
Inlet temperature, °F	380	290
Outlet temperature, °F	115	115
Excess Letdown Heat Exchanger		
Number		1
Heat transfer rate at design conditions, BTU/hr		5.2×10^6

Table 9.3-5 (continued)
Principal Component Data Summary
Chemical and Volume Control System

Excess Letdown Heat Exchanger (Continued)

	Shell Side	Tube Side
Design pressure, psig	150	2485
Design temperature, °F	250	650
Design flow, gpm	129,000	12,410
Inlet temperature, °F	105	557
Outlet temperature, °F	145	165
Fluid	Component Cooling Water	Borated Reactor Coolant
Material	Carbon Steel	Austenitic Stainless Steel

Seal Water Heat Exchanger (Design Case)

Number		1
Heat transfer rate at design conditions, BTU/hr		1.51×10^6
Design pressure, psig	150	150
Design temperature, °F	250	250
Design flow, gpm	115,000	64,075
Inlet temperature, °F	105	138
Outlet temperature, °F	118	115
Fluid	Component Cooling Water	Borated Reactor Coolant
Material	Carbon Steel	Austenitic Stainless Steel

Seal Water Heat Exchanger (Alt. Case)	Shell Side	Tube Side
Heat transfer rate, BTU/hr		1.58×10^6
Design flow, lb/hr	115,000	46,660
Inlet temperature, °F	105.0	148.8
Outlet temperature, °F	118.7	115.0

Table 9.3-5 (continued)
Principal Component Data Summary
Chemical and Volume Control System

Moderating Heat Exchanger	Shell Side	Tube Side
Number		1
Heat transfer rate at design conditions, BTU/hr		2.53×10^6
Design pressure, psig	300	300
Design temperature, °F	200	200
Design flow, lb/hr	59,600	59,600
Design inlet temperature (boron storage mode), °F	50	115
Design outlet temperature (boron storage mode), °F	92.4	72.6
Inlet temperature (boron release mode), °F	140	115
Outlet temperature (boron release mode), °F	123.7	131.3
Material	Austenitic Stainless Steel	Austenitic Stainless Steel
Letdown Chiller Heat Exchanger	**Shell Side**	**Tube Side**
Number		1
Heat transfer rate at design conditions, BTU/hr		1.65×10^6
Design pressure, psig	150	300
Design temperature, °F	200	200
Design flow (boron storage mode), lb/hr	175,000	59,600
Design inlet temperature (boron storage mode), °F	39	72.6
Design outlet temperature (boron storage mode), °F	48.4	45

Table 9.3-5 (continued)
Principal Component Data Summary
Chemical and Volume Control System

Letdown Chiller Heat Exchanger (Continued)	Shell Side	Tube Side
Flow (boron release mode), lb/hr	175.000	59,600
Inlet temperature (boron release mode), °F	90	123.7
Outlet temperature (boron release mode), °F	99.4	96.1
Material	Carbon Steel	Austenitic Stainless Steel
Letdown Reheat Heat Exchanger	**Shell Side**	**Tube Side**
Number		1
Heat transfer rate at design conditions, BTU/hr		1.49×10^6
Design pressure, psig	300	600
Design temperature, °F	200	400
Design flow, lb/hr	59,600	44,700
Inlet temperature, °F	115	280
Outlet temperature, °F	140	246.7
Material	Austenitic Stainless Steel	Austenitic Stainless Steel
NOTE: The tube side of the Letdown Reheat Heat Exchanger is no longer in use.		
Volume Control Tank		
Number		1
Volume, ft^3		300
Design pressure, psig		75
Design temperature, °F		250
Material		Austenitic Stainless Steel

Table 9.3-5 (continued)
Principal Component Data Summary
Chemical and Volume Control System

Boric Acid Tanks	
Number	2
Usable capacity, gal	21,000
Design pressure, psig	Atmospheric
Design temperature, °F	170
Material	Austenitic Stainless Steel
Batching Tank	
Number	1
Capacity, gal	400
Design pressure	Atmospheric
Design temperature, °F	300
Material	Austenitic Stainless Steel
Chemical Mixing Tank	
Number	1
Capacity, gal	5
Design pressure, psig	150
Design temperature, °F	200
Material	Austenitic Stainless Steel
BTRS Chiller Surge Tank	
Number	1
Volume, gal	500
Design pressure	Atmospheric
Design temperature, °F	200
Material	Carbon Steel

Table 9.3-5 (continued)
Principal Component Data Summary
Chemical and Volume Control System

Mixed Bed Demineralizers	
Number	2
Design pressure, psig	300
Design temperature, °F	250
Design flow, gpm	120
Resin volume, each, ft^3	30
Material	Austenitic Stainless Steel
Cation Bed Demineralizer	
Number	1
Design pressure, psig	300
Design temperature, °F	250
Design flow, gpm	60
Resin volume, each, ft^3	20
Material	Austenitic Stainless Steel
Thermal Regeneration Demineralizers	
Number	4
Design pressure, psig	300
Design temperature, °F	250
Design flow, gpm	120
Resin volume, each, ft^3	74
Material	Austenitic Stainless Steel

Table 9.3-5 (continued)
Principal Component Data Summary
Chemical and Volume Control System

Reactor Coolant Filter	
Number	1
Design pressure, psig	300
Design temperature, °F	250
Design flow, gpm	150
Particle size, 98% retention	≤ 25 micron
Material, (vessel)	Austenitic Stainless Steel
Seal Water Injection Filters	
Number	2
Design pressure, psig	2735
Design temperature, °F	200
Design flow, gpm	80
Particle size, 98% retention	≤ 5 micron
Material, (vessel)	Austenitic Stainless Steel
Seal Water Return Filter	
Number	1
Design pressure, psig	150
Design temperature, °F	250
Design flow, gpm	150
Particle size, 98% retention	≤ 25 micron
Material, (vessel)	Austenitic Stainless Steel

* More resin must be added to allow for compaction.

Table 9.3-5 (continued)
Principal Component Data Summary
Chemical and Volume Control System

Boric Acid Filter		
Number	1	
Design pressure, psig	150	
Design temperature, °F	250	
Design flow, gpm	150	
Particle size, 98% retention	≤ 25 micron	
Material, (vessel)	Austenitic Stainless Steel	
Letdown Orifice	45 gpm	60 gpm
Number	1	2
Design flow, lb/hr	22,400	29,800
Differential pressure at design flow, psia	1,700	1,700
Design pressure, psig	2,485	2,485
Design temperature, °F	650	650
Material	Austenitic Stainless Steel	Austenitic Stainless Steel
Boric Acid Blender		
Number	1	
Design pressure, psig	150	
Design temperature, °F	200	
Material	Austenitic Stainless Steel	
BTRS Chiller		
Number	1	
Capacity, BTU/hr	1.66×10^6	
Design flow, gpm	352	
Inlet temperature, °F	48.3	
Outlet temperature, °F	39	

Table 9.3-6
Principal Component Data Summary
Boron Recycle System

Recycle Evaporator Feed Pumps	
Number	2
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	30/100
Design head, ft	320/250
Material	Stainless Steel
Recycle Holdup Tanks	
Number	2
Capacity, gal	42,000
Design pressure	Atmospheric
Design temperature, °F	200
Material	Stainless Steel
Recycle Evaporator Reagent Tank - **NO LONGER IN SERVIC**E	
Number	1
Capacity, gal	5
Design pressure, psig	150
Design temperature, °F	200
Material	Stainless Steel
Reactor Grade Water System Demineralizers	
Number	3
Type	Sluiceable
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	35

Table 9.3-6 (CONTINUED)
Principal Component Data Summary
Boron Recycle System

Reactor Grade Water System Demineralizers (continued)	
Resin volume, ft^3	28
Material	Stainless Steel
Recycle Evaporator Feed Demineralizers	
Number	2
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	120
Resin volume, ft^3	30
Material	Stainless Steel
Recycle Evaporator Condensate Demineralizer	
Number	1
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	35
Resin volume, ft^3	20
Material	Stainless Steel
Recycle Evaporator Feed Filter	
Number	1
Design pressure, psig	300
Design temperature, °F	250
Design flow, gpm	150
Filtration rating, 98% removal	5 micron
Material (vessel)	Stainless Steel
Recycle Evaporator Condensate Filter	
Number	1
Design pressure, psig	200

Table 9.3-6 (CONTINUED)
Principal Component Data Summary
Boron Recycle System

Recycle Evaporator Condensate Filter (continued)	
Design temperature, °F	250
Design flow, gpm	35
Filtration rating, 98% removal	25 micron
Material (vessel)	Stainless Steel
Recycle Evaporator Concentrates Filter Number	
Number	1
Design pressure, psig	200
Design temperature, °F	250
Design flow, gpm	35
Filtration rating, 98% removal	25 micron
Material (vessel)	Stainless Steel
Recycle Evaporator Package - **NO LONGER IN SERVICE**	
Number	1
Design flow, gpm	15
Concentrate of concentrate (boric acid), wt percent	4
Concentrate of condensate	< 10 ppm boron as H_3BO_3
Material	Stainless Steel
Recycle Holdup Tank Vent Ejector	
Number	1
Design pressure, psig	150
Design temperature, °F	200
Suction flow, lb/hr	0.248 - 0.3
Motive flow, lb/hr	158
Material	Stainless Steel

Figure 9.3-1
DRAWING D-302-241
FSAR FIGURE REFERENCE

Figure 9.3-2
DRAWING D-302-271
FSAR FIGURE REFERENCE

Figure 9.3-3
DRAWING D-302-273
FSAR FIGURE REFERENCE

Figure 9.3-3A
DRAWING D-302-274
FSAR FIGURE REFERENCE

Figure 9.3-4
DRAWING D-302-771
FSAR FIGURE REFERENCE

Figure 9.3-5
DRAWING E-911-101
FSAR FIGURE REFERENCE

Figure 9.3-6
DRAWING E-911-102
FSAR FIGURE REFERENCE

Figure 9.3-7
DRAWING E-911-103
FSAR FIGURE REFERENCE

Figure 9.3-8
DRAWING E-911-104
FSAR FIGURE REFERENCE

Figure 9.3-9
DRAWING E-911-105
FSAR FIGURE REFERENCE

Figure 9.3-10
DRAWING E-911-106
FSAR FIGURE REFERENCE

Figure 9.3-11
DRAWING E-911-107
FSAR FIGURE REFERENCE

Figure 9.3-12
DRAWING D-302-821
FSAR FIGURE REFERENCE

Figure 9.3-13
DRAWING D-302-822
FSAR FIGURE REFERENCE

Figure 9.3-13A
DRAWING D-302-823
FSAR FIGURE REFERENCE

Figure 9.3-14
DRAWING D-302-352
FSAR FIGURE REFERENCE

Figure 9.3-15
DRAWING D-302-361
FSAR FIGURE REFERENCE

Figure 9.3-16, Sheet 1A
DRAWING E-302-671
FSAR FIGURE REFERENCE

Figure 9.3-16, Sheet 1B
DRAWING E-302-672
FSAR FIGURE REFERENCE

Figure 9.3-16, Sheet 1C
DRAWING E-302-673
FSAR FIGURE REFERENCE

Figure 9.3-16, Sheet 2
DRAWING E-302-674
FSAR FIGURE REFERENCE

Figure 9.3-16, Sheet 3
DRAWING E-302-675
FSAR FIGURE REFERENCE

Figure 9.3-16, Sheet 4
DRAWING E-302-676
FSAR FIGURE REFERENCE

Figure 9.3-16, Sheet 5
DRAWING E-302-677
FSAR FIGURE REFERENCE

Figure 9.3-18
DRAWING E-302-751
FSAR FIGURE REFERENCE

Figure 9.3-20
DRAWING D-302-772
FSAR FIGURE REFERENCE

9.4 AIR CONDITIONING, HEATING, COOLING, AND VENTILATION SYSTEMS

9.4.1 Control Building Area Ventilation System

Air conditioning, heating, cooling and ventilating systems are provided for the control room and other Control Building areas to satisfy the following general requirements:

1. To maintain ambient air temperatures in all areas as required for the comfort andsafety of personnel.
2. To satisfy environmental requirements of equipment.
3. To meet the radiation control requirements of 10 CFR 20.
4. To satisfy the design requirements of General Design Criterion 19, relative to the control room.

9.4.1.1 Design Bases

The systems for the Control Building areas are designed in accordance with the following:

1. The general requirements indicated in Section 9.4.1 are satisfied.
2. Equipment, motors and controls in Safety Class 2b systems are supplied from Class 1E power sources and are separated and redundant to meet the single failure criteria.
3. Instrumentation and control is provided to detect abnormal conditions, such as smoke, high temperature or high radiation levels which require operation in a recirculation mode, emergency filtration mode or outside air purging mode.
4. Operation, monitoring and control of these systems, except for the NNS cooling for office space, in the control room is provided.

9.4.1.2 System Description

The system diagrams for the various Control Building area systems are provided by the following figures:

1. Figure 9.4-1, Control Room System.
2. Figure 9.4-2, Relay Room System and Computer Room System.
3. Figure 9.4-3, Controlled Access Area Supply System and Miscellaneous Room Systems.
4. Figure 9.4-4, Controlled Access Area Exhaust System.
5. Figure 9.4-5, Computer Rooms and SAS Room Cooling System.

Design and performance data are indicated on these figures.

9.4.1.2.1 Control Room System

The main components of this system include:

1. Two (2) 100% capacity air handling units, each with roughing filters (80% efficiency on National Bureau of Standards (NBS) dust), chilled water cooling coil, face and bypass damper section and fan section.
2. Electric reheat coils in the supply ducts.
3. Redundant supply, return, relief and outside air ducts, including necessary fire dampers.
4. Two (2) 100% capacity emergency filter systems, each with filter plenum fan, filter train consisting of roughing filters (80% efficiency on NBS dust), HEPA filters (99.97% efficiency on 0.3 micron particles), charcoal filters (95% efficiency on methyl iodide at 70% relative humidity, 77°F) and final HEPA filters (same efficiency as previous HEPA filter). Each filter plenum also includes a water deluge system.

   The control room emergency filter plenums have been nominally sized for a capacity of 20,000 cfm (21,270 cfm as built) each. The individual filter banks of each plenum have been sized as follows:

   a. Roughing filters: 15 units at 2000 cfm each. Total capacity 30,000 cfm.
   b. HEPA filters: 15 units at 1500 cfm each. Total capacity 22,500 cfm.
   c. Charcoal filters: 11 vertical beds at 2000 cfm each. Total capacity 22,000 cfm.
5. Air operated, spring opposed dampers to isolate the emergency filter systems when not in use; in the face and bypass damper sections of the air handling units; and in the relief air ducts. Air operated butterfly valves with the safety related air accumulators are located in outside air ducts.
6. Instrumentation and control devices to perform the following functions:
   a. Measure pressure drop across normal and emergency filter banks (local indication only).
   b. Cause an alarm in the control room upon detection of high concentration of smoke in the air handling unit return duct or in the emergency filter return duct.
   c. Cause an alarm in the control room upon detection of high temperature in the discharge duct or in the emergency filter charcoal bed.
   d. Indicate, in the control room, the air flow rate in the outside air duct.
   e. Indicate, in the control room, the position of the outside air valves, relief dampers and the emergency filter system isolation dampers.
   f. Provide means for automatically placing the system in the emergency mode and starting the emergency filter system upon receipt of safety injection or high radiation signal from the gaseous activity channel of RM-A1. Provide means to automatically start the normal air handling units and emergency filter fans following loss of offsite power.

g. Provide means, in the control room, for manually initiating system damper positioning for the emergency modes of operation and starting the emergency filter system.

h. Provide means, in the control room, for manually overriding the emergency mode of system operation and to indicate, in the control room, that system override is in effect.

i. Maintain positive control room pressure by adjusting outside air valves. Control room pressure in excess of system setpoints causes an alarm in the control room.

j. Automatically maintain control room temperature by modulating face and bypass damper position and an electric reheat coil in the supply duct.

k. Automatically maintain control room humidity by controlling a humidifier.

l. Indicate, in the control room, air handling unit or emergency filter fan operation.

The system continuously supplies filtered, cooled or heated air to the control room, the technical support center and the cable spreading area under the control room, during normal conditions. Filtered and cooled air is provided during post accident and loss of offsite power conditions. By operation of either one of the two supply air trains, and control of the proper dampers and valves, the system admits small amounts of outside make-up air to the control room to maintain positive pressure during normal and emergency operation, or admits 100% outside air during purge mode. The system maintains space temperature by automatically varying the volume of air passing through the cooling coil and by energizing circuits in the electric reheat coil. The cooling coil is supplied with chilled water from the safety class Chilled Water System (see Section 9.4.7.2.4).

Upon receipt of a safety injection or high radiation signal from the gaseous activity channel of RM-A1, the system automatically places the dampers in the emergency mode and starts the normal air handling unit and emergency filter fan. A loss of offsite power causes the air handling units and emergency filter fans to start automatically. In the event of loss of offsite power, the system can be manually reset for normal operation. Operation of the emergency filter fans passes control room return air through the emergency filter system. Normal operation of the system is accomplished using manual switches in the control room.

The mechanical components, control devices and supply and return ductwork are redundant and separated to ensure system availability. Each system component requiring electrical power is supplied from the Class 1E electrical system. Both systems are supplied with required instrument air from the non-nuclear safety class instrument air system. Since instrument air is not safety-related, system design is such that failure of instrument air will not inhibit system operation in the safety related mode.

During normal operation control room air is recirculated through the control room toilets and kitchen, via an exhaust fan and carbon filter, and is discharged into the return ductwork.

9.4.1.2.2 Relay Room System

The main components of this system include:

1. Two (2) 100% capacity air handling units, each with roughing filters (80% efficiency on NBS dust), face and bypass section, chilled water cooling coil and fan section.
2. Electric reheat coils in the supply duct.
3. Redundant supply, return, relief and outside air ducts.
4. Air operated, spring opposed dampers in the face and bypass damper sections of the air handling units and in the return and relief air ducts.
5. Instrumentation and control devices in each system to perform the following functions:
   a. Measure the pressure drop across the air handling unit filter bank (local indication only).
   b. Cause an alarm in the control room upon detection of high air temperature in the discharge duct and upon detection of high or low temperature in the relay room.
   c. Indicate, in the control room, damper position for the outside air dampers and relief air dampers.
   d. Provide means for automatically placing the system in the emergency recirculation mode (close outside air and relief dampers and open return dampers) and starting the air handling units upon receipt of a safety injection signal or high radiation signal from the gaseous activity channel of RM-A1. Loss of offsite power starts the air handling units but does not cause dampers to be positioned for operation in the recirculation mode.
   e. Provide means for manually initiating system damper positioning for the emergency recirculation mode of operation.
   f. Provide means for manual control of outside, return, and relief damper position.
   g. Automatically maintain relay room temperature by modulating face and bypass damper position and an electric reheat coil in the supply duct.
   h. Indicate, in the control room, air handling unit operation.

The system continuously supplies filtered, cooled, or heated air to the relay room under normal conditions. Filtered and cooled air is provided under post accident and loss of offsite power conditions. By operation of either 1 of the 2 supply air trains and by automatic control of the proper dampers, the system admits fixed amounts of outside ventilation air, no outside air (i.e., recirculation mode), or 100% outside air (i.e., purge mode). The system maintains space temperature by automatically varying the volume of air passing through the cooling coil and by energizing circuits in the electric reheat coil. The cooling coil is supplied by the safety class Chilled Water System (see Section 9.4.7.2.4). Upon receipt of a safety injection or high radiation signal from the gaseous activity channel of RM-A1, the system automatically positions the outside air dampers for the recirculation mode. Receipt of an ESFLS signal starts the fans in both air handling units. The units are normally operated from the control room. Mechanical components, controls, duct system redundancy, separation, power supply, and equipment location are the same as for the control room system, discussed in Section 9.4.1.2.1.

9.4.1.2.3 Computer Room System

The main components of this system include:

1. Two (2) 100% capacity air handling units, each with roughing filters (80% efficiency on NBS dust), face and bypass section, chilled water cooling coil and fan section. Chilled water is provided by the Non-nuclear Safety Related Chilled Water System. See Section 9.4.7.2.12.
2. Electric reheat coils in the supply duct.
3. Redundant supply, return, relief, and outside air ducts.
4. Air operated, spring opposed dampers in the face and bypass damper sections of the air handling units and in the outside, return, and relief air ducts.
5. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the air handling unit filter bank (local indication only).
   b. Cause an alarm in the control room upon detection of high air temperature in the discharge duct and upon detection of high or low temperature in the computer room.
   c. Indicate, in the control room, damper position for the outside air dampers and relief air dampers.
   d. Provide means for manually initiating system damper positioning for recirculation mode of operation.
   e. Provide means for manual control of outside, return, and relief damper position.
   f. Automatically maintain computer room temperature by modulating face and bypass damper position, and an electric reheat coil in the supply duct.
   g. Indicate, in the control room, air handling unit operation.
   h. Provide means for automatically placing system dampers in the emergency recirculation mode positions (close outside air and relief dampers) upon receipt of a safety injection signal or high radiation signal from the gaseous activity channel of RM-A1.
   i. Automatically maintain constant computer room relative humidity by controlling a humidifier.

The system continuously supplies filtered, cooled, or heated air to the computer room under normal and post accident conditions if offsite power is available. By operation of either 1 of the 2 supply air trains and by automatic control of the proper dampers, the system admits fixed amounts of outside ventilation air, no outside air (i.e., recirculation mode), or admits 100% outside air (i.e., purge mode). The system maintains space temperature by automatically varying the volume of air passing through the cooling coils and by energizing circuits in the electric reheat coil. The cooling coil is supplied by the non-nuclear safety related Chilled Water System. Upon receipt of a safety injection or high radiation signal, the system dampers are automatically placed in the recirculation mode position, and the system continues to operate if normal power is available. Upon receipt of an ESF signal, the system dampers are automatically placed in the recirculation mode position

with the fan motors blocked from operation until manually reset. The units are connected to Class 1E power buses. The units are normally operated from the control room.

9.4.1.2.4 Controlled Access Area Supply System

The main components of this system include:

1. A 100% capacity air handling unit including roughing filters (80% efficiency on NBS dust), electric preheating coil, fan section, coil section with chilled water coil and electric heating coil, and a hot and cold deck zoning damper section. Chilled water is provided by the Non-nuclear Safety Related Chilled Water System. See Section 9.4.7.2.12.
2. A 100% capacity sample room and radiochemical laboratory hood supply fan.
3. Outside air, zone supply and hood supply ducts.
4. Air operated, spring opposed dampers to isolate the controlled access air handling unit and laboratory hood supply fan when not in use; in the air handling unit zoning damper section; and in the outside air intake duct.
5. Fire dampers in the zone supply ducts.
6. Instrumentation and control devices in each system to perform the following functions:
   a. Measure the pressure drop across the filter bank (local indication only).
   b. Cause an alarm in the control room upon detection of high temperature in the hood fan discharge duct or in the air handling unit supply duct to Zone II.
   c. Cause an alarm in the control room upon detection of high concentration of smoke in the laboratory hood supply fan discharge, or in the air handling unit supply duct to Zone II.
   d. Indicate, in the control room, the operating status of the laboratory hood supply fan and position of the isolation dampers.
   e. Interlock the position of the dampers with supply fan operation.
   f. Provide permissive interlocks so that controlled access air handling unit and the laboratory hood supply fan cannot operate unless control access filter exhaust fans are operating.
   g. Provide interlocks so that the outside air isolation dampers close on receipt of safety injection signal.
   h. Automatically maintain space temperature in each of four zones by modulating zoning dampers in the hot and cold decks of the air handling unit and by controlling the electric heating coil in the hot deck.
   i. Automatically maintain space temperature downstream of the preheat coil by energizing circuits of this coil as required by the temperature controller.
   j. Indicate, in the control room, the operating status of the air handling unit and the position of associated outside air dampers.

k. Measure and indicate locally, the differential pressure between the controlled access area and the outside and alarm in the control room upon detection of a high or low differential.

The system continuously supplies filtered, cooled or heated air to 4 zones of the controlled access area under normal and post accident conditions if offsite power is available. The system is connected to Class 1E buses. The air handling unit supplies a mixture of makeup and outside air. The laboratory hood supply fan furnishes air from the Turbine Building. The controlled access area ambient pressure and temperatures are controlled, and the various system motors are interlocked as indicated in the listing of instrumentation and control devices above. The cooling coils are each supplied from the NNS Chilled Water System. The air handling unit is located in the Control Building equipment area. The laboratory hood supply fan is located in the Turbine Building. The air handling unit and the laboratory hood supply fan is manually operated from the control room.

9.4.1.2.5 Controlled Access Area Exhaust System

The main components of the system include:

1. A 100% capacity controlled access area filter plenum, including roughing filters (80% efficiency on NBS dust), HEPA filters (99.97% efficiency on 0.3 micron particles), charcoal filters (95% efficiency on methyl iodide at 85% relative humidity and 70°F), and final HEPA filters (same efficiency as previous HEPA filters). The filter plenum also includes a water deluge system.
2. Two (2) 100% capacity controlled access area filter exhaust fans.
3. Exhaust ducts from controlled access areas to the filter plenum, exhaust fans, and plant vent.
4. Air operated, spring opposed dampers to isolate the exhaust fans when not in use.
5. Fire dampers in zone exhaust ducts.
6. Instrumentation and control devices for each component to perform the following functions:
   a. Measure the pressure drop across each filter bank (local indication only).
   b. Cause an alarm in the control room upon detection of high concentration of smoke at the filter inlet.
   c. Cause an alarm in the control room upon detection of high air temperature in the filter fan discharge ducts.
   d. Cause an alarm in the control room upon detection of high temperature of the plenum discharge air or in the filter charcoal bed.
   e. Indicate, in the control room, the position of the filter exhaust fan isolation dampers and interlock damper position with exhaust fan operation.
   f. Indicate, in the control room, exhaust fan operation.

The system operates continuously under normal conditions and emergency conditions if power is available. Power for the controlled access area exhaust and the laboratory hood exhaust fans is

normally supplied from the Class 1E bus. The system exhausts and filters air from normal and hot toilet, shower and locker areas, laundry areas, laboratory hood areas, count room, medical room, and storage areas of the controlled access area. After being filtered, the exhaust air is directed by either of the operating exhaust fans to the main plant vent. The controlled access area filter plenum and exhaust fans are in a shielded location in the Control Building. The exhaust fans are manually operated from the control room.

9.4.1.2.6 SAS/CPU Computer Rooms Cooling System

The main components of this system include:

1. A 32% capacity air handling unit (XAH-18-AH), including roughing filters (80% efficiency on NBS dust), coil face, bypass dampers, coil section with chilled water coil, and fan section. Chilled water is provided by the Non-nuclear Safety Related Chilled Water System. See Section 9.4.7.2.12.
2. A 68% capacity air handling unit (XAH-51-AH), including filters, coil section with R-22 refrigerant coil, and fan section.
3. Electric reheat coils in the supply duct.
4. Supply, return, relief, and outside air ducts.
5. Air operated, spring opposed dampers in the outside air, relief air, and return air ducts.
6. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the air handling unit XAH-18-AH filter bank (local indication only).
   b. Cause an alarm in the control room upon detection of high air temperature in the air handling unit XAH-18-AH discharge.
   c. Cause an alarm in the control room upon detection of high or low SAS/CPU computer rooms space temperature.
   d. Indicate, in the control room, damper position for the outside air, return air, and the relief air dampers.
   e. Provide means for manual control from the control room of the outside, return, and relief damper positions.
   f. Provide means for automatically placing the system in the emergency recirculation mode (close outside air and relief dampers and open return dampers) upon receipt of a safety injection signal or high radiation signal (RM-A1).
   g. Automatically maintain SAS/CPU computer rooms temperature by modulating coil face and bypass damper position and an electric reheat coil in the supply duct.
   h. Interlock the reheat coil so it is inoperative when its corresponding air handling unit fan is not energized.
   i. Indicate, in the control room, air handling unit operation (XAH-18-AH only).

j. Automatically shut down air handling unit XAH-18-AH and XAH-51-AH upon halon release to either computer room or the SAS room.

The system continuously supplies filtered, cooled or heated air to the SAS/CPU computer rooms when normal power is available. Outside air flow is manually controlled from the control room. The room temperature is maintained and system dampers are operated as indicated by the listing of instrumentation and control devices, above. The cooling coil in XAH-18-AH is supplied from the non-nuclear safety related Chilled Water System. The XAH-18-AH air handling unit is located in the Control Building equipment area. The units XAH-18-AH and XAH-51-AH, and the outside, return and relief dampers are manually operated from the control room. The cooling coil in XAH-51-AH is supplied from condensing unit XRC-24-AH. The XAH-51-AH air handling unit is located in the Control Building on elevation 436’-0”.

9.4.1.2.7 Microwave Relay Room System

The major components of the microwave relay room system include the following:

1. A 100% capacity air conditioning unit, including refrigeration system, electric heating coil, and fan.
2. Supply and return air ducts.
3. Filter-grille with roughing filter (30% efficiency on NBS dust).
4. Instrumentation and control devices to perform the following functions:
   a. Cause an alarm in the control room upon detection of high or low microwave relay room space temperature.
   b. Automatically maintain microwave relay room temperature by cycling the refrigeration system and the electric heating coil in the air conditioning unit.

The system continuously supplies filtered, cooled or heated air to the microwave relay room when normal power is available. This is a total recirculation system with no outside/exhaust air. Room temperature is maintained by the instrumentation and control devices noted above. The refrigeration system is self-contained and is air cooled. The air conditioning unit is located on the Control Building roof.

9.4.1.2.8 Microwave Battery Room System

Major components of the microwave battery room system include the following:

1. A 100% capacity exhaust fan.
2. A 100% capacity outside air intake head.
3. Supply and exhaust air ducts.
4. Filter-grille with roughing filter (30% efficiency on NBS duct).
5. Instrumentation and control devices to perform the following functions:

a. Cause an alarm in the control room upon detection of high or low microwave battery room space temperature.

b. Automatically maintain minimum microwave battery room temperature by cycling the electric unit heater.

c. Provide means to shift exhaust fan from low speed to high speed when outside air temperature exceeds the setpoint temperature.

The system continuously exhausts air from the microwave battery room to the atmosphere when normal power is available. Makeup air enters the space through louvers in the battery room door adjoining the corridor space. Outside air is drawn into the corridor space through an intake head and filter-grille in the corridor roof. An electric unit heater, located in the corridor heats the air as necessary to maintain the desired minimum microwave battery room space temperature. Equipment is located on the microwave battery room roof.

9.4.1.2.9 Control Building Office Space System

The major components of the Control Building office space cooling system include the following:

1. A 100% capacity air handling unit with roughing filter and refrigerant coil.
2. A 100% capacity remotely mounted condensing unit, including refrigerant compressor and controls.
3. Ductwork between the air handling unit and the office space for supply and return. The function of this system is to provide cooling for personnel comfort.
4. A 100% capacity electric unit heater.

9.4.1.2.10 Control Building Elevator Machine Room System

Major components of the Control Building elevator machine room system include the following:

1. A 100% capacity exhaust fan.
2. Fixed, wall inlet louvers.
3. A 100% capacity electric unit heater.
4. Instrumentation and control devices to perform the following functions:
   a. Automatically limit maximum elevator machine room temperature by cycling the exhaust fan.
   b. Automatically limit minimum elevator machine room temperature by cycling the electric unit heater.

The system cyclically exhausts air from the elevator machine room to the atmosphere in response to a room thermostat when normal power is available. Makeup air enters the room through wall

louvers. A built-in thermostat cycles the electric unit heater to maintain minimum room temperature. Equipment is located in the Control Building elevator machine room.

9.4.1.3 Safety Evaluation

The control room and relay room systems are designed, protected and arranged with sufficient redundancy to ensure system cooling and filtering operation after a LOCA, assuming a single failure. Loss of the nonredundant instrument air results in decreased space temperatures which do not adversely affect installed equipment. The control room and relay room areas are independent of each other. Each area is served by 2, separated, independent HVAC and filtering subsystems supplied from separate Class 1E electric power supplies. Each system is served by separate instrumentation for control and monitoring. This equipment is Seismic Category 1, located in a Seismic Category 1 structure, and is not subject to floods, weather, external missiles, jet impingement or pipe whip.

The equipment areas are separated by fire walls. Ducts from equipment areas to the control room and relay room are protected by fire dampers. Thus, fire in either equipment area is isolated to that area and operation of the standby system is not affected.

The gaseous activity channel of RM-A1 automatically closes the outside air dampers of the relay room places both systems in the recirculation or emergency mode upon detection of high activity in the air supplied to the control room. High temperature in the supply ducts to the control room and to the relay room or in the discharge duct from the emergency filter system causes an alarm to be actuated in the control room. Smoke in the return duct from the control room to the normal and emergency filter air handling systems causes an alarm to be actuated in the control room. Air flow rates in the outside air ducts to the control room and to the relay room are indicated in the control room.

During normal and emergency operation, the control room is pressurized through the introduction of a fixed amount of outside air. The flow of outside air to the relay room is fixed but is manually adjustable. In the emergency mode control room air is filtered through roughing, HEPA and charcoal filters. Recirculated relay room air is not filtered.

For smoke removal, system dampers for both control and relay room systems can be positioned manually to purge with outside air at rates up to 100%. Prior to purging the control room, the chlorine bottles in the chlorine shed, if installed, must have their cylinder valves closed, then the relief damper blanking plates and outside air duct blanking plates must be removed in conjunction with closing the system return air damper. Degradation of equipment performance as a result of excess temperature and humidity is not anticipated since the control and relay room systems are designed in accordance with the criteria specified above.

9.4.1.4 Inspection and Testing Requirements

The Control Building area systems are subjected to preoperational testing in accordance with written procedures to verify proper wiring and control hookup, filter and duct system in place

integrity and leak tightness, proper function of system components and control devices and to establish system design water and air flow rates.

To ensure a continued state of readiness of the Control Building area systems after completion of the preoperational tests, the following inspection, maintenance and test procedures are performed.

1. Control Room System
   a. Record filter pressure drops.
   b. Verify function of dampers, valves and control devices necessary for monitoring or component isolation or changeover from normal to emergency mode.
   c. Bearing lubrication.
   d. Switch components that normally operate from standby to operating mode
   e. Laboratory test of charcoal filter test canisters for decontamination efficiency.
   f. Inplace leak test of the HEPA and charcoal filters.
2. Relay Room System

   Relay room system inspection, maintenance and test requirements are the same as control room system requirements a. through d.

3. Computer Room System

   Computer room system inspection, maintenance and test requirements are the same as control room system requirements a. through d.

4. Controlled Access Area Supply System

   Controlled access area supply system inspection, maintenance and test requirements are the same as control room system requirements a. through d.

5. Controlled Access Area Exhaust System

   Controlled access area exhaust system inspection, maintenance and test requirements are the same as control room system requirements a. through f.

6. SAS/CPU Computer Room Cooling System

   SAS/CPU Computer room cooling system inspection, maintenance and test requirements are the same as control room system requirements a. and c.

7. Microwave Relay Room System

Microwave relay room system inspection, maintenance and test requirements are the same as control room system requirement c.

8. Microwave Battery Room System

   Microwave battery room system inspection, maintenance and test requirements are the same as control room system requirement c.

9. Control Building Elevator Machine Room System

   Control Building elevator machine room system inspection, maintenance and test requirements are the same as control room system requirement c.

9.4.2 Auxiliary and Radwaste Area Ventilation System

Heating, cooling, ventilation, exhaust and filtering are provided throughout various Auxiliary Building, radwaste and hot machine shop areas to satisfy the following general requirements:

1. Maintain ambient air temperatures in all areas between minimum and maximum levels suitable for personnel and equipment.
2. Minimize the release of radioactive airborne particulates and gaseous activity to the atmosphere.
3. Provide for filtration of the refueling water storage tank vent discharge.

9.4.2.1 Design Bases

The systems for the Auxiliary Building and radwaste areas are designed in accordance with the following:

1. The general requirements indicated in Section 9.4.2 are satisfied.
2. Equipment, motors and controls in the Safety Class 2b portions of these systems are supplied from Class 1E electric power sources and have sufficient separation and redundancy to satisfy the single failure criteria.
3. Provision is made for monitoring and actuating alarms in the control room upon detection of: high temperature in ducts, HEPA/charcoal plenums, or pump cubicles; high smoke concentration in ducts; high vibration at fan motors; and motor trip. Provisions are also made for monitoring the following in the control room: damper positions, main plant vent flow rate, and radiation levels in the main plant vent (RM-A3) and waste gas decay tank vent (RM-A10).
4. Manual control of these systems as indicated is provided in the control room. Pump room units operate automatically when the respective pump operates.

5. Continuous, controlled air flow is maintained from areas of low to progressively higher radiation levels. Maintenance of a negative Auxiliary Building pressure ensures that exfiltration from the Auxiliary Building does not occur.
6. Exhaust air flows through roughing and HEPA filters or through roughing, HEPA, charcoal and HEPA filters, depending upon the potential radioactivity of the areas exhausted.

9.4.2.2 System Description

The system diagrams for the various auxiliary building and radwaste area systems are as follows:

1. Figure 9.4-6, Auxiliary Building Main Supply System.
2. Figure 9.4-7, Auxiliary Building HEPA Exhaust System.
3. Figure 9.4-8, Auxiliary Building Charcoal Exhaust System.
4. Figure 9.4-9, Auxiliary Building Main Exhaust System.
5. Figure 9.4-10, Auxiliary Building Pump Room and Motor Control Center Cooling Systems
6. Figure 9.4-10a, Hot Machine Shop Ventilation System.
7. Figure 9.4-11, Fuel Handling Building Charcoal Exhaust System and Air Supply Distribution

9.4.2.2.1 Auxiliary Building Main Supply System

The main components of this system include:

1. A 100% capacity supply fan directing ventilation air to various areas of the Auxiliary Building, radwaste areas and to the Fuel Handling Building.
2. Two (2) 50% capacity supply air filter plenums, each consisting of roughing filters (80% efficiency on NBS dust) and electric preheat coils.
3. Electric reheat coils in the zone supply ducts.
4. Air operated, spring opposed dampers to isolate the supply fan when not in use and to close or control the outside air supply.
5. Ductwork from the outside air connection to the filtering and preheating plenums, to the supply fan and to the various Auxiliary Building and radwaste areas.
6. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the roughing filter banks (local indication only).
   b. Cause an alarm in the control room upon detection of high concentration of smoke in the supply main to the various Auxiliary Building areas.
   c. Cause an alarm in the control room upon detection of high temperature in the supply main to the various Auxiliary Building areas.
   d. Indicate, in the control room, supply fan isolation damper and outside air damper position.

e. Cause an alarm in the control room upon detection of excessive vibration of the supply fan.

f. Cause an alarm in the control room upon detection of high or low Auxiliary Building ambient air pressure.

g. Provide means for manual operation, from the control room, of the supply fan interlocked with its isolation dampers and with the main exhaust fan.

h. Automatically maintain minimum supply air temperature by controlling the supply system preheat coils and provide interlocks to prevent preheat coil operation unless supply fans are operating.

i. Automatically maintain fixed zone supply air temperature by controlling the zone reheat coils.

j. Maintain negative ambient static pressure within the Auxiliary Building by the setting of manual balancing dampers.

k. Indicate, in the control room, supply air fan operation.

l. Cause an alarm in the control room upon detection of supply air fan motor trip.

The Auxiliary Building main supply system continuously supplies outside air that is drawn through the Auxiliary Building supply air plenums where it is filtered and heated as required. The supply air is then ducted to various corridors, demineralizer tank areas, gas decay tank and holdup tank areas, valve areas, and stand-by air compressor area at elevations 485', 463', 436', 412', 397', 388', and 374'. This supply air is then drawn by various exhaust systems through equipment areas and through equipment cubicles. The supply air distribution is arranged so that the resultant exhaust air flow is toward progressively greater levels of activity. The Auxiliary Building supply air fan is manually controlled from the control room and operates continuously if normal power is available. The supply fan is electrically interlocked so that it cannot operate unless one of the Auxiliary Building main exhaust fans is operating, thereby ensuring that the Auxiliary Building ambient pressure does not become positive. The components for this system are located as follows:

1. Supply fan in the Auxiliary Building.
2. Filtering and heating plenums in the Auxiliary Building.

Outside air is drawn into the system through stormproof louvers in a mechanical equipment room roof penthouse.

9.4.2.2.2 Auxiliary Building HEPA Exhaust System

The main components of this system include:

1. Two (2) 100% capacity exhaust fans which exhaust air through the HEPA filter plenum.

2. A 100% capacity filter plenum with roughing filters (80% efficiency on NBS dust) and HEPA filters (99.97% efficiency on 0.3 micron particles).
3. Air operated, spring opposed dampers to isolate the exhaust fans when not in use.
4. Ductwork to direct the exhaust air from various Auxiliary Building areas to the HEPA filter plenum, the exhaust fans and, finally, to the plant vent.
5. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the roughing/HEPA filter banks (local indication only).
   b. Cause an alarm in the control room upon detection of high concentration of smoke at the inlet of the exhaust filter plenum.
   c. Cause an alarm in the control room upon detection of high temperature in the discharge of either exhaust fan.
   d. Indicate, in the control room, fan isolation damper position.
   e. Cause an alarm in the control room upon detection of excessive vibration of the exhaust fans.
   f. Provide means for manual operation, from the control room, of the exhaust fans interlocked with their respective isolation dampers and with the Auxiliary Building charcoal exhaust fans.
   g. Indicate, in the control room, exhaust fan operation.
   h. Cause an alarm in the control room upon detection of exhaust fan motor trip.

The Auxiliary Building exhaust system continuously exhausts the air furnished by the supply system described in Section 9.4.2.2.1. The exhaust air is drawn from auxiliary building areas with minimum potential for contamination at elevations 485', 463', 436', 412', 388', and 374'. The supply and exhaust ducts are arranged so that air flow is always in the direction of progressively greater potential radioactivity. The exhaust air from these areas is continuously drawn through the roughing/HEPA filter plenum prior to ducting to the main exhaust fans and the main plant vent. There is no bypass around this filter plenum. The exhaust fans for this system are manually controlled from the control room and operate continuously if normal power is available. The HEPA exhaust fans are electrically interlocked so that they cannot be operated unless the Auxiliary Building charcoal exhaust fans are in operation. Thus, exhaust flow is always toward the potentially more radioactive areas. The components for this system are located as follows:

1. Exhaust fans, in the Auxiliary Building.
2. Filter plenum, in the Auxiliary Building.

9.4.2.2.3 Auxiliary Building Charcoal Exhaust System

The Auxiliary Building charcoal exhaust system consists of 2 subsystems, one which serves the north portion of the building and the other which serves the south portion of the building. Each subsystem provides approximately 50% of the total building filtration.

The main components of this system include:

1. Two (2) 100% capacity exhaust fans for each subsystem which exhaust air through the HEPA/charcoal plenum.
2. One (1) 100% capacity filter plenum for each subsystem, which corresponds to 50% capacity relative to the entire Auxiliary Building, each with roughing filters (80% efficiency on NBS dust), HEPA filters (99.97% efficiency on 0.3 micron particles), charcoal filters (95% efficiency on methyl iodide at 85% relative humidity and 70°F) and final HEPA filter (same efficiency as previous HEPA filter bank). The filter plenum also includes a water deluge system.
3. Air operated, spring opposed dampers to isolate the exhaust fans not in use.
4. Ductwork to direct the exhaust air from various Auxiliary Building areas of potentially moderate contamination to the HEPA/charcoal plenum, the exhaust fans and, finally, to the main plant vent.
5. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the roughing/HEPA/charcoal filter banks (local indication only).
   b. Cause an alarm in the control room upon detection of high concentration of smoke in the inlet of each filter plenum.
   c. Cause an alarm in the control room upon detection of high temperature in the discharge of any exhaust fan or in either charcoal filter plenum.
   d. Indicate, in the control room, fan isolation damper position.
   e. Cause an alarm in the control room upon detection of excessive vibration of the exhaust fans.
   f. Provide means for manual operation, from the control room, of the exhaust fans interlocked with their respective isolation dampers.
   g. Indicate, in the control room, exhaust fan operation.
   h. Cause an alarm in the control room upon detection of exhaust fan motor trip.
   i. Cause an alarm in the control room upon detection of high radiation in the gas decay vent discharge (RM-A10).

The Auxiliary Building charcoal exhaust system continuously exhausts the air furnished by the supply system described in Section 9.4.2.2.1. The exhaust air is drawn from Auxiliary Building areas with moderate potential for radioactive contamination (demineralizers, storage tanks, gas decay tanks, evaporators, pump rooms, etc.) at elevations 463’, 436’, 412’, 397’, 388’, and 374’. The vent from the refueling water storage tank also discharges into this exhaust system. The supply and exhaust ducts are arranged so that air flow is always in the direction of progressively greater potential radioactivity. Exhaust air from these areas is drawn through the roughing/HEPA/charcoal filter plenums continuously and is ducted to the main exhaust fans and the main plant vent. There is no bypass around this filter plenum. The exhaust fans for this system are manually

controlled from the control room and operate continuously if power is available. The fans stop upon loss of Class 1E bus voltage but may be restarted after Class 1E electric power is regained.

Components of this system are located as follows:

1. Exhaust fans, in the Auxiliary Building.
2. Filter plenum, in the Auxiliary Building.

9.4.2.2.4 Auxiliary Building Main Exhaust System

The main components of this system include:

1. Two (2) 100% capacity main exhaust fans which exhaust air from various Auxiliary and Fuel Handling Building areas to the main plant vent.
2. Two (2) 100% capacity exhaust fan bypass dampers.
3. Air operated, spring opposed dampers to isolate the exhaust fans when not in use.
4. Ductwork to direct the exhaust air from the various systems through the main plant vent.
5. Instrumentation and control devices to perform the following functions:
   a. Cause an alarm in the control room upon detection of high concentrations of smoke in the discharge of either exhaust fan.
   b. Cause an alarm in the control room upon detection of high temperature in the discharge of either exhaust fan.
   c. Cause an alarm in the control room upon detection of excessive vibration of the exhaust fans.
   d. Indicate, in the control room, fan isolation damper position.
   e. Provide means for manual operation, from the control room, of the main exhaust fans. Fan isolation dampers operate in conjunction with associated fans. The Auxiliary Building HEPA exhaust fans must be operating prior to starting one of the main exhaust fans.
   f. Provide means for automatically opening the bypass dampers when neither of the main exhaust fans is operating.
   g. Indicate, in the control room, the main plant vent flow rate.
   h. Indicate, in the control room, exhaust fan operation.
   i. Cause an alarm in the control room upon detection of exhaust fan motor trip.
   j. Cause an alarm in the control room upon detection of a high radiation level in the main plant vent (RM-A3).

The Auxiliary Building main exhaust system operates continuously to direct all air from the Fuel Handling Building exhaust system, the Auxiliary Building HEPA exhaust system and the Auxiliary Building charcoal exhaust system to the main plant vent. Interlocking of the various

systems prevents operation of the Auxiliary or Fuel Handling Building supply fans unless the exhaust system is operating. Similar interlocking prevents operation of the Auxiliary Building HEPA exhaust fans unless the Auxiliary Building charcoal exhaust fans are operating. Thus, the Auxiliary Building and Fuel Handling Building ambient pressure does not become positive and the exhaust flow paths toward increasing potential radioactivity are not violated. The main exhaust fans are manually controlled from the control room and use non-Class 1E power.

9.4.2.2.5 Auxiliary Building Pump Room Cooling Systems

The main components of these systems include:

1. For each charging pump room and each residual heat removal/Reactor Building spray pump room, a 100% capacity air handling unit consisting of fan section, chilled water coil and roughing filter.
2. Ductwork supply and return from each air handling unit to its respective room.
3. Instrumentation and control devices for each system to perform the following functions:
   a. Measure the pressure drop across the roughing filter (local indication only).
   b. Cause an alarm in the control room upon detection of high concentration of smoke at the inlet of the charging pump room fans or at the discharge of the residual heat removal/Reactor Building spray pump room fans.
   c. Cause an alarm in the control room upon detection of high temperature in the discharge of the fan.
   d. Indicate, in the control room, fan operation.
   e. Cause an alarm in the control room upon detection of fan motor trip.
   f. Cause an alarm in the control room upon detection of high pump room temperature.
   g. Provide the means for manual control of pump room air handling units from the control room and for automatic operation of the units interlocked with pumps.

The air handling units are mounted in locations shielded from the pump rooms, accessible for maintenance, supplied with safety class chilled water and operate either manually or automatically when the pumps are energized. The units are powered from the Class 1E electric system.

9.4.2.2.6 Hot Machine Shop Ventilation System

A. Auxiliary Building Hot Machine Shop

The main components of this system include:

1. A 100% capacity supply fan directing ventilation air to the hot machine shop.
2. A 100% capacity, two-speed exhaust fan exhausting air from various hot machine shop areas.

3. Ductwork to the supply fan from an outside air inlet connection with roughing filters and electric heating coil. Ductwork from various hot machine shop areas to the fuel handling building exhaust filter plenums.
4. Three (3) electric unit heaters along the perimeter walls of the hot machine shop.
5. Instrumentation and control devices to perform the following functions:
   a. Modulate return and outside air dampers in the system ductwork in accordance with a differential pressure controller. The differential pressure controller maintains a negative differential pressure between the hot machine shop and the outside.
   b. Control the electric duct heater with a room thermostat.
   c. Control the electric unit heaters with integral thermostats.

When normal power is available, the hot machine shop supply and exhaust fans are operated so as to maintain air supply to and exhaust from the hot machine shop when required. The supply and exhaust fans are controlled from location stations and are supplied from non-Class 1E power sources.

B. Radiological Maintenance Building Hot Machine Shop

The main components of this system include:

1. Two (2) air handling units, each comprised of a roughing filter, electric heating coil, a direct expansion cooling coil, and fan section continuously operate. Each air handling unit is rated at 50% of the required supply air flow.
2. Each air handling unit has an associated air cooled condensing unit.
3. A centrifugal exhaust fan rated at 100% of the required exhaust air flow.
4. A filter plenum containing a roughing and HEPA filter bank. The filter is rated at 100% of the exhaust air flow.
5. Four (4) electric unit heaters provide perimeter heating. Two (2) electric unit heaters are installed at the outside roll-up door.
6. Ductwork between the air handling units and points of distribution, between exhaust registers and HEPA filter plenum, between HEPA filter plenum and exhaust fan, and between exhaust fan and the plant vent.
7. Instrumentation and control devices to perform the following functions:
   a. Each air handling unit, condensing unit, and exhaust fan is energized from a local disconnect switch.
   b. Air handling unit fans are interlocked with the exhaust fan.
   c. Room thermostats set at 104°F control the operation of the condensing units and cycle them as necessary.

d. A smoke detector in the discharge duct of each air handling unit de-energizes the associated fan if smoke is present in the duct.

e. Each electric unit heater is controlled by a built-in thermostat.

9.4.2.2.7 Hot Machine Shop Decontamination Area Ventilation System

The main components of this system include:

1. An air handling unit comprised of a roughing filter section, an electric heating coil section and a fan section. The unit is rated at 100% of the required supply air flow.
2. An exhaust fan rated at 100% of the required exhaust air flow.
3. A filter plenum containing a roughing and a HEPA filter bank. The filter is rated at 100% of the exhaust air flow.
4. Ductwork between the air handling unit and the points of distribution, between the wall hoods and the filter, between the filter and the exhaust fan, and between the exhaust fan and the plant vent. The ductwork contains an automatic isolation damper for each fan which closes when the respective fan is off and vice versa.
5. Instrumentation and control devices to perform the following functions:
   a. To sense and correct the air handling unit supply air temperature by energizing the electric heating coil.
   b. To sense and alarm locally in the event of high temperature air in both the supply and exhaust ducts.
   c. To indicate locally the pressure differential air on each exhaust filter bank.

All components of this system are non-nuclear safety. When normal power is available, both fans operate continuously to supply air to and exhaust air from the wall hoods when required. The fans are controlled from local stations and are supplied from non-Class 1E power sources.

9.4.2.2.8 Auxiliary Building Motor Control Center and Switchgear Areas Cooling Systems

The main components of these systems include:

1. Three (3) 100% capacity air handling units and 2 non-nuclear safety class supplemental air handling units for the safety class switching gear areas on elevation 412’ and 463’. Each of these air handling units serves 1 of the 3 motor control center and switchgear areas. The safety class air handling units serving motor control center and switchgear areas at elevations 412’ and 463’ each include a fan section, chilled water coil supplied with safety class chilled water (see Section 9.4.7.2.4) and roughing filter. The non-safety class air handling units serving the motor control center and switchgear areas includes a fan section, direct expansion type cooling coil and roughing filter. Also a part of the non-safety class systems are a remotely mounted condensing unit, including refrigerant compressor, condensing section, piping and controls.

2. Ductwork from the various air handling units to the areas requiring cooling.
3. Instrumentation and control devices for each system to perform the following functions:
   a. Measure the pressure drop across the roughing filter (local indication only), except the non-safety class units.
   b. Cause an alarm in the control room upon detection of high concentration of smoke in the electrical equipment room.
   c. Cause an alarm in the control room upon detection of high temperature in the discharge of the air handling unit or in the electrical equipment room.
   d. Indicate, in the control room, fan operation (safety related fans only).
   e. Cause an alarm in the control room upon detection of fan motor trip (safety related fans only).
   f. Automatically cycle the selected air handling unit in response to a room thermostat (safety related fans only).

The air handling units in each of the two safety related systems recirculate and cool while cycling on/off in response to a room thermostat. Under emergency conditions, the thermostat control of the safety related air handling unit is bypassed and the units start and operate continuously following receipt of a safety injection or loss of offsite power signal. Power is supplied to the safety related units at elevations 412’ and 463’ from separated, independent Class 1E power sources. Power is supplied to the non-safety related system from a non-Class 1E source. The air handling unit at elevation 436’ operates continuously when started at the local control station. The non-safety class cooling systems for the switchgear areas at elevation 412’ and 463’ are controlled by temperature switches in the rooms. A room thermostat controls the refrigerant solenoid valves. The safety related air handling units can be manually started or stopped from the control room.

9.4.2.2.9 Hot Instrument Repair Shop Ventilation System

The main components of this system are contained in a single, factory-assembled, through the wall, air conditioner with built-in electric heating coil. All controls are self-contained. No ductwork is employed with this system which is classed as non-nuclear safety.

This system operates continuously. The unit compressor and electric heating coil cycle as required to maintain the room temperature controlled by the self-contained thermostat.

9.4.2.2.10 Auxiliary Building Elevator Machine Room Exhaust System

The main components of this system are an exhaust fan with back-draft damper, a gravity-operated air louver and electric unit heater. A room thermostat cycles the fan. A self-contained thermostat cycles the unit heater. No ductwork is employed. The system is non-nuclear safety class.

9.4.2.2.11 HP Calibration Lab and Repair Shop HVAC System

The main components of this system include:

1. A self-contained, air-cooled heat pump containing a compressor motor, an indoor fan motor, an outdoor fan motor and an electric heating coil.
2. Ductwork to and from the lab and shop including manual balancing dampers in the return and outside air ducts, a splitter damper in the supply duct, supply air diffusers, return registers and a roughing filter.
3. Controls include a compressor crankcase heater, automatic defrost package, room thermostat and switchbase, emergency heat relay and outdoor thermostat package. All motors have thermal-and-current- sensitive overload devices.

This system is classed as non-nuclear safety.

The heat pump is started by a remote manual switch which causes its indoor fan to operate continuously to provide air circulation and ventilation. The compressor and electric heating coil cycle automatically under thermostatic control to maintain the space temperature.

9.4.2.3 Safety Evaluation

The auxiliary and radwaste area systems, excluding the pump room units, and motor control center and switchgear cooling units at elevations 412’ and 463’, are not safety class systems. However, redundant fans are provided for the main exhaust, the charcoal exhaust and the HEPA exhaust systems. Charcoal exhaust fans and plenums are physically separated, housed in shielded concrete enclosures and the fans receive power from the Class 1E electric system. All charcoal and HEPA filter plenums are constructed in accordance with Seismic Category 1 requirements. Additionally, provision is made for suitable maintenance and change-out space and adequate instrumentation and lighting, all of which reduce personnel exposure.

The pump room systems and the motor control center and switchgear cooling units are not redundant but are arranged as single units for each pump room. Loss of a pump room, motor control center or switchgear cooling unit requires use of redundant equipment and its cooling unit. The cooling units are separated, located in an accessible, shielded location and are not subject to floods, weather, external missiles, jet impingement or pipe whip. The pump room units are powered from separated Class 1E power supplies.

Where indicated, units are administratively controlled from the control room during normal operating or refueling periods. This control is subject to protective electric interlocking so that negative auxiliary building pressure and design air flow paths are maintained. Operation of the pump room units is automatic. These units operate when the associated pump operates.

Where indicated, units are monitored from and alarms are provided in the control room. The charcoal plenums have manually actuated water deluge systems for fire protection.

Radiation levels in the charcoal filters, the exhaust from the gas decay vent and the main plant vent exhaust are monitored from, and alarms are provided in, the control room. Exhaust filter plenums provide a minimum of 95% removal efficiency for both organic and elemental forms of iodine.

9.4.2.4 Inspection and Testing Requirements

The auxiliary and radwaste area ventilation systems are subjected to preoperational test procedures to verify proper wiring and control hookup, system inplace integrity and leak tightness, proper function of system components and control devices and to establish system design air flows.

To ensure a continued state of readiness of the auxiliary and radwaste area ventilation systems after completion of the preoperational tests, the following inspection, maintenance and test procedures are performed:

1. Auxiliary Building Charcoal Exhaust System
   a. Record filter pressure drops.
   b. Verify function of dampers or control devices necessary for monitoring, component isolation or changeover from normal to emergency mode.
   c. Bearing lubrication.
   d. Switch components that normally operate from standby to operating mode.
   e. Laboratory test of charcoal filter test canisters for decontamination efficiency.
   f. Inplace leak test of HEPA and charcoal filters.
2. Auxiliary Building HEPA Exhaust System

   Auxiliary Building HEPA exhaust system inspection, maintenance and testing requirements are the same as Auxiliary Building charcoal exhaust system requirements a. through d. and inplace leak test of HEPA filters.

3. Auxiliary Building Main Exhaust System

   Auxiliary Building main exhaust system inspection, maintenance and testing requirements are the same as Auxiliary Building charcoal exhaust system requirements b. through d.

4. Auxiliary Building Main Supply System

   Auxiliary Building main supply system inspection, maintenance and testing requirements are the same as Auxiliary Building charcoal exhaust system requirements a., c., and d.

5. Auxiliary Building Pump Room Cooling System

Auxiliary Building pump room cooling system inspection, maintenance and testing requirements are the same as Auxiliary Building charcoal exhaust system requirements a. through d.

6. Hot Machine Shop Ventilation System

   Hot machine shop ventilation system inspection, maintenance and testing requirements are the same as the Auxiliary Building charcoal exhaust system requirements a. through d.

7. Hot Machine Shop Decontamination Ventilation System

   Hot machine shop decontamination ventilation system inspection, maintenance and testing requirements are the same as the Auxiliary Building charcoal exhaust requirements a. through d., plus inplace leak test of HEPA filters.

8. Auxiliary Building Motor Control Center and Switchgear Areas Cooling System

   Auxiliary Building motor control center and switchgear areas cooling system inspection, maintenance and testing requirements are the same as the Auxiliary Building charcoal exhaust system requirements a. through d.

9. Hot Instrument Repair Shop Ventilation System

   Hot instrument repair shop package HVAC system inspection, maintenance and testing requirements are the same as the Auxiliary Building charcoal exhaust system requirement d.

10. Auxiliary Building Elevator Machine Room Exhaust System

    Auxiliary Building elevator machine room exhaust system inspection, maintenance and testing requirements are the same as the Auxiliary Building charcoal exhaust system requirement d.

11. HP Calibration Lab and Repair Shop HVAC System

    Calibration lab and repair shop air conditioning system inspection, maintenance and testing requirements are the same as the Auxiliary Building charcoal exhaust system requirements b. and d.

9.4.3 Fuel Handling Building Ventilation

Continuous ventilation and exhaust of the spent fuel pool area and the Fuel Handling Building results in an environment suitable for personnel and equipment. Additionally condensation from the fuel pool area and the release of airborne radioactivity to the atmosphere is minimized.

9.4.3.1 Design Bases

The system for the spent fuel pool area are designed in accordance with the following:

1. Equipment motors and controls in the safety class portions of the systems are supplied from Class 1E electric power sources and have sufficient redundancy to satisfy the single failure criteria.
2. Provision is made for monitoring and manual control of the safety class portions of the systems from the control room. Operation of exhaust system fans and dampers is initiated automatically by a loss of offsite power signal.
3. The supply and exhaust systems provide continuous flow across the spent fuel pool water surface and provide controlled ventilation air flow in other Fuel Handling Building spaces. Ventilation air flow is from areas of low to progressively higher radiation levels.
4. Ventilation air is supplied to the Fuel Handling Building from the Auxiliary Building by two non-safety related fans. These fans are not automatically tripped during accident or high radiation situations and will usually operate during normal and emergency conditions. One of two safety related exhaust fans is operated during normal and emergency conditions. Supply and exhaust air flow are balanced so that a negative pressure with respect to the outside of at least 1/8 inch water gage is maintained in the Fuel Handling Building with both supply fans and one exhaust fan operating. Postulated failures of the non-safety related supply fans would result in a negative pressure of more than 1/8 inch which would provide additional assurance in preventing the outflow of unfiltered air.
5. Ventilation air flow is directed through a roughing, HEPA and charcoal filter assembly to minimize the radioactivity being released to the plant vent.
6. Provision is made to maintain a minimum ventilating supply air temperature to the Fuel Handling Building of 65°F.
7. Provision is made to monitor normal and abnormal radiation levels in the area.

9.4.3.2 System Description

The system diagrams for the various spent fuel pool area systems are as follows:

1. Figure 9.4-11, Fuel Handling Building Charcoal Exhaust System and Air Supply Distribution.
2. Figure 9.4-6, Auxiliary Building Main Supply System.

Design and performance data are indicated on these figures.

9.4.3.2.1 Fuel Handling Building Supply and Charcoal Exhaust System

The main components of this system include:

1. Two (2) 100% capacity fuel handling building exhaust fans which draw air through the HEPA/charcoal filter plenums.
2. Three (3) 50% capacity filter plenums, each consisting of roughing filters (80% efficiency on NBS dust), HEPA filters (99.97% efficiency on 0.3 micron particles), charcoal filters (95% efficiency on methyl iodide at 95% relative humidity and 86o F, and final HEPA filters (same efficiency as previous HEPA filter). The filter plenum also includes a water deluge system.
3. A 100% capacity supply fan which directs outside air across the spent fuel pool surface.
4. Air operated, spring opposed dampers to isolate the supply and exhaust fans when not in use.
5. One electric reheat coil in each supply duct.
6. Ductwork which directs the supply air to the spent fuel pool surface, and various areas of the building, exhausts this air from the spent fuel pool surface and exhausts air from various Fuel Handling Building areas through the charcoal/HEPA filter plenum to the exhaust fans and the plant vent.
7. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the HEPA/charcoal filter banks (local indication only).
   b. Cause an alarm in the control room upon detection of high concentration of smoke in the inlet of the exhaust plenum.
   c. Cause an alarm in the control room upon detection of high temperature in any one of the charcoal filter plenums, in the discharge of either exhaust fan or in the discharge of the supply fan.
   d. Indicate, in the control room, supply and exhaust fan isolation damper position.
   e. Cause an alarm in the control room upon detection of excessive vibration of the supply or exhaust fans.
   f. Provide means for manual operation of the following components from the control room:
      (1) Exhaust fans interlocked with associated isolation dampers.
      (2) Supply fan interlocked with associated dampers and the exhaust fans.
   g. Provide means for automatic operation of the exhaust fans upon receipt of a loss of offsite power signal.
   h. Automatically maintain minimum supply air temperature by controlling the supply system reheat coil.
   i. Indicate, in the control room, supply or exhaust fan operation.
   j. Cause an alarm in the control room upon detection of exhaust fan motor trip.
   k. Provide for radiation monitoring (RM-A6) and cause an alarm in the control room upon detection of radioactivity levels exceeding the setpoint in the Fuel Handling Building exhaust (see Section 12.2.4).

The system continuously supplies outside air that has been drawn through the Auxiliary Building supply air plenums where it is filtered and heated as required. The supply air is directed across the width of the spent fuel pool water surface so that gases or particles are entrained in the "push-pull" air flow above the water surface. The exhaust air is collected along the opposite side of the spent fuel pool. Supply air is also directed to various other parts of the building. Exhaust air is also drawn from various decontamination, holdup, filter and general areas of the Fuel Handling Building with air flow rates varying from 6 to 10 changes per hour. Ventilation air flow is directed from areas of low to progressively higher activity. Higher ventilation air flow rates occur in potentially high radioactive areas.

The total exhaust from the Fuel Handling Building is drawn through the HEPA/charcoal filters and ducted to the Auxiliary Building main exhaust fans and the main plant vent. Both Fuel Handling Building exhaust fans operate following a loss of offsite power. Continuing exhaust flow maintains Fuel Handling Building negative pressure under loss of offsite power conditions.

The supply system may be operated if normal power is available. The components for this system are located as follows:

1. Exhaust fans, in the Auxiliary Building.
2. Exhaust filters, in the Auxiliary Building.
3. Supply fan, in the Auxiliary Building.

A comparison of the spent fuel pool area charcoal filter plenums with Regulatory Guide 1.52 requirements is given in Table 6.5-1. General compliance with Regulatory Guide 1.52 is discussed in Appendix 3A.

9.4.3.3 Safety Evaluation

The Fuel Handling Building exhaust system fans and filters are arranged with sufficient redundant equipment to ensure that the system can sustain a single failure without impairing full functional capability of the standby system or component. The exhaust system fans and filters are separated, shielded and are served by separate Class 1E electric power supplies. Each is served by separate instrumentation, control and monitoring components. The fans and filters are Seismic Category 1, located in a Seismic Category 1 structure and are not subject to floods, weather, external missiles, jet impingement or pipe whip. Additionally, provision is made for suitable maintenance and change-out space and adequate instrumentation and lighting, all of which reduce personnel exposure.

The supply and exhaust system are administratively controlled during normal operating or refueling periods. However, the exhaust system starts automatically upon loss of offsite power, thus ensuring that a negative pressure is maintained in the Fuel Handling Building.

Exhaust air from the spent fuel area and from potentially radioactive areas of the Fuel Handling Building is monitored for particulate, iodine and gaseous activity (RM-A6). A control room alarm

is actuated upon detection of high radiation. The charcoal exhaust plenums have internal temperature sensing devices and water deluge systems for fire protection.

The spent fuel ventilation system filter trains provide a minimum of 99.95% removal efficiency for particulates and a minimum of 95% removal efficiency for methyl iodine at 95% relative humidity and 86°F.

9.4.3.4 Inspection and Testing Requirements

The spent fuel pool equipment is subjected to preoperational testing in accordance with written procedures to verify proper wiring and control hookup, system inplace integrity and leaktightness, proper function of system components and control devices and to establish system design air flow rates.

To ensure a continued state of readiness of the spent fuel pool area ventilation system after completion of the preoperation tests, the following inspection, maintenance and test procedures are performed:

1. Spent Fuel Pool Exhaust Fans and Filters
   a. Record filter pressure drops.
   b. Verify function of dampers or control devices necessary for monitoring, component isolation or changeover from normal to emergency mode.
   c. Bearing lubrication.
   d. Switch components that normally operate from standby to operating mode.
   e. Laboratory test of charcoal filter test canisters for decontamination efficiency.
   f. Inplace leak test of HEPA and charcoal filters.
2. Spent Fuel Pool Supply Fan

   Spent fuel pool supply fan inspection, maintenance and testing requirements are the same as spent fuel pool exhaust fan and filter requirements b and c.

9.4.4 Turbine Building

Ventilation and cooling of the Turbine Building areas are provided by the Turbine Building ventilation system and by the Turbine Building switchgear room cooling system.

9.4.4.1 Design Bases

1. Limit the maximum average turbine building temperature to 120°F by means of the Turbine Building exhaust system.

2. Limit the maximum average switchgear room temperature to 104°F and the minimum average temperature to 40°F by means of the Turbine Building switchgear room cooling system.

All components of the Turbine Building ventilation system and switchgear room cooling system are non-nuclear safety class and non-Seismic Category 1.

9.4.4.2 System Description

The system diagrams for the Turbine Building area ventilation system are as follows:

1. Figure 9.4-12, Turbine Building Ventilation System.
2. Figure 9.4-13, Turbine Building Switchgear Room Cooling System.

9.4.4.2.1 Turbine Building Ventilation System and Switchgear Room Cooling System

The main components of this system include:

1. Seven (7) 120 inch diameter roof exhaust fans with powered isolation dampers over the general Turbine Building roof.
2. Three (3) 48 inch diameter roof exhaust fans with powered isolation dampers over the heater bay roof.
3. Inlet wall louvers along the north and east walls of the heater bay and along the south wall of the general Turbine Building.
4. Two (2) "draw-through" type air handling units for the switchgear rooms, each with roughing filters, chilled water cooling coil, fan and motor section. Chilled water is provided by the Turbine Building switchgear rooms chilled water system. See Section 9.4.7.2.11.
5. Supply and return ductwork from the switchgear units to the turbine room switchgear areas at elevations 412’, 436’, and 463’.
6. Five (5) thermostatically controlled electric unit heaters for the switchgear rooms.
7. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the switchgear room air handling unit roughing filter bank (local indication only).
   b. Cause an alarm in the control room upon detection of high temperature in the switchgear cooling system air handling unit supply duct or in the switchgear rooms.
   c. Cause an alarm in the control room upon detection of high concentration of smoke in the switchgear room cooling system air handling unit supply duct or at the Turbine Building exhaust fans.
   d. Provide interlocks so that the Turbine Building exhaust fans do not operate unless the exhaust dampers at the roof exhaust fans are open.

e. Provide means for manual operation and control of the roof exhaust fans from a local control station.

f. Provide for operation of switchgear room cooling system air handling units from a local station and automatic control of chilled water pumps by means of room thermostats.

g. Provide interlocks so that switchgear room cooling system air handling units do not operate unless isolation dampers are fully open.

h. Cause an alarm in the control room upon trip of the switchgear room cooling system air handling unit.

i. Provide interlocks so that Turbine Building exhaust fan dampers open upon detection of high temperature.

j. Automatically close the inlet wall louvers along the south wall of the Turbine Building upon receipt of a signal from the transformer area fire protection system.

9.4.4.3 Safety Evaluation

The Turbine Building ventilation system and the Turbine Building switchgear room cooling system serve no safety function. They maintain acceptable temperatures in the building during all seasons. Redundancy of equipment is provided to maintain Turbine Building switchgear room cooling. Failure of Turbine Building ventilation system or switchgear room cooling system components does not result in conditions affecting safe operation of the plant. There is no requirement to maintain any preferred air flow pattern or specific building pressure. The function and fire safety aspects of all units of these systems are monitored, and appropriate alarms are actuated upon the occurrence of abnormal conditions, in the control room.

9.4.4.4 Inspection and Testing Requirements

The Turbine Building ventilation system and the Turbine Building switchgear room cooling system are subjected to preoperational testing to verify proper wiring and functioning of system components and control devices. Turbine Building ventilation systems are maintained as necessary to provide adequate ventilation.

9.4.5 Engineered Safety Features Ventilation System

The engineered safety features ventilation system design bases, system description, safety evaluation and inspection and testing requirements are described in the following sections:

1. Reactor Building cooling units - Section 6.2.2.
2. Control room normal ventilation and emergency filter system - Section 9.4.1.2.1.
3. Relay room cooling system - Section 9.4.1.2.2.
4. Cooling units for residual heat removal/Reactor Building spray pump rooms - Section 9.4.2.2.5.
5. Cooling units for charging pump rooms - Section 9.4.2.2.5.

6. Engineered safety features switchgear rooms cooling systems - Section 9.4.6.2.2.
7. Battery rooms ventilation system - Section 9.4.6.2.3.
8. Service water booster pumps area cooling system - Section 9.4.6.2.5.
9. Cooling units for emergency feedwater pump rooms - Section 9.4.6.2.5.
10. Diesel Generator Building ventilation system - Section 9.4.7.2.1.
11. Service Water Pumphouse ventilation system - Section 9.4.7.2.2.

9.4.6 Intermediate Building Ventilation Systems

Heating, cooling, ventilating and exhaust are provided for various Intermediate Building systems to the extent indicated to maintain ambient air temperatures in all areas between minimum and maximum levels suitable for personnel and equipment.

9.4.6.1 Design Bases

1. Furnish continuous outside air ventilation for the battery room system.
2. Safety Class 2b systems are designed for adequate physical separation and are so located as not to be affected by floods, weather, external missiles, jet impingement or pipe whip.
3. Equipment, motors and controls in Safety Class 2b systems are supplied from Class 1E power sources and have sufficient redundancy to satisfy the single failure criterion.
4. Provide, in the control room, for monitoring of process conditions and equipment status necessary for operation of the systems.
5. Provide for operation and manual control of the Intermediate Building ventilation systems as described in Sections 9.4.6.2.1, 9.4.6.2.2, 9.4.6.2.3, 9.4.6.2.4, 9.4.6.2.5, and 9.4.6.2.6.
6. Provide steam propagation barriers / components (SPB) in the equipment and floor drainage system required to maintain area environmental conditions for equipment qualification (EQ) purposes. SPB components may include orifice plates, check valves, or loop seals designed to segregate EQ zones to ensure that the conditions for which the equipment qualification were based on are not exceeded. Plant procedures specify the technical criteria for design, procurement, installation /maintenance and inspection of these QR components.

9.4.6.2 System Description

The system diagrams for the various intermediate building systems are as follows:

1. Figure 9.4-14, CRDM Switchgear Room Cooling System and Chiller Area Ventilation System.
2. Figure 9.4-15, ESF Switchgear Rooms and Speed Switch Rooms Cooling Systems.
3. Figure 9.4-16, Battery Room System and BOP Charger Area System.

4. Figure 9.4-17, Intermediate Building and Intermediate Building Pump Room Cooling System.

9.4.6.2.1 CRDM Switchgear Room Cooling System

The main components of this system include:

1. Two (2) 100% capacity air handling units, each consisting of roughing filters (20% efficiency on NBS dust), chilled water cooling coil, fan and motor section. Chilled water is provided by the Non-nuclear Safety Related Chilled Water System. See 9.4.7.2.12.
2. Ductwork to direct air from each air handling unit to the CRDM switchgear room and return air from this room to the air handling unit.
3. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the roughing filter banks (local indication only).
   b. Cause an alarm in the control room upon detection of high smoke concentration in the CRDM switchgear room.
   c. Cause an alarm in the control room upon detection of high temperature in the supply duct of either air handling unit or upon detection of high room temperature.
   d. Automatically cycle the selected air handling unit in response to a room thermostat.

The CRDM switchgear room cooling system operates continuously during all normal operating and shutdown periods unless normal power is not available. The cooling coils are normally provided by the NNS Chilled Water System. In the event this system is unavailable, a back-up source from the Turbine Building switchgear rooms Chilled Water System can be used. The air handling units are normally powered from non-Class 1E buses. The air handling units are controlled from a local control station, the unit selected for automatic operation cycles in response to a room thermostat.

9.4.6.2.2 ESF Switchgear Rooms and Speed Switch Rooms Cooling Systems

The main components of these systems include:

1. One (1) 100% capacity air handling unit for each ESF switchgear room, one (1) 100% capacity air handling unit for the A and C speed switch room and A evacuation panel room, and 1 similar unit for the B and C speed switch room and B evacuation panel room. Each air handling unit consists of roughing filters (20% efficiency on NBS dust), chilled water cooling coil, and a fan and motor section.

   Each ESF switchgear room air handling unit is also equipped with a standby direct expansion cooling coil. These non-safety related standby cooling coils provide ESF switchgear room cooling when the safety class chilled water train is not operating.

The standby cooling coil rejects heat to an air-cooled condensing unit located on the Intermediate Building roof.

2. Ductwork to direct air from each air handling unit to the ESF switchgear room and return air from this room to the air handling unit; ductwork to direct air from the A air handling unit to the A and C speed switch room and A evacuation panel room and return ductwork to the A air handling unit; similar ductwork to and from the B air handling unit and B and C speed switch room and B evacuation panel room.
3. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the roughing filter banks (local indication only).
   b. Cause an alarm in the control room upon detection of high smoke concentration in the discharge ducts of any of the air handling units.
   c. Cause an alarm in the control room upon detection of high temperature in the discharge ducts of any of the air handling units and upon detection of high room temperature.
   d. Automatically cycle the selected air handling unit in response to a room thermostat.
   e. Automatically cycle the standby cooling coil system based on room temperature when the ESF switchgear is in a standby mode.
   f. Cause an alarm in the control room upon detection of air handling unit motor trip.

The air handling units cycle in response to a room thermostat under normal conditions to remove the heat generated by the ESF electrical equipment or by the speed switchgear. Under emergency conditions, the thermostatic control is bypassed and the air handling units start and operate continuously following receipt of a safety injection or loss of offsite power signal. Power is supplied to the air handling units from separated, independent Class 1E power sources. The air handling units can be manually started from the control room. The air handling units are located in separate equipment rooms in the Intermediate Building.

9.4.6.2.3 Battery Room Systems

The main components of these systems include:

1. Two (2) 100% capacity air handling units, each including roughing filter (20% efficiency on NBS dust), electric heating coil, face and bypass section, safety class chilled water cooling coil, fan, and motor section.
2. Two (2) 100% capacity exhaust air fans.
3. Air operated, spring opposed dampers to isolate the inactive battery room air handling unit and exhaust air fan.
4. One (1) 100% capacity air handling unit, including roughing filter (20% efficiency on NBS dust), chilled water cooling coil, fan, and motor section for the balance of plant charging space. Chilled water is provided by the Non-nuclear Safety Related Chilled Water System. See 9.4.7.2.12.

5. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the roughing filter bank (local indication only).
   b. Cause an alarm in the control room upon detection of high smoke concentration in the discharge of either air handling unit or exhaust fan.
   c. Cause an alarm in the control room upon detection of high temperature in the discharge ducts from the air handling units or exhaust fans.
   d. Cause an alarm in the control room upon detection of high temperature in any of the battery or charger rooms.
   e. Indicate, in the control room, isolation damper position.
   f. Provide means for manually operating the air handling units and exhaust fans from the control room. The isolation dampers operate in conjunction with the fans. The battery air handling units start automatically at full cooling rate upon receipt of safety injection or loss of offsite power signals.
   g. Automatically maintain battery room and charger room air temperature during normal operation by controlling the battery air handling unit heating coil, face and bypass damper, and the battery room reheat coils. During safety injection or loss of offsite power, the face and bypass damper moves to the full cooling position, isolating the heating coil from the system flow path. Heating may still be accomplished through the reheat coils if power is available. If battery room temperature becomes too low, the room will be isolated by means of an isolation damper in the room supply.
   h. Indicate, in the control room, air handling unit fan operation.
   i. Cause an alarm in the control room upon detection of air handling unit fan motor trip for the safety-related battery rooms supply and exhaust fans.
   j. Indicate local temperature in each battery room.

The battery room system operates during all normal, shutdown, and emergency periods. Continuous system operation maintains suitable ambient temperatures and prevents the accumulation of battery gases in these areas. The battery room air handling units and exhaust fans are supplied by separated Class 1E power sources. The balance of plant charging space air handling unit is supplied from non-Class 1E power. The air handling units and exhaust air fans can be manually started and their operation monitored from the control room. The battery room air handling equipment is located in separated equipment rooms in the Intermediate Building.

9.4.6.2.4 Intermediate Building Ventilation System

The main components of this system include:

1. Two (2) 50% capacity supply fans for the Intermediate Building.
2. Two (2) 50% capacity exhaust fans for the Intermediate Building.

3. One (1) 100% capacity supply filter plenum for the Intermediate Building, including roughing filter (20% efficiency on NBS dust), and an electric heating coil.
4. Air operated, spring opposed dampers to isolate a supply or exhaust fan if it is deenergized and to regulate the quantities of outside, return, and relief air.
5. Ductwork from the supply fans to the Intermediate Building, back to the exhaust fans.
6. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the roughing filter banks (local indication only).
   b. Cause an alarm in the control room upon detection of high smoke concentration in the fan discharges.
   c. Cause an alarm in the control room upon detection of high temperature in fan discharge ducts.
   d. Indicate, in the control room, fan isolation damper position.
   e. Provide means for manually operating the supply and exhaust fans from the control room. Supply fans are interlocked to prevent operation unless exhaust fans are operating. Isolation dampers are interlocked to operate with associated fans.
   f. Automatically maintain minimum supply air temperature by controlling the outside, return and relief dampers, and the Intermediate Building heating coil.
   g. Indicate, in the control room, supply and exhaust fan operation.
   h. Cause an alarm in the control room upon detection of fan motor trip.

The Intermediate Building ventilation system supply and exhaust fans operate continuously during all normal and shutdown periods. System operation maintains suitable ambient conditions and provides outside air ventilation. The units are supplied with normal power. The fans are operated from the control room.

9.4.6.2.5 Intermediate Building Pump Room Cooling Systems

The main components of these systems include:

1. Two (2) 100% capacity air handling units for each of the following locations: service water booster pump area and emergency feedwater pump area. Each air handling unit includes a roughing filter (20% efficiency on NBS dust), safety class chilled water cooling coil, fan, and motor section.
2. Ductwork from the pump room air handling units to the pump areas.
3. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the roughing filter banks (local indication only).
   b. Cause an alarm in the control room upon detection of high smoke concentration in air handling unit discharges.

c. Cause an alarm in the control room upon detection of high temperature in air handling unit discharge ducts.

d. Cause an alarm in the control room upon detection of high temperature in the pump room areas.

e. Provide means for manually operating the air handling units from the control room.

f. Indicate, in the control room, air handling unit operation.

g. Cause an alarm in the control room upon detection of air handling unit motor trip.

h. Provide a means of tripping the air handling unit fans on detection of high ambient temperature in the pump room area.

The pump room air handling units start automatically, provided a high ambient temperature condition does not exist in the area, with their respective pump. The air handling units remove heat generated due to normal equipment operation in the area. Upon detection of high ambient temperature conditions in the area, which may be caused by an HELB in the IB-412' area, fan operation is prohibited until area temperatures return to design parameter operational levels. Air handling units are supplied by separated class 1E power sources and are located in separate equipment rooms in the Intermediate Building.

9.4.6.2.6 Water Chiller Area Ventilating System

The main components of this system include:

1. One (1) ventilating fan arranged to supply, relieve, and return outside ventilating air.
2. One (1) duct mounted heating coil.
3. Ductwork with control dampers and fire dampers arranged to supply, relieve, and return air as required.
4. Instrumentation and control devices to perform the following functions:
   a. Cause an alarm in the control room upon detection of high smoke concentration in the return air duct.
   b. Cause an alarm in the control room upon detection of high temperature in the fan discharge.
   c. Automatically control the outside and return dampers and the heating coil using a temperature controller which senses return air temperature.
   d. Indicate, locally, fan operation.
   e. Cause an alarm in the control room upon detection of fan motor trip.

The system operates continuously after manual start. System equipment is supplied from a non-Class 1E power source.

9.4.6.3 Safety Evaluation

Since the Intermediate Building ventilation systems are redundant, loss of 1 of the air handling units or fans does not prevent system function. For the ESF switchgear rooms cooling systems, 1 air handling unit serves the A channel ESF switchgear and a second, separate air handling unit serves the B channel ESF switchgear.

Safety Class 2b equipment is located in physically separated equipment rooms accessible for maintenance and not subject to floods, weather, external missiles, jet impingement or pipe whip. Safety Class 2b equipment is supplied by separated Class 1E power supplies. Units are administratively controlled from the control room. ESF switchgear rooms air handling units, speed switchgear rooms air handling units and CRDM switchgear room air handling units are cycled by room thermostats. Upon receipt of a safety injection or loss of offsite power signal, the ESF switchgear rooms air handling units and speed switchgear rooms air handling units are automatically started and operated continuously. Pump room air handling units are operated automatically with their respective pump. Operation of units is monitored from, and alarms indicating abnormal conditions are provided in, the control room. Assurance of system operation capability is further provided by preoperational and post operational test procedures.

9.4.6.4 Inspection and Testing Requirements

The Intermediate Building ventilation systems are subjected to preoperational test procedures to verify proper wiring and control hookup, system "in-place" integrity and leak tightness, proper function of system components and control devices, and to establish system design air flow rates. To ensure a continued state of readiness of the Intermediate Building ventilation systems after completion of the preoperational tests, the following inspection, maintenance, and test procedures are performed:

1. CRDM Switchgear Room Cooling System
   a. Record filter pressure drops.
   b. Verify function of dampers or control devices necessary for monitoring or component isolation or changeover.
   c. Bearing lubrication.
   d. Switch components from standby to operating mode.
2. ESF Switchgear Rooms Cooling Systems

   ESF switchgear rooms cooling systems inspection, maintenance and test requirements are the same as CRDM switchgear room cooling system requirements a. through c.

3. Battery Room System

   Battery room system inspection, maintenance and test requirements are the same as CRDM switchgear room cooling system requirements a. through d.

4. Intermediate Building Ventilation System

   Inspection, maintenance and test requirements for this system are the same as CRDM switchgear room cooling system requirements a. through c.

5. Intermediate Building Pump Cooling Systems

   Inspection, maintenance and test requirements for these systems are the same as CRDM switchgear room cooling system requirements a. through d.

6. Speed Switchgear Rooms Cooling Systems

   Inspection, maintenance and test requirements for these systems are the same as CRDM switchgear room cooling system requirements a. through d.

9.4.7 Miscellaneous Building Ventilation and Cooling Systems

Heating, cooling, ventilation, exhaust, heat rejection and generation of mechanically chilled water are provided by various systems to the extent indicated in the following sections to maintain ambient air temperatures in areas discussed between minimum and maximum levels suitable for personnel and equipment.

9.4.7.1 Design Bases

The miscellaneous building ventilation and cooling systems are designed in accordance with the following criteria, where applicable:

1. Equipment, motors, and controls in Safety Class 2b systems are supplied from Class 1E power sources and have redundancy as required to satisfy the single failure criterion of 10 CFR 50, Appendix A.
2. Instrumentation and controls are provided to monitor normal operation and detect abnormal conditions, such as high or low temperatures, low pressure, smoke, equipment vibration and motor trip.
3. Provide outside air ventilation to remove heat developed by motors and electrical equipment.
4. Provide a system to generate and distribute mechanically chilled water to safety and non-nuclear safety class equipment.
5. Provide a heat rejection system for the Reactor Building cooling system.
6. Provide a comfort cooling system for the Service Building.
7. Provide for operation and manual control of these systems from the control room. Also, provide for automatic starting of the Diesel Generator Building ventilation system when the diesel generator is started and for automatically starting the Service Water Pumphouse ventilation system.

9.4.7.2 System Description

The system diagrams for the miscellaneous building ventilation and cooling systems are as follows:

1. Figure 9.4-18, Diesel Generator Building Ventilation System.
2. Figure 9.4-19, Service Water Pumphouse Ventilation System.
3. Figures 9.4-20 and 9.4-21, Service Building Ventilation System.
4. Figures 9.4-22 through 9.4-24, Chilled Water System.
5. Figure 9.4-25, Industrial Cooling Water System.
6. Figure 9.4-26, Substation Relay House System.
7. Figure 9.4-26a, Penetration Room Ventilation System.
8. Figure 9.4-26b, Miscellaneous Pump Room Systems and Lube Oil Room System.
9. Figure 9.4-26c, Water Treating Area Laboratory Heating and Cooling System.
10. Figure 9.4-26d, Unit 1 Relay House HVAC.
11. Figure 9.4-32, CRDM Cooling Water System.
12. Figure 9.4-33, Chilled Water - Turbine Building Switchgear Rooms.
13. Figure 9.4-34, Non-Nuclear Safety Chilled Water System.
14. Figure 9.4-35, SH. 1, EB HVAC - Electrical and Battery Room
15. Figure 9.4-35, SH. 2, EB HVAC - Diesel Generator 1 Room
16. Figure 9.4-36, AEB HVAC - Diesel Generator 2 Room

Design and performance data are provided on these figures.

9.4.7.2.1 Diesel Generator Building Ventilation System

The main components of this system for each diesel room include:

1. Two (2) 50% capacity ventilation fans to supply outside air to the diesel generator room, the diesel generator electric equipment room, and the diesel generator cable-pipe-basement area.
2. Air operated, spring opposed dampers with damper position limit switches to isolate the ventilation supply fans when not in use.
3. Ductwork to connect the two supply fans and distribute supply air to the various diesel room areas.
4. Instrumentation and control devices to perform the following functions:
   a. Cause an alarm in the control room upon detection of high smoke concentration in the discharge of each fan.

b. Cause an alarm in the control room upon detection of high temperature in the discharge of each fan.

c. Provide means for manually operating the supply fans from the control room. The supply fans are interlocked with the damper limit switches to prevent fan operation if dampers are closed.

d. Provide means for automatically cycling the supply fans under control of room thermostats located in the diesel generator rooms, and diesel generator electric equipment rooms. Cycling in this manner maintains acceptable temperatures when diesel generators are not operating.

e. Provide means for automatically starting each supply fan if the associated diesel generator is started. Associated supply fans operate continuously while the diesel generator is in operation.

f. Indicate, in the control room, supply air fan operating status.

g. Cause an alarm in the control room upon detection of fan motor trip.

The fans in this system cycle and associated dampers open and close in response to room thermostats located in the diesel generator rooms, and diesel generator electric equipment rooms when the diesel generators are not operating. Both fans associated with a diesel room start automatically and operate continuously whenever the diesel generator in that room operates. Ventilation air is drawn through roof openings shielded from external tornado missiles and forced into the diesel room by the fans. The ventilation air is ducted to various areas of the diesel room, diesel generator electric equipment room and cable-pipe areas under the diesel generator. Ventilation air is relieved from the cable-pipe areas and electric equipment room to the diesel room and through the exhaust silencer space to the outside. The relief air is vented to the outside through roof openings which are also shielded from external tornado missiles. The fans are powered from separated Class 1E power sources. The fans are manually operated from the control room or operate automatically as previously noted. System operation is monitored from the control room. The fans are located on the west end of the Diesel Generator Building.

9.4.7.2.2 Service Water Pumphouse Ventilation System

The main components of this system include:

1. Two (2) 100% capacity ventilation supply fans to provide outside air to various areas of the Service Water Pumphouse.
2. Air operated, spring opposed dampers to isolate the return air path to the ventilation supply fans and to regulate the quantities of outside, return and relief air. Gravity dampers are provided at the discharge of each supply fan.
3. Fire dampers are located in the switchgear and pump rooms supply and return ducts.
4. Eight electric unit heaters are provided to maintain minimum ambient temperatures during shutdown periods.

5. Ductwork is provided for supply, return and relief of ventilation air in service water pump areas and related motor control center and electrical rooms.
6. Instrumentation and control devices to perform the following functions:
   a. Cause an alarm in the control room upon detection of high smoke concentration in the return duct to each fan.
   b. Cause an alarm in the control room upon detection of high temperature in the discharge duct of each ventilation supply fan.
   c. Indicate, in the control room, open and closed positions of ventilation supply fan isolation, outside, return and relief air dampers.
   d. Cause an alarm in the control room upon detection of excess vibration of the ventilation supply fans.
   e. Indicate, in the control room, the air flow rate in the outside air supply ducts to the ventilation supply fans.
   f. Automatically control outside, return and relief air damper position by means of a return air temperature controller.
   g. Provide means for manually operating the ventilation system fans from the control room. These fans are interlocked with the associated inlet isolation dampers.
   h. Provide an outside/return air manual control station in the control room.
   i. Provide means for automatically starting the ventilation air supply fans upon receipt of a safety injection or loss of offsite power signal and bypassing the discharge temperature controller upon receipt of a safety injection signal.
   j. Indicate, in the control room, high and low ambient temperatures in the pump/screen room and in the switchgear rooms.
   k. Indicate, in the control room, ventilation supply fan operation.
   l. Cause an alarm in the control room upon detection of ventilation supply fan motor trip.

Either of the 2 supply fans operates continuously during normal operating periods. Both fans start automatically following receipt of a safety injection or loss of offsite power signal. Outside, return and relief air damper positions are automatically controlled by a return air temperature controller. Alternatively, position of these dampers can be manually controlled by a hand control station in the control room. The fans are powered from separate Class 1E power sources. The fans are manually started from the control room or are automatically started as previously noted. The air handling equipment is located in a shielded fan room above the equipment areas. Ductwork in the equipment areas is fireproofed. Fireproofing is accomplished by "boxing-in" the duct. System operation is monitored from the control room.

9.4.7.2.3 Service Building Ventilation System

Air conditioning, heating, cooling, and ventilation systems are provided for the Service Building areas to satisfy the following general requirements:

1. To maintain ambient air temperatures in all areas as required for the comfort and safety of personnel.

9.4.7.2.4 Safety Class Chilled Water System

The main components of this system include:

1. Three (3) 100% capacity screw type, electric motor driven water chilling machines.
2. Three (3) 100% capacity chilled water pumps.
3. Chilled water cooling coils for the following areas:
   a. Charging pump rooms.
   b. Residual heat removal/Reactor Building spray pump rooms.
   c. Emergency feedwater pump areas.
   d. Service water booster pump rooms.
   e. ESF switchgear rooms.
   f. Control room/Technical Support Center.
   g. Relay room/Technical Support Equipment Room.
   h. Auxiliary Building motor control center cooling units.
   i. Battery Room.
   j. Speed Switch Room.
4. Piping supply and return mains with expansion tanks, chemical feed, systems and provisions for balancing, manual and automatic isolation of portions of the system.
5. Instrumentation and control devices to perform the following functions:
   a. Cause an alarm in the control room upon detection of low chilled water flow.
   b. Indicate, in the control room, which chiller and chilled water pump are energized.
   c. Cause an alarm in the control room upon detection of chilled water pump motor trip.
   d. Cause an alarm in the control room upon detection of low chilled water pressure in pipe mains.
   e. Indicate, in the control room, chilled water temperature in the supply pipe mains and cause an alarm in the control room upon detection of high or low chilled water temperature.
   f. Indicate, in the control room, chilled water temperature in the discharge of the chiller and cause an alarm in the control room upon detection of high chilled water temperature.
   g. Cause an alarm in the control room upon detection of loss of chiller condenser water flow.

h. Indicate water temperature locally in the pipe supply and return mains at the inlet and outlet of each cooling coil.

i. Provide thermal wells for local testing in the supply and return mains and in the discharge of the A and B chillers.

j. Indicate water pressure locally at the suction and discharge of each pump.

k. Cause an alarm in the control room upon detection of low Chilled Water System water level.

l. Provide interlocks requiring chilled water pump operation before the chiller can be started.

m. Provide means to automatically start chilled water pumps and chillers following receipt of a safety injection or loss of offsite power signal.

n. Cause an alarm in the control room upon chiller trip.

Continuous operation of 1 of the 3 chillers and chilled water pumps is required during normal and emergency periods to provide 45°F water to the chilled water coils listed in Section 9.4.7.2.4, item 3. Use of 3 chillers and 3 chilled water pumps permits one unit to undergo extended maintenance, 1 unit to operate, and the remaining unit to be a nonrunning chiller and pump set. If all 3 chiller and pump sets are available, 1 is designated as a spare and its breaker(s) is racked out. Continuous chilled water flow is maintained through chilled water coils in the operating loop during normal plant operation. The Chilled Water System is a closed system with redundant supply and return mains. Chiller condenser cooling water is supplied by the Service Water System. Equipment is supplied from separated Class 1E power sources. The chillers and chilled water pumps may be started from the control room. All chillers may also be started locally. Local control of the "B" and "C" aligned "B" chilled water pumps only is available. This allows the "B" train of the Chilled Water System to be available in the event of a postulated exposure fire where "B" train is the selected train for plant shutdown. The operation and status of Chilled Water System components are monitored and alarms are annunciated in the control room. The chillers and chilled water pumps are located in 3 separated, concrete shielded, equipment spaces in the Intermediate Building.

9.4.7.2.5 Industrial Cooling Water System

The Industrial Cooling Water System has the ability to reject heat to either of two heat sinks, the industrial coolers (Wet-surface Air Cooler) or the RB Chiller Loop (via the industrial cooling heat exchangers). The main components of this system include:

1. Two (2) 50% capacity industrial coolers, each consisting of closed loop, sectionalized cooling water coils, an external spray system and sump, sump heaters, makeup and bleed off devices, 4 spray pumps (2 normal-2 standby), and 8 fans.
2. Two (2) 100% capacity industrial cooling water pumps to circulate water in the closed cooling loop from the industrial cooler (or industrial cooling heat exchangers) to air dryers,

air compressors, thermal regenerative chiller condenser, and the Reactor Building cooling units and back to the industrial cooler (or industrial cooling heat exchangers).

3. Piping supply and return mains with connections to the coils and heat exchangers noted in item 2, above. An expansion tank, chemical feed tank, and provisions for fill, drain, balancing, and isolation of system components are supplied.
4. Instrumentation and control devices for the Industrial Cooling Water System and the industrial coolers perform the following functions:
   a. Cause an alarm in the control room upon detection of loss of industrial cooling water flow.
   b. Indicate industrial cooling water flow locally.
   c. Indicate, in the control room, which industrial cooling water pump is energized.
   d. Cause an alarm in the control room upon detection of industrial cooling water pump motor trip.
   e. Cause an alarm in the control room upon detection of high industrial cooling water temperature.
   f. Cause an alarm in the control room upon detection of low water level in the industrial cooler expansion tank.
   g. Provide means to automatically reset the required discharge water temperature in response to Reactor Building ambient temperature changes.
   h. Indicate, locally, water temperature entering and leaving all components served by the Industrial Cooling Water System and water temperature entering and leaving the industrial coolers.
   i. Indicate, in the control room, water temperature entering the Industrial Cooling System at the discharge of the industrial cooling water pumps.
   j. Locally indicate water pressure at the suction and discharge of the industrial cooler pumps and at the inlet and discharge of each industrial cooler.
   k. Input to the plant computer for Industrial Cooling Water Heat Exchanger inlet and outlet temperatures.
5. The RB chiller loop of the Industrial Cooling Water system contains:
   a. Two (2) 100% capacity, variable flow chiller loop water pumps to circulate water in the closed cooling loop from the RB chillers to the industrial cooling heat exchanger and back to the RB chillers.
   b. Piping supply and return mains with connections to the heat exchangers noted in item 5a, above. An expansion tank, chemical feed tank, and provisions for fill, drain and isolation of system components are supplied.
   c. An Industrial Cooling Pump House (ICPH) which houses the pumps with variable frequency drives, chemical feed tank and chiller control panel.
   d. Instrumentation and control devices to perform the following functions:

i. Cause a common trouble alarm in the control room upon detection of either out of range water temperatures and flows, expansion tank level high/low, chiller failure or chiller pump failure.

ii. Industrial cooling supply water temperature to the Reactor Building is automatically controlled by the RB chiller loop.

iii. Provide local indication of differential pressure across Industrial Cooling Heat Exchangers.

iv. Input to the plant computer for Industrial Cooling Heat Exchanger chiller water inlet and outlet temperatures.

v. Input to plant computer for chiller loop expansion reservoir level.

vi. Provide local indication of water pressure at the suction and discharge of the chiller loop pumps.

Operation of one industrial cooling water pump is required during all normal, shutdown and Reactor Building leak rate test periods to circulate water through the closed system. During operation, heat is absorbed in the various heat exchangers and rejected to the outside via industrial coolers or via plate heat exchanger(s) and air-cooled chillers. The water supply and return main flows to the Reactor Building cooling units are automatically diverted from the industrial cooler or industrial cooling heat exchanger(s) to the Service Water System upon receipt of a safety injection or loss of offsite power signal. The industrial cooler fans and spray pumps are automatically controlled to maintain discharge water temperature. The RB chillers and chiller loop pumps are automatically controlled by RB chilled water temperature determined by ITK09205. RB Chiller loop flow is automatically controlled with variable frequency drive pumps. The required discharge water temperature is manually set to maintain a constant Reactor Building ambient temperature. Makeup water to the industrial cooling loop and RB chiller loop is supplied from the filtered water and demineralized water respectively. Industrial cooling water circulation pumps are manually controlled from the control room. Equipment is supplied with normal power.

9.4.7.2.6 Substation Relay House and Unit 1 Relay House Cooling Systems

The main components of the Substation Relay House system include:

1. One (1) 100% capacity self-contained cooling unit consisting of casing, roughing filters, direct expansion cooling coils, fan and motor section and controls.
2. One (1) 100% capacity air cooled condensing unit consisting of refrigerant compressor, condensing coil, condenser fan and motor section and controls.
3. Ductwork system with outlets, balancing devices and electrically operated outside air dampers.
4. Refrigerant piping system between condensing unit and cooling unit.
5. Two (2) 50% capacity, wall mounted, battery room exhaust fans.
6. Five (5) electric unit heaters for the relay room and storage areas.

The substation relay house cooling unit operates continuously after local manual start and is subsequently controlled automatically by self-contained equipment controls. Equipment is supplied from normal power supplies. No provisions are made for power supplied from an emergency source. The air handling unit is located along the east end of the substation relay house. The condensing unit is pad mounted directly outside.

The main components of the Unit 1 Relay House Cooling system include:

1. Air conditioning units are four (4) 33% capacity units. Each unit is a self contained unit with air conditioning and heating equipment. Each unit has its own wall mounted thermostat. Units have built in economizer with exhaust damper. The units are 5 ton units with 6kW heater.
2. Each battery room has two (2) 100% exhaust fans. One fan is running while the other is in standby. Loss of flow to the primary fan automatically starts the standby fan.

   The Unit 1 relay house cooling unit operates continuously after local manual start and is subsequently controlled automatically by self-contained equipment controls. Three (3) of the four (4) air conditioning units run during normal operation. Equipment is supplied from normal power supplies. No provisions are made for power supplied from an emergency source.

9.4.7.2.7 Penetration Access Areas Ventilation System

The main components of this system include:

1. Two (2) 100% capacity exhaust fans.
2. Two (2) 50% capacity ventilation supply air fans for each of the following locations:
   a. Elevation 412’, east penetration area.
   b. Elevation 412’, west penetration area.
   c. Elevation 436’, east penetration area.
   d. Elevation 436’, west penetration area.
3. Supply ductwork with outlets, control dampers and outside air intake provisions. Exhaust ductwork with control dampers and make-up air intake provisions.
4. Instrumentation and control devices to perform the following functions:
   a. Alarm in the control room upon detection of high concentrations of smoke in each penetration area, upon a fan motor trip, upon excessive exhaust fan vibration, and upon low exhaust air flow.
   b. Manual operation of supply and exhaust fans from remote control stations. The fans are also interlocked with their respective isolation dampers which open when their respective fan runs and vice versa.
   c. Automatically control outside and return air dampers in response to a room thermostat.

d. Indicate fan operation at each switch.

e. Automatic/Manuel control of the exhaust fan make-up damper in response to a local flow monitor.

The fans operate continuously after manual start from the local control stations. The amount of outside air introduced is controlled automatically by a room thermostat. Exhaust air is discharged to outdoors through the plant vent. The fans are powered from a non-Class 1E power source.

9.4.7.2.8 Miscellaneous Pump Room Systems and Lube Oil Room System

The main components of these systems include:

1. Two (2) exhaust fans and 2 motorized inlet openings for the motor driven fire service pump room.
2. One (1) exhaust fan and motorized inlet opening for the diesel driven fire service pump room.
3. One (1) exhaust fan and motorized inlet opening for the screen wash pump room.
4. Two (2) wall mounted exhaust fans each equipped with a gravity operated backdraft damper and a temperature controlled fire damper and a common room inlet equipped with a temperature controlled fire damper. (For the Turbine Lube Oil Treatment Room.)
5. Electric unit heaters for the following locations:
   a. Motor driven fire service pump room, 2 units.
   b. Diesel driven fire service pump room, 1 unit.
   c. Screen wash pump room, 1 unit.
6. Instrumentation and control devices to perform the following functions:
   a. Provide local control of each fan.
   b. Provide thermostat control for each of the exhaust fans noted in items 1 through 4, above.
   c. Provide interlocks so that the fans do not operate unless the inlet louver and fan isolation dampers are open. (Pump room ventilation systems only.)
   d. Provide local indication of fan operation.
   e. Provide control room indication of fan motor trip in the turbine lube oil treatment room.
   f. Provide thermostat control of the electric unit heaters described in Section 5 above.

Roof ventilators and dampers in the pump room ventilation system operate automatically in response to thermostats after manual start. Unit heaters, as described in Section 5 above, operate in response to integral thermostats. Equipment is powered from non-Class 1E power sources.

9.4.7.2.9 Water Treating Area Laboratory Heating and Cooling System

The main components of this system include:

1. One (1) package type heating and cooling unit, including direct expansion type air handling unit with electric heating coil and roughing filter and refrigerant condensing unit.
2. Two (2) laboratory hood exhaust fans and a chemical storage area exhaust fan.
3. Twelve (12) electric unit heaters in the chemical storage and general floor areas.
4. Ductwork connecting the air handling unit with the sample room and the water treating laboratory and for supply and exhaust of the laboratory hoods.
5. Instrumentation and control devices to perform the following functions:
   a. Automatically operate the condensing unit and the air handling unit heating coil in response to a room thermostat.
   b. Automatically place the outside, return and relief dampers under control of theoutside and return mixture temperature controller or at a fixed minimum position in accordance with outside temperature.
   c. Automatically prevent or permit the condensing unit to operate in accordance with outside temperature.
   d. Control electric unit heaters with integral thermostats.
   e. Automatically close hood inlet dampers when the entering air is below a set temperature.

The air handling unit operates continuously. The laboratory hood and chemical storage area exhaust fans are operated as required from local control stations. System components are supplied from non-Class 1E power sources.

9.4.7.2.10 CRDM Cooling Water System

(System has been abandoned in place pending demolition by ECR 50917)

The main components of this system include:

1. One (1) CRDM cooler rack assembly which is an air to water heat exchanger.
2. One (1) CRDM cooling water industrial cooler, including 2 electric heaters, 8 forced convection fans, and 4 circulation pumps.
3. One (1) expansion tank to control thermally induced water volume changes.
4. Two (2) 100% circulating water pumps, including a bypass line with a chemical feed tank.

The system is designed to remove heat from the containment air used to cool the Control Rod Drive Mechanism (CRDM) and dissipate this heat to the atmosphere via the Industrial Cooler.

The system can operate continuously while the plant is in operation. System components are powered from non-Class 1E power sources.

9.4.7.2.11 Turbine Building Switchgear Rooms Chilled Water System

The main components of this system include:

1. One (1) air-cooled, electric motor drive, reciprocating water chiller.
2. One (1) primary water pump.
3. Two (2) 100% capacity secondary water pumps.
4. Chilled water piping system including a compression tank, an air separator, a chemical feed tank, and valves.
5. Chilled Water Coils - 1 coil bank consisting of two (2) sections in each of 2 redundant Turbine Building switchgear rooms air handling units. Each section has 2 connections.
6. Instrumentation and control devices to perform the following functions:
   a. Chiller is equipped with a unit mounted starter and microprocessor based control panel with local controls, status panel, and diagnostic capability. When temperature or pressure is reported out of range by local sensors, a diagnostic is sent to the unit control panel. Chiller is interlocked with the primary pump; therefore the energized chiller will not start unless the primary pump is running.
   b. The primary pump is started by a remote manual switch. The primary pump is interlocked with the main power for the chiller; therefore the pump will not turn on without power running to the chiller.
   c. The secondary pumps are redundant and each is wired to run only with its respective air handling unit. The active pump is controlled by 1 of 3 parallel-wired room thermostats.
   d. Indicate locally the level of water in the compression tank and alarm of low level in the control.
   e. Alarm in the control room of low water flow.
   f. Indicate locally the temperature of water entering and leaving the chiller and provide a computer high temperature alarm and CRT display in the control room of water leaving the chiller.
   g. Indicate locally the pressure of water entering and leaving each pump.

Under normal conditions, the primary pump continuously circulates water in the primary pipe loop. This water is maintained at 45°F by the chiller which loads/unloads and cycles automatically under its self contained controls. The secondary pump circulates water between the primary loop and the chilled water coils identified in Section 9.4.4.2.1, subitem 4. It cycles upon demand of room thermostats.

Additionally, this system can provide chilled water to the CRDM Switchgear Room cooling coils via a booster pump in the event that chilled water is unavailable to these coils. This system can be provided chilled water from the non-nuclear safety related Chilled Water System. The system is non-nuclear safety class.

9.4.7.2.12 Non-nuclear Safety Related Chilled Water System

The main components of this system include:

1. One (1) air-cooled, electric motor driven reciprocating water chiller.
2. Two (2) 100% capacity chilled water circulating pumps.
3. One (1) chilled water booster pump.
4. Chilled water piping system including an atmospheric expansion tank, provisions for chemical sample and feed, and provisions for balancing the system.
5. Chilled water cooling coils for the following areas:
   a. CRDM Switchgear Room.
   b. Controlled Access Area.
   c. SAS/Computer Room.
   d. Computer Room.
   e. BOP Charger Area.
6. Instrumentation and control devices to perform the following functions:
   a. Cause an alarm at a local panel and a common trouble alarm in the control room upon detection of either low chilled water flow, high chilled water temperature, or low expansion tank level.
   b. Provide local indication of system flow.
   c. Provide interlocks which shut the chiller down on low system flow.
   d. Indicate water temperature locally at the pipe supply and return headers and at the inlet and outlet of each cooling coil.
   e. Provide thermowells for local testing in the supply and return headers at the chiller.
   f. Indicate water pressure locally at the suction and discharge of each pump.
   g. Provide the means for determining pressure drop across each system cooling coil.
   h. Provide local indication of expansion tank level.
   i. Provide a remote means for filling the system.
   j. Provide a local panel at the fill station to indicate "Normal," "Low," and "Fill Complete" expansion tank level with status lights.

Under normal conditions, the system provides chilled water via redundant circulating pumps to the cooling coils listed in Section 9.4.1.2.3, 9.4.1.2.4, 9.4.1.2.6, 9.4.6.2.1, and 9.4.6.2.3. The chiller loads/unloads and cycles automatically to maintain chilled water temperature at 45°F. This system can be aligned to provide a backup source of chilled water to the Turbine Building Switchgear Rooms cooling coils. In the event that chilled water is unavailable to the CRDM Switchgear Room cooling coils, the booster pump can be aligned to the Turbine Building Switchgear Rooms Chilled Water System to provide a backup source of cooling to the CRDM Switchgear Room.

9.4.7.2.13 ISFSI Electrical Building (EB) HVAC System

The main components of the system include:

1. Three (3) 50% capacity wall mounted HVAC units.
2. Two (2) 100% capacity Battery Room wall mounted ventilation fans.
3. One (1) 100% capacity EB Diesel Generator Room wall mounted ventilation fan.
4. One (1) 100% EB Diesel Generator Room Cooling wall mounted supply fan.
5. One (1) 100% EB Diesel Generator Room Cooling wall mounted exhaust fan.
6. One (1) 100% EB Diesel Generator Radiator Cooling wall mounted supply fan.
7. One (1) 100% EB Diesel Generator Engine Driven Radiator Cooling exhaust fan.

The EB HVAC units condition the air in the Electrical Room and Battery Room in order to maintain the UPS batteries within the normal operating temperature range. Ventilation air is supplied through the lead HVAC unit into the Electrical Room, drawn through a fire damper in the Battery Room wall into the Battery Room and then exhausted through a wall mounted exhaust fan to remove any hydrogen generated by the batteries and cool or heat the battery room air. The primary ventilation fan operates at all times. If air flow is lost through the primary ventilation fan, an alarm is generated on the Main Control Board and local panels XPN5386 and XPN5387 and the secondary fan is started automatically.

Ventilation air is drawn in through a gravity operated supply damper in the exterior wall of the EB Diesel Generator Room and exhausted by the EB Diesel Generator Room Ventilation fan exhaust fan to remove any diesel fumes released into the room. If air flow is lost through the ventilation fan an alarm is generated on the Main Control Board and local panels XPN5386 and XPN5387 and the EB Diesel Generator Room Cooling supply and exhaust fans will be started automatically. The EB Diesel Generator Radiator Cooling Supply fan is started automatically when the EB Diesel Generator is started along with the EB Diesel Generator Engine Driven Radiator Cooling exhaust fan. If room temperatures continue to increase above 80°F the Diesel Generator Room Cooling supply and exhaust fans will start to provide additional room cooling. Reference FSAR Figures 9.4-35, Sheets 1 and 2.

9.4.7.2.14 ISFSI Auxiliary Electrical Building (AEB) HVAC System

The main components of the system include:

1. One (1) 100% capacity AEB Diesel Generator Room wall mounted ventilation fan.
2. Two (2) 50% capacity AEB Diesel Generator Room Cooling wall mounted supply fans.
3. Two (2) 50% capacity AEB Diesel Generator Radiator Cooling wall mounted supply fans.
4. One (1) 100% capacity AEB Diesel Generator Room Cooling wall mounted exhaust fan.
5. One (1) 100% AEB Diesel Generator Engine Driven Radiator Cooling exhaust fan.

Ventilation air is drawn in through a gravity operated supply damper in the exterior wall of the AEB Diesel Generator Room and exhausted by the AEB Diesel Generator Room Ventilation fan exhaust fan to remove any diesel fumes released into the room. If air flow is lost through the ventilation fan an alarm is generated on the Main Control Board and local panels XPN5386 and XPN5387 and the AEB Diesel Generator Room Cooling supply and exhaust fans will be started automatically. The Diesel Generator Radiator Cooling Supply fan is started automatically when the AEB Diesel Generator is started along with the AEB Diesel Generator Engine Driven Radiator Cooling exhaust fan. If room temperatures continue to increase above 80°F the AEB Diesel Generator Room Cooling supply and exhaust fans will start to provide additional room cooling. Reference FSAR Figure 9.4-36.

9.4.7.3 Safety Evaluation

The Service Building ventilation system, Industrial Cooling Water System, substation relay house and Unit 1 relay house cooling systems, penetration access areas ventilation system, miscellaneous pump room systems and lube oil room systems, water treating area laboratory heating and cooling system, and Turbine Building switchgear rooms chilled water system perform no safety function. They do provide acceptable temperature levels in the various buildings.

Additionally, the substation battery room exhaust fan in both the substation relay house and the Unit 1 relay house cooling system prevents the occurrence of any appreciable hydrogen concentration in the battery room.

The Diesel Generator Building ventilation system, Service Water Pumphouse ventilation system, and safety class Chilled Water System do perform safety functions since total loss of the heat removal capability of any one of these systems could produce conditions affecting the safety of the plant. These systems are designed with redundant equipment and piping systems and are so arranged, serviced, and maintained such that complete loss of system function or system cooling is highly unlikely. Each of the safety class systems is located in equipment rooms accessible for maintenance but not subject to floods, weather, external missiles, main steam line break effects, jet impingement, or pipe whip. Each is supplied by separated Class 1E power supplies. The safety class systems are administratively controlled from the control room. Operation of the Diesel Generator Building ventilation system is automatically initiated by diesel generation. Operation of the Service Water Pumphouse ventilation system and the Chilled Water System are

automatically initiated by receipt of a safety injection or loss of offsite power signal. Safety class systems are monitored and alarms are annunciated in the control room.

9.4.7.4 Inspection and Testing Requirements

The miscellaneous building ventilation and cooling systems are subjected to preoperational testing to verify proper wiring and control hookup, system "in-place" integrity and leak tightness, proper function of system components and control devices, and to establish system design air and water flow rates. To ensure a continued state of readiness of the miscellaneous building ventilation and cooling systems after completion of the preoperational tests, the following inspection, maintenance, and test procedures are performed:

a. Verify function of dampers or control devices necessary for monitoring or component isolation or changeover from normal to emergency mode.

b. Bearing lubrication.

c. Switch components from standby to operating mode.

9.4.8 Reactor Building Cooling and Filtering Systems

Under normal operating conditions, continuous circulation and cooling of the Reactor Building air is required to maintain the ambient air temperature at a suitable level for continuous operation of equipment within the building.

Under shutdown conditions, heating and cooling of the Reactor Building is provided by the ventilation system as required.

Cleanup of the Reactor Building atmosphere is required before purging to minimize the release of radioactivity to the environment. Purging may be utilized to maintain a suitable environment for personnel prior to entering the Reactor Building for maintenance or refueling operations.

During a post accident period, the Reactor Building cooling system assists other heat removal systems in their heat removal function.

9.4.8.1 Design Bases

The ventilating, cooling and filtering systems of the Reactor Building are designed to perform the following functions:

1. Satisfy the general requirements stated in Section 9.4.8.
2. Maintain an average Reactor Building air temperature below a maximum of 120°F during normal power operation as assumed in the accident analyses and below 100°F during refueling operations for personnel comfort and safety.
3. Maintain an average Reactor Building air temperature above 60°F during shutdown conditions for personnel comfort and safety.

4. Provide post accident heat removal capability to assist in depressurizing the Reactor Building following a LOCA or main steam line rupture. See Section 6.2.2 for a discussion of the engineered safety features functions of the Reactor Building cooling system.
5. Provide forced air cooling systems in areas of high local heat release within the Reactor Building. These systems limit temperatures of the adjacent concrete to a maximum of 150°F and provide a suitable ambient temperature for instrumentation and equipment. These areas include the annular spaces between the reactor vessel, reactor vessel nozzles and the shielding concrete, the concrete under the reactor vessel supports, the neutron detector wells, the reactor coolant pumps, the pressurizer and steam generator compartments, and the rod position indicator data cabinet area.
6. Provide forced air cooling in sufficient capacity to remove control rod drive mechanism (CRDM) heat and reject it to the general Reactor Building atmosphere.
7. Provide Reactor Building cleanup capacity to reduce airborne radioiodine levels prior to personnel entry and to minimize radioactivity released during Reactor Building purging. Cleanup capacity is based upon equilibrium I-131 concentrations and 16 hours of cleanup system operation. Cleanup capacity is sufficient to reduce airborne I-131 levels to below the limits specified in 10 CFR 20, Appendix B, Table I.
8. Provide outside air purge capacity to reduce airborne radioactivity levels prior to personnel entry. The purge system design assumes a flow rate that, when considered with the site meteorology, results in site boundary concentrations that do not exceed allowable limits.
9. Provide a push-pull ventilation system for the refueling canal and refueling cavity which nominally causes air flow to travel across the entire water surface.
10. Provide control room monitoring of process conditions and equipment status necessary for operation of the systems.
11. Provide for remote operation, from the control room, of all systems except the push-pull refueling canal ventilation system and the elevator machine room ventilation system which are locally controlled.
12. For engineered safety features systems, provide sufficient redundancy and separation in air handling equipment, duct systems, controls and power supplies to satisfy the single failure criteria.

9.4.8.2 System Description

The system diagrams for the various reactor building systems are as follows:

1. Figure 9.4-28, Reactor Building Purge Supply and Exhaust System.
2. Figure 6.2-58, Post Accident Hydrogen Removal and Alternate Reactor Building Purge System.
3. Figure 9.4-29, Reactor Building Charcoal Cleanup System, Reactor Compartment Cooling System and Secondary Compartment Cooling System.

4. Figure 9.4-30, Reactor Building Refueling Water Surface System, Rod Position Data Cabinet System, and Reactor Building Elevator Machine Room System.
5. Figure 9.4-31, Reactor Building CRDM Shroud Cooling System.

Design and performance data are indicated on these figures.

9.4.8.2.1 Reactor Building Cooling System

The main components of this system include:

1. Four (4) air handling units, each capable of providing 33-1/3% of normal system cooling capacity. Each air handling unit has moisture separators, HEPA filters, a filter bypass section, cooling coils, fan and dual motors.
2. Gravity dampers to isolate each air handling unit discharge from the distribution duct system when the unit is not operating.
3. Ductwork from the discharge connection of the units to various elevations of the Reactor Building.
4. Instrumentation and control devices to perform the functions detailed in Section 6.2.2.5.2.

Section 6.2.2.2 presents detailed descriptions of system equipment and functions.

9.4.8.2.2 Reactor Building Purge Supply and Exhaust System

The main components of this system include:

1. Two (2) 50% capacity supply fans directing filtered and tempered outside air into the Reactor Building.
2. Two (2) 50% capacity exhaust fans exhausting Reactor Building air to the purge exhaust vent.
3. Two (2) 50% capacity supply plenums, each with roughing filters (80% efficiency on NBS dust), and electric heating coils.
4. One (1) 100% capacity exhaust filter plenum with roughing filters (80% efficiency on NBS dust), HEPA filters (99.97% efficiency on 0.3 micron particles), a charcoal filter (95% efficiency on methyl iodide at 85% relative humidity and 70°F) and a second bank of HEPA filters (same efficiency as the initial bank).
5. Four (4) 100% capacity containment isolation butterfly valves. These valves are air opened, spring closed and fail in the closed position upon loss of power or instrument air.
6. Air operated, spring opposed dampers to isolate supply or exhaust fans and the outside air inlet duct.
7. Supply ductwork to direct outside air to the supply plenums, the supply fans and into the Reactor Building. Exhaust ductwork to direct Reactor Building exhaust air to the exhaust plenums, the exhaust fans and the purge exhaust vent.

8. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the supply and exhaust filter banks by means of differential pressure gages (local indication only).
   b. Cause an alarm in the control room upon detection of high concentration of smoke in the discharge of each supply and exhaust fan.
   c. Cause an alarm in the control room upon detection of high temperature in the discharge of each supply and exhaust fan.
   d. Cause an alarm by means of a temperature scanner upon detection of high temperature in the charcoal filter plenum.
   e. Indicate fan isolation damper position by means of status lights in the control room.
   f. Indicate containment isolation butterfly valve position by means of status lights and ESF monitor lights in the control room.
   g. Provide means for manual operation of the following equipment from the control room.
      (1) Supply fans and associated isolation dampers. One (1) switch is provided for each fan. The isolation dampers operate in conjunction with the associated fan.
      (2) Exhaust fans and associated isolation dampers. One (1) switch for each fan is provided. Dampers operate in conjunction with the associated fans.
      (3) Containment isolation butterfly valves. One (1) switch is provided for each valve. Interlocks affecting valve operation are discussed in Section 9.4.8.3.2.
      (4) Outside air damper. One (1) switch is provided.
   h. Automatically maintain minimum supply air temperature by controlling the supply system heating coils by means of a pneumatic temperature controller.
   i. Indicate, in the control room, supply and exhaust fan motor status.
   j. Indicate and record, in the control room, Reactor Building purge exhaust flow rate.
   k. Cause an alarm in the control room upon detection of excessive fan vibration.
   l. Measure, record, and provide high radiation alarms and interlocks to close purge supply and exhaust isolation valves on the occurrence of high radiation levels in the Reactor Building cooling system duct (RM-A2) (see Section 12.2.4) and in the purge exhaust duct (RM-A4) (see Section 11.4).
   m. Measure, record, and provide high radiation alarms and interlocks to close purge supply and exhaust isolation valves on the occurrence of high radiation levels in the manipulator crane area of the Reactor Building (RM-G17A and RM-G17B) (see Section 12.1.4).
   n. Close the purge supply and exhaust isolation valves upon receipt of a containment isolation signal.

The 36 inch Reactor Building supply and exhaust system may be operated during cold shutdown and refueling to maintain suitable radiation levels inside the Reactor Building. This system is operated prior to personnel entering the Reactor Building to reduce radiation levels inside.

The 36 inch purge system supplies filtered and tempered outside air to the Reactor Building and exhausts air from the Reactor Building through HEPA and charcoal filters to the purge exhaust vent. The 36 inch purge system is powered from normal power sources, except for the solenoid valves and limit switches associated with the system containment isolation valves. These components are powered from Class 1E power sources. System equipment is operated and monitored from the control room. The 36 inch purge system supply and exhaust fans and plenums are located in the Auxiliary Building.

The 36 inch purge system and the 6 inch alternate purge system (see Section 9.4.8.2.3) use common outside air supply and exhaust vents, a common outside air intake damper and a common exhaust filter plenum. In other respects these 2 systems are separate.

9.4.8.2.3 Alternate Reactor Building Purge System

Major components of the alternate Reactor Building purge system include the following:

1. One (1) 100% capacity pressure blower to supply filtered outside air to the Reactor Building.
2. One (1) 100% capacity pressure blower to exhaust air from the Reactor Building to the purge exhaust vent.
3. One (1) 100% capacity supply filter plenum with roughing and medium efficiency (85-90% on NBS dust) filters.
4. One (1) 100% capacity exhaust filter plenum with roughing filters (80% efficiency on NBS dust), HEPA filters (99.97% efficiency on 0.3 micron particles), and a charcoal filter (95% efficiency on methyl iodine at 85% relative humidity and 70°F).
5. Four (4) containment isolation gate valves. These valves are spring return, air operated and fail in the closed position upon loss of power or instrument air.
6. Supply ductwork to direct air from the purge intake vent to the Reactor Building.
7. Exhaust ductwork to direct air from the Reactor Building to the purge exhaust vent on the Auxiliary Building roof.
8. Instrumentation and control devices to perform the following functions:
    a. Measure pressure drop across supply and exhaust filter banks by means of differential pressure gages (local indication only). (Part of Reactor Building purge supply and exhaust system.)
    b. Cause an alarm by means of a temperature scanner upon detection of high temperature in the charcoal filter plenum. (Part of Reactor Building purge supply and exhaust system.)
    c. Cause an alarm in the control room upon purge exhaust pressure blower motor trip.

d. Indicate containment isolation valve position by means of status lights in the control room.

e. Indicate purge exhaust pressure blower motor status by means of lights in the control room.

f. Indicate and record, in the control room, purge exhaust flow rate (recorder is part of Reactor Building purge supply and exhaust system).

g. Provide means for manual operation of the following equipment from the control room:

(1) Supply and exhaust pressure blowers.

(2) Containment isolation valves.

(3) Outside air intake damper.

h. Measure, record, and provide high radiation alarms and interlocks to close purge supply and exhaust isolation valves on occurrence of high radiation levels in the Reactor Building cooling system duct (RM-A2) and in the purge exhaust duct (RM-A4) (see Section 11.4).

i. Close the purge supply and exhaust isolation valves upon receipt of a containment isolation signal.

The 6 inch alternate Reactor Building purge system may be operated up to 1000 hours per year during modes 1 - 4 to maintain suitable moisture and radiation levels inside the Reactor Building. In addition to the ventilation functions described, the alternate Reactor Building purge system performs combustible gas control and pressure relief functions as discussed in Section 6.2.5.

9.4.8.2.4 Reactor Building Charcoal Cleanup System

The main components of this system include:

1. Two (2) 50% of system capacity fans to recirculate the general Reactor Building atmosphere through the Reactor Building charcoal cleanup filter plenums.
2. Two (2) 50% of system capacity Reactor Building charcoal cleanup filter plenums, each with roughing filters (80% efficiency on NBS dust), HEPA filters (99.97% efficiency on 0.3 micron particles), charcoal filters (95% efficiency on methyl iodide at 85% relative humidity and 70°F) and a second bank of HEPA filters (same efficiency as the initial bank).
3. Instrumentation and control devices to perform the following functions:
   a. Measure the pressure drop across the filter banks using differential pressure gages (local indication only).
   b. Cause an alarm in the control room upon detection of high concentration of smoke at the suction of each fan. Note that these duct detectors are maintained by the plant, but are not credited because other means exist to detect a fire in the Reactor Building. Their purpose is to aid plant operators in their decision making process.
   c. Cause an alarm in the control room upon detection of high temperature at the suction of each fan.

d. Cause an alarm in the control room upon detection of high temperature in the charcoal filter plenum.

e. Provide means to operate the fans from the control room. One (1) control switch is provided for each fan.

f. Cause an alarm in the control room upon detection of excessive fan and motor vibration.

g. Indicate, in the control room, fan motor status.

h. Cause an alarm in the control room upon fan motor trip.

The Reactor Building charcoal cleanup units are operated prior to Reactor Building access, during personnel access and during refueling operations to reduce iodine concentration to acceptable levels. One (1) or both units are manually operated and monitored from the control room. The units, when in operation, filter Reactor Building air and discharge it to the general Reactor Building atmosphere. The units are powered from normal power supplies.

The filter plenums and related fans are located on platforms along the perimeter of the Reactor Building above the operating floor.

9.4.8.2.5 Reactor Building Reactor Compartment Cooling System

The main components of this system include:

1. Two (2) 100% capacity supply fans to direct cooled Reactor Building air into the compartments surrounding the reactor vessel.
2. Gravity dampers to isolate the inactive fan.
3. Ductwork to direct cooled ambient air to the incore instrument chase from the discharge of the fans.
4. Instrumentation and control devices to perform the following functions:
   a. Cause an alarm in the control room upon detection of high concentration of smoke in the primary compartment incore instrument chase. Note that this detector is maintained by the plant, but is not credited because other means exist to detect a fire in the Reactor Building. Their purpose is to aid plant operators in their decision making process.
   b. Cause an alarm in the control room upon detection of high ambient temperature in the primary compartment incore instrument chase.
   c. Provide means to operate the fans from the control room. One (1) control switch is provided for each fan.
   d. Cause an alarm in the control room upon detection of excessive fan and motor vibration and trip the affected fan motor.
   e. Indicate, in the control room, fan motor status.
   f. Cause an alarm in the control room upon fan motor trip.

Either 1 of the 2 fans operates continuously during normal operation and, during shutdown so that heat losses from the reactor vessel and nozzles can be removed. In the unlikely event of the failure of both fans, full power operation can be supported by establishing natural circulation ventilation of the reactor cavity within 16 hours of the loss of forced ventilation. Natural circulation can be established by opening the door (RB-101) to the incore instrument chase. The fans are not required to operate during a post LOCA period. The fans when operating, direct air cooled by the Reactor Building cooling units into the reactor compartment from which it circulates around the reactor vessel, around neutron detector tubes, around the vessel supports and exits around the vessel nozzles and seal ring, thus removing heat from these items. The fans are supplied from normal power sources. The fans are operated and monitored from the control room. The fans are mounted in the wall enclosing the incore instrumentation tubes.

9.4.8.2.6 Reactor Building Secondary Compartment Cooling System

The main components of this system include:

1. Nine (9) supply fans to direct cooled Reactor Building air into the secondary compartments housing the reactor coolant pumps, steam generators and pressurizer. Six (6) of the 9 fans are normally required to operate.
2. Instrumentation and control devices to perform the following functions:
   a. Cause an alarm in the control room upon detection of high concentration of smoke in the discharge of each fan. Note that these detectors are maintained by the plant, but are not credited because other means exist to detect a fire in the Reactor Building. Their purpose is to aid plant operators in their decision making process
   b. Cause an alarm in the control room upon detection of high temperature in the discharge of each fan.
   c. Provide means to operate the fans from the control room. One control switch is provided for each fan.
   d. Cause an alarm in the control room upon detection of excessive fan and motor vibration and trip the affected fan motor.
   e. Indicate, in the control room, fan motor status.
   f. Cause an alarm in the control room upon fan motor trip.

Two (2) of the 3 fans for each of the 3 secondary compartments operate continuously during normal operation so that reactor coolant pump, steam generator, pressurizer and piping heat losses can be removed. The fans are not required to operate during a post LOCA period. The fans, when operating, direct air cooled by the Reactor Building cooling units into the secondary compartments where it absorbs the heat losses listed above. The heated air exits above the operating floor at an elevated temperature. The fans are supplied from normal power sources. The fans are operated and monitored from the control room. The fans are mounted in shielded wall openings in the secondary compartments.

9.4.8.2.7 Reactor Building Refueling Water Surface System and Rod Position Indication Cooling System

The main components of this system include:

1. Two (2) 50% capacity supply fans to direct Reactor Building ambient air to the refueling water surface duct system.
2. One (1) 100% capacity exhaust fan to direct exhaust air from the refueling water surface to the purge exhaust filter system.
3. Ductwork from 1 of the vertical ducts of the Reactor Building cooling system is provided to supply cooling air to the rod position indication data cabinet area. Flexible ducts provide air directly from a supply grille to each air inlet of the 2 cabinets. As a backup for cooling the cabinet area a 100% capacity air handling unit is provided to supply filtered and cooled air to the area.
4. Ductwork from the supply fans to the refueling water surface supply duct distribution system and from the exhaust side of this system to the exhaust fan and then to the purge exhaust duct. Ductwork to and from the rod position indication data cabinet area and the related air handling unit.
5. Instrumentation and control equipment, including a local control station and circuitry to interlock the operation of the supply and exhaust fans with Reactor Building purge exhaust fan operation.
6. Instrumentation to indicate, in the control room, excessive discharge temperature from the rod position indication cooling system. When the air handling unit cooling system is not operating, this instrumentation also indicates an excessive temperature in the cabinet area.

The Reactor Building refueling water surface system is not normally operated, but does operate continuously during refueling periods to reduce operator exposure due to the release of airborne radioactivity from the refueling canal and refueling cavity surface. The system is arranged to develop a moving air flow across the surface of the refueling canal and refueling cavity. The exhaust from this system is directed to the Reactor Building purge exhaust system. Each unit is supplied from normal power supplies. The fans are operated from a local control station. The supply and exhaust fans are mounted on the secondary compartment shield walls above the operating floor. The rod position indication air handling unit operates as a backup cooling system during normal operating periods to maintain the rod position indicator data cabinet at a suitable ambient temperature. The air handling unit is served by normal power supplies. The cooling coil is supplied from the industrial cooling water system. The air handling unit is located adjacent to the rod position data cabinet.

9.4.8.2.8 Integrated Head Assembly CRDM Cooling System

The Integrated Head Assembly CRDM Cooling System is contained within the Integrated Head Assembly (IHA). The IHA houses internal ducting that pulls RB area air into the IHA and draws the air downward past the CRDM coils, providing cooling. The air is then ducted upward to a

common air plenum which the fans draw from. Two (2) fans are normally operating which will exhaust the air from the plenum to the RB general area.

The main components of this system include:

1. Three (3) 50% capacity exhaust fans to draw general Reactor Building ambient air through the CRDM shroud for cooling.
2. Gravity dampers to isolate the inactive fans.
3. Ductwork connecting the exhaust ports of the CRDM shroud to the inlet connections of the exhaust fans, all within the Integrated Head Assembly (IHA).
4. Instrumentation and control devices to perform the following functions:
   a. Indicate, in the control room, the temperature of the air at the CRDM shroud plenum and cause an alarm in the control room upon detection of high air temperature.
   b. Cause an alarm in the control room upon detection of high temperature in the discharge of each fan.
   c. Provide means to operate the fans from the control room. One control switch is provided for each fan.
   d. Cause an alarm in the control room upon detection of excessive fan and motor vibration.
   e. Indicate, in the control room, fan motor status.
   f. Cause an alarm in the control room upon fan motor trip.

Each fan is normally supplied from a BOP power source. However, provision is made to manually connect 1 unit to a Class 1E bus. The fans are operated and monitored from the control room. The fans are located above the air plenum atop the IHA.

9.4.8.2.9 Reactor Building Elevator Machine Room System

Major components of the Reactor Building elevator machine room system include the following:

1. A 100% capacity exhaust fan.
2. Fixed, wall inlet louvers.
3. Instrumentation and control devices to automatically limit maximum elevator machine room temperature by cycling the exhaust fan.

The system cyclically exhausts air from the elevator machine room to the general open area of the Reactor Building in response to a room thermostat when normal power is available. Makeup air from the general open area of the Reactor Building enters the room through fixed, wall inlet louvers. Equipment is located in the Reactor Building elevator machine room wall.

9.4.8.3 Safety Evaluation

9.4.8.3.1 Reactor Building Cooling and Filtering System

A safety evaluation of this system is presented in Section 6.2.1.

9.4.8.3.2 Reactor Building Purge Supply and Exhaust System

Containment isolation is safeguarded through the use of redundant, fail closed, butterfly valves on both the purge supply and exhaust lines. For both the supply and the exhaust portions of this system, redundant fans are furnished so that equipment failure does not prevent purge but simply extends the required purge time period. Radiation monitoring of the purge exhaust vent is provided by radiation monitor RM-A4 (see Section 11.4). Electrical interlocks allow no more than 1 valve of a redundant pair of containment isolation valves to be open unless the exhaust system is operating (1 valve of the pair can be open for testing purposes). Automatic closure of the 4 containment isolation valves of this system occurs upon receipt of a containment isolation signal (see Section 7.3) or a high radiation signal (see Sections 11.4, 12.1.4, and 12.2.4). These measures, combined with administrative control of system operation, ensure that containment air is not released to the atmosphere through uncontrolled paths. The purge supply and exhaust system are not required to operate during a post accident period. The purge supply and exhaust isolation valves, as noted above, isolate the containment and are redundant safety class equipment.

9.4.8.3.3 Alternate Reactor Building Purge System

Containment isolation is assured through the use of redundant, fail closed, gate valves on both the alternate purge supply and exhaust lines. Automatic closure of the 4 containment isolation valves in the alternate Reactor Building purge system occurs upon receipt of a containment isolation signal (see Section 7.3) or a high radiation signal (see Sections 11.4 and 12.2.4). These measures, combined with administrative control of system operation, ensure that containment air is not released to the atmosphere through uncontrolled paths. Post accident operation of the alternate purge system is discussed in Section 6.2.5.

The alternate Reactor Building purge system containment isolation valves and accessories are safety class equipment. The remainder of the system is not safety related.

9.4.8.3.4 Reactor Building Charcoal Cleanup System

Redundancy of cleanup units provides iodine removal capability even if 1 of the units is not available. This condition extends the required cleanup time period prior to purging, but does not prevent eventual completion of system function. This system is not required to operate under accident conditions and is not supplied from emergency power sources. The system is not safety-related.

9.4.8.3.5 Reactor Building Reactor Compartment Cooling System, Secondary Compartment Cooling System and CRDM Shroud Cooling System

For each of the these 3 systems, adequate redundancy of system components is provided to ensure that sufficient cooling capacity is delivered under varying conditions of component availability. These systems are not required to operate under accident conditions and are not safety-related.

In the unlikely event that natural circulation is relied upon to cool the reactor cavity, the temperature of the concrete at the reactor vessel support anchorages, and the air temperature around the nuclear instrumentation will exceed the design basis values. These elevated temperatures have been acceptably evaluated to support full power operation until the next regularly scheduled outage.

9.4.8.3.6 Reactor Building Refueling Water Surface System

This system is operated only during refueling and has no post accident safety function.

9.4.8.3.7 Reactor Building Elevator Machine Room System

The Reactor Building elevator machine room system operates in response to the room thermostat. The system has no post accident safety function and is not safety related.

9.4.8.4 Inspection and Testing Requirements

The Reactor Building systems are subjected to preoperational test procedures to verify the following: proper wiring and control hookup, system "in-place" integrity and leak tightness, proper function of system components and control devices and to establish system design air flows.

To ensure a continued state of readiness of the Reactor Building systems after completion of the preoperational tests, the following inspection, maintenance and test procedures are performed:

1. Reactor Building Cooling System

   Inspection and testing of the Reactor Building cooling system are discussed in Sections 6.2.2.4.2 and 6.5.1.4.

2. Reactor Building Purge Supply and Exhaust System and Alternate Reactor Building Purge System.
   a. Record filter pressure drops.
   b. Verify function of dampers or control devices necessary for monitoring or component isolation or changeover from normal to emergency mode.
   c. Bearing lubrication.
   d. Laboratory test of charcoal filter test canisters for decontamination efficiency.

e. In place leak test of the HEPA and charcoal filters.

3. Reactor Building Charcoal Cleanup System

   Reactor Building charcoal cleanup system inspection, maintenance and testing requirements are the same as those for the Reactor Building purge supply and exhaust system.

4. Reactor Building Reactor Compartment Cooling System, Secondary Compartment Cooling System, CRDM Shroud Cooling System and Refueling Water Surface System.

   a. Bearing lubrication.

   b. Switch components that normally operate from standby to operating mode.

5. Reactor Building Elevator Machine Room System.

   a. Bearing lubrication.

9.4.9 References

1. American Air Filter Company, "Impregnated Activated Carbon for Removal of Radioiodine Compounds from Reactor Containment Atmospheres," AAF TR-7102.

Figure 9.4-1
DRAWING D-912-140
FSAR FIGURE REFERENCE

Figure 9.4-2
DRAWING D-912-136
FSAR FIGURE REFERENCE

Figure 9.4-3
DRAWING D-912-144
FSAR FIGURE REFERENCE

Figure 9.4-4
DRAWING D-912-147
FSAR FIGURE REFERENCE

Figure 9.4-5
DRAWING D-912-154
FSAR FIGURE REFERENCE

Figure 9.4-6
DRAWING D-912-115
FSAR FIGURE REFERENCE

Figure 9.4-7
DRAWING D-912-120
FSAR FIGURE REFERENCE

Figure 9.4-8
DRAWING D-912-125
FSAR FIGURE REFERENCE

Figure 9.4-9
DRAWING D-912-130
FSAR FIGURE REFERENCE

Figure 9.4-10
DRAWING D-912-132
FSAR FIGURE REFERENCE

Figure 9.4-10a
DRAWING D-912-150
FSAR FIGURE REFERENCE

Figure 9.4-11
DRAWING D-912-131
FSAR FIGURE REFERENCE

Figure 9.4-12
DRAWING D-912-160
FSAR FIGURE REFERENCE

Figure 9.4-13
DRAWING D-912-159
FSAR FIGURE REFERENCE

Figure 9.4-14
DRAWING D-912-139
FSAR FIGURE REFERENCE

Figure 9.4-15
DRAWING D-912-157
FSAR FIGURE REFERENCE

Figure 9.4-16
DRAWING D-912-138
FSAR FIGURE REFERENCE

Figure 9.4-17
DRAWING D-912-158
FSAR FIGURE REFERENCE

Figure 9.4-18
DRAWING D-912-134
FSAR FIGURE REFERENCE

Figure 9.4-19
DRAWING D-912-155
FSAR FIGURE REFERENCE

Figure 9.4-20
DRAWING D-912-151
FSAR FIGURE REFERENCE

Figure 9.4-21
DRAWING D-912-152
FSAR FIGURE REFERENCE

Figure 9.4-22
DRAWING D-302-841
FSAR FIGURE REFERENCE

Figure 9.4-23
DRAWING D-302-842
FSAR FIGURE REFERENCE

Figure 9.4-24
DRAWING D-302-843
FSAR FIGURE REFERENCE

Figure 9.4-25, Sheet 1
DRAWING D-302-851
FSAR FIGURE REFERENCE

Figure 9.4-25, Sheet 2
DRAWING D-302-851
FSAR FIGURE REFERENCE

Figure 9.4-26
DRAWING E-922-541
FSAR FIGURE REFERENCE

Figure 9.4-26A
DRAWING D-912-171
FSAR FIGURE REFERENCE

Figure 9.4-26B
DRAWING D-912-170
FSAR FIGURE REFERENCE

Figure 9.4-26C
DRAWING D-912-153
FSAR FIGURE REFERENCE

Figure 9.4-26D
DRAWING D-912-191
FSAR FIGURE REFERENCE

Figure 9.4-28
DRAWING D-912-103
FSAR FIGURE REFERENCE

Figure 9.4-29
DRAWING D-912-104
FSAR FIGURE REFERENCE

Figure 9.4-30
DRAWING D-912-105
FSAR FIGURE REFERENCE

Figure 9.4-31
DRAWING D-912-106
FSAR FIGURE REFERENCE

Figure 9.4-32
DRAWING D-302-852
FSAR FIGURE REFERENCE

Figure 9.4-33
DRAWING D-912-141
FSAR FIGURE REFERENCE

Figure 9.4-34
DRAWING D-302-845
FSAR FIGURE REFERENCE

Figure 9.4-35, Sheet 1
DRAWING D-912-192
FSAR FIGURE REFERENCE

Figure 9.4-35, Sheet 2
DRAWING D-912-192
FSAR FIGURE REFERENCE

Figure 9.4-36
DRAWING D-912-193
FSAR FIGURE REFERENCE

9.5 OTHER AUXILIARY SYSTEMS

9.5.1 Fire Protection

The fire protection program is based on the NRC requirements and guidelines, Nuclear Electric Insurance Limited (NEIL) Property Loss Prevention Standards and related industry standards. With regard to NRC criteria, the fire protection program meets the requirements of 10 CFR 50.48(c), which endorses, with exceptions, the National Fire Protection Association's (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants", 2001 Edition. V.C. Summer Nuclear Station (VCSNS) Unit 1 has further used the guidance of NEI 04-02, "Guidance for Implementing a Risk-Informed, Performance-Based Fire Protection Program under 10 CFR 50.48(c)" as endorsed by Regulatory Guide 1.205, "Risk-Informed, Performance Fire Protection for Existing Light-Water Nuclear Power Plants."

Adoption of NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants", 2001 Edition in accordance with 10 CFR 50.48(c) serves as the method of satisfying 10 CFR 50.48(a) and General Design Criterion 3. Prior to adoption of NFPA 805, General Design Criterion 3, "Fire Protection" of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Licensing of Production and Utilization Facilities," was followed in the design of safety and non-safety related structures, systems, and components (SSC), as required by 10 CFR 50.48(a).

NFPA 805 does not supersede the requirements of GDC 3, 10 CFR 50.48(a), or 10 CFR 50.48(f). Those regulatory requirements continue to apply. However, under NFPA 805, the means by which GDC 3 or 10 CFR 50.48(a) requirements are met may be different than under 10 CFR 50.48(b). Specifically, whereas GDC 3 refers to SSCs important to safety, NFPA 805 identifies fire protection systems and features required to meet the Chapter 1 performance criteria through the methodology in Chapter 4 of NFPA 805. Also, under NFPA 805, the 10 CFR 50.48(a)(2)(iii) requirement to limit fire damage to SSCs important to safety so that the capability to safely shut down the plant is satisfied by meeting the performance criteria in Section 1.5.1 of NFPA 805.

A Safety Evaluation was issued on February 11, 2015 by the NRC, that transitioned the existing fire protection program to a risk-informed, performance-based program based on NFPA 805, in accordance with 10 CFR 50.48(c).

9.5.1.1 Design Basis Summary

9.5.1.1.1 Defense-in-Depth

The fire protection program is focused on protecting the safety of the public, the environment, and plant personnel from a plant fire and its potential effect on safe reactor operations. The fire protection program is based on the concept of defense-in-depth. Defense-in-depth shall be achieved when an adequate balance of each of the following elements is provided:

1. Preventing fires from starting,

2. Rapidly detecting fires and controlling and extinguishing promptly those fires that do occur, thereby limiting fire damage,
3. Providing an adequate level of fire protection for structures, systems, and components important to safety, so that a fire that is not promptly extinguished will not prevent essential plant safety functions from being performed.

9.5.1.1.2 NFPA 805 Performance Criteria

The design basis for the fire protection program is based on the following nuclear safety and radiological release performance criteria contained in Section 1.5 of NFPA 805:

1. Nuclear Safety Performance Criteria. Fire protection features shall be capable of providing reasonable assurance that, in the event of a fire, the plant is not placed in an unrecoverable condition. To demonstrate this, the following performance criteria shall be met:
   a. Reactivity Control. Reactivity control shall be capable of inserting negative reactivity to achieve and maintain subcritical conditions. Negative reactivity inserting shall occur rapidly enough such that fuel design limits are not exceeded.
   b. Inventory and Pressure Control. With fuel in the reactor vessel, head on and tensioned, inventory and pressure control shall be capable of controlling coolant level such that subcooling is maintained for a PWR and shall be capable of maintaining or rapidly restoring reactor water level above top of active fuel for a BWR such that fuel clad damage as a result of a fire is prevented.
   c. Decay Heat Removal. Decay heat removal shall be capable of removing sufficient heat from the reactor core or spent fuel such that fuel is maintained in a safe and stable condition.
   d. Vital Auxiliaries. Vital auxiliaries shall be capable of providing the necessary auxiliary support equipment and systems to assure that the systems required under (a), (b), (c), and (e) are capable of performing their required nuclear safety function.
   e. Process Monitoring. Process monitoring shall be capable of providing the necessary indication to assure the criteria addressed in (a) through (d) have been achieved and are being maintained.
2. Radioactive Release Performance Criteria. Radiation release to any unrestricted area due to the direct effects of fire suppression activities (but not involving fuel damage) shall be as low as reasonably achievable and shall not exceed applicable 10 CFR, Part 20, Limits.

Chapter 2 of NFPA 805 establishes the process for demonstrating compliance with NFPA 805.

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features.

Chapter 4 of NFPA 805 establishes the methodology to determine the fire protection systems and features required to achieve the nuclear safety performance criteria outlined above. The methodology shall be permitted to be either deterministic or performance-based. Deterministic

requirements shall be “deemed to satisfy” the performance criteria, defense-in-depth, and safety margin and require no further engineering analysis. Once a determination has been made that a fire protection system or feature is required to achieve the nuclear safety performance criteria of Section 1.5, its design and qualification shall meet the applicable requirement of Chapter 3.

9.5.1.1.3 Codes of Record

For specific applications and evaluations of plant fire protection system codes and standards, refer to the FP Design Basis Document (DBD), NFPA 805 Fire Protection. The codes and standards used for the design and installation of plant fire protection systems are as follows:

- NFPA 10, Installation of Portable Fire Extinguishers (1973)
- NFPA 12, Standard on Carbon Dioxide Extinguishing Systems (1973)
- NFPA 13, Installation of Sprinkler Systems (1975, 1980)
- NFPA 14, Standpipe and Hose Systems (1974)
- NFPA 20, Centrifugal Fire Pumps (1974)
- NFPA 24, Standard for Outside Protection (1973)
- NFPA 30, Flammable and Combustible Liquids Code (1973)
- NFPA 50A, Gaseous Hydrogen Systems (1973)
- NFPA 51B, Standard for Fire Prevention During Welding, Cutting, and Other Hot Work (1999)
- NFPA 72, Standard for the Installation, Maintenance, and Use of Protective Signaling Systems (1990)
- NFPA 72E, Standard on Automatic Fire Detectors (1978)
- NFPA 76, Standard for the Fire Protection of Telecommunications Facilities (2009)
- NFPA 80, Fire Doors and Windows (1973)
- NFPA 90A, Installation of Air Conditioning and Ventilating Systems (1973)
- NFPA 101, Code for Safety to Life from Fire in Buildings and Structures (1976)
- NFPA 220, Types of Building Construction (1975)
- NFPA 241, Standard for Safeguarding Construction, Alteration, and Demolition Operations (2000)
- NFPA 251, Standard Methods of Tests of Fire Endurance of Building Construction and Materials (1999)
- NFPA 252, Standard Methods of Tests of Door Assemblies (1999)
- NFPA 255, Standard Method of Test of Surface Burning Characteristics of Building Materials (2000)
- NFPA 256, Standard Methods of Fire Tests of Roof Coverings (1998)
- NFPA 600, Standard on Industrial Fire Brigades (2005)
- NFPA 701, Standard Methods of Fire Tests for Flame Propagation of Textiles and Films (1999)
- NFPA 805, Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants (2001)
- NFPA 1081, Standard for Industrial Fire Brigade Member Professional Qualifications (2001)

9.5.1.2 System Description

9.5.1.2.1 Required Systems

Nuclear Safety Capability Systems, Equipment, and Cables

Section 2.4.2 of NFPA 805 defines the methodology for performing the nuclear safety capability assessment. The systems equipment and cables required for the nuclear safety capability assessment are contained in the FP DBD.

Fire Protection Systems and Features

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features. Compliance with Chapter 3 is documented in the FP DBD.

Chapter 4 of NFPA 805 establishes the methodology and criteria to determine the fire protection systems and features required to achieve the nuclear safety performance criteria of Section 1.5 of NFPA 805. These fire protection systems and features shall meet the applicable requirements of NFPA 805 Chapter 3. These fire protection systems and features are documented in the FP DBD.

Radioactive Release

Structures, systems, and components relied upon to meet the radioactive release criteria are documented in the FP DBD.

9.5.1.2.2 Definition of “Power Block” Structures

Where used in NFPA 805 Chapter 3 the terms “Power Block” and “Plant” refer to structures that have equipment required for nuclear plant operations. For the purposes of establishing the structures included in the fire protection program in accordance with 10 CFR 50.48(c) and NFPA 805, the plant structures listed in Table 9.5-1 are considered to be part of the “Power Block”.

9.5.1.3 Safety Evaluation

The FP DBD documents the achievement of the nuclear safety and radioactive release performance criteria of NFPA 805 as required by 10 CFR 50.48(c). This document fulfills the requirements of Section 2.7.1.2 “Fire Protection Program Design Basis Document” of NFPA 805. The document contains the following:

1. Identification of significant fire hazards in the fire area. This is based on NFPA 805 approach to analyze the plant from an ignition source and fuel package perspective.
2. Summary of the Nuclear Safety Capability Assessment (at power and non-power) compliance strategies.
    a. Deterministic compliance strategies.

b. Performance-based compliance strategies (including defense-in-depth and safety margin.

3. Summary of the Non-Power Operations Modes compliance strategies.
4. Summary of the Radioactive Release compliance strategies.
5. Summary of the Fire Probablistic Risk Assessments.
6. Key analysis assumptions to be included in the NFPA 805 monitoring program.

9.5.1.4 Fire Protection Program Documentation, Configuration Control and Quality Assurance

In accordance with Chapter 3 of NFPA 805 a fire protection plan documented in Station Administrative Procedure SAP-131 defines the management policy and program direction and defines the responsibilities of those individuals responsible for the plan's implementation. SAP-131:

1. Designates the senior management position with immediate authority and responsibility for the fire protection program.
2. Designates a position responsible for the daily administration and coordination of the fire protection program and its implementation.
3. Defines the fire protection interfaces with other organizations and assigns responsibilities for the coordination of activities. In addition, SAP-131 identifies the various plant positions having the authority for implementing the various areas of the fire protection program.
4. Identifies the appropriate authority having jurisdiction for the various areas of the fire protection program.
5. Identifies the procedures established for the implementation of the fire protection program, including the post-transition change process and the fire protection monitoring program.
6. Identifies the qualifications required for various fire protection program personnel.
7. Identifies the quality requirements of Chapter 2 of NFPA 805.

Detailed compliance with the programmatic requirements of Chapters 2 and 3 of NFPA 805 are contained in the FP DBD.

9.5.2 Communication Systems

9.5.2.1 Design Bases

The communication systems are designed to provide reliable communications between all essential areas of the station, and to essential locations remote from the plant during normal operations or under emergency conditions. This capability is provided by diverse types of communication systems.

9.5.2.2 Description

9.5.2.2.1 Intra-Plant Communications

The intra-plant communications network consists of the following systems:

1. A page/party public address with evacuation alarms and a fire alarm.
2. A maintenance communications system.
3. A redundant paging system in selected areas.
4. A fuel handling communication system (tied with main system, item 1).
5. A private telephone system.
6. Emergency Communications Plant Digital Radio Repeater System.

Working stations that may require communication between plant personnel and the control room or control room evacuation panel during and/or after transients or accidents are identified in Table 7.4-1. Types of communication systems available at each working station are shown by Figures 9.5-1a through 9.5-1h.

9.5.2.2.1.1 Page/Party Public Address System

The page/party public address system is the main plant communications system. It provides facilities for voice communications at stations located in strategic operating areas. From each of these stations, information can be broadcast over system speakers located in every building and control area throughout the plant. Paging type communications equipment is capable of effective operation to 110 decibels.

Two-way conversations are possible between stations over telephone type receiver-transmitter handsets. The system is common-talking so that all stations may take part in any conversation.

The public address system, powered from an uninterruptible power supply system vital bus, is normally used in daily operations to communicate messages between individuals in the plant. In an emergency, the system may be used to alert all personnel on the site. The evacuation alarms and fire alarm are manually initiated from the control room. These alarms are sounded through the paging system to ensure audibility throughout the plant, with the exception of the control room where the speakers associated with the main page/party public address system are muted. Alarms override the paging system when actuated.

A switching arrangement at each handset station enables that handset to be switched from the paging circuit to the amplified, party line circuits. Three (3) separate party line circuits are provided. Individual party line circuits are selected by a three-position selector switch. Speakers do not carry party line conversation. The circuits are so arranged that when the party line feature is in use, a second conversation can take place simultaneously over the page circuit with no interference between the 2 circuits. Handsets perform satisfactorily without the use of acoustic protective enclosures or devices in areas where the noise level may be as high as 115 decibels.

There are 2 subsystems to the main page/party system:

1. The fuel handling paging/party system.
2. A system of paging/party line access jacks for use with portable handset units.

The fuel handling paging/party system consists of handsets and dual input speakers which can be switched to a separate communications system during refueling. A switch is provided on the designated handsets to isolate them from the main plant system and to tie them to the dual input speakers. These speakers carry both the main plant system and the fuel handling paging system.

The paging/party line access jack receptacles are placed at locations where communication is desirable on a limited basis. Each jack accepts the plug from a portable handset/speaker station. The portable station functions in the same manner as a standard handset station.

All handset stations are designed for maximum safety and isolation from live circuits under all operating conditions.

9.5.2.2.1.2 Maintenance Communications System

The maintenance communications system contains a network of plug-in jacks in selected areas of the plant. This system is completely isolated from all other communication systems.

Headsets, consisting of earphones and a microphone, are connected through the plug-in jacks to 4 two-wire nonshielded channels permitting direct communications between persons in different areas. The system obtains its power from the non-Class 1E power system bus. This system is normally used for maintenance of calibration and equipment. During an emergency, the system may be used as an alternate means to relay messages between different areas of the plant.

9.5.2.2.1.3 Redundant Paging System

The redundant paging system consists of handsets, speakers, amplifiers, and accessories similar to the main page/party system. This system is powered from a Class 1E source. This system is completely independent of all other communication systems and is limited to areas where communications are required under emergency operating conditions.

All equipment in the redundant paging system is painted red. This system operates only in the paging mode and only over redundant speakers.

9.5.2.2.1.4 Private Telephone System

A private telephone system using commercial type telephone handsets is installed throughout the station for local use and offsite communications. The telephone system has a reliable power supply with battery backup which maintains the system in an operational condition during a loss of normal station power.

The system consists of switchboard equipment, power supply and telephones. The switchboard is equipped for multiple private subscribers, 2 wire lines for local service and links for simultaneous talking paths.

Backup control systems are provided for critical switching and signaling equipment so that if 1 component fails, the entire system is not lost.

9.5.2.2.1.5 Emergency Communications Plant Digital Radio Repeater System

This is a new plant digital radio repeater system. This system is installed for use by plant Operations, Maintenance and Fire Brigade personnel to meet NFPA 805 Emergency Communications criteria. This system is designated as the primary NFPA 805 Emergency Communications system, and the existing Gai-Tronics plant paging system is considered as a back-up system. The system has a reliable power supply with battery back-up which maintains the system in an operational condition for up to 24 hours during a loss of normal station power.

The system consists of strategically located antennas located within different areas of the power block buildings for radio coverage. This will enable Plant Operations, etc. to communicate via hand held radios for normal and fire safe shutdown communication purposes.

The system is designed using redundant “A” and “B” antenna signal loops so that if one loop is compromised during a fire event, emergency communications from that area is still received by the antenna equipment in the other loop.

9.5.2.2.2 Plant to Offsite Communications

Plant to offsite communications operate through the private telephone system and in conjunction with the commercial telephone landline system, as well as through a fiber optics receiving and transmitting system. Both the landline and fiber optics systems operate through the private telephone system switchboard.

Commercial telephone landlines are provided between the station, and the control office of the Southern Bell Telephone and Telegraph in Columbia and Chapin, S. C.

The fiber optics system, owned and operated by SCE&G, consists of solid-state equipment designed and engineered for voice communication. The tones received via this channel have volume, fidelity and noise suppression comparable with the quality normally obtained on a commercial telephone. The master station is located at the main SCE&G office in Columbia, S. C.

Redundant paging system equipment is capable of effective operation to 110 decibels.

9.5.2.2.3 Safety Evaluation

A failure of 1 communication system does not affect the operation of the other types of communication systems since they are of diverse types and are not interdependent.

The operability of the onsite communications system is assured by installation of the redundant communications system (see Section 9.5.2.2.1.3). This redundant system has separate phone stations, power supply, line balance equipment and cable system. Phone stations of the redundant system consist of telephone type receiver-transmitters, a handset, amplifiers and speakers. The redundant system provides paging facilities only.

The plant to offsite communications systems are not subject to common mode failure due to loss of station power or failure of the interconnecting wireway. The redundant system is powered by a diesel backed bus. The normal plant paging system is supplied from a battery backed, 60 Hz static inverter. The telephone landlines are fed from offsite sources by the commercial telephone company.

9.5.2.3 Inspection and Testing Requirements

The design of the communications systems permits routine testing and inspection without disrupting normal communications. Since all systems are in daily use, any degradation is readily identified and corrected. The evacuation alarms and fire alarm systems are tested periodically in accordance with written and approved procedures.

Effective communication between the work stations identified in Table 7.4-1 and the control room is verified during plant startup and testing and is reverified periodically.

9.5.3 Lighting Systems

The lighting system throughout the plant, Service Building and outdoor areas is designed to provide good light distribution with adequate light intensities. The lighting system is divided into normal, essential, and emergency lighting.

9.5.3.1 Normal Lighting

Normal lighting is provided in attended areas and constitutes the majority of plant lighting. Illumination is from incandescent, fluorescent and high intensity discharge (HID) light sources supplied from buses other than engineered safety features (ESF) buses. Local lighting panels for 480 Y/277 volt, 3 phase, 4 wire and 208 Y/120 volt, 3 phase, 4 wire power supply the branch circuits.

Outdoor lighting consists of roadway, perimeter security, area lighting and switchyard lighting. Outdoor lighting is supplied by 480 volt, single phase power from the nearest available 480 volt load center. All poles and luminaires are effectively grounded.

9.5.3.2 Essential Lighting

Essential lighting operates in conjunction with and supplements the normal lighting where a more reliable source of illumination is required for the performance of critical tasks or for access or egress. Essential lighting is provided for access in the Turbine Building, Auxiliary Building, Diesel Generator Building, Water Treatment Building, Intermediate Building and Control

Building. Essential lighting is also provided, with emergency d-c backup, for continuation of critical activities in the control room, relay room, computer room, and critical electrical distribution areas of the Control Building, as well as the evacuation panel and ESF switchgear rooms, and the diesel generator rooms. Essential lighting, supplied from ESF buses, is divided into Channel A and Channel B, as determined by the channel of the power supply bus. Class 1E fuses located in separate panels are connected in series with the Class 1E circuit breakers at the ESF bus to provide isolation, thereby eliminating the requirements for separation criteria identification. Local lighting panels for 480Y/280 volt, 3 phase, 4 wire and 208Y/120 volt, 3 phase, 4 wire supply the branch circuits.

9.5.3.3 Emergency Lighting

The emergency lighting system provides adequate station lighting in the Diesel Generator Building, Reactor Building, control room, and control room evacuation panels for control and maintenance of safety-related equipment, as well as for access and egress from these areas and egress from the Reactor Building. The Diesel Generator Building and Reactor Building emergency lighting panels are connected to the BOP battery, and the control room and control room evacuation panel room emergency lighting panels are connected to the ESF batteries. Emergency lighting is provided in buildings to satisfy the South Carolina Building Code and the Illuminating Engineers Society Handbook, 5th Edition, and is supplied from the station 125 volt d-c system.

The d-c power is supplied from multi-purpose batteries equipped with battery chargers. This lighting, which is not a part of the normal or essential lighting supplying the areas, only becomes energized upon loss of power to Reactor Building normal lighting or upon loss of power to the Diesel Generator Building or control room essential lighting. The individual branch circuits are run in conduits different from the conduits for the normal lighting. Circuits feeding the panel boards are run in the cable trays applicable to the separation channel of the d-c power supply.

In addition to the 125 volt d-c system, self-contained battery packs are used in areas required for remote shutdown lighting for access and egress in buildings affected by loss of power.

9.5.3.4 Tests and Inspection

Everyday use of the normal and essential lighting systems is considered to be proof of system integrity. Periodic testing of the d-c emergency lighting system is accomplished by tripping the emergency panel sensing circuits.

9.5.4 Diesel Generator Fuel Oil Storage and Transfer System

9.5.4.1 Design Bases

The diesel generator fuel oil storage and transfer system is safety-related and is designed in accordance with the recommendations of ANSI N195 (Reference 4) and satisfies the requirements of the DEMA Standard (Reference 6). The system is designed to withstand the safe shutdown earthquake (SSE) without loss of function. The system is also protected against

missiles. The diesel generator fuel oil storage tanks, day tanks and transfer pumps are designed in accordance with the ASME Code, Section III, and are classified Safety Class 2b, Seismic Category 1.

No single active or passive failure prevents the supply of fuel oil to at least 1 diesel generator.

The onsite capacity of each redundant diesel generator fuel oil storage and transfer system is sized to provide fuel oil for a minimum of 7 days of continuous operation of a diesel generator under time dependent load conditions enveloped by Table 8.3-3 Parts A2 and B2 following a design basis accident and loss of offsite power, as required by ANSI N195 (Reference 4), except that the fuel inventory margin for modes 1-4 is 2% vs. the 10% recommended by ANSI N195.

9.5.4.2 System Description

Two (2) emergency diesel generator sets are provided. The diesel engines are fueled with No. 2 diesel fuel oil supplied by the diesel generator fuel oil storage and transfer system. Figure 9.5-2 presents the system diagram.

The system includes the following components:

1. Two (2) underground (buried) diesel generator fuel oil storage tanks are provided. The locations of these tanks are shown by Figure 9.5-2a. Each tank has a nominal capacity of approximately 52,000 gallons of No. 2 diesel fuel oil. This nominal tank capacity (52,000 gallons) is sufficient to hold the required fuel oil to sustain the operation of one diesel generator for 7 days under time dependent load conditions identified in Table 8.3-3. Each storage tank is vented to atmosphere and is protected from corrosion as necessary.
2. Four (4) full capacity, a-c, electric motor driven fuel oil transfer pumps, located in the basement of the Diesel Generator Building, are provided. These pumps are powered from the Class 1E electric system. Two (2) pumps are associated with each diesel generator fuel oil storage tank. The pumps take suction from the storage tank and supply fuel oil to the fuel oil day tank. Each pump is provided with a pressure relief recirculation line to the associated diesel generator fuel oil storage tank.
3. Two (2) diesel generator fuel oil day tanks are provided, 1 for each diesel engine. Each day tank is located near the associated diesel engine and is sized to store approximately 550 gallons of No. 2 diesel fuel oil. Each tank has sufficient fuel oil capacity to sustain full load operation for approximately 1.5 hours. The day tanks are located in accordance with the diesel generator manufacturer’s requirements to ensure drainage of the normal clean fuel leakage from the injection pumps on the engines. Each day tank is separately vented to atmosphere and is provided with corrosion protection as necessary. An overflow line from each day tank returns fuel oil to the associated fuel oil storage tank. Two (2) positive displacement diesel fuel oil pumps are mounted on the engine. One (1) of these pumps is engine driven; the other, d-c motor driven. The pumps are of the positive displacement type with suction lift capability to draw fuel from the daytank. The diesel engine is also equipped with an engine mounted fuel oil accumulator tank to provide a reservoir which keeps the engine fuel oil headers full during engine shutdown periods.

4. A truck hose connection, strainer, pump, filter, associated piping and instrumentation are provided for fuel oil unloading.

Redundant components, except for the diesel generator fuel oil storage tanks, are located in a Seismic Category 1 structure and are isolated from each other. The diesel generator fuel oil storage tanks are coated to afford protection against corrosion. Vents, located 3 feet above the site grade (elevation 436’), are equipped with flame arrestors.

9.5.4.3 Safety Evaluation

As a result of the redundancy incorporated in the system design, the diesel generator fuel oil storage and transfer system provides the minimum required safety functions under any one of the following conditions:

1. Loss of offsite power coincident with failure of 1 diesel generator.
2. Loss of offsite power coincident with maintenance outage or failure of 1 diesel generator fuel oil transfer pump associated with each diesel generator.
3. Loss of offsite power coincident with maintenance outage or failure of either diesel generator fuel oil storage tank.
4. A single failure analysis for the diesel generator fuel oil system is in accordance with Table 9.5-2.

Each fuel oil storage tank contains sufficient No. 2 diesel fuel oil for 7 days continuous operation of its associated diesel generator, with the time dependent loads identified in Table 8.3-3. A 10% fuel margin is maintained for Modes 5-6 in compliance with ANSI N195, and a 2% fuel margin is maintained in Modes 1-4; this reduced margin for Modes 1-4 was approved by the NRC per License Amendment 150. Fuel oil in large quantities is available within 7 days from commercial sources. Each diesel generator fuel oil day tank is sized to store approximately 550 gallons of No. 2 diesel fuel.

9.5.4.4 Test and Inspection Requirements

The diesel generator fuel oil supply piping is pressure tested during construction. Active system components: pumps, valves and controls; are functionally tested during startup and periodically thereafter. Diesel fuel oil analyses are performed periodically in accordance with Technical Specification, Section 4.

Surveillance testing of the diesel generator fuel oil, both upon initial delivery and periodic testing is based upon applicable ASTM standards. Since some of the ASTM standards used are applicable to other applications of petroleum fuel oils, some requirements in the standards will not be complied with. Specific examples of exceptions to requirements in the applicable standards include:

- The Sample containers used for sampling fuel oil using the ASTM D2276-88 (Determination of Particulate Contamination in Fuel Oil) method will not have a clean piece of plastic film rinsed with petroleum ether placed over the top of the bottle.
- Filtered petroleum ether of filtered 1,1,2-trichloro-1,1,2-trifluoroethene used in the ASTM D2276-88 method may be substituted with unfiltered 1,1,2-trichloro-1,1,2-trifluoroethene, n-7 hexane, or iso-octane.
- The viscometer bath temperature will be allowed a 0.05 degree C variation during the performance of Kinematic Viscosity, as described in ASTM D445 (Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids).
- An alternate thermometer that meets the stated range and accuracy requirements of specified ASTM thermometers may be used during the analysis of diesel fuel oils.
- The determination of Flash Point in oil testing analysis results will not be corrected for barometric pressure.

The bases for these specific exceptions is documented in the Safety Evaluation for Amendment 164 to the facility Technical Specifications.

9.5.4.5 Instrumentation Application

Indication and monitoring of diesel fuel oil temperature is not required. The specified diesel fuel oil pour point range is 0°F to - 20°F. The diesel generator fuel oil storage tank and all fuel oil piping from the tank to the transfer pumps, located in the Diesel Generator Building, is buried below the frost line. The frost line was determined from National Fire Protection Association recommendations for depth of earth cover to avoid freezing of underground fire protection water mains.

Figure 9.5-2 shows pressure gages on the diesel fuel oil transfer pump discharge. Low fuel oil pressure in the diesel injector inlet header actuates an alarm on the main control board and the local diesel generator control panel. This low pressure alarm is not illustrated by Figure 9.5-2 because it is supplied by the diesel generator manufacturer.

9.5.5 Diesel Generator Cooling Water System

9.5.5.1 Design Bases

The diesel generator cooling water system is a self-contained, closed type system located in the Seismic Category 1 Diesel Generator Building. The water is cooled by thermostatically controlled heat exchangers wherein heat is rejected to the Service Water System (see Section 9.2.1). Cooling water is circulated by engine driven pumps through two subsystems. One, the intercooler system, provides cooling for the turbocharger air intercoolers and the alternator outboard bearing. The other, the jacket water system, cools the cylinder liners, cylinder heads and turbocharger cooling spaces. An expansion tank is provided and an electric heater and auxiliary, motor driven pump permit "keep warm" system operation under standby conditions.

The water in this closed system is treated with corrosion inhibitor in accordance with the manufacturer’s recommendations.

The diesel engine cooling system is classified Safety Class 2b, Seismic Category 1 and is designed and fabricated in accordance with the ASME Code, Section III, Class 3, except for certain components not commercially available as ASME Code, Section III, Class 3 items. In the case of such items, other established industry codes or standards are applied. The system is also designed in accordance with the DEMA Standard (Reference 6).

The expansion tank is non-nuclear safety class and is connected to a Safety Class 2b, ASME Code, Section lII, Class 3, standpipe by a non-nuclear safety class expansion joint. The 17 foot high standpipe is designed to provide sufficient static head to satisfy jacket water pump NPSH requirements and to provide adequate makeup to the system for 7 days of continuous operation of the diesel generator. The wall mounted expansion tank is seismically designed to preclude damage to safety related equipment during an earthquake.

9.5.5.2 System Description

The diesel generator cooling water system consists of 2 subsystems.

1. Intercooler System

   The turbocharger air intercoolers and alternator outboard bearing are cooled by the intercooler system. Circulation of treated cooling water is accomplished by an engine driven, centrifugal pump. Heat from the cooling water is rejected to the Service Water System through a thermostatically controlled heat exchanger. Also included is an expansion tank mounted on top of a standpipe which serves both the intercooler and jacket water systems. Figure 9.5-3 is a schematic of the system.

2. Jacket Water System

   The engine is cooled by the closed circuit jacket water system. Water, treated in accordance with the manufacturer’s recommendations, is circulated through the cylinder liners, cylinder heads and turbocharger cooling spaces by an engine driven, centrifugal pump. Heat from the cooling water is rejected to the Service Water System through a thermostatically controlled heat exchanger. Also included is an expansion tank mounted on top of a standpipe which serves both the jacket water and intercooler systems.

   An electric heater and auxiliary, motor driven centrifugal pump are furnished to permit "keep warm" operation under standby conditions. Figure 9.5-4 is a schematic of the system.

   Cooling water enters the engine from the external piping system through the lower headers at each side of the engine. It enters each cylinder at the lower end of the jacket through a duct in the frame opening (see Figure 9.5-5). The water circulates around the cylinder liner and then flows to the cylinder head through an external duct. The cylinder head cooling water also cools the exhaust valve guides. Cooling water also flows from the lower headers to the turbocharger.

After cooling, the water flows through the upper headers to the external piping and then to the heat exchanger.

Heat rejected and flow rates for both the intercooler system and jacket water system are summarized in Table 9.5-3, as are the design heat removal capacity and operating temperature differential.

9.5.5.3 Safety Evaluation

Each diesel generator unit is provided with a separate cooling water system. The use of engine driven pumps renders the cooling water systems immune to loss of offsite power. No single failure can compromise availability of emergency power since redundant diesel generators are provided.

Diesel generator protective trip signals, arising from malfunction of the diesel generator cooling water system, are bypassed under accident conditions.

9.5.5.4 Tests and Inspections

The diesel generator cooling water system is tested in conjunction with the testing of the diesel generator. No separate test of the cooling water system, except hydrostatic testing of certain portions, is performed. Those portions of the system upon which hydrostatic tests are performed by the manufacturer are indicated on notes of drawing 1MS-32-005. The diesel generator intercooler and jacket water systems, sheets 4 and 5 of drawing 1MS-32-005, are shown in simplified form in Figures 9.5-3 and 9.5-4.

9.5.5.5 Instrumentation Application

The diesel generator cooling water system is monitored and protected by pressure and temperature switches as shown in Figure 9.5-4. Local instrumentation is provided as shown by Figures 9.5-3 and 9.5-4.

The board mounted temperature indicator, with the high and low temperature alarm switches, senses temperature in the jacket water return line and indicates abnormal temperatures in the jacket water system. A low pressure alarm switch is also provided to indicate a system failure. These alarm switches are annunciated locally and by grouped alarms on the main control board. Excessive temperature or other maloperation of this intercooler system is indicated by board mounted temperature meters which sense air temperature in the engine air supply manifolds.

9.5.6 Diesel Generator Starting System

9.5.6.1 Design Bases

Each diesel generator is started by its own independent air starting system. These air starting systems cannot be cross connected in any manner. Each of the 2 air compressors for each diesel generator has sufficient capacity to recharge the air storage tanks from 0 to normal pressure in 110

minutes; the recharge time for each start with both compressors operating is approximately 5 minutes. The Diesel Generator procurement specification required the air storage tanks to have a sufficient capacity to permit 5 successive starts without recharge. Factory testing demonstrated the capacity for 10 consecutive starts, without recharge, using both air storage tanks. In these tests the engine was brought from rest to rated speed and voltage. These tests duplicate field starting conditions.

The air starting system is provided with a noncycling refrigerated air dryer. The air dryer provides air with a dew point of 35°F. Also, dirt and solid particles are filtered out during the drying process.

The diesel generator starting system is designed to remain operable during a total loss of offsite power.

The starting system was designed in accordance with the DEMA Standard (Reference 6) and is classified as Safety Class 2b, Seismic Category 1, with the exception of the air compressors and air dryer which are classified as non-safety related. The safety related position of the system is designed and fabricated in accordance with the ASME Code, Section III, and the DEMA Standard (Reference 6).

9.5.6.2 System Description

The starting system for one engine is shown by Figure 9.5-6, the simplified sketch of the manufacturer’s drawing, 1MS-32-005 Sht 6.

Each diesel generator is provided with 2 independent air starting systems, 1 for each bank of cylinders. Compressed air in the range of 375 to 415 psig is supplied by 2 separate a-c, motor driven air compressors and storage tank systems. Each bank of engine cylinders has its own engine driven air start distributor with a connection to each cylinder. The engine starts using either or both banks.

Starting air pressure is also used to operate the governor servo rack booster which opens the fuel injection pump racks to ensure adequate fuel at startup.

The air starting system features a moisture separator with trap and a refrigerated air dryer with trap to remove water, oil and foreign particles from the air supply to the storage tanks. These features preclude fouling of the air start valve by contaminants, such as oil or rust.

Each air storage tank is protected from overpressure by a safety valve. Each of these tanks is also equipped with a pressure gage.

The system is skid mounted and includes necessary pressure switches and control devices for automatic operation of the air compressors. A low air pressure alarm switch is provided on the diesel engine skid in each of the air supply lines to the diesel air start valves. Low air pressure actuates alarms on the local control panel and main control board. Figure 9.5-6 shows instrumentation.

9.5.6.3 Safety Evaluation

Each diesel generator is equipped with a separate and independent starting air system, thereby protecting against a single failure effecting both generators. Use of 2 air compressors and 2 air receivers within each starting air system and independent air start distributors for each bank of engine cylinders provides added assurance of engine start. The storage capacity of the system, sufficient for 10 successive engine starts without recharging, ensures starting in the event of a loss of offsite power.

Low air pressure alarms are provided to alert the operator should starting air pressure decay to an unsatisfactory level.

9.5.6.4 Tests and Inspections

The diesel generator air starting system is tested in conjunction with diesel generator during startup and periodically thereafter. Factory testing of the system included hydrostatic testing and functional testing for total number of starts without recharging, for recharging time, and for total starting time.

9.5.6.5 Instrumentation Application

The diesel generator starting system is monitored and protected by pressure and temperature instrumentation as shown in Figure 9.5-6.

Low pressure alarm switches are provided as a part of the engine mounted gauge board; this alarm is annunciated locally and in a separate alarm on the main control board. Pressure switches are also provided for compressor control and a temperature switch is provided to alarm on high exit temperature from the air compressor. In addition, local indicators are provided at the gauge board and on the air compressor --air storage tank skid.

9.5.7 Diesel Generator Lubrication System

9.5.7.1 Design Bases

The diesel generator lubrication system is integral with the engine and is positive in action. Three (3) subsystems are provided. The engine lube oil system supplies oil under pressure to all main bearings and, through a pressure reducing valve, to the camshaft bearings, cam followers, fuel injection pumps and valve push rods. This subsystem also provides oil to the crank pin journals and for piston cooling, as well as to accessory gearing. A separate rocker lube system supplies oil to each cylinder head rocker assembly. An auxiliary oil system permits continuous prelubrication of the engines at "keep warm" temperature during standby and continuous bypass filtration of the main oil supply during engine operation.

The diesel generator lubrication system was designed in accordance with the DEMA Standard (Reference 6) and is classified Safety Class 2b, Seismic Category 1. Also, the system is designed and fabricated in accordance with the ASME Code, Section III, Class 3, except for certain

components not commercially available as ASME Code, Section III, Class 3, items. In the case of such items, other established industry codes or standards are applied.

9.5.7.2 System Description

The diesel generator lubrication system is comprised of the following 3 subsystems:

1. Engine Lube Oil System

   In the engine lube oil system, an engine driven double rotor screw pump draws oil through a suction strainer from the engine sump and delivers it to a thermostatically controlled lube oil cooler and then through a 30 micron strainer to the main engine lube oil header. The header supplies lube oil under pressure to all main bearings and, through a pressure reducing valve, to the camshaft bearings, cam followers, fuel injection pumps and valve push rods. Branches from the main header supply lube oil to the camshaft and accessory drive gears.

   The main bearings are supplied through passages in the frame and bearings caps, feeding oil to the bearing groove. The oil flows through holes in the crank webs to the crank pin journals, providing bearing lubrication. Cooling oil then flows through the drilled connecting rod to furnish oil for piston cooling (see Figure 9.5-7).

   The lube oil cooler rejects a maximum of 1,395,000 Btu/hr to the Service Water System. Service water, at a maximum temperature of 95°F and flowing at 1000 gpm, is supplied to 3 series connected heat exchangers. The lube oil heat exchanger is the third in this series and receives service water nominally at 114°F and discharges the water nominally at 117°F, as designed by the diesel generator manufacturer.

2. Rocker Lube System

   To protect the crankcase oil from contamination by possible cooling water and fuel leaks at the cylinder head upper deck level, the valve rockers are lubricated and drained by a separate system. A gear type pump mounted at the free end of the engine is driven by the engine crankshaft. The pump draws oil from an engine mounted reservoir and discharges it under pressure through a duplex filter to a header. Pipes from the header supply each cylinder head rocker assembly. Drain pipes return the oil to a drain header which conveys the oil back to the reservoir. The system includes a small motor driven pump for prelubrication. This pump is run automatically once a week for 5 minutes. A backup timer is provided to shut down the pump and alarm on overrun. An alarm is also provided to indicate failure of the pump contactor to close. Figure 9.5-9 depicts oil flow through a valve rocker.

3. Auxiliary Oil System

   A motor driven gear pump, mounted on the diesel generator skid serves the following purposes:

a. It draws oil from the main sump through a suction strainer and discharges through an electric heater and a 5 micron filter into the engine lube oil system. During standby, this arrangement provides for continuous prelubrication at "keep warm" temperature.

b. During engine operation, this pump and associated components are used for continuous bypass filtration of the engine oil supply.

c. For initial engine startup, the pump is used to fill the external system and prelubricate the engine.

d. During maintenance, the pump is used to empty the engine sump.

9.5.7.3 Safety Evaluation

Each diesel generator is provided with a separate lubrication system, designed to operate under the same conditions as is the engine. The use of engine driven pumps for lube oil circulation renders the system immune to loss of offsite power and no single failure can compromise the availability of emergency power since redundant diesel generators are provided.

The diesel is provided with a crankcase cover installed with a pressure relief valve to mitigate the effects of a crankcase explosion. The diesel is also equipped with a high crankcase pressure alarm and trip (trip during test operating conditions only).

9.5.7.4 Tests and Inspections

The diesel generator lubrication system is tested in conjunction with the testing of the diesel generator.

To ensure diesel lube oil quality, periodic samples of oil are taken from the main and rocker lube oil systems. Lube oil is replaced when it no longer satisfies site standards.

In addition, the operation of the rocker arm prelube pump is verified weekly.

Visual inspection of the diesel lube oil system during periodic engine testing and the provision of the lube oil system pressure and level alarms facilitate detection of any system leakage.

9.5.7.5 Instrumentation Application

The diesel generator lubrication systems are monitored and protected by pressure and temperature switches as shown in Figure 9.5-7. Local instrumentation is also shown by Figure 9.5-7.

The diesel engine sump is provided with a low level alarm. The rocker arm lube system is not equipped with temperature alarms or temperature indicators since it is not designed to provide cooling.

The lube oil sump temperature switch provides a low temperature alarm in the event of failure of either the motor driven auxiliary lube oil system or the lube oil keep warm heater.

9.5.8 Diesel Generator Combustion Air Intake and Exhaust System

9.5.8.1 Design Bases

Design bases for the diesel generator combustion air intake and exhaust system include consideration of the following hazards and phenomena:

1. Wind loadings caused by tornadoes or hurricanes (see Section 3.3 for discussion of design basis wind and tornado).
2. Missile impact (see Section 3.5 for discussion of provisions for missile protection).
3. System capability to withstand single failure without loss of function of both diesel generators.

The elevation of the diesel generator combustion air intake and exhaust system is well above the maximum flood design water level (see Section 3.4). Contaminating substances in quantities sufficient to adversely affect diesel engine operation, if inducted with the combustion air, are not present at or near the site.

System components are classified as Seismic Category 1 and were designed in accordance with the DEMA Standard (Reference 6).

9.5.8.2 System Description

Two (2) separate and independent diesel generators are provided. For each diesel engine, the combustion air intake system consists of 2 filter/silencer units, mounted in a cubicle above the associated diesel generator, with connecting piping to the intake manifold of the engine. Each filter/silencer unit serves 1 engine cylinder bank. The exhaust system for each diesel engine consists of 1 muffler, mounted in a cubicle above the associated diesel generator, and connecting piping from the engine exhaust manifolds. A short exhaust stack extends from the muffler through the roof to the atmosphere.

The cubicles containing the filter/silencer units and the mufflers are Seismic Category 1 and are designed to protect the contained components from missile impact. Protection is accomplished by reinforced concrete construction and a labyrinth arrangement for admission of intake air to the filter/silencer units. See Section 3.5.1.4 for a discussion of missiles generated by natural phenomena.

The labyrinth arrangement also provides protection of the air intake system from atmospheric conditions. Louvers on the air intake opening and the labyrinth prevent wind circulation which could cause ice and snow buildup on the intake filter/silencer units.

The exhaust muffler is located within the Diesel Generator Building to provide protection from atmospheric conditions. The short, large diameter exhaust stack from the muffler is equipped with a weather protection cover. This cover precludes the possibility of clogging of the stack as a result

of atmospheric conditions, such as ice, freezing rain and snow, during standby or operation of the diesel generator.

Figures 1.2-11 through 1.2-14 illustrate the arrangement of the combustion intake and exhaust system. Figure 9.5-10 shows details of the combustion air intake labyrinth and exhaust piping arrangement.

9.5.8.3 Safety Evaluation

The functioning of the diesel generator combustion air intake and exhaust system is not adversely affected by any of the phenomena or events postulated to occur during plant life. Each of the 2 diesel generators which comprise the onsite emergency power source is provided with completely separate and independent combustion air intake and exhaust systems. These redundant systems are physically separated and are housed in Seismic Category 1, missile resistant structures.

Specific conditions considered in the design are as follows:

1. Recirculation of diesel engine combustion products to the air intake is prevented. The exhaust stacks are spatially separated from, and located at a higher elevation than the intake filter/silencer units. Thus, since hot exhaust gases rise and disperse, recirculation to the intake is prevented.
2. Gases that could adversely affect diesel generator operation are not stored in the vicinity of the Diesel Generator Building.
3. Restriction of intake air flow is prevented by housing air intake components in a missile resistant structure and providing labyrinth passages for air ingress. System piping is designed to withstand the SSE without significant deformation.
4. The intake of particulates is prevented by the filter/silencer units through which intake air is filtered.
5. Low barometric pressure does not affect engine operation since each diesel engine is equipped with turbochargers. The turbochargers compensate for varying barometric pressure by increasing or decreasing boost pressure as required.
6. No high energy piping systems are located within the diesel generator buildings. Thus, such systems do not pose a threat to the combustion air intake and exhaust system.

9.5.8.4 Inspection and Testing Requirements

Inspection requirements for the diesel generator combustion air intake and exhaust system include:

1. Periodic inspection and cleaning and/or replacement of the air intake filter in accordance with manufacturer's recommendations.
2. Periodic inspection of exhaust mufflers and exhaust piping for evidence of corrosion due to action of the exhaust gases.

No specific provisions for testing of the system are required since periodic testing of diesel generator operation verifies proper operation of the combustion air intake and exhaust system.

9.5.9 References

1. National Fire Protection Association, *Air Conditioning and Ventilating Systems,* NFPA 90A, 1975.
2. National Fire Protection Association, *Proprietary Signaling Systems,* NFPA 72D, 1975.
3. National Fire Protection Association, *Carbon Dioxide Systems*, NFPA 12, 1973.
4. American National Standards Institute, *Fuel Oil Systems for Standby Diesel Generators*, ANSI N195, April, 1976.
5. NOT USED.
6. Diesel Engine Manufacturers Association, *Standard Practices for Stationary Diesel Engines*.

Table 9.5-1
Power Block Structures

Structure Description	Structure ID(s)
Alternate Fire Service Pump House	AFSPH
Auxiliary Boiler House	ABH
Auxiliary Building	AB
Circulating Water Pump House	CWPH
Control Building	CB
Diesel Generator Building	DG
Fuel Handling Building	FH
Intermediate Building	IB
Potable Water Building	PWB
Radiological Maintenance Building	RMB
Reactor Building	RB
Service Water Pump House	SWPH
Storage Facilities for Hydrogen, Oxygen, Nitrogen, and CO2	HCO2S and HNS
Switchyard	SWYD
Turbine Building	TB
Water Treatment Building	WTB
Yard (includes targeted manhole areas, Condensate Storage Tank, Refueling Water Storage Tank, Diesel Generator Fuel Oil Storage Tanks, Auxiliary Boiler Oil Storage Tanks, Transformers)	YD and MH

Table 9.5-2
Single Failure Analysis Diesel Generator Fuel Oil System

Component	Malfunction	Comments
A-C Fuel Oil Transfer Pump	Fails to start or stops operating	Alternate a-c pump in parallel
Piping	Leakage	Switch load to second diesel generator
Diesel Generator Fuel Storage Tank	Leakage	Switch load to second diesel generator

Table 9.5-3
Diesel Generator Cooling Water System
Heat Transfer and Flow Rate (Major Components)

Compenent	Heat Rejection Rate (Btu/hr) (1)	Flow Rate (gpm)	Temp Diff (°F) (1)	Percentage Excess Heat Removal Cap.
Intercoolers (2)	3.906×10^6	1011	8	4.5
Intercooler Heat Exchanger	3.906×10^6	1010	8	7.3
Cylinder Liners (3) and Turbo Chargers (2)	5.776×10^6	896	13	Not Applicable
Jacket Water Heat Exchanger	5.776×10^6	650	18	36.5

(1) Heat rejection rates and temperature differentials are given for operation at 4676 kW (110 percent of continuous rating).
(2) Total for two.
(3) Total for twelve.

Figure 9.5-1, Sheet 1
DRAWING D-302-231
FSAR FIGURE REFERENCE

Figure 9.5-1, Sheet 2
DRAWING D-302-231
FSAR FIGURE REFERENCE

Figure 9.5-1, Sheet 3
DRAWING D-302-231
FSAR FIGURE REFERENCE

Figure 9.5-1, Sheet 4
DRAWING D-302-231
FSAR FIGURE REFERENCE

Figure 9.5-1, Sheet 5
DRAWING D-302-231
FSAR FIGURE REFERENCE

Figure 9.5-1A
DRAWING E-001-011
FSAR FIGURE REFERENCE

Figure 9.5-1B
DRAWING E-001-021
FSAR FIGURE REFERENCE

Figure 9.5-1C
DRAWING E-001-031
FSAR FIGURE REFERENCE

Figure 9.5-1D
DRAWING E-001-022
FSAR FIGURE REFERENCE

Figure 9.5-1E
DRAWING E-001-032
FSAR FIGURE REFERENCE

Figure 9.5-1F
DRAWING E-005-001
FSAR FIGURE REFERENCE

Figure 9.5-1G
DRAWING E-005-002
FSAR FIGURE REFERENCE

Figure 9.5-1H
DRAWING E-001-013
FSAR FIGURE REFERENCE

Figure 9.5-2
DRAWING D-302-351
FSAR FIGURE REFERENCE

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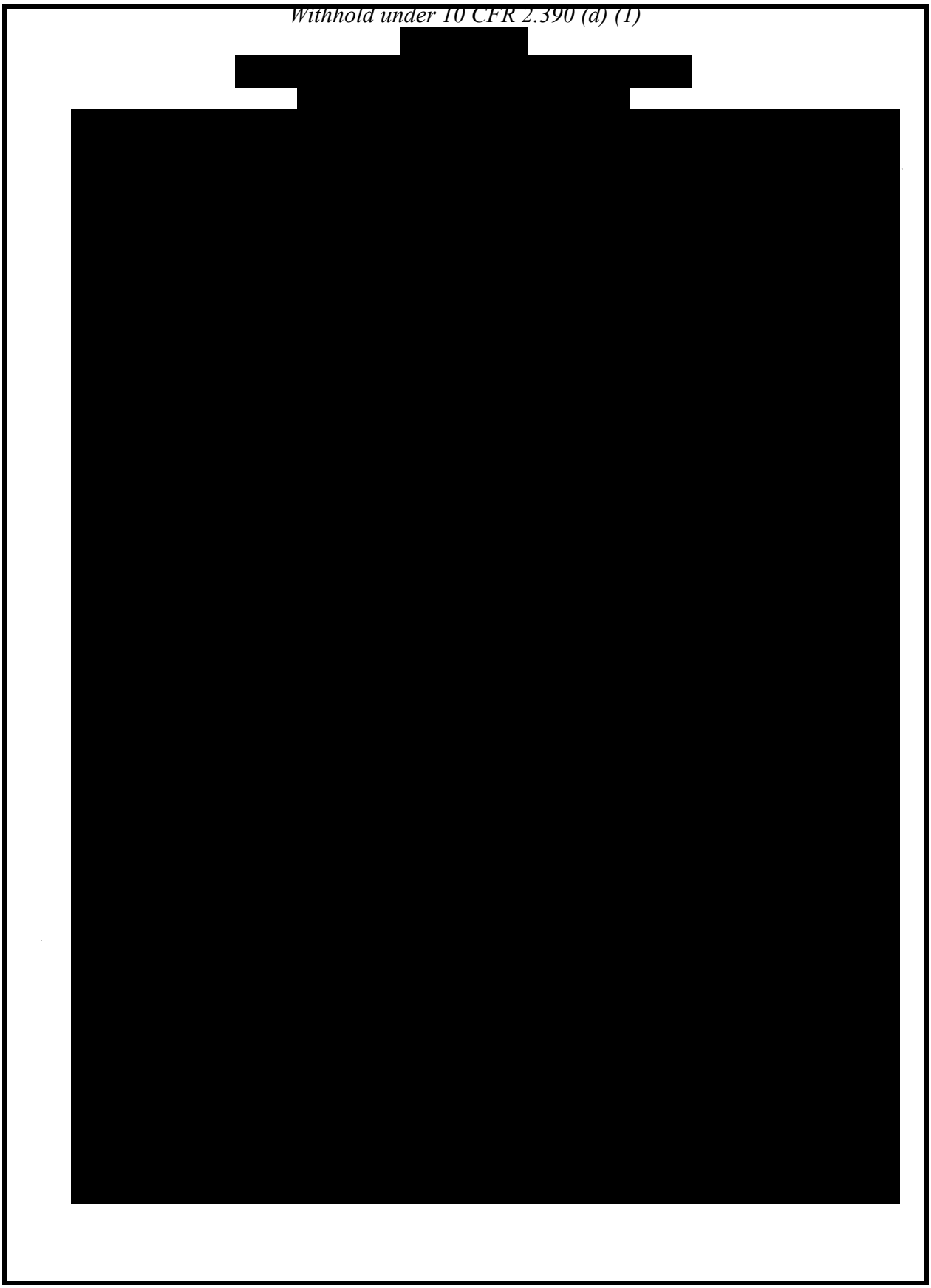

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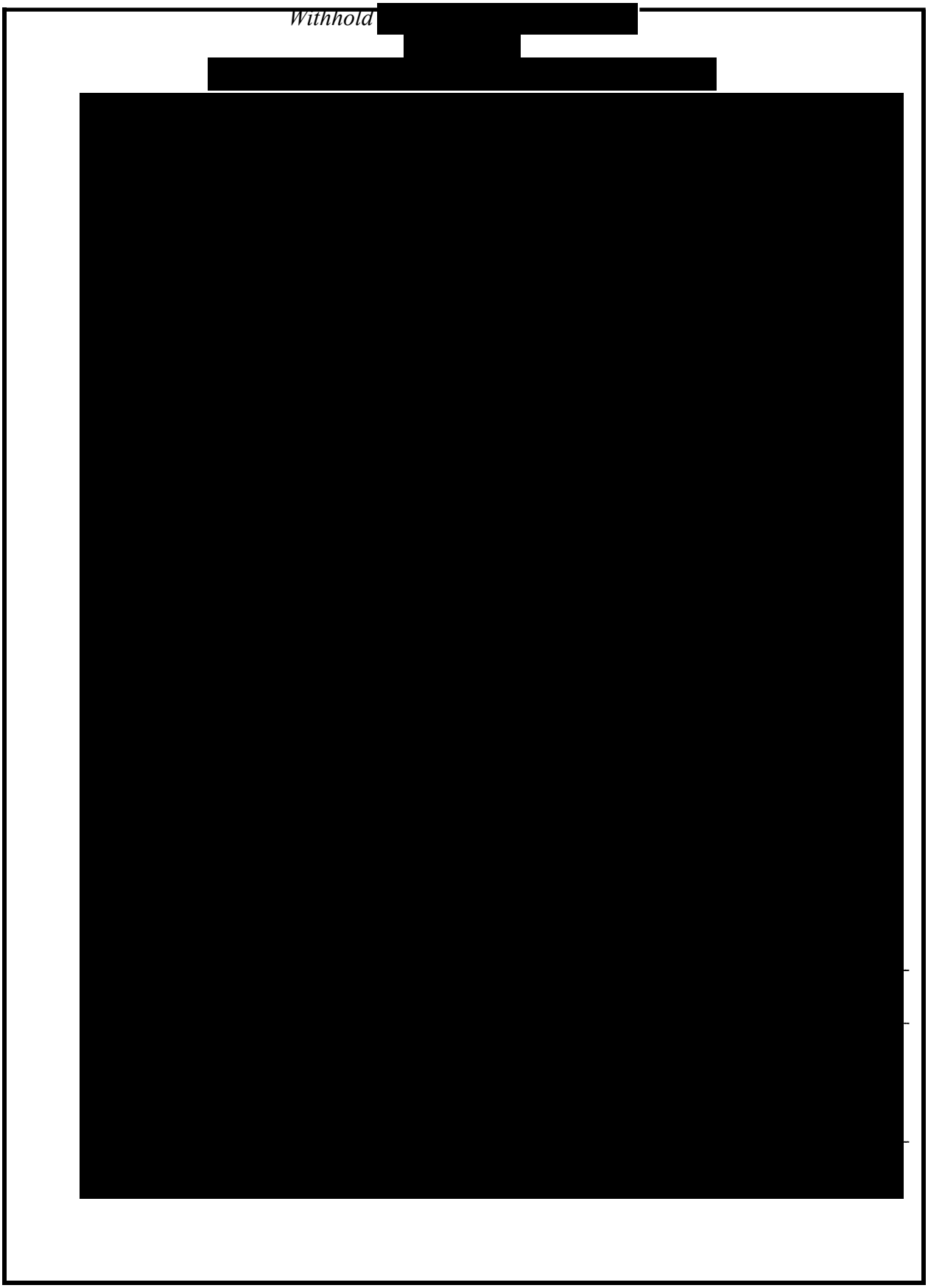
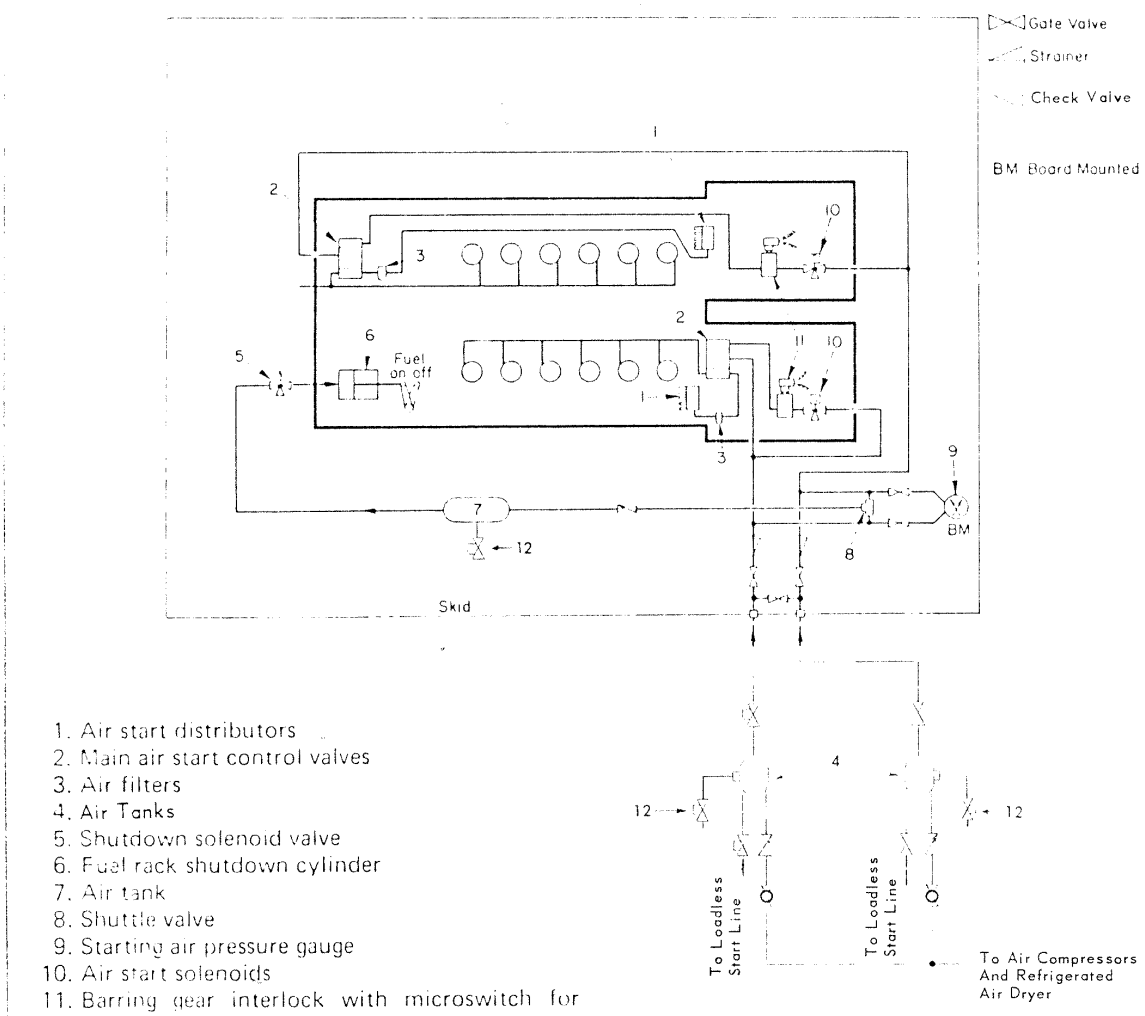


Figure 9.5-6
STARTING AIR SYSTEM
(1MS-32-005-6)



1. Air start distributors
2. Main air start control valves
3. Air filters
4. Air Tanks
5. Shutdown solenoid valve
6. Fuel rack shutdown cylinder
7. Air tank
8. Shuttle valve
9. Starting air pressure gauge
10. Air start solenoids
11. Barring gear interlock with microswitch for annunciation
12. Drain Valves

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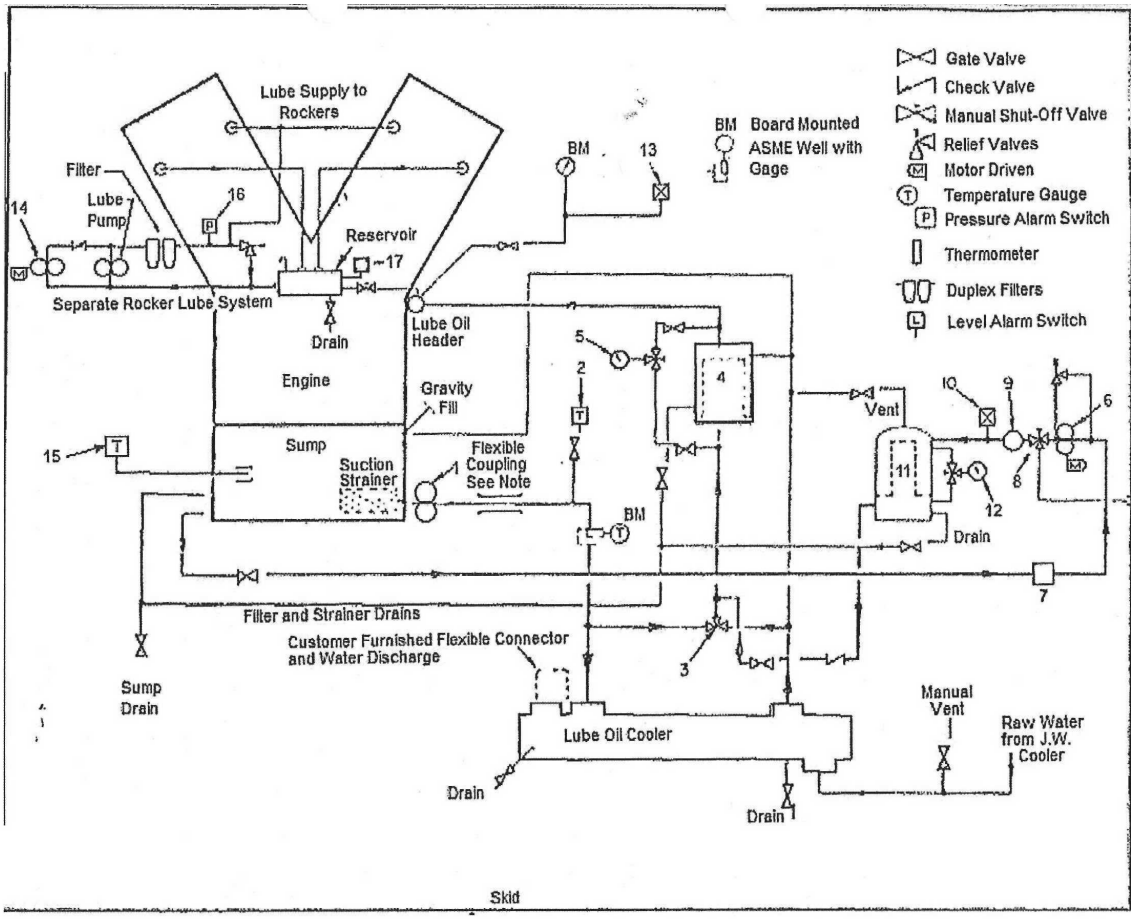
VIRGIL C. SUMMER NUCLEAR STATION

Starting Air
System
(1MS-32-005-6)

Figure 9.5-6

Figure 9.5-7

LUBRICATING OIL SYSTEM
ASSOCIATED WITH 1MS-32-005-3



1. Main Oil Pump – Engine Driven
2. Oil Temperature High Alarm Switch
3. Thermostatic Three-Way Valve
4. Main Lube Oil Strainer
5. Pressure Gauge *with Three-Way Valve
6. Auxiliary Motor Driven Oil Pump
7. Auxiliary Strainer
8. Three-Way Valve
9. Electric Heater
10. Thermostatic Switch-Oil Heater Control
11. Oil Filter with Bypass Valves
12. Pressure Gauge *with Three-Way Valve
13. Low Oil Pressure Shutdown Switch
14. Motor Driven Rocker Pre-Lube Pump
15. Oil Temperature Low Alarm Switch
16. Rocker Arm Low Oil Pressure Low Level Alarm Switch
17. Rocker Arm Reservoir High Level Alarm Switch

*To read pressure to or from the filters/strainers to establish differential

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July 2018

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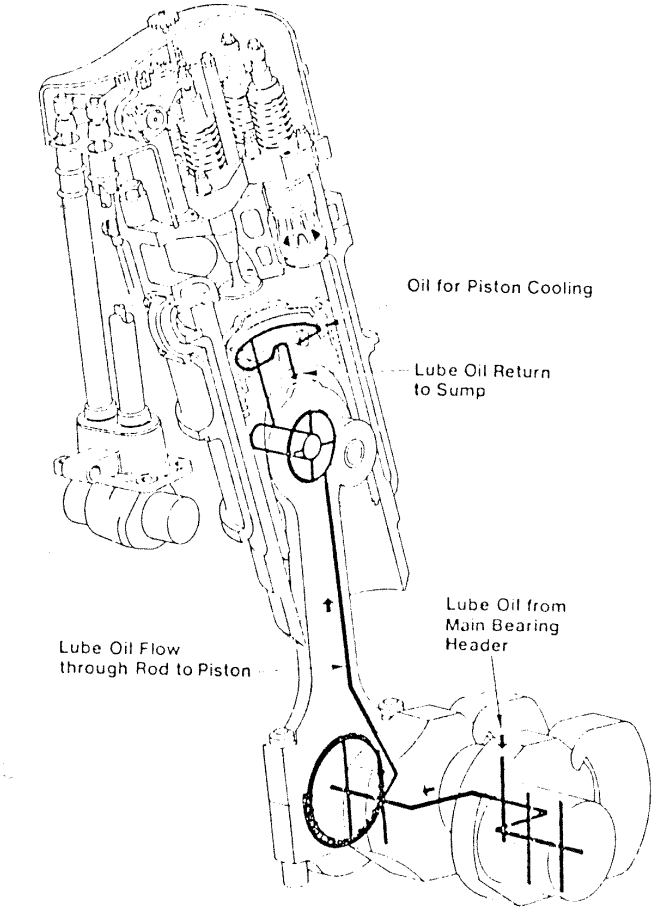
Lubricating Oil System Associated with 1MS-32-005-3 Figure 9.5-7

Figure 9.5-8

ENGINE LUBRICATION SYSTEM SHOWING FLOW THROUGH CRANKSHAFT, BEARINGS, CONNECTING ROD AND PISTON



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Engine Lubricating System Showing Flow Through Crankshaft, Bearings, Connecting Rod and Piston Figure 9.5-8

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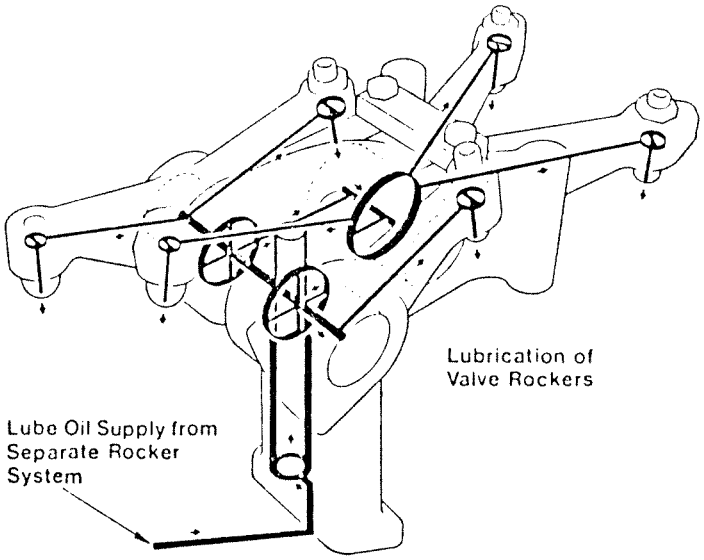
Figure 9.5-9
LUBRICATING SYSTEM FOR VALVE ROCKERS



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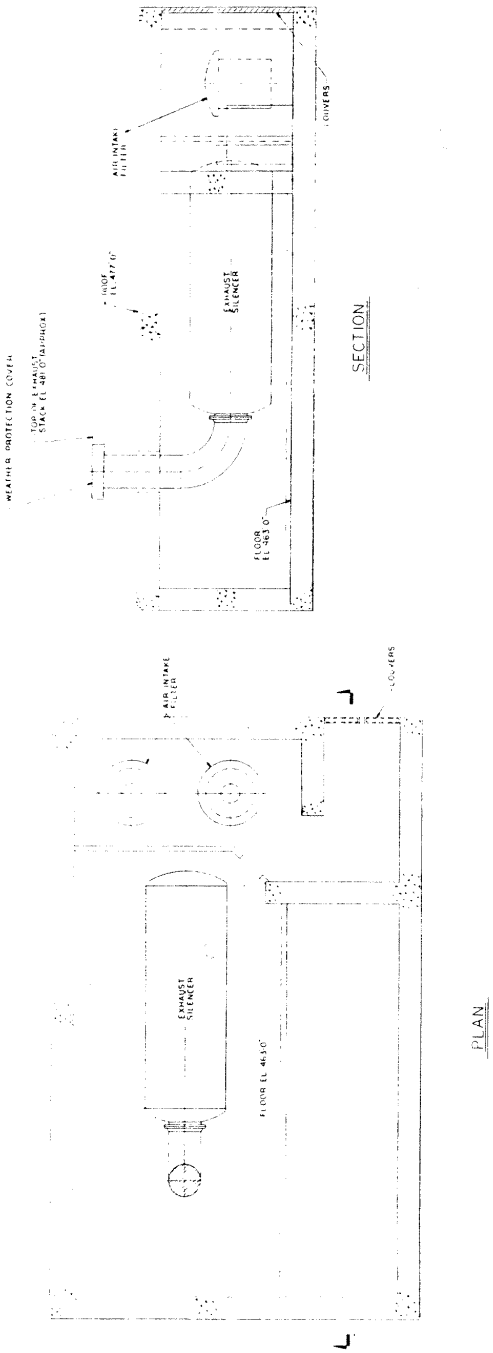
Lubrication System for Valve Rockers Figure 9.5-9

Amendment 0
August 1984

Figure 9.5-10

COMBUSTION AIR INTAKE LABYRINTH AND EXHAUST PIPING DETAILS (GAI DWG. NO. E-001-032)



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SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Combustion Air Intake Labyrinth and Exhaust Piping Details (GAI Dwg. No. E-001-032) Figure 9.5-10

Figure 9.5-11
DRAWING D-302-353
FSAR FIGURE REFERENCE

V.C. Summer Nuclear Station
Safety Analysis Report

Steam and Power Conversion System

Chapter 10

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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Figure 10.4-7A	DRAWING D-302-165 FSAR Figure Reference	10.4-72
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CHAPTER 10 - STEAM AND POWER CONVERSION SYSTEM

10.0 STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion system is shown schematically by Figure 10.1-1, Sheets 1 and 2. Principal design and performance characteristics are given in detail in Section 10.4. The heat balance guaranteed by the turbine manufacturer is shown by Figure 10.1-2. Figure 10.1-3 shows the maximum calculated turbine power (stretch power) heat balance.

The steam and power conversion system includes the following:

1. Main Steam System.
2. Turbine Generator.
3. Condensate System.
4. Condenser Air Removal System.
5. Feedwater System.
6. Turbine Bypass System.
7. Circulating Water System.
8. Steam Generator Blowdown System.
9. Emergency Feedwater System.

The thermal energy of steam generated by a 3 loop, Pressurized Water Reactor Nuclear Steam Supply System (NSSS) is converted to electrical energy through a tandem compound, 1800 rpm turbine generator.

Steam is produced in 3 steam generators where heat is transferred from the reactor coolant system to the feedwater. This steam flows from each steam generator to a distribution header. From this distribution header, 4 main steam lines convey the steam to a double flow, high pressure turbine. Steam exiting the high pressure turbine normally passes through 2 moisture separator reheaters prior to entering 2, double flow, low pressure turbines. Steam exits from the low pressure turbines to the main condenser. The high and low pressure turbines are equipped with a total of 6 extraction points which provide steam for feedwater heating. Moisture separator drains, steam reheater drains and high pressure heater drains are returned to a deaerating heater where they become part of the feedwater. Low pressure heater drains and steam packing condenser drains are cascaded to the main condenser.

Steam exhausted from the low pressure turbines is condensed and deaerated in a 2 shell surface condenser. Condensate is collected in a hotwell sized for a holding capacity of approximately 2 minutes at maximum condensate pump flow. Condensate is normally pumped from the hotwell by 2 of the 3 condensate pumps. The condensate passes through the steam packing condenser and 3

stages of low pressure heaters to the deaerating heater and deaerator storage tank. Each of the 3 stages of low pressure heaters is comprised of 2 parallel 50 percent capacity trains.

The feedwater booster pumps take suction from the deaerator storage tank and discharge to the feedwater pump suction. The feedwater pumps discharge to 2 trains of high pressure heaters. Feedwater exiting these heaters passes into a single header from which it is distributed to the feedwater flow control valves. The feedwater flows from the feedwater flow control valves through the containment isolation valves into the steam generators.

The Emergency Feedwater System provides an additional means for the supply of feedwater to the steam generators for use when the Feedwater System is not available. This permits continued transfer of reactor coolant thermal energy to feedwater in the steam generators. The Emergency Feedwater System consists of 2 electric motor driven and 1 turbine driven emergency feedwater pumps. These pumps, when required, provide feedwater to the steam generators from a reserve supply maintained in the condensate storage tank. A backup source of water is provided by connection to the Service Water System.

Noncondensible gases removed from the condenser by the Condenser Air Removal System are monitored for radioactivity. The condenser offgas is normally discharged to the Auxiliary Building Exhaust System charcoal filters. Provision is made for discharge of the noncondensibles to atmosphere.

Should a 100 percent loss of turbine load occur, reactor coolant thermal energy is dissipated through the formation of steam in the steam generators and subsequent bypassing of the steam to the condenser and/or the atmosphere through the Turbine Bypass System and through the power operated relief valves.

The following portions of the steam and power conversion system are safety-related:

1. Main Steam System piping inside the Reactor Building.
2. The portion of the Main Steam System which forms a part of the containment boundary, including main steam safety valves, power operated relief valves, and main and branch steam isolation valves.
3. The main steam piping to the emergency feedwater pump turbine.
4. The Emergency Feedwater System.
5. Feedwater System piping from the feedwater containment isolation valves to the steam generators.
6. Steam generator blowdown piping from the steam generator to and including the containment isolation valves.

Table 10.1-1
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Figure 10.1-1

STEAM AND POWER CONVERSION SYSTEMS COMPOSITE

(SHEET 1 OF 2)

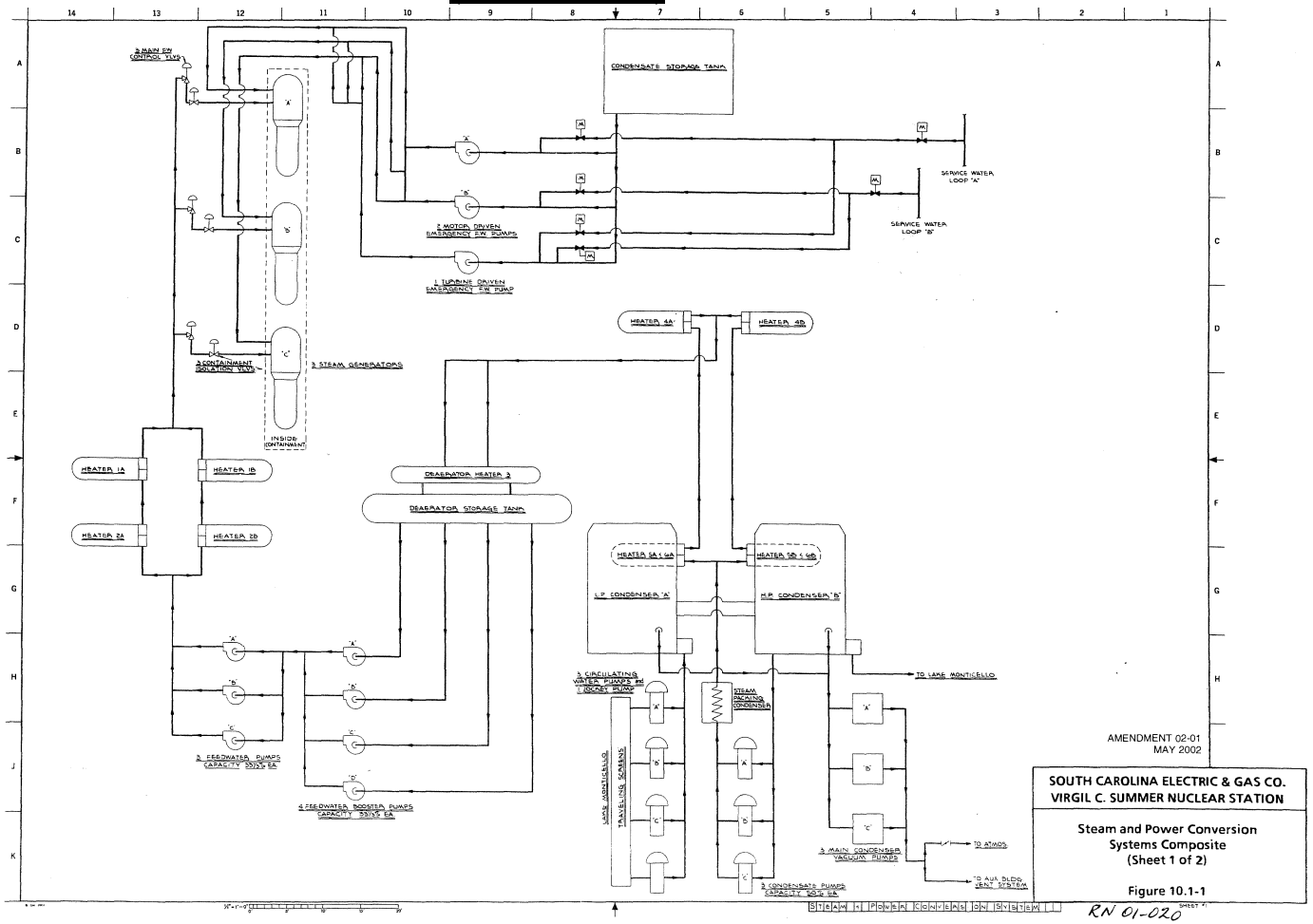


Figure 10.1-1

STEAM AND POWER CONVERSION SYSTEMS COMPOSITE
(SHEET 2 OF 2)

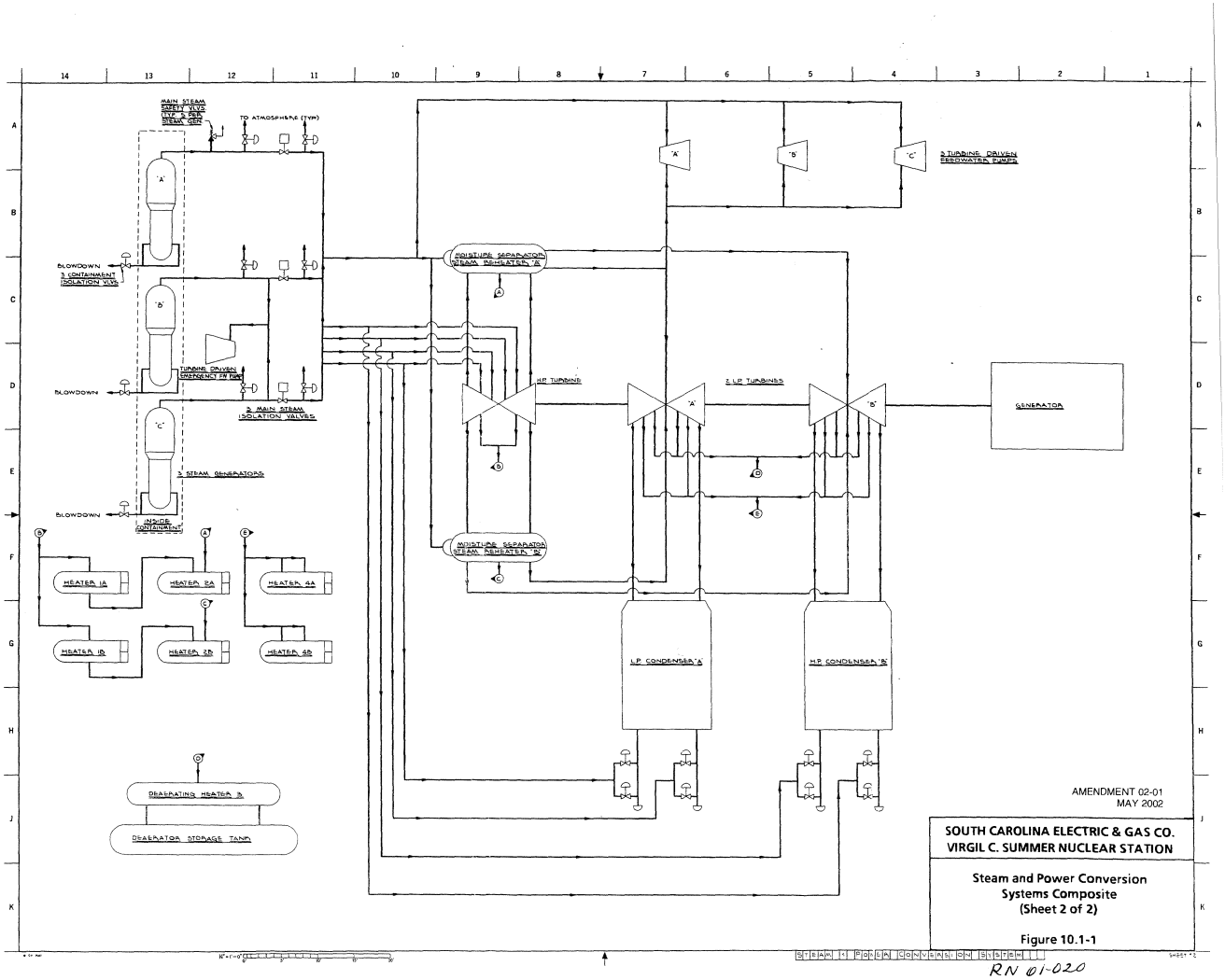


Figure 10.1-2

CALCULATED TURBINE POWER HEAT BALANCE

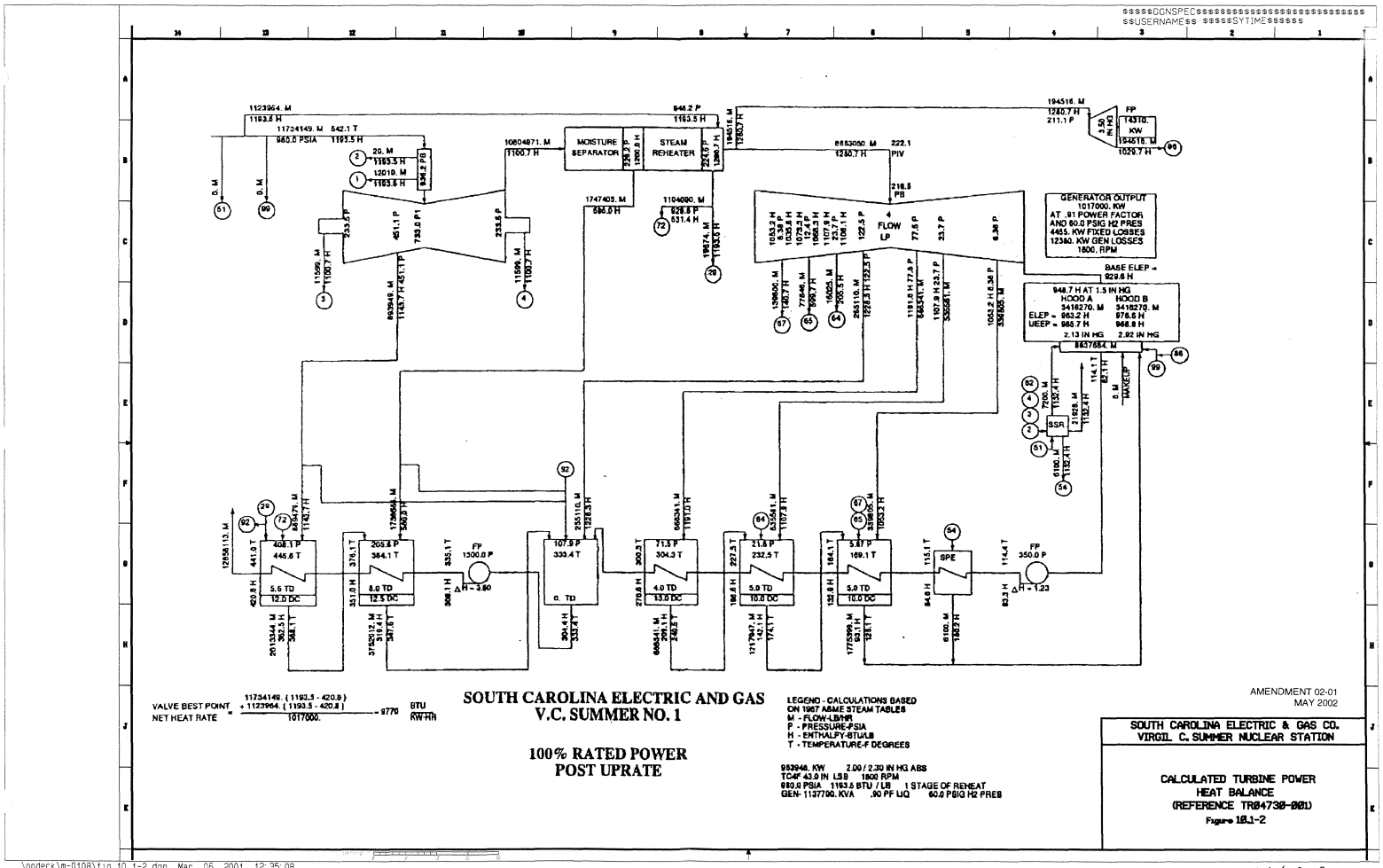
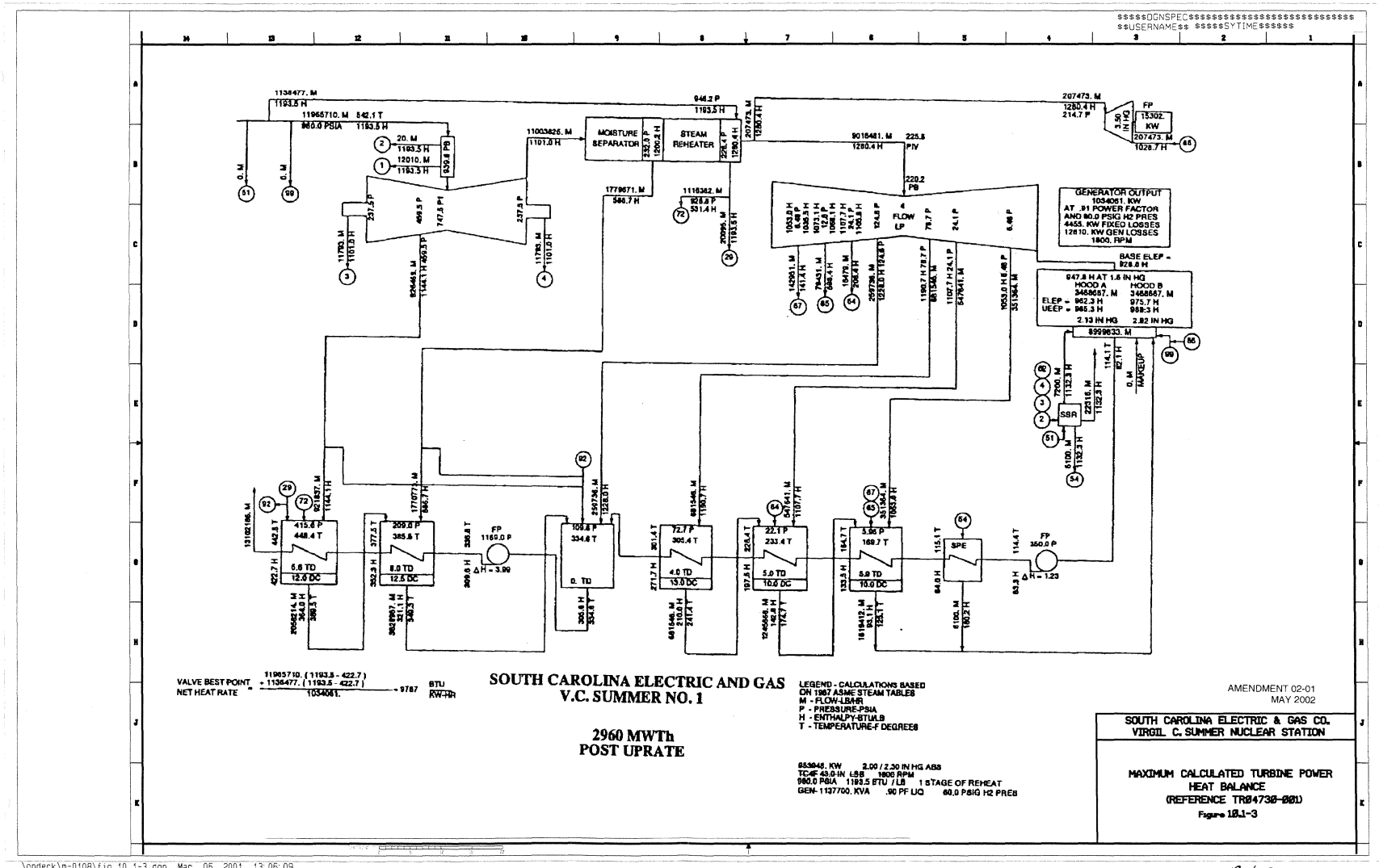


Figure 10.1-3

MAXIMUM CALCULATED TURBINE POWER
HEAT BALANCE



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RN 01-020

10.2 TURBINE GENERATOR

10.2.1 Design Bases

The turbine generator is a General Electric Company (GE) TC4F-43" LSB, tandem compound, 4 flow exhaust unit with moisture separation and reheat between the high pressure (HP) and low pressure (LP) sections. The unit operates at 1800 rpm and is rated at a gross generator output of 1,017,000 kW with all feedwater heaters in service, at the nominal plant exhaust pressure of 2.13/2.92 inches Hg (absolute) and zero makeup.

Steam conditions at the turbine inlet are 980 psia and 1193.5 BTU/lb. Normal and upset conditions are tabulated on the system diagram, Figure 10.3-2.

The turbine generator design capacity is 1,039,489 kW (Ref. Figure 10.1-3). The turbine generator is expected to operate in the base load mode for the majority of its design life. Normal load swings are limited to 5% per minute which is the rate of change permitted by the Nuclear Steam Supply System (NSSS). A step load change of 10% of full power rating can be accommodated without use of the Turbine Bypass System.

10.2.2 Description

10.2.2.1 General

The turbine consists of 3 casings: a double flow HP section followed by 2 double flow LP casings. The last stage turbine wheels have 43 inch buckets. Mechanical moisture separation and reheat are provided between HP and LP sections.

The heat cycle provides for extraction at 6 pressure stages:

1. One (1) on the high pressure turbine casing (heater No. 1).
2. One (1) on the moisture separator (heater No. 2).
3. Four (4) on each of the 2 LP turbine casings (heaters No. 3 through 6).

The generator operates at 1800 rpm. It is a 3 phase, 60 Hz unit, rated 1,137,680 kVA at 22,000 volts, 0.905 pf and 60 psig hydrogen pressure. A shaft driven alternator exciter, rated at 2940 kVA @ 0.95 power factor (pf) provides the power necessary for field excitation. Section 10.2.2.4 presents a discussion of the Generator Gas System.

10.2.2.2 Turbine Generator Control

An Electrohydraulic Control System (EHC) (using electronic computing devices and high pressure, fire resistant fluid) actuates and controls the steam valves. This system is completely separated from the bearing oil supply.

The original EHC analog control cabinet and turbine-generator skid interfaces underwent a significant upgrade during RF-19 to replace obsolete equipment and to enhance overall system reliability. The upgrade consists of a “triple modular redundant” (TMR) digital control system, which utilizes three separate and independent controller processor modules and associated redundant input/output. EHC control logic algorithms utilize 2-of-3 (typical) “software implemented fault tolerance” (SIFT) voting techniques to optimize input/output signal data integrity and diagnostic trending. Primary <Q> controllers perform primary system control and trip protection functions (including primary overspeed protection). Emergency <P> controllers perform emergency (backup) overspeed protection function.

<Q> and <P> controller protection functions which result in a Turbine Trip condition (as described below and per Figure 7.2-1, Sheet 15) interface with downstream Trip Manifold Assembly (TMA) electromechanical and hydraulic devices, located in the Turbine front standard. The TMA is comprised of two independent trains of three sets of Electronic Trip Device (ETD) solenoids/pilot-actuated dump valves, of which 2-of-3 in either train must change position to trip the turbine. A trip condition results in pressure relief of the emergency trip system (ETS) header, which in turn causes turbine steam valves closure due to the loss of ETS hydraulic fluid pressure.

During normal operation, reactor power is controlled (using the Reactor Control System, as described in Section 7.7.1) to match turbine load as measured by turbine first stage pressure. The desired turbine steady-state load is established manually by the operator through inputs into EHC. EHC control logic algorithms establish/maintain the allowable turbine speed and turbine load conditions, ensure the required positioning of all turbine steam valves, and facilitate other loading/unloading evolutions (e.g., shell/chest warming, runbacks). These algorithms perform programmed control functions based upon comparison of: actual turbine-related operating parameters monitored by EHC (e.g., valve positions, system pressures); desired operator input settings; and pre-programmed system state point limits (e.g., control valve steam flow-to-valve lift position characterizations [per steam flow to turbine load demand correlations], runback conditions, overspeed regulation, other system limitations).

Table 10.2-0 provides a listing of signals that will shut down the turbine. Figure 7.2-1, Sheet 15 functionally shows EHC and turbine system interfaces which perform turbine trip-related functions. Receipt of 2-of-3 actuations via either <Q> Primary Trip Relays (PTRs) or <P> Emergency Trip Relays (ETRs), in either train of its <Q> or <P> controllers, will result in the corresponding change of state of its downstream TMA EHC interface devices (i.e., de-energized ETD solenoids and tripped-open ETD pilot-actuated dump valves associated with the actuated train). The outcome of either train’s 2-of-3 dump valve actuation is loss of ETS hydraulic fluid, closure of Turbine Stop and Control Valves, and a Turbine Trip condition. This 2-of-3 Turbine Trip actuation can also result from a complete loss of both non-safety related power supply feeders to the EHC control system cabinet (including the loss of a dedicated EHC battery-backed uninterruptible power supply, in the alternate feeder circuit).

10.2.2.3 Turbine Generator Overspeed Protection

The turbine’s rotational speed is sensed by a total of six passive magnetic-type probes used in conjunction with a multi-toothed wheel on the turbine shaft. Three of these speed probes (in the

<Q> controllers) provide input signals to speed control and primary trip protection algorithms. The remaining three speed probes (in the <P> controllers) provide input signals directly to emergency trip protection algorithms.

Steam valves associated with turbine generator overspeed protection are shown by Figure 10.3-2. Control details for the main stop valves (MSV) are shown by Figure 10.2-2. Control details for the control valves are shown by Figure 10.2-3a. Control details for the combined intermediate valves (CIV), which are the intermediate stop valve (ISV) and intercept valve (IV), are shown by Figure 10.2-3b. The ISV and IV are 2, independent, separately actuated valves in the same valve body, called the CIV.

Overspeed protection mechanisms and the hydraulic trip system are shown by Figure 10.2-4.

ETD components (as described in Section 10.2.2.2) receive high pressure (1600 psig nominal) hydraulic fluid from the EHC power unit, and regulate the ETS header pressure condition. ETS pressure is high when the hydraulic trip system is reset, and low (at drain pressure) when the system is tripped. The condition of the ETS header depends upon the state of 2-of-3 ETD solenoids/dump valves.

During a turbine generator overspeed occurrence, the EHC control system receives <Q> and/or <P> speed sensor input signals which exceed the pre-defined Primary and/or Emergency speed setpoint levels. Turbine trip logic actuation will occur when 2-of-3 <Q> speed signals or 2-of-3 <P> speed signals exceed their respective speed setpoint. (Note that turbine trip actuation will also occur in the event of postulated speed sensor failures, including the <Q> and <P> speed difference fault trip and zero speed mismatch trips functionally shown on Figure 8.3-8.) Overspeed-related turbine trip logic actuation will cause ETD solenoids to de-energize and ETD dump valves to de-pressurize the ETS hydraulic trip header (identical to other turbine trip conditions, as described in Section 10.2.2.2).

1. The disc dump valves of the MSV, CV, IV, and ISVs are opened causing rapid closure of the steam valves due to spring and steam force.
2. The ETS pressure transmitters maintain the tripped condition within the EHC control system.
3. The extraction relay dump valve isolates the air supply to and vents air from the air cylinders of the turbine extraction nonreturn valves. Spring assist on the air cylinder aids in positive closure of the nonreturn valves.

Frequent inservice testing of the overspeed trip mechanisms and steam valves ensures the reliability of the overspeed protection systems. All steam valves, except the nonreturn valves, located inside the condenser in the low pressure feedwater heater extraction piping, are capable of online testing.

This system is designed to be fail safe, i.e., a malfunction of the system will trip close all turbine steam source valves, limiting turbine overspeed. A high or moderate energy piping failure at the turbine, which would cause a loss of power (electric or hydraulic) to the overspeed protection

system due to severance of electrical cable or hydraulic lines, would cause all turbine steam source valves to close.

The turbine trip logic also includes fail safe features which limit turbine overspeed. The trip logic verifies that at least 1 of the 2 low pressure steam source valves (i.e., intermediate stop valve or intercept valve) in each line to the turbine has closed and that all high pressure main turbine stop valves have closed before load is disconnected from the main generator. In the event of a pipe rupture, with manual turbine trip, load would not be disconnected from the main generator unless all turbine steam source valves, excluding extraction valves, were closed. The extraction valves are nonreturn (check) valves and, therefore, do not require external signals to close.

The connection from the low pressure turbine to the condenser is under vacuum during operation. In the event of failure of this connection, air would initially be drawn into the condenser and backpressure on the turbine would increase to the point where the turbine would trip due to the high backpressure. Venting of air into the condenser is a method normally used to quickly slow a turbine following a trip. Some steam may be released while the turbine is being tripped.

A turbine trip will initiate a reactor trip. The reactor trip from turbine trip will be automatically blocked by P-9 (power level less than 50% rated thermal power) and on increasing power reinstated automatically by P-9.

Since the turbine overspeed protection system is of a fail safe design and no credit is taken for reactor trip due to turbine trip in any accident analysis, protection from pipe rupture is neither required nor provided.

A failure analysis of the turbine generator overspeed protection system is presented by Table 10.2-2.

10.2.2.4 Generator Gas System

The bulk hydrogen and carbon dioxide storage facilities are located in the yard area south of the Turbine Building (see Figure 1.2-1). The hydrogen and carbon dioxide storage and distribution systems are schematically illustrated by Figure 10.2-5.

The hydrogen storage facility consists of 6 storage tanks, each pressurized to a nominal pressure of 2300 psig. Hydrogen pressure is reduced to the generator manufacturer’s control panel supply pressure in 2 stages.

Liquid carbon dioxide is stored in a refrigerated storage tank and is vaporized in the Turbine Building as required for generator purging.

The Generator Gas System is equipped with an inservice gas analyzer. This analyzer actuates an alarm upon detection of low (<90%) hydrogen purity.

Safety features associated with the Generator Gas System include the following:

1. Remote, outdoor, bulk hydrogen storage and pressure reduction facilities are provided. Hydrogen supply piping from the storage facility to the Turbine Building is under low pressure and is also buried.
2. The inservice generator gas analyzer actuates an alarm to warn of low hydrogen purity in advance of formation of an explosive mixture. A generator differential fan pressure gage provides an independent check of hydrogen purity.
3. The Generator Gas System is operated by experienced personnel.
4. Generator gases are vented to atmosphere independent of other plant vents.
5. Operating procedures require complete purging of the generator before and after maintenance. Hydrogen is purged from the generator by carbon dioxide before it is opened. When maintenance is completed, the generator is again purged with carbon dioxide to remove the air prior to refilling with hydrogen.
6. The generator gas analyzer is periodically calibrated to assure accuracy.
7. System valves are periodically checked for indication of leakage to assure system leak tightness.
8. Physical separation of the Generator Gas System from safety related equipment required for safe plant shutdown provides additional safety.

10.2.3 Turbine Missiles

The LP turbine built up rotors consisting of wheels shrunk-on a central shaft have been replaced by single piece monoblock rotors in spring, 1996. The monoblock turbine rotor design eliminates the brittle fracture failure mode and the probability for a wheel burst and missile generation at normal operating speeds. Furthermore, the 2011 installation of the digital EHC control system provides significant redundancy and reliability enhancements over the original overspeed protection. The improvements to rotors and controls (relative to the original plant design) provide for a further reduction in the probability of turbine missile generation due to an overspeed protection system failure.

A compilation report (Reference 4) contains various missile probability and reliability analyses performed by the turbine manufacturer, which encompass the current system configuration details (of the monoblock rotors and the digital control system retrofit). These analyses document the following summary of pertinent results:

- The maximum attainable main turbine shaft speed is 214% - 217% of normal running speed at the worst possible operating conditions. At this point, the driving forces in the steam are counteracted by the drag forces and the rotor train can no longer accelerate.

- A complete failure of the Main Turbine Control System is required to achieve the maximum attainable overspeed. The annual probability of a complete control failure is in the range 10^{-8}.

- The LP monoblock overspeed capability based on material properties and rotor design is 221% for LPA and 222% for LPB.

1. Turbine Design

   The turbine assembly was designed to withstand normal conditions and anticipated transients, including those resulting in turbine trip, without loss of structural integrity. The design of the turbine assembly satisfied the following criteria:

   a. Turbine shaft bearings were designed to retain structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

   b. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20% overspeed were controlled in the design and operation so as to cause no distress to the unit during operation.

   c. The maximum tangential stress in rotors resulting from centrifugal forces, interference fit and thermal gradients does not exceed 0.75 of the yield strength of the materials at 115% of rated speed.

2. Inservice Inspection

   The inservice inspection program for the turbine assembly will include the following:

   a. Disassembly of the turbine at approximately 10 year intervals, during plant shutdown, and complete inspection of all normally inaccessible parts, such as couplings, coupling bolts, turbine shafts, low pressure turbine buckets, low pressure wheels, and high pressure rotors.

   b. Visual, surface, and volumetric examinations, as indicated below:

      (1) A thorough volumetric examination of all low pressure wheels and high pressure rotors, including areas immediately adjacent to keyways and bores, will be conducted. This examination is predicated on the development of suitable remote inspection equipment.

      (2) Visual examination of all accessible surfaces of rotors and wheels.

      (3) Visual and surface examination of all low pressure buckets.

      (4) Surface examination (100%) of couplings and coupling bolts.

   The inservice inspection of main steam and reheat valves will include the following:

   a. Dismantle at least 1 main steam stop valve, 1 main steam control valve, 1 reheat stop valve, and 1 reheat intercept valve at approximately 3-1/3 year intervals during refueling or maintenance shutdowns, and conduct a visual and surface examination of valve seats, discs, and stems. If unacceptable flaws or excessive corrosion are found in a valve, all valves of that type will be inspected. Valve bushings will be inspected and cleaned, and bore diameters will be checked for proper clearance.

b. Main steam stop and control, reheat stop and intercept valves will be exercised at least once during a 3 month operating interval, by closing each valve and observing, by the valve position indicator, that it moves smoothly to a fully closed position. This observation will be made by actually watching the valve motion.

10.2.4 Evaluation

Turbine rotor missiles will not be generated with the rotor burst capability exceeding the overspeed potential. Therefore, the possibility of missiles being generated by a wheel burst due to stress corrosion cracking and causing damage to critical plant components, is no longer present, and there no longer exists any wheel disc integrity concern.

Reference 4 provides a detailed safety evaluation of steam valve arrangement and trip devices, turbine extraction line overspeed trip protection, and operating and testing of overspeed protection systems.

10.2.5 References

1. Deleted by RN 11-015.
2. Deleted by RN 11-015.
3. Deleted by RN 11-015.
4. V. C. Summer Nuclear Station, *Main Turbine Missile Probability and Reliability Reports*, VCSNS Technical Report TR03880-002, dated July 12, 2011.

Table 10.2-0

Turbine Shutdown Signals

1. Train A EHC external trips, from any one of the following conditions:
   - Train A Reactor Trip.
   - High-high steam generator level (2 of 3) or Train A Safety Injection.
   - Loss of 3-of-3 feedwater pumps.
   - Generator electrical fault.
   - LP Heater 5A, 5B, 6A, and/or 6B high-high levels (10 second time delay).
   - AMSAC actuation above C-20, due to low-low level in 2 of 3 steam generators.
2. Train B EHC external trips, from any one of the following conditions:
   - Train B Reactor Trip.
   - Hi-Hi steam generator level (2 of 3) or Train B Safety Injection.
   - AMSAC actuation above C-20, due to low-low level in 2 of 3 steam generators.
3. Manual turbine trip pushbuttons (2 of 2 at MCB, or 2 of 2 at Front Standard).
4. Main shaft oil pump discharge pressure low (2 of 3), and turbine speed greater than 1350 rpm.
5. Lube oil bearing header pressure low (2 of 3).
6. EHC hydraulic header pressure low (2 of 3).
7. Speed signal mismatch trips, in Primary (<Q>) and/or Emergency (<P>) controllers, from any one of the following conditions:
   - <Q> zero speed mismatch fault (2 of 3 Primary <Q> speed sensors indicate zero speed condition while <P> Emergency sensors indicate greater than 15% of rated speed).
   - <P> zero speed mismatch fault (2 of 3 Emergency <P> speed sensors indicate zero speed condition while <Q> Primary sensors indicate greater than 15% of rated speed).
   - <Q> and <P> speed difference fault (difference greater than 5%).
   - <Q> excessive acceleration or deceleration rate change (2 of 3 <Q> speed sensors).
   - <P> excessive acceleration or deceleration rate change (2 of 3 <P> speed sensors).
8. Primary (<Q> controllers) overspeed trip (109.5% of rated speed).
9. Emergency (<P> controllers) overspeed trip (110% of rated speed).
10. Exhaust vacuum (absolute) pressure high (2 of 3 in either [LP A or LP B] hood), and turbine speed greater than 150 rpm.
11. Exhaust hood high temperature (2 of 3 in either [LP A or LP B] hood).
12. Loss of stator cooling trip (due to failed runback).

TABLE 10.2-0 (Continued)
Turbine Shutdown Signals

13. Moisture separator reheater level high (15 second time delay) (2 of 3 in either A or B MSR).
14. Thrust bearing excessive wear detection (from 2 of 3 axial bearing position sensors).
15. Shaft bearing high vibration (10 second time delay); manual operator action required if automatic trip disabled.
16. Train A or Train B Off-line ETD Test tripped condition (2 of 3 electronic trip devices [ETDs] under test are de-energized [tripped]).

Table 10.2-1
Turbine Generator Overspeed Protection System

Overspeed Trip Mechanism	Set Speed	Action
Speed Governor (Normal)	1836 to 1872 RPM (102% to 104%)	Complete closure of intercept valves at 102% of rated speed; complete closure of control valves at 104% of rated speed. Loss of two speed signals actuates the hydraulic trip system.
Primary Overspeed Trip	1971 RPM (109.5%)	Actuates the hydraulic trip system.
Emergency Overspeed Trip	1980 RPM (110%)	Actuates the hydraulic trip system.

Table 10.2-2
Turbine Overspeed Protection System
Failure Analysis

Component	Malfunction	Comment
Steam Valve (MSV, CV, IV, ISV)	One valve fails to close on overspeed trip	Each steam line contains “paired” steam valves installed in series. Thus, failure of one valve (e.g., CV1) to close does not defeat its paired valve (e.g., MSV1). No impact to overspeed function exists.
Turbine Extraction Nonreturn Valve	One valve fails to close	The overspeed potential of the feedwater heating system is small. The total uncontrolled energy can contribute no more than 1.5% to the running speed of the turbine generator.
Primary <Q> Overspeed Trip Actuation Logic	One Train of <Q> protection logic fails to trip at Primary Overspeed setpoint	Two Trains of <Q> logic are installed. Thus, failure of one Train will not defeat the other Train. Furthermore, backup protection is provided by Emergency <P> Overspeed Trip Actuation Logic.
Emergency <P> Overspeed Trip Actuation Logic	One Train of <P> protection logic fails to trip at its Overspeed setpoint	Two Trains of <P> logic are installed. Thus, failure of one Train will not defeat the other Train.
Electronic Trip Device (ETD)	One Train of 2-of-3 ETD solenoid/dump valve components fail to trip	Trip manifold assembly consists of two trains of 2-of-3 ETD solenoid/dump valve components. Either ETD train will trip the turbine.

Table 10.2-2 (continued)
Turbine Overspeed Protection System
Failure Analysis

Component	Malfunction	Comment
Hydraulic Trip System Piping	Piping fails causing depressurization	All steam valves close as in overspeed trip.
Primary AC Power Supply Feeder	Loss of primary power supply (failure or other unavailability) to EHC control system	No impact to overspeed protection function exists. - Alternate AC feeder will maintain EHC control system power, to assure actuation logic function. - Complete loss of power will de-energize/dump ETD components.
Alternate AC Power Supply Feeder	Loss of alternate power supply (failure or other unavailability) to EHC control system	No impact to overspeed protection function exists. - If available, primary feeder available will maintain EHC control system power and actuation logic function. - If primary feeder is not available, a battery-backed UPS (in alternate feeder circuit) will permit timely manual turbine trip and post-trip monitoring. - Complete loss of power will de-energize/dump ETD components.

Figure 10.2-1
DELETED PER RN 01-042

Figure 10.2-2
DRAWING 1MS-27-247
FSAR FIGURE REFERENCE

Figure 10.2-3A
DRAWING 1MS-27-248
FSAR FIGURE REFERENCE

Figure 10.2-3B
DRAWING 1MS-27-249
FSAR FIGURE REFERENCE

Figure 10.2-4
DRAWING 1MS-27-250
FSAR FIGURE REFERENCE

Figure 10.2-5
DRAWING D-302-301
FSAR FIGURE REFERENCE

10.3 MAIN STEAM SUPPLY SYSTEM

The Main Steam Supply System conveys main steam from the steam generators to the turbine generator and, through branch lines, to the following: feedwater pump drive turbines, emergency feedwater pump drive turbine, moisture separator reheaters, auxiliary steam system, deaerating feedwater heater, and steam dumps to the condenser and atmosphere.

10.3.1 Design Bases

10.3.1.1 Codes and Standards

The Main Steam Supply System is designed in conformance with the following codes and standards:

1. Steam generator secondary sides, piping and valves, between the steam generators and main steam isolation valves, including the main steam isolation valves, main steam safety valves, and power relief valves, are classified as Safety Class 2a and are designed in accordance with the ASME Code, Section III, Class 2.
2. Steam piping and components in the lines to the emergency feedwater pump drive turbine are classified as Safety Class 2b and are designed in accordance with the ASME Code, Section III, Class 3.

   The emergency feedwater pump drive turbine exhaust piping is classified as safety class 2b and is designed in accordance with the ASME Code, Section III, Class 3 except for hydrotesting and code stamping.
3. Main steam piping in the Intermediate Building between the main steam isolation valves and the Turbine Building wall is non-nuclear safety class. However, this piping excluding branch lines, satisfies the requirements except for stamping, of the ASME Code, Section III, Code Class 2. This provides greater assurance of design and fabrication integrity, thus, reducing risk of postulated pipe rupture in this area. This piping is identified as “Note 1" piping on Figures 10.3-1 and 10.3-2.

   Originally the main and branch lines were designated as “Note 1" piping to reduce the number of postulated pipe rupture locations by the use of a code stress analysis to choose intermediate breaks. In the final pipe rupture analysis of the branch lines, stress analysis was not used and intermediate breaks were postulated at each fitting (see Section 3.6.2.5.1). Therefore, it was no longer necessary to provide code piping and the “Note 1" designation for these branch lines was deleted.
4. Piping other than that noted in 1, 2 and 3, above, is non-nuclear safety class and is designed in accordance with ANSI B31.1 (Reference 1).
5. Cast steel valves, except those noted in 1, 2 and 3, above, are non-nuclear safety class and are designed in accordance with ANSI B16.5 (Reference 2) 0.

6. Main Steam Supply System drains are designed using “Recommended Practices for the Protection of Water Damage to Steam Turbines Used for Electric Power Generation, Part II,” (Reference 3) as a guide.
7. The Main Steam Supply System is designed to permit inservice inspection as required by the ASME Code, Section XI.
8. The Main Steam Supply System is designed with the capability to dump steam to the condenser and/or the atmosphere as discussed in Section 10.4.4.

10.3.1.2 Heat Balance

The Main Steam Supply System is designed to deliver 11,734,149 lb/hr of steam to the turbine control valves and 1,123,964 lb/hr to the moisture separator reheater for a total of 12,858,113 lb/hr. (See GE Heat balance 170x595-21, Rev. 1).

10.3.1.3 Design Conditions

The system is designed to withstand the same conditions as are the steam generator secondary sides. Design pressure is 1185 psig; design temperature is 600°F. Design pressures and temperatures for piping, valves, and pressure retaining components are tabulated on Figures 10.3-1 through 10.3-4.

10.3.1.4 Environmental Conditions

Environmental conditions considered in the design of the Main Steam Supply System are presented in Table 10.3-1.

The emergency and faulted conditions are based on the Main Steam Line Break and Loss of Coolant Accidents. Components within the Reactor Building are also subjected to a spray of borated water and sodium hydroxide as described in Section 6.2.2.2.1.

10.3.2 Description

10.3.2.1 General

The Main Steam Supply System consists of 3 steam generators, 3 flow restrictors, 15 safety valves, 3 steam generator power relief valves, 3 main steam isolation valves, 8 steam dump valves to the condenser, 3 atmospheric steam dump valves and other required valves, steam traps, instrumentation, controls, and associated piping. See Figures 10.3-1 through 10.3-4.

The Main Steam Supply System conveys saturated steam from the 3 steam generators to the turbine generator.

One (1) line from each of the 3 steam generators conveys main steam to a header located in the Intermediate Building. From the header a total of 4 lines proceed to the turbine stop valves. Steam flow to the high pressure turbine is regulated by the turbine control valves.

Moisture separator reheater units are located immediately beside the turbine between the high pressure and low pressure elements. Heating tube bundles within each moisture separator reheater, supplied with steam from the Main Steam Supply System, superheat high pressure turbine exhaust steam approximately 136°F before it enters the low pressure turbine elements.

Main steam is also supplied to the following:

1. Feedwater pump drive turbines for startup and runout.
2. Auxiliary Steam System for the liquid waste evaporator as required during normal operation and during plant shutdown until the auxiliary boiler is operational.
3. Extraction Steam System for pegging and sparging the deaerator.
4. Emergency feedwater pump drive turbine during emergency and normal plant shutdown to supply minimum feedwater requirements.

The Main Steam Supply System was originally designed to follow a full load rejection, defined as a reduction from 100% of rated turbine generator load to plant auxiliary load, without reactor trip through actuation of the steam dump to the condenser and atmosphere. With the transition to longer fuel cycles and less negative moderator temperature coefficients at the beginning of the fuel cycle, a full load rejection can no longer be sustained without a reactor trip for all times in core life and all allowable values of full power, average coolant temperatures within the Reactor Coolant System.

Steam dump valves permit unit operation at turbine loads lower than the minimum power setting (15% reactor power) of the Nuclear Steam Supply System (NSSS) automatic control. In addition, the steam dump valves permit reduction of turbine generator load at a rate greater than the 5% per minute maximum rate of load reduction for the NSSS.

Steam generator power relief valves provide a means for plant cooldown by controlled steam discharge to the atmosphere should the condenser not be available. These valves pass a total of ¡«18.76% of the rated maximum steam flow (at full load pressure). One (1) valve is provided in each generator line, upstream of the main steam isolation valves.

10.3.2.2 Main Steam System Piping

Each line from the steam generators is 32 inch nominal OD, 1.15 inch minimum wall, carbon steel pipe. The piping inside the Reactor and Intermediate Buildings is routed and restrained to minimize the possibility of a single line failure affecting the other piping. In the area where the safety valves are located, the pipe OD is increased and the nominal wall thickness is 1.90 inches to provide extra strength. The 3 lines from the steam generators are manifolded into a 32 inch nominal OD, 1.15 inch minimum wall, carbon steel header.

From the header, steam flows through four(4) 30 inch nominal OD, 1.125 inch nominal wall, carbon steel lines to the turbine generator. Steam also flows from the header through a 24 inch OD, schedule 80, carbon steel pipe to the moisture separator reheater and feedwater pump drive turbines.

A 4 inch OD, schedule 80, carbon steel pipe supplies steam from each of 2 steam generator main steam lines to the emergency feedwater pump drive turbine. Steam from only one steam generator is needed for pump operation; 2 sources are provided for required redundancy.

Steam generators and flow restrictors are discussed in detail in Section 5.5.

10.3.2.3 Main Steam Isolation Valves

Each of the 3 main steam lines proceeding from the steam generators to the main steam header is equipped with a quick closing main steam isolation valve capable of tight closure, regardless of flow direction. The main steam isolation valves are of the articulated poppet, wye type design. These nominal 32 inch valves have a capacity of 4,277,315 lb/hr steam flow with an approximately 2.26 psi maximum calculated pressure drop across the fully open valve. These valves are designed for 1284 psig at 600°F. The valves are actuated by an air cylinder operator (air to open; spring to close). Closure time is adjustable. Maximum closure time is 7 seconds after receipt of a closure signal. Main steam isolation valve closure signals are as follows:

1. High containment pressure.
2. High steam flow with coincident lo-lo average primary coolant temperature.
3. Low steam pressure.
4. Manual.

These valves are located in the Intermediate Building downstream of the main safety valves.

The quick closing main steam isolation valves prevent reverse flow of steam. If a steam line rupture occurs between an isolation valve and a steam generator, the affected steam generator continues to blow down, while the isolation valves are automatically closed to prevent blowdown from the unaffected steam generators. Should an isolation valve not close, flow from the Main Steam System downstream of the main isolation valves is limited by either normally closed valves or by valves that are automatically closed by interlocks from the NSSS system or from the turbine generator system as tabulated in Table 10.3-2. This small steam flow does not impact the results of the main steam line break analysis in Section 15.4-2.

If a main steam line rupture occurs downstream of an isolation valve, all 3 isolation valves are automatically closed, stopping main steam flow. Closure of the isolation valves terminates the sudden large release of energy in the escaping steam, thereby preventing rapid cooldown of the Reactor Coolant System. Closure of the isolation valves also ensures a supply of steam for the 100% capacity, turbine driven emergency feedwater pump.

The maximum permissible main steam isolation valve leakage in the direction of normal flow is in accordance with the recommendations of MSS SP-61 (Reference 4). In the direction of reverse flow, leakage is less than 1% of normal steam flow through the main steam isolation valve.

10.3.2.4 Main Steam Safety Valves

Main steam safety valves are located in each main steam line outside the Reactor Building, upstream of the main steam isolation valves to protect the steam generators against overpressure. These valves are designed, fabricated and stamped in accordance with the ASME Code, Section III. The safety valve setpoints are given in Table 10.3-1a. The safety valves are sized to pass the steam flow resulting from complete load rejection or shutoff of main steam flow without reactor trip. The maximum steam flow through each individual valve is limited to 970,000 lb/hr at steam generator design conditions, in accordance with Nuclear Steam Supply System criteria. In the event that a single main steam safety valve sticks in the full open position, uncontrolled blowdown from the affected steam generator is restricted within limits compatible with maintenance of reactor fuel integrity and integrity of the reactor internals.

10.3.3 Evaluation

The Main Steam Supply System design limits the effects of a main steam line rupture. Seamless pipe is used inside the Reactor Building and for the spool piece of the penetration terminal end outside the Reactor Building. This minimizes the probability and consequences of postulated pipe rupture. Rupture of any main steam line, malfunction of any single isolation valve, or any consequential damage does not cause uncontrolled flow from more than 1 steam generator, nor does it result in containment pressure exceeding the design value.

The effects of pipe whip are considered in the layout of the system. Safety-related equipment is protected from the effects of pipe whip by restraints, physical separation, and/or barriers, if required. Pipe rupture is discussed in detail in Section 3.6, seismic design is discussed in Section 3.7.

10.3.4 Inspection and Testing Requirements

Inspection and testing requirements for the Main Steam Supply System can be divided into 2 parts: preoperational testing and inservice testing and inspection.

1. Preoperational Testing

   Preoperational testing of the Main Steam Supply System includes:

   a. Cold hydrostatic testing.
   b. Hot functional testing, including test of the functional capability of system valves.
   c. Preservice inspection to establish baseline data for subsequent inservice inspection, as required by the ASME Code, Section XI.

2. Inservice Testing and Inspection

   Inservice testing and inspection of the Main Steam Supply System includes:

a. Main steam isolation valve testing as follows:

(1) The main steam isolation valves are capable of being tested during normal plant operation to demonstrate their ability to respond to a “test close” signal. Upon receipt of a “test close” signal, the main steam isolation valve being tested moves to a 90 to 95% open (5 to 10% closed) position. Upon removal of the “test close” signal, the valve returns to the 100% open position. In the event that a close signal is received during this test, such a signal overrides the test signal and the isolation valve closes completely within the specified closing time. This testing is no longer performed based on NUREG 1482, “Guidelines for Inservice Testing at Nuclear Power Plants,” Section 4.2.4 recommendation.

(2) Testing for complete main steam isolation valve closure is performed under shutdown conditions and verifies the ability of the valves to fully close within the specified closure time.

b. Inservice inspection requirements, in accordance with the ASME Code, Section XI, apply to all Class 2 and Class 3 main steam piping from the steam generators to the point where the main steam piping enters the Turbine Building.

Weld examinations are performed in accordance with the ASME Code, Section XI. Inservice inspection of other Main Steam Supply System components within this boundary is discussed in Section 5.7. System components not within this boundary are not subject to inservice inspection.

10.3.5 Water Chemistry

Secondary side water chemistry “all volatile treatment” (AVT) for corrosion control consists of the following:

1. Addition of an amine or mixture of amines for pH control.
2. Addition of an oxygen scavenger to minimize dissolved oxygen concentration.
3. Continuous steam generator secondary side blowdown to limit concentrations of dissolved and suspended solids.
4. A Condensate Cleanup System, consisting of filter/demineralizers, operated during startup to approximately 50% flow and as required during condenser leakage and if needed, during shutdown.
5. Boric acid may be added to mitigate denting of steam generator tubes.
6. Ammonium Chloride may be added for molar ratio control.
7. Other chemicals may be added based on EPRI, NSSS supplier or SGOG guidelines and evaluation by SCE&G.

Secondary side water chemistry specifications are in accordance with the recommendations of EPRI. Recommendations of the NSSS supplier and/or the Steam Generator Owners Group (SGOG), may also be applied.

Samples of condensate, feedwater, steam, steam generator blowdown, and demineralized makeup water are available for use in monitoring and controlling secondary side water chemistry. Sampling equipment is located in the water treatment building and in the nuclear sampling room of the Control Building. Sampling equipment consists of pH, conductivity, cation conductivity, hydrazine, sodium, and dissolved oxygen analyzers for monitoring the appropriate samples at reduced temperature and pressure.

Steam generator blowdown samples are routed to the nuclear sampling room, as are other potentially radioactive samples (see Section 9.3.2). Samples from other secondary side sample points are routed to the sampling panel at the Water Treatment Building.

Grab samples are taken from secondary side sample points at regular intervals and are subjected to laboratory analyses to ensure that the analyzers are functioning properly and that secondary side water chemistry is within specification.

Steam generator water chemistry is controlled through sampling, steam generator secondary side blowdown, and chemical addition. During normal operation, amine injection for control of secondary side pH and oxygen scavenger for dissolved oxygen control may be regulated automatically or manually. Under transient conditions, amine and oxygen scavenger injections are manually regulated as required by grab sample analytical results. Amine and oxygen scavenger injection equipment is located in the Intermediate Building.

There are 3 possible mechanisms for hydrogen production in secondary side water. These mechanisms are as follows:

1. Corrosion.
2. Decomposition of hydrazine.
3. Leakage and/or diffusion from the primary side.

Hydrogen production rates will be inconsequential and any buildup in secondary side water will not be a safety hazard.

The secondary water chemistry control program will include a comprehensive monitoring program. The aim of this program is the minimization of overall system corrosion. Special emphasis will be placed on the inhibition of steam generator tube degradation. In general, the program will be based on recommendations and criteria supplied by EPRI. Recommendations from the NSSS vendor and/or the SGOG may also be incorporated. This program consists of procedures covering those items contained in Section 6.8 of the Technical Specifications.

10.3.6 Steam and Feedwater System Materials

10.3.6.1 Fracture Toughness

Where specified, test methods and acceptance criteria for fracture toughness are in compliance with the ASME Code, Section III, Article NC-2300. Charpy V-notch tests are specified for ferritic materials used in the following Class 2 components of the feedwater system:

1. Feedwater isolation valves.
2. Feedwater check valves.
3. Feedwater system Reactor Building penetration assemblies.
4. Feedwater piping.

Tests are specified for these feedwater system components because nominal pipe size exceeds 6 inches, material section thickness exceeds 5/8 inch and minimum service temperature can be as low as 50°F inside containment and 40°F outside containment.

Fracture toughness testing (impact testing) for ferritic materials used in the Main Steam System piping whose nominal pipe size exceeds 6 inches and material section thickness exceeds 5/8 inch was performed at a temperature of 120°F since minimum service temperature is approximately 327°F at 100 psia. This is the lowest temperature at which the steam generators are used to remove heat from the Reactor Coolant System. Testing was performed at 32°F on the main steam penetration process pipe. The Residual Heat Removal System is used at lower temperatures and pressures. The ASME Code, Section III does not specifically require impact testing of materials used in the Main Steam Supply System. The Code stipulates that the design specification must state whether or not impact testing is required. In consideration of the high minimum service temperature for the Main Steam Supply System, impact testing is not specified.

Fracture toughness testing (impact testing) is not required for ferritic Class 2 and Class 3 components of the Emergency Feedwater System, since pipe, fittings, pumps, and valves in this system have a nominal pipe size less than 6 inches. Articles NC-2311(b) and ND-2311(b) of the ASME Code, Section III exempt these materials from impact testing requirements.

10.3.6.2 Materials Selection and Fabrication

10.3.6.2.1 Materials Not Included in Appendix I to Section III of the ASME Code

Materials used are included in Appendix I to Section III of the ASME Code. Each line from the steam generators to the containment penetration assembly, inside the Reactor Building, is fabricated from SA-106, Grade C, seamless, carbon steel pipe material. The first straight piece of pipe attached to the containment penetration assembly outside the Reactor Building is also of this material. The main steam lines from this point to the Turbine Building wall, including piping in the penetration rooms and Intermediate Building, are fabricated from SA-155, KC-70, Class 1 welded, carbon steel pipe material.

Main steam piping within the Turbine Building is fabricated from A-155, KC-70, welded, carbon steel pipe material.

10.3.6.2.2 Austenitic Stainless Steel Components

No austenitic stainless steel components are used.

10.3.6.2.3 Cleaning and Handling of Class 2 and 3 Components

Cleaning and handling of components is performed in accordance with Regulatory Guide 1.37 (see Appendix 3A) and ANSI N45.2.1 (Reference 5).

10.3.6.2.4 Preheat Temperatures

Compliance with Regulatory Guide 1.50 is discussed in Appendix 3A.

10.3.6.2.5 Welding Procedures

Compliance with Regulatory Guide 1.71 is discussed in Appendix 3A.

10.3.7 References

1. American National Standards Institute, *Power Piping Code*, ANSI B31.1.0, 1967, with Addenda through Summer, 1972.
2. American National Standards Institute, *Steel Pipe Flanges, Flanged Valves, and Fittings*, ANSI B16.5, 1968.

3. American Society of Mechanical Engineers, *Recommended Practices for the Protection of Water Damage to Steam Turbines Used for Electric Power Generation, Part II*, TWDPS-1, April, 1973.
4. Manufacturers Standardization Society of the Valve and Fitting Industry, *Hydrostatic Testing of Steel Valves*, MSS SP-61, 1961.
5. American National Standards Institute, *Cleaning of Fluid Systems and Associated Components for Nuclear Power Plants*, ANSI N45.2.1, 1973.

Table 10.3-1
Environmental Conditions Considered in
Main Steam Supply System Design

	Condition	
	Normal and Upset I	Upset II, Emergency, and Faulted
Piping Inside Reactor Building - Most Severe Conditions (Emergency and Upset)		
Ambient Temperature, °F	50 to 120	380, max.
Ambient Pressure, psia	14.7	68.2, max.
Relative Humidity,%, max.	100	100
Total Radiation, rad	2.5×10^7	1.9×10^8
Piping in Penetration Rooms		
Ambient Temperature, °F	65 to 121	445, max.
Ambient Pressure, psia	14.7	20.3, max.
Relative Humidity,%, max.	90	100
Total Radiation, rad	2.4×10^6	1.6×10^7
Piping in Intermediate Building		
Ambient Temperature, °F	65 to 131	398, max.
Ambient Pressure, psia	14.7	17.8, max.
Relative Humidity,%, max.	90	100
Total Radiation, rad	1.5×10^6	1.6×10^7

Table 10.3-1a

Main Steam Line	Valve	Setpoint (psig)
A	2806A-MS	1176
	2806B-MS	1190
	2806C-MS	1205
	2806D-MS	1220
	2806E-MS	1235
B	2806F-MS	1176
	2806G-MS	1190
	2806H-MS	1205
	2806I-MS	1220
	2806J-MS	1235
C	2806K-MS	1176
	2806L-MS	1190
	2806M-MS	1205
	2806N-MS	1220
	2806P-MS	1235

Table 10.3-2
Steam Generator for Blowdown Rate

Flow Path	No. of Identical Paths	Max. Flow (all paths combined)	Type	Size, in.	Quality	Design Code	Valve Closure Time	Actuation	Closure Signal	Power Quality	Air Quality
Atmospheric Dump	3	2,910,000 lb/hr	Globe	8	QR	B31.1.0	3	Air	Normally closed, see FSAR Section 10.4.4 for control, fails closed	1E (Assoc) and Non-1E	NNS
Condenser Dump	8	7,760,000 lb/hr	Globe	8	QR	B31.1.0	3	Air	Normally closed, see FSAR Section 10.4.4 for control, fails closed	1E (Assoc) and Non-1E	NNS
Steam Dump Drains (Trap)	4	1,052 lb/hr*	Thermodynamic Steam Trap	1	NNS	N/A	N/A	Self	N/A	N/A	N/A
Steam Dump Drains (Bypass)	4	93,272 lb/hr*	Globe	1-1/2	NNS	B31.1.0	5	Air	Normally closed - fails open	Non-1E	NNS
Turbine Cycle Sampling	3	5,265 lb/hr*	Globe	3/8	NNS	B31.1.0	N/A	Manual	N/A 2 of 3 valves normally closed	N/A	N/A
Main Steam Drains / Upstream MSIV (Trap)	6	2,364 lb/hr*	Thermodynamic Steam Trap	1	NNS	N/A	N/A	Self	N/A	N/A	N/A
Main Steam Drains / Upstream MSIV (Bypass)	6	42,336 lb/hr	Globe	1-1/2	NNS	B31.1.0	5	Air	Normally closed - opens on hi drain pot level switch signal	Non-1E	NNS

Table 10.3-2 (continued)
Steam Generator for Blowdown Rate

Flow Path	No. of Identical Paths	Max. Flow (all paths combined)	Type	Size, in.	Quality	Design Code	Valve Closure Time	Actuation	Closure Signal	Power Quality	Air Quality
Main Steam Drains / Downstream MSIV (Trap)	8	2,628 lb/hr*	Thermodynamic Steam Trap	1	NNS	N/A	N/A	Self	N/A	N/A	N/A
Main Steam to Turbine Stop Valve	4	11,722,000 lb/hr	Turbine Stop Valve	30	QR	B31.1.0	0.15	Hydraulic	Normally closed post accident	QR	N/A
Main Steam Drains / Downstream MSIV (Bypass)	8	124,623 lb/hr	Globe	1-1/2	NNS	B31.1.0	5	Air	Normally closed - opens on hi-hi drain pot level switch signal	Non-1E	NNS
Gland Steam	1	32,000 lb/hr*	Gate	4	NNS	B31.1.0	30	Motor	Manual remote closure - normally open	Non-1E	NNS
Pegging Steam	1	160,000 lb/hr	Globe	8	NNS	B31.1.0	54	Air	Normally closed, fails closed. Remains closed for a FW isolation. (Modulating control from PT-2231)	Non-1E	NNS
Sparging Steam	1	16,000 lb/hr	Globe	2	NNS	B31.1.0	6	Air	Normally closed, fails closed. Remains closed for a FW isolation. (Modulating control from PC-2232)	Non-1E	NNS
MS to FW Pump	3	144,300 lb/hr*	Turbine Control Valve	4	NNS	B31.1.0	1	Hydraulic	FW Pump Turbine Trip	Non-1E	N/A

Table 10.3-2 (continued)
Steam Generator for Blowdown Rate

Flow Path	No. of Identical Paths	Max. Flow (all paths combined)	Type	Size, in.	Quality	Design Code	Valve Closure Time	Actuation	Closure Signal	Power Quality	Air Quality
MS to FW Pump Drains (Trap)	3	789 lb/hr*	Thermodynamic Steam Trap	1	NNS	N/A	N/A	Self	N/A	N/A	N/A
MS to FW Pump Drains (Bypass)	3	266,820 lb/hr	Globe	1-1/2	NNS	B31.1.0	N/A	Manual	N/A - Normally closed	N/A	N/A
MS to Aux. Steam	1	22,400 lb/hr	Globe	2	NNS	B31.1.0	6.1	Air	Normally closed with steam from extraction.	Non-1E	NNS
MS to Aux. Steam (Bypass)	1	22,400 lb/hr	Globe	1	NNS	B31.1.0	N/A	Manual	N/A - Normally closed	N/A	N/A

* Paths that would normally be open following a Main Steam Line Break accident.

Table 10.3-2 (continued)
Steam Generator for Blowdown Rate

Flow Path	No. of Identical Paths	Max. Flow (all paths combined)	Type	Size, in.	Quality	Design Code	Valve Closure Time	Actuation	Closure Signal	Power Quality	Air Quality
MS to Aux. Steam Drains (Trap)	1	263 lb/hr*	Thermodynamic Steam Trap	1	NNS	N/A	N/A	Self	N/A	N/A	N/A
MS to Aux. Steam Drains (Bypass)	1	13,860 lb/hr	Globe	3/4	NNS	B31.1.0	N/A	Manual	N/A - Normally closed	N/A	N/A
Reheat Steam	1	1,189,540 lb/hr	Gate	24	NNS	B31.1.0	100	Motor	Normally open. Closes on low pressure signal from PS-5635, following turbine trip.	Non-1E	N/A
Reheat Steam (Bypass)	1	148,000 lb/hr	Gate	4	NNS	B31.1.0	30	Motor	Normally open. Interlocked to close with Reheat Steam Valve.	Non-1E	N/A
MS Stop Valve Upstream Drain	4	94,752 lb/hr *	Globe	1	NNS	B31.1.0	N/A	Motor	Open for startup, shutdown, turbine trip and <15% load.	Non-1E	N/A
FW Turbine HP Stop Valve Upseat Drain	3	88,776 lb/hr *	Globe	1 1/2	NNS	B31.1.0	30	Motor	Open for startup, shutdown, turbine trip and <15% load.	Non-1E	N/A
EFW Pump Turbine Stop Valve Drain	2	7,146 lb/hr*	Globe	3/4	NNS	B31.1.0	N/A	Manual	Normally open.	Non-1E	N/A

* Paths that would normally be open following a Main Steam Line Break accident.

Figure 10.3-1
DRAWING D-302-011
FSAR FIGURE REFERENCE

Figure 10.3-2
DRAWING D-302-012
FSAR FIGURE REFERENCE

Figure 10.3-3
DRAWING D-302-014
FSAR FIGURE REFERENCE

Figure 10.3-4
DRAWING D-302-031
FSAR FIGURE REFERENCE

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 Main Condenser

The main condenser acts as a heat sink for the 2 low pressure turbine exhausts, limiting the back pressure and thus increasing the amount of available work from the turbines. The main condenser also serves as a collection point for main steam dump flow, low pressure heater drains, and other miscellaneous flows, as well as, being the makeup point for the secondary cycle. It deaerates and provides storage capacity for the condensate system.

The auxiliary condensers are heat sinks for their individual feed pump turbines. Condensate from these condensers is returned to the main condenser.

10.4.1.1 Design Bases

The main condenser is of the dual shell, dual pressure type (a high pressure shell and a low pressure shell). The high pressure shell is designed to operate at ~2.91 inches, HgA. The low pressure shell is designed to operate at ~2.13 inches, HgA with a design cooling water inlet temperature of 77 °F (circulating water temperature).

The low pressure shell features a false bottom plate which separates the low pressure condensing zone of the shell from a high pressure storage zone. The low pressure zone is connected to the high pressure zone by a downcomer. Condensate flows from the low pressure zone at a temperature of ~103.23°F to the high pressure zone by gravity. Condensate from the high pressure zone of the low pressure shell flows by gravity to the high pressure shell where it is reheated to 115.04 °F by mixing with high pressure shell hotwell condensate. The condensate is reheated to the saturation temperature of the high pressure shell at the design point. The condensate pumps take suction from the high pressure shell. The design temperature of condensate out of the high pressure shell is ~ 115.04 °F. Normal maximum operating pressure of the main condenser is limited to approximately 5 inches, HgA, and 175 °F at the turbine exhaust to any shell. Condenser design capacities are listed in Table 10.4-1. Radioactivity concentrations in the condenser are expected to be approximately equivalent to the concentrations given in Table 11.1-5 for steam. Radioiodine concentrations in the condenser should be slightly lower because of a main condenser/air ejector partition factor of 0.15 for volatile iodine species.

Noncondensable gases are removed by the vacuum pumps described in Section 10.4.2. Design air inleakage rates are 40 scfm for normal main condenser operation and 15 scfm, total, for normal auxiliary condenser operation.

The main condenser will receive approximately 6.93 x 10^6 lb/hr of main steam from the Turbine Bypass System. This flow is bypassed to the condenser as required following a large load rejection, turbine trip, or other similar occurrence.

Main steam pressure is reduced to approximately 100 psig by the turbine bypass system at the condenser main steam dump inlet header. The steam is then dispersed by the main condenser through an internal spray pipe which directs the steam flow to a stainless steel baffle. This internal

arrangement and the relatively low pressure (100 psig) protects the tubes and other components from impingement damage failure.

The condenser hotwell is capable of maintaining a normal water level corresponding to a retention time of at least 2 minutes (approximately 39,200 gallons).

Each condenser shell is provided with a compartmented hotwell and leak detection trays. A tray is located inside the hotwell adjacent to the tubesheet of each waterbox. The compartmented hotwells and leak detection trays are continuously sampled to provide early detection of tube leakage. Design of the compartmented hotwells and leak detection trays permits obtaining local samples to facilitate locating of tube leaks if necessary.

The combination of good quality (lake) cooling water and stainless steel tubes reduces corrosion and erosion of condenser tubes. An Amertap cleaning system is also provided for use in maintaining condenser tube cleanliness.

10.4.1.2 System Description

The main condenser is of the dual shell, dual pressure type with a rubber expansion joint in each neck. Circulating water is arranged to pass through the 2 sections in series. Condenser leakage is monitored by installed condensate monitoring instrumentation with an associated alarm in the control room. Heaters 5A and 6A are installed in the low pressure shell; heaters 5B and 6B are installed in the high pressure shell.

During normal operation the main condenser receives the following flows:

1. Main turbine exhaust steam.
2. Auxiliary condenser condensate and vents.
3. Low pressure heater drains.
4. Steam and water associated with the Turbine Gland Sealing System.
5. Condensate makeup.
6. Auxiliary condenser air removal (Low Pressure Condenser).

Possible additional flows during startup, shutdown or under transient conditions include:

1. Condensate pump and steam packing condenser minimum flow recirculation.
2. Startup vents.
3. Moisture separator/reheater drains.
4. Turbine bypass flow through the Main Steam Dump System.

10.4.1.3 Safety Evaluation

Disassociated hydrogen and other noncondensible gases are removed by the mechanical vacuum pumps to the atmosphere. These noncondensible gases may be routed to the Auxiliary Building Ventilation System charcoal filters if radiation levels in excess of established limits exist in the vacuum pump discharge. In the event 1 vacuum pump fails, another is available on standby. Thus, hydrogen buildup does not occur during operation of the condenser.

The influence of the main condenser on the Reactor Coolant System is reduced by the decoupling effect of the deaerator and steam generator water inventories. Therefore, control functions associated with the main condenser do not directly influence the operation of the Reactor Coolant System.

If the condenser pressure should start to rise, exhaust hood sprays are activated by a turbine exhaust hood temperature signal. Normal operation of the main condenser and its associated control functions do not affect the Reactor Coolant System. The only main condenser control function indirectly affecting the Reactor Coolant System is the loss of condenser vacuum which results in turbine trip. A turbine trip due to loss of condenser vacuum results in programmed steam dump to the atmosphere and reactor shutdown.

Provisions for protection of safety-related equipment from flooding as a result of condenser failure are discussed in Section 7.6.

10.4.1.4 Tests and Inspections

The condenser is subjected to a shell side hydrostatic test in the field. The pressure is limited to the static head of water at the turbine flange.

Condenser tubes are subjected to eddy current testing to ensure leak tight operation. The tubes are also subjected to periodic hydro cleaning to remove any scale, silt, or biological material which may inhibit heat transfer.

10.4.1.5 Instrumentation

The high pressure and low pressure condenser shells are equipped with level controllers for sensing of condenser water level. These level controllers provide signals to control valves which control the supply of condensate to the condensate storage tank and normal or emergency condensate flow to the condensate system. At low-low hotwell level, these level controllers open the demineralized water makeup valve to the low pressure hotwell. Monitoring of condenser water level is accomplished through level transmitters which provide signals to level indicators on the main control board in the control room. Each condenser shell has 1 pressure switch and 1 pressure transmitter to provide tripping and interlock functions upon loss of vacuum. If either of the pressure switches sense loss of vacuum, the turbine generator is tripped. The pressure transmitters operate bistables which interlock the turbine bypass system to prevent steam dump to the condenser upon loss of vacuum (see Section 10.4.4). Condenser vacuum is indicated and low vacuum is alarmed in the control room.

Condenser instrumentation is shown schematically on Figures 10.4-8 and 10.4-9.

10.4.2 Condenser Air Removal System

The Condenser Air Removal System maintains main and auxiliary condenser vacuum by removing noncondensible gases, including dissociated hydrogen and oxygen from the main and auxiliary condensers.

10.4.2.1 Design Bases

The non-nuclear safety class Condenser Air Removal System is designed to establish main and auxiliary condenser vacuum during plant startup and to maintain vacuum during normal operation. Mechanical vacuum pumps remove noncondensible gases from the main condensers and the auxiliary condensers via the main condensers. Under normal conditions, discharge is through the Auxiliary Building Ventilation System charcoal filters. Provision is made for discharge of the noncondensibles to atmosphere.

Mechanical vacuum pumps are designed for the capacities listed in Table 10.4-1 in accordance with Heat Exchange Institute Standards (Reference 4). Piping and valves are designed in accordance with ANSI B31.1 (Reference 1) and B16.5 (Reference 2), respectively.

10.4.2.2 System Description

Two (2) subsystems comprise the condenser air removal system: the main condenser air removal subsystem and the Auxiliary Condenser Air Removal Subsystem. Figure 10.4-1 provides the system diagram.

Each of the 2 main condenser shells is evacuated by an individual, 100% capacity, mechanical vacuum pump. A third pump is provided for backup. These pumps are used both to establish vacuum during plant startup (hogging) and to maintain vacuum during operation (holding).

The auxiliary condensers are piped to and normally aligned to the LP main condenser shell to maintain vacuum. Additionally, there are 2 mechanical vacuum pumps provided as back up for the auxiliary condensers. One (1) mechanical vacuum pump can be used to maintain vacuum in the three auxiliary condensers. A second pump is provided for backup.

All vacuum pumps can be operated during startup to speed the hogging operation.

Cooling water for the mechanical vacuum pumps is supplied from the Turbine Building Closed Cycle Cooling System. Seal water is provided by the condensate system.

Both subsystems discharge through the Auxiliary Building Ventilation System charcoal filters through a common line under normal conditions. Condenser discharge radiation monitor, RM-A9, is set to provide an alarm at approximately twice normal operating background. The high alarm is also normally set at approximately 2 times background. Provision is made for obtaining local samples for analysis and evaluation.

10.4.2.3 Safety Evaluation

The Condenser Air Removal System is not required to operate under emergency conditions nor is it necessary to achieve safe plant shutdown. Each subsystem is provided with a backup mechanical vacuum pump. Thus failure of an operating pump is not detrimental to continued plant operation.

Under normal conditions, the Condenser Air Removal System has no effect upon the Reactor Coolant System and radioactive leakage is negligible. However, should primary to secondary reactor coolant leakage occur, the flowpath through the Auxiliary Building charcoal filters limits the release of radioactivity to the environment. Anticipated release rates during normal operation are presented in Section 11.3.6.

10.4.2.4 Tests and Inspections

The Condenser Air Removal System is operated continuously during normal plant operation. Therefore, periodic testing is not required. System operation is verified prior to initial plant startup by preoperational and startup testing. During subsequent plant startups, system operation is verified by observation during hogging operations. System components are readily accessible for visual inspection under normal plant conditions.

10.4.2.5 Instrumentation

1. Main Condenser Air Removal

   Local pressure and air flow indication is provided to monitor vacuum pump performance. Lube oil pressure and discharge air temperature switches are provided for startup and shutdown interlocks. Alarms are sounded in the control room to alert the operator to vacuum pump trip, vacuum pump lube oil pump trip, low oil pressure, high off gas air temperature, and high off gas radiation.

2. Auxiliary Condenser Air Removal

   Local pressure and air flow indication is provided to monitor vacuum pump performance. Lube oil pressure and discharge air temperature switches are provided for startup and shutdown interlocks. Alarms are sounded in the Control Room to alert the operator to vacuum pump trip and high lube oil temperature.

10.4.3 Turbine Gland Sealing System

10.4.3.1 Design Bases

Main turbine and feedwater pump turbine shaft seals are of the injection/labyrinth/leakoff type. These seals are designed to prevent air leakage into and/or steam leakage out of the turbine casings.

The Turbine Gland Sealing System is not safety-related. Piping and valves associated with the system are designed in accordance with ANSI B.31.1 (Reference 1) and ANSI B16.5 (Reference 2), respectively.

10.4.3.2 System Description

Sealing steam is normally supplied to the Turbine Gland Sealing System from the Main Steam Supply System under all load conditions. Steam for turbine gland sealing may be provided by the auxiliary boiler through the Auxiliary Steam System. The sealing steam passes inward through the seals toward the turbines to a leakoff which is piped to the condenser. Gland sealing steam also passes though the seal toward the outside where it enters the vent annulus. The vent annulus is maintained at a slight vacuum by the steam packing condenser.

A small amount of air is drawn into the vent annulus and this air, together with the sealing steam, goes to the steam packing condenser. In the steam packing exhauster, the steam is condensed and the remaining saturated air is discharged to the atmosphere by a motor driven blower.

The turbine gland seal exhaust blower is part of the steam packing exhauster which is located in the Turbine Building at elevation 439’. Saturated air from this blower is discharged through a 12 inch pipe to the turbine building roof near the Intermediate Building wall. The saturated air is discharged to atmosphere approximately 8 feet above the roof (elevation 522’).

This discharge is not monitored for radiation. Radiation monitor RM-A9, which monitors the Main Condenser Air Removal System discharge, actuates an alarm in the event of primary to secondary leakage.

The LP turbine seals operate against vacuum at all times.

Pressure in the steam seal header is automatically controlled by steam seal regulating valves.

10.4.3.3 Safety Evaluation

As long as a steam generator tube leak does not occur, the steam supplied to the Turbine Gland Sealing System is nonradioactive. A steam generator tube leak may result in small amounts of radioactive process steam leakage from the steam packing condenser. Such steam generator tube leakage would be detected by the Steam Generator Blowdown System radiation monitor (RM-L3) or the condenser exhaust radiation monitor (RM-A9). See Sections 10.4.8 and 11.4.

Suitable manual regulator bypass valves are provided for use under emergency conditions. Relief valves are included to protect the system from over pressurization.

10.4.3.4 Tests and Inspections

No special tests or inspections are required.

10.4.3.5 Instrumentation

Steam seal header pressure is automatically controlled by a steam seal feed valve and a steam packing unloading valve. Controls for system operation, such as pressure indicators, switches, transmitters, and controllers are mounted on a local panel and the main control board. Additionally, a local level alarm switch and temperature indicator are provided.

10.4.4 Turbine Bypass System

10.4.4.1 Design Bases

The Turbine Bypass System is capable of bypassing main steam to the main condenser and/or to the atmosphere. This provides an artificial steam load for the steam generators so that differences between reactor output and turbine generator load can be absorbed without imposing undesirable transients upon the nuclear steam supply system.

System design permits the accommodation of large load reductions without reactor trip during most times in core life. The system also permits a gradual, orderly cooldown of the reactor to the point where the Residual Heat Removal System can assume the cooling function. The Turbine Bypass System is designed to operate in conjunction with the turbine generator, when available, or without the turbine generator if required. When including the power relief valves, it has sufficient capacity to pass ~ 93.6% of main steam flow at full load temperature and pressure. Capacities of individual valves in the Turbine Bypass System are presented in Section 10.4.4.2. The capacity of any 1 valve in the system does not exceed 970,000 lb/hr at 1,200 psia when fully open.

The Turbine Bypass System was originally designed to accommodate a full load rejection, defined as a reduction from 100% of rated turbine generator load to plant auxiliary load without a reactor trip. The transition to 18 months cycles, to less negative moderator temperature coefficients at the beginning of the fuel cycle, and to a full power T_{avg} operating window of 572 °F to 587.4 °F has, however, reduced this capability. Best estimate analyses indicated that a full load rejection is possible at all times in core life when operating with a full power T_{avg} of 587.4 °F. However, at a full power T_{avg} of 572 °F, full load rejection capability is feasible only for times in core burnup when the full power moderator temperature coefficient that is more negative than -18pcm/ °F. Therefore, full load rejection capability cannot be guaranteed for all values of full power T_{avg} and for all time in core life. Generally, margin to trip improves with core burnup due to the more negative moderator temperature coefficient.

Step load changes of up to 10% can be accommodated by the reactor control system in automatic mode without a reactor trip or actuation of the turbine bypass system.

System valves, piping and related equipment are designed and fabricated to satisfy the requirements of the following codes and standards and are non-nuclear safety class, non-Seismic Category 1, except as noted below:

1. Power relief valves are designed and fabricated to satisfy the ASME Code, Section III, Class 2 (Reference 5), and are classified Safety Class 2a, Seismic Category 1.
2. Atmospheric and condenser dump valves are designed and fabricated to satisfy ANSI B16.5 (Reference 2).
3. Vent diffusers are designed and fabricated to satisfy the ASME Code, Section VIII (Reference 6).
4. Inline diffusers are designed and fabricated to satisfy ANSI B31.1 (Reference 1).
5. Piping is designed and fabricated to satisfy ANSI B31.1 (Reference 1) and associated standards for fittings, flanges, etc.

Additionally, the Turbine Bypass System is designed to satisfy Occupational Safety and Health Act (OSHA) requirements concerning noise levels during operation.

10.4.4.2 System Description

The Turbine Bypass System is shown schematically by Figure 10.3-1. The system is comprised of the following components:

1. Condenser Dump Valve/Diffuser Combinations

   Eight condenser dump valved/diffuser combinations are provided and described in Table 10.3-2. The valve/diffuser combinations have an average rated/calculated capacity of ~ 6.74% of the main steam flow at full load pressure and temperature, thereby providing a bypass capacity to the condenser of ~ 53.95% of rated main steam flow. Each valve is provided with an inline diffuser mounted downstream of the valve. This combination produces reduced noise levels compared to levels generated by a valve without the diffusers. The system configuration separates the valve and diffuser, permitting location of the valve to allow easy access for maintenance. The diffusers are mounted in pairs in large, straight headers leading directly to the main condenser. Thus, problems associated with routing large diameter, hot piping are minimized.

2. Atmospheric Dump Valve/Diffuser Combinations

   Three atmospheric dump valve/diffuser combinations are provided and described in Table 10.3-2. The valve/diffuser combinations have an average rated/calculated capacity of ~ 6.95% of the main steam flow at full load pressure and temperature, thereby providing a bypass capacity to the atmosphere of ~ 20.85% of rated main steam flow. Each valve is provided with a diffuser mounted downstream of the valve. The system configuration separates the valve and diffuser, permitting location of the valve to allow easy access for maintenance. The diffusers are mounted on the intermediate building roof and discharge directly to the atmosphere.

3. Power Relief Valve/Diffuser Combinations

   Three power relief valve/diffuser combinations are provided. The power relief valves are similar to the atmospheric dump valves previously described, except for the design codes applied. The valve/diffuser combinations have an average rated capacity of ~ 6.25% of the main steam flow at full load pressure and temperature, thereby providing a bypass capacity to the atmosphere of ~ 18.76% of rated main steam flow. These valves serve a dual purpose. They operate in conjunction with the atmospheric dump valves to provide additional steam dump capacity to the atmosphere and they also serve as power operated relief valves for the steam generator secondary side.

   The power relief valves are Safety Class 2a and are located outside the Reactor Building, upstream of the main steam isolation valves in Safety Class 2a main steam piping. Piping downstream of the power relief valves, between the valves and diffusers is non-nuclear safety class.

   Operability testing of the valves was performed in accordance with the recommendations of Regulatory Guide 1.48 (Reference 11) as discussed in Appendix 3A. Electrical components (solenoid valves and position indicator limit switches) mounted on the valves are qualified to satisfy IEEE-382-1972. (Reference 10)

4. Piping and Other Valves

   System piping is provided to convey the steam to the condenser and to the Intermediate Building roof, where it may be discharged to the atmosphere. Manual isolation valves are provided for all control valves in the system to permit maintenance without shutting down.

   Turbine Bypass System control functions and control interactions with other plant controls and systems are discussed in detail in Section 7.7.1. A detailed analysis of system design adequacy is presented in Section 7.7.2.

10.4.4.3 Safety Evaluation

The Turbine Bypass System is not required for plant control following an accident and is not a safety related system. Failure of any single control valve to a wide open position results in uncontrolled secondary side blowdown that is within limits compatible with maintenance of reactor fuel integrity and integrity of the reactor internals.

The capacity of the power relief valves is in addition to that required by the ASME Code, Section III (Reference 5) for overpressure protection of the steam generators. Steam generator overpressure protection is provided by the main steam safety valves, discussed in Section 10.3.

Failure of the Turbine Bypass System to operate does not preclude operation of any essential systems since this system does not interface with any essential systems. Postulated failure of Turbine Bypass System high energy piping will not adversely affect or preclude operation of any safety- related systems or components located close to the Turbine Bypass System. Postulated

pipe rupture of high energy lines in the Turbine Bypass System is analyzed as discussed in Section 3.6.

10.4.4.4 Tests and Inspections

The Turbine Bypass System is tested prior to commercial operation. Proper system response to simulated temperature and pressure inputs is verified during preoperational testing. During hot functional testing, each valve is stroked open and closed to verify operation. After entering service, periodic testing is performed to assure availability. The power relief valves, which are Safety Class 2a, are tested and inspected in accordance with the applicable ASME Code, prescribed under 10CFR50.55a. This includes preservice and inservice inspection and test. Section 5.7 discusses a comprehensive program of compliance with the ASME Code, Section XI relative to inservice inspection.

10.4.4.5 Instrumentation Applications

Instrumentation and controls specifically related to the Turbine Bypass System are shown by Figures 10.3-1, and 10.4-3 through 10.4-4b. Setpoints are listed in Table 10.4-2. They are provided to permit monitoring of system performance and to permit manual valve operation if required.

10.4.5 Circulating Water System

The Circulating Water System removes thermal energy from the main and auxiliary condensers and dissipates this energy to Monticello Reservoir.

10.4.5.1 Design Bases

The principal performance requirement for the Circulating Water System is that it provide cooling water to the main and auxiliary condensers. The system is capable of pumping ~5.34 x 10^5 gpm of circulating water through the plant. This provides a heat transfer capability to the environment of 6.675 x 10^9 BTU/hr, with a nominal system temperature rise of 25 °F. This capability is adequate to satisfy system requirements for all normal and upset plant conditions, including turbine trip from full load. The system is not required to function under plant emergency or faulted conditions.

The following equipment is cooled by the Circulating Water System:

1. Main condenser - 2 shells.
2. Auxiliary condensers - 3 shells.
3. Circulating water motor bearing coolers are supplied only as backup cooling, (Normal Cooling Water Supply is from the Filtered Water System).

Circulating water is also used to wash the traveling screens and as a backup for circulating water pump motor bearings and jockey pump bearing lubrication.

Design parameters for major system components are presented in Table 10.4-3. The design pressure and temperature requirements for piping, valves, and pressure retaining parts are tabulated in the lower left margin of Figure 10.4-5. The upset condition tabulated is the shutoff head of the circulating water pumps. This condition occurs less than 1% of the time.

Circulating Water System piping and valves are designed in accordance with applicable industry codes and standards.

Condensers are designed in accordance with Heat Exchange Institute Standards. (Reference 4)

Pumps are designed in accordance with Hydraulic Institute Standards. (Reference 9)

10.4.5.2 System Description

Circulating Water System water requirements are supplied by three 33-1/3% capacity vertical wet pit pumps, located in the circulating water intake structure. The discharges from these pumps are headered into a main supply line to the plant. Two (2) or three (3) pumps are used during normal operation at reduced or full load.

The circulating water pumps can be controlled from the main control room or locally. Six (6) traveling water screens and two 100% capacity screen wash pumps with a strainer provide screened water to the pumps.

A circulating water jockey pump is included in the system to fill the circulating water system during startup.

The main condensers are supplied with cooling water through branches from the main circulating supply line. These branches are equipped with motor operated butterfly valves and expansion joints at the condenser waterbox inlet and discharge.

The auxiliary condensers, also supplied directly from the main circulating water line, are three (3) ~ 50% capacity units equipped with motor operated butterfly valves at the inlet and with manual butterfly valves at the discharge. Expansion joints are provided at the inlet and discharge.

The main and auxiliary condenser piping is equipped with automatic tube cleaning equipment of the sponge ball type.

10.4.5.3 Safety Evaluation

The Circulating Water System is independent of the emergency cooling facilities. It is not essential for safe operation and shutdown of the Nuclear Steam Supply System nor is it required to operate under accident conditions. Therefore, the system is non-nuclear safety class, non-Seismic Category 1.

A failure in the circulating water transport system inside the Turbine Building would be detected by a high water level alarm in the main condenser cleaning pit. As a result of effluent radiation

monitor response capabilities the sump pumps located in this pit are limited to a combined maximum capacity of 2000 gpm. A leak exceeding the capacity of these pumps would activate an alarm when the water level in the main condenser cleaning pit approached elevation 390'. The main condenser cleaning pit is located within the Amertap strainer pit.

A continued rise of water into the Amertap strainer pit to elevation 400' actuates 2 groups of 3 level switches. The actuation of any 2 switches within either group trips the circulating water pumps and initiates pump discharge valve and high pressure condenser discharge valve closure. Another alarm signals tripping of the pumps and closure of the pump and condenser discharge valves.

The lowest design pressure for any component in the Main Circulating Water System is 50 psig. Design data and system data are shown on Figure 10.4-5. To reduce the possibility of water hammer, slow closing, motor operated butterfly valves are used for condenser isolation.

A postulated complete failure of the condenser inlet expansion joint, which would result in an estimated flow rate of 780 ft3 /sec, would actuate the condenser cleaning pit alarm in less than 5 seconds. The rise of water to elevation 400' and resultant actuation of the alarm and pump trip would require approximately 46 seconds.

At initiation of pump trip, the pump discharge valves and high pressure condenser discharge valves begin to close. These valves require approximately 120 seconds and 90 seconds, respectively, to reach the fully closed position.

Pump coastdown time is extremely short and, for all practical purposes, is considered to be negligible.

The total time required to stop circulating water flow from the instant of failure would be approximately 2 min - 50 sec. Water levels versus time for a postulated expansion joint failure are presented in Table 10.4-3a.

A completely failed expansion joint would cause flooding of the Turbine Building basement (see Figure 1.2-16) up to elevation 413.5'. No essential systems or components are located in the Turbine Building. The lowest penetration of the Control Building or Intermediate Building walls, that could cause flooding from the Turbine Building, is at elevation 427', considerably above the flood elevation of 413.5'.

The system may be operated with less than 3 circulating water pumps in operation.

10.4.5.4 Tests and Inspection

Testing of the Circulating Water System is limited to that normally provided for non-safety related systems and includes:

1. Hot functional testing.

2. Normal, operational checking, and routine maintenance of the system.

10.4.5.5 Instrumentation

System instrumentation is shown schematically on Figure 10.4-5. The following instrumentation is provided to permit operator evaluation of major equipment performance and to provide a performance record:

1. Pressure indicators, switches, and test connections.
2. Level switches.
3. Temperature indicators and test connections.

10.4.6 Condensate Cleanup System

The Condensate Cleanup System is provided to aid in maintaining feedwater and steam generator water chemistry within specifications during all modes of plant operation and as required during condenser leakage. Figure 10.4-7a schematically illustrates the system.

10.4.6.1 Design Bases

1. The system is not safety related. Failure or malfunction of any system component will not affect the ability of the plant to achieve or maintain shutdown conditions.
2. The system is designed for cleaning up to approximately half of the maximum condensate flow.
3. System effluent purity will be within the limits provided in the Condensate System Design Basis Document as follows:

Total suspended solids, max. ppb	10
Sodium, max., ppb	1
Chloride. max., ppb	1

4. The system will be used when condensate polishing is required to maintain chemistry specifications.
5. Wastes from the system will be sent to the backwash receiving tank. Disposal from the tank will be dependent upon results of grab sample analysis.

10.4.6.2 System Description

The purpose of the Condensate Polishing System (CPS) is to minimize the time for plant startup. During plant operation, the Steam Generator Blowdown System is in service for system cleanup. However, the CPS will be used (assuming no SG leaks) to better maintain prescribed chemistry parameters in the condensate and feedwater cycle.

The CPS consists of 3 vessels in the condensate cycle. Two (2) vessels will be in service at a time with the third as a spare. The total flow through them will be a maximum of 8822 gpm (4411 each vessel). This is approximately 1/2 of the total condensate flow needed for full load capability of the V. C. Summer Nuclear Station, Unit 1.

The condensate polishers will be placed in service during plant startup for chemical cleaning of the condensate and feedwater cycles. There is a recirculation mode that will be used as a prestart cleanup of a major portion of the condensate and feedwater systems. This prestart cleanup will recirculate water using the condensate and feedwater booster pumps to the closed feed water isolation valves and back to the hotwell.

On unit startup, the polishers can be on line via the condensate pumps until the plant attains approximately 50% full load capacity.

During shutdown of the unit, the CPS could be placed in service when the plant load is approximately 50% if system chemistry indicates a need for cleanup.

If the condenser develops a leak, which will be detected by the Condenser Leak Detection System, the leak location will be determined and that half of the condenser will be taken out of service for repairs. At this time, the unit will be at a load of about 50% and the condensate polishers can be placed in service to assist in removing chemical impurities introduced by the detected leak.

If a primary to secondary leak occurs, it will be detected by the steam generator leak detection system and the CPS will be isolated. It is not intended to operate the CPS if a SG leak occurs. In the event that the condensate polishers are used in the presence of a steam generator tube leak, all applicable Health Physics measures and precautions will be observed.

Depleted resins are backflushed to a backwash receiving tank from which samples will be taken and analyzed prior to release. The results of gamma isotopic analyses are then utilized via established station procedures and administrative controls to determine if a release is possible. If a release is acceptable, the normally disconnected spool piece is installed and the depleted resins are discharged to the settling pond through RML-11. RML-11 will alarm on the local control panel and stop the backwash transfer pumps to prevent a release if its setpoint is exceeded.

If a release is not acceptable and the resin must be handled as solid radwaste, the contents of the backwash receiving tank are discharged to a DOT approved low level radwaste container. Using a preinstalled filter arrangement and the dewatering equipment shown in Figure 10.4-7a, excess water is removed from the powdex resin according to the Process Control Program for the packaging of low level radioactive waste. The resin may be dewatered to DOT requirements and shipped to a licensed low level radwaste burial facility. The dewatered resin may also be transported around to the Auxiliary Building truck bay entrance and solidified using the inplant solidification equipment.

The anticipated operational information is as follows:

1.	Flow rate each vessel:	condensate flow rate = 4411 gpm backwash flow = 375 gpm
2.	Backwash frequency:	3 backwashes per 24 hr startup
3.	Backwash holdup tank:	12,000 gallon capacity
4.	Average backwash rate:	18 backwashes per year
5.	Provisions exist for sampling condensate and resin backwash.	

10.4.6.3 Safety Evaluation

The Condensate Cleanup System is not safety related and is not required to ensure any of the following:

1. The integrity of the reactor coolant pressure boundary.
2. The capability to shut down the reactor and maintain it in a safety shutdown condition.
3. The ability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures in excess of established limits.

Dissolved and suspended solid impurities within the condensate and feedwater circuits are not expected to contribute to plant activity levels. Any radioactive contamination that might occur in the Main Steam/Condensate System is actually reduced during the condensate cleanup process.

Scheduled, infrequent operation of the condensate polishers minimizes the possibility of producing potentially radioactive waste.

10.4.6.4 Tests and Inspections

Prior to system startup, the service vessels are hydrostatically pressure tested and flushed clean. All components and instruments are checked for operational status. During plant operation, instruments are routinely calibrated with known standards for accurate monitoring of pH, dissolved oxygen, sodium and conductivity. Continual surveillance and prescribed inspections of system components are standard operating procedures.

To assure protection of plant personnel and the environment during suspected primary to secondary steam generator leakage the following precautions should be taken:

1. Increased radiation survey frequency in the condenser polisher area.
2. Grab sample analysis prior to backwash receiving tank discharge will be extended to include tritium and isotopic ß-y analysis.

10.4.6.5 Instrumentation Application

Manually initiated, automatic backwash sequence controls are provided for use in replacing exhausted powdered resins. Resin trap strainers in the effluent stream have differential pressure switches to actuate alarms upon detection of high pressure drop.

An automatic bypass valve around the demineralizer system opens upon detection of excessive differential pressure. Instrumentation also indicates high differential pressure across a demineralizer vessel. The demineralizer is then manually removed from service and replaced by the standby vessel. Instrumentation is also provided to monitor effluent for sodium, pH, dissolved oxygen, and conductivity.

10.4.7 Condensate and Feedwater Systems

10.4.7.1 Condensate System

The Condensate System pumps condensed turbine exhaust steam from the main condenser hotwell through the low pressure feedwater heaters to maintain deaerator storage tank level for anticipated operating conditions. It also serves as a source of cooling water for the steam packing condenser and the steam generator blowdown heat exchanger, and provides sealing water for various vacuum valves and the feedwater pump seals.

10.4.7.1.1 Design Bases

Design conditions for system piping, valves, and pressure retaining parts are tabulated in the lower left margin of Figures 10.4-8 and 10.4-9. At the discharge of the condensate pumps, the upset condition bounds the discharge pressure of the condensate pumps under minimum recirculation. This condition is expected to occur less than 1% of the time.

Condensate pumps are designed in accordance with the requirements of the Hydraulic Institute Standards. (Reference 9) The original pump design point was selected to satisfy the requirements of the turbine thermal cycle (at pre-uprate conditions) at the “valve wide open” condition, plus a wear margin.

For post-uprate operation, the design of the pumps was evaluated against predicted required flow plus an allowance for transients.

Low pressure feedwater heaters, deaerator, and deaerator storage tank are designed, fabricated, inspected, tested, and stamped in accordance with the ASME Code, Section VIII, Division 1. (Reference 6) Thermal performance is governed by the Heat Exchange Institute Standards (Reference 7).

The Condensate System, except for the condensate storage tank, is non-nuclear safety class. The condensate storage tank is Safety Class 2b, Seismic Category 1, since it is the primary inventory source for the Emergency Feedwater System.

The condensate storage tank is designed, fabricated, inspected, tested and stamped in accordance with the ASME Code, Section III. (Reference 5) During normal operation the condensate storage tank water level is not permitted to fall below a level corresponding to a usable volume of 160,054 gallons (see section 9.2.6.1). Makeup to the condensate storage tank is demineralized water, admitted through the condenser and condensate storage subsystem. See Section 9.2.6 for a description of condensate storage facilities.

Under transient conditions, the deaerator storage tank serves as an additional source of water for the Feedwater System, providing adequate net positive suction head (NPSH) for the feedwater booster pumps.

System piping and valves are designed in accordance with ANSI B31.1 (Reference 1) and ANSI B16.5 (Reference 2), respectively.

Design parameters of major components in the Condensate System are listed on Table 10.4-4.

10.4.7.1.2 System Description

The Condensate System contains three (3) 50% capacity motor driven condensate pumps, a 50% capacity powdered resin filter/demineralizer cleanup system (see Section 10.4.6), 3 stages of closed low pressure feedwater heaters, associated piping, valves, and instrumentation. The 2 lowest stages of feedwater heaters are located in the condenser neck.

Equipment interfacing with, but not part of, the Condensate System includes the steam packing condenser and steam generator blowdown heat exchangers.

Condensate is pumped from the hotwell storage area, located below the main high pressure condenser, by 2 normally operating condensate pumps through the steam packing condenser. The condenser then passes through two 50% capacity, parallel strings of low pressure heaters to the deaerator and deaerator storage tank.

Condensate pumps are of the 4 stage, vertical can, centrifugal type, and are electric motor-driven. Condensate flow is controlled by the deaerator level control valve which follows the difference between feedwater and condensate flow, trimmed by deaerator level. The pumps are protected from a low flow condition by individual recirculation valves back to the main condenser.

The steam packing condenser is a shell and U-tube type heat exchanger. Condensate passes through the tube side. A manual bypass is provided for maintenance.

Low pressure feedwater heaters are shell and U-tube heat exchangers with 2 heating zones: A condensing zone and an integral drain cooling zone. The three (3) 50% capacity feedwater heaters in each string are bypassed and isolated as a group when necessary. A bypass line is provided for use when 1 heater string is out of service. Turbine load must be adjusted according to the manufacturers instructions when a feedwater heater string is isolated.

The deaerator is of the horizontal, direct contact, tray type. The preheated condensate drops onto the stainless steel trays where it is scrubbed by rising steam. Condensate then passes from the trays to the deaerator storage tank which has a capacity of 75,000 gallons.

Condensate is also supplied to the suction of the exhaust hood spray pumps. These pumps provide hood spray, gland sealing for various valves in vacuum service and seal water for vacuum pumps and feedwater pump seals. A small amount of condensate is used as the coolant for the steam generator blowdown heat exchangers.

10.4.7.1.3 Safety Evaluation

Three (3) 50% capacity condensate pumps are provided. Two (2) of these pumps are normally operated. The third is in standby. Upon the trip of an operating pump, which is annunciated in the control room, the standby pump is started by the operator. No detrimental effect upon the Reactor Coolant System is realized.

System makeup is provided directly from the condensate storage tank to the low pressure condenser shell. Makeup to the condensate storage tank is accomplished by injection of demineralized water to the low pressure condenser shell and thence through the Condensate System to the condensate storage tank.

Sentinel type, tube side relief valves are provided for all closed feedwater heaters. A feedwater heater tube rupture causes high level alarms in the Control Room and initiates automatic valve operation where appropriate. A high-high level alarm on condenser neck heaters initiates turbine trip if the condition exists more than 10 seconds.

Pressure, temperature, or flow deviations due to a malfunction in the Condensate System is not immediately felt by the Reactor Coolant System due to the capacity of the deaerator storage tank and the Feedwater System. The deaerator storage tank allows corrective action, an orderly runback to a compatible load, or shutdown.

10.4.7.1.4 Tests and Inspections

Tests of the Condensate System are limited to that normally provided for non-safety related systems and includes:

1. Hot functional testing. (Historical)
2. Normal, operational checking and routine maintenance of the system.

The closed, low pressure feedwater heaters were subjected to both shell and tube side hydrostatic tests at 150% of the respective design pressures. The shell sides were also tested for vacuum. Alterations to the shells to obtain higher maximum allowable working pressures call for leak tests at system operating conditions.

10.4.7.1.5 Instrumentation Applications

Instrumentation provided for the Condensate System is shown on Figures 10.4-8 and 10.4-11. This instrumentation is provided to permit operator evaluation of major equipment performance and to provide a record of equipment performance. Instrumentation includes the following:

1. Pressure indicators, switches, and test connections.
2. Flow indicators, recorders, switches and test connections.
3. Level indicators, recorders, controllers and switches.
4. Temperature indicators, controllers, switches and test connections.

10.4.7.2 Feedwater System

The Feedwater System is designed to pump feedwater from the deaerator storage tank through 2 stages of high pressure heaters to the steam generators. Thus, heated, deaerated water required to maintain steam generator water level is provided during normal operation, after startup, and before shutdown.

10.4.7.2.1 Design Bases

Design conditions for system piping, valves, and pressure retaining parts are tabulated in the lower left margin of Figures 10.4-10 through 10.4-12.

Feedwater System piping and valve components from and including the feedwater check valves to the steam generators are Safety Class 2a, Seismic Category 1 and are in accordance with ASME Code, Section III (Reference 5), Class 2 requirements. System components upstream of the feedwater check valves in the Intermediate Building, excluding branch lines 2 inches and less, are Quality Related safety class (QR), Seismic Category 1 and satisfy ASME Code, Section III (Reference 5), Code Class 2 requirements; however, are not code stamped. This piping is identified as “Note 1” piping on Figure 10.4-12. Feedwater piping in the Turbine Building is designed in accordance with ANSI B31.1 (Reference 1); valves conform to ANSI B16.5. (Reference 2)

The feedwater booster pumps and feedwater pumps are designed in accordance with the requirements of the Hydraulic Institute Standards. (Reference 9) Original design points for these pumps were selected to satisfy the requirements of the turbine thermal cycle. At the “valve wide open” condition (pre-uprate power), plus a wear margin.

High pressure feedwater heaters are designed, fabricated, inspected, tested, and stamped in accordance with the ASME Code, Section VIII, Division 1. (Reference 6) Thermal performance of these feedwater heaters is governed by Heat Exchange Institute Standards. (Reference 7)

At less than approximately 3% plant load, the Emergency Feedwater System (see Section 10.4.9) is used to maintain steam generator water level. The Main Feedwater System is designed to

overlap the Emergency Feedwater System down to the no load conditions but the Emergency Feedwater System is normally used for conditions such as startup and shutdown.

10.4.7.2.2 System Description

The Feedwater System is divided into nuclear safety class and non-nuclear safety class portions. The nuclear safety class portion, downstream of and including the containment isolation valves, is schematically shown on Figure 10.4-12. Feedwater System parameters are listed on Table 10.4-5.

The non-nuclear safety class portion of the Feedwater System includes four 33-1/3% capacity, constant speed, motor driven, feedwater booster pumps; three 50% capacity, variable speed, turbine driven, feedwater pumps; 2 stages of high pressure heaters; valves, instrumentation, controls; and associated piping. The feedwater booster pumps take suction from the deaerator storage tank and discharge to the feedwater pump suction. The feedwater pumps discharge through 2 strings of high pressure heaters into a single 30 inch diameter header which distributes the feedwater to 3 feedwater flow control valves and/or 3 feedwater bypass control valves. A recirculation line runs from the termination of the 30 inch diameter header near the feedwater flow control valves to the deaerator. This line is equipped with block valves and a pressure breakdown orifice and is used during startup to permit warming of the Feedwater system to and including the 30 inch diameter header.

Feedwater flows from the feedwater flow control valves through individual lines and the feedwater isolation valves to the three steam generators.

The feedwater booster pumps are horizontal, split case, single stage and centrifugal pumps. They are motor driven at a constant speed of 1780 rpm. Minimum recirculation flow is bypassed to the deaerator storage tank, as required. Normally, 2 feedwater booster pumps operate at low load; three or four at intermediate or full load. Feedwater booster pumps provide the necessary flow and suction pressure for the feedwater pumps.

Steam is supplied to the deaerator storage tank through a sparger during initial stages of Feedwater System warmup. This is followed by admission of pegging steam to the deaerator to complete Feedwater System warmup.

The feedwater pumps are horizontal, split case, single stage, double suction, and diffuser pumps. The speed of the variable speed turbine drive is varied and the feedwater flow control valves adjusted to maintain water levels in each steam generator. In general, 2 feedwater pumps are operated at low or intermediate loads. Three (3) feedwater pumps are operated at full load. Feedwater pumps are protected by minimum flow, recirculation lines to the deaerator storage tank.

High pressure feedwater heaters are shell and U-tube type heat exchangers with 2 heating zones: a condensing zone and an integral drain cooling zone. The two 50% capacity feedwater heaters in each string are manually bypassed and isolated as a group to remove the string from service if necessary. Turbine load must be adjusted according to the manufacturer’s instructions when a feedwater heater string is isolated.

10.4.7.2.3 Safety Evaluation

1. General

If it becomes necessary to remove a feedwater booster pump or feedwater pump from service due to malfunction or failure or for maintenance, plant loads are reduced in accordance with a predetermined operating scheme. When the normal operating schemes are followed, the Feedwater System provides satisfactory service under plant operating conditions.

Reactor runback is minimized and reactor trip is avoided following loss of any 1 feedwater or feedwater booster pump from the normal operating scheme. It is possible to operate the Feedwater System beyond the normal operating scheme for short periods of time. Following the loss of any 1 operating feedwater booster pump or feedwater pumps, a power reduction may be necessary to prevent reactor trip due to low water level in the steam generators. Reactor trip is prevented when maximum pumping scheme capability satisfies or exceeds feedwater flow requirements at the time a pump is lost from service. The feedwater pumps and drive turbines may be operated at runout capacity temporarily, but extended off-design point operating results in drive turbine efficiency loss. The feedwater booster pumps may be operated up to their horsepower limits for extended periods of time without detrimental effects.

If a feedwater piping break should occur in the Intermediate Building, alarm and control devices act to prevent flooding of safety-related equipment on the floors. Section 7.6 outlines the details of provisions for leak detection. Pipe break is discussed in Sections 3.6 and 15.4.2. As noted in Section 10.4.7.2.1, feedwater piping in the Intermediate Building, excluding branch lines, satisfies the requirements, except for stamping, of the ASME Code, Section III (Reference 5), Code Class 2, to provide greater assurance of piping system integrity and to minimize the potential for postulated pipe rupture.

The feedwater isolation valves are designed to close within 5 seconds after receipt of a closure signal to provide containment isolation in the event of a feedwater line break either inside or outside the Reactor Building. These valves have relief valves installed to prevent pressure locking due to thermal expansion of fluid trapped between the double-disc gate following closure. These valves are designed with safety related air accumulators and fail as is upon loss of control air and to close upon loss of channel A electric power. Valve status is indicated by lights on the main control board and is monitored by the plant computer. Any of the following signals initiate closure:

a. Feedwater isolation signal (channel A only, see Table 6.2-54 signal D for initiating conditions).
b. High-high Intermediate Building sump level switches energized (see Section 7.6 for initiating conditions, channel A only).
c. Intentionally left blank by RN 00-082 in Amendment 02-01.
d. Intentionally left blank by Amendment 96-03.

e. Intentionally left blank by RN 00-082 in Amendment 02-01.

f. Manual switch train A in the control room.

The recommendations of the NSSS vendor are followed in routing of feedwater piping to minimize flow instabilities in the Feedwater System.

Standard industry safety precautions are observed in the handling of feedwater chemicals.

Table 10.4-6 presents a Feedwater System failure analysis.

10.4.7.2.4 Tests and Inspections

1. Operability Test for Containment Isolation Valves

   The containment isolation valves are subjected to periodic operability tests in accordance with the applicable ASME Code, prescribed under 10CFR50.55a.

   There are 3 containment isolation valves in this system: three (3) on the main feedwater line. These valves are tested for operability by complete closure and opening during plant shutdown.

2. System Tests

   Major equipment is periodically inspected to ensure proper conditions and operation. Additional testing includes:

   a. Hydrostatic testing of safety class system piping and equipment following construction and prior to placing the system in service.

   b. Hot functional testing subsequent to cold hydrostatic testing.

   c. Normal, operational checking, and routine maintenance of the system.

Inservice inspection of safety class portions of the system is performed in accordance with the ASME Code, Section XI (Reference 8), requirements.

10.4.7.2.5 Instrumentation Applications

Instrumentation for the Feedwater System is shown schematically by Figures 10.4-10 through 10.4-12. The following instrumentation is supplied for the non-nuclear safety class portion of the system to permit operator evaluation of major equipment performance and to provide a performance record:

1. Pressure indicators, switches, and test connections.
2. Flow indicators, controllers, and test connections.
3. Level switches.

4. Temperature indicators and test connections.

In the nuclear safety class portion of the system, instrumentation to permit monitoring of the temperature of feedwater entering the steam generators is provided. Instrumentation associated with the development of control signals for the containment isolation valves is provided in Section 7.3 and Table 6.2-54.

10.4.8 Steam Generator Blowdown System

10.4.8.1 Design Bases

10.4.8.1.1 General

The Steam Generator Blowdown System continuously purges the steam generators of concentrated impurities, thereby maintaining secondary side steam generator water chemistry. The Nuclear Blowdown Processing System is used to process cooled steam generator blowdown fluid and return decontaminated water to the secondary cycle. The steam generator wet layup system skid provides forced circulation of the steam generator secondary side water inventory during cold shutdown conditions.

Steam generator blowdown fluid can be directed to any 1 of the following:

1. Nuclear Blowdown Processing System.
2. Circulating water discharge.
3. Alum sludge lagoon.

Steam generator blowdown fluid is normally directed to the Nuclear Blowdown Processing System or the circulating water discharge. During plant startup, steam generator blowdown fluid may be directed to the alum sludge lagoon for reduction of suspended solids content prior to discharge. Radiation monitoring controls divert steam generator blowdown fluid to the Nuclear Blowdown Processing System upon detection of radioactivity in the fluid, thus limiting release of radioactivity to the environment.

The ATWS (Anticipated Transient Without Scram) Mitigation System Actuation Circuitry (AMSAC) isolates steam generator blowdown when 2 of 3 steam generators are at low-low level.

During cold shutdown and refueling, the steam generator wet layup system skid may be attached between the blowdown and Emergency Feedwater Systems. The skid circulates water through the steam generators to provide improved mixing and less severe concentration gradients to mitigate steam generator fouling and corrosion.

10.4.8.1.2 Thermal

Blowdown fluid from each steam generator is directed to a separate heat exchanger for heat recovery. A portion of the condensate flow serves as the cooling fluid in these heat exchangers. The heat exchangers are designed to cool the steam generator blowdown fluid to 120°F.

10.4.8.1.3 Secondary Side Contaminants

Impurities associated with the secondary cycle include:

1. Dissolved amines and an oxygen scavenger, introduced for control of feedwater pH and oxygen.
2. Ammonium chloride for molar ration control if required.
3. Boric acid for mitigation of steam generator tube denting if required.
4. Impurities associated with condenser leakage.
5. Ingress from the demineralized water system and/or the water treatment plant.

10.4.8.1.4 Primary Side Contaminants

Impurities associated with the Reactor Coolant System may enter the steam generator secondary side should steam generator tube leakage occur. Such impurities include radioactive and nonradioactive particulate and dissolved material.

10.4.8.1.5 Operating Parameters

1. Total Blowdown Flow
   a. Minimum flow - 30 gpm.
   b. Normal flow - as required to maintain secondary side water chemistry.
   c. Design flow - 1.0% of main steam flow (nominally 250 gpm).
   d. Cold shutdown on steam generator wet layup system - 100 gpm (nominal flow).
2. Water Chemistry of Steam Generator Blowdown Fluid

   Blowdown flow from each steam generator aids in maintaining secondary side water chemistry specifications. The controlling parameters include pH, cation conductivity, sodium, chloride and sulfate.

3. Steam Generator Tube Leakage

   For purposes of radioactive release determinations, a primary to secondary leakage rate of 100 lb/day and 0.12% failed fuel is used. The leakage rate is derived from NUREG-0017 (Reference 3).

For the design of equipment, a primary to secondary leakage rate of 0.1 gpm (1195 lb/day) under standard conditions is assumed. Major contaminants considered include boron and lithium with primary coolant concentrations of 1000 ppm and 2 ppm, respectively.

10.4.8.1.6 Codes and Standards

The Steam Generator Blowdown System is non-nuclear safety class and quality related class, except for that portion inside the Reactor Building and up to the containment isolation valve which is Safety Class 2a, Seismic Category 1. Safety class and quality related class piping is designed in accordance with the ASME Code, Section III (Reference 5), Class 2. Non-nuclear safety class piping is designed in accordance with ANSI B31.1 (Reference 1). Equipment classification is presented in Table 3.2-1.

10.4.8.2 System Description

The Steam Generator Blowdown System is illustrated by Figure 10.4-13. Individually regulated blowdown from each steam generator is cooled and reduced in pressure prior to combination with other blowdown streams. The total blowdown is then processed through the Nuclear Blowdown Processing System or is routed into the circulating water discharge and thence to Monticello Reservoir.

The Nuclear Blowdown Processing System is illustrated by Figures 10.4-14 and 10.4-15. Should blowdown activity exceed preset levels, the blowdown flow is automatically diverted to the nuclear blowdown holdup tank. One (1) of 2 nuclear blowdown holdup tank pumps then takes suction from the holdup tank and delivers the fluid through a filter, 2 demineralizers in series, and a post filter from which it returns to the secondary cycle through the main condenser (an alternate path being to the penstocks of the Fairfield Pumped Storage Facility [see Figure 10.4-17] during operation of that facility in the generation mode).

The Nuclear Blowdown Processing System includes a sluicing pump and spent resin storage tank for transfer and storage of exhausted demineralizer resin. Processing of solid waste is accomplished by the Solid Waste Disposal System (see Section 11.5).

10.4.8.2.1 Component Description

The general arrangement of system equipment is shown by Figures 1.2-5 and 1.2-6. Design parameters for major components are presented in Table 10.4-7. Major components of the Steam Generator Blowdown System include:

1. Radiation Monitors

   Radiation monitoring equipment is located to sample continuously the total Steam Generator Blowdown and Nuclear Blowdown Processing System demineralizer effluent. Section 11.4 describes radiation monitoring equipment in detail.

2. Steam Generator Blowdown System Heat Exchangers

Each of the 3 Steam Generator Blowdown System heat exchangers consist of 2 shell and tube vessels in series, designed to cool the steam generator blowdown fluid with condensate.

3. Nuclear Blowdown Holdup Tank

   The nuclear blowdown holdup tank retains potentially radioactive steam generator blowdown fluid for processing.

4. Nuclear Blowdown Monitor Tank

   The nuclear blowdown monitor tank is similar in design to the nuclear blowdown holdup tank. This tank provides additional holdup capacity, if required, as well as the capability for periodic effluent sampling.

5. Nuclear Blowdown Holdup Tank Pumps

   Two (2) 100% capacity, centrifugal, nuclear blowdown holdup tank pumps are provided. These pumps take suction from the nuclear blowdown holdup tank and discharge through the filter, demineralizers, and post filter.

6. Nuclear Blowdown Monitor Tank Pump

   A single, canned motor pump is provided. This pump takes suction from the nuclear blowdown monitor tank and discharges to the nuclear blowdown holdup tank or recirculates the monitor tank contents through the post filter.

7. Nuclear Blowdown Demineralizer Inlet Filter

   This inlet filter removes particulate matter from the holdup tank fluid upstream of the demineralizers, thus protecting against resin fouling and premature capacity loss. The filter is a disposable cartridge type. Pressure drop indication and an alarm are provided to alert the operator that filter media replacement is required. Since the filter is potentially radioactive, shielding is provided for personnel protection. Radiological controls to reduce personnel exposure are implemented during spent filter cartridge removal and transportation to the drumming station.

8. Nuclear Blowdown Demineralizer Discharge Filter

   This post filter traps and retains degraded or crushed resin particles which may pass through the demineralizers during normal operation. Design of this filter and radiation protection considerations are similar to those for the nuclear blowdown inlet filter.

9. Nuclear Blowdown Sluice Filter

   The sluice filter is located on the discharge side of the resin sluice pump. Its function is similar to that described for the nuclear blowdown demineralizer discharge filter.

10. Nuclear Blowdown Demineralizers

    Four (4) ion exchange vessels, arranged for 2 step demineralization with 100% standby capacity, are provided. This arrangement assures the capability for continuous removal of radionuclides as well as high effluent purity. Operation of each demineralizer is on a nonregenerable basis. Resin is removed and replaced as dictated by chemical analysis or radioactivity measurements.

11. Nuclear Blowdown Spent Resin Storage Tank

    The nuclear blowdown spent resin storage tank is provided to permit recycling of resin sluice water, storage of spent demineralizer resin, and transfer of spent resin to the drumming station.

12. Nuclear Blowdown Resin Sluice Pump

    The nuclear blowdown resin sluice pump is used to loosen resin in and transfer resin from nuclear blowdown demineralizers.

13. Steam Generator Wet Layup System Skid

    The Steam Generator Wet Layup System Skid consists of a pump, two 100% filters in parallel, valves, connectors, flexible hoses, and a skid-mounted motor control center. When used, during cold shutdown conditions, the pump suction is connected by flexible hose to the blowdown system and the discharge is similarly connected to the Emergency Feedwater System.

10.4.8.2.2 System Operation

System operations are divided into three categories, as follows:

1. Normal Operation

   During normal plant operation, steam generator blowdown is continuous to maintain secondary side steam generator water chemistry within the limits recommended by the Nuclear Steam Supply System (NSSS) vendor. Blowdown is normally directed to the Nuclear Blowdown Processing System or to the circulating water discharge after passing through the steam generator blowdown heat exchangers.

   The combined blowdown from the 3 steam generators is continuously sampled and analyzed for radioactivity. Should the activity level reach a pre-established setpoint, the discharge paths are automatically isolated and the total blowdown flow is automatically diverted to the nuclear blowdown holdup tank.

Low specific activity effluent resulting predominately from continuous steam generator blowdown sampling may be processed from the nuclear blowdown holdup tank to the main condenser or Turbine Building sump. When high radiation setpoint is reached for RM-L3 or RM-L10 and steam generator blowdown has been diverted to the holdup tank, the process pathway to the Turbine Building sump is terminated. The contents of the nuclear blowdown holdup tank are periodically analyzed for radioactivity and chemical contamination.

2. Special or Infrequent Operation

   As discussed in 1, above, blowdown radioactivity levels in excess of a

   pre-established setpoint (as sensed by RM-L3 and RM-L10) result in automatic diversion of blowdown flow to the nuclear blowdown holdup tank. Under such conditions, samples from each steam generator blowdown stream are analyzed to determine the source of the radioactivity. Once the source has been determined, the blowdown from the affected steam generator may be processed separately while blowdown from the remaining steam generators may continue to be discharged. If the faulty steam generator cannot be satisfactorily isolated, total blowdown flow continues to be directed to the nuclear blowdown holdup tank.

   A nuclear blowdown holdup tank pump starts at a preset holdup tank level to deliver tank contents to the inlet filter, demineralizers, post filter and thence to the main condenser. Detection of abnormally high activity by RM-L7 downstream of the post filter results in automatic termination of flow to the condenser or through the alternate path to the penstocks of the Fairfield Pump Storage Facility. This flow is then directed to the nuclear blowdown monitor tank.

3. Startup

   During plant startup and subsequent restarts, steam generator blowdown, up to the design flow rate, is used for removal of accumulated deposits from the steam generators and to bring steam generator water chemistry within recommended limits. The cooled steam generator blowdown fluid may be discharged through the circulating water discharge to Monticello Reservoir.

   During these operations, however, the steam generator blowdown fluid may contain high concentrations of corrosion products in the form of iron oxides. Should the concentrations of these impurities exceed acceptable limits, the blowdown fluid is routed to the alum sludge lagoon through the clarifier blowdown sump for reduction of suspended solids content prior to discharge.

4. Cold Shutdown and Refueling

   During cold shutdown and refueling the steam generator wet layup system skid may be attached, by flexible hoses, between the blowdown system and the Emergency Feedwater System. The skid takes suction from blowdown and returns water to the steam generators via the turbine-driven emergency feedwater pump header.

The Steam Generator Wet Layup System may be used only during modes 5 and 6. It must be isolated and disconnected before entering mode 4.

The blowdown and Emergency Feedwater System valves may be used to direct wet layup recirculation to any of the three steam generators, allowing one or more to be maintained in layup with one or more others open for maintenance.

Operation of the steam generator wet layup skid equipment is local and manual.

10.4.8.2.3 Radiological Considerations

Annual release quantities and expected doses to individuals at or beyond the site boundary are discussed in Section 11.2. Since heat exchangers are installed in the system to provide for cooling the blowdown fluid and to prevent flashing, negligible gaseous release is expected to result from this system. Process and effluent monitoring and sampling are discussed in Section 11.4.

10.4.8.3 Safety Evaluation

Steam generator blowdown flow is automatically terminated under the following conditions:

1. Receipt of a containment isolation signal.
2. Activation of the Emergency Feedwater System.

For 1, above, a containment isolation signal (S signal) is received which closes the steam generator blowdown containment isolation valves. For 2, above, a signal indicating emergency feedwater pump start is received resulting in closure of the steam generator blowdown containment isolation valves. The closure of valves resulting from 2, above, may be manually overridden, provided that plant and personnel safety requirements have been satisfied.

The Steam Generator Blowdown System is non-nuclear safety class and quality related class, except for that portion of the system inside the Reactor Building and up to the containment isolation valve, and is not required to function under accident conditions. Termination of steam generator blowdown may be accomplished manually. If the Nuclear Blowdown Processing System is operating at the time steam generator blowdown is terminated, the nuclear blowdown holdup tank level controller stops the pump when holdup tank level reaches the low level setpoint. Thus, the system is isolated.

Section 10.3.5 provides more detail concerning secondary side water chemistry.

Safety considerations directly associated with the steam generators are discussed in Section 5.5.2.

Since radioactive materials are concentrated in filters and demineralizers, radiation shielding is provided to protect personnel from these potential hazards.

10.4.8.4 Tests and Inspections

Steam generator tests and inspections are discussed in Section 5.5.2. No special maintenance is required for Steam Generator Blowdown System components. Equipment and piping is periodically subjected to visual examination for evidence of leakage, corrosion, proper support bolting, wear points, and electrical arcing or burning. Active components, including manual valves and controls are operated periodically to ensure availability when required.

10.4.8.5 Instrumentation Applications

The following instrumentation is shown schematically on Figures 10.4-13 through 10.4-15 and is provided to permit the operator to evaluate major equipment performance and to provide a performance record:

1. Pressure indicators, transmitters, and switches.
2. Flow indicators, controllers, recorders, switches, and transmitters.
3. Level indicators, transmitters, controllers, and switches.
4. Temperature indicators, controllers, and switches.
5. Conductivity analyzers, indicators, and switches.
6. Analyzers, indicators, and switches for pH.
7. Engineered safety features monitor lights, located on the main control board, for the containment isolation valves (see Section 7.5 for detailed description).
8. Radiation monitors.

10.4.8.5.1 Temperature Control

Steam generator blowdown temperature reduction is controlled by regulating the cooling water flow through the heat exchangers. The blowdown temperature is controlled below saturation to preclude flashing.

Temperature protection is provided for the demineralizers by a temperature switch located on the discharge header of the blowdown holdup tank transfer pumps. At high temperature, an alarm is actuated and the demineralizer inlet valves are automatically closed.

Additional temperature switches actuate alarms upon detection of high blowdown heat exchanger effluent temperature.

10.4.8.5.2 Flow Control

The hydraulic design of the blowdown piping provides for minimal pressure drop up to the blowdown control valves, downstream of the respective heat exchangers. Each blowdown control valve is designed to regulate blowdown flow and thus maintains a relatively constant downstream pressure of approximately 40 psig.

Flow indicating transmitters provide electronic inputs for high and low blowdown flow and blowdown flow control valve closure upon detection of high flow and to a controller to regulate blowdown pressure control valves: Electronic hand controllers are provided to permit adjustment of individual blowdown flows through the respective flow control valves.

10.4.8.5.3 Level Control

The blowdown holdup tank level transmitter provides an electronic input for high and low level alarms, dual level pump actuation and low level pump trip.

The monitor tank level transmitter provides an electronic input for high and low level alarms, low level pump trip, and low level closure of the tank discharge valve.

The spent resin storage tank level transmitter provides an electronic input for high and low level alarms and low level pump trip.

10.4.9 Emergency Feedwater System

10.4.9.1 Design Bases

The Emergency Feedwater System is required to deliver sufficient feedwater to the steam generators for cooldown upon loss of the normal feedwater supply and during a ATWS (Anticipated Transient Without Scram) event. The Emergency Feedwater System is used, additionally, to supply feedwater to the steam generators during startup, shutdown, and layup operations. Emergency feedwater pump starting is automatic. The Emergency Feedwater System operates in conjunction with the Turbine Bypass System, if available, or the main steam power relief valves and safety valves, to remove thermal energy from the steam generators.

The system is designed to automatically deliver feedwater, at a minimum total flow of 380 gpm, to at least 2 steam generators pressurized to 1211 psig. There is sufficient redundancy to establish this flow while sustaining a single active failure in the system in the short term or a single active or passive failure in the long term. The Emergency Feedwater System operates until the Residual Heat Removal (RHR) System can be placed in operation. The RHR system is started when reactor coolant pressure and temperature are approximately 400 psig and less than 350°F, respectively. Corresponding steam generator shell side pressure is approximately 125 psia. This pressure and temperature condition represents the lower limit of Emergency Feedwater System functional requirements as long as the reactor coolant pumps are operating.

When forced circulation from the reactor coolant pumps is not available, Emergency Feedwater System operation is required down to a main steam pressure of 100 psia. This corresponds to a reactor coolant cold leg temperature of 325°F and a hot leg temperature of 350°F. The primary coolant temperature differential is required in order to maintain a density gradient to drive natural circulation of primary coolant, in the absence of reactor coolant pump operation.

Sufficient feedwater is available under emergency conditions to bring the plant to a safe shutdown condition. Assuming prior plant operation at engineered safety design rating (ESDR) of 2900

MWt in the core, the minimum required usable volume for the condensate storage tank is 158,570 gallons based on maintaining the plant at hot standby conditions for 11 hours. This volume also satisfies the minimum required volume to cool down the plant to hot shutdown conditions assuming the plant is maintained at hot standby for 2 hours and then cooled down to hot shutdown in 4 hours.

The condensate storage tank is a Safety Class 2b tank. The Service Water System provides an additional safety class backup source of emergency feedwater. Both service water loops can supply the Emergency Feedwater System if required.

System components are classified Safety Class 2a or 2b, except as noted on the system diagram, Figure 10.4-16. Pressure retaining components are designed, fabricated, tested and inspected in accordance with the ASME Code, Section III (Reference 5), Classes 2 and 3 as applicable. Normal operating and design conditions are tabulated on Figure 10.4-16. Design upset condition is considered to be the shutoff head of the pumps and is expected to occur less than 1% of the time.

Any two emergency feedwater pumps operating together are designed to deliver a total of 380 gpm of feedwater distributed between 2 steam intact generators at pressures of 1211 psig, while also feeding the faulted steam generator which has flow passively limited by the cavitating venturi in the faulted loop. Any one emergency feedwater pump is designed to deliver 400 gpm total to all three steam generators at a pressure of 1211 psig during the non-faulted event. Pump suction is from the Safety Class 2b condensate storage tank, or, if this source is not available, from the Service Water System. Although the condensate storage tank is used for normal plant makeup, a reserve is maintained for emergency feedwater purposes. (See Section 9.2.6.1).

This reserve is 160,054 gallons, based on the physical configuration of the tank from the bottom of the condensate to condenser nozzle to the top of the emergency feedwater suction nozzle. The actual usable amount of this reserve, however, is dependent on the instrument setpoints of the automatic switchover controls to the backup Service Water supply.

The design, with automatic switchover to Service Water occurring prior to full utilization of the dedicated inventory, satisfies safe shutdown requirements. It is considered that full utilization of the dedicated inventory of condensate quality water is highly desirable from a commercial risk viewpoint, but is not absolutely required for safe shutdown as long as a redundant safety class alternate source is available.

The Emergency Feedwater System is required for plant startup. Fill and maintenance of steam generator water level is accomplished by manual control of feedwater flow rates from the Control Room. The flow rate to each steam generator is individually adjusted as required in response to the Control Room steam generator water level indication. After normal steam generator water level is reached, flow rates are adjusted as required. A sampling connection is supplied on the electric motor driven emergency feedwater pump recirculation lines for oxygen level tests.

After reactor criticality is achieved, a limited amount of steam may be withdrawn from the steam generators for steam line warmup and other startup steam uses. The amount of steam that may be

withdrawn is limited to the ability of the emergency feedwater pumps to maintain steam generator water level. Electric motor driven emergency feedwater pump head/flow characteristics result in flow rates of up to approximately 255 gpm per steam generator at hot standby conditions. Based on a nominal steam generator blowdown rate of 50 gpm per steam generator, (equivalent cold volume) approximately 307,488 lb/hr of steam may be withdrawn from the steam generators with 2 motor driven pumps operating. This corresponds to a nominal 3% plant load condition. The Main Feedwater System must be operated at loads which exceed the capacity of the Emergency Feedwater System.

If a loss of steam generator water level incident occurs during startup, after the reactor becomes critical, Emergency Feedwater System controls operate automatically. This action enhances proper system operation for plant shutdown.

Seismic and quality group classifications for components in this system are discussed in detail in Section 3.2. Environmental conditions are discussed in Section 3.11.

10.4.9.2 System Description

The Emergency Feedwater System includes 2 electric motor driven emergency feedwater pumps, 1 turbine driven emergency feedwater pump, the condensate storage tank, necessary piping, valves, instrumentation, and controls. The Emergency Feedwater System is essential to safety. The system is designed such that no single failure prevents delivery of the minimum feedwater flow to at least 2 steam generators while passively limiting flow to a postulated secondary side line break by virtue of cavitating venturis installed in the piping to each of the three steam generators (one cavitating venturi per steam generator). Pump and turbine bearings are cooled by the pumped emergency feedwater, thereby making pump operation independent of plant cooling systems. The quick start, steam turbine driven emergency feedwater pump is supplied with steam from the Main Steam System and is designed to operate without air or electrical power. Both motor driven emergency feedwater pumps are provided with a mechanical-type, automatic recirculation control valves (ARC), which provides for pump protection for low flows and maximizes flow to the steam generators by automatically closing the recirculation line once the pumps' minimum flow requirement is met. Conversely, the turbine driven pump utilizes a fixed-restriction minimum-flow system, which provides for continuous recirculation and overall system diversity; this fixed recirculation flow design feature is made possible due to the performance margins inherent in the turbine driven pump.

Each pump motor is supplied from a separate, independent Class 1E electric system bus. Complete physical separation is followed throughout for control and instrumentation systems. The required instrumentation and control are powered from separate and independent vital buses.

The steam supply to the turbine driven emergency feedwater pump consists of connections to the safety class sections of 2 main steam lines upstream of the main steam isolation valves. Two (2) connections are provided to obtain redundancy of supply in the event of a main steam line break. Each connection is provided with a remote manual motor operated gate valve and a check valve for positive isolation in the event of a main steam break. In the common line to the pump turbine, a normally closed, fail open steam inlet valve is provided. This valve has slow opening

characteristics to minimize shock to the turbine during automatic startup. This line then connects to a turbine trip and throttle valve which is part of the turbine package. The turbine discharge steam exhausts to atmosphere through a roof vent. Vent piping is safety-related since, if it were blocked, pump turbine operation would be affected.

The emergency feedwater pumps take suction from the condensate storage tank. There is an outlet valve and an outlet bypass valve in parallel at the EFW suction outlet in the tank. These valves are 10 inch manual valves feeding the 10 inch header and are locked open to prevent undesired isolation of the EFW system from its primary supply of water. Each pump draws from a common header through a locked open isolation valve and a check valve. The redundant backup source of supply is the Service Water System. The A service water loop can supply the A electric motor drive emergency feedwater pump and the turbine driven emergency feedwater pump. The B service water loop can also supply the turbine drive emergency feedwater pump and the B electric motor driven emergency feedwater pump. Suction lines to each pump from each service water loop have normally closed remote manual, motor operated isolation valves. These valves are automatically opened on low pressure in the emergency feedwater pump suction header from the condensate storage tank. The plant can operate indefinitely, if required, without normal feedwater. The Emergency Feedwater System can take suction from the Service Water System for an indefinite period of time.

There are 2 emergency feedwater headers supplying each steam generator, 1 header from the electric motor driven emergency feedwater pumps and one header from the turbine driven emergency feedwater pump. These headers join downstream of the flow control valves into one line for each steam generator. Each of the three parallel lines proceed through, a flow-limiting cavitating venturi, a containment isolation valve and a containment penetration to its respective steam generator. The containment isolation valve for each line is an air-piston assisted, hinged check valve that allows forward passage of emergency feedwater flow but closes to prevent reverse flow.

Each emergency feedwater pump discharge is provided with a check valve and locally operated isolation valve. These valves prevent backflow through an emergency feedwater pump and permit maintenance of a pump and/or check valve. Two (2) sets of normally open isolation valves and normally open, pneumatically operated, flow control valves, designed to fail open upon loss of control signal or air, are provided on each line to each steam generator. One (1) set control flow from the electric motor driven emergency feedwater pumps; the other, flow from the turbine driven emergency feedwater pump. Remote manual control of the flow control valves from the control room and CREP is provided, as well as provision for local manual operation. Safety class air accumulators are provided for the pneumatically operated valves. These accumulators have sufficient capacity to permit remote valve closure for isolation of a secondary system break. The air operated nonreturn valve functions as a containment isolation valve to prevent back flow in the event of a pipe break on the pump side of the valve.

A connection is provided for steam generator wet layup during cold shutdown conditions, using the steam generator wet layup skid of the blowdown system. (Section 10.4.8)

The EF system also has an automatic detection and isolation system in the event of an EF system pipe break between the automatic isolation valves and the cativating venturis.

10.4.9.3 Safety Evaluation

Normal Emergency Feedwater System conditions encompass the automatic, startup, operating, shutdown and testing modes. During the automatic mode, the system is aligned and set for automatic startup upon receipt of a signal. During the other modes 1 or 2 emergency feedwater pumps may be operating.

During normal plant operation the Emergency Feedwater System is idle. Controls for the system are set for automatic operation to allow for quick system start if necessary. The electric motor driven emergency feedwater pumps start automatically upon receipt of any of the following signals:

1. Two (2) out of 3 low-low steam generator level signals from any 1 of the 3 steam generators.
2. Trip of all 3 main feedwater pumps.
3. Engineered safety features loading sequence (under voltage on 1E bus and/or safety injection signal).
4. The ATWS (Anticipated Transient Without Scram) Mitigation System Actuation Circuitry (AMSAC) starts the motor driven pumps on low-low level in 2 out of 3 steam generators.

The turbine driven emergency feedwater pump starts automatically upon receipt of any of the following signals:

1. Two (2) out of 3 low-low steam generator level signals from any 2 steam generators.
2. Under voltage on diesel buses.
3. The ATWS (Anticipated Transient Without Scram) Mitigation System Actuation Circuitry (AMSAC) starts the turbine driven pump on low-low level in 2 out of 3 steam generators.

The turbine driven emergency feedwater pump and the parts of the system necessary for its operation are designed to operate under loss of electrical power and loss of compressed air conditions. Flow control valves fail in the open position and are normally open. Root valves in the main steam branch lines to the emergency feedwater pump drive turbine are left open during normal plant operations. When either root valve is closed, it is annunciated in the control room.

The essential controls, valve operators, and other supporting systems associated with the turbine driven emergency feedwater pump are independent from a-c power. The lube oil cooler receives cooling water from the pump discharge.

Subsequent to a start signal, the Emergency Feedwater System, automatically delivers no less than a total flow of 380 gpm to both intact steam generators assuming a secondary line break. For non-faulted conditions no less than a total of 400 gpm to all three steam generators can be supplied. In the event that a secondary break results in a depressurized steam generator, the

Emergency Feedwater System automatically (passively) limits the flow to the affected steam generator via cavitating venturis, thus resulting in more flow to the intact steam generators and less to the faulted steam generator. Also, since flow is immediately limited to the faulted steam generator, less mass and energy will be produced by the faulted steam generator before operator action is required to manually isolate the faulted steam generator. Thus, the cavitating venturis ensure sufficient flow is directed to the intact steam generators and limits flow to the faulted steam generator to ensure the design pressure of containment is not exceeded. Following an automatic startup signal, the operator adjusts flow rates to maintain steam generator water level while the plant is shut down or held at the hot standby condition.

The following operator actions are required to limit generation of mass and energy from the faulted steam generator following a secondary side break:

After 10 minutes:

1. Determine which steam generator is faulted.
2. Manually terminate emergency feedwater flow on the line associated with the break from the control room if possible by closing both parallel flow-control valves leading to the faulted steam generator.
3. Adjust flow rates to maintain intact steam generator water levels.
4. Monitor condensate storage tank water level and provide makeup, if available, or shift alignment to the service water supply before the condensate storage tank inventory is expended.

Within the next 20 minutes:

1. Close any flow control valve supplying a faulted steam generator if it failed to close after the first 10 minutes, from the control room or locally.
2. Close at least one additional isolation valve in series with each of the two, closed, parallel flow-control valves leading to the faulted steam generator to reduce the possibility of emergency feedwater leak-by.

During the 30 minute period, flow to the affected steam generator is limited by the cavitating venturi, if one or both isolation valves failed to close from the control room.

It is important to note that to ensure acceptable results from the feedwater line break event (FSAR Section 15.4.2.2), the manual actions described above are not required; the above described actions are only concerned with containment pressure-and temperature analysis and for determination of environmental conditions due to steam line breaks outside of containment.

The operator in the Control Room is provided with position indication for the six emergency feedwater isolation valves. In addition, isolation valve status is included in the ESF monitoring equipment on the main control board.

A summary failure analysis of the Emergency Feedwater System is presented by Table 10.4-8 for a secondary pipe break with a simultaneous loss of non-class 1E electrical power. A more detailed failure analysis, covering deterministic and probabilistic considerations, is documented in design calculations maintained by the PRA group.

Failure to automatically isolate emergency feedwater to the affected SG is an important consideration within two secondary pipe break analyses. For secondary side pipe breaks inside containment (FSAR Section 6.2), operator action at 30 minutes is credited to isolate emergency feedwater to the affected SG. Local or remote operator action within 30 minutes is required to prevent overpressurizing the containment. Secondly, for secondary side pipe breaks outside containment (FSAR Section 3.11.2.2.2.2), credit is taken for operator action at 10 minutes to isolate emergency feedwater to the affected SG. Since the harsh environment will limit local manual actions, operator action from the control room is required for secondary pipe breaks outside containment to preserve environment conditions for equipment qualification.

Operator action is required within 24 hours after the secondary side line break to visually inspect Emergency Feedwater System piping for passive failure.

If a pipe break should occur in the Intermediate Building, alarm and control devices act to prevent flooding at safety-related equipment on the floors. Section 7.6.5.1.2 outlines the details of the provisions for leak detection.

The Emergency Feedwater System is used to bring the plant to a sufficiently cold condition to permit Residual Heat Removal (RHR) System operation. The plant can operate indefinitely, if required, without normal feedwater. The Emergency Feedwater System can take suction from the Service Water System for an indefinite period.

Table 10.4-8 presents an Emergency Feedwater System failure analysis which addresses the consequences of various single active failures within the system in conjunction with a secondary side pipe break and a simultaneous loss of non-Class 1E electrical power. These conditions are considered to establish the limiting conditions for Emergency Feedwater System design. In addition, the emergency feedwater piping has been laid out to minimize water hammer occurrences induced by the piping system.

10.4.9.4 Inspection and Testing Requirements

Inservice functional testing is performed by manual startup of the emergency feedwater pumps. Pumps and valves may be tested while the plant is in operation.

The actuation circuitry of the service water-to-emergency feedwater cross connect valves is periodically tested during normal power operations. Stroke testing of these motor-operated valves is performed during cold shutdown to preclude contamination of the steam generators.

To avoid injection of cold water into the steam generators during normal plant operation, the flow control valves associated with the pump under test (motor driven or turbine driven) are closed during the test.

Periodic system and component checks and inspections are performed as specified by the applicable ASME Code, prescribed under 10CFR50.55a.

10.4.9.5 Instrumentation Requirements

Emergency Feedwater System instrumentation provides the necessary inputs for control, operation, and performance/status monitoring of the system.

Those devices (indicators, switches, alarms, computer monitoring, etc.) available to the operator in the Control Room are shown schematically on Figure 10.4-16. In addition, indicators and/or controls are also located on the control room evacuation panel, local panels, and near the components.

10.4.9.5.1 Pressure Measurement

1. Pressure Transmitters

   Pressure transmitters are provided in the common feed line to each steam generator for control room indication.

   In addition to the above pressure transmitters, 4 pressure transmitters are provided in the emergency feedwater pump suction header from the condensate storage tank. The output from these transmitters is arranged in a 2 out of 4 logic to automatically open the cross connect valves to the Service Water System (XVG-1037A-EF, XVG-1037B-EF, XVG-1001A-EF, XVG-1001B-EF, XVG-1002-EF, XVG-1008-EF) on low emergency feedwater pump suction header pressure.

2. Pressure Switches

   Pressure switches located in the suction line to each pump provide contacts for a low pressure alarm.

3. Pressure Indicators

   Pressure indicators are provided to monitor the availability of a water supply for each pump and to meet the inservice testing requirements for the pumps.

10.4.9.5.2 Level Measurement

Level Transmitters

Redundant level transmitters located on the condensate storage tank provide signals for low level alarms, computer inputs, and Control Room indicators (for post accident monitoring). In addition, the transmitters provide nonredundant signals for level indication at the panel supplied with the cycle makeup treatment plant and the control room evacuation panel.

10.4.9.5.3 Flow Measurement

Flow transmitters provide signals for alarms and redundant safety grade flow indication in the Control Room. Flow transmitters also provide signals for computer input, and for interlocks which automatically close the emergency feedwater flow control valves in case of a break in the emergency feedwater system between the flow control valves and the cavitating venturis. The emergency feedwater control valves are manually controlled from the Control Room or the control room evacuation panel for startup, shutdown and testing modes. Whenever an emergency feedwater control valve is in manual control and receives a signal indicative of an accident condition, the valve is automatically tripped open. During normal power operation, the emergency feedwater control valves are in the open position ready for automatic start of the emergency feedwater pumps. The control valves will remain open until throttled or closed by the operator or automatically closed by a high flow signal indicative of a break in the emergency feedwater system between the flow control valves and the cavitating venturis. Closure of the 2 emergency feedwater control valves terminates emergency feedwater flow only into the faulted steam generator loop. Due to the passive flow limitation of the cavitating venturis, the emergency feedwater control valves will not automatically close due to a faulted steam generator and will rely on operator action to isolate the faulted loop within 10 minutes.

For each emergency feedwater control valve (FV-3531, FV-3541, FV-3551, FV-3536, FV-3546, FV-3556), position indicating design provisions include the following:

1. Visual indication in the main control room by means of an ESF monitor light that will be “bright” when the valve is not open. Section 7.5.4 provides a more detailed explanation of the operation of the ESF monitor lights. An alarm will be annunciated via a common monitor light alarm if an emergency feedwater control valve is not open. This grouping highlights a valve not properly lined up. This light is energized from an ESF monitor light supply different from the valve control power and actuated by a valve limit switch. In addition to this visual position information, there are also red (open) and green (closed) position indicating lights at the control switch for each valve. These lights are actuated by valve limit switches and are powered by valve control power.
2. Audible and visual alarm annunciator points will be activated whenever an emergency feedwater control valve control switch is not in the auto position. The alarm activated by the control switch will be recycled by a timer at approximately 60 minute intervals to remind the operator of the improper valve line up. Both the alarm reflash annunciator point and the timer will be energized separately from the valve control power.

10.4.9.5.4 Speed Measurement

A speed transducer, supplied with the turbine driven emergency feedwater pump turbine, provides signals for Control Room indication.

10.4.9.5.5 Special Instrumentation

The main control board ESF monitor lights (see Section 7.5 for a more detailed explanation) provide an easily recognizable indication of the status of essential components and equipment. Included among the monitor lights for this system are status (position) indication of the flow control valves, the motor driven pumps, and the valve that admits steam to the turbine driven emergency feedwater pump.

An alarm is actuated if either control switch for the valve that admits steam to the turbine driven emergency feedwater pump is in the close position. The alarms ensure proper control switch alignment for normal operations. Switch covers are provided for these switches to prevent inadvertent operator action.

The emergency feedwater flow to each steam generator and condensate storage tank level are part of the post accident monitoring instrumentation (see Section 7.5 for a more detailed explanation).

10.4.9.5.6 Qualifications

Sections 3.10, 3.11, and 7.1 outline the qualifications and diversity of the instrumentation utilized in this system.

10.4.10 Turbine Building Closed Cycle Cooling Water System

The Turbine Building Closed Cycle Cooling Water System provides cooling water to components associated with the steam and power conversion system. The energy is dissipated to the atmosphere by a wet surface industrial cooling water.

10.4.10.1 Design Bases

The Turbine Building Closed Cycle Cooling Water System supplies non-nuclear safety class cooling water to the following components:

1. Turbine oil coolers
2. Hydrogen coolers
3. Exciter air cooler
4. Stator coolers
5. Main condenser vacuum pump coolers
6. Auxiliary condenser vacuum pump coolers
7. Instrument/service air compressors
8. Non-nuclear sample coolers
9. Non-nuclear sample chiller
10. Feedwater pump and turbine oil coolers

11. Feedwater booster pump mechanical seals and oil coolers
12. EHC oil coolers
13. Isophase bus duct coolers
14. Condensate pump seal coolers
15. Condensate demineralizer system air compressor

Major design parameters for the cooling water system pumps and the cooling tower are presented in Table 10.4-9.

System piping and valves are designed in accordance with the applicable ANSI industry standards B31.1 (Reference 1) and B16.5 (Reference 2) respectively. Hydrogen coolers, stator coolers, exciter air cooler, and turbine oil coolers are designed in accordance with the ASME Code, Section VIII (Reference 6), Division 1. Pumps are designed in accordance with Hydraulic Institute Standards. (Reference 9) The system is sized to ensure adequate heat removal based on 95° F nominal cooling tower water outlet temperature.

10.4.10.2 System Description

The Turbine Building Closed Cycle Cooling Water System components include a wet surface industrial cooling tower, two 100% capacity tower spray pumps, 4 cooling tower fans, two 100% capacity closed cycle cooling pumps, two 100% capacity closed cycle cooling booster pumps, various equipment coolers, and a head tank. Chemical injection and blowdown are provided to maintain the quality of the spray water.

Under normal operation, 1 of the 2 cooling water pumps circulates treated water through the cooling tower coils transferring the heat removed from the various components to the spray water and then to the atmosphere by evaporation of the spray water in the air stream produced by cooling tower fans. The dispersant and anti-fouling chemicals added to the cooling tower raw water are sufficiently diluted to ensure negligible effect on the environment. Cooling tower effluents, including salt drift and chemical discharges, will have negligible effect on plant structures and systems.

In the event of loss of the operating closed cycle pump while a-c power is available, the non-operating closed cycle pump starts automatically on detection of a pressure drop in the pump header.

The head tank located at the highest point in the system provides makeup and storage for thermal volume changes.

10.4.10.3 Safety Evaluation

The Turbine Building Closed Cycle Cooling Water System is independent of the plant emergency cooling facilities. This system is not required for reactor protection nor for safe shutdown of the nuclear portion of the plant and is therefore classified as non-nuclear safety class, non-Seismic

Category 1. Failure or malfunction of any system component will not affect the ability of the plant to achieve or maintain shutdown conditions.

A postulated failure in the Turbine Building Closed Cycle Cooling Water System inside the Turbine Building is bounded by the postulated failure of an expansion joint in the Circulating Water System piping as discussed in Section 10.4.5.3. Failure of the Turbine Building Closed Cycle Cooling Water System, having a limited volume of water which could be released into the turbine building, results in a lower flood level than the postulated event where circulating water is released through an expansion joint failure until the pump isolation valve closed.

The case of postulated missiles resulting from a broken cooling tower fiberglass fan blade is enveloped by the tornado missile spectrum applicable to the design of Seismic Category 1 structures.

10.4.10.4 Tests and Inspection

Testing of the Turbine Building Closed Cycle Cooling Water System is limited to that normally provided for non-safety related systems and includes:

1. Hot functional testing.
2. Normal, operational checking and routine maintenance of the system.

10.4.10.5 Instrumentation

System instrumentation to permit operator evaluation of equipment performance and to provide a performance record includes:

1. Pressure indicators, switches and test connections.
2. Flow indicators.
3. Level switches.
4. Temperature indicators and test connections.
5. Distributed Control System (DCS) for controlling and monitoring including operator interface.

10.4.11 References

1. American National Standards Institute, Power Piping, ANSI B31.1, 1967, Addenda through 1972.
2. American National Standards Institute, *Steel Pipe Flanges, flanged Valves and Fittings*, ANSI B16.5, 1968.
3. U. S. Nuclear Regulatory Commission, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors*, NUREG-0017, April, 1976.
4. Heat Exchange Institute, *Standards for Steam Surface Condensers*, Sixth Edition, 1970.
5. ASME Boiler and Pressure Vessel Code, Section III.
6. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.
7. Heat Exchange Institute, *Standard for Closed Feedwater Heaters*, Second Edition, 1974.
8. ASME Boiler and Pressure Vessel Code, Section XI.
9. Hydraulic Institute Standards, for Centrifugal, Rotary, and Reciprocating Pumps.
10. IEEE - Standard 382-1972, *Type Test of Class 1 Electric Valve Operators*.
11. Regulatory Guide 1.48, Rev. 0, *Design Limits and Leading Combinations for Seismic Category 1 Fluid System Components*.
12. GAI Report No. 2203, *Emergency Feedwater System Reliability Assessment*.

Table 10.4-1
Condenser Design Capacities

	Low Pressure Shell	High Pressure Shell
Size, ft^2	300,000	300,000
Shell Side		
Steam In, lbs/hr	3.43×10^6	3.43×10^6
U Service BTU/hr-ft^2-°F	539.1	559.1
Cleanliness factor,%	90	90
Saturation Temperature, °F	103.22	114.02
Log Mean Temperature Difference, °F	19.52	18.33
Operating Pressure, in HgA	2.13	2.91
Oxygen Guarantee in Hotwell,* cc/liter		0.005
Total Calculated Duty, BTU/hr	$\sim 6{,}232 \times 10^6$	
Tube Side		
Circulating Water Flow, gpm	~ 520,000	~ 520,000
Water In, °F	77	89.1
Water Out, °F	89.1	101
Number of Passes	One	One
Pressure Drop, ft of water	~ 12.7	~ 12.4
Velocity, ft/sec	~ 8.030	~ 8.030

* At turbine loads > 50%.

Table 10.4-1 (continued)
Condenser Design Capacities

Auxiliary Condensers	Each Shell
Quantity	3
Size ft^2	5,122
Shell Side (each condenser)	
Steam In, lb/hr	64,839
U Service BTU/hr-ft^2-°F	456
Cleanliness Factor,%	90
Saturation Temperature, °F	118.00
Log Mean Temperature Difference, °F	26.96
Operating Pressure, in HgA	3.2
Tube Side (each condenser)	
Circulating Water Flow, gpm	5,000
Water In, °F	77
Water Out, °F	101.4
Number of Passes	3
Pressure Drop, ft of water	12.6
Velocity, ft/sec	6.4 at 60°F
Main Condenser Vacuum Pumps	
Capacity, Free Dry Air, lb/hr (scfm)	90 (20), each pump
Capacity, Associated Vapor, lb/hr	198, each pump
Total Capacity, Air-Vapor Mixture, lb/hr	288, each pump
Auxiliary Condenser Vacuum Pumps	
Capacity, Free Dry Air, lb/hr (scfm)	67.5 (15), each pump
Capacity, Associated Vapor, lb/hr	147.5, each pump
Total Capacity, Air-Vapor Mixture, lb/hr	215.0, each pump

Table 10.4-2
Turbine Bypass Valve Setpoints

Applicable Valves	Condition	Device	Setpoint	Reference FSAR Figure
All	Lo-Lo T_{avg}	SSPS (K631)	552°F	10.4-4b
Condenser Dumps Only	Condenser Pressure	PY/3006A	5” HgA	10.4-4b
Condenser Dumps Only	Condenser Pressure	PY/3016A	5” HgA	10.4-4b
All	Turbine Impulse Chamber Pressure	PB447A	10% of load	10.4-4b
All	Turbine Impulse Chamber Pressure	PB447B	50% of load	10.4-4b
Condenser Dumps Only	Hi T_{avg} Load Rejection Steam Dump	TB408F	Hi 1-5.7°F Hi 2-16.9°F	10.4-4b
Atmospheric Relief and Power Relief Only	Hi T_{avg} Load Rejection Steam Dump	TB408P	Hi 3-22.4°F Hi 4-28°F	10.4-4b
Condenser Dumps Only	Hi T_{avg} Turbine Trip Steam Dump	TB408J	Hi 1-7.6°F Hi 2-30.4°F	10.4-4b
Power Relief Valves Only	Pressure Controller	PC **	1107 psia	10.4-4a
Power Relief Valves Only	Pressure Control	TY-408R1 TY-408R2	77.7 to 100% (1)	10.4-4a
Power Relief Valves Only	Pressure Bistable	PB ***	1148 psia inc.; reset at 1105 psia, dec.	10.4-4a
Atmospheric Relief Valves Only	Pressure Control	TY-408Q1 TY-408Q2	57.7 to 77.7% (1)	10.4-4a
Condenser Cooldown Valves Only	Pressure Control	TY-408N1 TY-408N2	0 to 14.4% (1)	10.4-4a

Table 10.4-2 (continued)
Turbine Bypass Valve Setpoints

Applicable Valves	Condition	Device	Setpoint	Reference FSAR Figure
Condenser Dump Valves Only	Pressure Control	TY-408P1 TY-408P2 TY-408P3	14.4 to 57.7% (1)	10.4-4a
IFV-2097-MB and IFV-2117-MB Only	Valve Open Permit	PY/3006B or PY/3016B	< 4.5” HgA	10.4-4a

(1) Operating bandwidth based on valve limitations. Percent of steam dump capacity (~ 93.6% of rated steam flow), as outlined on Figure 7.2-1, Sheet 10.

Table 10.4-3
Circulating Water System Design Parameters

Traveling Screens	
Quantity	6
Type	Through flow
Screen Material	304 Stainless steel
Screen Mesh Opening, in	3/8
Design Water Velocity, fps	0.75 (approach)
Capacity, gpm	95,000 @ 1.32 fps 120,000 @ 1.67 fps
Circulating Water Pumps	
Quantity	3
Type	Vertical, wet pit
Total Dynamic Head, ft	40.5
Capacity, gpm	~178,000
Speed (XPP0006A/B/C), rpm	(297/294/294)
Shutoff Head, ft	89
Horsepower	2250
Circulating Water Jockey Pump	
Quantity	1
Type	Vertical, wet pit
Total Dynamic Head, ft	38
Capacity, gpm	5000
Speed, rpm	690
Shutoff head, ft	50
Horsepower	75

Table 10.4-3 (continued)
Circulating Water System Design Parameters

Lube Water Booster Pump	
Quantity	1
Type	Vertical
Total Dynamic Head, ft	150
Capacity, gpm	50
Speed, rpm	3500
Shutoff Head, ft	170
Horsepower	7.5
Screen Wash Pumps	
Quantity	2
Type	Horizontal
Total Dynamic Head, ft	250
Capacity, gpm	2000
Speed, rpm	1750
Shutoff Head, ft	280
Horsepower	200

Table 10.4-3a
Water Level Versus Time for a Postulated Circulating
Water System Expansion Joint Failure

Elevation (ft.)	Time (sec)	Event
390	0-5	Alarm in main condenser cleaning pit
400	46	Second alarm, trip of circulating water pumps
412	102	Amertap strainer pit over-flows to turbine building floor
413	147	-
413.5	170	Circulating water pumps discharge valves close fully, flow stops

NOTE: Prior to pump discharge valve closure, water rise in the Turbine Building is approximately 16 in/min.

Table 10.4-4
Condensate System Equipment Parameters

Condensate Pumps	
Quantity	3
Design capacity, gpm	9635
Design Total Dynamic Head, ft	605
Efficiency at Design Condition%	82
NPSH Required at Design Point, ft	18
Design Speed, rpm	1187
Shutoff Head, ft	775
Minimum Flow, gpm	1000
Motor Rated Horsepower, HP	2000
Normal Operating Point Conditions	
Total Dynamic Head, ft	630
Flow, gpm	9177
Horsepower, BHP	1800
Deaerator	
Quantity	1
Condensate, lb/hr	8,837,684
Temperature, °F	300.3
Extraction Steam	
Flow, lb/hr	255,110
Pressure (at inlet), psia	107.9
Enthalpy, BTU/lb	1228.3
High Pressure Heater Drain, lb/hr	3,752,012

Table 10.4-4 (continued)
Condensate System Equipment Parameters

Capacity of Deaerator Storage		
Tank at Normal Water Level (5 ft above tank center line), gal		75,000
0_2 Content Guarantee, cm3/liter		0.005
Vented Steam Flow (Predicted), lb/hr		< 300
Design Pressure, psig		Full vacuum - 116
Operating Pressure, psia		107.9
Feedwater Heaters	Heater 4	Heaters 5 & 6
Quantity	2	2/2
Feedwater, lb/hr	4,418,842 (each)	4,418,842 (each)
Extraction Steam, lb/hr (each)	333,171	267,781/169,903
Drain, lb/hr Flow (from) each	333,171	608,974/887,700
Steam Pressure at Inlet, psia	71.5	21.8/5.87
Feedwater Inlet, °F	227.5	164.1/115.1
Feedwater Outlet, °F	300.3	227.5/164.1
Steam In, °F	324.4	237.1/172.7
Drains Out, °F	240.5	174.1/125.1
Drain Cooler approach, °F	13	10/10
Terminal Difference, °F	4.0	5/5
Total Heat Transferred, BTU/hr	326,994,308	281,480,235/ 216,081,374

Table 10.4-5
Feedwater System Equipment Parameters

Feedwater Booster Pumps	
Quantity	4
Configuration	Horizontal, single stage, double suction, horizontal split, dual volute casing
Operating* NPSH Required, ft	28
Operating* Total Dynamic Head, ft	565
Operating* Capacity, gpm	7200
Design NPSH Required, ft	29
Design Total Dynamic Head, ft	555
Design Capacity, gpm	7556
Design Shaft Horsepower Required, BHp	1150
Speed, rpm	1780
Feedwater Pumps	
Quantity	3
Configuration	Horizontal, single state, double suction, diffuser type
Operating* Capacity, gpm	9600 (each pump)
Operating* Total Dynamic Head, ft	2365
Operating* Speed, rpm	4550
Operating* Efficiency,%	87.5
Design Capacity, gpm	10,075 (each Pump)
Design Total Dynamic Head, ft	2585
Design Speed, rpm	4800
Maximum Shut Off Head, ft	4225 (± 6% at runout)

* At 100% Rated Power w/1% Blowdown

Table 10.4-5 (continued)
Feedwater System Equipment Parameters

Feedwater Heaters	Heaters 1A & 1B	Heaters 2A & 2B
Quantity	2	2
Type	Horizontal, U-tube, closed, with internal drains cooler	
Feedwater (In), lbs/hr; BTU/lb	6,429,057; 351.0	6,429,057; 308.1
Steam, lbs/hr; BTU/lb	444,740; 1143.7	869,334; 586.0
Drains to Heater lbs/hr; BTU/lb	552,045; 531.4	1,006,672;362.5
Steam Pressure at Inlet, psia	408.1	205.6
Feedwater Inlet, °F	376.1	335.1
Feedwater Outlet, °F	441.0	376.1
Steam Inlet, °F	456.6	393.0
Drains Out, °F	388.1	347.6
Drain Cooler approach, °F	12	12.5
Terminal Difference, °F	5.6	8.0
Total Heat Transferred, BTU/hr	448,748,179	275,806,545

Table 10.4-6
Feedwater System Failure Analysis

Component	Malfunction	Comment
Feedwater Booster Pump	1. Trip of one operating pump from normal operating scheme.	No effect.
	2. Trip of one operating pump from beyond normal operating scheme.	Limited power reduction in accordance with operating procedures.
Feedwater Pump	1. Trip of one operating pump from normal operating scheme.	Remaining feedwater pump(s) run out, no effect on NSSS.
	2.Trip of one operating pump from beyond normal operating scheme.	Reactor trip or runback in accordance with operating procedures.
Feedwater Flow Control Valve	Valve fails closed.	Reactor trip.
Feedwater Isolation Valve	Valve fails closed.	Reactor trip.
Feedwater Piping	Postulated pipe rupture.	See Section 10.4.7.2.3.

Table 10.4-7
Steam Generator Blowdown System
Component Design Parameters

Steam Generator Blowdown Heat Exchangers		
Quantity	3	
Type	Shell and tube	
	Shell Side	Tube Side
Fluid	Condensate	Blowdown
Design Pressure, psig	250	1185
Design Temperature, °F	400	650
Inlet Temperature, °F	106	557
Outlet Temperature, °F	338	120
Flow, lb/hr	79,450	40,700
Material	SA-515-70	SA-249-304
Effective Heat Transfer Area, ft^2	2082	
Heat Duty, BTU/hr	18.5×10^6	
Nuclear Blowdown Holdup Tank		
Quantity	1	
Capacity, gal	13,000	
Design Pressure	Atmospheric	
Design Temperature, °F	150	
Materials	Lined carbon steel	
Nuclear Blowdown Monitor Tank		
Quantity	1	
Capacity, gal	5,000	
Design Pressure	Atmospheric	
Design Temperature, °F	150	
Material	Type 304 stainless steel	

Table 10.4-7 (continued)
Steam Generator Blowdown System
Component Design Parameters

Nuclear Blowdown Holdup Tank Pumps	
Quantity	2
Type	Canned motor, centrifugal
Capacity, gpm (Includes 50 gpm of recirc flow)	300
Total Developed Head, ft	325
Material	Wetted parts - type 316 stainless steel
Nuclear Blowdown Monitor Tank Pump	
Quantity	1
Type	Canned motor, centrifugal
Capacity, gpm	250
Total Developed Head, ft	250
Material	Wetted parts - type 316 stainless steel
Nuclear Blowdown Demineralizer Inlet Filter	
Quantity	1
Design Flow, gpm	250
Design Pressure, psig	150
Design Temperature,°F	150
Pressure Drop	
Clean, psi	5
Dirty, psi	20
Particulate Retention, microns absolute	≤ 20
Vessel Material	Type 304 stainless steel

Table 10.4-7 (continued)
Steam Generator Blowdown System
Component Design Parameters

Nuclear Blowdown Demineralizers	Primary	Polishing
Quantity	2	2
Resin Capacity, ft^3	150	90
Design Flow, gpm	250	250
Design Pressure, psig	150	150
Design Temperature, °F	140	140
Material	Type 304 stainless steel	
Resin Type	Anion and/or cation exchange resins as required	
Nuclear Blowdown Spent Resin Storage Tank		
Quantity	1	
Capacity, ft^3	600	
Design Pressure, psig	150	
Design Temperature, °F	140	
Material	Type 304 stainless steel	
Nuclear Blowdown Resin Sluice Pump		
Quantity	1	
Type	Canned motor, centrifugal	
Capacity, gpm	150	
Total Developed Head, ft	230	
Material	Wetted parts - type 304 stainless steel	

Table 10.4-8
Emergency Feedwater System Failure Analysis for
Secondary Side Break With Los of Non-1E Electrical Power

Component	Malfunction	Comment
Any Emergency Feedwater Pump	Fails to start	The two remaining emergency feedwater pumps feed all three steam generators with the two unaffected steam generators receiving required flow. Flow is passively limited to the faulted SG steam generator by the cavitating venturi for 10 minutes (until operator action is credited). [1,2]
Motor Driven Pump ARC Valve	Fails to automatically isolate pump recirculation path	All three emergency feedwater pumps feed all three steam generators with the two unaffected steam generators receiving required flow. Flow is passively limited to the faulted SG steam generator by the cavitating venturi for 10 minutes (until operator action is credited). [1,2]
Electrical Channel A (instrumentation and power)	Failure (total loss)	Channel B motor driven emergency feedwater pumps and the Turbine Driven pump feed all three steam generators with the two unaffected steam generators receiving required flow. Flow is passively limited to the faulted SG steam generator by the cavitating venturi for 10 minutes (until operator action is credited). [1,2]

Table 10.4-8 (continued)
Emergency Feedwater System Failure Analysis for
Secondary Side Break With Los of Non-1E Electrical Power

Component	Malfunction	Comment
Electrical Channel B (instrumentation and power)	Failure (total loss)	Channel A motor driven emergency feedwater pump and the Turbine Driven pump feed all three steam generators with the two unaffected steam generators receiving required flow. Flow is passively limited to the faulted SG steam generator by the cavitating venturi for 10 minutes (until operator action is credited). [1,2]

(1) The pressure and temperature analyses for secondary side pipe breaks inside containment credit operator action at 30 minutes to isolate emergency feedwater to the affected SG and thus allow for operator action outside of the control room. Action is required to prevent overpressurizing the containment.
(2) The pressure and temperature analyses for secondary side pipe breaks outside containment credit operator action at 10 minutes to isolate emergency feedwater to the affected SG since the harsh environment will limit local manual actions. Action is required to prevent environment conditions for equipment qualifications.

Table 10.4-9
Turbine Building Closed Cycle Cooling
Water System Design Parameters

Turbine Building Closed Cycle Cooling Water System Pumps	
Quantity	2
Type	Horizontal
Total Dynamic Head, ft	165
Capacity, gpm	8750
Speed, rpm	1170
Motor Horsepower	600
Turbine Building Closed Cycle Cooling Water System Cooling Tower	
Quantity	1
Type	Wet Surface Air Cooler
Number of Cells	2
Number of Cooling Coils	8
Number of Fan Assemblies	4
Cooling Coil Water Flow, gpm	8800
Entering Coil Water Temperature, °F	107.8
Leaving Coil Water Temperature, °F	94
Design Heat Load, Btu/Hr	60,720,000
Cooling Tower Spray Pumps	
Quantity	2
Type	Vertical Turbine
Manufacturer	Goulds
Total Dynamic Head, ft	46
Capacity, GPM	8500
Speed, RPM	880
Minimum Flow, GPM	2000
Shut-off Head, ft	75
Horsepower	125

Figure 10.4-1
DRAWING D-302-131
FSAR FIGURE REFERENCE

Figure 10.4-2,
Figure 10.4-2a
Figure 10.4-2b
DELETED PER AMENDMENT 96-03

Figure 10.4-3
DRAWING SS-808-011
FSAR FIGURE REFERENCE

Figure 10.4-4, Sheet 1
DRAWING SS-808-031
FSAR FIGURE REFERENCE

Figure 10.4-4, Sheet 2
DRAWING SS-808-031
FSAR FIGURE REFERENCE

Figure 10.4-4, Sheet 3
DRAWING SS-808-031
FSAR FIGURE REFERENCE

Figure 10.4-4a

FUNCTIONAL DIAGRAM MAIN STEAM SYSTEM (NUCLEAR)

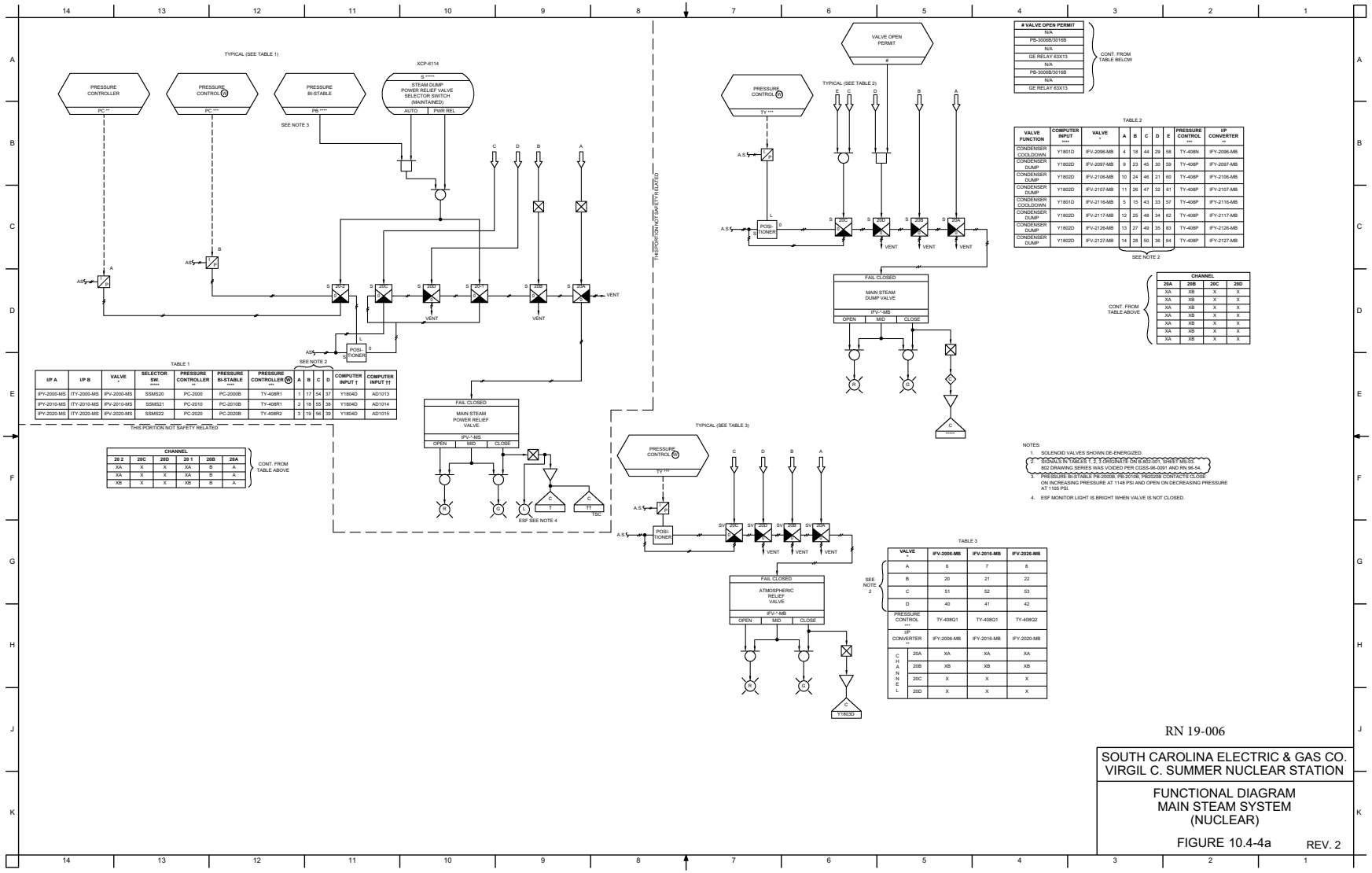

TABLE 1

I/P A	I/P B	VALVE *	SELECTOR SW. *****	PRESSURE CONTROLLER **	PRESSURE BI-STABLE *****	PRESSURE CONTROLLER M ***	A	B	C	D	COMPUTER INPUT †	COMPUTER INPUT ††
IPY-2000-MS	ITY-2000-MS	IPV-2000-MS	SSMS20	PC-2000	PC-2000B	TY-408R1	1	17	54	37	Y1804D	AD1013
IPY-2010-MS	ITY-2010-MS	IPV-2010-MS	SSMS21	PC-2010	PC-2010B	TY-408R1	2	18	55	38	Y1804D	AD1014
IPY-2020-MS	ITY-2020-MS	IPV-2020-MS	SSMS22	PC-2020	PC-2020B	TY-408R2	3	19	56	39	Y1804D	AD1015

CHANNEL					
20 2	20C	20D	20 1	20B	20A
XA	X	X	XA	B	A
XA	X	X	XA	B	A
XB	X	X	XB	B	A

TABLE 2

VALVE FUNCTION	COMPUTER INPUT *****	VALVE *	A	B	C	D	E	PRESSURE CONTROL ***	I/P CONVERTER **
CONDENSER COOLDOWN	Y1801D	IFV-2096-MB	4	18	44	29	58	TY-408N	IFY-2096-MB
CONDENSER DUMP	Y1802D	IFV-2097-MB	9	23	45	30	59	TY-408P	IFY-2097-MB
CONDENSER DUMP	Y1802D	IFV-2106-MB	10	24	46	21	60	TY-408P	IFY-2106-MB
CONDENSER DUMP	Y1802D	IFV-2107-MB	11	26	47	32	61	TY-408P	IFY-2107-MB
CONDENSER COOLDOWN	Y1801D	IFV-2116-MB	5	15	43	33	57	TY-408P	IFY-2116-MB
CONDENSER DUMP	Y1802D	IFV-2117-MB	12	25	48	34	62	TY-408P	IFY-2117-MB
CONDENSER DUMP	Y1802D	IFV-2126-MB	13	27	49	35	63	TY-408P	IFY-2126-MB
CONDENSER DUMP	Y1802D	IFV-2127-MB	14	28	50	36	64	TY-408P	IFY-2127-MB

VALVE OPEN PERMIT
N/A
PB-3006B/3016B
N/A
GE RELAY 63X13
N/A
PB-3006B/3016B
N/A
GE RELAY 63X13

CHANNEL			
20A	20B	20C	20D
XA	XB	X	X
XA	XB	X	X
XA	XB	X	X
XA	XB	X	X
XA	XB	X	X
XA	XB	X	X
XA	XB	X	X

TABLE 3

VALVE *	IFV-2006-MB	IFV-2016-MB	IFV-2026-MB
A	6	7	8
B	20	21	22
C	51	52	53
D	40	41	42
PRESSURE CONTROL ***	TY-408Q1	TY-408Q1	TY-408Q2
I/P CONVERTER **	IFY-2006-MB	IFY-2016-MB	IFY-2020-MB
CHANNEL 20A	XA	XA	XA
CHANNEL 20B	XB	XB	XB
CHANNEL 20C	X	X	X
CHANNEL 20D	X	X	X

SEE NOTE 2

Figure 10.4-4b

FUNCTIONAL DIAGRAM MAIN STEAM SYSTEM (NUCLEAR)

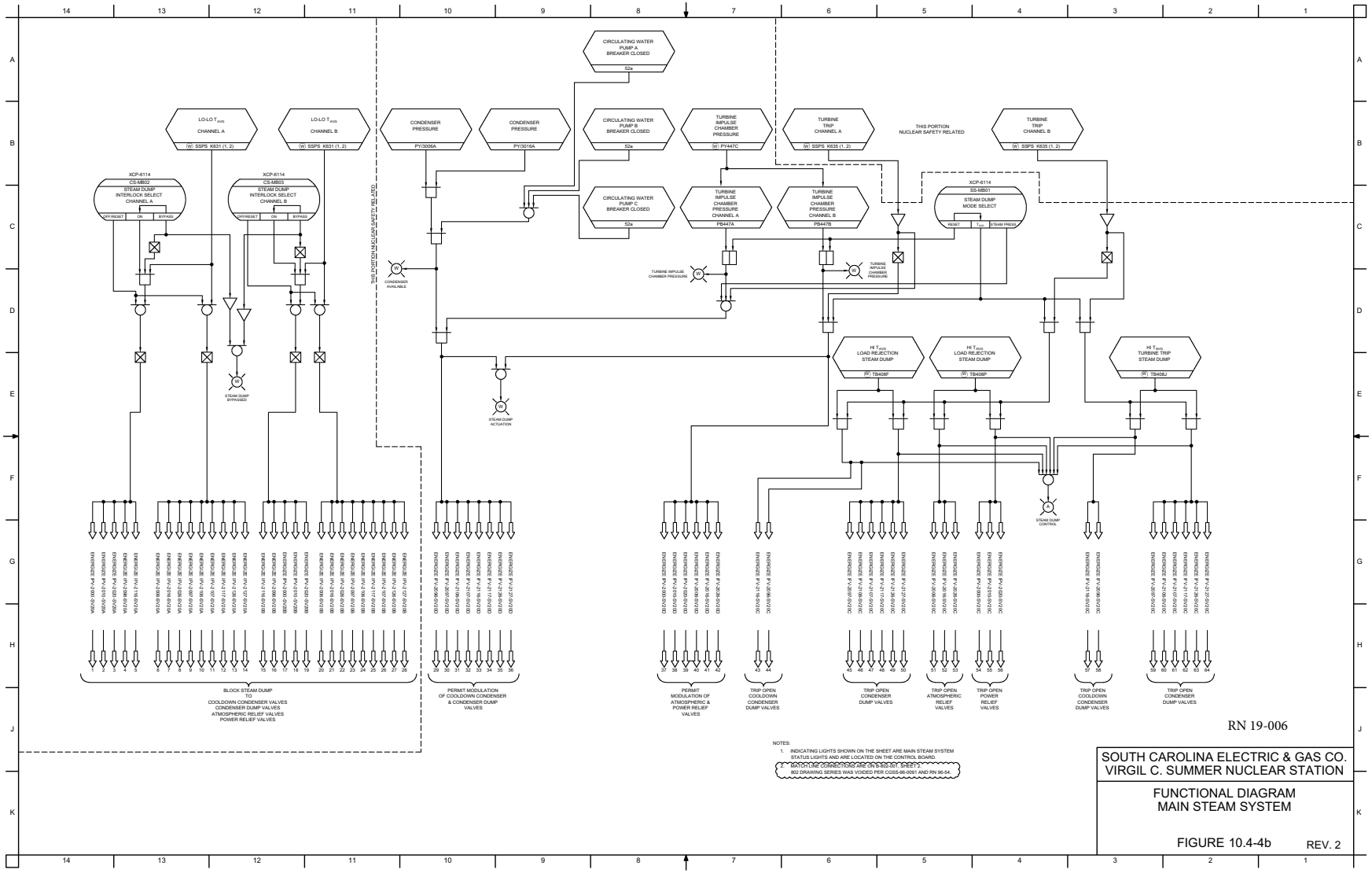

Figure 10.4-5
DRAWING D-302-201
FSAR FIGURE REFERENCE

Figure 10.4-6
D-302-202
DELETED PER AMENDMENT 96-03, MRF-90105, RN 96-44
AMENDMENT 96-03, SEPTEMBER 1996

Figure 10.4-7
D-302-203
DELETED PER AMENDMENT 96-03, MRF-90105, RN 96-44
AMENDMENT 96-03, SEPTEMBER 1996

Figure 10.4-6
FSAR FIGURE REFERENCE
IMPLEMENTED NEW FSAR FIGURE 10.4-6
D-302-204 ECR 50617 AUGUST 2006

Figure 10.4-7A
DRAWING D-302-165
FSAR FIGURE REFERENCE

Figure 10.4-8
DRAWING D-302-101
FSAR FIGURE REFERENCE

Figure 10.4-9
DRAWING D-302-102
FSAR FIGURE REFERENCE

Figure 10.4-10
DRAWING D-302-081
FSAR FIGURE REFERENCE

Figure 10.4-11
DRAWING D-302-082
FSAR FIGURE REFERENCE

Figure 10.4-12
DRAWING D-302-083
FSAR FIGURE REFERENCE

Figure 10.4-13
DRAWING D-302-781
FSAR FIGURE REFERENCE

Figure 10.4-14
DRAWING D-302-782
FSAR FIGURE REFERENCE

Figure 10.4-15
DRAWING D-302-783
FSAR FIGURE REFERENCE

Figure 10.4-16
DRAWING D-302-085
FSAR FIGURE REFERENCE

Figure 10.4-17
DRAWING D-302-362
FSAR FIGURE REFERENCE

V.C. Summer Nuclear Station
Safety Analysis Report

Radioactive Waste Management

Chapter 11

Revision 26--06/25/26

This Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 11 - RADIOACTIVE WASTE MANAGEMENT

11.1 Source Terms

The fission product inventory in the reactor core and the diffusion to the fuel pellet/cladding gap are presented in Chapter 15. Source terms and models used in the evaluation of radwaste treatment systems and effluent releases are based on operating plant data where available (Reference 1).

Two source terms are presented. The first is a conservative model which utilizes a conventional fuel clad defect model. This conservative model serves as a basis for calculations of the maximum offsite doses resulting from postulated accidents.

The second source term is a realistic model used to predict expected long term average concentrations of radionuclides and expected releases. This realistic model is based on ANSI/ANS-18.1-1984.

11.1.1 Radioactivities in Systems and Components, Conservative Model

11.1.1.1 Reactor Coolant Activity

The parameters used in the calculation of the reactor coolant fission product inventories, together with the pertinent information concerning the expected coolant cleanup flowrate and demineralizer effectiveness, are summarized in Table 11.1-1. Calculated reactor coolant radionuclide concentrations, based on the assumptions of Table 11.1-1, are presented in Table 11.1-2. In these calculations, the defective fuel rods are assumed to be present at the initial core loading and to be uniformly distributed throughout the core; thus, the fission product escape rate coefficients are based upon average fuel temperature.

For fuel failure and burnup experience, see Chapter 4.

The fission product activities in the reactor coolant during operation with small cladding defects (fuel rods containing pinholes or fine cracks) are computed using the following differential equations:

For parent nuclides in the coolant:

$$\frac{dN_{C_i}}{dt} = \frac{R_i N_{F_i}}{M_C} - \left[\lambda_i + D_i + \frac{Q_L}{M_C}\left(\frac{\psi_i + DF_i - 1}{DF_i}\right)\right] N_{C_i} \qquad (11.1\text{-}1)$$

For daughter nuclides in the coolant:

$$\frac{dN_{C_j}}{dt} = \frac{R_j N_{F_j}}{M_C} + f_i \lambda_i N_{C_i} - \left[\lambda_j + D_j + \frac{Q_L}{M_C}\left(\frac{\psi_j + DF_j - 1}{DF_j}\right)\right] N_{C_j} \qquad (11.1\text{-}2)$$

where:

N_c = Concentration of nuclide in the reactor coolant (atoms/gram)
NF = Inventory of nuclide in the fuel (atoms)
t = Operating time (seconds)
R = Nuclide release coefficient (1/sec) = F v
F = Fraction of fuel rods with defective cladding
v = Fission product escape rate coefficient (1/sec)
M_c = Mass of reactor coolant (grams)
λ = Nuclide decay constant (1/sec)
DF = Nuclide demineralizer decontamination factor
Q_L = Purification or letdown mass flow rate (grams/sec)
ψ = Nuclide volume control tank stripping fraction
f = Fraction of parent nuclide decay events that result in the formation of the daughter nuclide
D = Dilution coefficient for feed and bleed (1/sec) =

$$\frac{\beta}{B_o - \beta t} * \frac{1}{DF}$$

B_o = Initial boron concentration (ppm)
β = Boron concentration reduction rate (ppm/sec)

and where:

subscript i refers to the parent nuclide.
subscript j refers to the daughter nuclide.

The above equations are based on the assumption that there is no activity reduction due to pressurizer operation and that the nuclide concentration in the volume control tank can be approximated by:

$$N_{VL} = \frac{1-\psi}{DF} * N_c$$

where:

N_{VL} = Concentration of nuclide in the volume control tank (atoms/gram)

The corrosion product activities in the Reactor Coolant System are based on measurements at operating reactors (Reference 1). The reactor coolant inventories of corrosion products (which are independent of fuel defect level) are given in Table 11.1-2.

Another potential source of primary coolant activity is activation products from the silver-indium-cadmium control rods. The presence of Ag-110m has been noted in the primary coolant or plant discharges at a few of the operating plants. Several mechanisms can contribute to the presence of

this isotope; namely, fission product decay of the mass 109 chain followed by activation to Ag-110m, surface contamination of the control rods with absorber material, or escape of activation products from the control rods. The control rods are designed to contain products formed in the absorber material and are not expected to contribute to the coolant activity. Current information, however, is insufficient to determine the source of the silver, and thus no model is available for predicting coolant activity levels due to the above sources. Investigations of this will be continued as more data become available.

11.1.1.2 Gaseous Waste Processing System Activity

The stripping fractions used in determining the amount of fission gases removed from the reactor coolant in the volume control tank and collected by the Gaseous Waste Processing System (GWPS) are calculated as follows:

$$\psi = 1 - \left[\frac{KQ}{KQ + \lambda(KL + V) + P}\right] \quad (11.1\text{-}3)$$

where:

- ψ = Nuclide volume control tank stripping fraction
- K = RT / MH
- R = Gas constant = 45.59 atm/cc per gram-mole /°R
- T = Nominal volume control tank temperature (°R)
- M = Molecular weight of water = 18.0 grams/gram-mole
- H = Henry's Law constant
- Q = Letdown or purification flow rate (grams/sec)
- λ = Nuclide decay constant (1/sec)
- L = Volume control tank liquid mass (grams)
- V = Volume control tank vapor volume (cc)
- P = Volume control tank purge rate to the gaseous waste processing system (cc/sec at volume control tank conditions)

An activity balance is performed on the Reactor Coolant System and volume control tank to obtain the Reactor Coolant System activity, volume control tank activity, and stripping fraction. Stripping fractions are shown in Table 11.1-1. Gaseous waste source terms are discussed in Section 11.3.

11.1.1.3 Volume Control Tank Activity

Table 11.1-3 lists the maximum activities in the volume control tank using the assumptions summarized in Table 11.1-1. The liquid activity is assumed to be the same as the letdown coolant activity for the halogen and particulate activity.

11.1.1.4 Pressurizer Activity

The specific activities for major nuclides in the pressurizer are discussed below.

- Pressurizer Liquid Phase Source Strengths - The pressurizer liquid specific activity is assumed to be the same as that of the reactor coolant. Table 11.1-4 lists only those nuclides that are the major contributors to total source strength.

- Pressurizer Steam Phase - Pressurizer steam phase radiogas concentrations (Table 11.1-4) are based on the stripping of radiogases from the continuous 2-gpm pressurizer spray and the subsequent buildup of these radiogases in the steam space. The buildup time is assumed to be 480 days. Decay credit has been taken during spray line transit. The radiogases are assumed to be completely stripped from the spray, except for Kr-85 and Xe-133, which are in Henry's Law Equilibrium with the liquid in the pressurizer.

  Pressurizer steam phase iodine concentrations are obtained from the liquid phase nuclide activities and measured values of the partition coefficient for I-131. A large partition coefficient was chosen to maximize the activities. It was assumed to apply to all radioiodines.

The activities in the pressurizer are separated between the liquid and the steam phase and the results obtained are given in Table 11.1-4 using the above assumptions and those summarized in Table 11.1-1.

11.1.1.5 Liquid Waste Processing System Activity

Liquid waste source terms are discussed in Section 11.2.

11.1.1.6 Solid Waste

Solid waste source terms are discussed in Section 11.5.

11.1.2 Leakage Rates

As a necessary part of the effort to reduce effluent of radioactive liquid wastes, Westinghouse has been surveying various Pressurized Water Reactor (PWR) facilities which are in operation, to identify design and operating problems influencing reactor coolant and non-reactor grade leakage and hence the load on the LWPS.

Leakage sources have been identified in connection with pump shaft seals and valve stem leakage. Where packed glands are provided, a leakage problem may be anticipated, while mechanical shaft seals provide essentially zero leakage. Valve stem leakage was experienced where the originally specified packing was used. A combination of a graphite filament yarn packing sandwiched with asbestos sheet packing is used with improved results in several plants. A bellows seal is being utilized in later plants which eliminates all stem leakage.

In addition, seat leakage was experienced on some pressurized power operated relief valves. However, this was found to be due to a manufacturing error and has been corrected.

11.1.3 Radioactivities in the Fluid Systems, Realistic Model

The parameters used to describe the Virgil C. Summer Nuclear Station reactor are given in Table 11.1-6.

Specific activities in the primary coolant, steam generator water, and steam generator steam are based on the parameters of Table 11.1-6 and are given in Table 11.1-5.

11.1.4 Tritium

The release of tritium to the environment from operating Westinghouse PWRs has always been well below 10 CFR 20 limits. This section discusses the reduced tritium production in the plant as a result of employing Zircaloy clad fuel and silver-indium-cadmium control rods.

11.1.4.1 System Sources

There are two principal contributors to tritium production within the PWR system: the ternary fission source, and the dissolved boron in the reactor coolant. Additional contributions are made by Li6, Li7, and deuterium in the reactor water. Tritium production from various sources is shown in Table 11.1-7.

11.1.4.1.1 Fission Source

This tritium is formed within the fuel material and may:

1. Remain in the fuel rod uranium matrix,
2. Diffuse into the cladding and become hydrided and fixed there,
3. Diffuse through the clad for release into the primary coolant,
4. Release to the coolant through macroscopic cracks or failures in the fuel cladding.

Previous Westinghouse designs conservatively assumed that the ratio of fission tritium released into the coolant to the total fission tritium formed was approximately 0.30 for Zircaloy clad fuel. The operating experience at the Robert Emmett Ginna Station of the Rochester Gas and Electric Corporation, and at other operating reactors using Zircaloy clad fuel, has shown that the tritium release through the Zircaloy fuel cladding is less than the earlier estimates. Consequently, a tritium release rate into the primary coolant of 0.001 curies per megawatt-day or less can be anticipated.

11.1.4.1.2 Control Rod Source

The full length rods for the Virgil C. Summer Nuclear Station are silver-indium-cadmium. There are no reactions in these absorber materials which would produce tritium, thus eliminating any

contribution from this source. Activation products from control rods are discussed in Section 11.1.1.1.

11.1.4.1.3 Boric Acid Source

A direct contribution to the reactor coolant tritium concentration is made by neutron reaction with the boron in solution. The concentration of boric acid varies with core life and load follow so that this is a steadily decreasing source during core life. The principal boron reactions are the B^{10} (n, 2α) H^3 and B^{10} (n, α) Li^7 (n, nα) H^3 reactions. The Li^7 reaction is controlled by limiting the overall lithium concentration to approximately 2 ppm during operation. Li^6 is essentially excluded from the system by utilizing 99.9% Li^7.

11.1.4.1.4 Burnable Shim Rod Source

These rods are in the core only during the first operating cycle and their potential tritium contribution occurs only during this period.

11.1.4.1.5 Lithium and Deuterium

Lithium and deuterium reactions contribute only minor quantities to the tritium inventory as shown in Table 11.1-7. These sources are due to the activation of the lithium and deuterium in the Reactor Coolant System as they pass through the reactor.

11.1.4.2 Design Bases

The design intent is to reduce the tritium sources in the Reactor Coolant System to a practical minimum to permit longer retention of the reactor coolant within the plant without compromising operator exposures. Reduction of source terms is provided by utilizing silver-indium-cadmium control rods and the determination that the quantity of tritium released from the fuel rods with Zircaloy cladding is less than originally expected.

11.1.4.3 Design Evaluation

Table 11.1-7 lists the present expected release of tritium to the reactor coolant. It will be noted that there are two principal contributors to the tritium production: ternary fission source and the dissolved boron in the reactor coolant.

For a leakage from the Reactor Coolant System into the Reactor Building atmosphere of 50 pounds per day with an assumed tritium concentration of 3.5 μCi/gm, the tritium concentration in the Reactor Building atmosphere would be low enough to permit access with no Reactor Building purge and without protective equipment by plant maintenance personnel for an average of 2 hours per week.

During refueling operations, a refueling water concentration activity of 2.5 μCi/gm is expected to result in Reactor Building air concentrations at or below the 10 CFR 20 occupational Maximum

Permissible Concentration (MPC) value. This concentration would permit 40 hours per week access to the Reactor Building.

Although the actual relationship between reactor coolant activities and Reactor Building air concentrations will be determined by the particular operating conditions inside the Reactor Building (temperature, relative humidity, ventilation purge rate, etc.), field measurements indicate that the design objective of 3.5 μCi/gm in the reactor coolant and 2.5 μCi/gm in the refueling water are reasonable values.

11.1.5 References

1. *Source Term Data for Westinghouse Pressurized Water Reactors*, WCAP-8253, Revision 1, July 1975.
2. ANSI/ANS-18.1-1984, *Radioactive Source Terms for Normal Operation of Light Water Reactors*.
3. *Radiation Analysis Manual*, Virgil C. Summer (CGE), CGE / 3-1, Revision 0, 12/92.

Table 11.1-1
Parameters Used in the Calculation of Reactor Coolant Fission and Corrosion Product Activities

1.	Ultimate core thermal power, MWt	2958
2.	Clad defects, as a percent of rated core thermal power being generated by rods with clad defects	1.0
3.	Reactor coolant liquid volume, ft^3	883 0
4.	Reactor coolant full power average temperature, °F	592.8
5.	Reactor coolant density at system operating temperature and pressure, g/cc	0.7
6.	Purification flowrate, gpm	60
7.	Effective cation demineralizer flow, gpm	6.0
8.	Volume control tank volumes	
	a. Vapor, ft^3	150
	b. Liquid, ft^3	150
9.	Fission product escape rate coefficients:	
	a. Noble gas isotopes, sec^{-1}	6.5×10^{-8}
	b. Br, Rb, I, and Cs isotopes, sec^{-1}	1.3×10^{-8}
	c. Te isotopes, sec^{-1}	1.0×10^{-9}
	d. Mo, Tc, and Ag isotopes, sec^{-1}	2.0×10^{-9}
	e. Sr and Ba isotopes, sec^{-1}	1.0×10^{-11}
	f. Y, Zr, Nb, Ru, Rh, La, Ce, and Pr isotopes, sec^{-1}	1.6×10^{-12}
10.	Mixed bed demineralizers decontamination factors:	
	a. Br, I, Sr, and Ba	10.0
	b. Noble gases and all other isotopes	1.0
11.	Cation bed demineralizer decontamination factors	
	a. Kr and Xe isotopes	1
	b. Sr and Ba isotopes	1
	c. Rb-86, Cs-134, and Cs-137	10
	d. Rb-88, Rb-89, Cs-136, and Cs-138	1
	e. Other isotopes	1

Table 11.1-1 (continued)
Parameters Used in the Calculation of Reactor Coolant Fission and Corrosion Product Activities

12. Volume control tank noble gas stripping fractions:

Isotope	Stripping Fraction (1)
Kr-85	6.0×10^{-5}
Kr-85m	5.6×10^{-1}
Kr-87	8.2×10^{-1}
Kr-88	6.7×10^{-1}
Xe-131m	1.3×10^{-2}
Xe-133	3.0×10^{-2}
Xe-133m	6.8×10^{-2}
Xe-135	3.0×10^{-1}
Xe-135m	9.4×10^{-1}
Xe-138	9.4×10^{-1}

13. Initial boron concentrations	
High (2)	2100
Low (3)	1200
14. Pressurizer volumes	
a. Vapor, ft^3	577
b. Liquid, ft^3	865
15. Spray line flow, gpm	2.0
16. Pressurizer stripping fractions	
a. Noble gases (except Kr-85)	1.0
b. Kr-85	0.9
c. All other elements	0
17. Fuel cycle times (effective full power days) Equilibrium cycle	480
18. Number of reactor coolant loops	3

(1) Assuming no volume control tank purge.
(2) High value is assumed where high boron concentration is conservative (i.e., tritium production).
(3) Low value is assumed where low feed and bleed is conservative. (e.g., coolant fission product activities).

Table 11.1-1 (continued)
Parameters Used in the Calculation of Reactor Coolant Fission and Corrosion Product Activities

19.	Corrosion product parameters	
	Core wetted areas, effective (in^2)	
	a. Zirlo	7.6×10^6
	b. Stainless steel	4.9×10^5
	c. Inconel	7.7×10^5
	Out of core wetted area, Inconel (in^2)	3.2×10^7
	Coolant velocity (ft/sec)	
	a. Core	14.0
	b. Steam generator	18.0
	Nominal base metal release rates (mg/dm^2-mo)	
	a. Zirlo	0.0
	b. Stainless steel	0.5
	c. Inconel	1.0

Table 11.1-2
Reactor Coolant Equilibrium Fission and Corrosion Product Activities

(Based on parameters given in Table 11.1-1)

Isotope	Activity μCi/gm
Fission Products	
Br-84	4.2×10^{-2}
Rb-88	3.8
Sr-89	4.0×10^{-3}
Sr-90	2.0×10^{-4}
Sr-91	5.3×10^{-3}
Sr-92	1.2×10^{-3}
Y-90	5.7×10^{-5}
Y-91	5.4×10^{-4}
Y-92	1.1×10^{-3}
Zr-95	6.7×10^{-4}
Nb-95	6.7×10^{-4}
Mo-99	7.9×10^{-1}
I-131	3.0
I-132	3.1
I-133	4.6
I-134	6.0×10^{-1}
I-135	2.4
Te-132	2.9×10^{-1}
Te-134	2.8×10^{-2}
Cs-134	4.4
Cs-136	4.5
Cs-137	2.1
Cs-138	9.7×10^{-1}
Ba-140	4.4×10^{-3}
La-140	1.4×10^{-3}
Ce-144	4.7×10^{-4}
Pr-144	4.7×10^{-4}
Kr-85	7.6
Kr-85m	1.8
Kr-87	1.1
Kr-88	3.2
Xe-131m	2.3
Xe-133	2.9×10^{2}
Xe-133m	1.9×10^{1}
Xe-135	8.6
Xe-135m	5.2×10^{-1}
Xe-138	6.4×10^{-1}
Mn-54	4.1×10^{-4}
Mn-56	2.2×10^{-2}
Co-58	1.4×10^{-2}
Co-60	1.3×10^{-3}
Fe-59	5.2×10^{-4}
Cr-51	5.5×10^{-3}

Table 11.1-3
Volume Control Tank Equilibrium Activities

(Based on parameters given in Table 11.1-1)

Isotope	Vapor Activity (μCi/cc)
Kr-83m	3.3×10^{0}
Kr-85	1.6×10^{2}
Kr-85m	1.9×10^{1}
Kr-87	4.9×10^{0}
Kr-88	2.5×10^{1}
Xe-131m	3.2×10^{1}
Xe-133	4.2×10^{3}
Xe-133m	2.7×10^{2}
Xe-135	1.1×10^{2}
Xe-135m	9.4×10^{0}
Xe-138	6.5×10^{-1}

Isotope	Liquid Activity (μCi/gm)
Kr-88	8.9×10^{-1}
Rb-88	3.8×10^{0}
Xe-133	1.7×10^{2}
Xe-135	4.3×10^{0}
Cs-134	4.4×10^{0}
Cs-136	4.5×10^{0}
Cs-137	2.1×10^{0}
Cs-138	9.7×10^{-1}
I-131	3.0×10^{0}
I-132	3.1×10^{0}
I-133	4.6×10^{0}
I-134	6.0×10^{-1}
I-135	2.4×10^{0}

Table 11.1-4
Pressurizer Activities

(Based on parameters given in Table 11.1-1)

Isotope	Vapor Activity (μCi/cc)
N-16	1.5×10^{-3}
Kr-83m	1.8×10^{-2}
Kr-85	2.3×10^{1}
Kr-85m	2.1×10^{-1}
Kr-87	2.8×10^{-2}
Kr-88	2.2×10^{-1}
I-131	3.0×10^{-2}
I-132	3.1×10^{-2}
I-133	4.6×10^{-2}
I-134	6.0×10^{-3}
I-135	2.4×10^{-2}
Xe-131m	5.1
Xe-133	6.3×10^{2}
Xe-133m	2.8×10^{1}
Xe-135	2.1
Xe-135m	7.8×10^{-4}
Xe-138	7.9×10^{-4}

Isotope	Liquid Activity (μCi/gm)
N-16 (maximum)	2.9
Rb-88	3.8
I-132	3.1
I-133	4.6
I-135	2.4
Cs-134	4.4
Cs-136	4.5
Cs-138	9.7×10^{-1}
Kr-88	3.2
Xe-133	2.9×10^{2}
Xe-135	8.6

NOTE: See Section 11.1.1.4 for additional information.

Table 11.1-5
Normal Plant Operation Source Terms
Group I - Noble Gases
(Based on ANSI/ANS-18.1-1984)

No VCT Purge

Nuclide	Y Parameter	Reactor Coolant Activity (μCi/gram)	Steam Generator Steam Activity (μCi/gram)
Kr-85m	5.2×10^{-1}	1.6×10^{-1}	3.9×10^{-8}
Kr-85	5.1×10^{-5}	6.1×10^{-1}	1.5×10^{-7}
Kr-87	7.9×10^{-1}	1.7×10^{-1}	3.9×10^{-8}
Kr-88	6.3×10^{-1}	2.9×10^{-1}	7.2×10^{-8}
Xe-131m	1.1×10^{-2}	7.4×10^{-1}	1.8×10^{-7}
Xe-133m	5.9×10^{-2}	6.6×10^{-2}	1.7×10^{-8}
Xe-133	2.5×10^{-2}	2.5×10^{0}	6.1×10^{-7}
Xe-135m	9.3×10^{-1}	1.6×10^{-1}	3.8×10^{-8}
Xe-135	2.7×10^{-1}	8.3×10^{-1}	2.1×10^{-7}
Xe-137	9.8×10^{-1}	4.2×10^{-2}	1.0×10^{-8}
Xe-138	9.3×10^{-1}	1.5×10^{-1}	3.5×10^{-8}

VCT Purge of 2.36×10^{2} cm^3/sec

Nuclide	Y Parameter	Reactor Coolant Activity (μCi/gram)	Steam Generator Steam Activity (μCi/gram)
Kr-85m	7.0×10^{-1}	1.5×10^{-1}	3.7×10^{-8}
Kr-85	5.7×10^{-1}	1.1×10^{-2}	2.7×10^{-9}
Kr-87	8.3×10^{-1}	1.7×10^{-1}	3.9×10^{-8}
Kr-88	7.5×10^{-1}	2.8×10^{-1}	7.0×10^{-8}
Xe-131m	4.7×10^{-1}	7.6×10^{-2}	1.8×10^{-8}
Xe-133m	4.9×10^{-1}	2.4×10^{-2}	6.0×10^{-9}
Xe-133	4.8×10^{-1}	4.8×10^{-1}	1.2×10^{-7}
Xe-135m	9.3×10^{-1}	1.6×10^{-1}	3.8×10^{-8}
Xe-135	5.5×10^{-1}	6.8×10^{-1}	1.7×10^{-7}
Xe-137	9.8×10^{-1}	4.2×10^{-2}	1.0×10^{-8}
Xe-138	9.4×10^{-1}	1.5×10^{-1}	3.5×10^{-8}

Table 11.1-5
Normal Plant Operation Source Terms
Groups II, III, IV, and V
(Based on ANSI/ANS-18.1-1984)

Group II - Halogens

Nuclide	Reactor Coolant Activity (µCi/gram)	Steam Generator Liquid Activity (µCi/gram)	Steam Generator Steam Activity (µCi/gram)
Br-84	2.0×10^{-2}	1.2×10^{-7}	1.2×10^{-9}
I-131	5.0×10^{-2}	3.6×10^{-6}	3.6×10^{-8}
I-132	2.6×10^{-1}	5.4×10^{-6}	5.4×10^{-8}
I-133	1.6×10^{-1}	9.3×10^{-6}	9.3×10^{-8}
I-134	4.2×10^{-1}	4.0×10^{-6}	4.0×10^{-8}
I-135	3.1×10^{-1}	1.2×10^{-5}	1.2×10^{-7}

Group III - Rubidium, Cesium

Nuclide	Reactor Coolant Activity (µCi/gram)	Steam Generator Liquid Activity (µCi/gram)	Steam Generator Steam Activity (µCi/gram)
Rb-88	2.3×10^{-1}	8.6×10^{-7}	4.2×10^{-9}
Cs-134	7.5×10^{-3}	5.5×10^{-7}	2.9×10^{-9}
Cs-136	9.3×10^{-4}	6.7×10^{-8}	3.4×10^{-10}
Cs-137	9.9×10^{-3}	7.4×10^{-7}	3.7×10^{-9}

Group IV - N-16

Nuclide	Reactor Coolant Activity (µCi/gram)	Steam Generator Liquid Activity (µCi/gram)	Steam Generator Steam Activity (µCi/gram)
N-16	4.0×10^{1}	1.3×10^{-6}	1.3×10^{-7}

Group V - Tritium

Nuclide	Reactor Coolant Activity (µCi/gram)	Steam Generator Liquid Activity (µCi/gram)	Steam Generator Steam Activity (µCi/gram)
H-3	1.0×10^{0}	1.0×10^{-3}	1.0×10^{-3}

Table 11.1-5(Continued)
Normal Plant Operation Source Terms
Group VI - Miscellaneous Nuclides
(Based on ANSI/ANS-18.1-1984)

Nuclide	Reactor Coolant Activity (μCi/gram)	Steam Generator Liquid Activity (μCi/gram)	Steam Generator Steam Activity (μCi/gram)
Na-24	5.3×10^{-2}	2.8×10^{-6}	1.4×10^{-8}
Cr-51	3.3×10^{-3}	2.5×10^{-7}	1.2×10^{-9}
Mn-54	1.7×10^{-3}	1.2×10^{-7}	6.2×10^{-10}
Fe-55	1.3×10^{-3}	9.3×10^{-8}	4.7×10^{-10}
Fe-59	3.2×10^{-4}	2.3×10^{-8}	1.2×10^{-10}
Co-58	4.9×10^{-3}	3.6×10^{-7}	1.8×10^{-9}
Co-60	5.6×10^{-4}	4.2×10^{-8}	2.1×10^{-10}
Zn-65	5.4×10^{-4}	4.0×10^{-8}	1.9×10^{-10}
Sr-89	1.5×10^{-4}	1.1×10^{-8}	5.5×10^{-11}
Sr-90	1.3×10^{-5}	9.3×10^{-10}	4.7×10^{-12}
Sr-91	1.1×10^{-3}	5.2×10^{-8}	2.6×10^{-10}
Y-90	1.5×10^{-6}	1.1×10^{-10}	5.7×10^{-13}
Y-91m	5.6×10^{-4}	5.3×10^{-9}	2.7×10^{-11}
Y-91	5.5×10^{-6}	4.0×10^{-10}	2.1×10^{-12}
Y-93	4.8×10^{-3}	2.2×10^{-7}	1.1×10^{-9}
Zr-95	4.2×10^{-4}	3.0×10^{-8}	1.5×10^{-10}
Nb-95	3.0×10^{-4}	2.1×10^{-8}	1.1×10^{-10}
Mo-99	7.0×10^{-3}	4.7×10^{-7}	2.3×10^{-9}
Tc-99m	5.5×10^{-3}	2.0×10^{-7}	1.0×10^{-9}
Ru-103	8.0×10^{-3}	5.9×10^{-7}	3.0×10^{-9}
Ru-106	9.6×10^{-2}	7.0×10^{-6}	3.4×10^{-8}
Rh-103m	9.2×10^{-3}	5.2×10^{-7}	2.7×10^{-9}
Rh-106	1.1×10^{-1}	6.0×10^{-6}	2.9×10^{-8}
Ag-110m	1.4×10^{-3}	1.0×10^{-7}	5.1×10^{-10}
Te-129m	2.0×10^{-4}	1.5×10^{-8}	7.4×10^{-11}
Te-129	2.9×10^{-2}	3.7×10^{-7}	1.9×10^{-9}
Te-131m	1.7×10^{-3}	1.0×10^{-7}	5.1×10^{-10}
Te-131	9.5×10^{-3}	4.8×10^{-8}	2.5×10^{-10}
Te-132	1.8×10^{-3}	1.2×10^{-7}	6.2×10^{-10}
Ba-137m	9.4×10^{-3}	7.0×10^{-7}	3.5×10^{-9}
Ba-140	1.4×10^{-2}	9.8×10^{-7}	4.9×10^{-9}
La-140	2.7×10^{-2}	1.8×10^{-6}	8.7×10^{-9}
Ce-141	1.6×10^{-4}	1.2×10^{-8}	5.9×10^{-11}
Ce-143	3.1×10^{-3}	1.9×10^{-7}	9.6×10^{-10}
Ce-144	4.3×10^{-3}	3.0×10^{-7}	1.6×10^{-9}
Pr-143	3.7×10^{-3}	2.3×10^{-7}	1.2×10^{-9}
Pr-144	4.9×10^{-3}	2.6×10^{-7}	1.3×10^{-9}
W-187	2.8×10^{-3}	1.6×10^{-7}	8.3×10^{-10}
Np-239	2.4×10^{-3}	1.6×10^{-7}	7.9×10^{-10}

Table 11.1-6
Parameters Used to Describe the Reactor System-Realistic Model

Parameter	Symbol	Units	
Thermal power	P	MWt	2958
Steam flowrate	FS	lbs/hr	1.3×10^7
Weight of water in the Reactor Coolant System	WP	lbs	3.9×10^5
Weight of water in all steam generators	WS	lbs	3.4×10^5
Reactor coolant letdown flow (purification)	FD	lbs/hr	3.0×10^4
Reactor coolant letdown flow (yearly average for boron control)	FB	lbs/hr	300
Steam generator blowdown flow (total)	FBD	lbs/hr	4.2×10^4
Fraction of radioactivity in blowdown stream which is not returned to the secondary coolant system	NBD	-	1.0
Flow through the purification system cation demineralizer	FA	lbs/hr	3.0×10^3
Ratio of condensate demineralizer flowrate to the total steam flowrate	NC	-	0.0
Ratio of the total amount of noble gases routed to gaseous radwaste from the purification system to the total amount of noble gases routed to the primary coolant system from the purification system (not including the Boron Recycle System)	Y	-	See Table 11.1-5
Primary to Secondary Leak Rate	-	lbs/day	100

Table 11.1-7
Tritium Production

Tritium Source	Expected Release to Reactor Coolant Curies/Cycle
Produced in Core	
Ternary Fissions	1420
IFBAs	237
Produced in Coolant	
Soluble Boron	805
Soluble Lithium	142
Deuterium	3.24
Total	2607

Note: Power level = 2958 MWt
IFBA B-10 mass = 1730 gm
Initial cycle reactor coolant boron concentration = 1200 ppm
Equilibrium cycle reactor coolant boron concentration = 2100 ppm
Lithium concentration (99.9 atom percent Li^7) = 2.2 ppm

11.2 Liquid Waste Systems

This section describes the design and operating features of the Liquid Waste Processing System (LWPS). In addition the total plant liquid releases from all sources are estimated and summarized in Section 11.2.6. Section 11.2.2 describes an upper limit system capacity which can be maintained for an indefinite period of time.

11.2.1 Design Objectives

The LWPS is designed to receive, control, segregate, process, reuse, and discharge liquid wastes. The system design considers potential personnel exposure and assures that quantities of radioactive releases to the environment are in accordance with 10 CFR 50, Appendix I.

Under normal plant operation, the activity from radionuclides leaving the penstock of the Fairfield Pumped Storage Facility, due to releases from the LWPS, is a small fraction of the effluent concentration limits (ECLs) as defined in Appendix B of 10 CFR 20.

Section 11.2.6 establishes that the LWPS adequately meets the above listed design objectives.

11.2.2 Systems Descriptions

The LWPS primarily collects and processes potentially radioactive wastes for release to the environment. Provisions are made to sample and analyze fluids before they are discharged. Based on the laboratory analysis, these wastes are either released under controlled conditions via the penstocks of the Fairfield Pumped Storage Facility or retained for further processing. Permanent records of liquid releases are provided by analyses of known volumes of waste. Alternatively, the liquid waste may be reused in the plant.

The bulk of the radioactive liquids discharged from the Reactor Coolant System is processed by the Reactor Grade Demineralizer System discussed in Section 9.3.6. This limits input to the LWPS and results in processing of relatively small quantities of generally low activity level wastes.

The LWPS consists of five collection systems which are provided by the waste holdup tank, floor drain tank, the laundry and hot shower tank, the Excess Liquid Waste Processing System (ELWS) (the excess waste holdup tank and the decon pit collection tank), and the laboratory drain system. Capability for handling and storage of spent demineralizer resins is also provided.

The LWPS does not include provisions for processing secondary system wastes. The Nuclear Blowdown Processing System (NBS) is discussed in Section 10.4.8. The segregation of primary and secondary side wastes is maintained since ammonia from the secondary side could result in the loss of LWPS demineralizer efficiency, and condenser inleakage could lead to undesirable chemical inclusion in the LWPS. Additionally, the mixing of low activity wastes (secondary side) with those of higher activity (primary side) should be avoided since a large volume of contaminated water is produced. The present design, which segregates primary and secondary

wastes, minimizes the amount of water which must be processed by discharging low activity wastes directly, where permissible, with no treatment.

In the event of equipment faults of moderate frequency (Section 11.2.4.2), the LWPS is capable of processing up to 1 gpm of primary coolant leakage with no change in system operation.

As a practical upper limit of system operation, the LWPS can process 25 gpm not including laundry type effluents which are normally discharged without processing. This liquid may be collected in either the floor drain tank or waste holdup tank or in both tanks.

Instrumentation and controls necessary for the operation of the LWPS are located on a control board in the Auxiliary Building. Any alarm on this control board is relayed to the main control board in the Control Room.

11.2.2.1 Waste Holdup Tank

The waste holdup tank is provided to collect both reactor and non-reactor grade water which enters the LWPS via equipment leaks and drains, valve leakoffs, pump seal leakoffs, tank overflows, Reactor Building sump flows, and other tritiated and aerated water sources.

Deaerated tritiated water inside the Reactor Building from sources such as valve leakoffs, which is collected in the reactor coolant drain tank, need not enter the waste holdup tank. These may be routed directly to the recycle holdup tanks for processing.

The basic composition of the liquid collected in the waste holdup tank is normally boric acid and water with some radioactivity. Liquid collected in this tank is normally processed through the Waste Water System (Duratek demineralizers) and released to the environment under controlled conditions.

Liquid wastes are released from the waste monitor tanks through the penstocks of the Fairfield Pumped Storage Facility. The discharge valve is interlocked with a process radiation monitor and closes automatically when the radioactivity concentration in the liquid discharge exceeds a preset limit. The waste monitor tanks act as a reservoir for storing waste which is to be released from the LWPS to the Fairfield Pumped Storage Facility. Prior to entering these tanks, the liquid may pass through a waste monitor tank demineralizer and a waste monitor tank filter, if required for additional cleanup.

Normally, the waste monitor tank demineralizer and filter are bypassed. A sample is taken and, after analysis, the results are logged and the liquid is discharged. This radiation monitor, RM-L5, is described in Section 11.4. Liquid waste discharge flow and volume are recorded.

11.2.2.2 Floor Drain Tank

The floor drain tank is provided to collect non-reactor grade (non-recyclable) liquid wastes. These include floor drains, equipment drains containing non-reactor grade water, and other non-reactor grade sources. Normally, only non-radioactive water is collected in the floor drain tank which can

then be sent directly to the waste monitor tank without processing and subsequently discharged. If there is activity in the floor drain tank liquid and is such that the discharge limits cannot be met without cleanup, the liquid may be processed through the Waste Water System (Duratek demineralizers) and released under controlled conditions via the penstocks of the Fairfield Pumped Storage Facility.

Non-recyclable reactor coolant leakage normally enters the floor drain tank from system leaks in the Auxiliary Building via the floor drains. This liquid is not reused because it is diluted and contaminated by non- reactor grade water entering the floor drain tank from other sources. Sources of water include fan cooler leaks, secondary side steam and feedwater leaks, component cooling water leaks, and decontamination water.

11.2.2.3 Laundry and Hot Shower Tank

Laundry and hot shower drains normally need no treatment for removal of radioactivity. This water is transferred to waste monitor tank number 2 via the laundry and hot shower filter. A sample is taken and, after analysis, the results are logged and the water is discharged if the activity level is below acceptable limits.

11.2.2.4 Excess Liquid Waste Processing System (ELWS)

The ELWS consists of two storage tanks, the excess waste holdup tank and the decon pit collection tank.

The excess waste holdup tank is used to accept excess liquid waste from the floor drain tank, laundry and hot shower tank, and waste holdup tank when these tanks are filled to capacity. The liquid from this tank can be recycled back to these tanks, released directly to the environment via the waste monitor tank, or processed through the Duratek demineralizers prior to release from the plant.

The decon pit collection tank collects liquid from the Fuel Handling Building sumps, the Radiological Maintenance Building drains, excess waste holdup tank sump, excess waste holdup area sump, and decon pit drains. If the activity in this tank liquid is such that the discharge limits cannot be met without cleanup, the liquid is processed through the Duratek demineralizers and released under controlled conditions via the penstocks of the Fairfield Pumped Storage Facility.

This system also normally receives liquid waste from the Normal and Post Accident Sampling System waste pump. In addition, the Turbine Building Floor Drain System discharge will be directed to the ELWS when excessive radioactive discharge is detected by radiation monitor number RM-L8.

11.2.2.5 Laboratory Drain System

The laboratory drain system consists of three sinks in the radiochemical laboratory and two sinks in the sample room.

In the radiochemical laboratory spent reactor coolant samples, equipment rinse water and other non-reactor grade fluids are disposed of in the two sinks that drain to the floor drain tank. No liquids or wastes are intentionally disposed of in the sink that drains to the chemical drain tank.

In the sample room, excess sample purges of reactor grade water and excess reactor coolant samples are drained from one sink to the waste holdup tank for processing. The other sink is used for draining non-reactor grade fluids to the nuclear blowdown holdup tank.

11.2.2.6 Waste From Spent Resin

The spent resin sluice portion of the LWPS consists of a spent resin storage tank, a spent resin sluice pump, and a spent resin sluice filter. The equipment is arranged such that the resin sluice water after entering a demineralizer vessel returns to the spent resin storage tank for reuse. The purpose of this system is to transport spent resin to the spent resin storage tank without generating large volumes of waste liquid. This is accomplished by reusing the sluice water for subsequent resin sluicing operations.

11.2.3 System Design

11.2.3.1 Component Design

Principal design parameters for the LWPS equipment are given in Table 11.2-2. Parts or components in contact with borated water are fabricated from or clad with austenitic stainless steel except for the Royal Flex hose provided by the vendor as an integral part of the Duratek demineralizers. The Royal Flex hose is a reinforced Thermoplastic Vinyl Nitrile hose. Pumps are provided with vent and drain connections.

Component safety classes and the corresponding code and code class are shown in Table 3.2-1. Except for flanged joints and quick disconnect couplings, all-welded construction is used.

Table 11.2-3 lists the isotopic inventory of each major component, using the following assumptions:

1. Concentrations based on an equivalent fuel defect level of 1 percent. Values given in the table indicate liquid activity only.
2. For tanks upstream of the Duratek system (floor drain tank, waste holdup tank), the tanks were assumed 80 percent full of primary coolant.
3. The tanks downstream of the Duratek system were assumed 80 percent full of processed primary coolant.
4. The Duratek system components for a typical lineup are shown in Figure 11.2-5.
5. The laundry and hot shower tank was assumed 80 percent full of laundry waste water.

These activities are the recommended source terms for the analysis of consequences of a postulated failure of the LWPS components.

11.2.3.1.1 Pumps

11.2.3.1.1.1 Reactor Coolant Drain Tank Pumps

Two pumps are provided. One reactor coolant drain tank pump provides sufficient flow for normal tank operation with one pump for standby.

11.2.3.1.1.2 Waste Evaporator Feed Pump

One pump of standard design is used. The waste evaporator feed pump is used to transfer liquid from the waste holdup tank. The pump trips off in auto.

11.2.3.1.1.3 Waste Evaporator Condensate Pump

The waste evaporator condensate pump is a transfer pump. One pump of standard design is used to transfer the contents of the waste evaporator condensate tank to the waste monitor tank.

11.2.3.1.1.4 Chemical Drain Tank Pump

The chemical drain tank pump is of standard design and is used to transfer the liquid from the chemical drain tank.

11.2.3.1.1.5 Spent Resin Sluice Pump

This pump is identical to the reactor coolant drain tank pumps. Its delivery flow is based on the required velocity to sluice resin.

11.2.3.1.1.6 Laundry and Hot Shower Tank Pump

The laundry and hot shower tank pump is of standard design and is used to transfer the water to the waste monitor tank.

11.2.3.1.1.7 Floor Drain Tank Pump

The floor drain tank pump is of standard design and is used to normally transfer water to the waste monitor tank.

11.2.3.1.1.8 Waste Monitor Tank Pumps

A waste monitor tank pump is of standard design and is used for each tank to discharge water from the LWPS or for recycle if further processing is required. The pump may also be used for circulating the water in the waste monitor tank in order to obtain uniform tank contents and hence a representative sample before discharge. The pump can be throttled to achieve the desired discharge rate.

11.2.3.1.1.9 Excess Liquid Waste Pumps

The two excess liquid waste pumps are used to transport the waste fluid from the excess waste holdup tanks through the processing portion of the ELWS and to return waste to the LWPS. These pumps also circulate the waste in the tank to obtain proper mixing prior to sampling tank contents.

11.2.3.1.2 Reactor Coolant Drain Tank Heat Exchanger

The reactor coolant drain tank heat exchanger is a U-tube type with one shell pass and four tube passes. Although the heat exchanger is normally used in conjunction with the reactor coolant drain tank, it can also cool the pressurizer relief tank contents from 200 to 120°F in less than 8 hours.

11.2.3.1.3 Tanks

11.2.3.1.3.1 Reactor Coolant Drain Tank

One tank is provided. The purpose of the reactor coolant drain tank is to collect leakoff type drains inside the Reactor Building at a central collection point for further disposition through a single penetration via the reactor coolant drain tank pumps. The tank provides surge and net positive suction head requirements to the pumps.

Only water which can be directed to the recycle holdup tanks enters the reactor coolant drain tank. The water must be compatible with reactor coolant and it must not contain dissolved air.

Sources of water entering the reactor coolant drain tank include the reactor vessel flange leakoff, valve leakoffs, number 3 seal leakoffs from the reactor coolant pumps, and the excess letdown heat exchanger flow. No continuous leakage is expected from the reactor vessel flange during operation.

A constant level is maintained in the tank to minimize the amount of gas sent to the gaseous waste processing system and also to minimize the amount of hydrogen required. The level is maintained by running one pump continuously and using a proportional control valve in the discharge line. This valve operates on a signal from a level controller to limit the flow out of the system. The remainder of the flow is recirculated to the tank.

11.2.3.1.3.2 Waste Holdup Tank

One atmospheric pressure tank is provided outside the Reactor Building to collect equipment drains, valve and pump seal leakoffs, recycle holdup tank overflows, Reactor Building sump fluid, and other water from tritiated aerated sources.

11.2.3.1.3.3 Waste Evaporator Condensate Tank

One tank with a diaphragm to exclude air is provided to collect low level liquid waste prior to sending it to the waste monitor tank.

11.2.3.1.3.4 Chemical Drain Tank

One tank is available to collect chemically contaminated tritiated water from the laboratories; however, this tank is normally not used.

11.2.3.1.3.5 Spent Resin Storage Tank

The purpose of the spent resin storage tank is to provide a collection point for spent resin to allow for decay of short lived radionuclides before disposal. The tank serves also as a head tank for the spent resin sluice pump.

The tank is designed so that sufficient pressure can be applied in the gas space of the tank to push resin out and to the solid waste disposal unit, which is at a higher elevation than the spent resin storage tank.

The spent resin storage tank is shielded to limit the dose to personnel.

11.2.3.1.3.6 Laundry and Hot Shower Tank

One atmospheric pressure tank is used to collect laundry and hot shower drains.

11.2.3.1.3.7 Floor Drain Tank

One atmospheric pressure tank is used to collect floor drains from the reactor plant.

11.2.3.1.3.8 Waste Monitor Tanks

The two atmospheric waste monitor tanks are provided for monitoring liquid discharges from the plant site. Each tank is sized to hold a volume large enough such that sampling requirements are minimized, thus minimizing further laboratory effluent.

11.2.3.1.3.9 Excess Waste Holdup Tank

The excess waste holdup tank normally receives liquid waste from the floor drain tank, laundry and hot shower tank, and waste holdup tank when these tanks are filled to capacity.

This system also normally receives liquid waste from the Normal and Post Accident Sampling System waste pump. In addition, the Turbine Building Floor Drain System discharge will be directed to this tank when excessive radioactive discharge is detected by radiation monitor number RM-L8.

11.2.3.1.3.10 Decontamination Pit Collection Tank

The decontamination pit collection tank receives drainage from the Fuel Handling Building sumps, the Radiological Maintenance Building drains, excess waste holdup tank sump, excess waste holdup area sump, and decon pit drains.

11.2.3.1.4 Demineralizers

As part of a continuous PWR operating plant following, Westinghouse has obtained operational data on demineralizer decontamination factors for selected isotopes. The measured range of decontamination factors for these isotopes is given in Table 11.2-4.

These values were observed across mixed bed demineralizers containing cation resin in the lithium-7 form and anion resin in the borated form.

The minimum values in Table 11.2-4 were generally observed just prior to resin flushing and recharging, while during the operating life of the demineralizer, decontamination factors were consistently closer to the maximum values.

Although specific operating decontamination factors have not as yet been measured for other isotopes, their behavior in a similar purification media may be inferred from this data. One would anticipate, for example, bromine to have a decontamination factor similar to that given above for the iodine and fluorine.

11.2.3.1.4.1 Waste Water System (Duratek Demineralizers)

The Waste Water System (Duratek demineralizers) is provided to process radioactive waste prior to release to the environment. The Duratek demineralizers are located on the 447’ elevation of the Auxiliary Building. Prior to entering the mixed bed and cation Duratek demineralizers, the liquid waste stream is normally processed through a charcoal vessel. The charcoal media acts as a prefilter providing mechanical filtration capability prior to the Duratek demineralizers. The charcoal filtration provides for cleanup of oil and grease (organics), cobalt 58 and 60, initial iodines, cesium, and other suspended solids.

The liquid waste stream enters the Duratek demineralizers through a booster pump, a mechanical filter, and an Influent Control Leg which monitors waste stream parameters and provides attachments for service air and water. From the Influent Control Leg, the waste may enter one of the five pressure vessels that contain media for cleanup of the liquid waste. The media normally include:

- Cation resin to remove metals and transition metals.
- Mixed bed resin that reduces undesired positive and negative ions.
- Charcoal media for cleanup of oil and grease (organics), cobalt 58 and 60, initial iodines, and cesium and for service as a prefilter to protect the other demineralizer beds.

A typical lineup for the five Duratek demineralizers in series would be charcoal, cation, charcoal, cation, mixed bed with cation.

The actual required vessel lineup during normal plant operation is determined prior to processing by sampling the tank to be processed and determining the parameter(s) that are out of specification. Selection of the appropriate vessels is made by a quick-disconnect logic

arrangement. After processing, decontaminated effluent passes through an Effluent Control Leg which records waste volume, and may flow through a combined resin polisher.

Polyelectrolytes may be added upstream of the second charcoal vessel to help remove colloidal cobalt. This is mainly used during an outage post reactor coolant system cleanup.

11.2.3.1.4.2 Waste Evaporator Condensate Demineralizer

One demineralizer vessel is provided which is used during primary demineralizer resin (CVCS) transfer and provides a means to tie the resin supply and return headers together during resin transfer to prevent resin excursions throughout the solid waste system. The demineralizer vessel is empty (no contained resin beds) and is not used for waste decontamination.

11.2.3.1.4.3 Waste Monitor Tank Demineralizer

One demineralizer is provided upstream of the waste monitor tanks.

11.2.3.1.4.4 Excess Liquid Waste Demineralizers

Two redundant demineralizers are provided in the ELWS process train. Liquid wastes may be passed through one demineralizer prior to being discharged to a waste monitor tank.

11.2.3.1.5 Filters and Strainers

11.2.3.1.5.1 Filters

The filters provided are of a wound cartridge or spun cartridge type construction which relies on a tortuous path to filter particles with an absolute rating.

The methods employed to change filters and screens are dependent on activity levels. Filters are valved out of service with a pressure indicator between the isolation valves to assure the valves are not leaking and the filter is not at system pressure. The filter is drained to the appropriate tank and vented locally. If the radiation level of the filter is low enough, it is changed manually. If activity levels do not permit manual change, the spent cartridge is removed remotely with temporary shielding to protect personnel. The spent cartridge is placed in a shielded pig for removal to the solid waste disposal area. A new cartridge is installed, the housing is reassembled, vent and drain valves are closed, and the filter is valved into service. Filters are normally changed because of high ΔP rather than high radiation levels.

The excess liquid waste filters are back flushable and have cylindrical woven screen cartridges. One of the two excess liquid waste filters removes suspended solids from the waste water upstream of the demineralizers. The second filter traps resin fines downstream of the demineralizer.

11.2.3.1.5.2 Strainers

The strainers provided are basket type which are of a mesh or screen construction. The nominal rating of the strainers is given in Table 11.2-2.

The basket type laundry and hot shower strainer is not replaced after use, but is cleaned and put back in service. Because this screen traps only large particles, it contains only negligible activity and provides no hazard to personnel. It is cleaned regularly.

The decontamination pit collection tank strainer is a duplex basket strainer that removes large suspended particles from the wastes entering the decontamination pit collection tank. This strainer is also cleaned and put back into service.

11.2.3.2 Instrumentation Design

The system instrumentation is described in Table 11.2-5. The instrumentation readout is located mainly on the Waste Processing System (WPS) panel in the Auxiliary Building and excess liquid waste panel (ELWP) in the Fuel Handling Building. Some instruments are read where the equipment is located. Alarms are shown on the WPS panel or ELWP and further relayed to one common WPS annunciator on the main control board in the Control Room.

Pumps are protected against loss of suction pressure by a control setpoint on the level instrumentation for the respective vessels feeding the pumps. The reactor coolant drain tank pumps and the spent resin sluice pump are in addition interlocked with flowrate instrumentation and stop operating when the delivery flows reach minimum setpoints.

Pressure indicators upstream and downstream of filters, strainers, and demineralizers provide local indications of pressure drops across each component.

All releases to the environment are monitored for radioactivity.

11.2.3.3 Tank Overflow Protection

All tanks in the Chemical and Volume Control System (CVCS), Boron Recycle System (BRS), NBS, and WPS that could potentially contain radioactive liquids are designed to provide adequate warning of potential overflow conditions. A summary of the overflow protection features is given in Table 11.2-6. These tanks are provided with level indication instrumentation which has an alarm function on high liquid level in the tank. Alarm annunciation is provided separately on the local system control panel and further relayed to a common annunciator on the main control board in the Control Room for each system. A description of the level instrumentation provided for these systems is given in Sections 9.3.4.5, 9.3.6.5, 10.4.8.2, and 11.2.3.2 for the CVCS, BRS, NBS, and LWPS, respectively.

In addition to tank level monitoring and warning of potential overflow conditions, provisions are made in the systems design to collect and process overflows from tanks containing potentially radioactive liquids. The collection and processing provisions are delineated in Table 11.2-6.

Table 11.2-6a presents a comparison of tanks with Branch Technical Position ETSB 11-1 (Rev. 1), Paragraph B.1.b, Items (1) through (4).

11.2.4 Operating Procedures

The LWPS is manually operated except for some functions of the reactor coolant drain tank circuit. The system includes adequate control equipment to protect the system components and adequate instrumentation and alarm functions to provide operator information to ensure proper system operation.

11.2.4.1 Normal Operation

Operation of the LWPS is essentially the same during all phases of normal and defined off-normal reactor plant operation; the only differences are in the loads on the system. The following sections discuss the operation of the system in performing its various functions. In this discussion, the term “normal operation” should be taken to mean all phases of operation except operation under emergency or accident conditions. The LWPS is not regarded as an Engineered Safety Feature System.

11.2.4.1.1 Waste Holdup Tank

Water is accumulated in the waste holdup tank until sufficient quantity exists to warrant processing through the Waste Water System (Duratek demineralizers).

When this water has been sufficiently processed, it is discharged into the penstocks of the Fairfield Pumped Storage Facility at a rate so as not to exceed a small fraction of the 10 CFR 20 limits. Water leaving this system is discharged to the penstocks of the Fairfield Pumped Storage Facility and is monitored for radiation. This radiation monitor, RM-L5, is described in Section 11.4. Should the radiation monitor close the discharge valve, it must be reset/bypassed before the valve can be reopened. The monitor element can be cleared by flushing it with demineralized water from the temporary connection back to the waste monitor tank. During refueling, the load on the waste portion of the LWPS is increased but there is no change in operation.

During normal operation, the reactor coolant drain tank level regulation and pressure control are automatic and require no operator action.

Operation of the recycle portion of the LWPS during refueling is the same as for power operation, although the load on the system may be increased when refueling is complete. The water remaining in the fuel transfer canal following normal drain down is pumped to the suction of the refueling water purification pump by the reactor coolant drain tank pumps. When the pumps lose suction, the remainder is drained to the RB sump and pumped to the waste holdup tank for processing.

11.2.4.1.2 Floor Drain Tank

The water in the floor drain tank is sampled to determine the degree of processing required. Normally the water collected in the floor drain tank is not radioactive and can be sent directly to the waste monitor tanks. If required, it can be processed through the Waste Water System. When this water has been sufficiently processed, it is discharged into the penstocks of the Fairfield Pumped Storage Facility at a rate so as not to exceed a small fraction of the 10 CFR 20 limits. Water leaving this system is discharged to the penstocks of the Fairfield Pumped Storage Facility and is monitored for radiation. This radiation monitor, RM-L5, is described in Section 11.4. Should the radiation monitor close the discharge valve, it must be reset/bypassed before the valve can be reopened. The monitor element can be cleared by flushing it with demineralized water from the temporary connection back to the waste monitor tank. During refueling, the load on the waste portion of the LWPS is increased but there is no change in operation.

11.2.4.1.3 Laundry and Hot Shower Tank

Laundry and hot shower water enters the laundry and hot shower tank for holdup. There it is sampled, filtered, and transferred to the waste monitor tank for discharge.

11.2.4.1.4 Excess Liquid Waste Processing System (ELWS)

The excess waste holdup tank is normally only used to collect excess flow from the floor drain tank, laundry and hot shower tank, and waste holdup tank when these tanks are filled to capacity. The decontamination pit collection tank receives drainage from the Fuel Handling Building sumps, the Radiological Maintenance Building drains, excess waste holdup tank sump, excess waste holdup area sump, and decon pit drains. The contents of these tanks are sampled to determine the degree of processing required. The liquid from this tank can be released directly to the environment via the waste monitor tank or, if required, processed through the Duratek demineralizers prior to release from the plant.

When this water has been sufficiently processed, it is discharged into the penstocks of the Fairfield Pumped Storage Facility at a rate so as not to exceed a small fraction of the 10 CFR 20 limits. Water leaving this system is discharged to the penstocks of the Fairfield Pumped Storage Facility and is monitored for radiation. This radiation monitor, RM-L5, is described in Section 11.4. Should the radiation monitor close the discharge valve, it must be reset/bypassed before the valve can be reopened. The monitor element can be cleared by flushing it with demineralized water from the temporary connection back to the waste monitor tank. During refueling the load on the waste portion of the LWPS is increased but there is no change in operation.

11.2.4.1.5 Laboratory Drain Portion

The laboratory drain system consists of three sinks in the radiochemical laboratory and two sinks in the sample room.

In the radiochemical laboratory spent reactor coolant samples, equipment rinse water and other non-reactor grade fluids are disposed of in the two sinks that drain to the floor drain tank. No liquids or wastes are intentionally disposed of in the sink that drains to the chemical drain tank.

In the sample room, excess sample purges of reactor grade water and excess reactor coolant samples are drained from one sink to the waste holdup tank for processing. The other sink is used for draining non-reactor grade fluids to the nuclear blowdown holdup tank.

11.2.4.1.6 Spent Resin Handling Portion

This portion of the system sluices resin from the demineralizers, transports resin from the spent resin storage tank to the solid waste disposal unit.

11.2.4.1.6.1 Resin Sluicing

Before resin sluicing begins, the demineralizer is valved out of service and the flowpath is aligned from the spent resin sluice pump through the process line of the demineralizer, through the screen at the top of the demineralizer, and back to the spent resin storage tank. The spent resin sluice pump provides flush water for loosening the bed for sluicing. After about 15 minutes of back flushing, the valves in the back flush circuit are closed and the sluice line is opened. The resin then flows to the spent resin storage tank. After the spent resin sluice pump is shut off, the fresh resin is added via the resin fill line and the valve is then closed. The flowpath is now aligned the same as for resin flushing, e.g., through the process line, through the screen at the top of the demineralizer, and back to the spent resin storage tank. The pump is then started to remove resin fines, should any remain. The valves are then realigned for normal process operation. Resins are never sluiced through the spent resin sluice pump

11.2.4.1.6.2 Resin Drumming

No resin drumming is performed on site.

11.2.4.1.7 Analysis of System Operation

In order to evaluate the expected operation of the LWPS, an analysis has been performed presenting average operating parameters and expected isotopic concentrations throughout the system. The analysis is based on normal operation, including anticipated operational occurrences, of the plant and the LWPS and a realistic estimation of the potential input sources based on plant operating experience. Hence, the results are representative of the anticipated operation of the LWPS of the Virgil C. Summer Nuclear Station. The input sources assumed in the study are summarized in Table 11.2-7, and the isotopic concentrations are based on reactor coolant inventories as given in Table 11.1-5. The resulting isotopic concentrations at key locations in the LWPS are given in Table 11.2-1. The study is not indicative of maximum system capacity as the maximum processing capability is considerably greater than the values given in Table 11.2-7. The analysis is not used as a basis for the plant release evaluation, which is based on the GALE Code (see Section 11.2.6).

11.2.4.2 Faults of Moderate Frequency

The system is designed to handle the occurrence of equipment faults of moderate frequency such as:

1. Malfunction in the LWPS

   Malfunction in this system could include pump, valve, or demineralizer failure. Because of pump standardization throughout the system, a spare pump can be used to replace most pumps in the system. There is sufficient surge capacity in the system to accommodate waste until the failure can be fixed and normal plant operation resumed.

2. Excessive Leakage in Reactor Coolant System Equipment

   The system is designed to handle a 1 gpm reactor coolant leak in addition to the expected leakage during normal operation.

   Operation of the system is almost the same as for normal operation except the load on the system is increased. A 1 gpm leak into the reactor coolant drain tank is handled automatically.

   If the 1 gpm leak enters the waste holdup tank, operation is the same as normal except for the increased load on the demineralizers. Abnormal reactor coolant leakage can also be accommodated by the floor drain tank and processed.

   As discussed in Section 11.2.2, a practical upper limit to the Duratek demineralizer processing capacity is 25 gpm. Depending on the source of the liquid, the 25 gpm may be collected in either the floor drain tank or waste holdup tank or both tanks. Normally the potentially radioactive fluids are only collected in the waste holdup tank since the floor drain tank is typically used to collect non-radioactive leakage. If the flow is collected in both tanks, the effluent should be discharged after processing. It is possible to operate in this condition for an indefinite time.

3. Excessive Leakage in Auxiliary System Equipment

   Leakage of this type could include water from fan cooler leaks inside the Reactor Building which is collected in the Reactor Building sump and sent to the waste holdup tank. Other sources could be Component Cooling water leaks, Service Water Leaks, and steam and secondary side leaks. This water enters the floor drain tank and is processed and discharged as during normal operation.

NOTE 11.2.5

Section 11.2.5 is being retained for historical purposes only.

11.2.5 Performance Tests

Initial performance tests are performed to verify the operability of the components, instrumentation and control equipment, and applicable alarms and control setpoints.

The specific objectives are to demonstrate the following:

1. Pumps are capable of producing the flowrate and head as required.
2. Waste filters are capable of passing the required flowrate.
3. Waste evaporator is operable to specifications.
4. Instrumentation, controllers, and alarms operate satisfactorily to maintain process parameters, indicate, record, and alarm as required.
5. All sampling points are available for sampling.

During reactor operation, the system is used at all times and hence is under continuous surveillance.

11.2.6 Estimated Releases

Liquid releases from the Virgil C. Summer Nuclear Station are calculated using the PWR-GALE Code[1] as specified by Regulatory Guide 1.112 (see Appendix 3A). The input parameters used to calculate liquid releases are listed in Table 11.2-8 and are discussed in more detail below. Releases calculated using the parameters listed in Table 11.2-8 are presented in Tables 11.2-12 and 11.2-13. A comparison of effluent concentrations with 10 CFR 20, Appendix B, Table II, Column 2 values is presented in Section 11.2.8.

11.2.6.1 Reactor Grade Demineralizers

A conservatively estimated 300 gpd of reactor grade wastes are collected by the reactor coolant drain tank (equipment drain wastes).

The equipment drain wastes are processed via the reactor grade demineralizers prior to entering a waste monitor tank for monitoring and discharge. The release calculations use an assumed discharge fraction of 1.0.

Radioactive decay during collection of the equipment drains is conservatively calculated using a collection time of 2.08 days. Radioactive decay during processing is calculated using a process time of 0.11 days. No credit is taken for radioactive decay during discharge since the waste monitor tank may be discharged prior to complete processing.

The minimum expected decontamination factors for radionuclide removal with the Duratek system are 1,000 for iodine, 200 for cesium and rubidium, and 10,000 for other nuclides. These values are based upon the decontamination factors for two mixed bed and one cation demineralizer in series. In calculating the effluent releases, the above values are conservatively reduced by a factor 10.

The isotopic distribution of this release is given in Table 11.2-12.

11.2.6.2 Liquid Waste Processing System

11.2.6.2.1 Waste Holdup Tank

Wastes from reactor grade sample drains, valve and pump leakoffs, and equipment drains outside the Reactor Building (clean wastes) are collected in the 10,000 gallon waste holdup tank and processed through the Waste Water System. The processed wastes are pumped to a waste monitor tank for monitoring and discharge or additional processing, if required. Based upon the information in (Reference 1) for liquid waste volumes and activities and on expected volumes and activities for liquid wastes not included in (Reference 1), the total flow is conservatively estimated to be 200 gpd at primary coolant activity (PCA). The release calculations conservatively use a discharge fraction of 1.0.

Radioactive decay during collection in the waste holdup tank is calculated using a collection time of 2.08 days. This value is based upon filling the waste holdup tank to 40 percent of capacity. Radioactive decay during processing is calculated using a process time of 0.11 days. This value is based upon processing 80 percent of the waste holdup tank capacity at the design flow rate of 25 gpm. No credit is taken for radioactive decay during discharge since the waste monitor tank may be discharged before the waste holdup tank is completely processed.

The minimum expected decontamination factors for radionuclide removal with the Waste Water System are 1,000 for iodine, 200 for cesium and rubidium, and 10,000 for other nuclides. These values are based upon the decontamination factors for two mixed bed and one cation demineralizer in series. In calculating the effluent releases, the above values are conservatively reduced by a factor of 10.

The isotopic distribution of this release is given in Table 11.2-12.

11.2.6.2.2 Floor Drain Tank

Wastes from floor drains, laboratory drains, and miscellaneous sources are collected in a 10,000 gallon floor drain tank, sampled to determine the degree of processing required and processed as necessary through the Waste Water System. The processed wastes are then pumped to a waste monitor tank for monitoring and discharge. Based upon the information in Reference 1 for liquid waste volumes and activities, the waste flow is estimated to be 1340 gpd at 0.05 PCA. Since all of the processed wastes are normally discharged, a discharge fraction of 1.0 is used in the release calculations.

Radioactive decay during collection in the floor drain tank is calculated using a collection time of 2.97 days. This value is based upon filling the floor drain tank to 40 percent of capacity. Radioactive decay during processing is calculated using process time of 0.11 day. This value is based upon processing 80 percent of the floor drain tank capacity at the design flow rate of 25 gpm. No credit is taken for radioactive decay during discharge since the waste monitor tank may be discharged before the floor drain tank is completely processed.

The minimum expected decontamination factors for radionuclide removal with the Waste Water System are 1,000 for iodine, 200 for cesium and rubidium, and 10,000 for other nuclides. These values are based upon the decontamination factors given in Reference 1 for two mixed bed and one cation demineralizer in series. In calculating the effluent releases, the above values are conservatively reduced by a factor 10.

The isotopic distribution of this release is given in Table 11.2-12.

11.2.6.3 Detergent Wastes

The plant typically ships all protective clothing off site for cleaning. There is a washer and dryer located in the HP area that is periodically used to clean personal garments. The potential release from this mechanism is considered negligible. Therefore, since there are no full scale onsite laundry facilities, consistent with the assumptions in the PWR-GALE Code (Reference 1), there are no releases assumed from this pathway.

11.2.6.4 Secondary System

11.2.6.4.1 Turbine Building Floor Drains

The discharge from the Turbine Building Floor Drain System is monitored by a flow meter and a radiation monitor since wastes collected by the Turbine Building Floor Drain System may contain small quantities of radioactive materials resulting from secondary system leakage. These wastes are not treated prior to discharge. The isotopic distribution of this release is given in Table 11.2-12.

The discharge flow is monitored by radiation monitor number RM-L8. If radiation discharge limits are exceeded, the sump pumps are automatically tripped and the flow path may be aligned to discharge to the Excess Liquid Waste System per plant procedure HPP-710.

11.2.6.4.2 Condensate Cleanup System

The Condensate Cleanup System is used during startup and as required during condenser leakage. Scheduled, infrequent operation minimizes the possibility of producing potentially radioactive waste. Based upon PWR-GALE Code (Reference 1) criteria and infrequent operation, polishers will have no impact on release calculations.

11.2.6.4.3 Steam Generator Blowdown

Blowdown from the steam generators is processed as required through the NBS and returned to the condenser. There are also provisions for the discharge of treated or untreated blowdown. If the blowdown contains any significant quantity of radioactivity, radiation-monitor-controlled valves automatically divert the blowdown flow to the NBS.

With the 100 lbs/day primary-to-secondary leakage used in the PWR-GALE Code (Reference 1), blowdown flow would always be diverted to the NBS. Consequently, release calculations were performed on this basis.

Blowdown that is to be processed through the NBS is routed to a 14,000 gallon holdup tank and is processed through one of two demineralizer trains, each containing a mixed bed primary demineralizer and a mixed bed polishing demineralizer. Release calculations are based upon processing 45,000 lbs/hr of blowdown through one of the demineralizer trains and discharging 100 percent of the treated blowdown.

Radioactive decay during collection in the holdup tank is calculated using a collection time of 0.01 day. This value is based upon filling the holdup tank to 40 percent capacity. No credit is taken for radioactive decay during processing or discharge.

The decontamination factors used in calculating radionuclide removal are 1,000 for iodine, 100 for cesium and rubidium, and 1,000 for other nuclides. These values are based upon the decontamination factors given in Reference 1 for two steam generator blowdown mixed bed demineralizers in series.

The isotopic distribution of this release is given in Table 11.2-12.

11.2.6.5 Adjustments to Liquid Radwaste Source Term for Anticipated Operational Occurrences

The PWR-GALE Code (Reference 1) increases the calculated source term by 0.15 Ci/yr per reactor using the same isotopic distribution as the calculated source term to account for anticipated operational occurrences. This adjustment, plus the calculated tritium release, results in the releases given in Table 11.2-12.

11.2.6.6 Criteria for Reuse, Discharge, and Recycle

Processed liquids are normally discharged under the following conditions:

1. The processed water does not satisfy plant operating requirements for water quality and tritium buildup.
2. The effluent concentrations are within the limits specified by 10 CFR 20, Appendix B, Table II, Column 2.
3. The discharge does not cause the limits of 10 CFR 50, Appendix I to be exceeded.

Processed liquids could be reused within the plant if desired, provided that the following criteria are satisfied:

1. The plant water inventory requires makeup.
2. The water to be reused satisfies system water quality requirements.
3. Tritium buildup is less than plant operating requirements.

11.2.7 Release Points

Flow diagrams for the systems which have the potential to release radioactive materials in liquid effluents are shown by Figures 9.3-14, 9.3-18, 10.4-7a, 10.4-13, 10.4-14, 10.4-17. The locations of the release points for three systems are as follows:

Releases from the LWPS (Figure 11.2-1) and Reactor Grade System (Figure 9.3-18) are made through waste monitor tank 1 or 2 in the LWPS. Releases of detergent wastes are made through waste monitor tank 2 in the LWPS. Releases from the waste monitor tanks are piped to the penstocks of the Fairfield Pumped Storage Facility where they are diluted by the water released to the Broad River during the generating portion of the pumped hydro cycle. Planned liquid releases are made only during the generating portion of the cycle. Figure 11.2-3 shows the location of this release point relative to the plant site. Figure 11.2-4 is a close-up of the facility.

If processed steam generator blowdown (see Figure 10.4-14) is released to the environment, it is piped to the penstocks of the Fairfield Pumped Storage Facility where it is diluted by the water released through the dam during the generating portion of the cycle. If unprocessed steam generator blowdown (see Figure 10.4-13) is released to the environment, it is released through the circulating water discharge canal. During startup, blowdown may be routed to the alum sludge lagoon in the Industrial Waste System. Releases from this system are routed to the discharge canal by a 24 inch pipe which terminates at the circulating water discharge structure. The circulating water discharge canal is shown by Figure 2.4-1.

Liquid effluents from the Turbine Building floor drains (Figure 9.3-15) are released through a collecting sump in the Industrial Waste System which, when discharged, is routed to the circulating water discharge canal.

11.2.8 Dilution Factors

Concentrations of radioactive effluents in waters affected by operation of the plant were calculated according to the methods set forth in Regulatory Guide 1.113. The specific rationale utilized is as follows.

During the daily generating phase of the Fairfield Pumped Storage Facility, 29,000 acre-feet of water from Monticello Reservoir will flow into Parr Reservoir. A similar amount will later be pumped back into Monticello Reservoir during periods of off-peak power demand; this volume of water is equivalent to 14,620 cfs over a 24 hour period. In contrast, the average stream flow of the Broad River at Parr Dam is about 5,600 cfs, amounting to less than 40 percent of the daily volume

of water exchanged. Thus, mixing between the two reservoirs is expected to be relatively complete. This expectation has been confirmed by physical model studies conducted by Alden Research Laboratories (Reference 2) which indicate that effluents present in the plant discharge achieve nearly equal steady-state concentrations throughout the Parr-Monticello system. Therefore, it is preferable to consider the system as a single reservoir unit for the purposes of aquatic modeling. Several analytical models suitable for use in simulation of reservoirs and cooling ponds are described in Appendix A, Section 5, of Regulatory Guide 1.113. For the Parr-Monticello system, the pond blowdown rate, Q_b, is equivalent to the flow rate of the Broad River. A flow rate of 5,600 cfs, equal to the average stream flow of the Broad River at Parr Dam, was used. The plant pumping rate, Q_p, is the plant condenser water recirculation rate. A flow rate of 480,000 gpm, or 1,069 cfs, was utilized as an appropriate value under average conditions. The resulting recirculation factor, R, is determined by the ratio Q_b/Q_p and has a value of 5.24. Review of Figure 12 from Regulatory Guide 1.113 shows that, with the above determined values of 5.24 for R and a flushing time, Vt/Q_b, of 36.2 days, the partially mixed flow model approaches the plug flow model for relatively long lived isotopes. Conservatively ignoring credit for radiological decay and use of the plug flow model is conservative for short lived isotopes.

Therefore, conservatively ignoring radiological decay, the dilution factor simply relates to the final flow or 5,600 cfs, equal to the average stream flow of the Broad River at Parr Dam (FSAR Table 2.4-3).

In addition to the limits for each isotope, the requirements of 10 CFR 20 state that, for a mixture of radionuclide, the following relationship must hold:

$$\sum_{i=1}^{N} \frac{C_i}{ECiL} \leq 1$$

where:

C_i = concentration of radionuclide I.
EC_iL = effluent concentration limit (ECL) of radionuclide i from 10 CFR 20, Appendix B, Table II, Column 2.
N = number of radionuclides in the mixture.

The sum of the ratios of expected radionuclide concentrations to their ECL values for the mixture defined by the second column of Table 11.2-13 is 6.8×10^{-4}, which is less than unity, as required.

11.2.9 Estimated Doses

Potential pathways of exposure of man to radioactive materials in liquid effluents from the Virgil C. Summer Nuclear Station are identified and discussed in Section 11.6.2. Doses to individuals in the environs of the plant from each of the potentially significant pathways were calculated; methodology for and results of the calculations are discussed in the following paragraphs.

All results presented in these sections were obtained using the calculational techniques prescribed in Regulatory Guide 1.109. Except where noted in discussion of doses for specific pathways, all usage and consumption values, transport times, bioaccumulation factors, dose conversion factors, and other constants utilized were those suggested in Regulatory Guide 1.109.

Dilution factors for liquid pathways were calculated according to the methods of Regulatory Guide 1.113, as discussed in Section 11.2.8.

Doses to individuals were calculated for drinking water, fish consumption, and recreational activity (swimming, boating, shoreline activity) pathways. Assumptions, including point of exposure, are described for each pathway in the following paragraphs; the calculated liquid pathway doses are summarized in Table 11.2-14. Each dose was calculated at the location of the highest dose offsite at which the pathway could be assumed to exist.

The nearest downstream point of withdrawal of drinking water for human use is at Columbia, S. C., where the city of Columbia water supply system utilizes water from the Broad River. The dose to an individual obtaining his entire annual water requirement from this system was calculated. The maximum calculated dose to a single organ from this pathway was 1.4×10^{-1} mrem/yr to an infant's liver; maximum whole body dose was 4.6×10^{-2} mrem/yr to an adult.

Radionuclides released from the plant were assumed to be immediately available for uptake by fish. For purposes of determining the annual dose to man from the fish consumption pathway, a transport time of 0 hours was used. The maximum predicted dose to a single organ from the fish consumption pathway was 3.3 mrem/yr to a teen's liver. Maximum total body dose was 1.35 mrem/yr to a teen.

Exposure to an adult swimming or boating on the reservoir or engaging in recreational activity on the shore was evaluated by assuming that the individual receiving the maximum dose spends 100, 500, and 500 hours per year, respectively, in the three activities. Doses from these pathways were evaluated based on the average radionuclide concentrations in the Parr-Monticello system. The doses from recreational exposure are summarized in Table 11.2-15. Maximum predicted total dose to a single organ from recreational pathways was 0.15 mrem/yr to the skin. Maximum calculated total body dose was 0.12 mrem/yr.

Maximum individual doses calculated as described above were used to evaluate the status of conformance of predicted liquid effluents from the Virgil C. Summer Nuclear Station with the requirements of Appendix I to 10 CFR 50. The assumptions and results of this evaluation are summarized in Table 11.2-15. It will be noted that the calculated doses indicate that liquid effluents from the plant will conform to the "as low as reasonably achievable" criteria established in Appendix I.

11.2.10 References

1. U.S. Nuclear Regulatory Commission, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors*, NUREG-0017, April 1976.

2. *Radioactive Diffusion Study: Parr Hydroelectric Project for South Carolina Electric and Gas Company*, Alden Research Laboratories, 1973.

Table 11.2-1
Isotopic Values in the Liquid Waste Processing System(1)

Isotope	Input to Waste Holdup Tank	After Charcoal Processing	After Mixed Bed Processing	After Cation Processing	Input to FD Tank	After Charcoal Processing	After Mixed Bed Processing	After Cation Processing
	µCi/cc	µCi/cc	µCi/cc	µCi/cc	µCi/cc	µCi/cc	µCi/cc	µCi/cc
AG-110M	4.20E-04	4.19E-06	4.19E-07	2.09E-08	4.20E-05	4.19E-07	4.19E-08	2.09E-09
BA-137M	2.82E-03	6.97E-27	6.97E-28	0.00E+00	2.82E-04	6.97E-28	6.97E-29	0.00E+00
BA-140	4.20E-03	3.95E-05	3.95E-06	1.97E-07	4.20E-04	3.95E-06	3.95E-07	1.97E-08
CE-141	4.80E-05	4.68E-07	4.68E-08	2.34E-09	4.80E-06	4.68E-08	4.68E-09	2.34E-10
CE-143	9.30E-04	5.46E-06	5.46E-07	2.73E-08	9.30E-05	5.46E-07	5.46E-08	2.73E-09
CE-144	1.29E-03	0.00E+00	0.00E+00	0.00E+00	1.29E-04	0.00E+00	0.00E+00	0.00E+00
CO-58	1.47E-03	1.45E-05	1.45E-06	7.27E-08	1.47E-04	1.45E-06	1.45E-07	7.27E-09
CO-60	1.68E-04	1.68E-06	1.68E-07	8.40E-09	1.68E-05	1.68E-07	1.68E-08	8.40E-10
CR-51	9.90E-04	9.62E-06	9.62E-07	4.81E-08	9.90E-05	9.62E-07	9.62E-08	4.81E-09
CS-134	2.25E-03	2.25E-04	2.25E-05	1.12E-06	2.25E-04	2.25E-05	2.25E-06	1.12E-07
CS-136	2.79E-04	2.63E-05	2.63E-06	1.31E-07	2.79E-05	2.63E-06	2.63E-07	1.31E-08
CS-137	2.97E-03	2.97E-04	2.97E-05	1.49E-06	2.97E-04	2.97E-05	2.97E-06	1.49E-07
FE-55	3.90E-04	3.90E-06	3.90E-07	1.95E-08	3.90E-05	3.90E-07	3.90E-08	1.95E-09
FE-59	9.60E-05	9.43E-07	9.43E-08	4.72E-09	9.60E-06	9.43E-08	9.43E-09	4.72E-10
H-3	3.00E-01	3.00E-01	3.00E-01	1.50E-01	3.00E-02	3.00E-02	3.00E-02	1.50E-02
I-131	1.50E-02	1.36E-04	1.36E-05	6.82E-06	1.50E-03	1.36E-05	1.36E-06	6.82E-07
I-132	7.80E-02	2.74E-05	2.74E-06	1.37E-06	7.80E-03	2.74E-06	2.74E-07	1.37E-07
I-133	4.80E-02	2.15E-04	2.15E-05	1.08E-05	4.80E-03	2.15E-05	2.15E-06	1.08E-06
I-134	1.26E-01	3.95E-06	3.95E-07	1.97E-07	1.26E-02	3.95E-07	3.95E-08	1.97E-08
I-135	9.30E-02	1.35E-04	1.35E-05	6.73E-06	9.30E-03	1.35E-05	1.35E-06	6.73E-07
LA-140	8.10E-03	6.64E-05	6.64E-06	3.32E-07	8.10E-04	6.64E-06	6.64E-07	3.32E-08
MN-54	5.10E-04	5.09E-06	5.09E-07	2.54E-08	5.10E-05	5.09E-07	5.09E-08	2.54E-09
MO-99	2.10E-03	1.59E-05	1.59E-06	7.95E-08	2.10E-04	1.59E-06	1.59E-07	7.95E-09
NA-24	1.59E-02	7.65E-10	7.65E-11	3.82E-12	1.59E-03	7.65E-11	7.65E-12	3.82E-13
NB-95	9.00E-05	9.08E-07	9.08E-08	4.54E-09	9.00E-06	9.08E-08	9.08E-09	4.54E-10

Table 11.2-1 (continued)
Isotopic Values in the Liquid Waste Processing System(1)

Isotope	Input to Waste Holdup Tank µCi/cc	After Charcoal Processing µCi/cc	After Mixed Bed Processing µCi/cc	After Cation Processing µCi/cc	Input to FD Tank µCi/cc	After Charcoal Processing µCi/cc	After Mixed Bed Processing µCi/cc	After Cation Processing µCi/cc
NB-95m	0.00E+00	2.16E-09	2.16E-10	1.08E-11	0.00E+00	2.16E-10	2.16E-11	1.08E-12
NP-239	7.20E-04	5.21E-06	5.21E-07	2.61E-08	7.20E-05	5.21E-07	5.21E-08	2.61E-09
PR-143	1.11E-03	1.05E-05	1.05E-06	5.24E-08	1.11E-04	1.05E-06	1.05E-07	5.24E-09
PR-144	1.47E-03	0.00E+00	0.00E+00	0.00E+00	1.47E-04	0.00E+00	0.00E+00	0.00E+00
RH-103M	2.76E-03	2.36E-05	2.36E-06	1.18E-07	2.76E-04	2.36E-06	2.36E-07	1.18E-08
RH-106	3.30E-02	0.00E+00	0.00E+00	0.00E+00	3.30E-03	0.00E+00	0.00E+00	0.00E+00
RU-103	2.40E-03	2.35E-05	2.35E-06	1.18E-07	2.40E-04	2.35E-06	2.35E-07	1.18E-08
RU-106	2.88E-02	2.87E-04	2.87E-05	1.44E-06	2.88E-03	2.87E-05	2.87E-06	1.44E-07
SR-89	4.50E-05	4.43E-07	4.43E-08	2.21E-09	4.50E-06	4.43E-08	4.43E-09	2.21E-10
SR-90	3.90E-06	3.90E-08	3.90E-09	1.95E-10	3.90E-07	3.90E-09	3.90E-10	1.95E-11
SR-91	3.30E-04	7.28E-07	7.28E-08	3.64E-09	3.30E-05	7.28E-08	7.28E-09	3.64E-10
TC-99	0.00E+00	1.86E-13	1.86E-14	9.29E-16	0.00E+00	1.86E-14	1.86E-15	9.29E-17
TC-99M	1.65E-03	1.47E-05	1.47E-06	7.33E-08	1.65E-04	1.47E-06	1.47E-07	7.33E-09
TE-129	8.70E-03	9.81E-07	9.81E-08	4.90E-09	8.70E-04	9.81E-08	9.81E-09	4.90E-10
TE-129M	6.00E-05	5.86E-07	5.86E-08	2.93E-09	6.00E-06	5.86E-08	5.86E-09	2.93E-10
TE-131	2.85E-03	7.47E-07	7.47E-08	3.74E-09	2.85E-04	7.47E-08	7.47E-09	3.74E-10
TE-131M	5.10E-04	2.85E-06	2.85E-07	1.43E-08	5.10E-05	2.85E-07	2.85E-08	1.43E-09
TE-132	5.40E-04	4.27E-06	4.27E-07	2.13E-08	5.40E-05	4.27E-07	4.27E-08	2.13E-09
W-187	8.40E-04	4.07E-06	4.07E-07	2.04E-08	8.40E-05	4.07E-07	4.07E-08	2.04E-09
Y-90	4.50E-07	3.38E-09	3.38E-10	1.69E-11	4.50E-08	3.38E-10	3.38E-11	1.69E-12
Y-91	1.65E-06	3.41E-08	3.41E-09	1.71E-10	1.65E-07	3.41E-09	3.41E-10	1.71E-11
Y-91M	1.68E-04	5.01E-07	5.01E-08	2.51E-09	1.68E-05	5.01E-08	5.01E-09	2.51E-10
Y-93	1.44E-03	3.45E-06	3.45E-07	1.73E-08	1.44E-04	3.45E-07	3.45E-08	1.73E-09
ZN-65	1.62E-04	1.61E-06	1.61E-07	8.07E-09	1.62E-05	1.61E-07	1.61E-08	8.07E-10
ZR-95	1.26E-04	1.24E-06	1.24E-07	6.22E-09	1.26E-05	1.24E-07	1.24E-08	6.22E-10

Table 11.2-1 (continued)
Isotopic Values in the Liquid Waste Processing System(1)

Isotope	Waste Holdup Tank Ci	Floor Drain Tank Ci	Charcoal Bed (2) Ci	Mixed Bed (2) Ci	Cation (2) Ci	Waste Monitor Tank (1) Ci
AG-110M	1.27E-02	1.27E-03	2.05E-02	1.86E-04	1.86E-05	1.90E-07
BA-137M	8.54E-02	8.54E-03	1.32E-25	1.20E-27	0.00E+00	0.00E+00
BA-140	1.27E-01	1.27E-02	1.62E-01	1.48E-03	1.48E-04	1.79E-06
CE-141	1.45E-03	1.45E-04	2.15E-03	1.95E-05	1.95E-06	2.13E-08
CE-143	2.82E-02	2.82E-03	1.02E-02	9.28E-05	9.28E-06	2.48E-07
CO-58	3.91E-02	3.91E-03	6.94E-02	6.31E-04	6.31E-05	0.00E+00
CO-60	4.45E-02	4.45E-03	8.30E-03	7.54E-05	7.54E-06	6.60E-07
CR-51	5.09E-03	5.09E-04	4.36E-02	3.96E-04	3.96E-05	7.63E-08
CS-134	3.00E-02	3.00E-03	1.01E-01	1.01E-02	1.01E-03	4.37E-07
CS-136	6.81E-02	6.81E-03	9.85E-03	9.85E-04	9.85E-05	1.02E-05
CS-137	8.45E-03	8.45E-04	1.34E-01	1.34E-02	1.34E-03	1.19E-06
FE-55	8.99E-02	8.99E-03	1.92E-02	1.75E-04	1.75E-05	1.35E-05
FE-59	1.18E-02	1.18E-03	4.41E-03	4.01E-05	4.01E-06	1.77E-07
I-131	2.91E-03	2.91E-04	5.10E-01	4.64E-03	6.71E-07	4.28E-08
I-132	9.08E+00	9.08E-01	3.08E-02	2.80E-04	7.67E-06	1.36E+00
I-133	4.54E-01	4.54E-02	3.46E-01	3.15E-03	0.00E+00	6.20E-05
I-134	2.36E+00	2.36E-01	1.52E-03	1.38E-05	0.00E+00	1.24E-05
I-135	1.45E+00	1.45E-01	1.70E-01	1.55E-03	0.00E+00	9.78E-05
LA-140	3.82E+00	3.82E-01	2.30E-01	2.09E-03	2.09E-04	1.79E-06
MN-54	2.82E+00	2.82E-01	2.50E-02	2.27E-04	2.27E-05	6.11E-05
MO-99	2.45E-01	2.45E-02	4.03E-02	3.67E-04	3.67E-05	3.02E-06
NA-24	1.54E-02	1.54E-03	8.53E-08	7.75E-10	7.75E-11	2.31E-07
NB-95	6.36E-02	6.36E-03	4.59E-03	4.17E-05	4.17E-06	7.23E-07
NB-95m	4.82E-01	4.82E-02	2.87E-05	2.61E-07	2.61E-08	3.47E-11
NP-239	2.73E-03	2.73E-04	1.23E-02	1.12E-04	1.12E-05	4.12E-08
PR-143	0.00E+00	0.00E+00	4.35E-02	3.96E-04	3.96E-05	9.82E-11

Table 11.2-1 (continued)
Isotopic Values in the Liquid Waste Processing System[1]

Isotope	Waste Holdup Tank Ci	Floor Drain Tank Ci	Charcoal Bed (2) Ci	Mixed Bed (2) Ci	Cation (2) Ci	Waste Monitor Tank (1) Ci
RH-103M	2.18E-02	2.18E-03	1.09E-01	9.95E-04	9.94E-05	2.37E-07
RU-103	3.36E-02	3.36E-03	1.09E-01	9.93E-04	9.93E-05	4.76E-07
RU-106	4.45E-02	4.45E-03	1.41E+00	1.28E-02	1.28E-03	0.00E+00
SR-89	8.36E-02	8.36E-03	2.09E-03	1.90E-05	1.90E-06	1.07E-06
SR-90	9.99E-01	9.99E-02	1.93E-04	1.75E-06	1.75E-07	0.00E+00
SR-91	7.27E-02	7.27E-03	9.97E-04	9.06E-06	9.06E-07	1.07E-06
TC-99	8.72E-01	8.72E-02	2.38E-09	2.17E-11	2.17E-12	1.31E-05
TC-99M	1.36E-03	1.36E-04	3.78E-02	3.43E-04	3.43E-05	2.01E-08
TE-129	1.18E-04	1.18E-05	9.14E-04	8.31E-06	8.31E-07	1.77E-09
TE-129M	9.99E-03	9.99E-04	2.69E-03	2.45E-05	2.45E-06	3.31E-08
TE-131	0.00E+00	0.00E+00	1.15E-03	1.05E-05	1.05E-06	8.44E-15
TE-131M	5.00E-02	5.00E-03	5.14E-03	4.67E-05	4.67E-06	6.66E-07
TE-132	2.63E-01	2.63E-02	1.17E-02	1.06E-04	1.06E-05	4.45E-08
W-187	1.82E-03	1.82E-04	6.78E-03	6.16E-05	6.16E-06	2.66E-08
Y-90	8.63E-02	8.63E-03	8.48E-06	7.71E-08	7.71E-09	3.39E-08
Y-91	1.54E-02	1.54E-03	1.80E-04	1.63E-06	1.63E-07	1.29E-07
Y-91M	1.64E-02	1.64E-03	6.87E-04	6.25E-06	6.25E-07	1.94E-07
Y-93	2.54E-02	2.54E-03	4.79E-03	4.36E-05	4.36E-06	1.85E-07
ZN-65	1.36E-05	1.36E-06	7.91E-03	7.19E-05	7.19E-06	1.54E-10
ZR-95	5.00E-05	5.00E-06	5.92E-03	5.38E-05	5.38E-06	1.55E-09

(4) System modeled with first three components in Duratek processing system (Charcoal processing, mixed bed resin demineralizer, and cation demineralizer). No credit taken for additional removal prior to waste monitor tank.
(5) Activity values based on 50% waste holdup tank processing and 50% floor drain tank processing.

Table 11.2-2
Equipment Principal Design Parameters

	Component	
PUMPS		
1.	Reactor Coolant Drain Tank Pumps	
	Number	2
	Type	Canned
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	
	1	100 (140) (1)
	2	100 (140) (1)
	Design head, ft	
	1	300 (250) (1)
	2	300 (250) (1)
	Material	Stainless Steel
2.	Waste Evaporator Feed Pump (Used As Waste Holdup Tank Pump)	
	Number	1
	Type	Canned
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	
	1	35
	2	100
	Design head, ft	
	1	250
	2	200
	Material	Stainless Steel
3.	Waste Evaporator Condensate Pump	
	Number	1
	Type	Canned
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	
	1	35
	2	100
	Design head, ft	
	1	250
	2	200
	Material	Stainless Steel
4.	Chemical Drain Tank Pump	

Table 11.2-2 (continued)
Equipment Principal Design Parameters

	Component
	Number	1
	Type	Canned
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	
	1	35
	2	100
	Design head, ft	
	1	250
	2	200
	Material	Stainless Steel
5.	Spent Resin Sluice Pump	
	Number	1
	Type	Canned
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	
	1	140 (100) (2)
	2	140 (100) (2)
	Design head, ft	
	1	250 (300) (2)
	2	250 (300) (2)
	Material	Stainless Steel
6.	Laundry and Hot Shower Tank Pump	
	Number	1
	Type	Mechanical Seal
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	
	1	35
	2	100
	Design head, ft	
	1	250
	2	200
	Material	Stainless Steel

Table 11.2-2 (continued)
Equipment Principal Design Parameters

	Component	
7.	Floor Drain Tank Pump	
	Number	1
	Type	Mechanical Seal
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	
	1	35
	2	100
	Design head, ft	
	1	250
	2	200
8.	Waste Monitor Tank Pumps	
	Number	2
	Type	Canned
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	
	1	35
	2	100
	Design head, ft	
	1	250
	2	200
	Material	Stainless Steel
9.	Excess Liquid Waste Pumps	
	Number	2
	Type	Canned
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	35
	Design head, ft	315
	1	250
	2	200
	Material	Stainless Steel

Table 11.2-2 (continued)
Equipment Principal Design Parameters

Component		
HEAT EXCHANGERS		
1. Reactor Coolant Drain Tank Heat Exchanger		
Number		1
Type		U-tube
Estimated UA, BTU/hr°F		70,000
Design pressure, psi	Shell	150
	Tube	150
Design temperature, °F	Shell	250
	Tube	200
Design flow, lb/hr	Shell	112,000
	Tube	44,600
Temperature, in, °F	Shell	105
	Tube	180
Temperature, out, °F	Shell	125
	Tube	130
Material	Shell	Carbon Steel
	Tube	Stainless Steel
TANKS		
1. Reactor Coolant Drain Tank		
Number		1
Usable volume, gallons		350
Type		Horizontal
Design pressure, psig (3)		100
Design temperature, °F		250
Material		Stainless Steel
Diaphragm		No
2. Waste Holdup Tank		
Number		1
Usable volume, gallons		10,000
Type		Vertical
Design pressure, psig		Atmosphere
Design temperature, °F		200
Material		Stainless Steel
Diaphragm		No

Table 11.2-2 (continued)
Equipment Principal Design Parameters

	Component	
3.	Waste Evaporator Condensate Tank	
	Number	1
	Usable volume, gallons	5,000
	Type	Vertical
	Design pressure, psig	Atmosphere
	Design temperature, °F	200
	Material	Stainless Steel
	Diaphragm	Yes
4.	Chemical DrainTank	
	Number	1
	Usable volume, gallons	600
	Type	Vertical
	Design pressure, psig	Atmosphere
	Design temperature, °F	200
	Material	Stainless Steel
	Diaphragm	No
5.	Spent Resin StorageTank	
	Number	1
	Usable volume, ft^3 (4)	350
	Type	Vertical
	Design pressure, psig	150
	Design temperature, °F	200
	Radiation level inside compartment, R/hr	1000
	Material	Stainless Steel
	Diaphragm	No
6.	Laundry and Hot Shower Tank	
	Number	1
	Usable volume, gallons	10,000
	Type	Vertical
	Design pressure, psig	Atmosphere
	Design temperature, °F	200
	Material	Stainless Steel
	Diaphragm	No

Table 11.2-2 (continued)
Equipment Principal Design Parameters

	Component	
7.	Floor Drain Tank	
	Number	1
	Usable volume, gallons	10,000
	Type	Vertical
	Design pressure, psig	Atmosphere
	Design temperature, °F	200
	Material	Stainless Steel
	Diaphragm	No
8.	Waste Monitor Tanks	
	Number	2
	Usable volume, gallons	5,000
	Type	Vertical
	Design pressure, psig	Atmosphere
	Design temperature, °F	200
	Material	Stainless Steel
	Diaphragm	No
9.	Waste Evaporator Reagent Tank **(No Longer in Service)**	
	Number	1/evaporator
	Usable volume, gallons	5
	Type	Vertical
	Design pressure, psig	150
	Design temperature, °F	200
	Material	Stainless Steel
	Diaphragm	No
10.	Excess Waste Holdup Tank	
	Number	1
	Usable volume, gallons	10,000
	Type	Vertical
	Design pressure, psig	Atmosphere
	Design temperature, °F	200
	Material	Stainless Steel
	Diaphragm	No

Table 11.2-2 (continued)
Equipment Principal Design Parameters

Component	
11. Decontamination Pit Collection Tank	
Number	1
Usable volume, gallons	10,000
Type	Vertical
Design pressure, psig	Atmosphere
Design temperature, °F	200
Material	Stainless Steel
Diaphragm	No
DEMINERALIZERS	
1. Waste Evaporator Condensate Demineralizer	
Number	1
Type	Flushable
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	35
Resin volume, ft^3	NA
Material	Stainless Steel
Purification media	None
Design process decontamination factor	NA
2. Waste Monitor Tank Demineralizer	
Number	1
Type	Flushable
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	35
Resin volume, ft^3	30
Material	Stainless Steel
Purification media	Anion and/or cation exchange resins as required
Design process decontamination factor	10
3. Excess Liquid Waste Demineralizers	
Number	2
Type	Flushable
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	35
Resin volume, ft^3	30
Material	Stainless Steel
Purification media	Anion and/or cation exchange resins as required

Table 11.2-2 (continued)
Equipment Principal Design Parameters

Component	
4. Duratek Demineralizer Vessels	
Number	5
Type	Flushable
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	25
Resin volume, ft^3	19.5 to 45
Material	Stainless Steel
Purification media	Charcoal Bed, Mixed Bed, and/or cation exchange resins as required
5. Polishing Vessel	
Number	1
Type	Flushable
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	25
Resin volume, ft^3	30
Material	Stainless Steel
Purification media	Mixed Bed and Cation
FILTERS	
1. Waste Evaporator Condensate Filter	
Number	1
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	35
ΔP at design flow, psi	≈5
Size of particles, 98% ret., microns (nominal)	≤25
Materials	
Housing	Stainless Steel
Filter element	EICF (5)

Table 11.2-2 (continued)
Equipment Principal Design Parameters

	Component	
2.	Spent Resin Sluice Filter	
	Number	1
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	250
	ΔP at design flow, psi	≈5
	Size of particles, 98% ret., microns (nominal)	≤25
	Surface radiation level, R/hr	100
	Materials	
	Housing	Stainless Steel
	Filter element	EICF (5)
3.	Laundry and Hot Shower Tank Filter	
	Number	1
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	35
	ΔP at design flow, psi	≈5
	Size of particles, 98% ret., microns (nominal)	≤25
	Surface radiation level, R/hr	100
	Materials	
	Housing	Stainless Steel
	Filter element	EICF (5)
4.	Floor Drain Tank Filter	
	Number	1
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	35
	ΔP at design flow, psi	≈5
	Size of particles, 98% ret., microns (nominal)	≤25
	Surface radiation level, R/hr	100
	Materials	
	Housing	Stainless Steel
	Filter element	EICF

Table 11.2-2 (continued)
Equipment Principal Design Parameters

Component	
5. Waste Monitor Tank Filter	
Number	1
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	35
ΔP at design flow, psi	≈5
Size of particles, 98% ret., microns (nominal)	≤25
Surface radiation level, R/hr	90
Materials	
Housing	Stainless Steel
Filter element	EICF
6. Excess Liquid Waste Filters	
Number	2
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	35
ΔP at design flow, psi	<5
Size of particles, 98% ret., microns (nominal)	20
Surface radiation level, mR/hr	<100
Materials	
Housing	Stainless Steel
Filter element	Stainless Steel
STRAINERS	
1. Laundry and Hot Shower Tank Strainer	
Number	1
Type	Basket
Design pressure, psig	150
Design temperature, °F	200
Design flow, gpm	35
ΔP at design flow, psi	0.2 (Estimated)
Nominal rating, inch	0.0625
Surface radiation level	Negligible
Materials	Stainless Steel

Table 11.2-2 (continued)
Equipment Principal Design Parameters

	Component	
2.	Floor Drain Tank Strainer	
	Number	1
	Type	Basket
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	35
	ΔP at design flow, psi	0.2 (Estimated)
	Nominal rating, inch	0.0625
	Surface radiation level	Negligible
	Materials	Stainless Steel
3.	Decontamination Pit Collection Tank Strainer	
	Number	1
	Type	Duplex Basket
	Design pressure, psig	150
	Design temperature, °F	200
	Design flow, gpm	350
	Nominal rating, inch	0.015
	Materials	Stainless Steel
EVAPORATORS		
1.	Waste Evaporator **(No Longer in Service)**	
	Number	1
	Design flow, gpm	15
	Feed conc., ppm boron	10 - 2500
	Bottoms conc., ppm boron	7000 - 21,000
	Design process decontamination factor	1000
	Steam design pressure, psig	50

(1) Also serves as spent resin sluice pump.
(2) Also serves as reactor coolant drain tank pump.
(3) External design pressure - 60 psig.
(4) Total for resin and liquid.
(5) Epoxy Impregnated Cellulose Fiber or glass fiber.

Table 11.2-3
Liquid Waste Processing System Major Component Inventories

Isotope	Reactor Coolant Concentration at 1% Fuel Defect µCi/cc	Waste Monitor Tank Number 1 (4000 gal) Curies	Waste Monitor Tank Number 2 (4000 gal) Curies	Duratek Charcoal Demineralizer (45 cu ft) Curies	Duratek Mixed Bed Demineralizer (28 cu ft resin) Curies	Duratek Cation Demineralizer (28 cu ft) Curies	Reactor Coolant Drain Tank (280 gal) Curies	Waste Holdup Tank (8000 gal) Curies	Floor Drain Tank (8000 gal) Curies	Excess Waste Holdup Tank (10,000 gal) Curies	Decontamination Pit Collection Tank (10,000 gal) Curies
H-3	3.50E+00	5.30E+01	*	**	**	**	3.71E+00	1.06E+02	1.06E+02	***	****
AG-110M	3.00E-03	4.54E-02	*	2.66E-01	2.42E-03	2.42E-04	3.18E-03	9.08E-02	9.08E-02	***	****
BA-137M	2.00E+00	3.03E+01	*	1.08E+02	1.07E+01	1.07E+00	2.12E+00	6.06E+01	6.06E+01	***	****
BA-140	4.40E-03	6.66E-02	*	3.10E-01	2.81E-03	2.81E-04	4.66E-03	1.33E-01	1.33E-01	***	****
BR-83	8.90E-02	1.35E+00	*	4.38E-02	3.98E-04	0.00E+00	9.43E-02	2.70E+00	2.70E+00	***	****
BR-85	5.20E-03	7.87E-02	*	6.48E-23	5.89E-25	0.00E+00	5.51E-03	1.57E-01	1.57E-01	***	****
CE-141	6.90E-04	1.04E-02	*	5.62E-02	5.11E-04	5.11E-05	7.31E-04	2.09E-02	2.09E-02	***	****
CE-143	5.20E-04	7.87E-03	*	1.04E-02	9.44E-05	9.44E-06	5.51E-04	1.57E-02	1.57E-02	***	****
CE-144	4.70E-04	7.12E-03	*	0.00E+00	0.00E+00	0.00E+00	4.98E-04	1.42E-02	1.42E-02	***	****
CO-58	1.40E-02	2.12E-01	*	1.20E+00	1.09E-02	1.09E-03	1.48E-02	4.24E-01	4.24E-01	***	****
CO-60	1.30E-03	1.97E-02	*	1.17E-01	1.06E-03	1.06E-04	1.38E-03	3.94E-02	3.94E-02	***	****
CR-51	5.50E-03	8.33E-02	*	4.40E-01	4.00E-03	4.00E-04	5.83E-03	1.67E-01	1.67E-01	***	****
CS-134	4.40E+00	6.66E+01	*	3.58E+02	3.58E+01	3.58E+00	4.66E+00	1.33E+02	1.33E+02	***	****
CS-136	4.50E+00	6.81E+01	*	2.89E+02	2.89E+01	2.89E+00	4.77E+00	1.36E+02	1.36E+02	***	****
CS-137	2.10E+00	3.18E+01	*	1.72E+02	1.72E+01	1.72E+00	2.23E+00	6.36E+01	6.36E+01	***	****
FE-55	2.40E-03	3.63E-02	*	2.15E-01	1.96E-03	1.96E-04	2.54E-03	7.27E-02	7.27E-02	***	****
FE-59	5.20E-04	7.87E-03	*	4.35E-02	3.95E-04	3.95E-05	5.51E-04	1.57E-02	1.57E-02	***	****
I-130	3.30E-02	5.00E-01	*	2.50E-01	2.27E-03	0.00E+00	3.50E-02	9.99E-01	9.99E-01	***	****
I-131	3.00E+00	4.54E+01	*	1.85E+02	1.68E+00	6.93E-05	3.18E+00	9.08E+01	9.08E+01	***	****
I-132	3.10E+00	4.69E+01	*	1.30E+01	1.18E-01	7.49E-03	3.29E+00	9.39E+01	9.39E+01	***	****
I-133	4.60E+00	6.97E+01	*	6.04E+01	5.49E-01	0.00E+00	4.88E+00	1.39E+02	1.39E+02	***	****
I-134	6.00E-01	9.08E+00		1.32E-02	1.20E-04	0.00E+00	6.36E-01	1.82E+01	1.82E+01	***	****
I-135	2.40E+00	3.63E+01		7.98E+00	7.25E-02	0.00E+00	2.54E+00	7.27E+01	7.27E+01	***	****
LA-140	1.40E-03	2.12E-02	*	2.69E-01	2.45E-03	2.45E-04	1.48E-03	4.24E-02	4.24E-02	***	****

Table 11.2-3 (continued)
Liquid Waste Processing System Major Component Inventories

Isotope	Reactor Coolant Concentration at 1% Fuel Defect µCi/cc	Waste Monitor Tank Number 1 (4000 gal) Curies	Waste Monitor Tank Number 2 (4000 gal) Curies	Duratek Charcoal Demineralizer (45 cu ft) Curies	Duratek Mixed Bed Demineralizer (28 cu ft resin) Curies	Duratek Cation Demineralizer (28 cu ft) Curies	Reactor Coolant Drain Tank (280 gal) Curies	Waste Holdup Tank (8000 gal) Curies	Floor Drain Tank (8000 gal) Curies	Excess Waste Holdup Tank (10,000 gal) Curies	Decontamination Pit Collection Tank (10,000 gal) Curies
MN-54	4.10E-04	6.21E-03	*	3.65E-02	3.32E-04	3.32E-05	4.35E-04	1.24E-02	1.24E-02	***	****
MN-56	2.20E-02	3.33E-01	*	1.29E-02	1.17E-04	1.17E-05	2.33E-02	6.66E-01	6.66E-01	***	****
MO-99	7.90E-01	1.20E+01	*	2.76E+01	2.51E-01	2.51E-02	8.37E-01	2.39E+01	2.39E+01	***	****
NB-95	6.70E-04	1.01E-02	*	6.01E-02	5.46E-04	5.46E-05	7.10E-04	2.03E-02	2.03E-02	***	****
NB-95m	0.00E+00	0.00E+00	*	2.78E-04	2.53E-06	2.53E-07	0.00E+00	0.00E+00	0.00E+00	***	****
PR-143	6.20E-04	9.39E-03	*	4.72E-02	4.29E-04	4.29E-05	6.57E-04	1.88E-02	1.88E-02	***	****
RB-86	3.60E-02	5.45E-01	*	2.48E+00	2.48E-01	2.48E-02	3.82E-02	1.09E+00	1.09E+00	***	****
RB-89	1.80E-01	2.73E+00	*	1.76E-06	1.76E-07	1.76E-08	1.91E-01	5.45E+00	5.45E+00	***	****
RH-103M	6.90E-04	1.04E-02	*	5.30E-02	4.82E-04	4.82E-05	7.31E-04	2.09E-02	2.09E-02	***	****
RH-106	2.10E-04	3.18E-03	*	1.87E-02	1.70E-04	1.70E-05	2.23E-04	6.36E-03	6.36E-03	***	****
RU-103	6.40E-04	9.69E-03	*	5.30E-02	4.82E-04	4.82E-05	6.78E-04	1.94E-02	1.94E-02	***	****
RU-106	2.10E-04	3.18E-03	*	1.87E-02	1.70E-04	1.70E-05	2.23E-04	6.36E-03	6.36E-03	***	****
SR-89	4.00E-03	6.06E-02	*	3.40E-01	3.09E-03	3.09E-04	4.24E-03	1.21E-01	1.21E-01	***	****
SR-90	2.00E-04	3.03E-03	*	1.80E-02	1.63E-04	1.63E-05	2.12E-04	6.06E-03	6.06E-03	***	****
SR-91	5.30E-03	8.03E-02	*	3.02E-02	2.75E-04	2.75E-05	5.62E-03	1.61E-01	1.61E-01	***	****
SR-92	1.20E-03	1.82E-02	*	7.86E-04	7.15E-06	7.15E-07	1.27E-03	3.63E-02	3.63E-02	***	****
TC-99	0.00E+00	0.00E+00	*	1.69E-06	1.54E-08	1.54E-09	0.00E+00	0.00E+00	0.00E+00	***	****
TC-99M	8.40E-01	1.27E+01	*	2.65E+01	2.41E-01	2.41E-02	8.90E-01	2.54E+01	2.54E+01	***	****
TE-125M	4.70E-04	7.12E-03	*	4.00E-02	3.63E-04	3.63E-05	4.98E-04	1.42E-02	1.42E-02	***	****
TE-127	1.50E-02	2.27E-01	*	8.08E-02	7.35E-04	7.35E-05	1.59E-02	4.54E-01	4.54E-01	***	****
TE-127M	3.60E-03	5.45E-02	*	3.14E-01	2.86E-03	2.86E-04	3.82E-03	1.09E-01	1.09E-01	***	****
TE-129	2.00E-02	3.03E-01	*	1.19E+00	1.08E-02	1.08E-03	2.12E-02	6.06E-01	6.06E-01	***	****
TE-129M	2.10E-02	3.18E-01	*	1.73E+00	1.57E-02	1.57E-03	2.23E-02	6.36E-01	6.36E-01	***	****
TE-131	1.60E-02	2.42E-01	*	1.19E-01	1.08E-03	1.08E-04	1.70E-02	4.85E-01	4.85E-01	***	****

Table 11.2-3 (continued)
Liquid Waste Processing System Major Component Inventories

Isotope	Reactor Coolant Concentration at 1% Fuel Defect µCi/cc	Waste Monitor Tank Number 1 (4000 gal) Curies	Waste Monitor Tank Number 2 (4000 gal) Curies	Duratek Charcoal Demineralizer (45 cu ft) Curies	Duratek Mixed Bed Demineralizer (28 cu ft resin) Curies	Duratek Cation Demineralizer (28 cu ft) Curies	Reactor Coolant Drain Tank (280 gal) Curies	Waste Holdup Tank (8000 gal) Curies	Floor Drain Tank (8000 gal) Curies	Excess Waste Holdup Tank (10,000 gal) Curies	Decontamination Pit Collection Tank (10,000 gal) Curies
TE-131M	2.90E-02	4.39E-01	*	5.31E-01	4.83E-03	4.83E-04	3.07E-02	8.78E-01	8.78E-01	***	****
TE-132	2.90E-01	4.39E+00	*	1.14E+01	1.04E-01	1.04E-02	3.07E-01	8.78E+00	8.78E+00	***	****
TE-134	2.80E-02	4.24E-01	*	1.15E+01	1.05E-01	1.05E-02	2.97E-02	8.48E-01	8.48E-01	***	****
Y-90	5.70E-05	8.63E-04	*	1.31E-02	1.19E-04	1.19E-05	6.04E-05	1.73E-03	1.73E-03	***	****
Y-91	5.40E-04	8.18E-03	*	4.90E-02	4.46E-04	4.46E-05	5.72E-04	1.64E-02	1.64E-02	***	****
Y-91M	2.90E-03	4.39E-02	*	2.08E-02	1.89E-04	1.89E-05	3.07E-03	8.78E-02	8.78E-02	***	****
Y-92	1.10E-03	1.67E-02	*	3.15E-03	2.86E-05	2.86E-06	1.17E-03	3.33E-02	3.33E-02	***	****
ZR-95	6.70E-04	1.01E-02	*	5.73E-02	5.14E-04	5.21E-05	7.10E-04	2.03E-02	2.03E-02	***	****

* Normal discharge path for Laundry and Hot Shower Tank - No significant activity.
** Not calculated.
*** Excess Waste Holdup is not normally used. If used, the estimated inventories would be similar to the Waste Holdup Tank.
**** Estimated inventories would be similar to the Floor Drain Tank.

Table 11.2-4
Range of Measured Demineralizer Decontamination Factors for Selected Isotopes

Isotope	Minimum	Maximum
I-131	$1.1.x\ 10^{1}$	1.6×10^{4}
I-133	1.1×10^{1}	1.8×10^{4}
I-135	1.4×10^{1}	2.0×10^{4}
Cs-137	2.4	1.3×10^{3}
F-18	1.73×10^{1}	1.5×10^{3}
Co-58	3.2×10^{1}	8.2×10^{3}
Mn-54	$> 2.5 \times 10^{1}$	$> 1.3 \times 10^{2}$

Note: Mixed bed demineralizers cation resin in lithium^{-7} form, anion resin in borated form.

Table 11.2-5
Liquid Waste Processing System Instrumentation
Principal Design Parameters

F- FLOW
Q - Flow Integrator
P - Pressure
L - Level
T - Temperature
R - Radiation
I - Indication
C - Control
A - Alarm

Flow Instrumentation

Channel Number	Location of Primary Sensor	Design Pressure (psig)	Design Temperature (°F)	Range *	Location of Readout
FI-1007	Waste Evaporator Feed Pump Discharge	150	200	0-30 gpm	Local
FIC-1008	Reactor Coolant Drain Tank Pump Discharge	150	250	0-250 gpm	WPS Panel
FIA-1009	Reactor Coolant Drain Tank Recirculation	150	250	0-250 gpm	WPS Panel
FICA-1011	Spent Resin Sluice Pump Discharge	150	200	1-150 gpm	WPS Panel
FI-1085A	Waste Monitor Tank Pump Number 1 Discharge	150	200	0-100 gpm	WPS Panel
FI-1085B	Waste Monitor Tank Pump Number 2 Discharge	150	200	0-100 gpm	WPS Panel
FICA-4845	Nuclear Blowdown Sluice Pump Discharge	150	200	0-250 gpm	NB Panel
Pressure Instrumentation					
PIA-1004	Reactor Coolant Drain Tank	150	250	0-30 psig	WPS Panel
PIA-1006A	Spent Resin Storage Tank	150	200	0-100 psig	WPS Panel

Table 11.2-5 (continued)
Liquid Waste Processing System Instrumentation
Principal Design Parameters

PIA-1006B	Spent Resin Storage Tank	150	200	0-100 psig	Solid Waste Disposal Panel

Pressure Instrumentation

Channel Number	Location of Primary Sensor	Design Pressure (psig)	Design Temperature (°F)	Range *	Location of Readout
PIA-4842A	Nuclear Blowdown Spent Resin Storage Tank	150	200	0-160 psig	Local
PIA-4842B	Nuclear Blowdown Spent Resin Storage Tank	150	200	0-150 psig	Solid Waste Disposal Panel
PI-1016	Waste Evaporator Feed Pump Filter Inlet	150	200	0-160 psig	Local
PI-1017	Waste Evaporator Feed Filter Outlet	150	200	0-160 psig	Local
PI-1018A	Reactor Coolant Drain Tank Pump Number 1 Discharge	150	250	0-160 psig	Local
PI-1018B	Reactor Coolant Drain Tank Pump Number 2 Discharge	150	250	0-160 psig	Local
PI-1018C	Laundry and Hot Shower Tank Pump Discharge	150	200	0-160 psig	Local
PI-1018D	Chemical Drain Tank Pump Discharge	150	200	0-160 psig	Local
PI-1018G	Waste Evaporator Condensate Pump Discharge	150	200	0-160 psig	Local
PI-1074	Waste Evaporator Outlet – NO LONGER IN SERVICE –	150	200	0-160 psig	Local
PI-1075	Waste Evaporator Condensate Demineralizer Outlet	150	200	0-160 psig	Local
PI-1076	Waste Evaporator Condensate Filter Outlet	150	200	0-160 psig	Local

Table 11.2-5 (continued)
Liquid Waste Processing System Instrumentation
Principal Design Parameters

PI-1078	Floor Drain Tank Filter Inlet	150	200	0-160 psig	Local
PI-1079	Floor Drain Tank Filter Outlet	150	200	0-160 psig	Local

Pressure Instrumentation

Channel Number	Location of Primary Sensor	Design Pressure (psig)	Design Temperature (°F)	Range *	Location of Readout
PI-1080	Laundry and Hot Shower Tank Filter Inlet	150	200	0-160 psig	Local
PI-1081	Laundry and Hot Shower Tank Filter Outlet	150	200	0-160 psig	Local
PI-1084A	Waste Monitor Tank Pump Number 1 Discharge	150	200	0-160 psig	Local
PI-1084B	Waste Monitor Tank Pump Number 2 Discharge	150	200	0-160 psig	Local
PI-1086	Resin Sluice Filter Inlet	150	200	0-160 psig	Local
PI-1087	Resin Sluice Filter Outlet	150	200	0-160 psig	Local
PI-1088	Waste Monitor Tank Filter Inlet	150	200	0-160 psig	Local
PI-1089	Waste Monitor Tank Filter Outlet	150	200	0-160 psig	Local
PI-1090	Floor Drain Tank Pump Discharge	150	200	0-160 psig	Local
PI-7657	Waste Evaporator Concentrates Tank Pump Discharge	150	200	0-100 psig	Local
PI-7903	Excess Liquid Waste Filter Inlet	110	100	0-160 psig	Local
PI-7907	Excess Liquid Waste Filter Outlet	110	100	0-160 psig	Local
PI-7911	Excess Liquid Waste Demineralizer Filter Inlet	110	100	0-160 psig	Local

Table 11.2-5 (continued)
Liquid Waste Processing System Instrumentation
Principal Design Parameters

PI-7913	Excess Liquid Waste Demineralizer Filter Outlet	110	100	0-160 psig	Local
PI-7921	Excess Waste Sump Pump A Discharge	25	100	0-60 psig	Local

Pressure Instrumentation

Channel Number	Location of Primary Sensor	Design Pressure (psig)	Design Temperature (°F)	Range *	Location of Readout
PI-7923	Excess Waste Sump Pump B Discharge	25	100	0-60 psig	Local
PI-7925	Excess Liquid Waste System Area Sump Pump Discharge	25	100	0-60 psig	Local
Level Instrumentation					
LICA-1001A and 1001B	Waste Holdup Tank	150	200	0-100%	Local & WPS Panels
LICA-1002A and 1002B	Chemical Drain Tank	150	200	0-100%	Local & WPS Panels & Solid Waste Disposal Panel
LICA-1003	Reactor Coolant Drain Tank	150	250	0-100%	WPS Panel
LICA-1005A and 1005B	Spent Resin Storage Tank	150	200	0-100%	WPS Panel & Solid Waste Disposal Panel
LICA-1010A and 1010B	Laundry and Hot Shower Tank	150	200	0-100%	Local & WPS Panels
LICA-1012A and 1012B	Waste Evaporator Condensate Tank	150	200	0-100%	Local & WPS Panels
LICA-1077A and 1077B	Floor Drain Tank	150	200	0-100%	Local & WPS Panels
LICA-1082A and 1082B	Waste Monitor Tank Number 1	150	200	0-100%	Local & WPS Panels
LICA-1083A and B	Waste Monitor Tank Number 2	150	200	0-100%	Local & WPS Panels

Table 11.2-5 (continued)
Liquid Waste Processing System Instrumentation
Principal Design Parameters

LICA-4843A	Nuclear Blowdown Spent Resin Storage Tank	150	200	0-100%	Solid Waste Disposal Panel
LICA-4843	Nuclear Blowdown Spent Resin Storage Tank	150	200	0-72"	Nuclear Blowdown Panel

Level Instrumentation

Channel Number	Location of Primary Sensor	Design Pressure (psig)	Design Temperature (°F)	Range *	Location of Readout
LICA-7651A&B	Waste Evaporator Concentrates Tank	150	200	0-100%	Local & Solid Waste Disposal Panel
LICA-7901	Excess Waste Holdup Tank	Atmosphere	100	0-100%	Local
LICA-7905	Decontamination Pit Collection Tank	Atmosphere	100	0-100%	Local
Temperature Instrumentation					
TIA-1058	Reactor Coolant Drain Tank	150	250	50-250°F	WPS Panel
TI-7655	Waste Evaporator Concentrates Tank	150	200	30-180°F	Local
Radiation Instrumentation					
RML-5	Waste Discharge Line	150	100	10^1-10^6 cpm	WPS & Radiation Monitor Panels & Local
RML-9	Waste Discharge Line	150	100	10^1-10^6 cpm	Radiation Monitor Panel & Local

* Note: Use of wider range instrumentation than specified is allowed provided that the required instrument accuracy in the measured range is maintained.

Table 11.2-6
Tank Overflow Protection

Tank	System	Monitoring	Annunciation	Overflow of Collection Provisions	Processing of Overflow
Volume Control Tank	CVCS	Level Indication	High Level Alarm	Flow diverted to Recyle Holdup Tank on high level	By Recycle Holdup Tank
Reactor Makeup Water Storage Tank	MU	Level Indication	High Level Alarm	Overflow to Drain	Via Waste Holdup Tank
Boric Acid Tank	CVCS	Level Indication	High Level Alarm	Overflow to Drain	Via Waste Holdup Tank
Boric Acid Batching Tank	CVCS	Level Indication		Overflow to Drain	Via Waste Holdup Tank
Recycle Holdup Tank	BRS	Level Indication	High Level Alarm	Overflow on Floor to Drain	Via Waste Holdup Tank via Floor Sump Pump
Reactor Coolant Drain Tank	LWPS	Level Indication	High Level Alarm	Overflow on Floor to Drain	Via Waste Holdup Tank via Reactor Building Sump Pump
Waste Holdup Tank	LWPS	Level Indication	High Level Alarm	Overflow on Floor to Drain	Floor Drain Tank via Floor Sump Pump
Floor Drain Tank	LWPS	Level Indication	High Level Alarm	Overflow on Floor to Drain	Floor Drain Tank via Floor Sump Pump
Miscellaneous Waste Drain Tank	ND	Level Indication	High Level Alarm	Overflow on Floor to Drain	Floor Drain Tank via Floor Sump Pump
Waste Evaporator Concentrates Tank	WD	Level Indication	High Level Alarm	Overflow on Floor to Drain	Via Waste Holdup Tank

Table 11.2-6 (continued)
Tank Overflow Protection

Tank	System	Monitoring	Annunciation	Overflow of Collection Provisions	Processing of Overflow
Laundry and Hot Shower Tank	LWPS	Level Indication	High Level Alarm	Overflow on Floor to Drain	Flow Drain Tank via Floor Sump Pump
Chemical Drain Tank	LWPS	Level Indication	High Level Alarm	Overflow on Floor to Drain	Flow Drain Tank via Floor Sump Pump
Waste Evaporator Condensate Tank	LWPS	Level Indication	High Level Alarm	Overflow to Drain	Waste Holdup Tank via Miscellaneous Waste Holdup Tank
Waste Monitor Tank	LWPS	Level Indication	High Level Alarm	Overflow to Drain	Via Floor Drain Tank
LWPS Spent Resin Storage Tank	LWPS	Level Indication	High Level Alarm	Relief to Drain	Via Waste Holdup Tank
Nuclear Blowdown Spent Resin Storage Tank	NB	Level Indication	High Level Alarm	Relief to Secondary Side Drain Channel	Nuclear Blowdown Holdup Tank
Refueling Water Storage Tank	SF	Level Indication	High Level Alarm	Overflow to Drain	Via Waste Holdup Tank
Excess Waste Holdup Tank	ELWS	Level Indication	High Level Alarm	Overflow to Area Sump	Via ELWS
Decontamination Pit Collection Tank	ELWS	Level Indication	High Level Alarm	Overflow to Area Sump	Via ELWS
Nuclear Blowdown Holdup Tank	NB	Level Indication	High Level Alarm	Overflow to Secondary Side Drain	Nuclear Blowdown Holdup Tank
Nuclear Blowdown Monitor Tank	NB	Level Indication	High Level Alarm	Overflow to Secondary Side Drain	Nuclear Blowdown Holdup Tank

Table 11.2-6a
Comparison of Tanks Outside Containment with Provisions of Branch Technical Position ETSB 11-1 (Rev. 1), Paragraph B.1.b

Tank	Location [1] Elevation	ETSB 11-1 (Rev. 1), Paragraph B.1.b Item No. [2]					
		Item (1)		Item (2)		Items (3) and (4)	
		Monitor	Alarm	Overflow	Drain	Curb, etc.	Routed to LWS
Miscellaneous Waste Drain Tank	AB; 374’	C	C	C	C	NC	C
Laundry and Hot Shower Drain Tank	AB; 374’	C	C	C	C	NC	C
Floor Drain Tank	AB; 374’	C	C	C	C	NC	C
Waste Holdup Tank	AB; 374’	C	C	C	C	C	C
Chemical Drain Tank	AB; 374’	C	C	C	C	NC	C
Recycle Holdup Tank	AB; 388’	C	C	C	C	C	C
Waste Evaporator Condensate Tank	AB; 388’	C	C	C	C	NC	C
Waste Evaporator Concentrates Tank	AB; 412’	C	C	C	C	NC	C
Primary Spent Resin Tank	AB; 412’	C	C	C	C	C	C
Nuclear Blowdown Spent Resin Tank	AB; 412’	C	C	C	C	C	C
Nuclear Blowdown Holdup Tank	AB; 436’	C	C	C	C	C	C
Nuclear Blowdown Monitor Tank	AB; 436’	C	C	C	C	C	C

Table 11.2-6a (continued)
Comparison of Tanks Outside Containment with Provisions of Branch Technical Position ETSB 11-1 (Rev. 1), Paragraph B.1.b

		ETSB 11-1 (Rev. 1), Paragraph B.1.b Item No. (2)					
		Item (1)		Item (2)		Items (3) and (4)	
Tank	Location (1) Elevation	Monitor	Alarm	Overflow	Drain	Curb, etc.	Routed to LWS
Boric Acid Tank	AB; 463’	C	C	C	C	C	C
Volume Control Tank	AB; 463’	C	C	C	C	C	C
Waste Monitor Tank	AB; 463’	C	C	C	C	NC	C
Excess Waste Holdup Tank	FB; 412’ -9”	C	C	C	C	C	C
Decontamination Pit Collection Tank	FB; 412’ -9”	C	C	C	C	C	C
Refueling Water Storage Tank	YD; 412’	C	C	C	C	C	C
Reactor Makeup Water Tank	YD; 412’	C	C	C	C	C	C
Condensate Storage Tank	YD; Grade	C	C	NC	NC	NC	NC

Notes:

(1) Location
AB - Auxiliary Building
FB - Fuel Handling Building
YD - Yard; refueling water storage and reactor makeup water tanks are in an outdoor extension of the Auxiliary Building
(2) C - Conforms to ETSB 11-1 (Rev. 1)
NC - Does not conform to ETSB 11-1 (Rev. 1)

Table 11.2-7
Parameters Used in the Calculation of Estimated
Activity in Liquid Wastes(1)

Collector Tank With Sources	Volume of Liquid Waste	Collection Period Assumed Before Processing	Comments
Reactor Coolant Drain Tank Waste Holdup Tank (1)			
1. Shim Bleeds	500 gal/day		
2. Equipment drains	100 gal/day		
3. WHT inputs	75 gal/day		
Total	675 gal/day	6.0 days	Discharged
Floor Drain Tank (1)			
1. FDT inputs	450 gal/day	8.8 days	Discharged
Total	410,100 gal/yr		

(1) This table does not represent system capacity. The estimated waste processing system capacity based on indefinite operation for liquids collected in the floor drain tank and waste holdup tank is 25 gpm or approximately 12,500,000 gal/yr.

Table 11.2-8
(Sheet 1)

PWR-GALE Code Input Parameters Used in Calculating Releases
of Radioactive Materials in Liquid Effluents

Reactor Power Level, MWt	2900
Primary System	
Mass of Primary Coolant, thousand lbs	377.9
Average Letdown Rate, gpm	105
Average Letdown Cation Demineralizer Flow Rate, gpm	10.5
Secondary System	
Steam Flow Rate, million lbs/hr	12.85
Mass of Steam/Steam Generator, thousand lbs	7.407
Mass of Liquid/Steam Generator, thousand lbs	109
Mass of Secondary Coolant, thousand lbs	2220
Steam Generator Blowdown Rate, thousand lbs/hr	45
Steam Generator Blowdown Treatment Option	See Section 11.2.6.4.3

Table 11.2-8 (continued)
(Sheet 2)

PWR-GALE Code Input Parameters Used in Calculating Releases
of Radioactive Materials in Liquid Effluents

Stream	Flow Rate (gal/day)	Fraction of Primary Coolant Activity	Fraction Discharged	Collection Time (days)	Decay Time (days)	Determination Factors		
						I	Cs	Others
Shim Bleed	1.45×10^3	NA	1.0	2.08	0.11	1×10^2	2×10^1	1×10^3
Equipment Drains	3.00×10^2	1.00	1.0	2.08	0.11	1×10^2	2×10^1	1×10^3
Clean Wastes	2.00×10^2	1.00	1.0	2.08	0.11	1×10^2	2×10^1	1×10^3
Dirty Wastes	1.34×10^3	0.05	1.0	2.97	0.11	1×10^3	2×10^2	1×10^3
Blowdown	_ (2)	_ (1)	1.0	0.01	0	1×10^3	1×10^2	1×10^3
Detergent Wastes	_ (1)	_ (1)	1.0	NA (3)	NA	NA	NA	NA

(1) Calculated by PWR-GALE Code.
(2) Value given on Sheet 1, Table 11.2-8.
(3) Not Applicable.

Table 11.2-9
Deleted by RN 03-038

Table 11.2-10
Deleted by RN 03-038

Table 11.2-11
Deleted by RN 03-038

Table 11.2-12
Liquid Effluents Annual Releases

NUCLIDE	HALF-LIFE (DAYS)	PRIMARY (MICRO CI/ML)	SECONDARY (MICROCI/ML)	EQUIP. DRAIN (CURIES)	MISC. WASTES (CURIES)	SECONDARY (CURIES)	ADJUSTED TURB BLDG (CURIES)	DETERGENT TOTAL LWS (CURIES)	TOTAL TOTAL (CI/YR)	WASTES (CI/YR)	(CI/YR)
COOLANT CONCENTRATIONS----------											
CORROSION AND ACTIVATION PRODUCTS											
CR 51	2.78E+01	1.15E-03	1.01E-07	.00069	.00041	.00000	.00000	.00110	.00112	.00000	.00110
MN 54	3.03E+02	1.86E-04	2.41E-08	.00011	.00007	.00000	.00000	.00018	.00019	.00000	.00019
FE 55	9.50E+02	9.61E-04	8.41E-08	.00059	.00035	.00000	.00000	.00095	.00097	.00000	.00097
FE 59	4.50E+01	6.04E-04	6.19E-08	.00036	.00022	.00000	.00000	.00058	.00060	.00000	.00060
CO 58	7.13E+01	9.64E-03	8.57E-07	.00586	.00351	.00000	.00001	.00938	.00959	.00000	.00960
CO 60	1.92E+03	1.20E-03	1.08E-07	.00074	.00044	.00000	.00000	.00118	.00121	.00000	.00120
NP239	2.35E+00	7.88E-04	5.84E-08	.00035	.00020	.00000	.00000	.00056	.00057	.00000	.00057
FISSION PRODUCTS											
BR 83	1.00E-01	5.02E-03	1.56E-07	.00101	.00046	.00000	.00000	.00147	.00151	.00000	.00150
BR 84	2.21E-02	3.08E-03	2.99E-08	.00001	.00000	.00000	.00000	.00001	.00001	.00000	.00001
RB 86	1.87E+01	5.23E-05	5.28E-09	.00355	.00072	.00000	.00000	.00426	.00436	.00000	.00440
RB 88	1.24E-02	2.44E-01	1.28E-06	.00031	.00006	.00000	.00000	.00037	.00038	.00000	.00038
SR 89	5.20E+01	2.11E-04	2.47E-08	.00013	.00008	.00000	.00000	.00020	.00021	.00000	.00021
SR 91	4.03E-01	5.41E-04	3.00E-08	.00007	.00004	.00000	.00000	.00012	.00012	.00000	.00012
Y 91M	3.47E-02	4.16E-04	4.19E-08	.00005	.00003	.00000	.00000	.00008	.00008	.00000	.00008
Y 91	5.88E+01	3.86E-05	3.69E-09	.00003	.00002	.00000	.00000	.00004	.00004	.00000	.00004
ZR 95	6.50E+01	3.62E-05	3.68E-09	.00002	.00001	.00000	.00000	.00004	.00004	.00000	.00004
NB 95	3.50E+01	3.02E-05	3.75E-09	.00002	.00001	.00000	.00000	.00003	.00003	.00000	.00003
MO 99	2.79E+00	5.45E-02	5.49E-06	.02547	.01492	.00000	.00005	.04044	.04136	.00000	.04100
TC 99M	2.50E-01	4.35E-02	2.00E-05	.02367	.01409	.00000	.00012	.03788	.03874	.00000	.03900
RU103	3.96E+01	2.72E-05	2.49E-09	.00002	.00001	.00000	.00000	.00003	.00003	.00000	.00003
RH103M	3.96E-02	5.16E-05	2.72E-08	.00002	.00001	.00000	.00000	.00003	.00003	.00000	.00003
TE125M	5.80E+01	1.75E-05	1.11E-09	.00001	.00001	.00000	.00000	.00002	.00002	.00000	.00002
TE127M	1.09E+02	1.68E-04	1.09E-08	.00010	.00006	.00000	.00000	.00016	.00017	.00000	.00017
TE127	3.92E-01	7.11E-04	1.02E-07	.00017	.00010	.00000	.00000	.00028	.00028	.00000	.00028
TE129M	3.40E+01	8.46E-04	7.51E-08	.00051	.00030	.00000	.00000	.00081	.00083	.00000	.00083
TE129	4.79E-02	1.81E-03	7.83E-07	.00033	.00020	.00000	.00000	.00053	.00055	.00000	.00055
I130	5.17E-01	1.68E-03	1.08E-07	.00299	.00138	.00000	.00001	.00438	.00448	.00000	.00450
TE131M	1.25E+00	1.75E-03	1.29E-07	.00060	.00034	.00000	.00000	.00095	.00097	.00000	.00097
TE131	1.74E-02	1.32E-03	7.67E-07	.00011	.00006	.00000	.00000	.00017	.00018	.00000	.00018
I131	8.05E+00	1.67E-01	1.56E-05	.93165	.43224	.00000	.00152	1.36541	1.39624	.00000	1.40000
TE132	3.25E+00	1.73E-02	1.39E-06	.00842	.00494	.00000	.00001	.01337	.01367	.00000	.01400
I132	9.58E-02	1.05E-01	1.16E-05	.06297	.02969	.00000	.00020	.09286	.09496	.00000	.09500
I133	8.75E-01	2.79E-01	2.04E-05	.77052	.35541	.00000	.00166	1.12759	1.15305	.00000	1.20000
I134	3.67E-02	5.42E-02	7.88E-07	.00106	.00049	.00000	.00000	.00155	.00158	.00000	.00160
CS134	7.49E+02	1.51E-02	1.46E-06	1.06596	.21496	.00000	.00001	1.28093	1.30985	.00000	1.30000
I135	2.79E-01	1.69E-01	8.77E-06	.15241	.07011	.00000	.00047	.22299	.22803	.00000	.23000
CS136	1.30E+01	8.06E-03	6.84E-07	.53751	.10831	.00000	.00001	.64583	.66041	.00000	.66000
CS137	1.10E+04	1.08E-02	9.71E-07	.76787	.15485	.00000	.00001	.92272	.94356	.00000	.94000
BA137M	1.77E-03	1.98E-02	1.35E-05	.71796	.14478	.00000	.00001	.86275	.88223	.00000	.88000
BA140	1.28E+01	1.35E-04	1.20E-08	.00008	.00005	.00000	.00000	.00012	.00013	.00000	.00013
LA140	1.67E+00	1.02E-04	1.79E-08	.00007	.00004	.00000	.00000	.00011	.00011	.00000	.00011
CE141	3.24E+01	4.23E-05	3.76E-09	.00003	.00002	.00000	.00000	.00004	.00004	.00000	.00004
CE143	1.38E+00	2.77E-05	2.21E-09	.00001	.00001	.00000	.00000	.00002	.00002	.00000	.00002
PR143	1.37E+01	3.05E-05	2.66E-09	.00002	.00001	.00000	.00000	.00003	.00003	.00000	.00003
CE144	2.84E+02	1.98E-05	2.41E-09	.00001	.00001	.00000	.00000	.00002	.00002	.00000	.00002
PR144	1.20E-02	3.99E-05	3.17E-08	.00001	.00001	.00000	.00000	.00002	.00002	.00000	.00002
ALL OTHERS		4.24E-04	1.24E-08	.00002	.00001	.00000	.00000	.00003	.00003	.00000	.00003
TOTAL (EXCEPT TRITIUM)		1.22E+00	1.06E-04	5.08446	1.55406	.00000	.00411	6.64263	6.79263	.00000	6.80000
TRITIUM RELEASE		580	CURIES PER YEAR								

Table 11.2-13
Comparison of Radionuclide Concentrations in Liquid Effluents to the Limits of 10 CFR 20

Isotope	Annual Release Ci/yr	Expected Site Boundary Concentration µCi/cc	Effluent Concentration Limit - ECL (1) µCi/cc	Ratio of Expected Concentration to ECL
CR 51	1.1E-03	2.2E-13	5.0E-04	4.4E-10
MN 54	1.9E-04	3.8E-14	3.0E-05	1.3E-09
FE 55	9.7E-04	1.9E-13	1.0E-04	1.9E-09
FE 59	6.0E-04	1.2E-13	1.0E-05	1.2E-08
CO 58	9.6E-03	1.9E-12	2.0E-05	9.6E-08
CO 60	1.2E-03	2.4E-13	3.0E-06	8.0E-08
NP239	5.7E-04	1.1E-13	2.0E-05	5.7E-09
BR 83	1.5E-03	3.0E-13	9.0E-04	3.3E-10
BR 84	1.0E-05	2.0E-15	4.0E-04	5.0E-12
RB 86	4.4E-03	8.8E-13	7.0E-06	1.3E-07
RB 88	3.8E-04	7.6E-14	4.0E-04	1.9E-10
SR 89	2.1E-04	4.2E-14	8.0E-06	5.3E-09
SR 91	1.2E-04	2.4E-14	2.0E-05	1.2E-09
Y 91M	8.0E-05	1.6E-14	2.0E-03	8.0E-12
Y 91	4.0E-05	8.0E-15	8.0E-06	1.0E-09
ZR 95	4.0E-05	8.0E-15	2.0E-05	4.0E-10
NB 95	3.0E-05	6.0E-15	3.0E-05	2.0E-10
MO 99	4.1E-02	8.2E-12	2.0E-05	4.1E-07
TC 99M	3.9E-02	7.8E-12	1.0E-03	7.8E-09
RU103	3.0E-05	6.0E-15	3.0E-05	2.0E-10
RH103M	3.0E-05	6.0E-15	6.0E-03	1.0E-12
TE125M	2.0E-05	4.0E-15	2.0E-05	2.0E-10
TE127M	1.7E-04	3.4E-14	9.0E-06	3.8E-09
TE127	2.8E-04	5.6E-14	1.0E-04	5.6E-10
TE129M	8.3E-04	1.7E-13	7.0E-06	2.4E-08
TE129	5.5E-04	1.1E-13	4.0E-04	2.8E-10
I130	4.5E-03	9.0E-13	2.0E-05	4.5E-08
TE131M	9.7E-04	1.9E-13	8.0E-06	2.4E-08
TE131	1.8E-04	3.6E-14	8.0E-05	4.5E-10
I131	1.4E+00	2.8E-10	1.0E-05	2.8E-05
TE132	1.4E-02	2.8E-12	9.0E-06	3.1E-07
I132	9.5E-02	1.9E-11	1.0E-04	1.9E-07
I133	1.2E+00	2.4E-10	7.0E-06	3.4E-05
I134	1.6E-03	3.2E-13	4.0E-04	8.0E-10
CS134	1.3E+00	2.6E-10	9.0E-07	2.9E-04
I135	2.3E-01	4.6E-11	3.0E-05	1.5E-06
CS136	6.6E-01	1.3E-10	6.0E-06	2.2E-05
CS137	9.4E-01	1.9E-10	1.0E-06	1.9E-04
BA140	1.3E-04	2.6E-14	8.0E-06	3.3E-09
LA140	1.1E-04	2.2E-14	9.0E-06	2.4E-09
CE141	4.0E-05	8.0E-15	3.0E-05	2.7E-10
CE143	2.0E-05	4.0E-15	2.0E-05	2.0E-10
PR143	3.0E-05	6.0E-15	7.0E-05	8.6E-11
CE144	2.0E-05	4.0E-15	3.0E-06	1.3E-09
PR144	2.0E-05	4.0E-15	2.0E-05	2.0E-10
ALL OTH	3.0E-05	6.0E-15	1.0E-08	6.0E-07
H-3	5.8E+02	1.2E-07	1.0E-03	1.2E-04
			TOTAL	6.8E-04

(1 From 10 CFR 20, Appendix B, Table 2, Column 2.

Table 11.2-14
Summary of Calculated Liquid Pathway Doses
Virgil C. Summer Nuclear Station

Pathway	Location	Age Group	Organ Receiving Maximum Dose: Dose Organ	Organ Receiving Maximum Dose: Dose (mrem/yr)	Total Body Dose (mrem/yr)
Drinking Water	Columbia Water Supply System	Adult	Liver	6.1E-2	4.6E-2
		Teen	Liver	5.6E-2	2.5E-2
		Child	Liver	1.1E-1	2.6E-2
		Infant	Liver	1.4E-1	1.8E-2
Fish Ingestion	Parr/Monticello System	Adult	Liver	3.2E+0	2.4E+0
		Teen	Liver	3.3E+0	1.4E+0
		Child	Liver	2.9E+0	5.2E-1
Shoreline Activity	Parr/Monticello System	Adult	Skin	1.5E-1	1.3E-1
		Teen	Skin	2.0E-2	1.7E-2
		Child	Skin	4.1E-3	3.5E-3
Swimming	Parr/Monticello System	Adult	Total Body	1.2E-4	1.2E-4
Boating	Parr/Monticello System	Adult	Total Body	3.0E-4	3.0E-4

Table 11.2-15
Appendix I Conformance Summary Table
Virgil C. Summer Nuclear Station
Liquid Effluents

	Appendix I Criteria		Virgil C. Summer Nuclear Station	
Type of Dose	Design Objective (1)	Point of Dose Evaluation	Calculated Dose	Point of Dose Evaluation (6)
Liquid Effluents				
Dose to total body from all pathways	5 mrem/yr per site	Location of the highest dose offsite (2)	2,54 mrem/yr (3)	Parr/Monticello (4) Reservoir System
Dose to any organ from all pathways	5 mrem/yr per site	Same as above	3.41 mrem/yr (5)	Parr/Monticello (4) Reservoir System

(1) Design objectives as specified in the Commission's Appendix I Conformance Option, 40 FR 40816, September 4, 1975.
(2) Evaluated at a location that is anticipated to be occupied during plant lifetime or evaluated with respect to such potential land and water usage and food pathways as could actually exist during the term of plant operation.
(3) Dose to adult.
(4) Fish were assumed to be exposed to average radionuclide concentrations in the Parr/Monticello Reservoir System.
(5) Dose to teen liver.
(6) Points given correspond to points of does evaluation under Appendix I heading.

Figure 11.2-1

LIQUID WASTE PROCESSING SYSTEM
PROCESS FLOW DIAGRAM

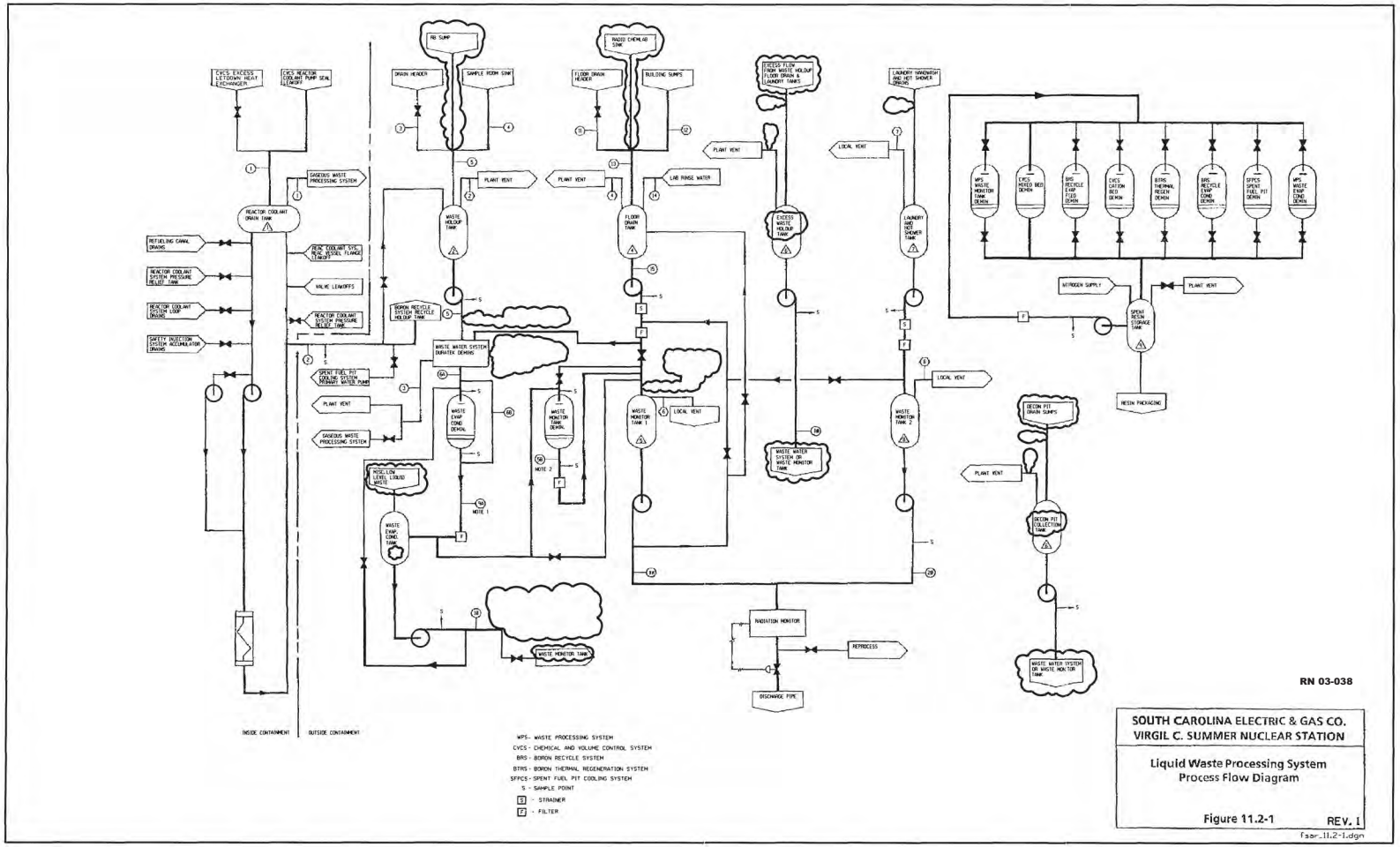


Figure 11.2-2
DELETED BY RN 03-038

Figure 11.2-3

LOCATION OF LIQUID RELEASE POINTS

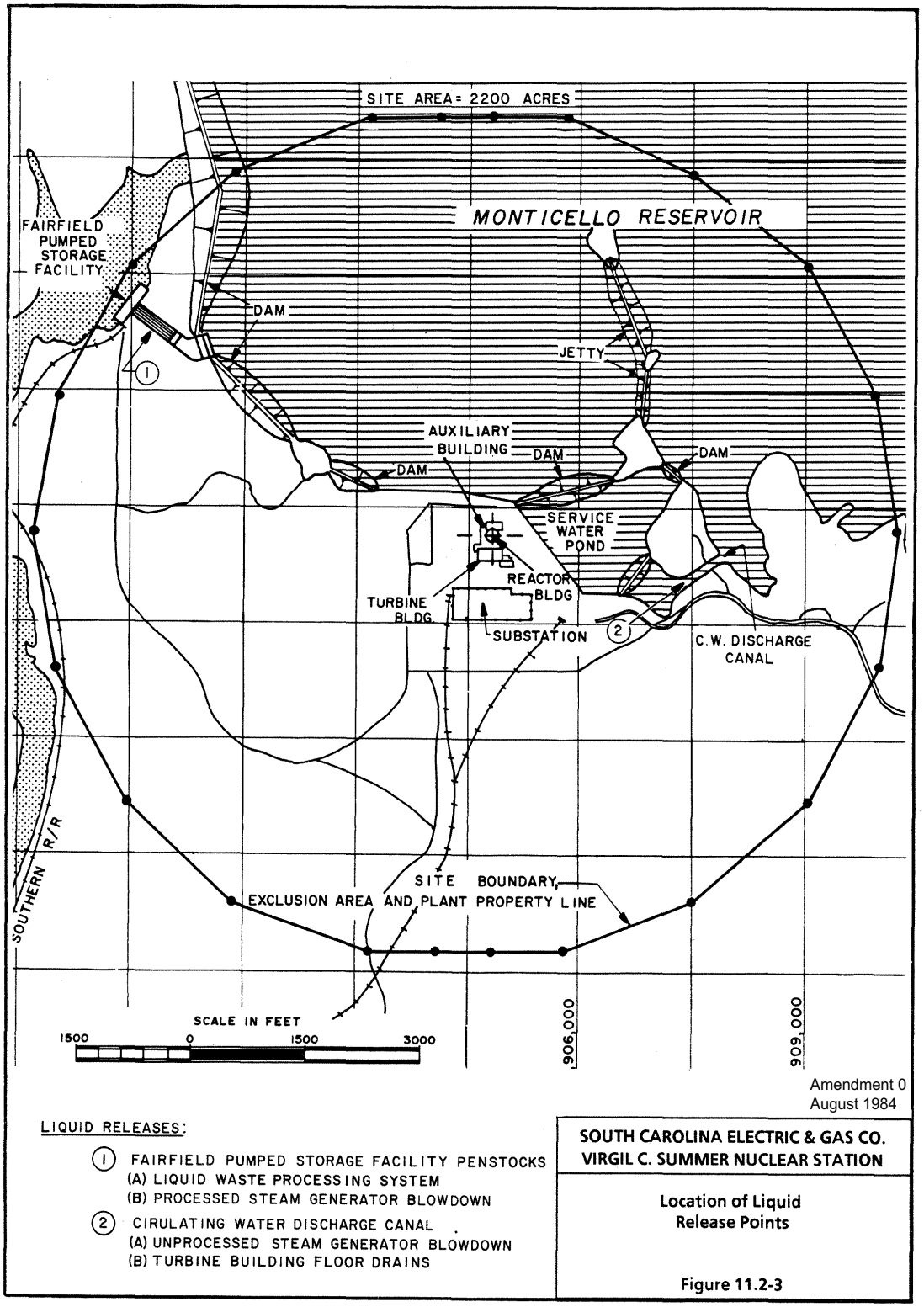
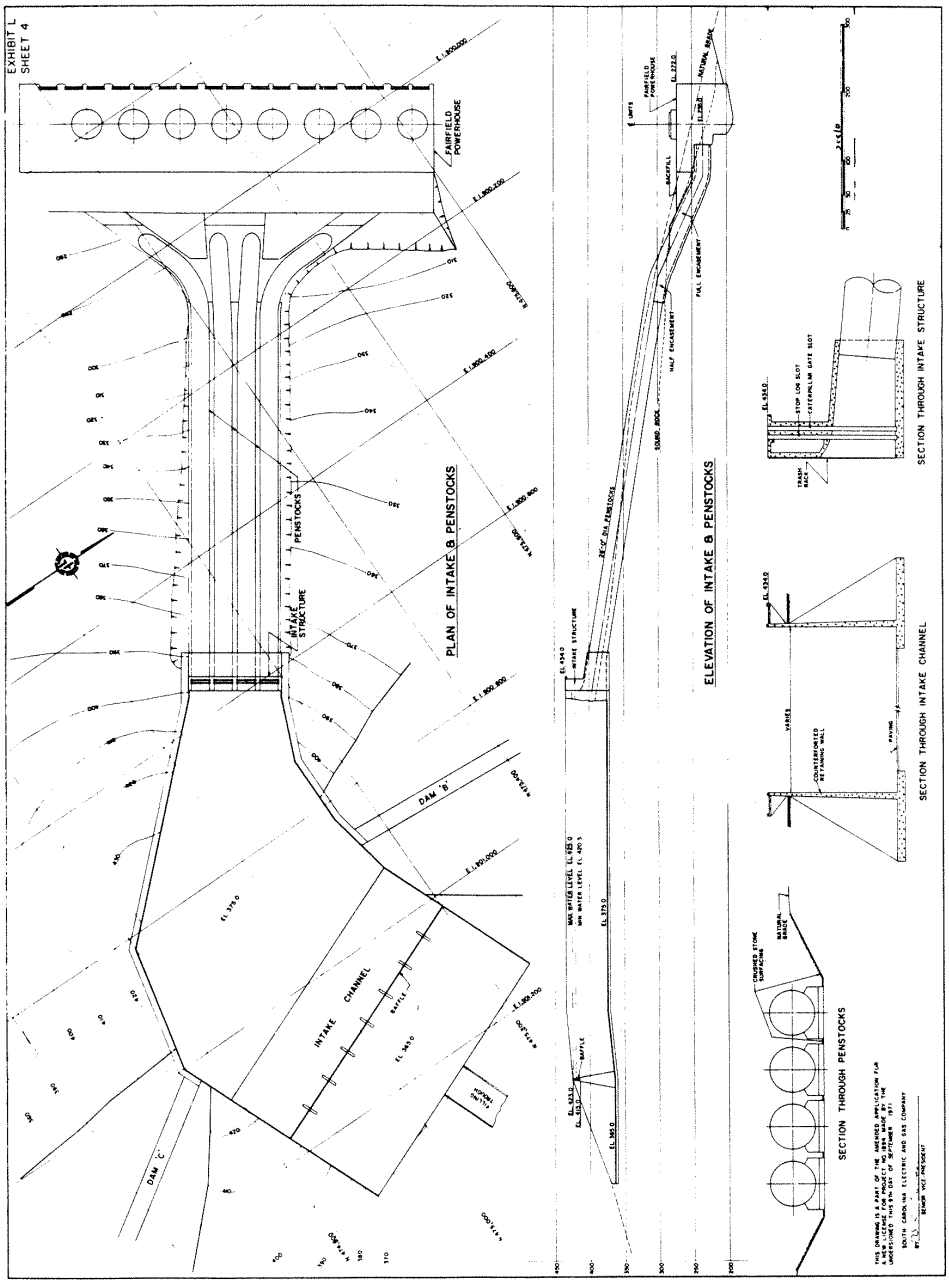


Figure 11.2-4
FAIRFIELD PUMPED STORAGE FACILITY



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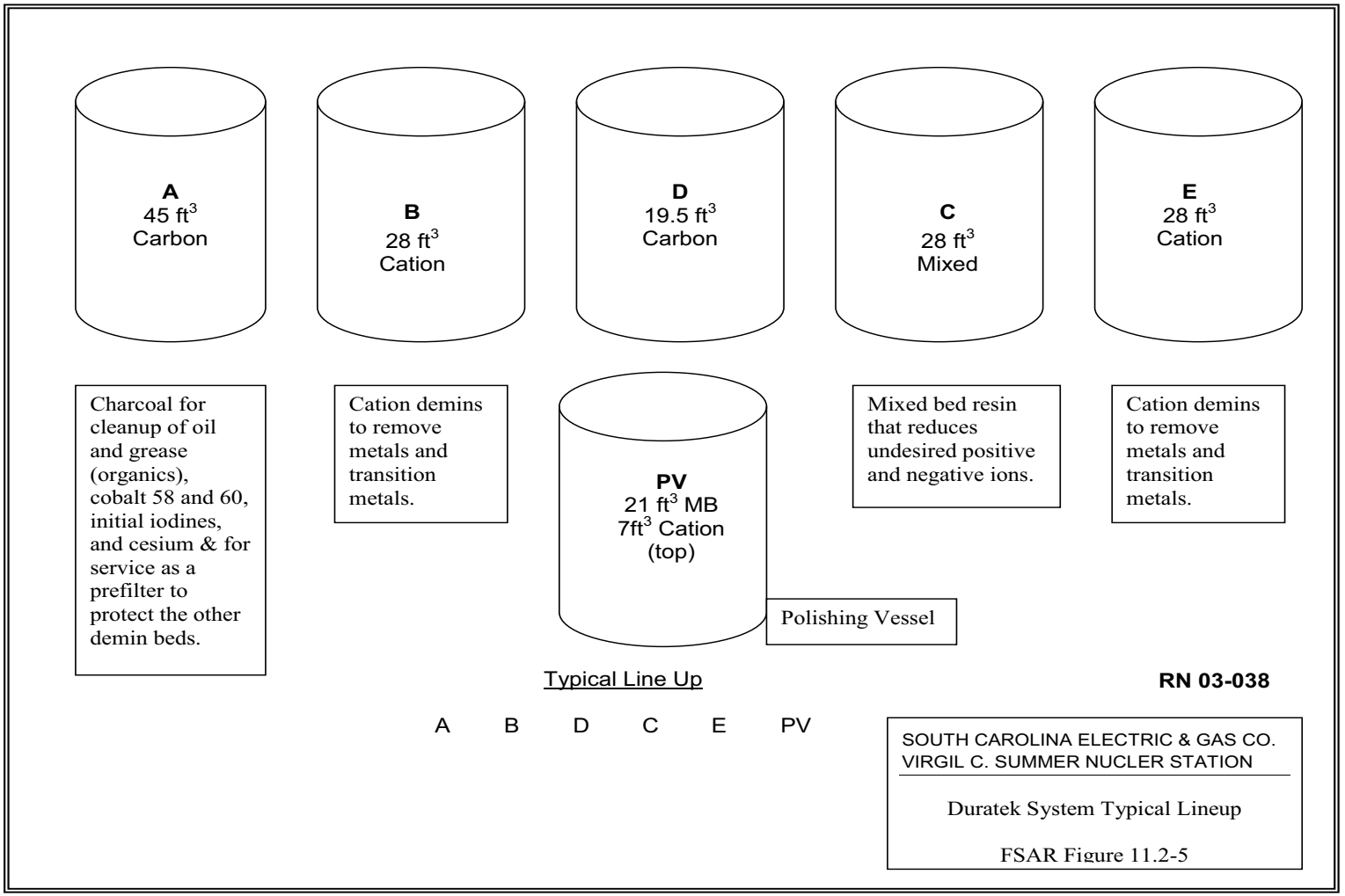
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Fairfield Pumped Storage Facility
Figure 11.2-4

Figure 11.2-5

DURATEK SYSTEM TYPICAL LINEUP



11.3 Gaseous Waste System

11.3.1 Design Objectives

The Gaseous Waste Processing System (GWPS) is designed to remove fission product gases from the reactor coolant in the volume control tank. The system is also designed to collect gases from the boron recycle and waste evaporators, reactor coolant drain tank, recycle holdup tanks, and reactor vessel. The system has the capacity for long term storage.

Under normal operation, the annual releases due to leakage and routine releases from the GWPS will be sufficiently low such that site boundary doses will be a small fraction of regulation requirements.

The system is capable of operating under conditions of fuel defects in combination with equipment faults of moderate frequency.

The system is designed to preclude the possibility of an internal explosion. However, the system volume is distributed so that the dose in the unlikely event of an explosion is approximately the same as the dose due to a gas decay tank rupture as analyzed in Section 15.3.5.

11.3.2 System Description

The GWPS consists mainly of a closed loop comprised of two waste gas compressors, two catalytic hydrogen recombiners, and gas decay tanks to accumulate the fission product gases. The routing of piping containing radioactive gases is either through shielded cubicles or behind shield slabs.

NOTE:

The following paragraph is being retained for historical purposes only.

Components of a similar design to those used in the GWPS have been operating for several years with excellent performance. Systems constructed from carbon steel have been in service for more than three years and no failure due to corrosion damage has been reported.

The major input to the GWPS during normal operation is taken from the gas space in the volume control tank.

Table 11.3-1, based on the Reactor Coolant System activities given in Table 11.1-2, shows the maximum fission product inventory in the GWPS over the 40 year plant life. Table 11.3-2, based on the Reactor Coolant System activities given in Table 11.1-5, shows the expected fission product inventory in the GWPS over the 40 year life.

Figure 11.3-1, based on the reactor coolant activities given in Table 11.1-2, shows that for a given power rating with 1% fuel defects, the quantity of fission gas activity accumulated after 40 years continuous operation is about twice the activity accumulated after short term operation.
Figure 11.3-2, based on realistic reactor coolant activities given in Table 11.1-5, shows that the

quantity of fission gas activity accumulated after 40 years continuous operation is essentially Krypton-85 with the short lived isotopes contributing approximately 12% of the total. This is because the accumulated activity other than Krypton-85 arises from short lived isotopes which reach equilibrium after a short operating period.

This accumulation of Krypton-85 is not a hazard to the plant operator because:

1. Radiation background levels in the plant are not noticeably affected by the accumulation of Krypton-85 which is a beta emitter, for which the tanks themselves provide adequate shielding.
2. The system activity inventory is distributed in several tanks so that the maximum permissible inventory in any single tank is actually less than that of earlier GWPS designs.

Since this system permits fission gas removal from the reactor coolant during normal operation, it is expected to reduce plant activity levels caused by a leakage of reactor coolant. With operation of this system, it is possible to collect virtually all of the Krypton-85 released to the reactor coolant and to achieve a reduction in the fission product gas inventory in the Reactor Coolant System as shown in Table 11.3-3. Table 11.3-3 is based on the Reactor Coolant System activities given in Table 11.1-1. Provisions are made to collect any residual gases stripped out of solution by the boron recycle and waste evaporators, gases from the reactor coolant drain tank, gases from the recycle holdup tanks, and gases from the reactor vessel.

Process flow diagrams and piping and instrumentation diagrams are shown on Figures 11.3-3 and 11.3-4, respectively. Table 11.3-4 gives process parameters for key locations in the system, with reference to locations on Figure 11.3-3 and based on the Reactor Coolant System activities given in Table 11.1-5.

The process parameters are derived assuming the system to operate as described in Section 11.3.4. The stripping efficiency used in the analysis is 0.4, and the volume control tank purge rate is 0.7 scfm of hydrogen.

11.3.3 System Design

11.3.3.1 Component Design

Gaseous waste processing equipment parameters are given in Table 11.3-5. Component safety classes and the corresponding code and code class are shown in Table 3.2-1. All materials used for pressure retaining components are allowed by Section III of the ASME Code, and no malleable wrought or cast iron or plastic pipe is used.

Quality assurance requirements of Westinghouse Administrative Specifications for the Procurement of Nuclear Steam Supply System Components, Revision 5, March 1975 are applied to all NNS components within Westinghouse scope. Hence, all components within Westinghouse scope meet the design guidance as outlined in Branch Technical Position ETSB 11-1.

11.3.3.1.1 Waste Gas Compressor Packages

Two waste gas compressor packages are provided to circulate gases around the system loop. One unit is normally used with the other on a standby basis.

The units are water-sealed centrifugal displacement machines which are skid-mounted in a self-contained package. Construction is primarily of carbon steel. Mechanical seals are provided to minimize the out-leakage of seal water.

11.3.3.1.2 Catalytic Hydrogen Recombiner Packages

Two catalytic hydrogen recombiners are provided. One of the two recombiners is normally used to remove hydrogen from the hydrogen-nitrogen-fission gas mixtures by oxidation to water vapor, which is removed by condensation. The other recombiner is available on a standby basis. Both units are self-contained and designed for continuous operation. The recombiner is located in the system where the hydrogen concentration and pressure are optimum with respect to hydrogen removal.

11.3.3.1.3 Waste Gas Decay Tanks

Waste gas decay tanks are provided as described in Table 11.3-5. The tanks are of vertical-cylindrical type and are constructed of carbon steel. There are eight waste gas decay tanks, six are used during normal operation while the remaining two are used for shutdown and startup.

11.3.3.1.4 Valves

Each valve in the recombiner system is designed to meet the temperature, pressure, and code requirements for the specific application in which it is used. The recombiner circuits contain manual valves provided with a metal diaphragm to prevent stem leakage and control valves with gaseous leakoffs returned to the GWPS. Other parts of the GWPS use control valves with bellows seal. Relief valves have soft seats and operate at pressures which are normally less than 2/3 of the relief valve set pressure. The relief valves of the major components discharge to the shutdown tanks. This permits decay and controlled disposal of all discharges less than about 3000 scf. It also provides a means for containing and detecting seat leakage across the relief valves.

11.3.3.2 Instrumentation and Control Design

The main system instrumentation is described in Table 11.3-6 and shown on the piping and instrumentation diagrams, Figure 11.3-4.

The instrumentation readout is located mainly on the Waste Processing System (WPS) panel in the Auxiliary Building. Some instruments are read near the equipment location.

All alarms are shown separately on the WPS panel and further relayed to one common WPS annunciator on the main control board.

Where suitable, instrument lines are provided with diaphragm seals to prevent fission gas outleakage through the instrument.

Figure 11.3-5 shows the location of the instruments on the compressor package.

The compressors are interlocked with the seal water inventory in the moisture separators and trip off on either a high or a low moisture separator level. During normal operation, the proper seal water inventory is maintained automatically.

Figure 11.3-6 indicates the location of the instruments on the recombiner installation.

The catalytic hydrogen recombiner packages are designed for automatic operation with a minimum of operator attention. Each package includes four online gas analyzers, one each to measure hydrogen in, oxygen in, hydrogen out, and oxygen out, which are the primary means of recombiner control. A multipoint temperature recorder monitors temperatures at several locations in the packages.

Process gas flowrate is measured by an orifice located upstream of the recombiner preheater. Local pressure gauges indicate pressure at the recombiner inlet and the oxygen supply pressure.

The following controls and alarms are incorporated to maintain the gas composition outside the range of flammable and explosive mixtures:

1. A high flow alarm actuates when the volume control tank purge flow exceeds a predetermined value. This high flow alarm is set below the flow which corresponds to the maximum inlet concentration (6% hydrogen by volume) the recombiner can process in one pass.
2. If the hydrogen concentration in the recombiner feed exceeds 4% by volume, a high hydrogen and high-high hydrogen/oxygen shutdown alarm sounds, the oxygen feed is terminated through TCV01114, and the volume control tank hydrogen purge flow is terminated. The control and alarm setpoints were lowered to a identical setpoint of 4% by volume to limit the possible accumulation of hydrogen in the system to 4% by volume for compliance with Technical Specifications.
3. If the oxygen concentration in the recombiner feed reaches 2% by volume, a high oxygen and high-high oxygen/shutdown alarm sounds, oxygen feed flow is limited through HCV01118, and the oxygen feed is terminated through TCV01114. The control and alarm setpoints were lowered to a identical setpoint of 2% by volume which is below the flammable limit for hydrogen-oxygen mixtures for Technical Specifications compliance.
4. If hydrogen in the recombiner discharge exceeds 0.15% by volume, an alarm sounds. This alarm warns of high hydrogen feed, possible hydrogen-oxygen catalytic reactor malfunction, or loss of oxygen feed.
5. If oxygen in the recombiner discharge exceeds 60 ppm, an alarm sounds and oxygen feed is terminated. This control prevents any accumulation of oxygen in the system in case of catalytic reactor malfunction.

6. On low flow through the recombiner, oxygen feed is terminated. This control prevents an accumulation of oxygen following system malfunction.
7. High discharge temperature from the cooler-condenser (downstream from the catalytic reactor) will terminate oxygen feed. This protects against loss of cooling water flow in the cooler-condenser.
8. High temperature indication by any one of six thermocouples in the catalyst bed will limit oxygen feed so that no further increase is possible.
9. High temperature indication at the recombiner catalytic reactor discharge will terminate oxygen feed to the recombiner.

11.3.4 Operating Procedures

11.3.4.1 General Description

The GWPS is a closed loop comprised of two waste gas compressors, two catalytic hydrogen recombiners, six gas decay tanks for normal power service, two gas decay tanks for service at shutdown and startup, one gas decay tank drain pump, one waste gas drain filter, and four gas traps. All of the equipment is located in the Auxiliary Building.

11.3.4.2 Startup Operation

Startup commences with the system flushed free of air by purging with nitrogen which is discharged to the atmosphere. One compressor, one recombiner, and one shutdown decay tank are in service. The reactor is at cold shutdown and the volume control tank contains nitrogen in the gas space. Reactor coolant contains neither hydrogen nor fission gases, but it may be saturated with air.

When the reactor startup procedure requires that a hydrogen blanket be established in the volume control tank gas space, fresh hydrogen is charged into the tank. The hydrogen-nitrogen mixture vented from the tank enters the circulating nitrogen stream at the compressor suction. Since the pressure downstream remains constant by use of a pressure regulating valve, nitrogen added to the loop will accumulate in the shutdown decay tank causing the tank pressure to rise.

Initially, the volume control tank vent gas will be very lean in hydrogen, and almost all the influent gas will accumulate in the tank. As the operation continues, however, the vent gas hydrogen content will gradually increase until it is almost totally hydrogen at the point when all of the nitrogen has been removed from the coolant. At that time, hydrogen gas is entering the volume control tank at 0.7 scfm and mixing with the 40 scfm circulating nitrogen stream to give a 1.8 volume% mixture of hydrogen in nitrogen at the recombiner inlet. Approximately 0.35 scfm of oxygen is added in the recombiner and reacted with the hydrogen to yield a discharge stream of 0.1 volume% hydrogen in nitrogen after water vapor is condensed.

When the reactor coolant nitrogen concentration is within operating specifications, the shutdown tank is isolated and flow is routed to one of the decay tanks provided for normal power service.

Gas accumulated in the shutdown tank will be retained for use during operations to strip hydrogen from the reactor coolant when the plant is shut down.

11.3.4.3 Normal Operations

During normal power operation, nitrogen gas is continuously circulated around the loop by one of the two compressors. Fresh hydrogen gas is charged to the volume control tank where it is mixed with fission gases which are stripped from the reactor coolant into the tank gas space. The contaminated hydrogen gas is then vented from the tank into the circulating nitrogen stream to transport the fission gases into the GWPS. The resulting mixture of nitrogen-hydrogen-fission gas is pumped by the compressor to the recombiner where enough oxygen is added to reduce the hydrogen to a low residual level by oxidation to water vapor on a catalytic surface. After the water vapor is removed, the resulting gas stream is circulated to the waste gas decay tanks and back to the compressor suction to complete the loop circuit.

Each waste gas decay tank is capable of being isolated and the number of tanks valved into operation at any time is restricted to diminish the amount of radioactive gases which could be released as a consequence of any single failure, such as the rupture of any single tank or connected piping. By alternating use of these tanks, the accumulated activity is distributed among the tanks.

11.3.4.4 Shutdown

When the hydrogen contained in the reactor coolant must be removed in preparation for a cold shutdown, the normal gas decay tanks are valved out of service and one of the two shutdown tanks is placed in service. Additional nitrogen may have to be added to raise the shutdown tank to an acceptable pressure for this operation. In addition, the flow of hydrogen to the volume control tank is stopped, and the tank pressure is maintained with nitrogen. The volume control tank level may be raised and lowered to aid in hydrogen removal. Once the hydrogen concentration has been lowered to acceptable levels, the volume control tank purge to the waste gas system may be secured.

11.3.5 Performance Tests

NOTE:

The following paragraph is being retained for historical purposes only.

Compressor and recombiner packages are subjected to helium leak test after assembly. Initial performance tests are performed to verify the operability of the components, instrumentation, and control equipment.

During reactor operation, the system is in use and hence is under continuous surveillance. The system design permits the use of industry standard leak detection methods for leak testing and subsequent elimination of leaks.

11.3.6 Estimated Releases

Gaseous releases from the Virgil C. Summer Nuclear Station were calculated using the PWR-GALE Code[1] as specified in Regulatory Guide 1.112 (see Appendix 3A). The input parameters used to calculate gaseous releases are listed in Table 11.3-7 and are discussed in more detail in Sections 11.3.6.2 through 11.3.6.4. Calculated releases using the parameters listed in Table 11.3-7 are presented in Table 11.3-8. A comparison of effluent concentrations with 10 CFR 20, Appendix B, Table 2, Column 1 is presented in Section 11.3.8.

11.3.6.1 Gaseous Waste Processing System

The GWPS collects and stores gases stripped from the primary coolant in a continuously recirculating loop which includes pressurized storage tanks. Release calculations for the GWPS are based upon the options allowed by the PWR-GALE Code[1] for such a system (continuous purging of Volume Control Tank, 90 days decay time in storage tanks, zero day fill time). Using these options and the input parameters given in Table 11.3-7, the GWPS releases are calculated to be 214 Ci/yr of noble gases, 4×10^{-4} Ci/yr of airborne particulates, and 7 Ci/yr of Carbon-14. The isotopic distribution of these releases is given in Table 11.3-8.

11.3.6.2 Reactor Building Purge

Radioactive gases are released inside the Reactor Building when primary system components are opened or if leakage from the primary system occurs. The gaseous activity inside the Reactor Building may be purged up to 1000 hours per year in Modes 1-4 by the 6 inch low volume purge system. The low volume purge rate is 600 cfm. Activity is also released periodically when the 36 inch Reactor Building Purge System is used during Modes 5-6. The Reactor Building Charcoal Cleanup System is operated intermittently to reduce airborne iodine concentrations prior to Reactor Building access or purge system operation. The Reactor Building 36 inch and 6 inch purge flow is exhausted to the atmosphere through HEPA filters and charcoal adsorbers. Release calculations are based upon the PWR-GALE Code (Reference 1) parameters for leakage rate (1%/day of primary coolant noble gas inventory, 0.001%/day of primary coolant iodine inventory), recirculation cleanup time (16 hours), mixing efficiency (70%), decontamination factors (100 for HEPA filters, 10 for charcoal adsorbers) and number of high volume purges (36 inch during cold shutdown) per year (4) and a conservatively assumed continuous low volume purge (6 inch) rate of 1000 cfm. Using these parameters and the input parameters given in Table 11.3-7, the Reactor Building purge releases are calculated to be 2638 Ci/yr of noble gases, 2.5×10^{-2} Ci/yr of iodine, 1.9×10^{-3} Ci/yr of airborne particulates, and 1 Ci/yr of Carbon-14. The isotopic distribution of these releases is given in Table 11.3-8.

11.3.6.3 Auxiliary Building Ventilation

The Auxiliary Building Charcoal Exhaust System continuously exhausts air drawn from Auxiliary Building areas with moderate potential for radioactive contamination (demineralizers, storage tanks, gas decay tanks, evaporators, pump rooms, etc.). The supply and exhaust ducts are arranged so that air flow is always in the direction of progressively greater potential contamination. Exhaust air from these areas is drawn through the roughing/HEPA/charcoal filter

plenums continuously and is ducted to the main exhaust fans and the main plant vent. There is no bypass around this filter plenum.

The release calculations are based upon the assumption that reactor coolant leakage in the Auxiliary Building occurs primarily in the areas exhausted by the charcoal exhaust system. PWR-GALE Code (Reference 1) parameters for Auxiliary Building leakage (160 lbs/day), iodine partition factor (0.0075), and decontamination factors (100 for HEPA filters, 10 for charcoal adsorbers) have been used in the calculations. Using these parameters and the input parameters given in Table 11.3-7, the Auxiliary Building ventilation release is calculated to be 128 Ci/yr of noble gases, 1.1×10^{-2} Ci/yr of iodine, and 1.6×10^{-3} Ci/yr of airborne particulates. The isotopic distribution of this release is given in Table 11.3-8.

11.3.6.4 Secondary System

11.3.6.4.1 Turbine Building Vents

Turbine Building steam leakage may release radioactive gas to the Turbine Building atmosphere if primary to secondary leakage occurs. Turbine Building Ventilation System exhausts are not treated prior to release. Release calculations were based on the PWR-GALE Code (Reference 1) parameters for steam leakage (1700 lbs/hr), primary to secondary leakage (100 lbs/day), and fraction of iodine that remains airborne (Reference 1). Using these parameters and the input parameters given in Table 11.3-7, the Turbine Building vent release is calculated to be 2.4×10^{-3} Ci/yr of iodine. The isotopic distribution of this release is given in Table 11.3-8.

11.3.6.4.2 Condenser Air Removal System

Offgas from the Condenser Air Removal System may contain radioactive gases, if primary to secondary leakage occurs. When condenser offgas contains any significant amount of radioactivity, it is exhausted through HEPA filters and charcoal adsorbers in the Auxiliary Building Charcoal Exhaust System from particulate and iodine removal. Release calculations are based upon taking credit for the charcoal adsorbers and the PWR-GALE Code (Reference 1) parameters for primary to secondary leakage (100 lbs/day), steam generator partition factors (0.01 for iodine and 0.001 for nonvolatiles), and Main Condenser/Condenser Air Removal System partition factors (0.15 for volatile iodine species and zero for nonvolatile species). Using these parameters and the input parameters given in Table 11.3-7, the Condenser Air Removal System release is calculated to be 81 Ci/year of noble gases and 6.9×10^{-3} Ci/yr of iodine. The isotopic distribution of this release is given in Table 11.3-8.

11.3.6.4.3 Steam Generator Blowdown

The Steam Generator Blowdown Processing System provides for cooling the blowdown in heat exchangers to prevent flashing. Consequently, no gaseous release is expected to result from steam generator blowdown.

11.3.6.5 Release Criteria

It is the intent of the Applicant to operate this system by periodically discharging gases stored by the GWPS. This method of operation minimizes disposal of the accumulated inventory at the end of plant life and reduces plant personnel exposure. Planned discharges during periods of favorable meteorology are made after a sample of decayed gaseous effluent is analyzed and are continuously monitored during release. Radiation monitor (RM-A10) automatically terminates the discharge upon detection of high activity by closing the appropriate tank outlet valve. This method of operation provides both operational flexibility and assures that the release of radioactive material in gaseous effluents is within the limits of 10 CFR 20, Appendix B, Table 2, Column 1 and the limits of Appendix I to 10 CFR 50.

11.3.7 Release Points

Release points for potentially radioactive gaseous wastes are shown schematically by Figure 11.3-7. Figure 11.3-8 shows the physical locations of these, and other nonradioactive exhausts. Table 11.3-9 presents data for the numbered vents shown by Figure 11.3-8. The data include base and exit elevations of the stacks, cross section dimensions, volumetric flow rate, exit velocity, and comments. Table 11.3-9 compares exhaust system equipment to Branch Technical Position ETSB 11-2.

11.3.8 Dilution Factors

Dilution factors (χ/Qs) utilized in evaluating the releases of gaseous effluents were calculated according to the methods set forth in Regulatory Guide 1.111, based on one year of onsite meteorological data. A detailed discussion of the applicable methodology appears in Section 2.3.5.2; the results of the calculation of annual average (χ/Q's) values are listed in Table 2.3-133. Examination of Table 2.3-133 reveals that the highest concentration of gaseous effluents at the exclusion zone boundary is expected to occur in the southeastern sector, where relative concentration of 5.3×10^{-6} sec/m^3 was calculated.

Expected annual gaseous release rates presented in Table 11.3-8 were used in conjunction with a (χ/Qs) value of 5.3×10^{-6} sec/m^3 to estimate maximum expected radioisotope concentrations in air outside the restricted area. The release rates, the expected concentrations, and the effluent concentration limits from 10 CFR 20, Appendix B, Table 2, are listed in Table 11.3-10. As prescribed in 10 CFR 20, these concentrations are those expected as an average at the exclusion zone boundary over a one-year period. It can be seen that the expected concentration level of each isotope is well below the individual limit specified. In addition to the limits for each isotope, the requirements of 10 CFR 20, Appendix B state that, for a mixture of radionuclides, the following relationship must hold:

$$\sum_{i=1}^{N} \frac{C_i}{ECL_i} \leq 1$$

where:

C_i= concentration of radionuclide i.
ECL_i=effluent concentration limit of radionuclide i from 10 CFR 20, Appendix B, Table 2, Column 1.
N= number of radionuclides in the mixture.

The sum of the ratios of expected radionuclide concentrations to their effluent concentration limits for the mixture defined by the second column of Table 11.3-10 is 3.5×10^{-3}, which is less than unity, as required.

11.3.9 Estimated Doses (2)

Potential pathways of exposure (1) of man to radioactive materials in gaseous effluents from the Virgil C. Summer Nuclear Station are identified and discussed in Section 11.6.2. Doses to individuals in the environs of the plant from each of the potentially significant pathways were calculated; methodology for the results of the calculations is discussed in the following paragraphs.

Dilution factors and relative deposition were calculated according to the methods of Regulatory Guide 1.111, as discussed in Section 2.3.

All results presented in these sections were obtained using the calculational techniques prescribed in Regulatory Guide 1.109. Except where noted in discussion of doses for specific pathways, all usage and consumption values, transport times, bioaccumulation factors, dose conversion factors, and other constants utilized were those suggested in Regulatory Guide 1.109.

Maximum doses to individuals were calculated for cloud submersion, ground plane contamination, inhalation, and vegetable, milk, and meat ingestion pathways. Assumptions, including point of exposure, are described for each pathway in the following paragraphs; the calculated gaseous pathway doses are summarized in Table 11.3-11. All estimates were based on the predicted gaseous releases given in Table 11.3-8. Each dose was calculated at the location of the highest dose offsite at which the pathway could be assumed to exist.

Exposure to an individual from submersion in a cloud containing radioactive effluents was evaluated at the nearest residence, located 1.1 miles to the east-southeast of the plant. The total body dose was calculated to be 6.4×10^{-2} mrem/yr, while the skin dose was 1.8×10^{-1} mrem/yr.

External irradiation from activity deposited on the ground surfaces was also evaluated at the nearest residence. These analyses indicate that a dose of 5.0×10^{-3} mrem/yr to the skin and 4.3×10^{-3} mrem/yr to the total body can be expected from this pathway.

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(1) The term “exposure” as used in this Section refers only to the disposition of radioactive materials in the environment in such a way that persons could receive a dose from them.
(2) Current values are being maintained in the ODCM.

In addition, the nearest residence is the location for estimating the maximum individual dose to be received from the air inhalation pathway. The maximum dose to an organ of an individual at this location inhaling radioiodine and radioparticulates in the plant effluent was calculated to be 6.9×10^{-2} mrem/yr to an adult's thyroid.

The predicted dose to an individual obtaining 100% of his vegetable consumption from a garden adjacent to the nearest residence was also determined. Maximum calculated exposure from this pathway was 7.7×10^{-1} mrem/yr to a child's thyroid. Maximum total body dose was 7.1 x 10-^{1} mrem/yr to a child.

Predicted doses from ingestion of milk from animals grazing year-round on land contaminated by radioparticulates deposited from the effluent plume were evaluated at the location of the nearest cow, in the west-southwest sector at 1.5 miles from the plant. Although the cow at this location is not currently being milked, the suitability of the location for raising dairy cattle and the increasing popularity of dairying in the region were considered sufficient reasons to assume that the pathway could reasonably be expected to exist at this location during the life of the plant. The maximum organ dose from ingestion of milk from a cow grazing year-round at this location was 1.1 x 100 mrem/yr to an infant's thyroid. The infant is also expected to receive the maximum total body dose of 3.2×10^{-1} mrem/yr.

Exposure from consumption of meat was evaluated at the same location as that for cow milk. The maximum organ dose to an individual from ingestion of meat from a cow grazing year-round at this location was 1.4×10^{-1} mrem/yr to the bones of an adult. The maximum total body dose from the meat ingestion pathway was 4.6×10^{-2} mrem/yr to a child.

Maximum individual doses calculated as described above were used to evaluate the status of conformance of predicted gaseous effluents from the Virgil C. Summer Nuclear Station with the requirements of Appendix I to 10 CFR 50.

The assumptions and results of this evaluation are summarized in Table 11.3-12. Beta and gamma doses in air were calculated according to the methods of Regulatory Guide 1.109. It will be noted that the calculated doses indicate the plant design conforms to the "as low as reasonably achievable" criteria established in Appendix I. Conformance with 10 CFR 50, Appendix I was demonstrated using meteorological data observed during 1975 and preoperational land use census data. During plant operation, conformance with Appendix I will be demonstrated in the USNRC Regulatory Guide 1.21 Annual Radioactive Effluent Release Report. Meteorological data used in preparation of the annual effluent report may consist of meteorological data averaged over multiple years to provide a better estimate of dispersion values. The maximum exposed individual location used for gaseous release dose calculation will be based on current census data.

11.3.10 References

1. U.S. Nuclear Regulatory Commission, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors*, NUREG-0017, April 1976.

Table 11.3-1
Design Basis Accumulated Radioactivity Per Unit
in the Gaseous Waste Processing System After 40 Years Operation

Isotope	Activity (Curies) Following Plant Shutdown: Zero Decay	30 Days	50 Days
Kr-85	53,000	52,700	52,500
All other noble gases			
Kr-83m	4.3	~ 0	~ 0
Kr-85m	47.0	~ 0	~ 0
Kr-87	4.6	~ 0	~ 0
Kr-88	45.0	~ 0	~ 0
Xe-131m	530	91	28.1
Xe-133	56,000	1090	78.8
Xe-133m	2900	~ 0	~ 0
Xe-135	500	~ 0	~ 0
Xe-135m	2.1	~ 0	~ 0
Xe-138	0.13	~ 0	~ 0

The table is based on 40 years continuous operation with 1% fuel defect and 60 gpm letdown. Power assumed to be 2958 MWt. The data are based on a volume control tank purge rate of 0.7 scfm, a 40% stripping efficiency and the stripping fractions listed in Table 11.1-1.

Table 11.3-2
Expected Accumulated Radioactivity Per Unit
in the Gaseous Waste Processing System After 40 Years Operation

Isotope	Activity (Curies) Following Plant Shutdown: Zero Decay	30 Days	50 Days
Kr-85	6400	6370	6340
All other noble gases			
Kr-85m	5.0	~ 0	~ 0
Kr-87	0.88	~ 0	~ 0
Kr-88	5.1	~ 0	~ 0
Xe-131m	200	34.3	10.6
Xe-133	550	10.7	0.8
Xe-133m	11	~ 0	~ 0
Xe-135	47	~ 0	~ 0
Xe-135m	0.047	~ 0	~ 0
Xe-138	0.037	~ 0	~ 0

Inventories are based on reactor coolant concentrations given in Table 11.1-5. The table is based on 40 years continuous operation with 60 gpm letdown. Power assumed to be 2958 MWt. The data are based on a volume control tank purge rate of 0.7 scfm, a 40% stripping efficiency and the stripping fractions listed in Table 11.1-6.

Table 11.3-3
Reduction in Reactor Coolant System Gaseous Fission Products Resulting From Normal Operation of the Gaseous Waste Processing System (1)

	Reactor Coolant Gaseous Fission Product Activities - μc/gm	
Isotope	GWPS Operating (2)	GWPS Not Operating
Kr-83m	0.42	0.43
Kr-85	0.052	7.6
Kr-85m	1.7	1.8
Kr-87	1.1	1.1
Kr-88	3.1	3.2
Kr-89	0.089	0.089
Xe-131m	0.23	2.3
Xe-133	58	290
Xe-133m	7.2	19
Xe-135	6.9	8.6
Xe-135m	0.52	0.52
Xe-137	0.18	0.18
Xe-138	0.64	0.64

(1) Based on operating with cladding defects in fuel generating 1% of the rated core thermal power (2958 MWt) and a purification letdown rate of 60 gpm.
(2) Volume control tank purge rate is 0.7 scfm.
Stripping efficiency is 40%.

Table 11.3-4
Process Parameters for Gaseous Waste Processing System*

BASIS: Power Level - 2900 MWt
No. of Units - 1

Gas Decay Tanks (Note 4) - 8
Operating Interval - 1 day
Stripping Efficiency - 0.4

ITEM DESCRIPTION GAS STREAMS	TEMP °F	PRESS PSIG	FLOW SCFM	N_2 %	H_2 %	ISOTOPIC CONCENTRATION, µC/cc (NOTE 1) KR85 (NOTE 3)	KR85M	KR87	KR88	XE-133	XE-133M	XE-135
1. VOLUME CONTROL TANK PURGE	130	15	0.7	0	100	3.07×10^{-2}	1.81×10^{-1}	6.51×10^{-2}	1.67×10^{-1}	1.95×10^{1}	3.81×10^{-1}	8.74×10^{-1}
2. GAS DECAY TANK DISCH. TO COMP.	AMB	0.5	40	99.9	0.1	1.31×10^{1}	9.95×10^{-2}	5.61×10^{-3}	1.45×10^{-1}	3.79×10^{1}	1.40	5.50×10^{-1}
3. COMPRESSOR SUCTION	AMB	0.5	40.7	98.3	1.7	1.29×10^{1}	1.01×10^{-1}	6.63×10^{-3}	1.45×10^{-1}	3.76×10^{1}	1.39	5.56×10^{-1}
4. COMP. DISCH. TO RECOMBINER	140	45	40.7	98.3	1.7	1.29×10^{1}	1.01×10^{-1}	6.63×10^{-3}	1.45×10^{-1}	3.76×10^{1}	1.39	5.56×10^{-1}
5. RECOMBINER DISCH. TO GAS DECAY TANKS	140	30	40	99.9	0.1	1.31×10^{1}	1.03×10^{-1}	6.75×10^{-3}	1.48×10^{-1}	3.82×10^{1}	1.41	5.66×10^{-1}
6. MISC. VENTS-EVAPS. RCDT. RECYCLE HOLDUP TANK EDUCTOR	140	0.5	NEG	0	100	0	0	0	0	0	0	0
7. RECOMBINER OXYGEN SUPPLY	AMB	50	0.35	0	0	0	0	0	0	0	0	0
8. RECOMBINER CALIBRATING GAS	AMB	15	0.004	100	4	0	0	0	0	0	0	0
9. RECOMBINER CALIBRATING GAS	AMB	ATM	0.004	100	4	0	0	0	0	0	0	0

Table 11.3-4 (continued)
Process Parameters for Gaseous Waste Processing System*

ITEM DESCRIPTION GAS STREAMS	TEMP °F	PRESS PSIG	FLOW SCFM	N_2 %	H_2 %	ISOTOPIC CONCENTRATION, µC/cc (NOTE 1) KR85 (NOTE 3)	KR85M	KR87	KR88	XE-133	XE-133M	XE-135
10. WASTE GAS SYSTEM NITROGEN SUPPLY	AMB	100	0	100	0	0	0	0	0	0	0	0
11. NSSS NITROGEN SUPPLY	AMB	100	0	100	0	0	0	0	0	0	0	0
12. NITROGEN RELIEF TO PLANT VENT	AMB	100	0	100	0	0	0	0	0	0	0	0
13. NSS HYDROGEN SUPPLY	AMB	100	0.7	0	100	0	0	0	0	0	0	0
14. VOLUME CONTROL TANK HYDROGEN	AMB	100	0.7	0	100	0	0	0	0	0	0	0
15. HYDROGEN RELIEF TO PLANT VENT	AMB	100	0	0	100	0	0	0	0	0	0	0
16. WASTE GAS DISCH. TO PLANT VENT	AMB	ATM	0	100	0	1.31×10^{1}	0	0	0	0	0	0
17. RECYCLE GAS TO VOLUME CONTROL TANK	AMB	100	0	100	0	0	0	0	0	0	0	0
18. PRESSURIZER RELIEF TANK VENT AND RETURN	120	3	0	100	0	0	0	0	0	0	0	0
19. SHUTDOWN TANK RELIEF	AMB	ATM	0	100	0	0	0	0	0	0	0	0

Table 11.3-4 (continued)
Process Parameters for Gaseous Waste Processing System*

ITEM DESCRIPTION LIQUID STREAMS	TEMP °F	PRESS PSIG	FLOW GPD	ISOTOPIC CONCENTRATION, µC/cc (NOTE 2) KR85 (NOTE 3)	KR85M	KR87	KR88	XE-133	XE-133M	XE-135
1. WASTE GAS COMPRESSOR DRAIN	140	45	0	3.43	2.69×10^{-2}	1.77×10^{-3}	3.87×10^{-2}	8.27	3.05×10^{-1}	1.22×10^{-1}
2. RECOMBINER DRAIN	140	30	6	2.61	2.05×10^{-2}	1.35×10^{-3}	2.95×10^{-2}	6.30	2.32×10^{-1}	9.32×10^{-2}
3. GAS DECAY TANK DRAINS	AMB	40	36	9.18×10^{-1}	6.98×10^{-3}	3.94×10^{-4}	1.02×10^{-2}	2.20	8.13×10^{-2}	3.19×10^{-2}
4. SYSTEM DRAINS TO VOL CONTROL TANK	140	30-45	42	1.16	8.91×10^{-3}	5.30×10^{-4}	1.29×10^{-2}	2.78	1.02×10^{-1}	4.07×10^{-2}
5. RECOMBINER REACTOR MAKEUP WATER	AMB		0	0	0	0	0	0	0	0
6. COMPRESSOR MAKEUP WATER	AMB		36	0	0	0	0	0	0	0

Table 11.3-4 (continued)
Process Parameters for Gaseous Waste Processing System*

ITEM	COMPONENT	TEMP	PRESS	VOL	N_2	H_2	COMPONENT INVENTORY, CURIES						
		°F	PSIG	FT^3	%	%	KR85 (NOTE 3)	KR85M	KR87	KR88	XE-133	XE-133M	XE-135
A	COMPRESSOR	140	45	4	98.3	1.7	6.02	4.58×10^{-2}	2.58×10^{-3}	6.67×10^{-2}	1.74×10^{1}	6.45×10^{-1}	2.53×10^{-1}
B.	RECOMBINER	140	30	4	99.9	0.1	4.51	3.42×10^{-2}	1.93×10^{-3}	4.99×10^{-1}	1.3×10^{1}	4.82×10^{-1}	1.89×10^{-1}
C.	GAS DECAY TANK	AMB	1.0	600	99.9	0.1	1.04×10^{3}	1.80	1.02×10^{-1}	2.62	6.86×10^{2}	2.54×10^{1}	9.96
	TOTAL SYSTEM						6.28×10^{3}	1.88	1.06×10^{-1}	2.74	3.18×10^{3}	2.65×10^{1}	1.04×10^{1}

* based on stripping fractions from Table 11.1-6 and reactor coolant activities from Table 11.1-5.

NOTES:

1. Concentration in c per cc of gas at atmospheric pressure and 140F.
2. Concentrations in c per cc liquid at room temperature.
3. Kr - 85 concentrations are maximum values, but do not occur simultaneously with other isotope maximum concentrations.
4. Includes two shutdown tanks.
5. AMB - Ambient
6. NEG - Negligible
7. ATM - Atmospheric

Table 11.3-5
Gaseous Waste Processing System Component Data

Waste Gas Compressor Packages	
Number	2
Design pressure, psig	150
Design temperature, °F	180
Normal operating temperature, °F	70-140
Normal operating pressure, psig	
Suction	0.5-2.0
Discharge	0-110
Design flowrate (N_2 at 60°F, 0 psig), scfm	40
Waste Gas Decay Tanks	
Number	8
Design pressure, psig	150
Design temperature, °F	180
Volume (Each). ft^3	600
Normal operating pressure, psig	0-110
Normal operating temperature, °F	50-140
Material of construction	Carbon Steel
Catalytic Hydrogen Recombiner Packages	
Number	2
Design inlet pressure, psig	110
Design inlet temperature, °F	140
Design flowrate, scfm	40
Design hydrogen recombiner rate, scfm	2.4
Design discharge pressure, psig	15
Design discharge temperature, °F	140
Material of construction	Stainless Steel

Table 11.3-6
Gaseous Waste Processing System Instrumentation Design Parameters

A - Alarm
C - Control
F - Flow
I - Indication
L - Level
P - Pressure
Q - Water Integrator
R - Radiation
T - Temperature

Channel Number	Location of Primary Sensor	Design Pressure (psig)	Design Temperature (°F)	Range	Alarm Setpoint	Control Setpoint	Location of Readout
FLOW INSTRUMENTATION							
FIA - 1094	Volume Control Tank Discharge Flow	150	250	0.3-1.2 scfm	1.2 scfm		WPS panel
QAI - 1091	Gas Decay Tank Water Flush	150	180	0-6000 gal	3000-6000 gal (adjustable)		Local
PRESSURE INSTRUMENTATION							
PI - 1031	Moisture Separator	150	180	0-160 psig			Local
PI - 1033	Moisture Separator	150	180	0-160 psig			Local
PIA - 1036	Gas Decay Tank Number 1	150	180	0-150 psig 0-30 psig	100 psig 20 psig		
PIA - 1037	Gas Decay Tank Number 2	150	180	0-150 psig 0-30 psig	100 psig 20 psig		WPS panel
PIA - 1038	Gas Decay Tank Number 3	150	180	0-150 psig 0-30 psig	100 psig 20 psig		WPS panel
PIA - 1039	Gas Decay Tank Number 4	150	180	0-150 psig 0-30 psig	100 psig 20 psig		WPS panel

Table 11.3-6 (continued)
Gaseous Waste Processing System Instrumentation Design Parameters

Channel Number	Location of Primary Sensor	Design Pressure (psig)	Design Temperature (°F)	Range	Alarm Setpoint	Control Setpoint	Location of Readout
PRESSURE INSTRUMENTATION (Cont)							
PIA - 1052	Gas Decay Tank Number 5	150	180	0-150 psig 0-30 psig	100 psig 20 psig		WPS panel
PIA - 1053	Gas Decay Tank Number 6	150	180	0-150 psig 0-30 psig	100 psig 20 psig		WPS panel
PIA - 1054	Gas Decay Tank Number 7	150	180	0-150 psig 0-30 psig	100 psig 20 psig		WPS panel
PIA - 1055	Gas Decay Tank Number 8	150	180	0-150 psig 0-30 psig	100 psig 20 psig		WPS panel
PIA - 1065	Hydrogen Supply Header	150	180	0-150 psig	90 psig		WPS panel
PIA - 1066	Nitrogen Supply Header	150	180	0-150 psig	90 psig		WPS panel
PICA - 1092	Compressor Suction Header	150	180	2 psi vac.- 2 psig	0.5 psi	0.5 psi vac.	WPS panel
PI - 1093	Gas Decay Tank Makeup Water	150	180	0-150 psig	2 psi		Local
PA - 1094	Volume Control Tank Discharge Pressure	150	250	0-20 psig			Local

Table 11.3-6 (continued)
Gaseous Waste Processing System Instrumentation Design Parameters

LEVEL INSTRUMENTATION							
LICA - 1030	Compressor Moisture Separator	150	180	0-30 inches H_20	15 inches H_20	15 to -10 inches 8 to -5 inch -1 inches H_20	WPS panel and local
LICA - 1032	Compressor Moisture Separator	150	180	0-30 inches H_20	15 inches H_20	15 to -10 inches -8 to -5 inches -1 inches H_20	WPS panel and local
RADIATION INSTRUMENTATION							
RM - A10	Gas Discharge Monitor	15	100	-	Adjustable	-	WPS panel and control room

Table 11.3-7
PWR-GALE Code Input Parameters Used in Calculating Releases
of Radioactive Materials in Gaseous Effluents

Reactor Power Level, MWt	2914
Holdup Time for Xenon Stripped from Primary Coolant, days	90
Holdup Time for Krypton Stripped from Primary Coolant, days	90
Reactor Building Free Volume, million ft^3	1.84
Flow Rate through Reactor Building Charcoal Cleanup System, thousand cfm	24
Continuous Reactor Building Ventilation Rate, cfm	1000 (1)
Primary System	
Mass of Primary Coolant, thousand lbs	404
Letdown Rate, gpm	60
Letdown Cation Demineralizer Flow Rate, gpm	6
Secondary System	
Steam Flow Rate, million lbs/hr	12.2
Mass of Steam/Steam Generator, thousand lbs	8.56
Mass of Liquid/Steam Generator, thousand lbs	94
Mass of Secondary Coolant, thousand lbs	2260
Steam Generator Blowdown Rate, thousand lbs/hr	61
Steam Generator Blowdown Tank Vent Option	Not applicable because of cooling by heat exchangers.
HEPA/Charcoal Treatment of Releases	
Gaseous Waste Processing System	See Section 11.3.6.1
Reactor Building Purge	See Section 11.3.6.2
Auxiliary Building Ventilation	See Section 11.3.6.3
Condenser Air Removal System	See Section 11.3.6.4.2
Gas Stripping of Letdown Flow Option	Continuous purging of volume control tank.

(1) Conservative scenario that maximizes the estimated annual gaseous effluents via Reactor Building purge. The current Technical Specifications limit the Reactor Building purge at power to no more than 1000 hours per year at a design flow of 600 cfm.

Table 11.3-8
Calculated Releases of Radioactive Materials in Gaseous Effluents from the Plant [1]

	Releases (Ci/yr)					
Nuclide	Gaseous Waste Processing System	Reactor Building Purge Exhaust	Auxiliary Building Leakage	Turbine Building Leakage	Condenser Air Removal System	Total
Kr-83m	(2)	1	(2)	(2)	(2)	1
Kr-85m	(2)	11	2	(2)	2	15
Kr-85	210	4	(2)	(2)	(2)	220
Kr-87	(2)	2	1	(2)	(2)	3
Kr-88	(2)	14	5	(2)	3	22
Kr-89	(2)	(2)	(2)	(2)	(2)	(2)
Xe-131m	3	10	(2)	(2)	(2)	13
Xe-133m	(2)	42	2	(2)	1	45
Xe-133	1	2500	110	(2)	71	2700
Xe-135m	(2)	(2)	(2)	(2)	(2)	(2)
Xe-135	(2)	54	7	(2)	4	65
Xe-137	(2)	(2)	(2)	(2)	(2)	(2)
Xe-138	(2)	(2)	1	(2)	(2)	1
I-131	(2)	1.4×10^{-2}	4.6×10^{-3}	1.1×10^{-3}	2.8×10^{-3}	2.3×10^{-2}
I-133	(2)	1.1×10^{-2}	6.6×10^{-3}	1.3×10^{-3}	4.1×10^{-3}	2.3×10^{-2}
Mn-54	4.5×10^{-5}	2.1×10^{-4}	1.8×10^{-4}	(3)	(3)	4.3×10^{-4}
Fe-59	1.5×10^{-5}	7.3×10^{-5}	6.0×10^{-5}	(3)	(3)	1.5×10^{-4}
Co-58	1.5×10^{-4}	7.3×10^{-4}	6.0×10^{-4}	(3)	(3)	1.5×10^{-3}
Co-60	7.0×10^{-5}	3.3×10^{-4}	2.7×10^{-4}	(3)	(3)	6.7×10^{-4}
Sr-89	3.3×10^{-6}	1.7×10^{-5}	1.3×10^{-5}	(3)	(3)	3.3×10^{-5}
Sr-90	6.0×10^{-7}	2.9×10^{-6}	2.4×10^{-6}	(3)	(3)	5.9×10^{-6}
Cs-134	4.5×10^{-5}	2.1×10^{-4}	1.8×10^{-4}	(3)	(3)	4.3×10^{-4}
Cs-137	7.5×10^{-5}	3.7×10^{-4}	3.0×10^{-4}	(3)	(3)	7.4×10^{-4}
C-14	7	1				8
H-3						580
Ar-41		25				25

(1) Based upon the parameters given in Table 11.3-7.
(2) Less than 1 Ci/yr noble gases, less than 10^{-4} Ci/yr for iodine.
(3) Less than 1% of total for nuclide.

Table 11.3-9
Stack Release Information

Item No. (1)	Item	Location (Building)	Base Elevation	Exit Elevation	Exit Area Cross Section	Volume Flow Rate	Estimated Exit Velocity
1.	Main Plant Vent	Auxiliary	511'-0"	524'-0"	72 by 96 in	172,000 cfm	3,583 fpm
2.	Purge Exhaust	Auxiliary	511'-0"	524'-0"	36 by 36 in	20,000 cfm	2,220 fpm
3.	Condensate Return Unit Vent	Auxiliary	418'-0"	455'-3"	28.9 in^2	2,700 lb/hr (2)	6,000 fpm
4.	Air Exhaust	Control	505'-0"	512'-0"	72 by 48 in	9,000 cfm	375 fpm
5.	Air Exhaust	Control	505'-0"	512'-0"	72 by 48 in	9,000 cfm	375 fpm
6	Air Exhaust (3)	Intermediate	463'-0"	492'-0"	38 by 14 in	10,200 cfm	2,760 fpm
7.	Air Exhaust (3)	Intermediate	485'-0"	463'-0"	84 by 24 in	40, 000 cfm	2,860 fpm
8.	Condenser Exhaust (4)	Turbine	415'-0"	454'-6"	113.1 in^2	800 lb/hr	750 fpm
9.	Main Steam Dump (5) (3 points)	Intermediate	463'-0"	471'-0"	101.6 in^2 each	740,000 lb/hr each	(6)
10.	Main Steam Safety and Relief Valves(7) (10 points)	Intermediate	463'-0"	475'-0"	233.7 in^2 each	930,000 lb/hr each	40,000 fpm
	Main Steam Safety and Relief Valves(7) (5 points)	Auxiliary	485'-0"	497'-0"	233.7 in^2 each	930,000 lb/hr each	40,000 fpm

Table 11.3-9 (continued)
Stack Release Information

Item No. (1)	Item	Location (Building)	Base Elevation	Exit Elevation	Exit Area Cross Section	Volume Flow Rate	Estimated Exit Velocity
11.	Main Steam Power Relief Valves(5) (2 points)	Intermediate	463'-0"	475'-0"	113.1 in^2 each	740,000 lb/hr each	(6)
	Main Steam Power Relief Valve(5) (1 point)	Auxiliary	485'-0"	497'-0"	113.1 in^2 each	740,000 lb/hr each	(6)
12.	Roof Vent (3 points)	Turbine	-	503'-0"	48 in dia each	34,087 cfm each	1,115 fpm
13.	Roof Vent (7 points)	Turbine	-	533'-0"	120 in dia each	199,958 cfm each	1,000 fpm
14.	Reheat Steam Safety Relief Valves(8) (4 points)	Turbine	474'-0"	531'-0"	975.8 in^2	2.33 x 106 lb/hr	40,000 fpm
15.	EFW Pump Exhaust	Intermediate	420'-0"	475'-0"	135 in^2	15,000 cfm	15,000 fpm

Table 11.3-9 (continued)
Stack Release Information

NOTES

(1) See Figure 11.3-8 for location.

(2) Condensate return unit vent volume flow rate is maximum theoretically possible.

(3) Location of intermediate building air exhaust relative to air intakes has not been finalized.

(4) Condenser exhaust flow is continuous.

(5) Main steam dump and power relief estimated occurrences are as follows:

a. Actual, 22 times per year for 10 minutes each time.
b. Test, 12 times per year for 1 minute each time.

(6) Main steam dump and power relief exit velocities are not available. Each vent incorporates a valve and exit diffuser of a proprietary design which diffuses and disperses the flow in a horizontal pattern, 360 degrees around the vent vertical axis. The volume flow rate is the flow through the vent stack prior to diffuser release.

(7) Main steam safety and relief estimated occurrences are as follows:

a. Actual, 2 times per year for 2 minutes each time.
b. Test, 3 times per year for less than 1 minute each time.

(8) Not expected to occur during life of plant. Test monthly for 10 minutes each time.

Table 11.3-9a

Comparison of Normal Ventilation Exhaust System Air Filtration and Adsorption Units with Branch Technical Position ETSB 11-2

Branch Technical Position ETSB 11-2 Item	Reactor Building Purge Exhaust System	Reactor Building Charcoal Cleanup System	Auxiliary Building HEPA Exhaust System	Auxiliary Building Charcoal Exhaust System	Fuel Handling Building Charcoal Exhaust System	Controlled Access Area Exhaust System	Hot Machine Shop Ventilation System
B-1-a	System complies, except design is for intermittent operation.	System complies, except design is for intermittent operation.	System complies.	System complies.	System complies.	System complies.	System complies.
B-1-b	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.
B-1-c	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.
B-1-d	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.
B-2-a	System complies, except that heaters or cooling coils have not been used because relative humidity will not exceed 70 percent.	System complies, except that heaters or cooling coils have not been used because relative humidity will not exceed 70 percent.	System complies, except charcoal filters are not used.	System complies, except that heaters or cooling coils have not been used because relative humidity will not exceed 70 percent.	System complies, except that heaters or cooling coils have not been used because relative humidity will not exceed 70 percent.	System complies, except that heaters or cooling coils have not been used because relative humidity will not exceed 70 percent.	System complies, except charcoal filters are not used.
B-2-b	System complies.	System complies.	System plenum capacity is 50,000 cfm, 2 banks each, 5 filters wide by 5 filters high.	System plenum capacity is 45,000 cfm, 9 filters wide by 5 filters high.	System complies.	System complies.	System complies.
B-2-c	System has local differential pressure devices across filter banks - no alarm.	System has local differential pressure devices across filter banks - no alarm.	System has local differential pressure devices across filter banks - no alarm.	System has local differential pressure devices across filter banks - no alarm.	System has local differential pressure devices across filter banks - no alarm.	System has local differential pressure devices across filter banks - no alarm.	System has local differential pressure devices across filter banks - no alarm.
B-2-d	Wiring was purchased and qualified to IPCEA and IEEE Standards.	Wiring was purchased and qualified to IPCEA and IEEE Standards.	Wiring was purchased and qualified to IPCEA and IEEE Standards.	Wiring was purchased and qualified to IPCEA and IEEE Standards.	Wiring was purchased and qualified to IPCEA and IEEE Standards.	Wiring was purchased and qualified to IPCEA and IEEE Standards.	Wiring was purchased and qualified to IPCEA and IEEE Standards.
B-2-e	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.

Table 11.3-9a (continued)
Comparison of Normal Ventilation Exhaust System Air Filtration and Adsorption Units with Branch Technical Position ETSB 11-2

Branch Technical Position ETSB 11-2 Item	Reactor Building Purge Exhaust System	Reactor Building Charcoal Cleanup System	Auxiliary Building HEPA Exhaust System	Auxiliary Building Charcoal Exhaust System	Fuel Handling Building Charcoal Exhaust System	Controlled Access Area Exhaust System	Hot Machine Shop Ventilation System
B-2-f	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.
B-2-g	Plenums were specified to indicate no leakage through soap bubble testing with ducts at 2 psig.	Plenums were specified to indicate no leakage through soap bubble testing with ducts at 2 psig.	Plenums were specified to indicate no leakage through soap bubble testing with ducts at 2 psig.	Plenums were specified to indicate no leakage through soap bubble testing with ducts at 2 psig.	Plenums were specified to indicate no leakage through soap bubble testing with ducts at 2 psig.	Plenums were specified to indicate no leakage through soap bubble testing with ducts at 2 psig.	Plenums were specified to indicate no leakage through soap bubble testing with ducts at 2 psig.
	Ducts were specified to satisfy leakage testing requirements of SMACNA, Chapter 8, 1967.	Ducts were specified to satisfy leakage testing requirements of SMACNA, Chapter 8, 1967.	Ducts were specified to satisfy leakage testing requirements of SMACNA, Chapter 8, 1967.	Ducts were specified to satisfy leakage testing requirements of SMACNA, Chapter 8, 1967.	Ducts were specified to satisfy leakage testing requirements of SMACNA, Chapter 8, 1967.	Ducts were specified to satisfy leakage testing requirements of SMACNA, Chapter 8, 1967.	Ducts were specified to satisfy leakage testing requirements of SMACNA, Chapter 8, 1967.
B-3-a	Heaters not used in exhaust system plenums because relative humidity is not expected to exceed 70 percent.	Heaters not used in exhaust system plenums because relative humidity is not expected to exceed 70 percent.	Heaters not used in exhaust system plenums because relative humidity is not expected to exceed 70 percent.	Heaters not used in exhaust system plenums because relative humidity is not expected to exceed 70 percent.	Heaters not used in exhaust system plenums because relative humidity is not expected to exceed 70 percent.	Heaters not used in exhaust system plenums because relative humidity is not expected to exceed 70 percent.	Heaters not used in exhaust system plenums because relative humidity is not expected to exceed 70 percent.
B-3-b	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement
B-3-c	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement
B-3-d	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement	System complies. with this requirement

Table 11.3-9a (continued)
Comparison of Normal Ventilation Exhaust System Air Filtration and Adsorption Units with Branch Technical Position ETSB 11-2

Branch Technical Position ETSB 11-2 Item	Reactor Building Purge Exhaust System	Reactor Building Charcoal Cleanup System	Auxiliary Building HEPA Exhaust System	Auxiliary Building Charcoal Exhaust System	Fuel Handling Building Charcoal Exhaust System	Controlled Access Area Exhaust System	Hot Machine Shop Ventilation System
B-3-e	System generally complies, except access has been provided on one side of plenum.	System generally complies, except access has been provided on one side of plenum.	System generally complies, except access doors have been provided on one side of plenum and capacity is 51,000 cfm.	System generally complies, except access doors have been provided on one side of plenum and capacity is 45,000 cfm.	System generally complies, except access doors have been provided on one side of plenum.	System generally complies, except access doors have been provided on one side of plenum.	System generally complies, except access doors have been provided on one side of plenum.
B-3-f	System generally complies, except testing is in accordance with SMACNA Standards.	System generally complies, except testing is in accordance with SMACNA Standards.	System generally complies, except testing is in accordance with SMACNA Standards.	System generally complies, except testing is in accordance with SMACNA Standards.	System generally complies, except testing is in accordance with SMACNA Standards.	System generally complies, except testing is in accordance with SMACNA Standards.	System generally complies, except testing is in accordance with SMACNA Standards.
B-3-g	System complies.	System complies.	Not applicable.	System complies.	System complies.	System complies.	Not applicable.
B-3-h	System complies.	System complies.	Not applicable.	System complies.	System complies.	System complies.	Not applicable.
B-3-i	System generally complies.	System generally complies.	System generally complies.	System generally complies.	System generally complies.	System generally complies.	System generally complies.
B-3-j	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.
B-3-k	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.
B-3-l	System generally complies.	System generally complies.	System generally complies.	System generally complies.	System generally complies.	System generally complies.	System generally complies.
B-4-a	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.
B-4-b	System complies, except door sizes are 30” by 60”.	System complies, except door sizes are 30” by 60”.	System complies, except door sizes are 30” by 60”.	System complies, except door sizes are 30” by 60”.	System complies, except door sizes are 30” by 60”.	System complies, except door sizes are 30” by 60”.	System complies, except door sizes are 30” by 60”.
B-4-c	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.	System complies.

Table 11.3-9a (continued)
Comparison of Normal Ventilation Exhaust System Air Filtration and Adsorption Units with Branch Technical Position ETSB 11-2

Branch Technical Position ETSB 11-2 Item	Reactor Building Purge Exhaust System	Reactor Building Charcoal Cleanup System	Auxiliary Building HEPA Exhaust System	Auxiliary Building Charcoal Exhaust System	Fuel Handling Building Charcoal Exhaust System	Controlled Access Area Exhaust System	Hot Machine Shop Ventilation System
B-4-d	Openings have been provided for insertion of test probes.	Openings have been provided for insertion of test probes.	Openings have been provided for insertion of test probes.	Openings have been provided for insertion of test probes.	Openings have been provided for insertion of test probes.	Openings have been provided for insertion of test probes.	Openings have been provided for insertion of test probes.
B-4-e	System startup and operating procedures comply with this requirement.	System startup and operating procedures comply with this requirement.	System startup and operating procedures comply with this requirement.	System startup and operating procedures comply with this requirement.	System startup and operating procedures comply with this requirement.	System startup and operating procedures comply with this requirement.	System startup and operating procedures comply with this requirement.
B-5-a	Filter plenum tested in place initially and at frequency not to exceed 18 months. Tests include visual inspection.	Filter plenum tested in place initially and at frequency not to exceed 18 months. Tests include visual inspection.	Filter plenum tested in place initially and at frequency not to exceed 18 months. Tests include visual inspection.	Filter plenum tested in place initially and at frequency not to exceed 18 months. Tests include visual inspection.	Filter plenum tested in place initially and at frequency not to exceed 18 months. Tests include visual inspection.	Filter plenum tested in place initially and at frequency not to exceed 18 months. Tests include visual inspection.	Filter plenum tested in place initially and at frequency not to exceed 18 months. Tests include visual inspection.
B-5-b	Filter system total flow rate will be checked for ±10 percent.	Filter system total flow rate will be checked for ±10 percent.	Filter system total flow rate will be checked for ±10 percent.	Filter system total flow rate will be checked for ±10 percent.	Filter system total flow rate will be checked for ±10 percent.	Filter system total flow rate will be checked for ±10 percent.	Filter system total flow rate will be checked for ±10 percent.
B-5-c	Filter plenums will be DOP tested at frequency noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with ANSI 101.1 Section 3.	Filter plenums will be DOP tested at frequency noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with ANSI 101.1 Section 3	Filter plenums will be DOP tested at frequency noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with ANSI 101.1 Section 3	Filter plenums will be DOP tested at frequency noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with ANSI 101.1 Section 3	Filter plenums will be DOP tested at frequency noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with ANSI 101.1 Section 3	Filter plenums will be DOP tested at frequency noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with ANSI 101.1 Section 3	Filter plenums will be DOP tested at frequency noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with ANSI 101.1 Section 3

Table 11.3-9a (continued)
Comparison of Normal Ventilation Exhaust System Air Filtration and Adsorption Units with Branch Technical Position ETSB 11-2

Branch Technical Position ETSB 11-2 Item	Reactor Building Purge Exhaust System	Reactor Building Charcoal Cleanup System	Auxiliary Building HEPA Exhaust System	Auxiliary Building Charcoal Exhaust System	Fuel Handling Building Charcoal Exhaust System	Controlled Access Area Exhaust System	Hot Machine Shop Ventilation System
B-5-d	Filter plen. will be tested with refrig. at the freq. noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with App. B of DP-1082.	Filter plen. will be tested with refrig. at the freq. noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with App. B of DP-1082.	Not applicable.	Filter plen. will be tested with refrig. at the freq. noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with App. B of DP-1082.	Filter plen. will be tested with refrig. at the freq. noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with App. B of DP-1082.	Filter plen. will be tested with refrig. at the freq. noted in B-5-a above & following painting, fire, or chem. release near the filter plenum. Filters will be tested in accor. with App. B of DP-1082.	Not applicable.
B-6-a,b	Char. media from those plen. shall be lab tested at a freq. not to exceed 18 mo. Sample shall be obtained by removing 1 entire bed from an adsorber tray & with drawing a 2” thick x 2” dia. sample. Lab test shall verify an iodine removal eff. of 90 percent for radioactive methyl iodine and it shall be in accor. w/RDT M16-IT para. 4.5.3	Char. media from those plen. shall be lab tested at a freq. not to exceed 18 mo. Sample shall be obtained by removing 1 entire bed from an adsorber tray & with drawing a 2” thick x 2” dia. sample. Lab test shall verify an iodine removal eff. of 90 percent for radioactive methyl iodine and it shall be in accor. w/RDT M16-IT para. 4.5.3	Not applicable.	Char. media from those plen. shall be lab tested at a freq. not to exceed 18 mo. Sample shall be obtained by removing 1 entire bed from an adsorber tray & with drawing a 2” thick x 2” dia. sample. Lab test shall verify an iodine removal eff. of 90 percent for radioactive methyl iodine and it shall be in accor. w/RDT M16-IT para. 4.5.3	Char. media from those plen. shall be lab tested at a freq. not to exceed 18 mo. Sample shall be obtained by drawing a 2” thick x 2” dia. sample. Lab test shall verify an iodine removal eff. of 95 percent for radioactive methyl iodine and it shall be in accor. w/ ASTM D3803-1989 at a test media temperature of 30°C.	Char. media from those plen. shall be lab tested at a freq. not to exceed 18 mo. Sample shall be obtained by removing 1 entire bed from an adsorber tray & with drawing a 2” thick x 2” dia. sample. Lab test shall verify an iodine removal eff. of 90 percent for radioactive methyl iodine and it shall be in accor. w/RDT M16-IT para. 4.5.3	Not applicable.

Table 11.3-10
Comparison of Radionuclide Concentrations in Gaseous Effluents to the Limits of 10 CFR 20

Isotope	Annual Release (Ci/yr)	(Expected) [1] Site Boundary Concentration (μCi/ml)	Effluent [2] Concentration Limit in Air (μCi/ml)	Ratio of Expected Concentration to Concentration Limit
Kr-85m	15	2.6E-12	1.0E-7	2.6E-5
Kr-85	220	3.7E-11	7.0E-7	5.3E-5
Kr-87	3	5.1E-13	2.0E-8	2.6E-5
Kr-88	22	3.7E-12	9.0E-9	4.1E-4
Xe-131m	13	2.2E-12	2.0E-6	1.1E-6
Xe-133m	45	7.6E-12	6.0E-7	1.3E-5
Xe-133	2700	4.6E-10	5.0E-7	9.2E-4
Xe-135	65	1.1E-11	7.0E-8	1.6E-4
Xe-138	1	1.7E-13	2.0E-8	8.5E-6
I-131	2.3E-2	3.7E-15	2.0E-10	1.9E-5
I-133	2.3E-2	3.7E-15	1.0E-9	3.7E-6
Mn-54	4.3E-4	7.3E-17	1.0E-9	7.3E-8
Fe-59	1.5E-4	2.6E-17	5.0E-10	5.2E-8
Co-58	1.5E-3	2.6E-16	1.0E-9	2.6E-7
Co-60	6.7E-4	1.1E-16	5.0E-11	2.2E-6
Sr-89	3.3E-5	5.6E-18	2.0E-10	2.8E-8
Sr-90	5.9E-6	1.0E-18	6.0E-12	1.7E-7
Cs-134	4.3E-4	7.3E-17	2.0E-10	3.7E-7
Cs-137	7.4E-4	1.3E-16	2.0E-10	6.5E-7
C-14	8	1.3E-12	3.0E-9	4.3E-4
H-3	580	9.7E-11	1.0E-7	9.7E-4
Ar-41	25	4.2E-12	1.0E-8	4.2E-4
			TOTAL	3.5E-3

(1) Expected concentration in worst sector averaged over a one-year period.
(2) From 10 CFR 20, Appendix B, Table 2, Column 1.

Table 11.3-11
Summary of Calculated Gaseous Pathway Doses
Virgil C. Summer Nuclear Station

Pathway	Location	Age Group	Organ Receiving Maximum Dose: Organ	Organ Receiving Maximum Dose: Dose (mrem/yr)	Total Body Dose (mrem/yr)
Cloud Submersion	Nearest Residence (1.1 Miles ESE)	All	Skin	2.8E-1	1.1E-1
Ground Plane Contamination	Nearest Residence (1.1 Miles ESE)	All	Skin	9.8E-3	8.4E-3
Air Inhalation	Nearest Residence (1.1 Miles ESE)	Adult	Thyroid	8.6E-2	5.8E-2
		Teen	Thyroid	5.5E-2	3.2E-2
		Child	Thyroid	6.3E-2	3.2E-2
		Infant	Thyroid	8.7E-2	3.4E-2
Vegetable Ingestion	Nearest Residence (1.1 Miles ESE)	Adult	Bone	7.4E-1	2.7E-1
		Teen	Thyroid	4.4E-1	3.4E-1
		Child	Thyroid	8.7E-1	7.1E-1
Cow Milk Ingestion	Nearest Cow (1.5 Miles WSW) (Not now milked)	Adult	Thyroid	3.5E-1	5.3E-2
		Teen	Thyroid	5.2E-1	7.5E-2
		Child	Thyroid	1.0E-0	1.6E-1
		Infant	Thyroid	2.4E-0	3.2E-1
Meat Ingestion	Nearest Cow (1.5 Miles WSW)	Adult	Bone	1.4E-1	3.7E-2
		Teen	Thyroid	3.3E-2	2.6E-2
		Child	Thyroid	5.7E-2	4.6E-2

Table 11.3-12
Appendix I Conformance Summary Table
Virgil C. Summer Nuclear Station
Gaseous Effluents

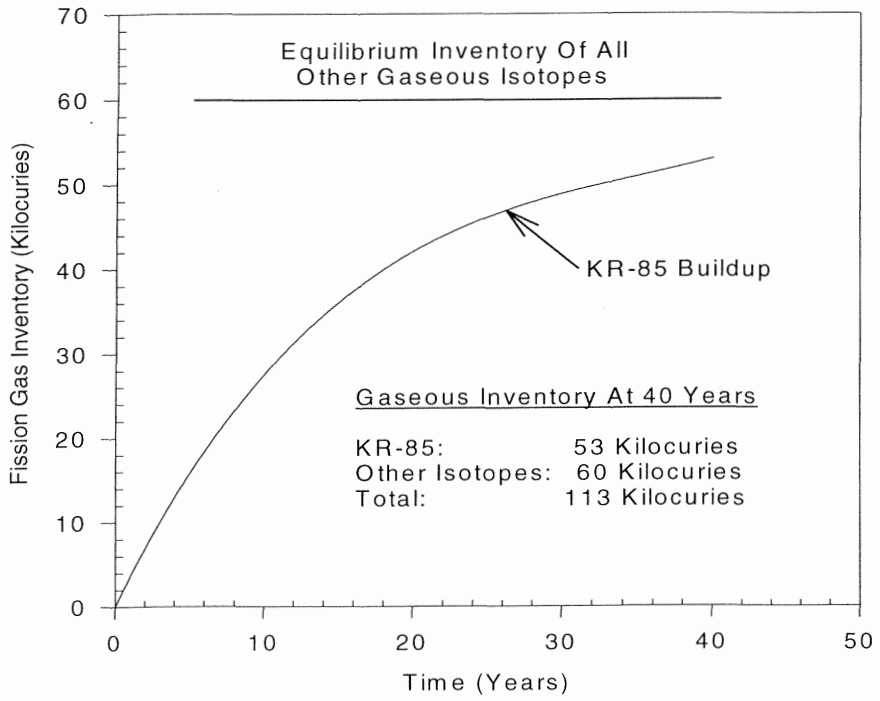
	Appendix I Criteria		Virgil C. Summer Nuclear Station	
Type of Dose	Design Objective (1)	Point of Dose Evaluation	Calculated Dose	Point of Dose Evaluation (9)
Gaseous Effluents (3)				
Gamma dose in air	10 mrad/yr per site	Location of the highest dose offsite (2)	0.29 mrad/yr	Location of highest annual average concentration at the site boundary (SE at 1 mile)
Beta dose in air	20 mrad/yr per site	Same as above	0.62 mrad/yr	Same as above
Dose to total body	5 mrem/yr per site	Location of the (2) highest dose offsite	0.11 mrem/yr	Nearest residence (ESE at 1.1 miles)
Dose to skin of an individual	15 mrem/yr per site	Same as above	0.28 mrad/yr	Same as above
Radioiodines and Particulates (5) Released to the Atmosphere				
Dose to any organ from all pathways	15 mrem/yr per site	Location of the (6) highest dose offsite	2.49 mrem/yr (8)	Nearest cow (7) (WSW at 1.5 miles)

Table 11.3-12 (continued)
Appendix I Conformance Summary Table
Virgil C. Summer Nuclear Station
Gaseous Effluents

(1) Design objectives as specified in the Commission's Appendix I Conformance Option, 40 FR 40816, September 4, 1975.
(2) Evaluated at a location that is anticipated to be occupied during plant lifetime or evaluated with respect to such potential land and water usage and food pathways as could actually exist during the term of plant operation.
(3) Calculated only for noble gases.
(4) Evaluated at a location that could be occupied during the term of plant operation.
(5) Doses due to carbon-14 and tritium intake from terrestrial food chains are included in this category.
(6) Evaluated at a location where an exposure pathway actually exists at time of licensing. However, if the applicant determines design objectives with respect to radioactive iodine on the basis of existing conditions and if potential changes in land and water usage and food pathways could result in exposures in excess of the guideline values given above, the applicant should provide reasonable assurance that a monitoring and surveillance program will be performed to determine: (1) the quantities of radioactive iodine actually released to the atmosphere and deposited relative to those estimated in the determination of design objectives; (2) whether changes in land and water usage and food pathways which would result in individual exposures greater than originally estimated have occurred; and (3) the content of radioactive iodine and foods involved in the changes, if and when they occur.
(7) Cows are not currently milked at this location. Doses evaluated were based on the assumption that pathways could reasonably be expected to exist during plant life.
(8) Dose to an infant thyroid from air inhalation and cow milk ingestion.
(9) Points given correspond to points of dose evaluation under Appendix I heading.

Figure 11.3-1

GASEOUS WASTE PROCESSING SYSTEM FISSION GAS ACCUMULATION BASED ON CONTINUOUS CORE OPERATION AT 2958 MWT WITH 1% FUEL DEFECTS AND 60 GPM CONTINUOUS LETDOWN



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July 2002

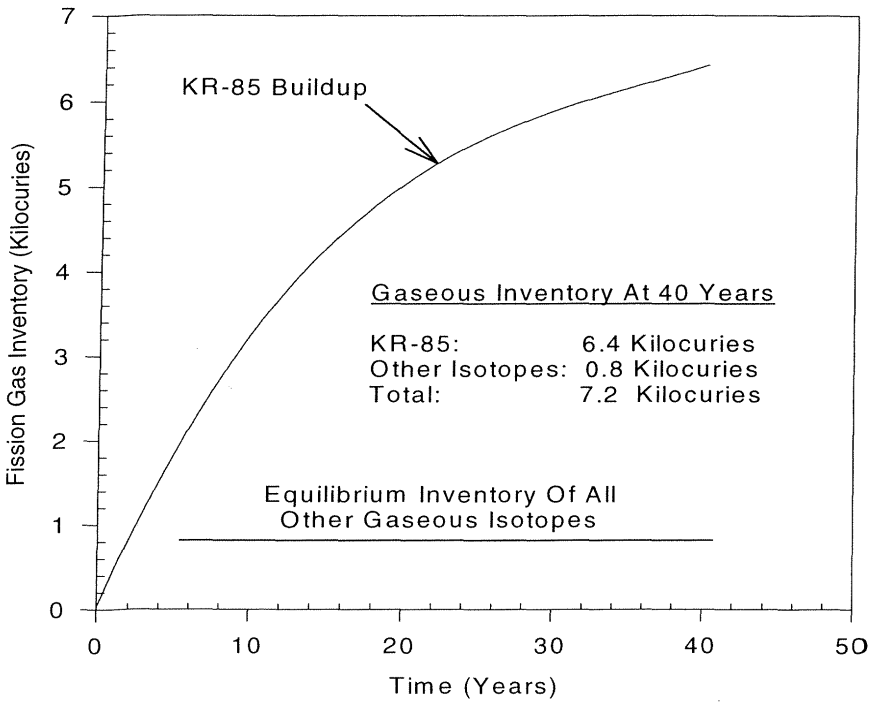
SOUTH CAROLINA ELECTRIC & GAS CO
VIRGIL C. SUMMER NUCLEAR STATION

Gaseous Waste Processing System Fission Gas Accumulation Based on Continuous Core Operation at 2958 Mwt with 1% Fuel Defects and 60 gpm Continuous Letdown

Figure 11.3-1

Figure 11.3-2

ESTIMATED GASEOUS WASTE PROCESSING SYSTEM FISSION GAS ACCUMULATION BASED ON Table 11.1-5 **AND FULL POWER OPERATION AT 2958 MWT AND 60 GPM CONTINUOUS LETDOWN**



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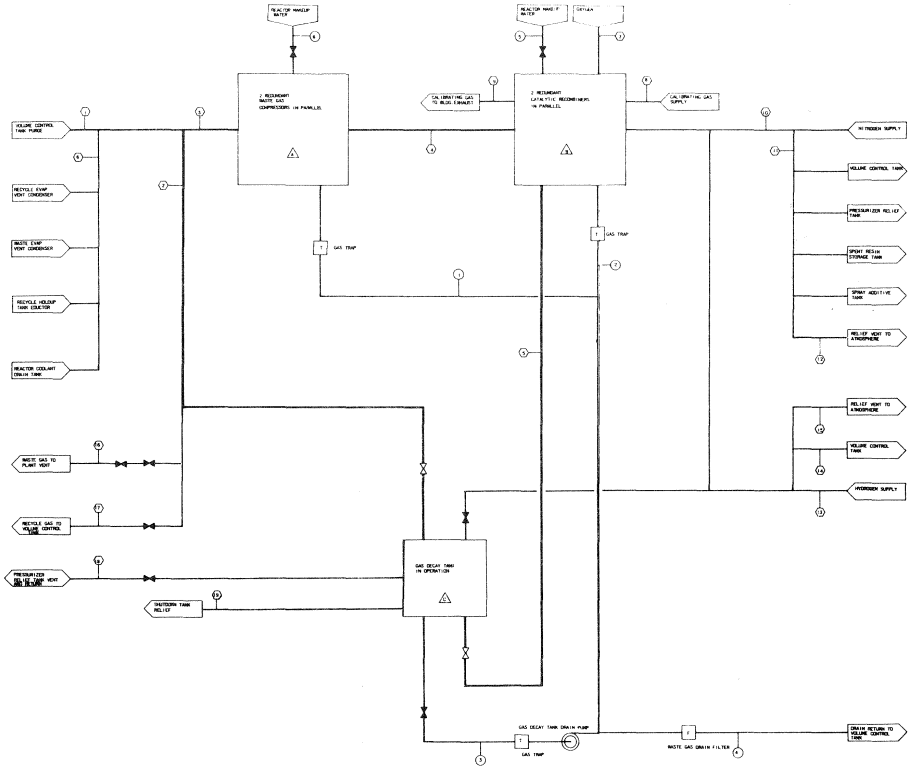
SOUTH CAROLINA ELECTRIC & GAS CO
VIRGIL C. SUMMER NUCLEAR STATION

Estimated Gaseous Waste Processing System Fission Gas Accumulation Based on Table 11.1-5 and Full Power Operation at 2958 Mwt and 60 gpm Continuous Letdown

Figure 11.3-2

Figure 11.3-3

GASEOUS WASTE PROCESSING SYSTEM
PROCESS FLOW DIAGRAM



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August 1984

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Gaseous Waste Processing System Process Flow Diagram
Figure 11.3-3

Figure 11.3-4
(SHEET 1) FSAR FIGURE REFERENCE
DRAWING E-302-741

Figure 11.3-4
(SHEET 2) FSAR FIGURE REFERENCE
DRAWING E-302-743

Figure 11.3-4
(SHEET 3) FSAR FIGURE REFERENCE
DRAWING E-302-742

Figure 11.3-5

WASTE GAS COMPRESSOR PACKAGE

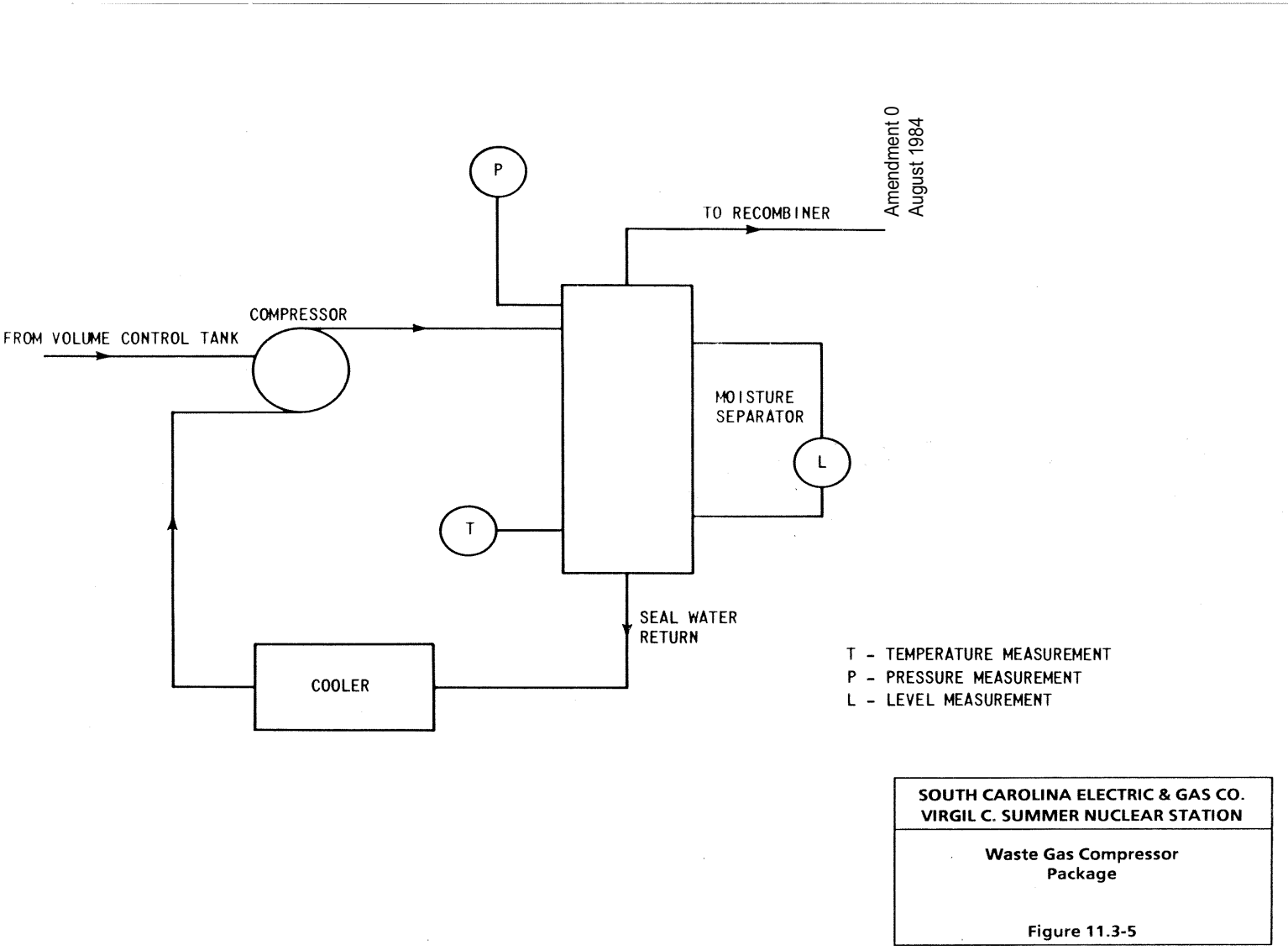
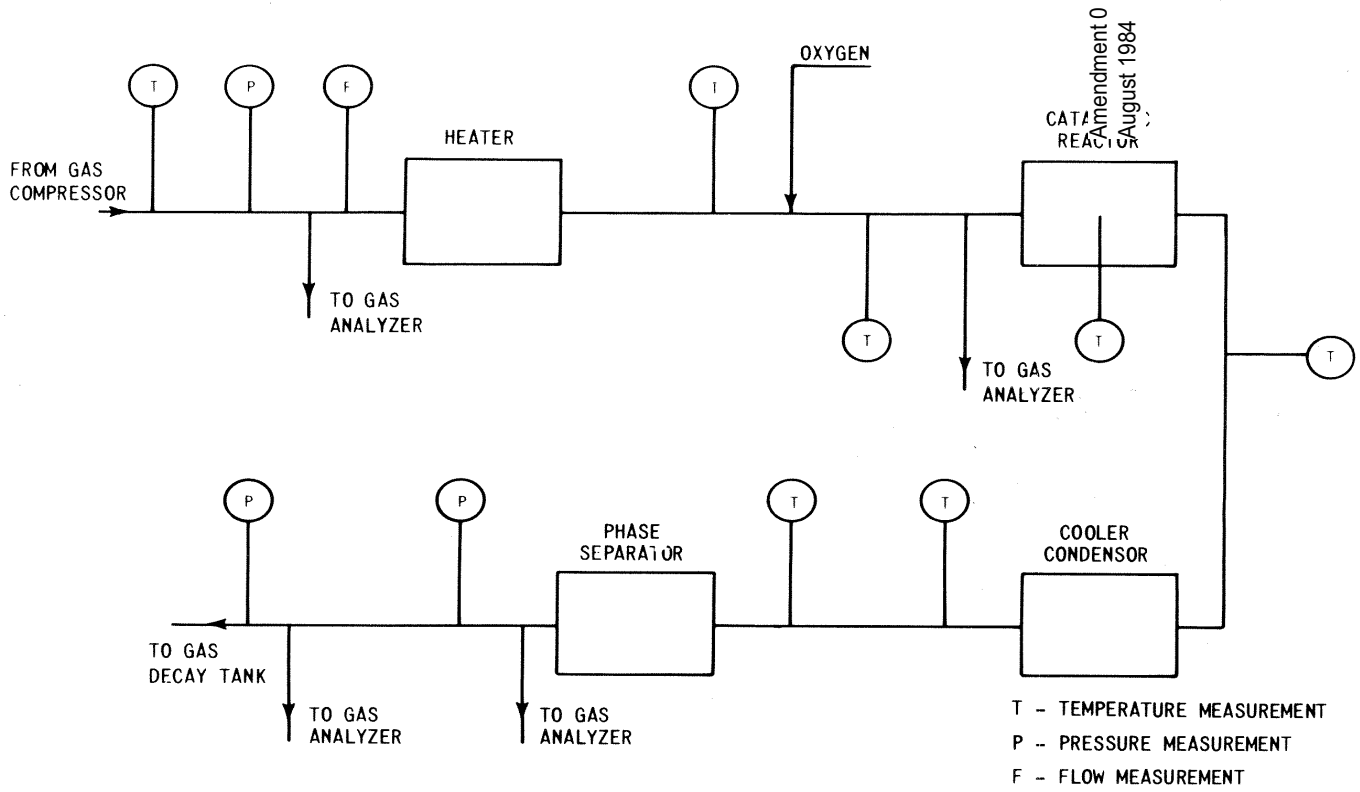


Figure 11.3-6

CATALYTIC HYDROGEN RECOMBINER PACKAGE



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Catalytic Hydrogen Recombiner Package Figure 11.3-6

Figure 11.3-7

GASEOUS WASTE RELEASE POINTS

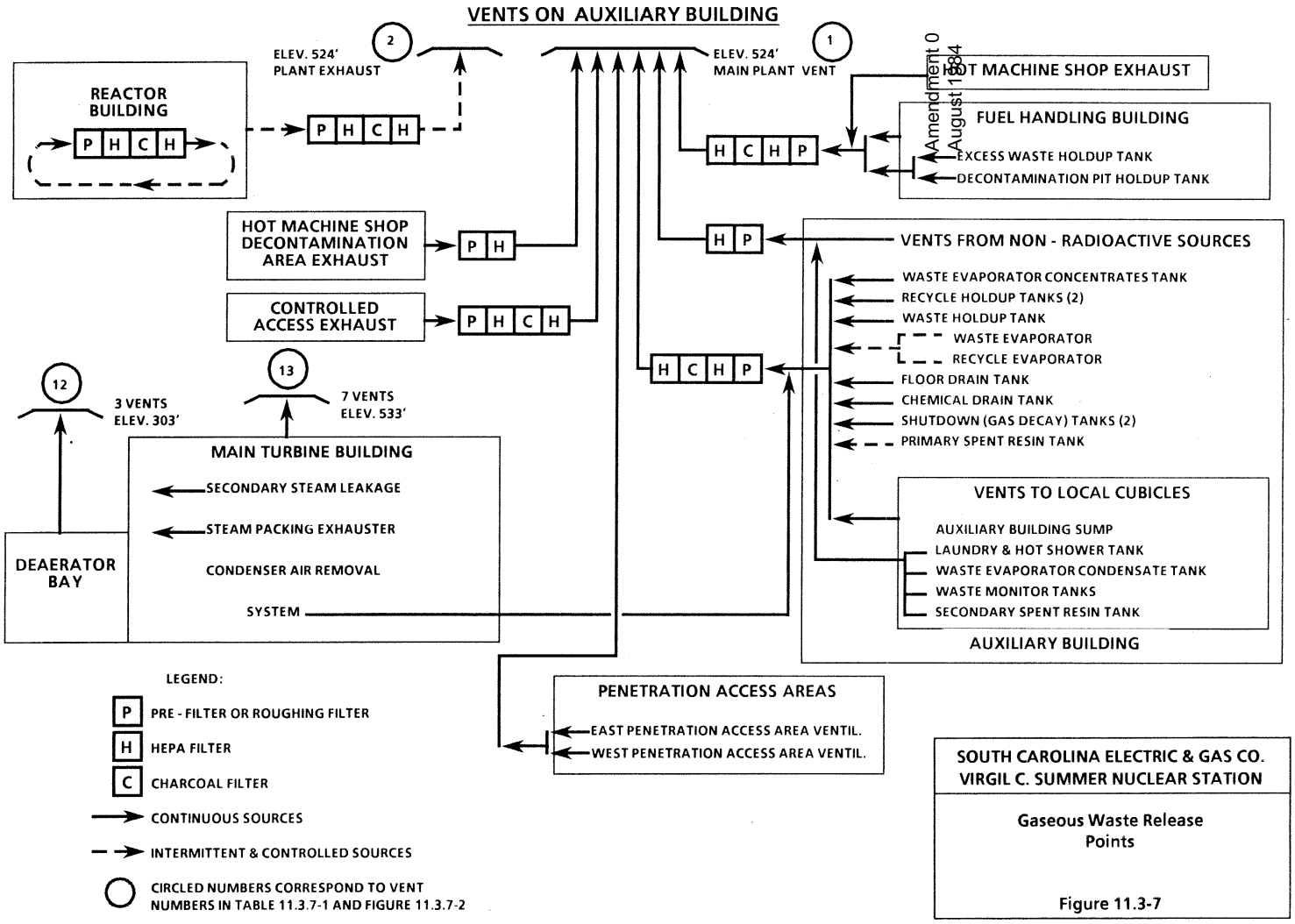


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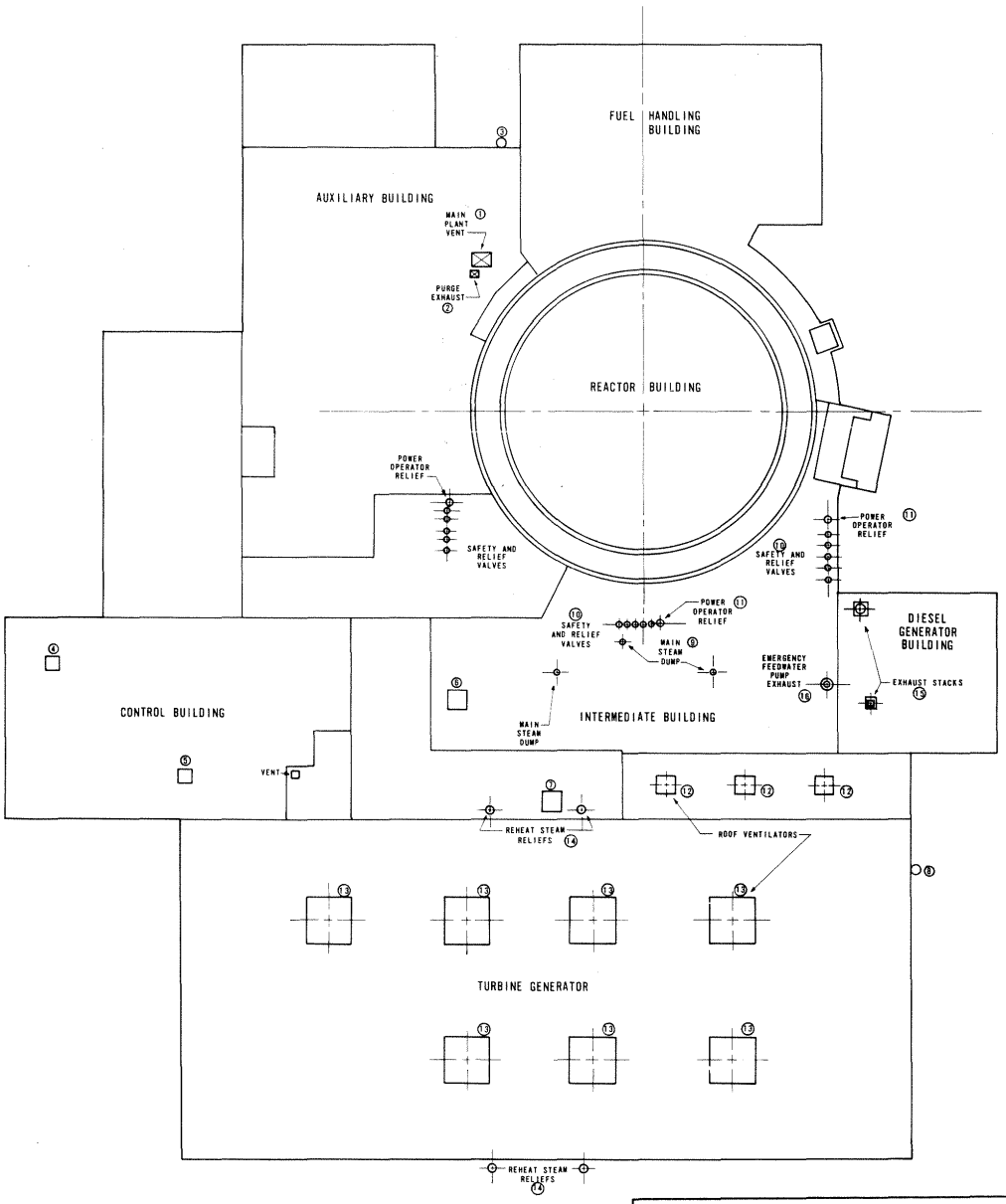
Figure 11.3-8

POTENTIALLY RADIOACTIVE GASEOUS WASTE RELEASE POINTS



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Potentially Radioactive Gaseous Waste Release Points
Figure 11.3-8

Amendment 0
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11.4 Process and Effluent Radiological Monitoring Systems

Radiation monitors and analysis of samples are used to monitor process and effluent streams in order to record and control releases of radioactive materials generated as a result of normal operations, including anticipated operational occurrences, and during postulated accidents. The general description and approximate ranges of radiation monitors that measure, indicate, and record the activity of process and effluent streams in the plant are tabulated in Table 11.4-1. Additional radiation monitors are discussed in Sections 12.1.4 and 12.2.4. More detailed information on instrument ranges may be found in Health Physics procedures.

11.4.1 Design Objectives

Major and potentially significant effluent discharge paths for release of radioactive material during normal reactor operation, including anticipated operational occurrences, are monitored as required by General Design Criterion 64. These effluent discharge paths are as follows:

1. Major Effluent Discharge Paths
    a. Reactor Building purge exhaust
    b. Plant vent exhaust (including the gaseous waste discharge)
    c. Liquid waste discharge
2. Potentially Significant Effluent Discharge Paths
    a. Condenser exhaust
    b. Nuclear Blowdown waste effluent
    c. Steam Generator Blowdown
    d. Turbine room sump
    e. Condensate Polish Backwash Tank effluent

Additionally, samples of these effluents are required for laboratory analysis to allow evaluation of the measured releases and compliance with the reporting requirements of Regulatory Guide 1.21 (see Appendix 3A). Monitoring and analysis of samples provide information useful in complying with the objectives of Appendix I to 10 CFR 50.

Process systems which do not discharge to the environment are monitored to permit identification of possible system or equipment malfunction through detection of activity levels in the system. The systems monitored are the following:

1. Component Cooling Water
2. Primary Coolant Letdown
3. Spent Fuel Cooling Water

The Radiation Monitoring System continuously monitors the normal plant effluent discharge paths under steady-state, transient, or accident condition. After an accident, the system provides information to aid in determining the magnitude of the accident. Locations where permanently mounted monitors are not provided are monitored periodically with portable instruments. Radiation monitoring, effluent flow measurements, and meteorological instrumentation provide data which, under emergency procedures, determine the direction and rate of movement of radioactive effluents.

The monitors located in the normal plant effluent discharge paths, area gamma monitors, and manual sampling provide information on the rate and location of releases.

Radiation monitoring, analysis of samples, and Health Physics surveillance provide data used for assuring compliance with the requirements of 10 CFR 20.

Utilization of off-line process monitors provides improved access for maintenance and inspection. Remotely actuated check sources for the radiation monitor detectors facilitate routine functional verification. Detector assemblies are removable in the event that extensive maintenance is required. Decontamination of process monitors is facilitated by use of appropriate taps or valving to allow flushing or cleaning.

Expected process flow, composition, and contamination are a function of the specific process system being monitored and are discussed in the section where the system is discussed.

11.4.2 Continuous Monitoring

Measurement data from the effluent radiation monitors and the analysis of samples by laboratory equipment (see Section 11.4.3) provide information used to comply with Regulatory Guide 1.21 (see Appendix 3A) and for evaluation of the releases to the environment.

Measured activity levels are indicated and recorded on the Radiation Monitoring control panel located in the Control Room (except RM-L8 and RM-L11). Local indication at or near the detector location is provided for each channel. The turbine room sump radiation monitor, RM-L8, is equipped for local indication, recording, and high level alarm and also actuates an alarm in the Control Room. If radiation discharge limits are exceeded, the sump pumps are automatically tripped and the flow path may be aligned to discharge to the Excess Liquid Waste System.

The condensate polish backwash effluent radiation monitor RM-L11 is equipped for local indication, recording, and high level alarm. Alarm is also provided through the local control panel for the condensate polishing system. A high radiation alarm will trip the backwash tank discharge pumps.

Detectors have remotely actuated check sources to provide functional verification. In addition, the monitoring channels are routinely calibrated by exposure to a calibrated test source for verification against initial calibration curves. Radiation monitor detection range is based upon the type of fluid being monitored for activity, the capability of commercial instrumentation, and the function of the monitor. Each rate meter is equipped with two adjustable alarm levels (alert and

high) and a channel failure/loss of power alarm. These alarms, except for movable monitors, are annunciated on the Radiation Monitoring System control panel in the Control Room. Channels which have an interlock function with other systems (see Figure 11.4-1) are provided with a bypass switch for use during maintenance or testing. Use of the bypass switch is annunciated. Reliable power for the fixed, process, and effluent radiation monitoring instrumentation is obtained from the diesel backed, 120 volt instrument bus. Associated sample pumps obtain power from the 480 volt diesel backed bus. Radiation monitors RM-L8 and RM-L11 are powered by local 120 volt a-c power.

Individual ratemeter power supplies are independent of each other. The reliable a-c power source is divided between two trains (see Table 11.4-1) to provide a high degree of availability.

Specific instrumentation channels used for process and effluent monitoring are as follows:

1. Primary Coolant Letdown Monitor, Channel RM-L1

   A sample of the primary coolant letdown from the Nuclear Sampling System is monitored by this channel utilizing an off-line monitor located outside the Reactor Building (see Figure 9.3-4). The sample is delayed to allow decay of N16 activity. Two detectors, overlapping in ranges, as shown by Table 11.4-1, are used to obtain a wide measuring range, from approximately 1 x 10^{-3} μCi/cc to 10^{3} μCi/cc, based upon Cs-137.

   The reactor coolant gross gamma activity resulting from instantaneous mixing of fission products from a small fraction of one fuel rod at equilibrium causes a net signal increase approximately equal to the signal produced by one percent failed fuel within four minutes. The contribution to gross gamma activity from corrosion products and tramp uranium is minor compared to that from one percent failed fuel.

   The alarm setpoint is established at a level such that any sudden increase above the normal or expected operational reactor coolant activity is suspected as being due to gross fuel failure. Analyses of a manual sample provide verification of compliance with Technical Specifications and indicate any action to be taken.

   No automatic interlock functions are served by this channel. If the detector is not available, the sampling frequency is increased. Loss of sample flow is annunciated in the Control Room.

   Use of two detectors, scintillation and Geiger-Mueller (G-M), and two alarm modules provides a high level of availability.

2. Component Cooling Water Monitors, Channels RM-L2A and RM-L2B

   Each of the two Component Cooling Water loops (see Figure 9.2-4) is equipped with an off-line, shielded sampler having a gamma sensitive scintillation detector for measurement of gross gamma activity in a sample of the cooling water. These monitors detect leakage of radioactivity into the Component Cooling Water and cause an alarm to sound upon detection

of excessive activity levels. Sensitivity and range of these monitors is approximately 2 x 10^{-6} to 2 x 10^{-2} μCi/cc, Cs-137.

High activity, approximately one decade above normal background, causes an alarm and initiates closure of the Component Cooling Water surge tank vent valve. Laboratory analysis of a Component Cooling Water sample is used to verify the cause of an alarm and the extent of leakage into the Component Cooling Water loop.

3. Steam Generator Blowdown Monitor, Channel RM-L3

   A fluid sample from the combined Steam Generator Blowdown (see Figure 10.4-13) is passed through a shielded, off-line sampler having a gamma sensitive scintillation detector for measurement of gross gamma activity. This monitor is used to detect primary to secondary leakage and sound an alarm upon detection. Design, sensitivity and range are similar to RM-L2A.

   High activity causes an alarm and initiates valve operations to divert blowdown flow to the Nuclear Blowdown holdup tank. Laboratory analysis of Steam Generator Blowdown samples is used to verify the alarm condition.

4. Spent Fuel Cooling Water, Channel RM-L4

   A sample of Spent Fuel Cooling Water (see Figure 9.1-3) is monitored by a shielded, off-line sampler using a gamma sensitive scintillation detector for measurement of gross gamma activity. Alarms are sounded upon detection of excessive activity. Design, sensitivity, and range are similar to RM-L2A.

   The monitor alarms alert the operator to an increase of activity. Such an increase is then verified by laboratory analysis of a manual grab sample.

5. Liquid Waste Effluent Monitor, Channel RM-L5

   An off-line monitor is used to sample the Liquid Waste effluent. A lead shielded sampler with a gamma sensitive scintillation detector is located upstream of the discharge dilution point for measurement of effluent gross gamma activity (see Figure 11.2-2, Sheet 4). Sensitivity and range are similar to RM-L2A.

   High effluent activity causes an alarm and initiates closure of the waste processing discharge valve. The activity level at which this interlock is actuated is adjustable based upon the activity level of an analyzed sample of the waste batch and/or dilution flow available. The activity and dilution flow are evaluated prior to discharge. A high level alarm is also provided at the local Liquid Waste System control panel.

6. Boron Recycle System Monitor, Channel RM-L6 --**NO LONGER IN SERVICE**--

   A sample of the discharge (see Figure 9.3-18) from the Boron Recycle System recycle evaporator condensate filter to the reactor makeup storage tank is monitored by an off-line, shielded sampler. This sampler uses a gamma scintillation detector to measure gross gamma activity. Sensitivity and range are similar to RM-L2A.

   High activity in the recycle evaporator condensate filter discharge to the reactor makeup storage tank causes an alarm and initiates diversion of the discharge flow from the reactor makeup storage tank to the recycle evaporator. Laboratory analysis of a sample is used to verify the alarm condition.

7. Nuclear Blowdown Waste Effluent Monitor, Channel RM-L7

   A sample of the discharge (see Figure 10.4-14) from the Nuclear Blowdown Processing System is monitored for gross gamma activity by a shielded, gamma sensitive detector. This off-line monitor is used to detect excessive activity releases from the Nuclear Blowdown Processing System. Alarms are sounded upon detection of such releases. Design, sensitivity, and range are similar to RM-L2A.

   High activity causes alarms and initiates valve operations to terminate discharge and divert the flow to the Nuclear Blowdown Processing System monitor tank. Laboratory analysis of the process discharge fluid is used to verify alarm conditions. The alarm setpoint is based upon the maximum release activity and dilution of the discharge stream.

8. Turbine Room Sump Monitor, Channel RM-L8

   A sample of the turbine room sump discharge is monitored by a shielded gamma scintillation detector to provide local measurement, indication, and alarm of gross gamma activity. The monitor sample valve is opened and the 120 volt a-c sample pump is started when the turbine room sump pumps are operated. A high activity alarm annunciated in the control room stops the sump pumps.

9. Main Plant Vent Exhaust Monitor, Channel RM-A3

   This channel monitors particulate, iodine, and gaseous activity released through the main plant vent from the Auxiliary Building. The particulate detector, a beta scintillator, has a sensitivity and range of approximately 10^{-11} to 10^{-7} µCi/cc, Cs-137. The iodine detector, a gamma scintillator, has a sensitivity and range of approximately 2×10^{-11} to 10^{-7} µCi/cc, I-131. The gas detector, a beta scintillator, has a sensitivity and range of approximately 2.6×10^{-6} to 2×10^{-2} µCi/cc, Kr-85.

   A particulate collection filter with an efficiency of 90 percent for particles 0.3 microns or larger is provided and is removable for laboratory analysis. A charcoal filter cartridge, removable for laboratory analysis and having an efficiency of 95 percent for elemental iodine, is also provided.

The plant vent discharge sample is taken downstream of the filtering units by a nozzle located near the point of discharge to the environment (see Figure 9.4-9). Sample nozzle flow is adjusted to be isokinetic at a nominal discharge flow rate (227,588 cfm) from the vent stack.

The pumping station and the three shielded detection channels are located on the floor below the sampling point to minimize sample line losses. This pumping station is equipped with two pumps to permit continued operation when pump maintenance is required.

Should the gaseous activity released through the main plant vent reach or exceed the Hi-Rad setpoint, the gaseous activity detection channel initiates closure of the Waste Gas decay tank discharge valve.

The RM-A3 setpoints are estimated by plant procedures to ensure that the site boundary dose limits specified in the ODCM are not exceeded.

Radiation monitor RM-A3 utilizes detectors which are 4-Pi shielded with 3 inches of lead to minimize the effect of the background radiation in normal operation in an environment as listed in Table 3.11-3.

10. Reactor Building Purge Exhaust Monitor, RM-A4

This monitor measures particulate, iodine, and gaseous activity in the discharge of the Reactor Building Purge Exhaust System during purging operations. This monitor is similar to RM-A3 with respect to its description, range, and sensitivity.

The monitored sample is obtained through an isokinetic nozzle located in the purge exhaust duct upstream of the discharge point (see Figure 9.4-28). The monitor is located on the floor below the duct to minimize sample line loses. The monitor obtains its sample from either of two sample probes in the discharge duct. One probe is isokinetic at the design discharge flow rate (20,000 cfm), the other probe is isokinetic at the design low flow rate. The duct flow rate is measured and indicated in the Control Room. Under operating conditions where this flow is more than 10 percent below design conditions, the data collected by RM-A4 will be corrected for an isokinetic sampling in accordance with ANSI 13.1 1969 Appendix C. Appendix C implies that an isokinetic correction for particle sizes less than 4 microns does not need to be considered. Particles penetrating the containment HEPA filters are normally less than 0.3 microns.

Should an unplanned gaseous activity release rate of approximately 4×10^{1} µCi/sec, Kr-85, be exceeded, this monitor initiates closure of the Reactor Building purge valves. This activity release rate is based upon a flow rate of 20,000 cfm through the Reactor Building purge vent and a gaseous activity level setpoint of approximately two times the expected background at the monitor location. Such a setpoint provides for rapid detection of any unplanned release.

The alarm setpoints for particulate and iodine activity are estimated by plant procedures to ensure that the site boundary dose limits specified in the ODCM are not exceeded.

Alarm setpoints may be readjusted prior to commencement of Reactor Building purging based upon existing activity levels within the Reactor Building.

Radiation monitor RM-A4 utilizes detectors which are 4-Pi shielded with 3 inches of lead to minimize the effect of the background radiation in normal operation in an environment as listed in Table 3.11-3.

The gamma dose rate from the charcoal cartridge located inside the atmospheric monitor (RM-A4) shield assembly at a distance of one foot is approximately 2.8 mr/hr, assuming a sample activity of 102 μCi/cc, sample flow of 1 cfm, 95 percent collection efficiency, average E of 0.5 Mev, and 30 minutes collection time.

11. Condenser Exhaust Monitor, RM-A9

This monitor is a shielded, off-line unit with a gamma scintillation detector which monitors gaseous samples taken from the condenser exhaust discharge line (see Figure 10.4-1). Its purpose is detection of primary to secondary system leakage. Range of this monitor is approximately 2×10^{-6} to 2×10^{-2} μCi/cc, Xe-133. This range combined with a design discharge flow rate of 40 cfm permits monitoring of an activity discharge rate of 7.5×10^{-2} to 7.5×10^{2} μCi/sec.

12. Waste Gas Discharge Monitor, Channel RM-A10

This monitor is a shielded beta scintillation detector which monitors and controls the gaseous activity released from the Waste Gas decay tanks. Sensitivity and range of this monitor are approximately 2×10^{-4} to 2 μCi/cc, Xe-133.

Detection of high gaseous activity initiates closure of the Waste Gas decay tank discharge valve. Prior to a planned Waste Gas decay tank release, the alarm setpoint may be readjusted according to analyzed activity level existing in the Waste Gas decay tanks.

13. Main Plant Vent Exhaust High Range Gas Discharge Monitor, Channel RM-A13

This monitor (see Figure 11.4-2) provides extended range backup to channel RM-A3. The monitor utilizes an ion chamber gamma sensitive detector with a sensitivity and range of approximately 10^{-2} to 10^{+5} μCi/cc, XE-133. Detection of high activity provides an alarm, indication, and a record of excessive gas activity released through the main plant vent exhaust. The energy dependence is ± 10 percent from 80 KeV to 3 MeV. Background correction is achieved by a 2-inch lead shield which reduces background and provides collimation of the detector to respond to the gamma radiation from the exhaust duct.

Graphs will be available to operating personnel to reflect the readout of RM-A13 versus the curie concentration for a given release and an assumed isotopic mixture of the effluent.

14. Liquid Waste Effluent Monitor, Channel RM-L9

    An off-line monitor is used to sample the Liquid Waste effluent to the penstocks. A lead shielded sampler with a gamma sensitive scintillation detector is located downstream of radiation monitor RM-L5 to monitor the discharge from the Liquid Waste Processing System or the discharge from the Nuclear Blowdown Processing System. Sensitivity and range of this monitor are similar to RM-L2A.

    High effluent activity actuates an alarm and initiates closure of the waste discharge valve, thus terminating flow to the penstocks. The activity level at which this interlock is actuated is adjusted to limit the maximum permitted activity of the discharge to the penstocks and to provide backup for radiation monitors RM-L5 and RM-L7.

15. Steam Generator Blowdown Discharge Monitor, Channel RM-L10

    A fluid sample from the Steam Generator Blowdown discharge to the Circulating Water System is passed through a shielded, off-line sampler having a gamma sensitive scintillation detector for measurement of gross gamma activity. This monitor is used to terminate the discharge flow to the Circulating Water System in the event of primary to secondary leakage in the steam generators. Design, sensitivity, and range of this monitor are similar to RM-L2A.

    High activity actuates an alarm and initiates valve closure to terminate Steam Generator Blowdown flow to the Circulating Water System. This monitor backs up radiation monitor RM-L3. Laboratory analysis of Steam Generator Blowdown samples is used to verify the alarm condition.

16. Purge Exhaust Effluent High Range Radiation Monitor, Channel RM-A14

    This monitor (see Figure 11.4-2) provides extended range backup to channel RM-A4. The monitor utilizes an ion chamber gamma sensitive detector with a sensitivity and range of approximately 10^{-2} to 10^{+5} μCi/cc, Xe-133. Detection of high activity provides an alarm, indication, and a record of excessive gas activity released through the purge vent exhaust. The energy dependence is ± 10 percent from 80 KeV to 3 MeV. Background correction is achieved by a 2-inch lead shield which reduces background and provides collimation of the detector to respond to the gamma radiation from the exhaust duct.

    Graphs will be available to operating personnel to reflect the readout of RM-A14 versus the curie concentration for a given release and an assumed isotopic mixture of the effluent.

17. Steam Line High Range Monitors, Channels RM-G19A, B, and C

    Each Main Steam line header upstream of the relief valves (2806-MS) is provided with a high range gamma sensitive monitor to provide indication of the steam activity in the event of a release equivalent to 2 curies/sec/MW_{th} of Xe-133.

These monitors are responsive to 0.1 mr/hr up to 10^7 mr/hr gamma with a flat response of ± 10 percent from 80 KeV to 3 MeV. The anticipated dose response, calculated for the detector due to an equivalent concentration of Xe-133 in the discharge effluent from the steam line, is 6.1×10^{-1} mr/hr/μCi/cc. Background correction for each monitor is achieved by 2-inch lead shielding to reduce background and provide collimation of the detector to respond to the gamma radiation from the steam line.

18. Condensate Polish Backwash Effluent Monitor, Channel RM-L11

A sample of the recirculated or batch discharge fluid from the Condensate Polish System backwash receiver tank is monitored for gross gamma activity by an off-line liquid radiation monitor, RM-L11 (see Figure 10.4-7a). Sensitivity is approximately 1×10^{-6} μCi/cc referenced to Cs-137. Indication, alarms, and recording are provided locally.

Interlocks are provided to trip the backwash pumps upon a high activity alarm. The activity of the fluid is evaluated prior to discharge. Alarm is also provided at the local Condensate Polish System control panel.

As agreed with the NRC Staff, this monitor is required to be installed prior to startup after the first refueling.

11.4.3 Sampling

The requirements of General Design Criterion 64 are satisfied with respect to effluent discharge paths as stated below.

Radiation monitoring is accomplished using the Radiation Monitoring System and laboratory analysis of samples in accordance with Regulatory Guide 1.21 (see Appendix 3A).

Table 11.4-2 presents normal and potential discharge paths from the plant and lists the monitoring and analyses performed. The frequency of sampling is increased should abnormal levels of activity be detected.

Effluent monitors RM-L5, RM-L11, and RM-A10 provide backup control of the administrative release of liquid and gaseous waste. These batch releases are analyzed and evaluated prior to discharge. Main plant vent exhaust monitor RM-A3 provides additional backup to the Waste Gas discharge monitor RM-A10.

Ventilation discharge effluent monitors RM-A3 (main plant vent exhaust) and RM-A4 (Reactor Building purge exhaust) provide removable particulate filters and charcoal cartridges for laboratory analyses which allow evaluation of normal and/or abnormal releases.

Continuous effluent discharge radiation monitor (RM-A3, RM-A9, and RM-L7) readings of gas or liquid activity would be affected by abnormal background directly following a LOCA and would, at that time, indicate a higher gas or liquid activity than was actually being discharged. This would result only in the possibility of premature actuation of interlocks or alarms. Use of

portable instrumentation, sample analysis, and appropriate emergency procedures, as well as the radiation monitors, permits evaluation of the plant discharge to the environment under accident conditions.

Liquid effluent monitor RM-L7 (Nuclear Blowdown waste) diverts the process discharge upon detection of excessive gross gamma activity. A manual sample of the diverted discharge fluid is analyzed in the laboratory for evaluation of the isotopic content.

Primary to secondary leakage is detected by the condenser exhaust monitor, RM-A9. Additional backup information is provided by the steam generator liquid blowdown monitor, RM-L3. Subsequent analysis of liquid samples in the laboratory provides verification.

In the event of simultaneous primary to secondary and turbine leaks, the Turbine Building Ventilation System and Floor Drain System become potential discharge points. Portable monitors and manual samples are used to determine the rate of release.

Liquid radiation monitor, RM-L8, monitors turbine room sump discharge and stops the sump pumps upon occurrence of a high radiation alarm.

The ventilation exhaust from the Intermediate Building is not considered a potential discharge point due to a lack of potential sources within this building. Routine Health Physics surveillance with portable monitors and analysis of particulate portable sampler filters are used for verification.

General Design Criterion 60 is satisfied by use of interlock circuits which are illustrated by Figure 11.4-1. In addition, alarms resulting from detection of high activity alert the operator to the need for appropriate action.

Requirements of General Design Criterion 63, with respect to the monitoring of radiation levels in radioactive waste process systems, are satisfied by use of the effluent and process radiation monitoring instrumentation, area gamma monitoring, Health Physics surveillance with portable instruments, and laboratory analysis of process samples.

11.4.4 Inservice Inspection, Calibration, and Maintenance

The analyses of radioactive effluents are performed in accordance with requirements set forth in Regulatory Guide 1.21 (see Appendix 3A). Inplant laboratory facilities for these analyses include a separate sample room, radiochemistry laboratory, and count room located in the Control Building. Appropriate equipment for the safe handling of samples and standards is provided. Count room equipment includes the following:

1. Germanium detectors
2. Liquid scintillation counter
3. Gross alpha counter
4. Appropriate shielding for detection devices

5. Multichannel analyzers
6. Data reduction and storage system

Detailed written analytical laboratory procedures are provided to assure compliance with sensitivity, accuracy, and reproducibility requirements within the capabilities of commercially available equipment.

The schedule for routine calibration of laboratory equipment used for effluent sample analysis is detailed in such a manner as to assure the continuing accuracy of measurements. Calibration performance for the various equipment is closely monitored to determine if malfunction due to procedural difficulties or minimal equipment failure has occurred and, where applicable, whether equipment maintenance is required. Functional checks of equipment performance are performed on a more frequent basis than is calibration in accordance with written laboratory procedures. These checks use materials with the accuracy, stability, and range (though not necessarily traceable to the National Institute of Standards and Technology) necessary to assure a timely indication of equipment operational status. Maintenance or readjustment of the laboratory counting equipment is followed by appropriate recalibration.

Laboratory counting systems used in the analysis of effluent samples are calibrated using specific standards consistent with the particular effluent sample geometry.

The radioactive material in these standards is either certified by the National Institute of Standards and Technology or has been calibrated against standard reference material certified by the National Institute of Standards and Technology. Calibration standards have the accuracy, stability, and range required for the intended use. Detailed written procedures for calibration of laboratory counting equipment and preparation of standards are provided to assure the continuing adequacy of effluent sample measurements. Intercomparison and interlaboratory spiked samples and analyses of such samples provide further assurance of system measurement accuracy. Equipment ancillary to qualification and quantification of effluent samples is also calibrated using detailed written procedures such as those called for in Regulatory Guides 1.21 and 1.23 (see Appendix 3A) to assure analytical accuracy.

Maintenance of laboratory equipment used in the analysis of effluent samples is performed in accordance with procedures recommended by the equipment manufacturers. Laboratory equipment availability is maximized as follows:

1. The incorporation of modular designs where appropriate
2. Provision of spare parts
3. Interchangeability of certain components within different laboratory counting systems when consistent with design considerations.

The process sampling system is described in Section 9.3.2.

11.4.5 References

1. Title 10, Code of Federal Regulations, Part 20, Appendix B, *Concentrations in Air and Water above Natural Background*.

Table 11.4-1
Process and Effluent Radiological Monitors

Monitor	Function	Detector	Power
RM-L1 Primary Coolant Letdown	Liquid process monitor, detection of gross activity buildup in reactor coolant.	NaI and G-M; Gamma 10^{-3} to 10^{2} µCi/cc & 10^{-1} to 10^{3} µCi/cc, Cs-137	Bus A
RM-L2A Component Cooling Water Closed Loop A	Liquid process monitor, detection of leakage into component cooling water system.	NaI; Gamma 2 x 10^{-6} to 2 x 10^{-2} µCi/cc, Cs-137	Bus A
RM-L2B Component Cooling Water Closed Loop B	Liquid process monitor, detection of leakage into component cooling water system.	NaI; Gamma 2 x 10^{-6} to 2 x 10^{-2} µCi/cc, Cs-137	Bus B
RM-L3 Steam Generator Blowdown	Liquid process monitor, detection of leakage into steam generators.	NaI; Gamma 2 x 10^{-6} to 2 x 10^{-2} µCi/cc, Cs-137	Bus A
RM-L4 Spent Fuel Cooling Water	Liquid process monitor, detection of pool water contamination.	NaI; Gamma 2 x 10^{-6} to 2 x 10^{-2} µCi/cc, Cs-137	Bus B
RM-L5 Liquid Waste Effluent	Liquid effluent monitor, terminates discharge of waste liquid on detection of excessive activity. Backup to predischarge analysis of liquid waste tank contents.	NaI; Gamma 2 x 10^{-6} to 2 x 10^{-2} µCi/cc, Cs-137	Bus B
-NO LONGER IN SERVICE- RM-L6 Boron Recycle System	Liquid process monitor, diverts discharge on detection of excess activity.	NaI; Gamma 2 x 10^{-6} to 2 x 10^{-2} µCi/cc, Cs-137	Bus B

Table 11.4-1 (continued)
Process and Effluent Radiological Monitors

Monitor	Function	Detector	Power
RM-L7 Nuclear Blowdown Waste Effluent	Liquid effluent monitor, terminates discharge and diverts flow upon detection of excess activity.	NaI; Gamma 2×10^{-6} to 2×10^{-2} µCi/cc, Cs-137	Bus B
RM-L8 Turbine Room Sump Monitor	Liquid effluent monitor, stops sump pumps upon detection of excessive activity.	NaI; Gamma 2×10^{-7} to 2×10^{-2} µCi/cc, Cs-137	120 Volt
RM-L9 Liquid Waste Discharge	Effluent liquid monitor, terminates liquid waste discharge to penstocks upon detection of high activity. Provides backup to radiation monitors RM-L5 and RM-L7.	NaI; Gamma 2×10^{-6} to 2×10^{-2} µCi/cc, Cs-137	Bus A
RM-L10 Steam Generator Blowdown Discharge	Effluent liquid monitor, terminates steam generator blowdown discharge to circulating water system upon detection of high activity. Provides backup to radiation monitor RM-L3.	NaI; Gamma 2×10^{-6} to 2×10^{-2} µCi/cc, Cs-137	Bus B
RM-L11 Condensate Polish Backwash Effluent	Effluent liquid monitor, terminates backwash discharge pump operation upon detection of high activity. Provides backup to analysis of batch activity.	NaI; Gamma 10^{-6} to 10^{-2} µCi/cc, Cs-137	120v-ac Local

Table 11.4-1 (continued)
Process and Effluent Radiological Monitors

Monitor	Function	Detector	Power
RM-A3 Main Plant Vent Exhaust	Effluent atmospheric monitor, detects excessive release from auxiliary building exhaust.	Particulate - Beta 4.7×10^{-11} to 10^{-7} μCi/cc, Cs-137 Iodine - NaI; Gamma 2×10^{-11} to 2×10^{-7} μCi/cc, I-131 Gas - Beta 2.6×10^{-6} to 2×10^{-2} μCi/cc, Kr-85	Bus A
RM-A4 Reactor Building Purge Exhaust	Effluent atmospheric monitor, terminates purge exhaust on detection of excess gas activity.	Particulate - Beta 4.7×10^{-11} to 10^{-7} μCi/cc, Cs-137 Iodine - NaI; Gamma 2×10^{-11} to 2×10^{-7} μCi/cc, I-131 Gas - Beta 2×10^{-6} to 2×10^{-2} μCi/cc, Kr-85	Bus A
RM-A9 Condenser Exhaust	Effluent gas monitor, detects leakage into steam generator system.	NaI; Gamma 2×10^{-6} to 2×10^{-2} μCi/cc, Xe-133	Bus B
RM-A10 Waste Gas Discharge	Effluent gas monitor, terminates discharge of waste gas on detection of excess activity. Backup to predischarge analysis of waste gas tank contents.	Gamma 2×10^{-4} to 2 μCi/cc, Xe-133	Bus B
RM-A13 Main Plant Vent Exhaust, High Range Gas Discharge	Effluent High Range Gas Monitor	Ion Chamber - Gamma Ref. 10^{-2} to 10^{5} μCi/cc, Xe-133 (0.1 to 10^{7} mr/hr)	Bus A
RM-A14 Purge Exhaust Effluent, High Range	Effluent High Range Gas Monitor	Ion Chamber - Gamma Ref. 10^{-2} to 10^{5} μCi/cc, Xe-133 (0.1 to 10^{7} mr/hr)	Bus A
RM-G19, A,B,C	Steam Line High Range Gamma Monitor	Ion Chamber - Gamma 0.1 to 10^{7} mr/hr	Bus B

Table 11.4-2
Discharge Monitoring and Analysis

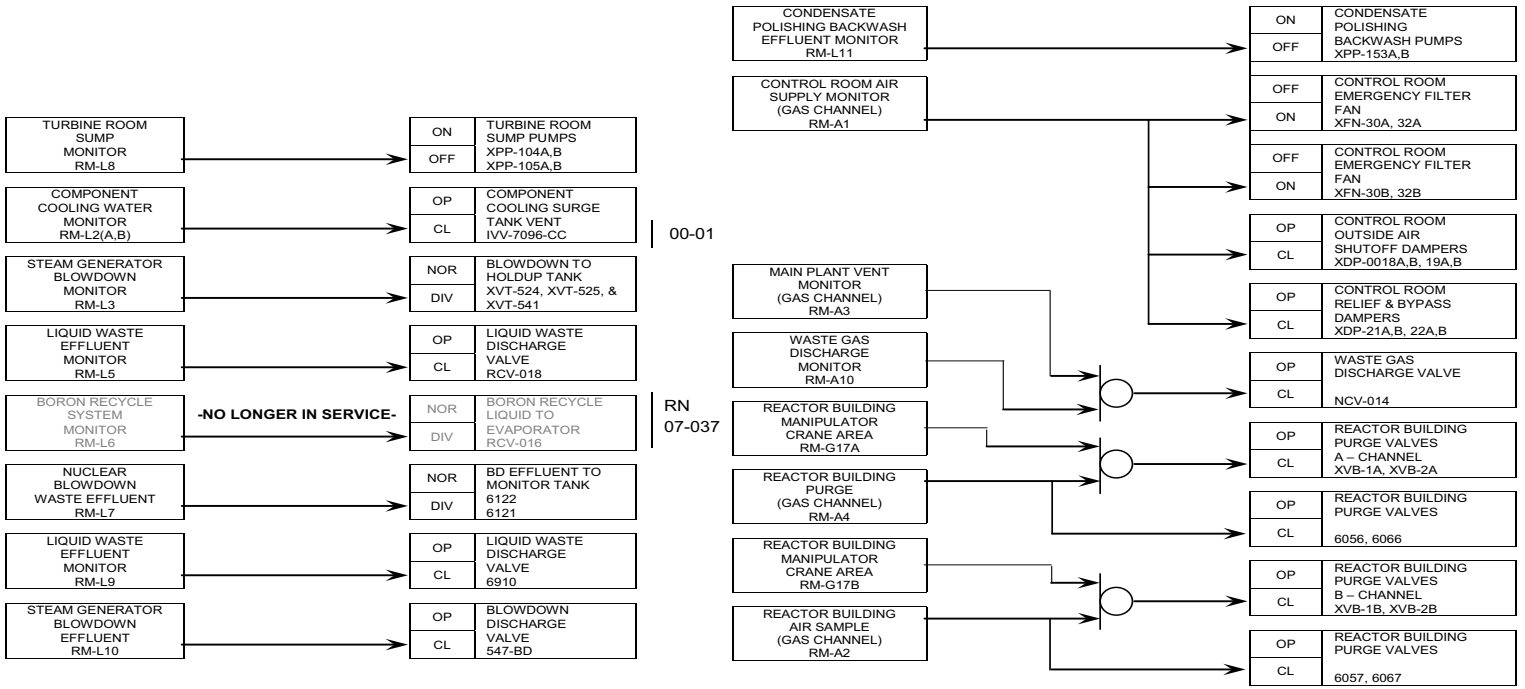
Normal Discharge Paths	Type of Continuous Monitoring	Samples for Isotopic Analysis	Frequency of Sampling
Main Plant Vent	RM-A3 Particulate (β) RM-A3 Iodine (γ) RM-A3 Gas (β)	Fixed filter Charcoal cartridge Gas sample from gas decay tank (includes tritium)	Weekly
Reactor Building Purge	RM-A4 Particulate (β) RM-A4 Iodine (γ) RM-A4 Gas (β)	Fixed filter Charcoal cartridge Gas sample from containment atmosphere (includes tritium)	Before each purge and weekly during a continuous purge (e.g., refueling period)
Liquid Waste Effluent Discharge	RM-L5 Liquid (γ) RM-L9 Liquid (γ)	Aliquot from holdup tank (includes tritium)	Prior to batch release
Waste Gas Discharge	RM-A10 Gas (β)	Gas sample from gas decay tank	Prior to batch release

Table 11.4-2 (continued)
Discharge Monitoring and Analysis

Normal Discharge Paths	Type of Continuous Monitoring	Samples for Isotopic Analysis	Frequency of Sampling
Steam Generator Blowdown	RM-L3 Liquid (γ) and/or RM-L10 Liquid (γ)	Aliquot from blowdown/discharge	Daily for composite and immediately following detection of a high radiation level
Nuclear Blowdown Waste Effluent	RM-L7 Liquid (γ)	Aliquot from Nuclear Blowdown Monitor Tank	Prior to batch release and immediately following detection of a high radiation level
Turbine Room Sump Discharge	RM-L8 Liquid (γ)	Aliquot from sump	Daily for composite and immediately following detection of a high radiation level
Condensate Polish Backwash Effluent	RM-L11 Liquid (γ)	Aliquot from Backwash tank	Prior to discharge and following detection of a high radiation level

Figure 11.4-1

RADIATION MONITORING SYSTEM INTERLOCKS



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Radiation Monitoring System Interlocks

Figure 11.4-1 Rev. 2

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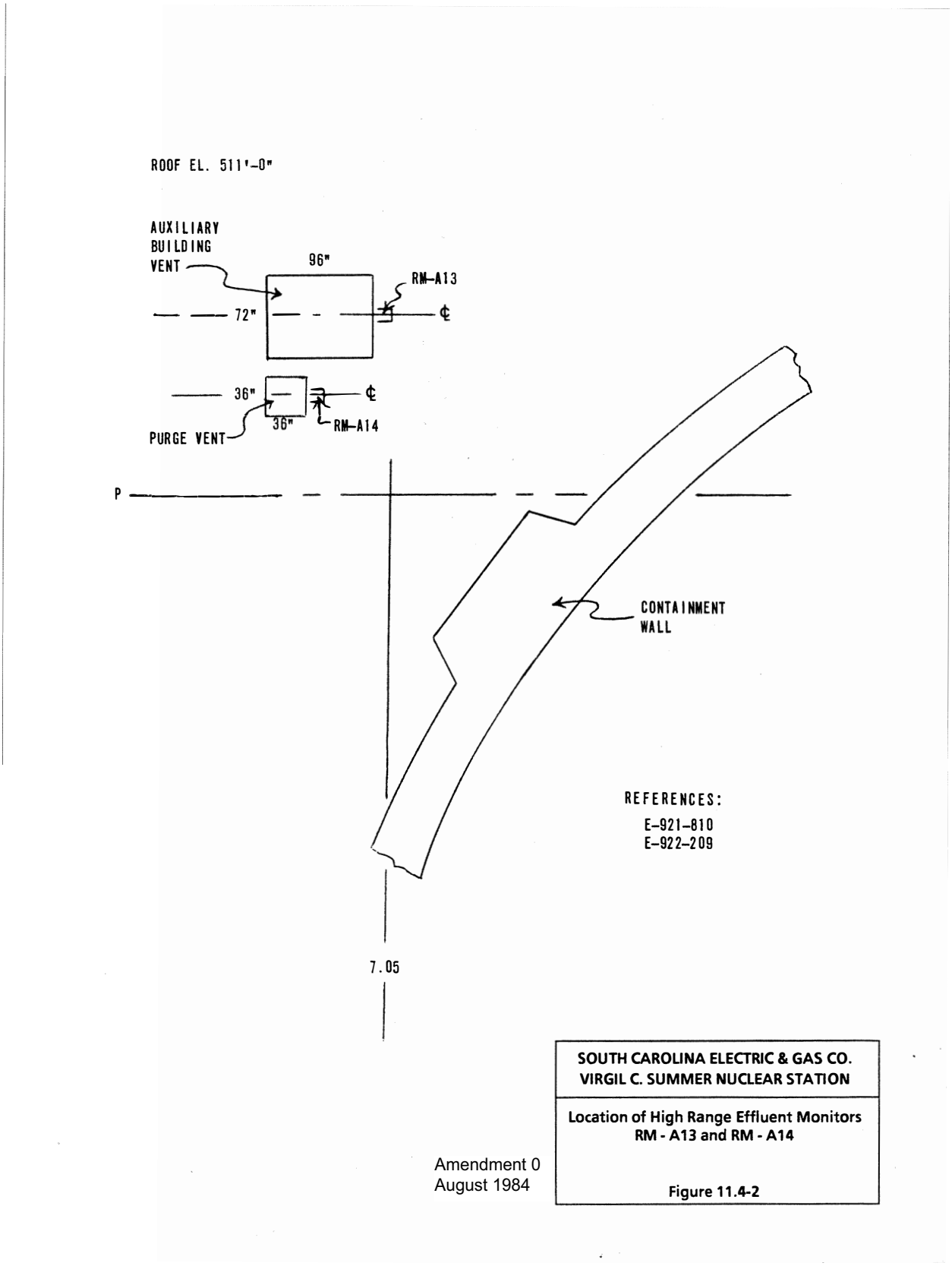
Figure 11.4-2

LOCATION OF HIGH RANGE EFFLUENT MONITORS RM-A13 AND RM-A14



Amendment 0
August 1984

11.5 SOLID WASTE SYSTEM

11.5.1 Design Objectives

The Solid Waste System is designed to package and/or solidify radioactive wastes for shipment to an approved offsite burial facility in accordance with applicable Department of Transportation (DOT), NRC, and State regulations. The system conforms to 10 CFR 20 and 10 CFR 50 requirements by providing shielding so that radiation exposure of operating personnel and the public is within acceptable limits. Solid waste packaging is accomplished in an area located on the ground floor (elevation 436') of the Auxiliary Building, a Seismic Category 1 structure.

Design, fabrication, and testing of Solid Waste System components and piping is in accordance with ANSI B31.1 and other accepted standards referenced by ANSI B31.1. Additional onsite system tests will be performed using nonradioactive materials prior to commercial operation. Packaging and shipping conform to 49 CFR 171 through 49 CFR 178.

Individual container shields and casks are used, when required, to maintain radiation levels within applicable radioactive materials regulations.

11.5.2 System Inputs

Radioactive waste packaged includes:

1. Spent resins.
2. Used filter cartridges.
3. Radioactive hardware.
4. Compacted waste such as rags, paper, clothing, etc.

Secondary side condensate polisher resin may also be handled by the Solid Waste System (refer to 10.4.6).

Design quantities and activity levels of the various wastes are listed in Tables 11.5-1 through 11.5-4.

11.5.3 Equipment Description

11.5.3.1 Processing

The input to the Solid Waste System consists of the contents of several radioactive waste storage tanks containing primary spent resins, reactor grade demineralizer spent resins, non-reactor grade demineralizer spent resins, and nuclear blowdown spent resins and the associated valves, piping, and pumps. These components are located at elevation 412' and 447' in the Auxiliary Building.

Radwaste solidification when required is accomplished using approved equipment and process control program. Liquid waste contained in the reactor grade and non-reactor grade demineralizer

is recirculated using their respective pumps and a sample is taken. This sample is used in the Process Control Program to determine pH adjustment, waste/binder ratio, and for the purpose of test solidification. Liquid waste is transferred to the fill head and into the liner located in the solidification area.

Primary and secondary spent resins are transferred from their respective holdup tanks to either a disposable liner in the solidification area or a liner in the truck bay. A process shield or a DOT cask may be used when activity or exposure dictates. The resins may then be either solidified or dewatered for shipment. Dewater return is routed to the Excess Liquid Waste Hold up Tank, the Decon Pit Collection Tank, or the Floor Drain Tank.

Each waste transfer is immediately followed by a flush operation of the waste transfer piping and the internals of the fill head when used.

Labyrinth shield walls separate the drumming station control room, the piping process skid cubicle, and the container fill area from one another. Equipment is described in more detail in Section 11.5.3.2.

11.5.3.2 Equipment

The equipment comprising the Solid Waste System is described in Sections 11.5.3.2.1 through 11.5.3.2.6. Table 11.5-5 provides equipment design parameters.

Table 11.5-7 shows how the utility equipment, components, structures, and services that interface with the vendor-supplied solidification system comply with the applicable criteria of Regulatory Guide 1.143, Rev. 1, October 1979, “Design Guidance for Radioactive Waste Management Systems, Structures and Components Installed in Light-Water-Cooled Nuclear Power Plants” and Branch Technical Position ETSB 11-3, Rev. 2, July 1981, “Design Guidance for Solid Radioactive Waste Management Systems Installed in Light-Water-Cooled Nuclear Power Plants.”

11.5.3.2.1 Waste Storage Tanks and Pumps

Tanks containing radioactive waste and wetted parts of pumps are fabricated from stainless steel, type 304, except as noted. The primary spent resin storage tank and pump are described in Section 11.2. Other radwaste tanks and pumps are the Nuclear Blowdown spent resin storage tank and Nuclear Blowdown spent resin storage tank pump.

The spent resin storage tank and the associated pump are located in the Auxiliary Building at floor elevation 412’. The waste holdup tank and the associated pump are located at floor elevation 374’.

The resin transfer lines are sloped to avoid low points in the piping. Also, 5 diameter pipe bends are used from the resin tanks to the solidification area. These long sweeping bends are necessary to avoid plugging that could occur in the inner wall of a bend. Instrument lines are kept to a minimum to avoid dead legs. All lines will be flushed with makeup water prior to any

maintenance activities. The reactor grade and non-reactor grade demineralizers located on elevation 447’ are flushed directly to liners in the truck bay at elevation 436’.

The resin and waste transfer lines are 2" nominal diameter. This size is sufficient for the desired flow rates without causing excessively large pressure drops that could result in line plugging.

11.5.3.2.2 Instrumentation and Controls

The system uses temperature, flow, pressure, and level instruments to monitor and/or control the process located throughout the system.

1. Inplant Control Panel

   The inplant control panel is a standard enclosure of NEMA 12 construction. The inplant control panel provides full operational control for resin and liquid waste transfer operations to the waste processing equipment. It is also used to interface with equipment for dewater return and for flushing operations. This panel contains switches and lights for valves and pumps which facilitate these operations.

2. Power Panel

   The power panel provides power for the operation of the various pump motors and valve motors in the system.

3. Radiation Monitoring

   Radiation monitoring is provided by portable instrumentation and/or semi-permanent radiation monitoring equipment.

11.5.3.2.3 Waste Containers and Shielding

All wastes are packaged in containers which meet DOT/NRC requirements. The containers used for solidification and resin dewatering provide appropriate connections for processing.

Higher activity wastes will be processed with the liner already in a cask located in the truck bay access. A double lid cask top will be used to limit exposure in this area. The main part of the lid shields the entire top of the cask except the immediate area required for the fill head. After the process is complete, the fill head is removed and the secondary cask lid is installed.

Final closure of all radwaste liners may be accomplished by remote handling equipment, if required. High integrity containers are remotely sealed by a hand manipulated device which screws the closure cap into the liner.

11.5.3.2.4 Contamination Control Facilities

An adjacent decontamination area is provided for cleanup of contaminated containers. Exposed surfaces of filled containers or casks are surveyed by the Health Physics Group to identify the presence of removable radioactive contamination prior to transfer to storage or shipment. Containers are decontaminated in the adjacent decontamination area, if required.

11.5.3.2.5 Handling Equipment

Equipment used for handling waste containers and equipment within the radwaste area and for truck loading includes the following:

1. One ton jib crane.
2. Three ton jib crane.
3. Twenty ton hoist and monorail.
4. Three ton bridge crane.
5. Ten ton bridge crane.

The one ton jib crane is located on a wall above the truck access floor at elevation 455’. It is used for hoisting chemicals and equipment from the truck access area to the mezzanine floor. It has a lift of 23 feet at a speed of 22 ft/min.

The three ton jib crane is located on a wall above the solidification area. It is used to handle the vendor’s fill head and other equipment. It has a 23 foot lift at a speed of 11 ft/min.

The 20 ton hoist and monorail is used to load the containers on a truck for transport to a burial site. It has a lift of 27 feet at a speed of 10 ft/min.

The three ton bridge crane is located over the radioactive filter area at floor elevation 463’. It is used in conjunction with a 3-1/2 inch thick lead filter transfer cask to remove spent radioactive filter cartridges from the filter housings located in concrete cubicles on the floor below at elevation 452’-6”. The trolley has a transfer mechanism which permits the hoist and the cask to engage a monorail which extends over the radwaste fill area. A hatch at floor elevation 463’ is removed and the hoist lowers the cask to the radwaste area at floor elevation 436’. It has a lift of 52 feet at a speed of 22 ft/min and a trolley speed of 65 ft/min.

The ten ton bridge crane is located in the hot machine shop. It is chiefly used to service the machine shop. However, a portion of the floor area in the machine shop is partitioned from the rest of the shop for storage of unused containers, 55 gallon drums, pallets, etc. The storage area is also serviced by this crane. The hoist has a lift of 24 feet at either 7 or 20 ft/min. The trolley has a speed of either 32-1/2 or 65 ft/min.

11.5.3.2.6 Waste Compactors

One waste compactor is available for use and is capable of handling 90 cubic feet of waste in one compaction.

11.5.3.2.6.1 Normal Use Compactor

An electromechanical compactor with a compressive force capacity of 100,500 lbs. is used to compact dry wastes into a 90 cubic foot container. During compaction, the container is completely enclosed. A self-contained HEPA filter and blower system filters the air released in the compaction process before any air is discharged to the Fuel Handling Building Charcoal Exhaust System. An electrical interlock prevents the operation of the compactor if the door which encloses the container is not completely closed. This prevents injury to the operator and unfiltered air from escaping to the Hot Machine Shop atmosphere.

11.5.3.2.6.2 Standby Compactor -**No Longer In Service**-

11.5.3.2.7 Truck Loading Features

A wall penetration is provided between the fill and truck access area to fill directly to containers on a truck. This penetration is located in the shielded cubicle of the solidification area such that exposure in the truck access is limited.

11.5.4 Expected Volumes

The expected annual volume of solid radioactive wastes together with the associated Curie content of principal nuclides to be processed are described in Sections 11.5.4.1 through 11.5.4.4.

11.5.4.1 Activity Levels

The activity level of the wastes generated directly from operation of the Nuclear Steam Supply System is based upon reactor plant operation at a base load factor of 80 percent power with reactor coolant activity levels determined on the basis of fission product diffusion through cladding defects in 0.12 percent of the fuel rods. The system is conservatively designed to accommodate solid wastes generated by plant operations with up to one percent fuel defects. Source term data used for system design are presented in Section 11.1.

Table 11.5-1 lists the demineralizer resin volumes and expected volumes replaced on an average yearly basis. Table 11.5-2 presents a summary of the anticipated total solid radioactive waste generated per year. The expected activity of the solid waste at time of shipment is dependent upon the decay storage time. An isotopic breakdown of spent resin activities is presented in Table 11.5-3. The maximum activity of expended filter cartridges is given in Table 11.5-4. The associated Curie content and volume of waste shipped from a number of Westinghouse designed operating reactors is given in Table 11.5-6 for each year from 1971 through 1974.

11.5.4.2 Processed Wastes

In the case of primary spent resins, the Curie content totals approximately 1390 Ci/yr. Nuclear Blowdown System spent resins are estimated, for design purposes, to account for approximately 4.0 Curies per year.

11.5.4.3 Filter Cartridges

The volume of expended filter cartridges processed for disposal by the Solid Waste System is based upon the expected filter cartridge change frequency for potentially radioactive filters. The assumption is made that filters processing reactor coolant will require cartridge renewal due to excessive radiation levels or high ΔP.

The maximum expected activity of expended filter cartridges shipped from the site is conservatively based upon a shielding criteria of a maximum contact dose rate.

11.5.4.4 Miscellaneous Solid Wastes

The annual volume of miscellaneous solid wastes processed by the solid waste compactor is assumed to amount to 85 containers of 90 cubic feet of compacted refuse. The wastes consist of rags, coveralls, ventilation filter cartridges, and various other potentially contaminated refuse. This refuse is normally classified as low specific activity.

11.5.5 Packaging

11.5.5.1 Evaporator Bottoms and Chemical Samples -**No Longer In Service**-

11.5.5.2 Spent Resin

Resin in a demineralizer is considered spent when its decontamination factor falls below a permissible level. The spent resin, from demineralizers in the primary system, is stored in a 350 ft^3 storage tank. The spent resin from nuclear blowdown demineralizers in the secondary system is stored in a 600 ft^3 Nuclear Blowdown System storage tank. The resin stored in the primary system is normally allowed to decay for a period of up to several months.

The reactor grade water demineralizers normally contain 28 ft^3 of resin per demineralizer in each of the three demineralizers. The non-reactor grade water demineralizers contain 28 ft^3 of resin per demineralizer in each of the seven demineralizers. These ten demineralizers are located on elevation 447’ of the auxiliary building and are sluceable directly to an available liner in the truck bay. These demineralizers are flushed when the decontamination factor falls below a permissible level.

When a sufficient quantity of resin has accumulated and decayed, the resin is sampled, analyzed for isotopic constituents and activities, and packaged. Prior to packaging, nitrogen is sparged into the tank to form a slurry which is transferred to the liner by nitrogen cover gas pressure. Dewatering of the resin is accomplished using dewatering equipment with the water being

returned either to the Excess Liquid Waste Holdup Tank, the Decon Pit Collection Tank, or the Floor Drain Tank. Spent resin may also be solidified.

The radiation level of the primary resin is expected to require use of a 4 inch lead shield on some occasions. The radiation level of the Nuclear Blowdown System resin is expected to require not more than 1-1/2 inch lead shield.

The primary spent resin storage tank has a two inch discharge line located along the tank center line, protruding from its top and extending to within 3 inches above the dished bottom. In preparation for packaging, the discharge valve is opened and the center discharge tube cleared by backflush with a burst of flush water from the Reactor Makeup Water System. Pressure to 100 psig is available, if required. Flush water may continue to be added if needed to obtain a reasonable slurry. The discharge valve is then closed. Loosening of the resin is achieved by introducing nitrogen through seven spargers at the tank bottom. Resin sluice water can be recirculated through the spargers to loosen the resin if desired. When the nitrogen pressure increases to that required for resin transfer, the resin discharge valve is opened. Nitrogen continues to bubble through the resin bed to maintain a gas pressure for transfer of the resin until the liner reaches the full level. The liner vent during this operation is directed to the plant vent or to a portable ventilation unit. Similarly, the reactor grade and non-reactor grade demineralizers are flushed directly to a truck bay liner.

The Nuclear Blowdown System spent resin storage tank is discharged by use of a procedure similar to that used for the primary spent resin storage tank. The resin slurry is discharged through a 2 inch nozzle located at the tank bottom. Nitrogen gas is bubbled into the tank bottom connection to loosen and mix the resin and pressurize the tank. When the tank gas pressure increases to that required for resin transfer, the resin slurry discharge valve is opened. Operation of both tanks from this point is similar.

When the transfer is complete, the resin discharge and nitrogen supply valves are closed and a tank vent valve is opened to discharge the nitrogen cover gas from the storage tank. In addition, the flush water supply valve is opened to backflush and forward flush and decontaminate the resin transfer line. A flow diagram of the primary resin system is provided by Figure 11.2-2, Sheet 3. Figure 10.4-15 describes the nuclear blowdown resin storage.

A flow of approximately 40 gpm is required to transfer the resin slurry to the liner in the radwaste area. It is anticipated that approximately 1300 std ft^3 and 2200 std ft^3 of nitrogen gas will be the maximum required for each resin transfer operation from the 350 ft^3 primary resin storage tank and 600 ft^3 nuclear blowdown resin storage tank, respectively.

The Nitrogen System is set to supply nitrogen to the resin storage tanks at a pressure of 100 psig, if needed. The resin storage tanks are designed for 150 psig. Relief valves on the primary and nuclear blowdown resin storage tanks are set to relieve at 100 psig and 150 psig, respectively. The primary resin storage tank relieves to the waste holdup tank. The Nuclear Blowdown resin storage tank relieves to the Nuclear Blowdown System reservoir by way of an open drain.

11.5.5.3 Filter Disposal

Filters are of the disposable cartridge type contained in housings having hinged tops. They are replaced when surface dose rate or pressure drop exceeds established levels. Filters which are potentially radioactive are located in individual cubicles in an area close to the drumming station area. If the radiation level of the cartridge requires shielding during removal, a concrete plug in the floor above the housing is removed and another plug with a hole in it is placed in the stepped opening. A filter cask with 3 1/2" lead encased in stainless steel is placed over the hole. The filter housing is opened and the cartridge is drawn into the cask by the use of special tools having extension rods. Once the filter is in place, the cask bottom is closed and the tops installed. The cask is then transported by an overhead crane to a hatch at floor elevation 463' of the Auxiliary Building. This hatch is located above the drumming station area on the floor below. The cask is lowered into the drumming station area. Storage and disposal of all filters is within either high integrity containers or DOT approved containers depending on the specific activity of the filters. For filters requiring shielding, the container is stored in a shielded cask. The filter transfer cask is positioned over a small opening in the shield cask, the bottom slide is pulled open, and the filter is lowered into the shielded container. In this manner, the handling of highly contaminated filters is kept to a minimum.

11.5.5.4 Radioactive Hardware

Radioactive hardware can consist of damaged or used equipment or instruments which, due to geometry or materials of fabrication, cannot be readily decontaminated. Such material is disposed of in much the same way as are filter cartridges or as compacted waste, depending upon radiation levels.

11.5.5.5 Compacted Wastes

An electromechanical compactor provides 100,500 lbs. of compressive force for the compaction of compressible waste into 90 cubic foot containers. During compaction, the container and compacting mechanism are enclosed and the enclosure is vented to the Fuel Handling Building Charcoal Exhaust System through a HEPA filter by a blower. The blower and filter are contained within the compactor. The blower is automatically operated when the door is closed; however, a manual switch is provided so the blower may be operated without compactor operation. The compactor will not operate unless the door is closed, protecting the operator from injury and preventing escape of unfiltered air to the atmosphere.

11.5.6 Storage

Compactable waste, filled containers of compacted waste, and spent filter cartridges are stored in the shielded areas of the radwaste area or in a location determined by the Manager, Radiological Protection and Chemistry. Contaminated hardware and tools may also be stored in these rooms. Solidified waste, after solidification is complete, and dewatered resins, once dewatering is complete, may be shipped off-site for immediate burial at a licensed facility. Primary spent resins will normally have at least a one month decay period while being held in the spent resin storage tank. Secondary blowdown resins do not normally require a decay period.

If solidified waste and/or dewatered resins require storage for any reason, they will be stored in the radiation control area outside the truck access on the concrete pavement or in a location determined by the Manager, Radiological Protection and Chemistry. Waste stored in the storage area will be shielded as required by portable shields and/or casks used for shipment.

Storage areas for solidified waste, dewatered resins, and compacted waste are sufficient, based on the estimates presented in Section 11.5.4, to accommodate greater than 30 days waste generation.

11.5.7 Shipment

Shipment, in accordance with applicable regulations, is made as necessary--dependent upon operational considerations and storage area availability.

The primary activity determination method will be to sample the waste stream (resins and liquid waste) during transfer to a process container and analyze the sample using the appropriate counting instrumentation. An isotopic determination is made of the radionuclides present and the activity of each. Summation of the individual activities is used to calculate the Curie content of the processed container.

For cases where the primary method cannot be used, an alternate technique will be implemented. The alternate method entails using the dose rate of the packaged waste in order to calculate the Curie content. The calculation considers the waste characteristics, geometry of the waste package, characteristics of the container and solidification media (if applicable), and the average gamma energy. For spent cartridge filters, this alternate method will be used to determine the Curie content. The appropriate counting instrumentation is used to analyze samples taken from the process stream to identify radionuclides present and the average gamma energy.

11.5.8 Potential for Releases

11.5.8.1 Potential for Release during Container Filling

The filling operation may be terminated via visual inspection using a remote monitor/television camera. Termination is accomplished by closing valves MOV-2 and MOV-5.

There is no airborne release to the atmosphere in the fill areas. Air in the container and gas, if any, from the waste entering the container are vented to the building exhaust, through a local filter, or through a portable ventilation unit. Only one line feeds waste to the container. This is flushed with water as the final phase of the fill cycle.

If leaks of any kind or spills are observed, the operation in progress can be immediately terminated. Any spill which may occur will be contained by permanent curbing in the solidification area.

Except for the curb in the solidification area, there are no physical barriers in the immediate fill areas to contain spills. Spills from the shipping container would need to be drained to a specific location or container as determined by the type of material spilled.

The floor surfaces have a special nonporous finish to permit decontamination of the surface, if required.

11.5.8.2 Potential for Release from Storage Tanks

11.5.8.2.1 Waste Evaporator Concentrates Tank -**No Longer In Service**-

11.5.8.2.2 Chemical Drain Tank -**No Longer In Service**-

11.5.8.2.3 Primary Spent Resin Storage Tank

This tank contains only a negligible quantity of radioactive gases in the gas space. The gas is normally contained in the tank by a closed vent valve. This vent is ducted to the Auxiliary Building Exhaust System and is open only during transfer of resin from the demineralizers or at the conclusion of transferring resin from this tank to the radwaste packaging area.

Overflow is not anticipated since primary spent resin storage tank capacity is sufficient to accommodate at least 60 days waste generation under normal plant operating conditions. Overflow protection is provided by a high level alarm at the Solid Waste System control panel. Excess water can either be pumped or drained to the waste holdup tank. Overflow, if it occurs, is to the waste holdup tank through a relief valve.

The tank is enclosed within a concrete cubicle with entrance from an overhead shield slab. Any leakage is directed to the floor drain tank through a floor drain.

11.5.8.2.4 Nuclear Blowdown Spent Resin Storage Tank

This tank contains only trace amounts of radioactive gas. The gas is normally contained in the tank by a closed vent valve. The tank is vented to the cubicle, which is serviced by the building exhaust system, only during transfer of resin from the demineralizers or at the conclusion of resin transfer from this tank to the radwaste packaging area.

Overflow is not anticipated since the nuclear blowdown spent resin storage tank capacity is sufficient to accommodate at least 30 days waste generation under normal plant operating conditions.

Overflow protection is provided by a high level alarm at the Solid Waste System control panel. Excess water can either be pumped or drained to the Nuclear Blowdown System reservoir. Overflow, if it occurs, is to the Nuclear Blowdown System reservoir through a relief valve.

The tank is enclosed within a concrete cubicle with entrance from an overhead shield slab. Any leakage is directed to the Nuclear Blowdown System reservoir through a floor drain.

Table 11.5-1
Spent Resin Volumes

Demineralizer	Number	Resin Volume per Bed (ft^3)	Expected Average Resin Volume Replaced/year (ft^3)
CVCS Mixed Bed	2	30	60 (minimum)
CVCS Cation Bed	1	20	20 (minimum)
Recycle Evaporator Feed	2	30	30 (minimum)
Boron Thermal Regeneration	4	70	70
Waste Monitor Tank	1	30	540
Nuclear Blowdown			
Primary	2	150	450
Polishing	2	90	270
Spent Fuel Pool	1	54	54
Excess Liquid Waste	2	30	540
Reactor Grade Process Water	3	28	28
Non-Reactor Grade Process Water	7	28	56

Table 11.5-2
Anticipated Solid Waste Generated Per Year

	VOLUME (FT^3) (1)
Primary Spent Resins	1340
Reactor Grade Demineralizer Spent Resins	28
Non-Reactor Grade Demineralizer Spent Resins	56
Dry Waste (Compacted)	5000
Nuclear Blowdown Spent Resins	500
Spent Filters	
Primary	320
Nuclear Blowdown	160
Totals	7404

(1) Before solidification.

Table 11.5-3
Maximum Expected Concentrations of Waste to be Packaged (1)

Isotope	Spent Resin Activity (μ/cc)
Cr-51	1.9×10^{1}
Mn-54	1.9×10^{1}
Fe-55	1.3×10^{2}
Fe-59	1.6×10^{1}
Co-58	3.9×10^{2}
Co-60	1.7×10^{2}
Rb-86	3.2×10^{-1}
Sr-89	6.2
Sr-90	8.7×10^{-1}
I-131	7.9×10^{2}
Cs-134	1.1×10^{3}
Cs-136	3.5×10^{1}
Cs-137	9.0×10^{2}
Ba-140	1.0
TOTAL	3.6×10^{3}

(1) This table is based on N237 Standard.

Table 11.5-4
Maximum Expected Activities of Expended Filter Cartridge

Filter	Number of Filters	Activity Per Cartridge (Ci)					Contact Dose Rate (R/Hr) (1)
		Co-58	Co-60	Cs-134	Cs-137	Others	
Reactor Coolant	1	4.0	2.8	2.9	2.0	-	500.0
Seal Water Injection	2	5.4×10^{-1}	3.9×10^{-1}	3.8×10^{-1}	2.7×10^{-1}	-	100.0
Seal Water Return	1	8.2×10^{-1}	4.7×10^{-1}	5.7×10^{-1}	4.1×10^{-1}	-	100.0
Recycle Evaporator Feed	1	8.2×10^{-1}	4.7×10^{-1}	5.7×10^{-1}	4.1×10^{-1}	-	100.0
Waste Monitor Tank	1	8.1×10^{-1}	4.6×10^{-1}	5.8×10^{-1}	4.2×10^{-1}	-	100.0
Spent Fuel Pool	2	8.2×10^{-1}	4.7×10^{-1}	5.7×10^{-1}	4.1×10^{-1}	-	100.0
Spent Fuel Pool Skimmer	1	8.2×10^{-1}	4.7×10^{-1}	5.7×10^{-1}	4.1×10^{-1}	-	100.0
Spent Resin Sluice	1	8.1×10^{-1}	4.6×10^{-1}	5.8×10^{-1}	4.2×10^{-1}	-	100.0
Floor Drain Tank	1	8.1×10^{-1}	4.6×10^{-1}	5.8×10^{-1}	4.2×10^{-1}	-	100.0
Nuclear Blowdown							
a. Demineralizer Inlet	1	8.8×10^{-3}	8.8×10^{-3}	7.3×10^{-3}	2.1×10^{-2}		1.111
b. Demineralizer Outlet	1	1.1×10^{-2}	2.6×10^{-3}	4.8×10^{-2}	1.3×10^{-1}		3.1
c. Spent Resin Sluice	1	4.4×10^{-3}	4.0×10^{-3}	3.4×10^{-3}	1.0×10^{-2}		0.5

(1) Unshielded surface dose rate.

Table 11.5-5
Solid Waste System Equipment Design Parameters

Waste Evaporator Concentrates Tank **- No Longer In Service -**	
Waste Evaporator Concentrates Pump (XPP0052) **- No Longer In Service -**	
Nuclear Blowdown Spent Resin Storage Tank	
Quantity	1
Volume, ft^3	600
Type	Vertical
Design Pressure, psig	150
Nuclear Blowdown Spent Resin Storage Tank Sluice Pump (XPP0110)	
Quantity	1
Type	Canned Centrifugal
Design Capacity, gpm	150
Shutoff Head, ft	249
Design Pressure, psig	150
Design Operating Temperature, °F	100 - 135
Design Temperature, °F	140

Table 11.5-6
Solid Radioactive Waste Processed from Westinghouse Designed Operating Reactors

Plant	Ci (Ft^3) 1971	1972	1973	1974
Connecticut Yankee	$2.7x10^2$ ($2.2x10^3$)	$4.0x10^3$ ($3.9x10^3$)	$5.7x10^2$ ($5.6x10^3$)	$9.4x10^2$ ($7.1x10^3$)
Yankee Rowe	2.9 ($1.1x10^3$)	2.3 ($7.8x10^3$)	2.9 ($4.2x10^2$)	$1.3x10^2$ ($7.8x10^3$)
San Onofre	1.2 ($7.8x10^2$)	$8.0x10^1$ ($3.9x10^3$)	$3.8x10^2$ ($3.9x10^3$)	$2.3x10^2$ ($2.4x10^3$)
Robert E. Ginna	$4.7x10^1$ (2.5x104)	$1.4x10^3$ ($1.3x10^3$)	$6.0x10^2$ ($7.1x10^3$)	$6.1x10^2$ ($9.9x10^3$)

Note:

Annual Average Per Plant, Ci(ft^3) = 5.8 x 10^2 (5.6 x 10^3)

Table 11.5-7
Valves (GAI); Valves (Westinghouse); Equipment; Piping (GAI); Piping (Westinghouse)

TYPE	DESIGN AND FABRICATION	INSPECTION AND TESTING	MATERIALS *
	VALVES (GAI)		
Diaphragm (Dia.)	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (6/74)
Check (H_20)	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (6/74)
Dia. (auto.)	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (6/74)
Plug (auto.)	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (3/73)
Check	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (2/74)
Check (N_2)	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (6/74)
Dia. (N_2)	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (6/74)
Dia. (Control N_2)	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (6/75)
	VALVES (WESTINGHOUSE)		
Dia.	ANSI B16.5 (1968) ASME B&PV Sec. III	ANSI B16.5 (1968)	ASTM (1/73)
Dia. (auto)	ANSI B16.5 (1968) ASME B&PV Sec. III	ANSI B16.5 (1968)	ASTM (1/73)
Check	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (11/71)
Globe	ANSI B16.5 (1968)	ANSI B16.5 (1968)	ASTM (11/71)

* Dates listed under Materials refer to specification issue dates.
The ASTM Standard applicable to these dates applies.

EQUIPMENT

EQUIPMENT	SPEC. ISSUE DATE *	DESIGN AND FABRICATION	INSPECTION AND TESTING	MATERIALS *
Tank (PSRS)	/726	ASME B&PV Sec. III	ASME B&PV Sec. III	ASME B&PV Sec. III
Tank (NBSRS)	6/75	ASME Sec. VIII	ASME Sec. VIII	ASTM
Tank (PSR)	11/71	ASME Sec. III, Hydraulic Inst. Standard (HIS)	ASME Sec. III, HIS	ASME Sec. III
PUMP (NBSR)	1/74	HIS	HIS	ASTM
Filters	7/72	ASME Sec. VIII	ASME Sec. VIII	ASTM

Table 11.5-7 (continued)
Valves (GAI); Valves (Westinghouse); Equipment; Piping (GAI); Piping (Westinghouse)

EQUIPMENT	SPEC. ISSUE DATE *	DESIGN AND FABRICATION	INSPECTION AND TESTING	MATERIALS *
		PIPING (GAI)		
Waste, H_20	10/73	ANSI B31.10	ANSI B31.10	ASTM
N_2, Air	10/73	ANSI B31.10	ANSI B31.10	ASTM
		PIPING (WESTINGHOUSE)		
Waste, N_2, H_20	8/71	ANSI B31.10	ANSI B31.10	ASTM

NOTES:
CD = Chemical Drain **- No Longer In Service -**
PSRS = Primary Spent Resin Storage
NBSRS = Nuclear Blowdown Spent Resin Storage
WEC = Waste Evaporator Concentrates **- No Longer In Service -**
B&PV = Boiler and Pressure Vessel Code

Figure 11.5-1
REV. 18 - DELETED BY RN08-003, JANUARY 2011

11.6 Offsite Radiological Monitoring Program

The offsite Radiological Environmental Monitoring Program is described in The Offsite Dose Calculation Manual.

11.7 DELETED BY RN 12-005

V.C. Summer Power Station
Safety Analysis Report

Radiation Protection

Chapter 12

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 12 - RADIATION PROTECTION

NOTE: Section 12.0 is being retained for historical purposes only.

12.0 RADIATION PROTECTION

Paragraph 20.1(c) of 10 CFR 20, states that licensees should, in addition to complying with the limits set forth in that part, make every reasonable effort to maintain radiation exposures as far below the limits as practicable. The as low as practicable philosophy was followed in designing the Virgil C. Summer Nuclear Station.

This philosophy is reflected in the design by layout recommendations for pipes carrying radioactive fluids, equipment design, handling, and maintenance features. For example, pipe runs carrying radioactive fluid are arranged to minimize potential crud traps. Lines which transport spent resin are arranged with five diameter bends and continuous sloping. Piping vent and drain locations are minimized to reduce possible leakage paths and crud traps. Where possible, vents and drains are consolidated so that one vent and one drain serve several lines. Components that may require periodic maintenance are shielded from components most likely to be high radiation sources. Shielding is provided for fixed sample vessels associated with equipment stream pumps. Canned pumps are used in the liquid waste processing system (LWPS) to minimize potential leakage of radioactive fluids. Pumps requiring local start-stop or jog switches are placed in shielded cubicles. Control switches for such pumps are located outside the cubicles. Filters have lifting bails located on the heads to facilitate cartridge assembly removal and disposable cartridges for ease of changing. Demineralizers in the LWPS are considered to be potentially radioactive and are located inside individually shielded cubicles. Tanks containing radioactive waste are located in watertight compartments to contain the tank contents in the event of leakage. Heat exchangers incorporate design features that minimize exposure time during maintenance. Valves are located so that operation and maintenance can be performed from standard service equipment. Valves which normally carry radioactive fluid have leakoffs.

Equipment and/or components that may require servicing are located or designed to be movable to the lowest practicable radiation field. Penetrations through shielding walls are designed to minimize exposure. Radiation sources and normally occupied areas are separated. Pipes or ducts containing potentially highly radioactive fluids either do not pass through occupied areas or are shielded by shield slabs. Provisions are made for flushing equipment prior to maintenance where practicable. Ventilation systems are designed for easy access and service to minimize doses during maintenance, decontamination, filter changes, etc. Remote handling equipment is provided wherever practicable. Movable shields and means for their utilization are available for use as practicable. Where practicable, shielding is provided between radiation sources and areas requiring normal or routine access. As a result of operating experience, permanent removable shielding has been incorporated to minimize radiation exposure for operations and maintenance personnel in local areas such as for parts of the Residual Heat Removal and Safety Injection piping.

General guidance on the radiation protection aspects of the balance of plant design (BOP) is provided to engineers and designers by the appropriate discipline project engineer. Specific guidelines concerning BOP design are provided to the individual engineers whose specialties are radiation protection. These guidelines are based upon accumulated indepth design experience available to the architect-engineer from previously completed nuclear projects, as well as the experience acquired from frequent visits to operating nuclear plants. In addition to the design experience of the architect-engineer, conceptual shielding design guidelines are also provided from References 3, 8, and 9 (see Section 12.1.7).

BOP design is reviewed by both the architect-engineer and SCE&G personnel who are competent in radiation protection.

The review by the architect-engineer is accomplished through internal circulation of drawings and other design documents. When these documents contain design information that affects the radiation exposures to which plant workers will be subjected, they are reviewed by a group of specialists competent in radiation protection. This review results in the elimination or mitigation, to the extent practicable, of design features that would result in unnecessary radiation exposure. The individuals who have performed such reviews for the Virgil C. Summer Nuclear Station have the following position titles: Supervising Engineer, Project Engineer, Nuclear Engineer, Staff Health Physicist. Their qualifications include either a B. S. or M. S. degree in nuclear engineering, health physics or a related science, and six to ten years of experience related to radiation protection.

Westinghouse is responsive to the ALARA requirements of Regulatory Guide 8.8 and has devoted considerable effort via design and technology to minimize occupational radiation exposures due to equipment/systems/components within Westinghouse scope. Although Westinghouse does not charge the design engineers whose expertise lies in fluid dynamics, thermodynamics, etc. with radiation protection functions, Westinghouse does employ system analysis engineers, competent in the area of health physics and radiation protection, to work with those engineers in their disciplines of component or system design. Together, these personnel participate in the design review process in a systematic manner.

Following the review of design by the architect-engineer, and NSSS vendor, the design documents are similarly reviewed through internal circulation by the Applicant’s Engineering and Operations groups. Comments or changes required as a result of these reviews are incorporated or resolved prior to the issuance of the documents for construction. This review is accomplished by various engineers cognizant of radiation protection considerations assigned to the Nuclear Engineering Group, by the Staff Health Physicist, and by Station Health Physics. Qualifications of these reviewing personnel include appropriate education/degrees and experience ranging from 5 to 10 years.

Specific examples of BOP areas reviewed during the design review process and changes made in the BOP as a result of the design review include:

1. Radiation Shielding

   a. A permali shield for the push-pull rod for the out-of-core detector at the 180° reactor vessel position was added to prevent neutron streaming to an area outside the secondary shield.

   b. The gap between the reactor building and the fuel handling building was shielded to prevent streaming when spent fuel elements are transferred from the reactor building to the fuel handling building.

   c. The wall separating the mixed bed demineralizers in the chemical and volume control system (CVCS) was increased in thickness to lower the potential dose from the adjacent demineralizer.

   d. The sample sink was relocated to make it possible to put the sample lines and the sample vessels in a shielded chase.

2. Facility and Equipment Design

   a. The original design of the solid radwaste area, which did not include provisions for separation of high and low level waste, was modified to provide separate storage areas.

   b. The decontamination area in the hot machine shop was increased and additional equipment (a turbolator and additional ultrasonic sinks) was added to provide more capability for equipment and tool decontamination.

   c. The design previously included a provision for processing blowdown with minimal radioactivity through the cycle makeup demineralizers. This provision was deleted to preclude the possibility of a significant radiation source occurring in an unlimited access area.

3. Location of Instrumentation

   Two (2) monitors were relocated to lower radiation areas. Radiation monitor RM-L1 was moved from a CVCS piping area to a lower radiation area. Radiation Monitor RM-L6 was moved from a valve gallery to an operator access corridor.

   Examples of design features developed by the NSSS vendor and other features in Westinghouse PWR’s that reduce occupational radiation exposure are given in WCAP-8872, “Design, Inspection, Operation and Maintenance Aspects of the Westinghouse NSSS to Maintain Occupational Exposures as Low as Reasonably Achievable, edited by R. J. Lutz, April, 1977."

   These radiation protection design considerations have resulted in satisfying 10 CFR 20. Thus, the basic intent of Regulatory Guide 8.8 concerning as low as reasonably achievable (ALARA) is satisfied. It is the policy of the management of SCE&G that future design and construction also be accomplished in such a manner as to maintain occupational radiation exposures ALARA.

12.1 RADIATION SHIELDING

Radiation protection of plant operating personnel is accomplished by the use of adequate shielding against radiation. This radiation shielding is provided principally by concrete walls, floors, and ceilings, the thickness of which was determined by the need for access to the area, the type of radiation sources present, and structural requirements. Therefore, where structural strength is the controlling criteria, the radiation shielding provided is in excess of requirements.

NOTE: Section 12.1.1 is being retained for historical purposes only.

12.1.1 Design Objectives

The primary objective of the radiation protection systems, shielding design, and administrative controls is protection of operating personnel and the general public from potential radiation sources in the reactor, radwaste systems, and other auxiliary systems, including associated equipment and piping.

During normal operation, including anticipated operational occurrences, the design objectives for the radiation shielding are as follows:

1. To restrict the quarterly and annual doses to plant operating personnel and visiting radiation workers to within the limits set forth in 10 CFR 20. These limits are given in Table 12.1-1. Maximum whole body exposure rates are generally less than 100 mrem/hr, except in the case of certain maintenance, inspection, and refueling functions. The maximum dose rate in each instance is determined by the 10 CFR 20 quarterly restriction, by the required exposure time and by the previous and anticipated subsequent doses during the quarter.
2. To limit onsite whole body doses to nonoccupational workers and site visitors to 500 mrem/yr, with a maximum whole body dose during any given seven consecutive day period of 100 mrem. These personnel are not permitted in areas where whole body exposure rates are greater than 2.0 mrem/hr.
3. To ensure that the integrated offsite dose is within the limits specified by 10 CFR 20.
4. To protect certain components from excessive radiation damage or activation.

In the unlikely event of an accident, the radiation shielding design objectives are as follows:

1. To satisfy the requirements of 10 CFR 50, Appendix A, Criterion 19, i.e., to provide adequate radiation protection for operating personnel following a reactor accident such that the accident may be terminated without excessive radiation exposure to the operators or the general public.
2. To limit offsite doses from both contained and released radioactivity to within the limitations set forth in 10 CFR 50.67.

The above shielding objectives served as an upper limit during design of the radiation shielding. The philosophy followed during design and construction of the plant has been to give extensive consideration to the shielding design to assure that radiation exposures to personnel are kept as low as is reasonably achievable (ALARA). This philosophy has resulted in a shielding design that results in occupational and general public exposures being well within the design objectives previously listed. During the operational phase of plant life, this policy of maintaining radiation exposures at a minimum will be continued.

12.1.2 Design Description

Scaled layouts and cross sections of the Reactor Building and surrounding shield buildings and of the Auxiliary, Control, and Fuel Handling Buildings are provided by Figures 12.1-1 through 12.1-20. While these figures do show specific layout of equipment, the purpose of presenting these figures is to show specific areas in the plant which have been zoned in accordance with maximum design radiation levels and occupancy requirements. These figures will be revised only when the boundaries or designations of the radiation zones change and will not be revised to show equipment relocations, deletions, additions, etc. Figure 1.2-1 shows the total plant layout within the site boundary, as well as identifying any outside storage areas and railroad spur or siding locations.

12.1.2.1 Plant Shielding Description

Specific areas in the plant have been zoned in accordance with maximum design radiation levels and occupancy requirements. The occupancy requirements have been based on the general access requirements (as defined by an analysis of the operation of the plant and from information obtained from operating facilities) and access requirements for other operations such as maintenance, refueling, instrument calibration, and similar reoccurring activities. An explanation of each of the five zones and the maximum dose rates anticipated are given below:

Zone	Occupancy	Dose Rate (mrem/hr)
I	Uncontrolled. No restrictions on occupancy expected.	< 1.0
II	Controlled, Unlimited access, 40 hrs./week	< 2.5
III	Controlled. Limited access, 6 to 40 hrs./week.	< 15.0
IV	Limited access for short periods, 1 to 6 hrs/week.	< 100.0
V	Controlled, high radiation area, occupancy averages less than one hr/week.	> 100.0

The radiation shielding is designed to attenuate direct and scattered radiation according to the dose limits required by this zoning.

The locations of these radiation zones throughout the plant are depicted in the layouts shown by Figures 12.1-1 through 12.1-20. An equipment list is presented as Figure 1.2-28a. Figures 12.1-1 through 12.1-9 show this radiation zoning for the plant during normal operation, while Figures

12.1-10 through 12.1-18 depict this zoning for zoning of the Control Building during normal operating and shutdown periods. The radiation sources used in determining these radiation levels are defined in Section 12.1.3 and were calculated assuming fuel cladding failures of one percent. The thickness of radiation shielding in various parts of the plant is presented in Table 12.1-1A.

Plant radiation shielding is divided into six categories: primary, secondary, Reactor Building, Control Room, fuel transfer, and Auxiliary Building shielding. Each of these categories is discussed below:

1. Primary Shield

   The primary shield is a concrete structure surrounding the reactor pressure vessel. It is of varied thickness and has inspection openings (above the reactor-to-coolant pipe nozzles) and penetration ports adjacent to the core for excore neutron detectors.

   The excore neutron detector push rods penetrate the primary shield at the height of the core. Where these penetrations are not inside the secondary shield, one foot thick permali (densified beechwood laminate) shield covers are provided to preclude any neutron streaming from these penetrations.

   The inspection openings above the reactor-to-coolant pipe nozzles remain open during operation. They are closed during shutdown for refueling. The design of the reactor cavity and control rod missile shield is such that a direct exposure to plant personnel from these inspection openings or from the annular gap between the reactor vessel and primary shield is not possible. However, the scattering of neutron and gamma radiation from the Reactor Building dome will result in dose rates that range from 1 mrem/hr to 100 mrem/hr at the operating floor level. Measured dose rates in operating plants support this conclusion. Exposure of workers to these dose rates will be minimized since access to the operating floor during power operation is under strict administrative control.

   The three basic paths by which neutron and gamma radiation may stream out of the primary shield are indicated by Figure 12.1-21, with the basic locations involved as follows:

   a. Primary piping penetrations.
   b. Excore neutron detector instrumentation push rods.
   c. Vertical streaming of neutrons along the pressure vessel wall.

   Primary piping penetrations do not contribute an appreciable amount to the dose rate in any accessible area since the penetrations are only open to the inside of the secondary compartments which are inaccessible at all times during power operation.

Neutron detector push rods penetrate the primary shield in an area which is not circumscribed by the secondary shield and neutrons of energy less than 1.0 MEV stream in iron; therefore, the COHORT-II Monte Carlo computer code with a mono-directional point source directed into the inner end of the push rod was utilized to calculate a neutron removal cross Section for this particular geometry. Neutron shield covers were designed to cover the areas where the push rods exit the primary shield. The neutron dose rate outside these shield covers is estimated to be less than 50 mrem/hr.

It is well known that neutrons emanating from the core scatter up and out of the gap between the pressure vessel and the concrete primary shield, whereupon they are free to scatter to the operating elevation inside containment. The magnitude of the neutron dose rate on the operating elevation from this neutron source is strongly dependent upon the size of the gap between the pressure vessel flange and the primary shield. The gap width between the pressure vessel flange and the primary shield is only 7.25 inches. Therefore, it may be anticipated that the neutron dose rate on the operating elevation will be rather low.

Additionally, Monte Carlo calculations have been performed utilizing the COHORT-II computer code. The main feature of the geometry of the pressure vessel, primary shield, gap, nozzles, reactor cavity, and containment were incorporated. The source was conservatively assumed to be isotropic and located in the gap on the surface of the pressure vessel over the core height. Neutrons were biased in direction (going up the gap) and in energy (toward the high energy end of the spectrum). Point fluxes and resultant dose rates were obtained on the operating level using this code. These calculation estimates indicate that the neutron dose rate will be less than 100 mrem/hr on the operating level.

Primary shielding includes the following:

a. The elements inside the reactor pressure vessel, including the core baffle, core barrel, thermal shield, and water annuli.

b. The reactor vessel wall.

c. The concrete structure surrounding the reactor vessel. This structure extends from below the floor at the 412’ elevation to an elevation of 437’-2-3/4" and, at a reduced thickness except across the refueling canal, from the 437’-2-3/4" elevation up to the operating floor (elevation 463’). The shield thickness in the lower region of the primary shield ranges in thickness from 8’-8-1/4" to 13’-8-1/4", while the upper, reduced thickness portion of the shield has a thickness of 4 feet. The upper part of the primary concrete shielding is completed by the walls of the refueling canal which also extend upward to the 463’ elevation. These walls have a minimum thickness of 3 feet.

   The primary shield as a whole or in part serves to:

   (1) Attenuate the neutron flux sufficiently to prevent excessive radiation damage to the reactor vessel.

(2) Reduce the heat flux from neutron and gamma radiation at the reactor vessel outer surface such that any cooling necessary to avoid high temperatures and possible dehydration in the surrounding concrete is an easier task.

(3) Attenuate neutron and gamma fluxes to prevent excessive radiation damage and activation of plant components and structures.

(4) Reduce, in conjunction with the secondary shield, the radiation escaping the reactor vessel sufficiently to allow limited access to certain areas of the Reactor Building during normal full power operation.

(5) Reduce the radiation escaping the reactor vessel sufficiently to permit access inside the secondary shield, at a reasonable time after shutdown, for routine maintenance and inspection.

1. Secondary Shield

   The secondary shield is a series of concrete structures which enclose the reactor coolant loops and pumps, the pressurizer and pressurizer relief tank, the steam generators, and portions of the primary shield. These structures extend from the floor at the 412’ elevation to varying elevations, the highest of which is elevation 513’-6". The secondary shield is 3’-8" thick.

   The main function of the secondary shield is to reduce the dose rates from the primary coolant loops such that most areas within the Reactor Building outside the secondary shield are classified as radiation Zone IV during normal full power operation and Zone III when the plant is shut down.

2. Reactor Building

   The Reactor Building is a steel reinforced concrete structure consisting of a 4 foot thick cylindrical wall and a 3 foot thick shallow dome roof. This structure encloses the Nuclear Steam Supply System (NSSS) and serves to attenuate any radiation escaping the primary-secondary shield complex such that the radiation level in occupied areas outside the Reactor Building permits unlimited occupancy. In addition, this structure shields operating personnel and the general public from radiation sources resulting from activity released to the Reactor Building from postulated accidents. The general shielding considerations employed in the arrangement of the Reactor Building penetrations are discussed in Section 12.1.2.2.

3. Control Room Shielding

   Shielding for the Control Room is designed to satisfy the requirements of General Design Criterion 19, i.e., adequate radiation shielding is provided to permit continuous occupancy of the Control Room under accident conditions described in Regulatory Guide 1.183 (see Appendix 3A) without personnel receiving radiation exposures in excess of 5 rem TEDE for the duration of the accident. The shielding that is provided for the control room is as follows:

a. Control Building walls - each 2 feet thick.

b. Control Building roof - 2 feet thick.

c. Control Room floor - 8 inches thick.

d. Control Room ceiling - 9 inches thick between column lines G and H and 2 feet thick between column lines H and H.6 (see Figure 1.2-19).

This shielding is of ordinary concrete and is adequate to attenuate radiation from external sources (e.g., activity inside the Reactor Building, airborne activity external to the Control Room, and activity in areas surrounding the Control Building) to a small fraction of the 5 rem TEDE limit in accordance with Regulatory Guide 1.183. A more significant portion of the radiation dose to Control Room personnel during a design basis accident is due to airborne activity within the Control Room. This subject is discussed in Chapter 15.

Figures 12.1-19 and 12.1-20 present a layout and section of the Control Room.

4. Fuel Transfer Shielding

During fuel transfer operations, the refueling canal and the region above the reactor vessel are filled with borated water to an elevation of 461.5’. The water level in the fuel transfer canal and spent fuel pool in the Fuel Handling Building is also at elevation 461.5’. This water, along with the surrounding concrete, serves as radiation shielding for the spent fuel as it is removed from the core, transferred through the refueling canal and transfer tubes, stored in the spent fuel pool, and, after a decay period, loaded into a shipping cask. This water and concrete also provide shielding from activated control rod clusters and reactor internals which are removed during refueling periods. The concentration of radioactivity in the refueling water is controlled by administrative procedures and a sufficient depth of water above the fuel assembly is maintained so that the direct exposure rate at the surface of the water does not normally exceed 2.5 mrem/hr. However, certain manipulations of fuel assemblies, rod clusters, or reactor internals may produce short term exposures in excess of 2.5 mrem/hr. The fuel transfer tube is shielded to limit doses due to radiation streaming through penetrations and gaps. Lead shielding is provided in the fuel transfer tube inspection accessway inside the Reactor Building, in the gap between the refueling cavity wall and the Reactor Building liner, and in the gap between the Reactor Building and Fuel Handling Building (see Figure 12.1-22). This shielding ensures that radiation doses do not exceed 100 mrem/hr in areas adjacent to the tube during transfer of fuel inside the Reactor Building.

Lead shielding was not provided on the underside of the 3 inch gap between the Reactor Building and the cantilevered top of the retaining wall adjacent to the Reactor Building. Access to this area will be limited during refueling operations by administrative control. Radiation levels are closely monitored during refueling operations to ensure that plant personnel doses are maintained well within the limits specified by 10 CFR 20.

5. Auxiliary Building Shielding

   Shielding in the Auxiliary Building is designed to protect plant personnel from radiation from components and piping of the following systems during normal operation, including anticipated operational occurrences:

   a. Chemical and Volume Control System.
   b. Waste Processing Systems.
   c. Solid Waste Disposal System.
   d. Residual Heat Removal System.
   e. Spent Fuel Cooling System.
   f. Boron Recycle System.
   g. Sampling Systems.
   h. Nuclear Blowdown Processing System.

   Auxiliary Building shielding includes concrete floors, walls, doors, covers and/or removable blocks, and local permanent shielding such as lead plates supported by steel framing. The shielding is designed to satisfy the radiation zoning requirements set forth previously.

   Where practical, shielding is also provided between components to permit plant personnel to enter the equipment compartments under controlled conditions and perform required maintenance without shutdown or decontamination of adjacent compartments.

   Additionally, shielding design considered the location of certain manways to components to provide optimum accessibility and the best possible work area to reduce exposure time during required maintenance.

   For example, in the case of the recycle holdup tanks, entrance to the cubicle is from the 412’ elevation (bottom of tank is at elevation 388’-6") since the compartment is watertight up to a level equivalent to the maximum volume of the tank. For normal maintenance, a platform is provided around the east side of the tank. For major maintenance, such as removal of the tank diaphragm or tank cleaning, the tank will be emptied and flushed prior to the commencement of maintenance. The manway, approximately three feet above the floor (elevation 388’), is located to maximize freedom of movement into and out of the tank. The minimal increase in exposure during major maintenance to a worker walking to the manway is more than offset by the provision of the best possible work area at the manway.

12.1.2.2 Plant Shielding Design Criteria

To ensure that doses to plant personnel are kept within the limits specified in Section 12.1.1, shield walls are erected around plant components and piping which are anticipated to contain potentially significant amounts of radioactive materials. These shield walls are constructed of

ordinary concrete (density of 145 lb/ft^3) and are sized such that radiation levels are reduced to satisfy the radiation zoning requirements defined in Section 12.1.2.1. The calculational methods used to determine the thickness and other dimensions of the shield walls are discussed in Section 12.1.2.4. In cases where access to equipment enclosures is through these shield walls, shielding effectiveness is maintained through the use of labyrinth entrances. Separation of shielded components and equipment compartments, where practicable, has been utilized in efforts to limit potential exposure during plant operation. The design criterion for piping penetrations, ducts, voids, and other irregularities in the shield walls is to situate them to minimize radiation streaming from a high radiation area to low radiation areas. If the penetrations, etc., cannot be so situated, compensatory shielding (e.g., steel or lead wool, steel plates, shadow shields, etc.) are provided. Examples of use of compensatory shielding are discussed below:

1. Most of the Reactor Building penetrations are in compartmentalized penetration access areas which provide further shielding for those areas of the plant more frequently occupied. Location of equipment anticipated to require frequent attention has been minimized in these access areas.
2. A concrete shadow shield for the Reactor Building equipment hatch above the 463’ elevation is provided.
3. A shadow shield is provided for the out of core neutron detector push rod penetrations of the primary shield.
4. Most of the Auxiliary Building shield wall penetrations are located close to the ceiling of the shielded penetration access areas.

When practical, piping containing radioactive material is routed through high radiation areas where accessibility is precluded. When this is not possible, such piping is routed through shielded pipe chases which serve to reduce radiation exposure rates to plant personnel when in the vicinity of this piping. Based on operating experience additional permanent, removable local shielding has been added to local areas such as around parts of the Residual Heat Removal and Safety Injection piping to reduce radiation exposure to operation and maintenance personnel.

Piping containing highly radioactive fluid is routed by engineering as stated in Section 12.0. Changes in the routing of such piping due to field conditions must be approved by engineering. In this manner, the same controls and considerations applied to the original pipe routing are applied to the field changes. If the changes are not acceptable from the standpoint of radiation exposure, other measures, such as additional shielding, etc., are employed.

Routing of very small piping is accomplished in the same manner as is the routing of large piping. Small, safety class piping is designed and routed by engineering, not by the field.

Equipment which contains or processes radioactive fluids is so located as to cause minimal occupational dose to plant personnel. Demineralized Water Nuclear Services supplies hose fittings located approximately every 50 feet along Reactor Building, Auxiliary Building, and Fuel Handling Building access ways for decontamination.

The components of the Excess Liquid Waste System, such as filters, demineralizers, tanks, and pumps, provide illustrative examples of equipment location. These components are located in individual shielded cubicles with labyrinthine entrances if personnel entry is required (see Figure 12.1-3).

Figures 12.1-3 through 12.1-20 illustrate the location of equipment associated with systems, such as Spent Fuel Cooling, Reactor Makeup Water, Sampling, and Solid Waste Disposal, and individual items, such as the miscellaneous waste drain tank. Color codes on these figures indicate expected dose rates in various areas and the length of time such areas may be occupied (on a weekly basis) by plant personnel.

Systems processing radioactive liquids are equipped with diaphragm type, leak proof valves to minimize spillage of radioactive materials.

Elevated door stops, concrete curbs, and floor drain systems which route a spill to the proper waste processing system are employed to minimize the spread of contamination. An effort has been made to locate instruments requiring inplace calibration in the lowest practicable radiation zones.

Provisions have been made to allow for flushing of systems that may become contaminated.

Remote handling equipment and portable shielding is available on site for use when needed.

12.1.2.3 Accident Shielding

The accident shielding objective is to attenuate radiation exposures due to activity in the Reactor Building to a small fraction of 10 CFR 100 limits and to a level at which required access to onsite locations can be achieved. The shielding design review performed for NUREG-0578 addresses the limitations imposed by the post-accident radiation fields on the timely recovery from an accident due to limited personnel access capability and/or safety equipment operation degradation. The results of the shielding review are presented in Appendix 12A.

12.1.2.4 Shielding Calculational Methods

The sizing of the radiation shielding required to reduce the exposure rates from the sources defined in Section 12.1.33 to satisfy the radiation zoning defined in Section 12.1.2.1 is done using the computer codes SDC (Reference 1) or QAD6G (Reference 2) and/or hand calculations. Both SDC and the hand calculations are utilized in performing basic shielding calculations involving relatively simple geometric source configurations, such as point, line, cylinder, sphere, slab, or disk. These methods employ many of the integrations and techniques found in Reference 3. QAD6G is a point kernel code utilized in performing shielding calculations with more generalized, complex geometric configurations.

Radiation dose rates in and around shielded labyrinth entranceways to cubicles were estimated using a simplified albedo hand calculation. The wall that is directly exposed to the radiation source was divided into scattering areas. Then, using the geometrical configuration to determine

the appropriate angles, the incident dose rates on each of the scattering areas and tabulated values of concrete gamma ray albedos, an estimate of radiation dose rates at areas in and around the labyrinths can be determined. This methodology has been checked using the G3 Code (Reference 10).

Source strengths and geometric models used for equipment during the performance of shielding calculations are presented in Tables 12.1-2 through 12.1-5.

12.1.3 Source Terms

The shielding design source items are based upon the three general plant conditions of normal full power operation, shutdown, and design basis events.

12.1.3.1 Sources for Normal Full Power Operation

Design consideration has been given to the reduction of activation product formation and buildup. For example, materials with low cobalt content are specified for primary coolant system alloys. However, the availability, durability, and economics of component materials must always be considered during material procurement. High cobalt, hard facing wear materials, such as Stellite, which come in contact with the primary coolant are used only where substitute materials cannot meet performance requirements.

The process of high flow rate/high temperature filtration is not a standard practice in Westinghouse NSSS and is not planned for Virgil C. Summer Nuclear Station.

These methods of cobalt reduction along with valve design and quantities of nickel alloys in the primary system are discussed in detail in WCAP-8872, “Design, Inspection, Operation and Maintenance Aspects of the Westinghouse NSSS to Maintain Occupational Radiation Exposures as Low as Reasonably Achievable.”

To minimize exposure levels associated with valve stem leakage, packless valves are provided for those systems that normally contain radioactive fluid. These valves are designed for zero stem leakage. A metal bellows seal is used in high pressure applications; an elastomer diaphragm, in low pressure applications. For safety related diaphragm valves, a new valve design is used. This design substantially reduces maintenance requirements since diaphragm life has been increased by a factor of five.

Several features are incorporated into the design of packed valves to reduce crud buildup and maintenance requirements. These features include positive backseats to permit inline replacement of packing, lantern ring seal leakoffs, and special, close tolerance graphoil packing in lieu of conventional packing.

The main sources of radiation during normal full power operation are the reactor core, the reactor coolant, and auxiliary systems associated with the processing or handling of reactor coolant.

12.1.3.1.1 Reactor Core

The neutron fluxes at the inside surface of the primary shield concrete at the core midplane are listed in Table 12.1-6. These fluxes represent average values on the core center plane and are based upon a core axial peaking factor of 1.30. Axial variation factors for off midplane variation of neutron flux in the primary shield concrete are also listed in Table 12.1-6.

The gamma fluxes at the inside surface of the primary shield concrete at the core midplane are listed in Table 12.1-7. Values of gamma fluxes above and below the core midplane can be obtained by applying the axial variation factors which are also presented in Table 12.1-7.

12.1.3.1.2 Reactor Coolant

The main sources of activity in the reactor coolant during normal full power operation are N_{16} from coolant activation processes, fission products from fuel clad defects, and corrosion and activation products. All shielding has as its design basis the maximum case of clad defects in fuel rods producing 1.0 percent of core thermal power. Activity concentrations in the reactor coolant are listed in Table 11.1-6. The activities in the pressurizer steam and liquid phases are given in Table 11.1-4 and the pressurizer deposited sources in Table 12.1-8. The N16 activity of the coolant is given in Table 12.1-9 as a function of transport time in a reactor coolant loop.

The N-16 sources in Table 12.1-9 include the effects of irradiation of the coolant both in the core and reflector regions outside the core. Transit times around a coolant loop and within the reactor vessel are based on design flow rates and active flow volumes at 100% power operation. The transit times are included in Table 12.1-9.

12.1.3.1.3 Sources for Auxiliary Systems

The auxiliary system equipment for which a determination of shielding sources is required consists of pumps, heat exchangers, demineralizers, filters, units of evaporator packages, liquid tanks, gas tanks, and pipes. Reactor coolant activities assumed in the development of all auxiliary system source terms are given in Table 11.1-2 and are based upon 1.0 percent failed fuel.

12.1.3.1.3.1 Chemical and Volume Control System Sources

The purpose of the Chemical and Volume Control System (CVCS) is to provide continuous purification and volume control of the reactor coolant water. The major equipment items include the regenerative and letdown heat exchangers, mixed bed and cation bed demineralizers, reactor coolant filter, volume control tank, and charging pumps. The Boron Thermal Regeneration (BTR) subsystem contains the three BTR heat exchangers and the BTR demineralizers. The Seal Water subsystem for the reactor coolant pumps includes the injection and return filters and the seal water heat exchanger. The spectral source strengths in the CVCS purification letdown flow are tabulated in Table 12.1-10. The sources assume sufficient delay time from the reactor coolant loop for decay of the N16 isotope.

The radiation sources in the ion exchangers of the CVCS system are listed in Table 12.1-2. The mixed bed retains the fission product activity, both cations and anions, and the corrosion product (crud) metals. The cation bed can be used intermittently to remove lithium for pH control and to supplement the mixed bed in removing yttrium, cesium, molybdenum, and the crud metals. The Boron Thermal Regeneration beds are used to regulate the boron concentration in the reactor coolant water. They are utilized during load following operations and for removal of boron from the coolant as the nuclear fuel is depleted. These demineralizers also collect radioactive anions, such as iodine, which may have passed through the mixed bed.

The sources in the volume control tank are listed in Table 12.1-3. These sources correspond to a nominal tank operating level of 125 ft^3 in the liquid phase and 175 ft^3 in the vapor phase.

Before transferring the contents of the evaporator batch tank to the boric acid tank, a sample is taken which should satisfy two criteria:

1. A boron content of ~ 7000 ppm
2. An activity concentration of < 0.01 μc/cc

If both criteria are not satisfied, the contents are recycled through the evaporator feed demineralizers. An activity concentration of < 0.01 μc/cc in the feed to the boric acid storage tanks is the basis for not shielding the tanks and associated piping.

For filters in the CVCS system, the design criteria for handling and shielding are primarily based upon operating experience and are as follows:

1. Capability should be provided for changing filters with radiation levels of 100 R/hr at contact with the filter housing. This criterion is applicable to the following filters: seal water injection and seal water return.
2. Capability should be provided for changing the reactor coolant filter with radiation levels of 500 R/hr at contact with the filter housing.
3. The total combined exposure to personnel changing any one of the above filters should not exceed 100 mr.

The exposure rates listed in Items 1 and 2, above, are considered to be maximums, with limits controlled by periodic monitoring.

The specific source strengths of the subject filters are included in Table 12.1-4. The sources for the reactor coolant filter correspond to an exposure rate of 500 R/hr at contact. The sources for the remaining filters correspond to an exposure rate of 100 R/hr at contact. The filters are assumed to be drained of process fluid and are considered to be homogeneous sources.

The radiation sources in the heat exchangers of the CVCS system are listed in Table 12.1-5. The regenerative and excess letdown heat exchangers are located in the Reactor Building. They provide the initial cooling for the reactor coolant letdown and their sources include N16 activity.

The remaining CVCS heat exchangers are located in the Auxiliary Building where N16 activity is not a significant factor. The letdown heat exchanger provides second stage cooling for the reactor coolant prior to entering the demineralizers. The seal water heat exchanger cools water from several sources, including the reactor coolant discharged from the excess letdown heat exchangers. The activity of these heat exchangers is identical to that listed in Table 12.1-10. The thermal regeneration heat exchangers include the moderating, chiller, and letdown reheat units. The radiation sources in this equipment are modified to account for activity removed by the demineralizers upstream of the units.

12.1.3.1.3.2 Boron Recycle System Sources

The major equipment items included in the Boron Recycle System (BRS) are the recycle holdup tank and the Reactor Water Grade System Demineralizers and associated equipment, i.e., feed demineralizers and filter, condensate demineralizers and filter, and concentrates filter. Radiation sources in the various pumps are assumed to be identical to the liquid sources in the tank from which the pump takes suction.

The radiation sources in the BRS ion exchangers are listed in Table 12.1-2. The evaporator feed demineralizers are located upstream of the holdup tanks and contain resins which remove nongaseous activity from the reactor coolant directed to the holdup tanks. A decontamination factor (DF) of 10 across those beds is taken for all particulate activity.

The recycle holdup tanks are each equipped with a diaphragm. Gases which flash from the reactor coolant letdown to the holdup tanks are retained under the diaphragm until approximately 500 ft^3 of gas has accumulated. The gases are then removed to the Waste Gas System. The radiation sources in the holdup tanks are based upon an assumed letdown rate of 120 gpm to a single holdup tank with 50 percent of the volatile activity flashing into the vapor phase. These sources are listed in Table 12.1-3.

The recycle evaporator feed filter and condensate filter are located downstream of their respective demineralizers and serve to retain particulates and any resin fines which may escape from the demineralizers. The maximum radiation sources in these filters are listed in Table 12.1-4. The sources for the feed filter correspond to a radiation level of 100 R/hr at contact. The condensate filter sources result in levels of less than 1 R/hr at contact. The radiation sources in the concentrates filter correspond to an exposure rate of approximately 10 R/hr.

12.1.3.1.3.3 Waste Processing System Sources

The radiation sources in the Waste Processing System (WPS) are tabulated in Tables 12.1-2 through 12.1-5 and 12.1-11. The major equipment items in the waste gas portion are the waste gas compressors, hydrogen recombiners, and gas decay tanks. The radiation sources in this equipment are based upon cold shutdown procedures during which the radioactive gases are stripped from the reactor coolant system. Since the gases are continuously recirculated, the radiation sources in the waste gas equipment are identical.

The Liquid Waste Processing System is considered as several subsystems, based upon intended use during normal operation.

Low activity, non-reactor grade water is directed to the Floor Drain Laundry and Hot shower, or Excess Waste/Decon Pit Collection (ELWS) tanks. Normally this water is analyzed, then discharged. If activity levels prevent this, the water can be processed by a demineralizer/filter. The equipment items included in the subsystems are the floor drain tank and filter, laundry and hot shower tank and filter, excess waste holdup tank demineralizer and filter, decon pit collection tank demineralizer and filter, waste monitor tank demineralizer and filter, and two waste monitor tanks. The floor drain, waste monitor, and excess waste tanks provide surge capacity for the waste holdup tank during periods when abnormal volumes of liquid waste are encountered. Hence, for shielding purposes, the radiation sources in these tanks are assumed to be the same, i.e., degassed reactor coolant. Similarly, the sources in the floor drain tank filter are based on degassed reactor coolant. The sources in the waste monitor tank demineralizer and filter are based upon circulating reactor coolant through these components.

Maximum radiation sources in demineralizers of the WPS and ELWS are presented in Table 12.1-2. Radioactive spent resins, discharged from the various demineralizers, are retained in the spent resin storage tank. Mixed bed demineralizers contain the most radioactive resin discharged to the spent resin storage tank. These sources determine the required tank shielding. The short lived activity is allowed to decay (approximately 30 days) and the resin is then directed to the drumming station for packaging. The associated equipment includes the spent resin storage tank and the resin sluice pump and filter. The resin sluice filter is shielded for radiation levels of 100 R/hr at contact.

The waste monitor tank demineralizer can be used to remove activity admitted to the waste monitor tanks.

The maximum radiation sources in the various filters of the WPS and ELWS are listed in Table 12.1-4. The waste monitor tank filter is located downstream of the demineralizer. The sources in the condensate filter result in radiation levels of approximately 1 R/hr at contact. The monitor tank filter sources produce approximately 85 R/hr at contact. The maximum radiation levels in the spent resin sluice and floor drain tank filters are 100 R/hr at contact.

Radiation sources in the various pumps of the WPS and ELWS are assumed to be identical to the liquid sources in the tank from which the pump takes suction.

Sources in the laundry and hot shower tank and filter and in the waste condensate tank are negligible. Therefore, these items do not require shielding.

Sources of solid waste for the drumming station are given in Table 12.1-11. A description of the solid waste system is given in Section 11.5.

12.1.3.1.3.4 Sources for Blowdown Systems

Radiation sources for equipment in the Steam Generator Blowdown and Nuclear Blowdown Processing Systems are presented in Tables 12.1-2 through 12.1-5.

The major equipment items in these systems are the steam generator blowdown heat exchangers, nuclear blowdown holdup and monitor tanks, blowdown filters, blowdown demineralizers, and the blowdown spent resin storage tank. Radiation sources are based upon one percent failed fuel and a maximum steam generator tube leakage rate of 0.1 gpm.

12.1.3.1.3.5 Sources for Spent Fuel Cooling Systems

The radiation sources in the spent fuel demineralizer and filter are listed in Tables 12.1-2 and 12.1-4, respectively. This equipment is used to maintain water clarity and remove activity released during refueling operations and the subsequent fuel cooling period. The filter sources correspond to an exposure rate of 100 R/hr at contact. The spent fuel pool skimmer is used only for cleaning the surface of the spent fuel pool water and does not require shielding.

12.1.3.2 Sources for Shutdown

12.1.3.2.1 Primary System Sources at Shutdown

The core gamma sources after shutdown are used to establish radiation shielding requirements during refueling operations and during shipment of spent fuel. The sources associated with the spent fuel are based upon an average power assembly with an irradiation time of 108 seconds (3.1 years). These source strengths per unit volume of homogenized core are listed in Table 12.1-12 for various times after shutdown.

The irradiated control rod sources are used in establishing radiation shielding requirements during refueling operations and during shipment of irradiated control rods. The absorber material used in the control rods is silver-indium-cadmium (Ag-In-Cd). The source strengths associated with the control rods are listed in Table 12.1-13 for various times after shutdown. The values are in terms of centimeter of height of a single control rod for an irradiation period of 100,000 hours.

The Ag-In-Cd control rod sources included in Table 12.1-13 are based on an irradiation period of 100,000 hours. This design basis leads to conservative source term values since it is not expected that any control rod will spend a majority of its design life (15 years) in the inserted position.

The incore detector drive wire sources are used in establishing the radiation shielding requirements for the wires when the detectors are not in use and during shipment when the detectors have failed.

The incore drive wire sources are based on the assumption that the drive wire has been lodged in the core for one full year. These sources are tabulated in Table 12.1-14 and are conservative in that the drive wires will normally be inserted in the core for short periods of time during flux mapping.

The activities of steam generator primary side surfaces are used in determining access limitations in and around the steam generators at plant shutdown.

Estimated corrosion product deposited sources are given in Table 12.1-8 and 12.1-15. The corrosion product sources are based on the methods and equations presented in the following reference:

S. Yerazunis, E. H. Alkire and R. L. Seidel, *Mechanisms of Reactor System Activatio*n, KAPL-M-SMS-98, May, 1959.

The transport and corrosion parameters used in the calculations are selected so that the results predicted by this method reflect operating plant data. The buildup of corrosion products deposits is treated as follows:

a. Transient crud layers are assumed to exist at a nominal thickness of 50 mg/dm^2.

b. Permanent crud films are assumed to build up to 90% of their maximum thickness (nominally assumed to be 50 mg/dm^2) early in the initial cycle of operation. The remaining 10% of the deposit is then assumed to build up linearly thereafter, over the operating period.

12.1.3.2.2 Auxiliary Cooling System Sources

The maximum specific source strengths in the Residual Heat Removal System are listed in Table 12.1-16. The Residual Heat Removal System is placed in operation approximately 4 hours after the start of reactor shutdown and reduces the reactor coolant temperature to approximately 120°F within about 20 hours after the start of shutdown. The sources are maximum values with credit taken for 4 hours of activity decay and purification. Accident sources in the Residual Heat Removal System are considered separately in Section 12.1.3.3.

12.1.3.3 Sources Under Accident Conditions

The sources for accident conditions are provided in Chapter 15.

12.1.4 Area Monitoring

12.1.4.1 Design Basis

The area radiation monitors are designed to detect, indicate, annunciate, and record the radiation levels monitored at selected locations inside the plant. These locations were selected on the basis of monitoring normally occupied zones critical to plant operation, monitoring occupied areas, access corridors and fuel handling areas with potential for airborne radioactivity, and having the capability to monitor the trend of Reactor Building activity following a loss of coolant accident. These monitors provide supporting data to the surveillance of plant radiation levels as recommended by ANSI N13.2 (Reference 5) and Regulatory Guide 8.2, and as required by 10

CFR 20. Area monitor instrumentation is provided to supply information and to aid in maintaining dose rates ALARA and is not considered safety-related.

Permanently installed area radiation monitors are not provided for the containment equipment access hatch area, low level waste storage area, or high level waste storage area because of the following considerations:

1. Portable radiation monitoring equipment will be used to survey these areas or any other potentially radioactive areas prior to access by personnel.
2. Access to these areas is required infrequently and will be permitted only under the supervision of health physics personnel after issuing a radiation work permit (RWP) as described in Section 12.3.2.3.7.
3. Although Figure 12.1-5 (sheet 2 of 2) indicates that the dose rates in the low and high level waste storage areas result in classification of these areas as Zone V, the dose rates will normally be reduced to a level less than required for Zone V classification by use, as required, of shielding.

12.1.4.2 System Description

The area radiation monitors consist of eighteen fixed and one movable channel, as identified in Table 12.1-19. The area radiation monitoring instruments provide indication of proper plant operation by measurement of the gamma dose rate levels in selected areas of the plant. Reliable power for the instrumentation is obtained from the diesel backed, 120 volt instrument buses. The local audible and visual alarm are powered from the 120 volt buses. The movable channel is powered from a 120 volt outlet.

Except for the movable unit, which is equipped for local recording and indication, the measured dose rate levels are indicated and recorded on the Area Radiation Monitoring System control panel located in the Control Room. Local indication is provided for each monitor except RM-G18. Each area radiation monitor is equipped with two adjustable alarm levels (alert and high) and a channel failure and/or loss of power alarm except RM-G7. Channel RM-G7 provides the following alarms: alert, high radiation, loss of power to the alarm module. These alarms (from the fixed monitors) are connected to an annunciator panel on the Radiation Monitoring System control panel in the control room. Each area radiation monitor, except for RM-G17A&B, RM-G7, and RM-G18, is provided with a local audible and visual alarm located near the detector or local readout. The manipulator crane area monitors RM-G17A&B, each have an audible alarm in the fuel handling area. The alarm setpoints are adjustable and are dependent upon the location of the individual monitors. In general, the alert setpoint is adjusted to a level below the high setpoint to provide warning of a change in normal plant operation conditions. The high setpoint is generally established by the zone limitations established for each area. The gamma dose rate resulting from a postulated loss of coolant accident (LOCA) is monitored by the high range Reactor Building monitors, RM-G7 and RM-G18. RM-G7 and RM-G18 are located inside the containment and are designed to meet IEEE-323-1974, IEEE-344-1975, ANSI N320-1978.

Channels RM-G7 and RM-G18 are composed of a Victoreen model 877-1 stainless steel ion chamber detector and a Victoreen model 876A-1, 7-decade ratemeter. Both of these channels of instrumentation meet seismic separation and 1E power source criteria and provide the appropriate display indication, record, and alarms in the Control Room. They also meet the IEEE-323 and LOCA environmental qualification requirements. Both channels have a clear view of the operating floor area of the containment as shown in Figure 1.2-6. The response of these channels to gamma (photon) radiation at 1 mev is approximately 100% and approximately 85% at 80 kev. Based on the average gamma energy anticipated after a LOCA as shown in report NUREG CR-1237, SAND 79-2143 (January 1980), RM-G7 and RM-G18 will respond to within +8%.

Radiation Monitors RM-G7 and RM-G18 were added to the Radiation Monitoring System to meet the requirements of NUREG-0578, NUREG-0737, and Regulatory Guide 1.97, Rev. 2. These provide a diverse means of measuring the containment for high level gamma radiation. The detectors are stainless steel gamma sensitive ion-chamber that are wall mounted inside the containment above the 463 foot floor elevation, reference Figure 1.2-6. Continuous 7 - decade analog readout is provided in the Control Room Radiation Monitoring System panel with an indication range of 1 to 10^7 R/h. The detector energy response is sensitive to 60 KEV, -15% at 80 KEV and within ± 10% from 100 KEV to 3 Mev.

The analog signals are recorded on multipoint recorders which are seismically mounted on the Radiation Monitoring System panel. High gamma dose rate or channel failure is annunciated in the Control Room.

1E instrument power is obtained from the A and B-train diesel backed 120 Vac. The detector and Control Room readout have been type tested for seismic qualification to meet the requirements of IEEE-323(1974). The detector and its interface cable-connector assembly have been type tested for LOCA environment to meet Regulatory Guide 1.89. Calibration of the high range containment gamma monitors is performed during refueling and consists of verification of the readouts by a calibrated current source and by a point source verification of response of the ion-chamber detectors in the low range (approximately 10R).

The gamma dose rate in the Reactor Building manipulator crane area, during refueling, is monitored by RM-G17A and RM-G17B. Either one, upon detection of high activity or loss of signal, interlock to close the purge discharge valves (Figure 11.4-1). These monitors are not required during normal operation.

Area radiation monitor electronics have a five decade logarithmic scale with a nominal measurement accuracy of ± 25 percent of the reading. The precision is ± 15 percent at all levels. Area radiation monitors are calibrated on a routine basis and after any maintenance work is performed on the detector by exposure to a standard radioactive source with its calibration traceable, directly or indirectly, to the National Bureau of Standards. Calibration of the high range area monitor, RM-G7 and RM-G18 uses a calibrated electrical current source to verify the performance of the readouts. Functional verification of all area radiation monitors, except RM-G7 and RM-G18 is achieved by use of remotely actuated check sources (isotopic or LED signal input). Functional verification of RM-G7 and RM-G18 is achieved through use of a built-in electronic test signal.

12.1.5 Operating Procedures

The Manager, Radiological Protection and Chemistry is responsible for developing the radiation protection training program, the radiation protection program and health physics procedures to ensure that exposures of all personnel are kept within the limits of 10 CFR 20 and ALARA. These procedures and programs are developed incorporating guidance contained in Regulatory Guides 8.2, 8.8, and 8.10. Plant personnel will receive radiation protection training, the depth of which will depend upon the work assignments, individual responsibilities, and the degree of radiation hazard anticipated.

Personnel whose duties entail entering controlled areas, or directing the activities of others who enter controlled areas, are required to have radiation protection training. This training qualifies personnel to implement plans and procedures, each in his area of responsibility, to maintain doses ALARA.

Administrative controls are established to assure that procedures and requirements relating to radiation protection are followed by plant personnel.

Radiation control procedures are established for systems that contain, collect, store, or transport radioactive liquids, gases, and solids. These procedures ensure that occupational radiation exposures are ALARA. The procedures that control radiation exposure are subject to review and approval as outlined in Section 13.5. The basic principles of time, distance, and shielding are applied during operation and maintenance to ensure that personnel exposure is within limits. The following techniques are employed:

1. During initial startup, neutron and gamma dose rate surveys are performed to verify the adequacy of shielding.
2. During normal operations dose rate, surface contamination, and airborne radioactivity surveys are performed periodically throughout the plant and areas are zoned accordingly. These surveys ensure that data is available for planning operation and maintenance activities.
3. Areas are conspicuously posted in accordance with 10 CFR 20.1902 as appropriate.
4. A radiation work permit (RWP) system is employed to ensure proper administrative control over work in restricted areas. The RWP is designed to ensure that the radiation conditions are defined and that appropriate measures are taken to minimize the dose received by personnel. Section 12.3.1.3 explains the use of the RWP.
5. Extension tools are used when practicable to increase the distance from the radiation source to the worker.
6. Equipment is moved to areas of lower radiation fields for maintenance when practicable.
7. Portable shielding in the form of lead bricks, lead sheets, lead shot, high density concrete block, or steel plates is used as practicable.
8. A personnel dosimetry program, as described in Section 12.3.3, is administered by the Health Physics group to ensure compliance with 10 CFR 20.

Experience gained from the operation and maintenance of several nuclear plants with whom SCE&G has contact is used to provide a basis for further evaluation.

12.1.6 Estimates of Exposure

The estimates of exposure presented in this Section address both the peak radiation exposure rates and expected annual doses. Personnel doses are based upon the radiation zone and the anticipated occupancy requirements for that area.

12.1.6.1 Dose Rates at Selected Inplant Locations

Figures 12.1-1 through 12.1-20 illustrate the location of the various zones throughout the plant. These zones have been established using design parameters and estimated occupancy requirements. Expected radiation levels should be only a fraction of the design values. Table 12.1-20 lists selected inplant locations and the associated design dose rate for each area.

12.1.6.2 Estimates of Personnel Occupancy Requirements

Occupancy requirements throughout the plant, based upon operating experience and estimated SCE&G personnel requirements, are considered in the establishment of radiation zones described in Section 12.1.2.1. To estimate occupancy requirements, plant personnel were categorized into five groups according to work function. Table 12.1-21 lists the estimated size of each group and the estimated occupancy requirements for each group in Zones I, II, and III. Estimates were not made for Zones IV and V since routine occupancy is not anticipated in these zones during normal operation or during anticipated operational occurrences.

12.1.6.3 Estimates of Annual Man-Rem Doses

Annual doses to plant personnel are estimated based upon the assumption of 2000 hours per year work time for each employee. For each zone, the lower and upper ends of the range have been evaluated in determining man-Rem doses. It is anticipated that the general radiation levels for each zone will be equal to or less than the lower values stated for the zone although isolated higher levels will exist in certain areas within the zone.

The estimated man-Rem doses for the various categories of plant personnel as discussed in Section 12.1.6.2 are listed in Table 12.1-21. The total annual dose for plant operation is conservatively estimated to range from 72 to 364 man-Rems. From the years 1969 to 1974, operational data indicate that for all light water reactors the average dose was approximately 404 man-Rem/unit/year (Reference 6). At Virgil C. Summer Nuclear Station the man-Rem doses are maintained ALARA by utilizing applicable operational data and guidance available in the industry and from the government in conjunction with the Health Physics ALARA oriented program (see Section 12.3).

Numerous dose assessment techniques are utilized in optimizing shielding design and in maintaining radiation doses ALARA. Regulatory guidance, such as that found in Regulatory

Guide 8.8, is followed in plant design and review. Some of the specific dose assessment techniques are as follows:

1. Utilization of operational data:
   a. Operational radiation levels.
   b. Trends in radiation levels associated with years of operation, plant type, plant size, power levels, plant design, etc.
   c. Radiation zones as described by occupancy requirements and actual radiation levels.
   d. Location of components with respect to plant operability.
   e. Reliability of components.
   f. Adequacy of plant layout in terms of traffic patterns; space allocation, such as around radioactive components requiring maintenance and inspection; pipe routing, etc.
   g. Number of plant employees associated with different tasks and the resulting man-Rem doses.
2. Review equipment and instrumentation and locate in zones I and II whenever possible to minimize occupancy requirements in higher radiation zones.
3. Review of the plant design by a competent professional in radiation protection and by the utility radiation protection manager.

As indicated by Table 12.1-22 no man-Rem estimates were made for Zones IV and V. It is anticipated that entry to these zones will be primarily during plant shutdown when special maintenance will be performed. Every effort will be made to decrease the radiation dose to the maintenance personnel by utilizing temporary shielding, component decontamination, or other acceptable techniques for assuring that radiation doses are ALARA. An analysis of operational data indicates that special maintenance has contributed approximately 20 percent to the annual plant dose (Reference 6 and Reference 7). Other operations have contributed to the annual plant man-Rem dose as follows (Reference 6):

1. Routine reactor operation and surveillance, 14 percent.
2. Routine maintenance, 45 percent.
3. Inservice inspection, 2.7 percent.
4. Waste processing, 2.5 percent.
5. Refueling, 14 percent.

A further estimate of the man-Rem doses has been made by identifying specific tasks anticipated to occur at the plant. Various data from operating plants and in current publications (see References 11 through 19) were used in identifying these tasks, manpower effort required to complete each task, and the radiation levels associated with doing the work. Tables 12.1-22A and 12.1-22B list the tasks anticipated for normal operation and those expected during an outage. Tables 12.1-22C and 12.1-22D provide a breakdown of personnel that will be involved with each

of the tasks and the extent of their involvement. Special maintenance tasks have been analyzed although it is anticipated that these tasks will occur infrequently. When these tasks, such as steam generator maintenance, are performed the man-Rem dose varies directly with the conditions surrounding the maintenance and the extent of the work to be performed at the time. Therefore, because of the variability of the man-Rem dose for special maintenance, special maintenance has been excluded from the yearly personnel dose commitment (see Table 12.1-22E).

Radiation doses associated with airborne radioactivity have not been analyzed in terms of tasks due to the lack of sufficient data. Conservative estimates were made using the occupancies given in Table 12.1-21. Table 12.1-22F presents the dose rates in various parts of the plant using calculated airborne contamination levels listed in Table 12.2-1. To determine the man-Rem dose commitment from airborne activity (see Table 12.1-22G), it was assumed that the airborne radiation levels to which plant personnel will be exposed are represented by those levels for the Turbine Building (Zone I), Auxiliary Building (Zone II) and the letdown heat exchangers (Zones III through V) listed in Table 12.1-22F. No man-Rem doses were calculated using the specific concentrations for the Reactor Building since routine occupancy of this area during normal operation is not anticipated.

12.1.6.4 Doses at the Radiation Controlled Area Boundary

The Radiation Controlled Area is located within the site boundary as defined in Figure 2.1-3. Additionally, except for unusual and unanticipated situations, the Radiation Controlled Area will not extend beyond the Protected Area fence. The only normal exceptions to this are: 1) the Radiography Vault which is operated under a separate license and 2) the storage of very low level materials such as exempt sources and other materials which present no significant radiological hazards. The Radiation Controlled Area consists of the Reactor Building, Auxiliary Building, Fuel Handling Building, the west penetration access areas, the east penetration access area (412’ elevation), portions of the Intermediate Building and tendon access area, radioactive waste areas, hot maintenance areas, hot warehouse, and other areas designated by Health Physics for the purposes of radiation protection. Areas may be removed from the Radiation Controlled Area at the direction of Health Physics when operating conditions and radiation levels are such that control is not necessary for the purposes of radiation protection. The area outside the Radiation Controlled Area has been zoned less than 1 mrem/hr. It is expected that, under normal operating conditions and during anticipated operational occurrences, the radiation level outside the above mentioned Radiation Controlled Area will be only a fraction of this design level.

12.1.7 References

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NOTE: Table 12.1-1 is being retained for historical purposes.

Table 12.1-1
Dose Limits for Occupational Workers

	Maximum Dose (Rem)		
	Quarterly	Annually	Accumulated Dose
Whole body; head and trunk; active blood forming organs; lens of eyes; or gonads	3	12	5 (N-18) (1)
Hands and forearms; feet and ankles	18.75	75	
Skin of whole body	7.5	30	

(1) N equals the individual's age at last birthday.

Table 12.1-1A
Radiation Shielding Thicknesses

Equipment	Minimum Shielding Provided Between Equipment and Areas of Radiation Zone I or II (ft)
Demineralizers:	
Mixed Bed	3.50
Cation Bed	3.50
Boron Thermal Regeneration	2.50
Spent Fuel Pit	2.50
Waste Monitor Tank	3.50
NBS Primary	2.00
NBS Polishing	2.00
Excess Liquid Waste	3.00
Tanks:	
Volume Control Tank	3.50
Waste Holdup	2.50
Floor Drain	2.50
Waste Monitor	2.00
Spent Resin Storage	4.00
Catalytic Hydrogen Recombiner	2.00
Waste Gas Compressor	2.00
Gas Decay	3.50
Recycle Holdup	3.50
Reactor Coolant Drain (1)	_ (1)
NBS Holdup	2.00
NBS Monitor	2.00
NBS Spent Resin Storage	4.00

Table 12.1-1A (continued)
Radiation Shielding Thicknesses

Equipment	Minimum Shielding Provided Between Equipment and Areas of Radiation Zone I or II (ft)
Excess Waste Holdup	2.50
Decontamination Pit Collection	2.50
Pressurizer Relief	3.67 (1)
Filters	
Reactor Coolant	2.00
Seal Water Return	2.00
Seal Water Injection	2.00
Recycle Evaporator Condensate	2.00
Recycle Evaporator Concentrates	2.00
Spent Fuel Purification	2.00
Floor Drain Tank	2.00
Spent Resin Sluice	2.00
Waste Monitor Tank	2.00
Waste Evaporator Condensate	2.00
Nuclear Blowdown Demineralizer Inlet	2.00
Nuclear Blowdown System Spent Resin Sluice	2.00
Nuclear Blowdown Demineralizer Outlet	2.00
Waste Gas Drain	2.00
Excess Liquid Waste	2.00
Heat Exchangers:	
Regenerative	2.00
Letdown	2.00
Seal Water	2.00
Excess Letdown (1)	1.00 (1)
Moderating	2.00

Table 12.1-1A (continued)
Radiation Shielding Thicknesses

Equipment	Minimum Shielding Provided Between Equipment and Areas of Radiation Zone I or II (ft)
Letdown Chiller	2.00
Reactor Coolant Drain Tank (1)	_ (1)
Letdown Reheat	2.00
Spent Fuel Pit	0.00
Residual Heat Removal	3.00

(1) This equipment is inside containment and the shielding provided is not intended to lower radiation exposure rates during normal operation to values appropriate for Zone I or II designation.

Table 12.1-2
Radiation Source Terms for Demineralizers

Source	Source Location	Source Geometry	Source Volume (Ft^3)	Activity (Mev/cc-sec) for Energy (Mev) of 0.40	0.80	1.30	1.70	2.20	2.50	3.50
Mixed Bed Demineralizer (2)	AB-M	Cylinder	30.02	$1.3x10^8$	$2.6x10^8$	$3.1x10^7$	$1.3x10^7$	$3.8x10^6$	$8.7x10^4$	$1.7 x 10^5$
Cation Bed Demineralizer (1)	AB-M	Cylinder	20.00	$1.5x10^6$	$2.9x10^8$	$4.0x10^6$	$3.0x10^6$	-	-	-
Boron Thermal Regeneration Demineralizer (4)	AB-M	Cylinder	69.02	$1.0x10^6$	$6.0x10^5$	$2.3x10^5$	$1.0x10^5$	$3.8x10^4$	-	-
Evaporator Feed Demineralizer (2)	AB-M	Cylinder	30.02	$1.2x10^7$	$3.4x10^7$	$3.0x10^6$	$1.5x10^6$	$3.9x10^5$	-	-
Recycle Evaporator Condensate Demineralizer	AB-M	Cylinder	20.00	$4.6x10^4$	$2.6x10^4$	$6.3x10^3$	$2.8x10^3$	$1.2x10^3$	-	-
Spent Fuel Pool Demineralizer (1)	AB-M	Cylinder	43.08	$2.1x10^6$	$7.4x10^5$	$4.1x10^3$	$4.7x10^3$	-	-	-
Waste Evaporate Condensate Demineralizer (1)	AB-M	Cylinder	30.02	$2.8x10^4$	$1.8x10^4$	$4.3x10^3$	$1.7x10^3$	$6.5x10^2$	-	-
Waste Monitor Tank Demineralizer (1)	AB-M	Cylinder	30.02	$8.8x10^5$	$3.3x10^6$	$8.3x10^5$	$4.1x10^5$	$1.6x10^5$	-	-
NBS Primary Demineralizer (2)	AB-M	Cylinder	150.00	$3.3x10^4$	$1.2x10^5$	$1.5x10^4$	$2.4x10^2$	$6.7x10^2$	-	-
NBS Polishing Demineralizer (2)	AB-M	Cylinder	90.00	$3.3x10^4$	$1.2x10^5$	$1.5x10^4$	$2.4x10^2$	$6.7x10^2$	-	-
Excess Liquid Waste Demineralizer (2)	FB-B	Cylinder	30.00	$2.8x10^4$	$1.8x10^4$	$4.3x10^3$	$1.7x10^3$	$6.5x10^2$	-	-

Table 12.1-2 (continued)
Radiation Source Terms for Demineralizers

Source	Source Location	Source Geometry	Source Volume (Ft^3)	Activity (Mev/cc-sec) for Energy (Mev) of						
				0.40	0.80	1.30	1.70	2.20	2.50	3.50
Duratek Demineralizer (5)	AB (447')	Cylinder	(1)		(2)					

Source Location Legend

Location	Elevation
AB - Auxiliary Building	B - Basement
RB - Reactor Building	M - Mezzanine
FB - Fuel Handling Building	O - Operating Floor
Y - Yard	S - Sub-Basement

(1) For Source Volumes see Figure 11.2-5.

(2) Source Terms in Curies Provided in Table 11.2-1.

Table 12.1-3
Radiation Source Terms for Tanks

Source	Source Location	Source Geometry	Source Volume (Ft^3)	Activity (Mev/cc-sec) for Energy (Mev) of						
				0.40	0.80	1.30	1.70	2.20	2.50	3.50
Volume Control Tank (1) -VAPOR	AB-O	Cylinder	180.00	7.3×10^5	3.0×10^5	-	1.5×10^5	3.4×10^5	6.9×10^5	-
Volume Control Tank (1) -LIQUID	AB-0	Cylinder	120.00	9.3×10^4	7.5×10^4	2.3×10^4	2.7×10^4	4.2×10^4	8.7×10^4	2.0×10^3
Waste Holdup Tank (1)	AB-S	Cylinder	1,337.00	3.9×10^4	2.2×10^5	1.1×10^5	4.9×10^4	1.7×10^4	-	-
Floor Drain Tank (1)	AB-S	Cylinder	1,337.00	3.9×10^4	2.2×10^5	1.1×10^5	4.9×10^4	1.7×10^4	-	-
Waste Monitor Tank (2)	AB-0	Cylinder	668.00	3.9×10^4	2.2×10^5	1.1×10^5	4.9×10^4	1.7×10^4	-	-
Spent Resin Storage Tank (1)	AB-B	Cylinder	350.00	1.3×10^8	3.1×10^8	3.3×10^7	1.4×10^7	3.9×10^6	8.6×10^4	1.7×10^5
Catalytic Hydrogen Recombiner (2)	AB-S	Cylinder	2.02	3.6×10^5	9.1×10^4	-	7.1×10^4	1.3×10^5	3.1×10^5	-
Waste Gas Compressor (2)	AB-S	Cylinder	2.09	3.6×10^5	9.1×10^4	-	7.1×10^4	1.3×10^5	3.1×10^5	-
Gas Decay Tank (8)	AB-S	Cylinder	600.00	3.6×10^5	9.1×10^4	-	7.1×10^4	1.3×10^5	3.1×10^5	-
Recycle Holdup Tank (2) -VAPOR	AB-S	Sphere	494.00	2.8×10^5	7.8×10^4	-	5.7×10^4	1.2×10^5	2.7×10^5	-
Recycle Holdup Tank (2) -LIQUID	AB-S	Cylinder	5,120.00	4.7×10^5	5.7×10^4	1.7×10^3	3.2×10^4	1.2×10^5	1.7×10^5	-
Reactor Coolant Drain Tank (1)	RB-B	Cylinder	46.8	4.3×10^5	7.6×10^4	2.3×10^4	2.7×10^4	4.2×10^4	8.7×10^4	2.0×10^3
Nuclear Blowdown System Holdup Tank (1)	AB-M	Cylinder	1,740.00	8.4×10^1	2.9×10^2	1.0×10^2	1.7×10^1	5.2×10^1	-	-
Nuclear Blowdown System Monitor Tank (1)	AB-M	Cylinder	670.00	8.4×10^1	2.9×10^2	1.0×10^2	1.7×10^1	5.2×10^1	-	-

Table 12.1-3 (continued)
Radiation Source Terms for Tanks

Source	Source Location	Source Geometry	Source Volume (Ft^3)	Activity (Mev/cc-sec) for Energy (Mev) of 0.40	0.80	1.30	1.70	2.20	2.50	3.50
Nuclear Blowdown Spent Resin Storage Tank (1)	AB-B	Cylinder	600.00	1.3×10^8	3.1×10^8	3.3×10^7	1.4×10^7	3.9×10^6	-	-
Excess Waste Holdup Tank (1)	FB-B	Cylinder	1,340.00	3.9×10^4	2.2×10^5	1.1×10^5	4.9×10^4	1.7×10^4	-	-
Decontamination Pit Collection Tank (1)	FB-B	Cylinder	1,340.00	3.4×10^4	2.2×10^5	1.1×10^5	4.9×10^4	1.7×10^4	-	-
Pressurizer Relief Tank (1) (See Note 1)	RB-B	Cylinder	1,300.00	1.9×10^4	6.8×10^4	1.1×10^4	4.2×10^3	1.6×10^3	3.2×10^0	9.9×10^1

(1) In addition to the activity given in table, the other activities are 1.8 x 105 (mev/cc-sec) and 1.6 x 104 (mev/cc-sec) for 6.13 (mev) and 7.11 (mev), respectively.

Table 12.1-4
Radiation Source Terms for Filters

Source	Source Location	Source Geometry	Source Volume (Ft^3)	Activity (Mev/cc-sec) for Energy (Mev) of						
				0.40	0.80	1.30	1.70	2.20	2.50	3.50
Reactor Coolant Filter (1)	AB-M	Cylinder	0.40	-	5.7×10^7	1.5×10^7	-	-	-	-
Seal Water Return Filter (1)	AB-M	Cylinder	0.40	-	1.1×10^7	3.0×10^6	-	-	-	-
Seal Water Injection Filter (2)	AB-M	Cylinder	0.06	-	4.8×10^7	1.2×10^7	-	-	-	-
Recycle Evaporator Feed Filter (1)	AB-M	Cylinder	0.40	-	1.1×10^7	3.0×10^6	-	-	-	-
Recycle Evaporator Condensate Filter (1)	AB-M	Cylinder	0.04	1.6×10^5	8.0×10^4	3.3×10^4	-	-	-	-
Recycle Evaporator Concentrates Filter (2)	AB-M	Cylinder	0.04	-	1.2×10^6	-	-	-	-	-
Spent Fuel Purification Filter (2)	AB-M	Cylinder	0.40	-	5.7×10^7	1.5×10^7	-	-	-	-
Floor Drain Tank Filter (1)	AB-M	Cylinder	0.04	-	3.4×10^7	8.9×10^6	-	-	-	-
Spent Resin Sluice Filter (1)	AB-M	Cylinder	0.40	-	1.1×10^7	3.0×10^6	-	-	-	-
Waste Monitor Tank Filter (1)	AB-M	Cylinder	0.04	-	2.8×10^7	5.7×10^6	2.8×10^6	1.1×10^6	-	-
Waste Evaporator Condensate Filter (1)	AB-M	Cylinder	0.04	1.2×10^5	2.2×10^5	2.5×10^4	-	-	-	-
Laundry and Hot Shower Filter (1)	AB-S	Cylinder	0.04	-	1.1×10^7	3.0×10^6	-	-	-	-
Nuclear Blowdown Demineralizer Inlet Filter (1)	AB-M	Cylinder	0.50	3.3×10^4	1.2×10^5	1.5×10^4	2.4×10^3	6.7×10^2	-	-
Nuclear Blowdown Spent Resin Sluice Filter (1)	AB-M	Cylinder	0.50	3.3×10^4	1.2×10^5	1.5×10^4	2.4×10^3	6.7×10^2	-	-

Table 12.1-4 (continued)
Radiation Source Terms for Filters

Source	Source Location	Source Geometry	Source Volume (Ft^3)	Activity (Mev/cc-sec) for Energy (Mev) of						
				0.40	0.80	1.30	1.70	2.20	2.50	3.50
Nuclear Blowdown Demineralizer Outlet Filter (1)	AB-M	Cylinder	0.50	3.3×10^4	1.2×10^5	1.5×10^4	2.4×10^3	6.7×10^2	-	-
Waste Gas Drain Filter (1)	AB-M	Cylinder	0.04	1.9×10^6	3.6×10^5	9.1×10^4	7.1×10^4	1.3×10^5	1.3×10^5	-
Excess Liquid Waste Filter (1)	FB-B	Cylinder	0.24	-	3.4×10^7	8.9×10^6	-	-	-	-

Table 12.1-5
Radiation Source Terms for Heat Exchangers

Source	Source Location	Source Geometry	Source Volume (Ft^3)	Activity (Mev/cc-sec) for Energy (Mev) of						
				0.40	0.80	1.30	1.70	2.20	2.50	3.50
Regenerative Heat Exchanger (1)	RB-B	Cylinder	9.75	4.96×10^5	2.57×10^5	1.56×10^5	1.14×10^5	1.84×10^5	1.57×10^5	1.72×10^4
Letdown Heat Exchanger (1)	AB-B	Cylinder	48.05	1.48×10^5	8.42×10^4	5.23×10^4	3.77×10^4	6.39×10^4	4.94×10^4	5.81×10^3
Seal Water Heat Exchanger (1)	AB-B	Cylinder	27.3	1.72×10^5	9.78×10^4	6.07×10^4	4.38×10^4	7.08×10^4	5.73×10^4	6.74×10^3
Excess Letdown Heat Exchanger	RB-M	Cylinder	5.21	1.13×10^5	6.40×10^4	3.97×10^4	2.87×10^4	4.64×10^4	3.75×10^4	4.42×10^3
Moderating Heat Exchanger (1)	AB-B	Cylinder	30.90	4.80×10^5	1.10×10^5	2.30×10^4	4.10×10^4	1.30×10^5	1.70×10^5	2.00×10^3
Letdown Chiller Heat Exchanger (1)	AB-B	Cylinder	38.92	1.21×10^5	2.76×10^4	5.78×10^3	1.03×10^4	3.27×10^4	4.27×10^4	5.03×10^2
Reactor Coolant Drain Tank Heat Exchanger (1)	RB-B	Cylinder	9.97	1.66×10^5	9.45×10^4	5.87×10^4	4.24×10^4	7.17×10^4	5.54×10^4	6.52×10^3
Steam Generator Blowdown Heat Exchanger (3)	TB-B	Cylinder	75.3	1.42×10^1	5.26×10^1	2.93×10^1	6.55×10^0	1.73×10^1	6.89×10^{-1}	1.62×10^0
Letdown Reheat Heat Exchanger (1)	AB-B	Cylinder	1.92	4.80×10^5	1.10×10^5	2.30×10^4	4.10×10^4	1.30×10^5	1.70×10^5	2.0×10^3
Spent Fuel Pit Heat Exchanger (2)	AB-S	Cylinder	154.0	-	9.85×10^0	5.24×10^1	6.4×10^{-1}	-	-	-
Residual Heat Removal Heat Exchanger (2)	AB-B	Cylinder	208.3	1.32×10^5	4.90×10^4	1.66×10^4	1.09×10^4	9.42×10^3	1.58×10^4	-

Table 12.1-6
Neutron Source Term for Primary Concrete Shield

Neutron Fluxes on Inside Surface of Primary Concrete

Energy Group	Neutron Flux (Neutrons/cm2-sec)
ϕ1 (E > 1.0 Mev)	1.6×10^{9}
ϕ1 (5.53 kev < E ≤ 1.0 Mev)	2.2×10^{10}
ϕ3 (0.625 ev < E ≤ 5.53 Kev)	1.2×10^{10}
ϕ4 (E < 0.625 ev)	3.3×10^{9}

Axial Variation of Neutron Fluxes

Distance Above/Below Core Centerline (ft)	Variation Factor
0	1.0
1	1.0
2	0.99
3	0.93
4	0.76
5	0.51
6	0.30

Table 12.1-7
Gamma Source Term for Primary Concrete Shield

Gamma Fluxes on Inside Surface of Primary Concrete

Group	Flux (Mev/cm^2-sec)	Group Energy (Mev/Y)
1	6.9×10^9	7.5
2	6.2×10^9	4.0
3	3.2×10^9	2.5
4	2.0×10^9	0.8

Axial Variation of Gamma Fluxes

Distance Above/Below Core Centerline (ft)	F_a
0	1.0
1	1.0
2	0.99
3	0.93
4	0.76
5	0.51
6	0.30

Table 12.1-8
Pressurizer Deposited Activity

Isotope	Activity ($\mu ci/cm^2$)
Cr-51	9.8×10^{-2}
Mn-54	1.5×10^{-1}
Mn-56	2.2×10^{-2}
Co-58	3.8
Co-60	1.6×10^{-1}
Fe-59	1.4×10^{-1}

Table 12.1-9
Reactor Coolant N^{16} Activity

Position in Loop	Loop Transit Time (sec)	N^{16} Activity μCi/gram
Leaving core	0	132
Leaving reactor vessel	1.0	119
Entering steam generator	1.4	110
Leaving steam generator	6.6	74
Entering reactor coolant pump	7.2	70
Entering reactor vessel	7.9	65
Enter Core	10.4	52
Leaving core	11.3	132

Table 12.1-10
Radiation Source Term - Letdown Coolant

Gamma Energy (Mev/Y)	Specific Source Strength (Mev/gm-sec)
0.4	5.1×10^5
0.8	2.7×10^5
1.3	1.8×10^5
1.7	1.3×10^5
2.2	2.2×10^5
2.5	1.7×10^5
3.5	2.0×10^5

Table 12.1-11
Solid Waste Source for Drumming Station

Gamma Energy (Mev/Y)	Spent Resin Source Strength (Mev/cc-sec)
0.8	1.0×10^{8}
1.3	1.0×10^{7}

Table 12.1-12
Core Average Gamma Ray Source Strengths at
Various Times After Shutdown

Energy Group MeV / gamma	Source Strengths at Time After Shutdown (MeV / Watt-sec)								
	12 Hours	24 Hours	100 Hours	1 Week	1 Month	3 Months	6 Months	1 Year	5 Years
0.20 - 0.40	1.8e+09	1.5e+09	8.3e+08	5.9e+08	1.5e+08	5.2e+07	3.1e+07	1.8e+07	2.3e+06
0.40 - 0.90	1.1e+10	9.7e+09	6.6e+09	5.7e+09	3.6e+09	2.1e+09	1.2e+09	5.4e+08	1.5e+08
0.90 - 1.35	2.0e+09	1.4e+09	7.3e+08	5.6e+08	1.7e+08	4.8e+07	3.2e+07	2.4e+07	9.3e+06
1.35 - 1.80	3.7e+09	3.3e+09	2.7e+09	2.3e+09	6.5e+08	4.8e+07	2.0e+07	1.5e+07	2.8e+06
1.80 - 2.20	3.4e+08	2.6e+08	1.8e+08	1.5e+08	6.0e+07	2.0e+07	1.4e+07	8.6e+06	2.5e+05
2.20 - 2.60	2.4e+08	1.8e+08	1.5e+08	1.3e+08	3.9e+07	1.5e+06	1.1e+04	0	0
2.60 - 3.00	6.2e+06	3.2e+06	2.7e+06	2.3e+06	6.7e+05	2.6e+04	2.0e+02	0	0
3.00 - 4.00	4.3e+06	1.3e+06	1.1e+06	9.1e+05	2.6e+05	1.0e+04	0	0	0
Total	2.0e+10	1.6+10	1.1e+10	9.4e+09	4.7e+09	2.3e+09	1.2e+09	6.1e+08	1.7e+08

Table 12.1-13
Irradiated Ag-In-Cd Control Rod Source Strengths

Photon Energy (MeV / gamma)	Source Strength at Time After Shutdown (MeV / cm^3-sec)				
	1 Day	1 Week	1 Month	6 Months	1 Year
0.20 - 0.40	2.3e+08	2.3e+08	2.2e+08	1.4e+08	8.7e+07
0.40 - 0.90	1.1e+12	1.1e+12	1.0e+12	6.7e+11	4.1e+11
0.90 - 1.35	2.0e+11	1.9e+11	1.8e+11	1.2e+11	7.3e+10
1.35 - 1.80	3.8e+11	3.8e+11	3.5e+11	2.3e+11	1.4e+11

The absorber cross-sectional area is 0.589 square centimeters per rod.
The absorber material density is 10.17 grams per cubic centimeter.

Table 12.1-14
Irradiated Incore Detector Drive Cable Source Strengths

Energy Group MeV / gamma	Source Strength Time After Shutdown (MeV / cm^3-sec)						
	8 Hours	1 Day	1 Week	1 Month	6 Months	1 Year	5 Years
0.20 - 0.40	5.9e+08	5.8e+08	5.0e+08	2.9e+08	1.0e+07	2.9e+05	0
0.40 - 0.90	1.7e+10	1.2e+10	1.2e+10	1.1e+10	8.0e+09	5.1e+09	2.0e+08
0.90 - 1.35	1.6e+10	1.6e+10	1.5e+10	1.2e+10	5.7e+09	4.3e+09	2.6e+09
1.35 - 1.80	2.1e+07	1.1e+07	1.1e+07	8.7e+06	2.0e+06	3.4e+05	0
1.80 - 2.20	4.6e+09	6.2e+07	0	0	0	0	0
2.20 - 2.60	1.5e+08	2.0e+06	0	0	0	0	0
2.60 - 3.00	1.6e+08	2.1e+06	0	0	0	0	0
3.00 - 4.00	3.7e+07	5.1e+05	0	0	0	0	0

The drive cable effective cross-sectional area is 0.095 square centimeters.

Table 12.1-15
Deposited Corrosion Product Activity
On Steam Generator Surfaces ($\mu Ci/cm^2$)

	Operating Time (Months)				
Isotope	0	6	12	24	36
Mn-54	0.0	0.15	0.60	1.5	2.0
Mn-56	0.0	3.3	3.3	3.3	3.3
Co-58	0.0	4.5	10.2	11.0	11.0
Fe-59	0.0	1.4	3.0	3.0	3.0
Co-60	0.0	0.20	0.80	2.0	3.5

Table 12.1-16
Residual Heat Removal Loop Shutdown Source

Gamma Energy (MeV/Y)	Specific Source Strength (Sec/gm-sec)
0.4	3.5×10^5
0.8	1.3×10^5
1.3	4.4×10^4
1.7	2.9×10^4
2.2	2.5×10^4
2.5	4.2×10^4

Table 12.1-19
Area Radiation Monitors

Monitor	Function	Sensitivity	Power Source
RM-G1 Control Room	Monitor control room operational area	10^{-1} to 10^{4} mR/hr	Bus A
RM-G2 Radiochemical Lab	Monitor radiochemical lab area	10^{-1} to 10^{4} mR/hr	Bus A
RM-G3 Sampling Room	Monitor sampling room near entrance	10^{-1} to 10^{4} mR/hr	Bus B
RM-G4 Hot Machine Shop	Monitor area in hot machine shop	10^{-1} to 10^{4} mR/hr	Bus B
RM-G5 Reactor Building Personnel Access	Monitor area inside containment near access, alarm inside & outside of access	10^{-1} to 10^{4} mR/hr	Bus A
RM-G6 Reactor Building Refueling Bridge	Monitor pool area and fuel handling	10^{-1} to 10^{4} mR/hr	Bus A
RM-G7 Reactor Building High Range	Provide indication of magnitude of LOCA	1.0 to 10^{7} R/hr	Bus B
RM-G8 Fuel Handling Building Fuel Handling Bridge	Monitor pool area and fuel handling	10^{-1} to 10^{4} mR/hr	Bus B
RM-G9 Auxiliary Building Demineralizer Area	Monitor access area near demineralizers	10^{-1} to 10^{4} mR/hr	Bus A

Table 12.1-19 (continued)
Area Radiation Monitors

Monitor	Function	Sensitivity	Power Source
RM-G10 Auxiliary Building Waste Gas Decay Tank Area	Monitor corridor near tank area	10^{-1} to 10^{4} mR/hr	Bus A
RM-G11 Auxiliary Building Drumming Area	Monitor operations area	10^{-1} to 10^{4} mR/hr	Bus B
RM-G12 Auxiliary Building Waste Holdup Tank Area	Monitor corridor near tank area	10^{-1} to 10^{4} mR/hr	Bus B
RM-G13 Auxiliary Building Charging Pump Area	Monitor access corridor to pump cubicles	10^{-1} to 10^{4} mR/hr	Bus A
RM-G14 Reactor Incore Instrument Area	Monitor near seal table of incore instrumentation	10^{-1} to 10^{4} mR/hr	Bus A
RM-G15 Movable Unit	Recording backup unit	10^{-1} to 10^{4} mR/hr	120 volt outlets
RM-G16 Turbine Building	Monitor area on main operating floor	10^{-1} to 10^{4} mR/hr	Bus A
RM-G17A Reactor Building Manipulator Crane	Monitor fuel handling area during refueling & close purge supply & exhaust isolation valves on high rad.	1 to 10^{5} mR/hr	Bus A

Table 12.1-19 (continued)
Area Radiation Monitors

Monitor	Function	Sensitivity	Power Source
RM-G17B Reactor Building Manipulator Crane	Monitor fuel handling area during refueling and close purge supply and exhaust isolation valves on high rad.	1 to 10^5 mR/hr	Bus B
RM-G18 Reactor Building High Range	Provide indication of magnitude of LOCA	1 to 10^7 R/hr	Bus A

Table 12.1-20
Radiation Dose Rates in Selected Inplant Locations

Location Normal Operation and Anticipated Operational Occurrences	Design Dose Rate (mrem/hr)
Control Room	≤ 1
Reactor Building Operating Floor	≤ 100
Auxiliary Building Corridors	≤ 2.5
Valve Galleries	≤ 100
Fuel Handling Building	≤ 2.5
Radwaste Processing Area (control panel)	≤ 2.5
Health Physics Control Complex	≤ 1
Hot Machine Shop (general area)	≤ 2.5
Turbine Building	≤ 1
Service Building	≤ 1

Table 12.1-21
Estimates of Personnel Occupancy
Requirements in Specific Radiation Zones

Personnel Type	Estimated Number Required	Occupancy in Zones		
		I	II	III
Administrative	19	0.90	0.10	0
Operations	31	0.75	0.23	0.02
Maintenance	34	0.60	0.38	0.02
Technical Support	25	0.60	0.38	0.02

Table 12.1-22
Man-Rem Estimates for Normal Plant Operation,
Anticipated Operational Occurrences, and
Routine Maintenance

	Zone I (mrem/hr)		Zone II (mrem/hr)		Zone III (mrem/hr)	
Personnel Type	0	1.0	1.0	2.5	2.5	15
Administrative	0	34	4	10	0	0
Operations	0	47	14	35	3	19
Maintenance	0	41	26	65	3	20
Technical Support	0	30	19	48	3	15

TOTALS:

1. Estimated Lower Limit 72 mrem
2. Estimated Upper Limit 364 mrem

Table 12.1-22A
Man-Rem Dose Per Task - Normal Operation

Task	Est. Avg Dose Rate (mRem/hr)	Duration (manhours/ task-year)	Calculated Man-Rem/yr
Routine Patrol	2.5	1,100	3
Radiation Surveys	2.5	2,220	6
Radiation Surveys	15	725	11
Radiation Surveys	< 100	25	9
Periodic Tests, Calibrations and Inspections	2.5	625	2
Periodic Tests, Calibrations and Inspections	15	300	5
Routine Maintenance:			
Pumps	50	100	5
Valves	100	100	10
Misc. Items	40	150	6
Waste Disposal, Drumming, and Shipping	15	2,200	33
Filter Changes	25	100	3
Control Room Operation	0.1	17,500	2

Table 12.1-22B
Man-Rem Dose Per Task - Refueling Outage

Task	Est. Avg Dose Rate (mRem/hr)	Duration (manhours/ task-year)	Calculated Man-Rem/yr
Health Physics Coverage	25	750	19
Head Removal and Installation	27 (1)	1,500	40
Fuel Handling	20	400	8
Incore Instrumentation Removal and Replacement	50	200	10
Integrated Leak Rate Test	5	400	2
Inservice Inspection	75	520	39
Insulation Removal	50	200	10
Routine Maintenance:			
Pumps	50	150	8
Valves	100	150	15
Misc. Items	40	300	12
Special Maintenance:			
Steam Generator Testing and Repair	100 (1)	1,000 (2)	100 (3)
Reactor Coolant Pump Seal Inspection and Repair	80	400 (2)	32 (3)
Snubber Inspection	2.5	2,000 (2)	5 (3)
Evaporator Maintenance	60	100 (2)	6 (3)

(1) See Vance, J., Weaver, C. L., and Lepper, E. M., "A Preliminary Assessment of the Potential Impacts on Operating Nuclear Power Plants of a 500 mrem/yr Occupational Exposure Limit," report to the Nuclear Regulatory Staff of the Atomic Industrial Forum, April, 1978, for a detailed breakdown of task.
(2) Manhours/task
(3) Man-Rem

Table 12.1-22C
Percent Time of Worker Effort Per Task - Normal Operation

Task	Man-Rem/yr	Percent							
		C.R. Ops.	Plt. Ops.	Eng.	QA	Mech.	Elec.	I&C	Chem./ H.P.
Routine Patrols	3	-	70	-	-	10	10	10	-
Routine Surveys	26	-	-	-	-	-	-	-	100
Periodic Tests, Calibration and Inspections	7	-	-	5	5	25	25	25	15
Routine Maintenance	21	-	-	-	-	40	40	20	-
Waste Disposal, Drumming and Shipping	33	-	70	-	-	-	-	-	30
Filter Changes	3	-	20	-	-	40	-	-	40
Control Room Operation	2	100	-	-	-	-	-	-	-

Table 12.1-22D
Percent Time of Worker Effort Per Task - Refueling Outage

Task	Man-Rem/yr	Percent							
		C.R. Ops	Pit. Ops.	Eng.	QA	Mech.	Elec.	I&C	Chem./ H.P.
Health Physics Coverage	20	-	-	-	-	-	-	-	100
Head Removal and Installations	40	-	-	-	10	60	15	15	-
Fuel Handling	8	-	90	10	-	-	-	-	-
Incore Instrumentation Removal and Replacement	10	-	-	-	-	20	40	40	-
Integrated Leak Rate Test	2	-	50	20	-	-	-	20	10
Inservice Inspection	39	-	100	-	-	-	-	-	-
Insulation Removal	10	-	25	-	-	75	-	-	-
Routine Maintenance	35	-	-	-	-	40	40	20	-
Special Maintenance:									
Steam Generator Testing and Repair	100	-	80	-	5	15	-	-	-
Reactor Coolant Pump Seal Inspection and Repair	32	-	10	-	-	90	-	-	-
Snubber Inspection	5	-	40	-	-	60	-	-	-
Evaporator Maintenance	6	-	20	-	-	50	15	15	-

Table 12.1-22E
Calculated Man-Rem/Year Per Identified Task

	Personnel Group							
	C.R. Ops.	Plt. Ops.	Eng.	QA	Mech.	Elec.	I&C	Chem./H.P.
No. of Personnel	(12)	(19)	(5)	(2)	(18)	(8)	(8)	(18)
Normal Operation	2 (1)	25.5	2	1	12	11	7	38
Refueling Outage	-	49.7	2	4	48	24	18	21
Total (Man-Rem)	2	75.2	4	5	60	35	25	59
Dose/Individual	0.17	4.0	2	2.5	3.3	4.4	3.1	3.2

(1) Man-Rem/year; special maintenance has been excluded.

Sample Calculation: Group – Plant Operators

$Man\text{-}rem_{T1} = (DoseRate)_{Task1} (Manhours)_{Task1} (Effort)_{Task1}$

Normal Operation:

Routine Patrols: (2.5 mRem/hr) (1100 manhours) (0.7) = 1.9

Waste Disposal: (15 mRem/hr) (2200 manhours) (0.7) = 23.1

Filter Changes: (25 mRem/hr) (100 manhours) (0.2) = 0.5

Refueling Outage:

Fuel Handling: (20 mRem/hr) (400 manhours) (0.9) = 7.2

Integrated Leak Rate Test: 5 mRem/hr) (400 manhours) (0.5) = 1

In-Service Inspection: (75 mRem/hr) (520 manhours) (1) = 39

Table 12.1-22E (continued)
Calculated Man-Rem/Year Per Identified Task

Insulation Removal: (50 mRem/hr) (200 manhours) (0.25) = 2.5

Sample Calculation: Group - Plant Operators

TOTALS:

Normal Operation:	25.5 man-Rem/yr
Refueling Outage:	49.7 man-Rem/yr
Summation:	75.2 man-Rem/yr
Avg. Dose/Individual:	75.2 man-Rem/yr / 19 men = 4.0 rem/yr

Table 12.1-22F
Estimated Radiation Dose Rates From Airborne
Contamination in Specific Areas of the Plant

Plant Area	Whole Body Dose Rate, Gamma (mRem/hr)	Thyroid (mRem/hr)	Tritium Inhalation (mRad/hr)
Turbine Building	2.94-7	1.0-4	3.98-5
Auxiliary Building	8.42-3	5.7-2	1.94-3
Letdown Heat Exchanger	1.20+0	7.8	3.96-2
Reactor Building	2.77+1	1.10+2	7.13+1

Table 12.1-22G
Estimated Man-Rem Doses From Airborne Contamination

Whole Body Gamma Dose

Personnel Type	Zone 1	Zone 2	Zone 3
Administrative	1.01-5	3.20-2	0
Operations	1.37-5	1.20-1	1.49+0
Maintenance	1.20-5	2.18-1	1.63+0
Technical Support	8.82-6	1.60-1	1.20+0

Thyroid Inhalation Dose

Personnel Type	Zone 1	Zone 2	Zone 3
Administrative	3.42-3	2.17-1	0
Operations	4.65-3	8.13-1	9.67+0
Maintenance	4.08-3	1.47+0	1.06+1
Technical Support	3.00-3	1.71+0	7.8+0

Tritium Inhalation Dose

Personnel Type	Zone 1	Zone 2	Zone 3
Administrative	1.36-3	7.37-3	0
Operations	1.85-3	2.77-2	4.91-2
Maintenance	1.62-3	5.01-2	5.39-2
Technical Support	1.19-3	3.70-2	3.96-2

Sample Calculation:

$$(2.94-7\ \text{mRem/hr})\left(\frac{\text{Rem}}{1000\ \text{mRem}}\right)\left(\frac{2000\ \text{hrs}}{\text{yr}}\right)(19\ \text{people})(0.9\ \text{fraction of time in particular zone})$$
$$= 1.05-5\ \text{man-Rem/yr}$$

Table 12.1-24
Estimated Post LOCA Response of Containment Monitor RM-G7

Post LOCA Time	Estimated Radiation Inside Containment (M-Rad/hr)	Average Gamma Energy (Mev)	Anticipated Response RM-G7 (M-Rad/hr)
1-min.	.060	1.075	.049
1-hr.	3.70	0.648	3.09
12-hr.	1.50	0.466	1.22
1-day	1.20	0.458	0.96
4-day	0.84	0.488	0.66
10-day	0.46	0.507	0.36
30-day	0.31	0.543	0.25
60-day	0.26	0.577	0.22

Reference Legend for Section 12.1 Figures
Plant Radiation Zone Designations

Zone	Color Code	Description	Dose Rate (mRem/hr)
I		Uncontrolled No restrictions on occupancy expected	< 1.0 mRem/hr
II		Controlled Unlimited access, 40 hrs/week	< 2.5 mRem/hr
III		Controlled Limited access, 6 to 40 hrs/week	< 15.0 mRem/hr
IV		Limited access for short periods, 1 to 6 hrs/week	< 100 mRem/hr
V		Controlled, High Radiation Area Occupancy averages less than one hour per week	> 100 mRem/hr

Notes For Layout Drawings
Showing Radiation Color Code

Figures 12.1-12, 12.1-13, 12.1-17 and 12.1-18

The solid color of the cross-hatched areas represents the radiation zone designations during a shutdown/refueling period while the RHR system is not in operation. The cross-hatched color represents the radiation zone designations during a shutdown/refueling period while the RHR system is in operation.

Figure 12.1-16

The solid color of the cross-hatched areas represents the radiation zone designations during a shutdown/refueling period while the refueling canal and the region above the reactor vessel are flooded. The cross-hatched color represents the radiation zone designations during a shutdown/refueling period while the refueling canal and the region above the reactor vessel are not flooded.

Figure 12.1-1
FSAR FIGURE REFERENCE
DRAWING E-001-001
Figure 12.1-2
FSAR FIGURE REFERENCE
DRAWING E-001-002

Figure 12.1-2a
FSAR FIGURE REFERENCE
DRAWING E-001-002

Figure 12.1-3
FSAR FIGURE REFERENCE
DRAWING E-001-011
Figure 12.1-4
FSAR FIGURE REFERENCE
DRAWING E-001-012
Figure 12.1-5 Sht.1
FSAR FIGURE REFERENCE
DRAWING E-001-021

Figure 12.1-5 Sht.2
FSAR FIGURE REFERENCE
DRAWING E-001-021
Figure 12.1-6
FSAR FIGURE REFERENCE
DRAWING E-001-022
Figure 12.1-7
FSAR FIGURE REFERENCE
DRAWING E-001-031
Figure 12.1-8
FSAR FIGURE REFERENCE
DRAWING E-002-001
Figure 12.1-9
FSAR FIGURE REFERENCE
DRAWING E-002-002
Figure 12.1-10
FSAR FIGURE REFERENCE
DRAWING E-001-001
Figure 12.1-11
FSAR FIGURE REFERENCE
Figure 12.1-11a
FSAR FIGURE REFERENCE
DRAWING E-001-014
Figure 12.1-12
FSAR FIGURE REFERENCE
DRAWING E-001-011
Figure 12.1-13
FSAR FIGURE REFERENCE
DRAWING E-001-012
Figure 12.1-14
FSAR FIGURE REFERENCE
DRAWING E-001-021
Figure 12.1-15
FSAR FIGURE REFERENCE
DRAWING E-001-022
Figure 12.1-16
FSAR FIGURE REFERENCE
DRAWING E-001-031
Figure 12.1-17
FSAR FIGURE REFERENCE
DRAWING E-002-001
Figure 12.1-18
FSAR FIGURE REFERENCE
DRAWING E-002-002

Figure 12.1-19
WITHHOLD UNDER 10 CFR 2.390 (D) (1)

[redacted]

Figure 12.1-19a
FSAR FIGURE REFERENCE
DRAWING E-005-002

Figure 12.1-20

CONTROL COMPLEX SECTIONS
RADIATION EXPOSURE ZONES

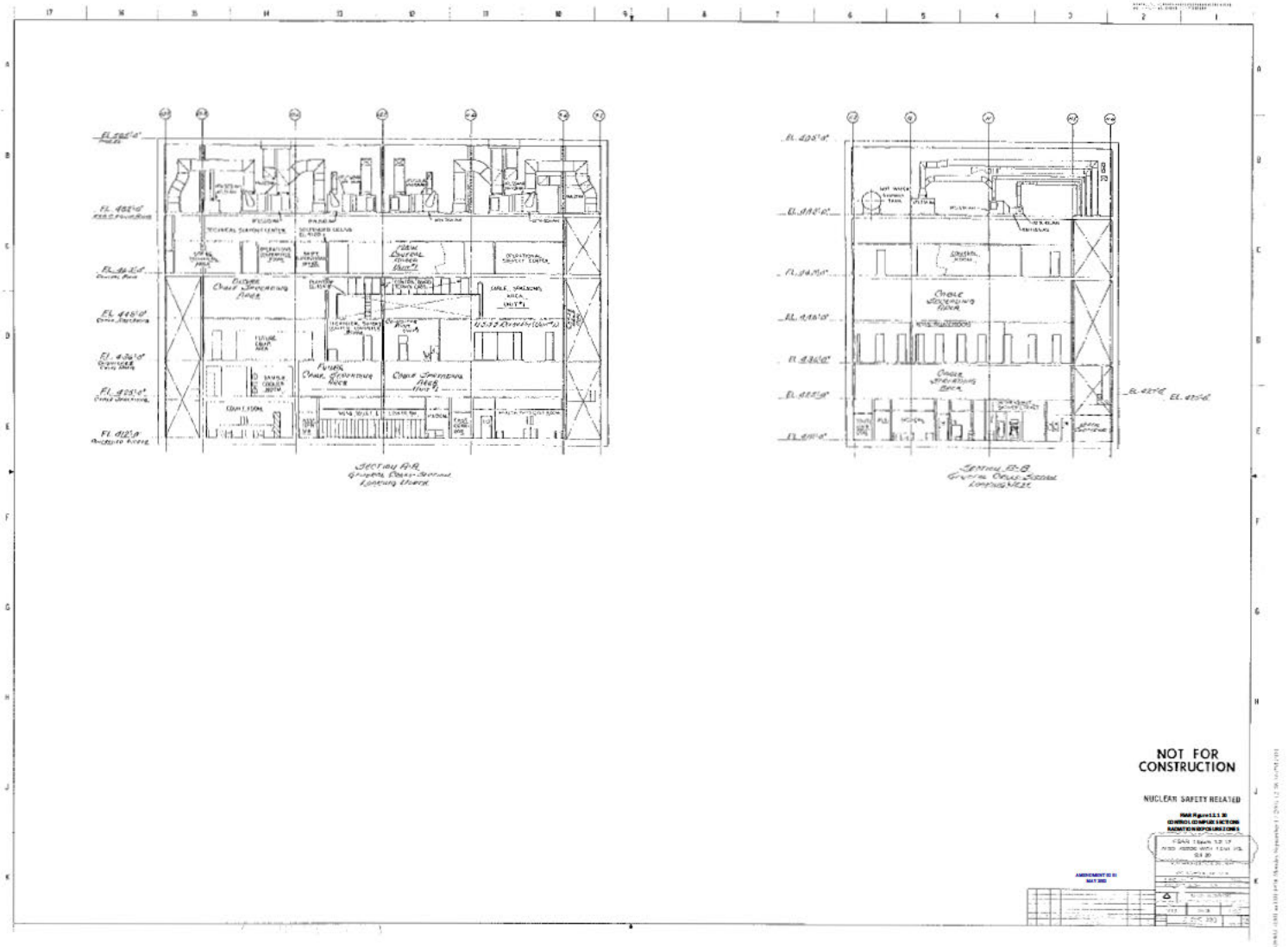
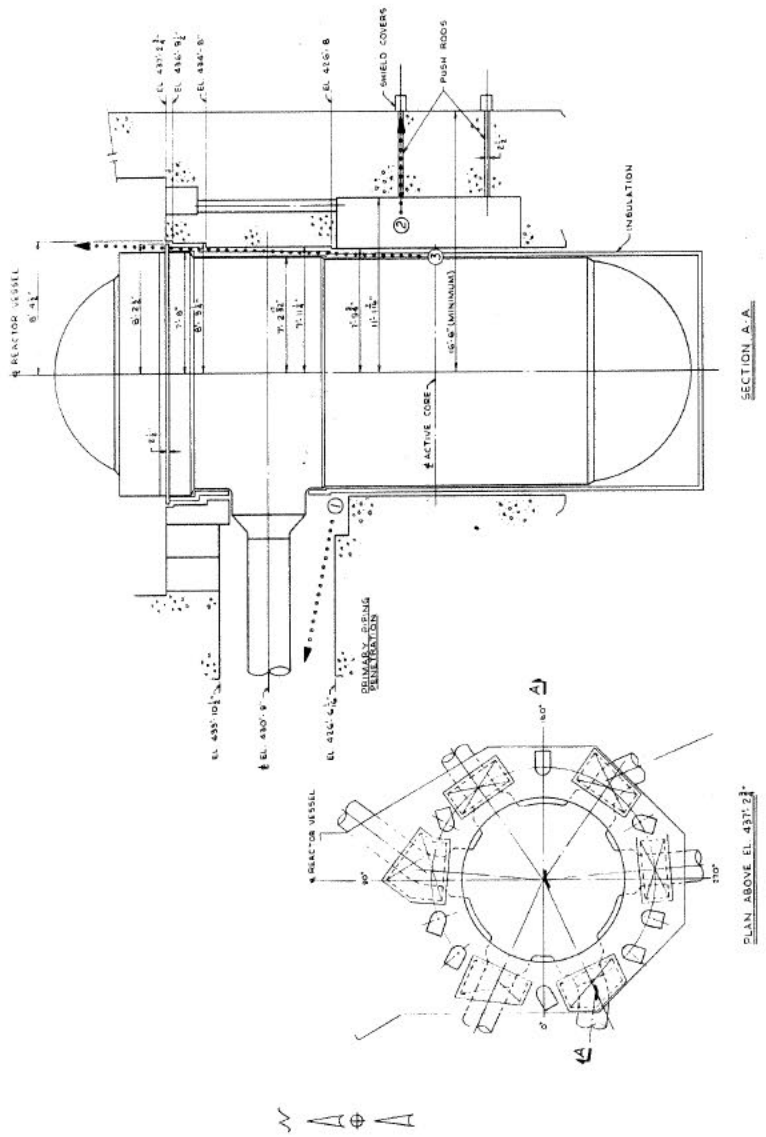


Figure 12.1-21
PRIMARY SHIELD STREAMING PATHS

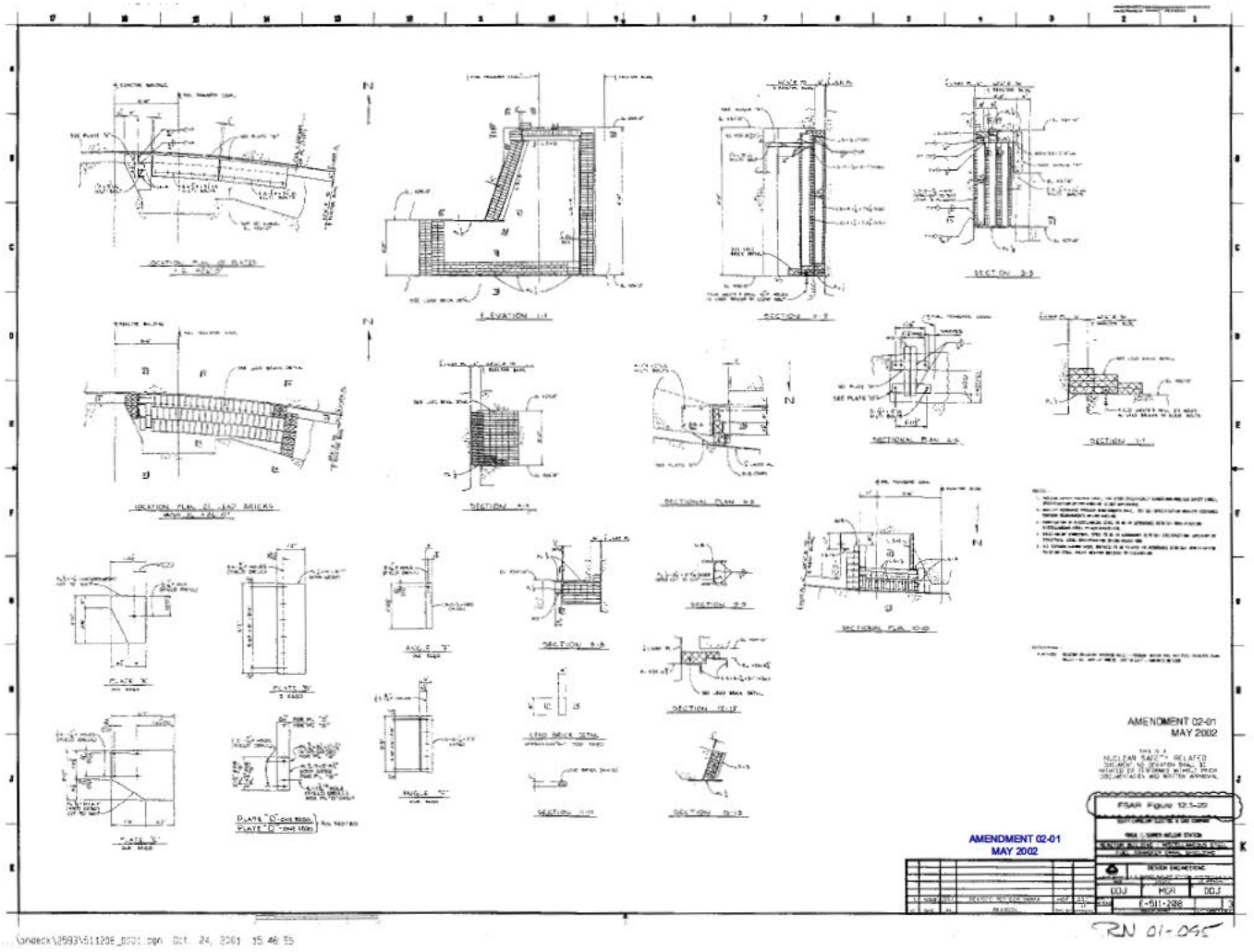


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Primary Shield Streaming Paths
Figure 12.1-21

AMENDMENT 0
AUGUST 1984

Figure 12.1-22

REACTOR BUILDING - MISCELLANEOUS STEEL
FUEL TRANSFER CANAL SHIELDING



12.2 VENTILATION

12.2.1 Design Objectives

The ventilation systems for various buildings and areas are designed to maintain ambient air temperatures suitable for personnel and equipment and to aid in minimizing radioactivity levels so that personnel are not exposed to airborne concentrations which exceed the limits of 10 CFR 20.

Calculated airborne radioactivity levels for various buildings during normal operation, including anticipated operational occurrences, are presented in Table 12.2-1, based upon the assumptions discussed in Sections 12.2.3 and 12.2.6. Calculated inhalation dose rates to personnel in various buildings are discussed in Sections 12.2.6.1.1, 12.2.6.1.2, and 12.2.6.1.3.

12.2.2 Design Description

Ventilation systems serving potentially radioactive areas and the Sections where detailed descriptions are presented are as follows:

1. Control Room Ventilation System, Section 9.4.1.2.1.
2. Controlled Access Area Exhaust System, Section 9.4.1.2.5.
3. Auxiliary and Radwaste Area Ventilation Systems, Section 9.4.2.
4. Spend Fuel Pool Area Ventilation System, Section 9.4.3.
5. Turbine Building Ventilation Systems, Section 9.4.4.
6. Reactor Building Charcoal Cleanup System, Section 9.4.8.2.4.

Air flow rates and approximate free volumes of buildings served by these ventilation systems are presented in Table 12.2-2.

The ventilation system protective features concerning airborne and effluent radioactivity and shielding are described in Sections 11.4, 12.1, 12.1.4, and 12.2.4.

Figures 1.2-15 and 12.2-1 indicate the arrangement of the control room emergency charcoal filter plenum components and available service space. Figure 12.2-1 is representative of all charcoal-HEPA filters in the plant. Test connections are provided in the duct system or housings after installation is completed.

Criteria for change of filters is dependent upon results of laboratory and field tests of filter system components. Test requirements are listed in Sections 6.5.1.4, 9.4.1.4, 9.4.2.4, 9.4.3.4, and 9.4.8.4.

Regulatory Guide 1.52 is discussed in Appendix 3A while design guidance contained in Regulatory Guide 8.8 is further described in Section 12.0.

12.2.3 Source Terms

The airborne radioactivity which workers might be exposed to during normal operations have been considered as follows:

The concentration of radioactive gases in the coolant prior to reactor vessel head removal is established based on DAC considerations and containment ventilation system capabilities of the plant. The major isotope of concern is Xe-133, since the other noble gas isotopes have either decayed away or been removed during the system degasification period. With conservative calculations, RCS activity which would result in the 10CFR20 occupational DAC in the containment atmosphere is approximately 0.1 μc/cc of Xe-133. However, operating plant experience has indicated that no problem with fission gas release to the containment atmosphere was incurred when the vessel head was removed, with the coolant Xe-133 concentration reduced to .05 μc/gm. Also, the exposure period is short so long as the containment purge is in operation during head removal.

The discharge of relief valves on lines which contain reactor coolant is piped to tanks, such as the pressurizer relief tank, volume control tank, recycle holdup tanks, reactor coolant drain tank, or waste holdup tank. Consequently, exposure of workers to airborne radioactivity from this source is precluded.

The gaseous activity released to the refueling water during the movement of spent fuel is expected to be insignificant. Fission product release from defective fuel cladding during refueling operations is a relatively slow process as compared to release during normal operation. Shutdown escape rate coefficients are several orders of magnitude below those during operation. Also, the noble gas activity inventories available for release from the defective fuel are reduced by radioactive decay during the fuel transfer operations.

Personnel entry into the Reactor Building at power will be limited to that absolutely necessary for essential operations. Appropriate radiological safety precautions will be implemented if entry into the reactor building at power is required.

The Reactor Building is normally purged prior to entry under shutdown conditions. If the shutdown is for maintenance, airborne activity is expected to be minimal. If the shutdown is for refueling, evaporation of tritiated water from the refueling cavity is expected to be the only source of airborne activity. As discussed in Section 11.1.4.3, airborne tritium concentrations during refueling will be low enough to allow 40 hour per week access to the reactor building if the tritium concentration in the refueling water is limited to 2.5 μCi/gm.

Airborne radioactivity is introduced into plant buildings when equipment processing or holding radioactive materials develops a leak. The assumed leakage rates into various buildings and the assumptions concerning the amount of radioactive material released from the leaked materials are presented in Sections 12.2.3.1 through 12.2.3.4. The values presented are based upon data presented in NUREG-0017 (Reference 1).

12.2.3.1 Assumptions Used in Determining Airborne Activity in the Reactor Building

1. Leakage to the Reactor Building is 1 percent per day of the primary coolant noble gas inventory and 0.001 percent per day of the primary coolant halogen inventory. It is conservatively assumed that the tritium leakage rate is equivalent to the noble gas leakage rate.
2. Primary coolant inventory is based upon values provided in Table 11.1-5.
3. A Reactor Building purge frequency of 24 per year is assumed.
4. Radioactive nuclides are removed between purges by radioactive decay only.

12.2.3.2 Assumptions Used in Determining Airborne Activity in the Auxiliary Building

1. Leakage to the Auxiliary Building is 160 lb/day at primary coolant activity.
2. Primary coolant inventory is based upon values provided in Table 11.1-5.
3. A partition factor of 1 is assumed for noble gases and 0.0075 for halogens.

12.2.3.3 Assumptions Used in Determining Airborne Activity in the Turbine Building

1. Leakage to the Turbine Building atmosphere is 1700 lb/hr of steam at main steam activity.
2. Main steam activity is based upon values provided in Table 11.1-5.
3. A partition factor of 1 is assumed for both noble gases and halogens.

12.2.3.4 Assumptions Used in Determining Airborne Activity in Other Buildings

All other buildings are expected to have negligible noble gas and halogen airborne activity.

12.2.4 Airborne Radioactivity Monitoring

12.2.4.1 Design Basis

The airborne radioactivity monitors are designed to detect, indicate, annunciate and record the radioactivity levels monitored at selected locations inside the plant. These monitors provide supporting data for the surveillance of plant radioactivity levels as recommended by ANSI N13.2 (Reference 2) and, Regulatory Guides 8.2 and 8.8, and as required by 10 CFR 20. Fixed continuous airborne radioactivity monitors taking particulate samples from ventilation ducts utilize isokinetic nozzles for air sampling designed according to ANSI N13.1-1969. Lengths of sample lines are minimized to reduce particulate sample loss. Sample point locations are selected to obtain an optimum mixed air sample. Areas not covered by airborne radioactivity monitors are periodically checked with movable air samplers. The Reactor Building and normally occupied areas which are considered sources of airborne activity such as the spent fuel area and the sampling room are monitored with equipment sensitive to DAC levels. Controlled access areas which contain sources of airborne activity require Health Physics air sampling prior to work in

these areas. Ventilation air flow design provides clean air for normal access corridors. These corridors are periodically monitored by portable air samplers. This monitoring instrumentation aids in maintaining airborne exposure as low as reasonably achievable (ALARA).

12.2.4.2 Airborne Radioactivity Monitors System Description

The airborne monitors consist of ten fixed and three movable channels. Some of these channels are used for effluent monitoring, as discussed in Section 11.4.

Ventilation ducts, local areas, and effluent paths are monitored in selected locations, as listed in Table 12.2-3, to provide assurance of proper plant operation.

Ventilation air flow in the Auxiliary Building is so arranged that the air flow path is in the direction of progressively greater potential contamination. This is accomplished by supplying clean air to the normally accessible areas, which are considered to be relatively free of airborne activity, and removing air from areas that could potentially have high levels of airborne activity. These areas are considered to be controlled areas, access to which is under strict administrative control. The air in the Auxiliary Building discharge path contains air from both clean and potentially contaminated areas. Thus, this air would not be representative of air breathed by personnel in the normally accessible areas regardless of whether samples are obtained upstream or downstream of the filters.

In the Fuel Handling Building, the spent fuel area could be considered as a source of airborne activity. Since this is a normally accessible area, the local air and the exhaust air prior to filtration are monitored for airborne activity as discussed in Sections 12.2.4.2.5 and 12.2.4.2.7.

In the control complex, the sampling room could be considered as a source of airborne activity. This air is monitored for airborne activity as discussed in Section 12.2.4.2.6.

Periodic surveillance of accessible areas, in accordance with Sections 12.1.5 and 12.3.2, will be performed.

Reliable power for the fixed instrumentation is obtained from the diesel backed, 120 volt instrument buses. Associated sample pumps obtain power from the 480 volt diesel backed buses. This assures continuity of operation in the event of a loss of offsite power. Measured activity levels are indicated and recorded (except RM-A11) on the Radiation Monitoring System control panel located in the control room. Local indication is provided for each channel. A differential pressure switch is provided on the particulate and iodine collection filter holders to cause an alarm on filter blockage. Another differential pressure switch is provided across the two filter holders (except on RMA-4) to cause an alarm on loss of flow. The loss of flow alarm for RMA-4 originates from the flow indication device (photohelic). The movable monitors have local indication, recording, and alarms. Detectors have remotely actuated check sources to provide functional verification. In addition, each channel is calibrated routinely by exposure to a calibrated source traceable either directly or indirectly to NIST for verification against its initial calibration. Calibration of the monitors is performed following any required maintenance of the detectors. Measurements have an accuracy of ± 25 percent of the true value. Precision is ± 15

percent at all levels. Each ratemeter is equipped with two adjustable alarm levels (alert and high) and a channel failure/or loss of power alarm. These alarms, associated with the fixed monitors, are annunciated on the Radiation Monitoring System control panel in the control room. Channels which have interlock functions with other systems (see Figure 11.4-1) are provided with a bypass switch for use during maintenance or testing. Use of this switch is annunciated.

12.2.4.2.1 Control Room Supply Air, Channel RM-A1

This channel monitors the particulate, iodine, and gaseous activity of air supplied to the control room. A sample of air is taken from the air supply duct through an isokinetic sampler nozzle and is drawn successively through a particulate sampler, an iodine sampler, and a gas sampler. The particulate sampler is equipped with a fixed filter which is continuously monitored by a lead shielded scintillator detector. The iodine sampler is similar to the particulate sampler except that an activated charcoal cartridge is used instead of a fixed filter. The fixed filter and the charcoal filter are designed to be removable for laboratory analysis. The sensitive volume of the gas sampler is shielded with lead and monitored by a scintillation detector. The approximate sensitivity and range of this channel are as follows:

1. Particulate, 4.7×10^{-11} to 10^{-7} μCi/cc based upon Cs-137.
2. Gas, 2×10^{-6} to 2×10^{-2} μCi/cc based upon Kr-85.
3. Iodine, 2×10^{-11} to 2×10^{-7} μCi/cc based upon I-131.

A high activity alarm from the gas channel automatically places the Control Room, Computer Room, Relay Room, and Instrument Repair Room Ventilation Systems in the recirculation mode, starts the Control Room Emergency Ventilation System, and closes the outside air dampers. The iodine and particulate channels provide high activity alarms to alert operating personnel. The high alarm setpoints are established on the basis of the requirements of the plant Technical Specifications and the sensitivity of the detection channels.

12.2.4.2.2 Reactor Building Air Sample Line, Channel RM-A2

This channel monitors the particulate, iodine, and gaseous activity level of the air inside the Reactor Building and is located inside the Auxiliary Building. Reactor Building air drawn from and returned through Reactor Building penetrations is monitored by RM-A2. The readout of the monitor is used to detect leaks in systems containing primary coolant. Channel ranges are similar to those of Channel RM-A1. To meet initial licensing requirements, the sensitivity of this monitor provides the capability to detect 10-MPC-hours of particulate and iodine radioactivity.

The monitor air sample and return lines are isolated (closed) upon occurrence of a containment isolation signal (Phase A). Post accident, this monitor can be used as a Reactor Building air sampling station, provided that Reactor Building pressure and temperature have been reduced sufficiently to allow opening of the sample line isolation valves. This monitor is also designed to withstand seismic conditions as recommended by Regulatory Guide 1.45.

The monitor design is similar to that of RM-A1, except that a moving particulate filter is used. An additional sample pump is also provided to allow operation when one pump is undergoing maintenance. The pumps and valves are located in a separate adjoining panel (XPN7321).

A high activity alarm from the gas channel initiates closure of the Reactor Building purge valves (see Figure 11.4-1).

High alarm setpoints are based upon plant operating requirements, sensitivity, and measured normal background.

A fixed alarm setpoint is not applicable to radiation monitoring for reactor coolant leak detection. The activity of the reactor coolant and background radiation must be taken into consideration.

The particulate and gas channels of radiation monitor RM-A2 will be operated with an initial setpoint of not less than twice background and may subsequently be readjusted based upon the changes in reactor coolant leakage and reactor building activity. Typically, the adjustments are made to provide the most sensitive response without causing an excessive number of spurious alarms. The maximum setpoint will be limited to no more than twice the operational equilibrium or operability limit defined in design calculations for the monitor, whichever is less.

12.2.4.2.3 Main Plant Vent Exhaust, Channel RM-A3

This channel is discussed in Section 11.4.2. It is used for detection of activity in the prefiltered discharge effluent from the Auxiliary Building main plant vent.

12.2.4.2.4 Reactor Building Purge Exhaust, Channel RM-A4

This channel is discussed in Section 11.4.2. It is used for detection of activity in the prefiltered purge discharge effluent from the Reactor Building.

12.2.4.2.5 Fuel Handling Building Exhaust, Channel RM-A6

This channel is used to monitor Fuel Handling Building exhaust air activity. Its function is to provide early detection of activity released. To meet initial licensing requirements, the sensitivity of this monitor provides for detection of 10-MPC-hours of particulate, iodine, and gaseous activity. A sample of the exhaust air is taken by an isokinetic nozzle located in the exhaust duct upstream of the exhaust filters. A local audible alarm is provided. The design, range, and sensitivity of this channel are similar to those of RM-A1. The high level alarm setpoints are based upon the sensitivity of the detectors and are set to alarm per the plant Technical Specifications.

12.2.4.2.6 Sampling Rooms, Channel RM-A7

Channel RM-A7 is a movable unit normally used to monitor a non-isokinetic sample of the sampling room air for particulate, iodine, and gaseous activity. Its design, range, and sensitivity are similar to those of RM-A1. The monitor may be used in other areas during refueling or as required by Health Physics personnel. The high level alarm setpoints are based upon the

sensitivity of the detectors and are normally set to provide a local high alarm upon the occurrence of activity in excess of 10 CFR 20 limitations.

12.2.4.2.7 Spent Fuel Area, Channel RM-A8

Channel RM-A8 is a movable unit similar to RM-A7. It is normally used for ambient air monitoring in the Fuel Handling Building for detection of particulate, iodine, and gaseous activity. The unit may be used in other areas at the discretion of Health Physics personnel. The alarm setpoints are based upon the sensitivity of the detectors and are normally set to provide a local high alarm upon occurrence of activity in excess of 10 CFR 20 limitations.

12.2.4.2.8 Condenser Air Removal, Channel RM-A9

This channel is discussed in Section 11.4.2. It is used for detection of activity in the effluent discharge of the Condenser Air Removal System and for detection of primary to secondary leakage.

12.2.4.2.9 Waste Gas Discharge, Channel RM-A10

This channel is discussed in Section 11.4.2. It is used to provide backup control of the batch release of waste gas from the waste gas decay tanks.

12.2.4.2.10 Auxiliary Building Ventilation Monitor, Channel RM-A11

Auxiliary Building ventilation duct air samples are monitored (see Figures 9.4-7 and 9.4-8) by a shielded scintillation detector for beta activity which is indicative of the presence of noble gases in the ventilation exhaust ducts. A pumping station is provided to sequentially obtain up to 12 different air samples from the Auxiliary Building ventilation ducts. Each of the 12 areas normally will be sequentially monitored at least once per hour. The activity of each sample is recorded locally. Indication and alarms are provided on the Radiation Monitoring System control panel in the control room. Should the sequential monitor alarm, operators in the control room can alert both individuals in the area and appropriate Health Physics personnel through the use of the Plant PA system. Should a high level alarm condition exist, appropriate Health Physics personnel can be dispatched to the specific area with portable sampling equipment. These samples will provide, on a timely basis, the information necessary to assess the airborne particulate and iodine radioactivity of the area. The approximate sensitivity and range of this channel are as follows: gas, 2×10^{-6} to 2×10^{-2} μCi/cc based upon Kr-85. Setpoints are adjusted as required by Health Physics personnel.

12.2.4.2.11 Movable Particulate Unit, Channel RM-A12

Channel RM-A12 is a movable, cart mounted unit provided to monitor and record particulate airborne activity in areas selected by Health Physics personnel. The unit provides a removable fixed particulate filter and a removable charcoal filter for laboratory analysis. The alarm setpoints

are set as required by Health Physics personnel for the zones being monitored. Sensitivity and range of the particulate monitor are approximately 10^{-11} to 10^{-7}, referenced to Cs-137.

12.2.4.3 Detection of DAC Levels of Airborne Radioiodine and Particulates

An analysis of the capability of the Airborne Radioactivity Monitoring System to detect DAC levels of airborne radioiodine and particulates in areas having potential for airborne contamination and which are normally accessed by personnel is presented in Sections 12.2.4.3.1 through 12.2.4.3.3.

The assumptions upon which this analysis is based are as follows:

1. DAC for airborne iodine is 2×10^{-8} μCi/cc.
2. DAC for airborne particulates (as cesium) is 6×10^{-8} μCi/cc.
3. Sensitivity of radiation monitor, RM-A7, is as follows:
   a. For Cs-137, 8 hour sampling, 4.7×10^{-11} μCi/cc.
   b. For I-131, 8 hour sampling, 2×10^{-11} μCi/cc.

12.2.4.3.1 Control Building

The sampling room is the area in the Control Building complex considered to have potential as a source of airborne activity. This room is sampled by a three channel radiation monitor, RM-A7, which measures airborne particulate, iodine, and gaseous activity.

It is assumed that if DAC levels of iodine and cesium activity are present in the sampling room air, the local radiation monitor, RM-A7, will detect this activity in a sampling time which is inversely proportional to the concentration:

$$\frac{\text{Monitor sensitivity}}{\text{Air concentration}} : \frac{\text{Sample time}}{8 \text{ hours}}$$

Therefore, the sample time to detect one DAC of cesium is determined as follows:

$$\text{Sample time} = \frac{4.7 \times 10^{-11} \mu\text{Ci/cc}}{6 \times 10^{-8} \mu\text{Ci/cc}} \times 8 \text{ hrs} \times \frac{60 \text{ min}}{1 \text{hr}}$$
$$= 0.38 \text{ min}$$

Assuming a high alarm setpoint at 3 times background, the time for response to one DAC of cesium would be approximately 1.1 minutes.

Similarly, the sample time to detect one DAC of iodine is determined as follows:

$$\text{Sample time} = \frac{2 \times 10^{-11} \mu\text{Ci/cc}}{2 \times 10^{-8} \mu\text{Ci/cc}} \times 8 \text{ hrs} \times \frac{60 \text{ min}}{1 \text{hr}}$$
$$= 0.48 \text{ min}$$

Assuming a high alarm setpoint at 3 times background, the time for response to one DAC of iodine would be approximately 1.4 minutes.

12.2.4.3.2 Fuel Handling Building

1. Spent Fuel Pool Floor Area

   Use of the local radiation monitor, RM-A8, would provide response times similar to the estimates used for the sampling room radiation monitor, RM-A7 (see Section 12.2.4.3.1):

Concentration	Detection Time (min)	Alarm at 3 Times Background (Min)
I-131, 2×10^{-8} μCi/cc	0.48	1.4
Cs-137, 6×10^{-8} μCi/cc	0.38	1.1

2. Fuel Handling Building Exhaust

   Use of radiation monitor, RM-A6, in the Fuel Handling Building exhaust would provide the following detection capability under the previously stated assumed conditions, based upon the discharge flow rates shown by Figure 12.2-2.

   The exhaust air flow from the Fuel Handling Building is approximately 27,000 cfm. This flow is monitored by RM-A6, a three channel monitor, which samples the air in the discharge duct upstream of the filter plenum through an isokinetic nozzle. By use of a dilution factor, based upon the ratio of sub-area exhaust air flow to total air flow, an estimate of detection times can be determined as follows:

$$\text{Detection time for one DAC in sub-area} = \frac{\text{Detection time for one DAC}}{\text{Dilution ratio}}$$

   Estimates of detection times for I-131 and Cs-137 obtained from the preceding expression are presented in Table 12.2-4.

12.2.4.3.3 Auxiliary Building

Normally accessible areas of the Auxiliary Building are supplied with clean air which then passes through such areas to restricted access areas with potentially high airborne activity levels. Use of a movable surveillance monitor, such as RM-A12, with an assumed sensitivity of 1.0×10^{-11} μCi/cc for cesium would provide the followingdetection capability:

$$\frac{1.0 \times 10^{-11}\ \mu Ci/cc}{6 \times 10^{-8}\ \mu Ci/cc} : \frac{x\ min}{480\ min}$$

Where:

6×10^{-8} µCi/cc is DAC for cesium

x is the time to detect one DAC, local activity (i.e., 0.1 min).

With the alarm set at 3 times background, the response to one DAC of Cs-137 in the area under surveillance would be approximately 0.3 minutes.

Periodic surveillance sampling by Health Physics personnel will provide samples for laboratory analysis of particulates and radioiodine to verify operational levels of airborne activity in the plant.

12.2.4.4 Reactor Coolant Leak Detection

Assumptions relative to reactor coolant leak detection are as follows:

1. Free containment volume, 1.8×10^{6} ft^3.
2. Continuous purge rate, approximately 1000 cfm.
3. Reactor Building Charcoal Cleanup System, not operating.
4. Reactor coolant activity, as listed below for the predominate isotopes.
5. Sensitivity of radiation monitor RM-A2, satisfies requirements of Regulatory Guide 1.45.

The major isotopes of interest and corresponding design basis activities for both the particulate and gas channels are as follows:

1. Cs-134, 2.6×10^{-2} µCi/gm.
2. Cs-137, 1.9×10^{-2} µCi/gm.
3. Co-58, 1.7×10^{-2} µCi/gm.
4. Co-60, 2.1×10^{-3} µCi/gm.
5. Rb-88, 2.3×10^{-1}µCi/gm.
6. Xe-133, 5.1 µCi/gm (gas).

Assuming a steady reactor coolant leak rate of 0.1 gpm, the equilibrium concentrations of particulate isotopes in the reactor building atmosphere are as follows:

1. Cs-134, 7.38×10^{-8} µCi/gm.
2. Cs-137, 5.40×10^{-8} µCi/gm.
3. Co-58, 4.77×10^{-8} µCi/gm.
4. Co-60, 5.96×10^{-9} µCi/gm.

5. Rb-88, 9.19 x 10^{-9}μCi/gm.

A step increase in leakage to 1 gpm for a period of 1 hour would increase total particulate activity by 75 percent which is readily detectable by the particulate channel of radiation monitor RM-A2.

Figure 12.2-3 shows the increase in the RB particulate concentration following a 1-gpm leak.

The major isotope of interest for gas channel detection is Xe-133. A reactor coolant leak of 0.1 gpm would result in an equilibrium Xe-133 concentration of 4.14 x 10^{-5} μCi/cc. A subsequent leak of 1 gpm over 1 hour would result in an increase of 1.55 x 10^{-5} μCi/cc. This is equivalent to a 37 percent increase which is detectable by the gas channel of radiation monitor RM-A2.

Figure 12.2-4 shows the increase in Xe-133 concentration.

12.2.5 Operating Procedures

The Health Physics group is responsible for developing procedures for evaluating potential airborne radioactivity concentrations and providing guidance for minimizing personnel exposures. Occupational exposure is minimized during operations and maintenance by using the following methods and procedures to determine and cope with potential hazards:

1. Monitoring

   High volume air samples of various flow rates are used to collect particulates on high efficiency filter media, at regularly scheduled intervals, for subsequent counting. For tritium sampling, freezeout methods, bubblers, or desiccants are used to obtain samples for counting by the use of liquid scintillation techniques. Assay of noble gases is performed on a regular schedule by drawing an air sample into an evacuated chamber for appropriate analysis.

2. Respiratory Protection

   It is the responsibility of the Health Physics group to monitor and post areas of airborne radioactivity, to establish the requirements for respiratory equipment, to control the use of respiratory equipment, and to control access to areas through the radiation work permit program. Training programs for respiratory protection are the responsibility of Health Physics Supervision.

   Experience gained during operation and maintenance of several nuclear plants with whom SCE&G has contact is used to provide one basis for further evaluation and development of respiratory protection programs. Guidance contained in Regulatory Guides 8.2, 8.8, and 8.10 is utilized in the development and review of these programs.

   In relation to TMI Action Plan Item II.F.1, “Additional Accident Monitoring Instrumentation,” station procedures will contain the following information for converting instrument readings to concentrations or/and release rates:

a. Graphs relating cpm readings to concentration (μCi/ml) for effluent radiation monitors based on the manufacturer's recommendation or measurements from onsite analyses.

b. Graph or formula for determining the release rate (Ci/sec) based on effluent radiation monitor readings and measured flow rates of the main vent.

c. Graph or formula for determining the volume of steam discharged after opening of main steam safety valves. A concentration based on the average reading of the radiation monitors can be used to quickly approximate the total amount of radioactivity released. Subsequent laboratory analysis more accurately determines the quantity and spectrum of radionuclides released.

Computer capabilities can also be used to assist with these calculations.

Also, as required by TMI Action Plan Item II.F.1, the Station Radiation Monitor Calibration Program is as follows:

Initial vendor calibration included the determination of response to various radioactive isotopes where they were calibrated to provide traceability to the National Bureau of Standards. The Liquid monitors were checked against Cs-137 and Mn-54; Particulate monitors were checked against Cs-137 and Ce-144; Iodine monitors were checked against Cs-137 and Ba-133; Gas monitors were checked against Kr-85 and Cs-137. The Condenser Offgas monitor was checked against Xe-133 and Cs-137. Area monitors were checked against Ra-226.

Inplant calibration will normally use calibrated sources for determination of monitor response. These sources will typically be Cs-137 or Co-60 for Area Gamma monitors; Cs-137 for Particulate monitors; Ba-133 for Iodine monitors; and Cs-137 for Liquid monitors. Frequency of periodic calibration is normally on a yearly basis except for those channels identified in the Technical Specification where frequency has been fixed. The High Range Gamma Area monitors require electronic verification as described in Section 12.1 as the use of high level isotopes is not practical.

12.2.6 Estimates of Inhalation Doses

The annual inhalation doses to plant personnel from airborne activity in the various plant buildings depend upon the occupancy of the various plant areas in which airborne activity can occur. The dose to plant personnel is controlled by limiting personnel occupancy in contaminated areas, using engineering controls when available, and by using respiratory protection equipment when warranted by TEDE-ALARA evaluation of the task being performed. The doses to plant personnel are therefore limited to the values specified in 10 CFR 20 for occupationally exposed individuals.

Sections 12.2.6.1.1 through 12.2.6.1.3 discuss peak airborne concentrations and inhalation dose rates for various plant buildings based upon the leak rates discussed in Section 12.2.3. The methods used to calculate concentrations and inhalation dose rates are discussed in Section 12.2.6.2.

12.2.6.1 Peak Airborne Concentrations and Inhalation Dose Rates

12.2.6.1.1 Reactor Building

Peak airborne concentrations for the Reactor Building during operation at power are presented in Table 12.2-1. The concentrations presented in Table 12.2-1 are those that would occur at the end of the interval between purges with the assumptions given in Section 12.2.3.1.

Exposure to the reactor building concentrations given in Table 12.2-1 would result in an upper limit inhalation dose rate of 21.9 mRem/hr to the thyroid. Exposure of workers to this dose rate is unlikely since operation of the Reactor Building Charcoal Cleanup System and/or partial purging of the Reactor Building normally occur prior to any lengthy access. Respiratory protection equipment is used for short term access when required by plant procedures.

12.2.6.1.2 Auxiliary Building

Average airborne concentrations for the Auxiliary Building were calculated using the assumptions given in Section 12.2.3.2 and the building volume and flow rate discussed in Section 12.2.2. These concentrations are given in Table 12.2-1. The corresponding inhalation dose rate to the thyroid is 1.8×10^{-2} mRem/hr.

As described in Section 9.4.2, the Auxiliary Building Ventilation System supplies clean air to areas expected to be relatively free of airborne activity and removes air from areas that could potentially have high levels of airborne radioactivity. Thus, airborne activity levels in normally occupied areas should be significantly lower than the calculated average concentrations presented in Table 12.2-1.

The peak airborne concentrations in the Auxiliary Building are expected to be in the individual rooms which house auxiliary reactor equipment, such as the letdown heat exchanger, volume control tank and connecting instrumentation, piping, and valves. These rooms are within controlled areas and access to these areas is maintained under strict administrative control. Respiratory protection equipment or other protective measures are used in accordance with plant procedures.

For calculational purposes in determining peak concentrations, it has been assumed that one half of the total leakage in the Auxiliary Building occurs around the letdown heat exchanger. The resultant calculated concentrations for the letdown heat exchanger are presented in Table 12.2-1. The corresponding inhalation dose rate to the thyroid is 2.5 mRem/hr.

12.2.6.1.3 Turbine Building

Average airborne concentrations for the Turbine Building were calculated using assumptions given in Section 12.2.3.3 and the building volume and flow rate discussed in Section 12.2.2. These concentrations are given in Table 12.2-1. The corresponding inhalation dose rate to the

thyroid is 2.8 x 10^{-5} mRem/hr. The Turbine Building concentrations and inhalation dose rate are sufficiently small to allow normal occupancy without the use of protective measures.

12.2.6.2 Methods Used to Estimate Airborne Concentrations and Inhalation Doses

The concentration of radionuclides in a given volume, V, with a steady-state leakage rate is determined from an activity balance. For the i^{th} isotope, the activity balance is as follows:

$$\frac{d}{dt}C_i(t) = \frac{S_i}{V} - \Lambda_i C_i(t) \qquad (12.2\text{-}1)$$

Where:

$C_i(t)$ = Concentration of i^{th} isotope at time t (μCi/cc).

S_i = Leakage rate of i^{th} isotope (μCi/sec).

Λ_i = Removal constant of i^{th} isotope (sec^{-1}).

In Equation (12.2-1), ingrowth from radioactive parent nuclides has been neglected and a homogeneous mixing model has been assumed. The solution is as follows:

$$C_i(t) = \frac{S_i(1 - e^{-\Lambda_i t})}{V\Lambda_i} + C_i(0)e - \Lambda_i t \qquad (12.2\text{-}2)$$

If the system is purged at a flow rate, R, then, for a volume, V, the removal constant is:

$$\Lambda = \lambda_i + \frac{R}{V} \qquad (12.2\text{-}3)$$

Where:

λ_i = The decay constant of the i^{th} isotope.

When an intermittent purging scheme is used, there is a period of buildup followed by a period of removal. During the building interval, the removal constant is:

$$\Lambda = \lambda_i \qquad (12.2\text{-}4)$$

Once the airborne concentrations have been determined, inhalation dose rates are calculated using the following formula:

Inhalation Dose Rate = $(C_i)(BR)(DCF_i)$

Where:

Ci = Equilibrium concentration of isotope i (μCi/cc).

BR = Breathing rate (cc/hr).

DCF_i = Dose conversion factor for isotope i (mRem/μCi).

12.2.7 References

1. U.S. Nuclear Regulatory Commission, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors*, NUREG-0017, April 1976.
2. American National Standards Institute, *Guide for Administrative Practices in Radiation Monitoring*, ANSI N13.2, 1969.

Table 12.2-1
Calculated Airborne Concentrations (1)

Isotope	Reactor Building Concentrations (2) (µCi/cc)	Auxiliary Building Concentrations (µCi/cc)	Letdown Heat Exchanger Room Concentrations (3) (µCi/cc)	Turbine Building Concentrations (µCi/cc)
H-3	8.7×10^{-4}	1.4×10^{-8}	2.0×10^{-7}	3.0×10^{-10}
Kr-85m	1.3×10^{-6}	2.1×10^{-9}	2.9×10^{-7}	1.1×10^{-14}
Kr-85	9.6×10^{-6}	1.6×10^{-10}	2.2×10^{-8}	8.2×10^{-16}
Kr-87	4.3×10^{-7}	2.1×10^{-9}	3.2×10^{-7}	1.2×10^{-14}
Kr-88	1.6×10^{-6}	3.8×10^{-9}	5.4×10^{-7}	2.1×10^{-14}
Xe-131m	3.0×10^{-5}	1.1×10^{-9}	1.5×10^{-7}	5.4×10^{-15}
Xe-133m	2.5×10^{-6}	3.4×10^{-10}	4.7×10^{-8}	1.8×10^{-15}
Xe-133	1.1×10^{-4}	6.9×10^{-9}	9.5×10^{-7}	3.6×10^{-14}
Xe-135m	8.2×10^{-8}	1.4×10^{-9}	2.5×10^{-7}	1.0×10^{-14}
Xe-135	1.2×10^{-5}	9.6×10^{-9}	1.3×10^{-6}	5.1×10^{-14}
Xe-137	5.3×10^{-9}	1.6×10^{-10}	3.9×10^{-8}	2.1×10^{-15}
Xe-138	7.0×10^{-8}	1.2×10^{-9}	2.3×10^{-7}	9.5×10^{-15}
Br-84	2.1×10^{-11}	1.6×10^{-12}	2.6×10^{-10}	3.4×10^{-16}
I-131	1.6×10^{-8}	5.4×10^{-12}	7.4×10^{-10}	1.1×10^{-14}
I-132	1.2×10^{-9}	2.6×10^{-11}	3.7×10^{-9}	1.6×10^{-14}
I-133	6.6×10^{-9}	1.7×10^{-11}	2.4×10^{-9}	2.8×10^{-14}
I-134	7.3×10^{-10}	3.8×10^{-11}	5.8×10^{-9}	1.2×10^{-14}
I-135	4.1×10^{-9}	3.3×10^{-11}	4.5×10^{-9}	3.6×10^{-14}

Table 12.2-1 (continued)
Calculated Airborne Concentrations [1]

Isotope	Reactor Building Concentrations [2] (μCi/cc)	Auxiliary Building Concentrations (μCi/cc)	Letdown Heat Exchanger Room Concentrations [3] (μCi/cc)	Turbine Building Concentrations (μCi/cc)

(1) Based upon the assumptions given in Sections 12.2.3 and 12.2.6.
(2) Concentrations at the end of interval between purges and without operation of the reactor building charcoal cleanup system.
(3) Concentrations are based upon the assumption that one-half of the auxiliary building leakage occurs in the letdown heat exchanger room.

Table 12.2-2
Air Flow Rates and Approximate Net Free
Volumes Served by Ventilation Systems

System	System Exhaust Flow Rate	Approximate Net Free Volume Served (ft^3)
Control Room Ventilation System	21,270 cfm/emergency system fan	226,040
Controlled Access Area Exhaust System	16,000 cfm/fan	73,890 (1)
Spent Fuel Pool Area Ventilation System	27,000 cfm/fan	629,260 (1)
Auxiliary and Radwaste Area Ventilation Systems	123,800 cfm, total	1,890,000
Turbine Building Ventilation Systems	1,500,000 cfm, total	3,700,000
Reactor Building Charcoal Cleanup System	24,000 cfm, total	1,800,000

(1) Original Licensing / Construction Estimates

Table 12.2-3
Airborne Radioactivity Monitors

MONITOR	FUNCTION	DETECTORS	POWER SOURCE
RM-A1 Control Room Supply Air	Monitors ventilation air supplied to control room	1. Particulate-Beta, 4.7×10^{-11} to 10^{-7} µCi/cc, Cs-137 2. Iodine-Gamma, 2×10^{-11} to 2×10^{-7} µCi/cc, I-131 3. Gas-Beta, 2×10^{-6} to 2×10^{-2} µCi/cc, Kr-85	Bus B (1)
RM-A2 Reactor Building Air Sample Line	Monitors sample taken from containment	1. Particulate-Beta, 5.5×10^{-11} to 10^{-7} µCi/cc, Cs-137 2. Iodine-Gamma, 2×10^{-11} to 2×10^{-7} µCi/cc, I-131 3. Gas-Beta, 2.6×10^{-6} to 2×10^{-2} µCi/cc, Kr-85	Bus B (1)
RM-A3 Main Plant Vent Exhaust	Monitors effluent from auxiliary building	1. Particulate-Beta, 4.7×10^{-11} to 10^{-7} µCi/cc, Cs-137 2. Iodine-Gamma, 2×10^{-11} to 2×10^{-7} µCi/cc, I-131 3. Gas-Beta, 2.6×10^{-6} to 2×10^{-2} µCi/cc, Kr-85	Bus A (1)
RM-A4 Reactor Building Purge Exhaust	Monitors effluent from containment during purge	1. Particulate-Beta, 4.7×10^{-11} to 10^{-7} µCi/cc, Cs-137 2. Iodine-Gamma, 2×10^{-11} to 2×10^{-7} µCi/cc, I-131 3. Gas-Beta, 2×10^{-6} to 2×10^{-2} µCi/cc, Kr-85	Bus A (1)
RM-A6 Fuel Handling Building Exhaust	Monitors ventilation discharge from fuel handling building	1. Particulate-Beta, 4.7×10^{-11} to 10^{-7} µCi/cc, Cs-137 2. Iodine-Gamma, 2×10^{-11} to 2×10^{-7} µCi/cc, I-131 3. Gas-Beta, 2×10^{-6} to 2×10^{-2} µCi/cc, Kr-85	Bus B (1)

Table 12.2-3 (continued)
Airborne Radioactivity Monitors

MONITOR	FUNCTION	DETECTORS	POWER SOURCE
RM-A7 Sampling Rooms	Monitors air sample from sampling room. Movable unit - may be used for other areas as required.	1. Particulate-Beta, 4.7×10^{-11} to 10^{-7} µCi/cc, Cs-137 2. Iodine-Gamma, 2×10^{-11} to 2×10^{-7} µCi/cc, I-131 3. Gas-Beta, 2×10^{-6} to 2×10^{-2} µCi/cc, Kr-85	480 volt outlets
RM-A8 Spent Fuel Area	Monitors local air sample. Movable unit - may be used for other areas as required.	1. Particulate-Beta, 4.7×10^{-11} to 10^{-7} µCi/cc, Cs-137 2. Iodine-Gamma, 2×10^{-11} to 2×10^{-7} µCi/cc, I-131 3. Gas-Beta, 2×10^{-6} to 2×10^{-2} µCi/cc, Kr-85	480 volt outlets
RM-A9 Condenser Air Removal	Monitors effluent of condenser off-gas discharge	Gas-Gamma, 2×10^{-6} to 2×10^{-2} µCi/cc, Xe-133	Bus B
RM-A10 Waste Gas Discharge	Monitors discharge of waste gas-provides backup to decay tank analysis	Gas-Gamma, 2×10^{-4} to 2 µCi/cc, Xe-133	Bus B
RM-A11 Auxiliary Building Ventilation	Sequentially monitors various auxiliary building ventilation exhaust ducts	Gas-Beta, 2×10^{-6} to 2×10^{-2} µCi/cc, Kr-85	Bus B (1)

Table 12.2-3 (continued)
Airborne Radioactivity Monitors

MONITOR	FUNCTION	DETECTORS	POWER SOURCE
RM-A12 Movable Particulate Unit	Provides local particulate monitoring and iodine sampling	Particulate-Beta, 10^{-11} to 10^{-7} μCi/cc, Cs-137	120 volt outlets
RM-A13 Main Plant Vent Exhaust, High Range Gas Discharge	Effluent High Range Gas Monitor	Ion Chamber - Gamma 0.1 to 10^{7} mr/hr (10^{-2} to 10^{5} μCi/cc, Xe-133)	Bus A
RM-A14 Purge Exhaust Effluent, High Range	Effluent High Range Gas Monitor	Ion Chamber - Gamma 0.1 to 10^{7} mr/hr (10^{-2} to 10^{5} μCi/cc, Xe-133)	Bus A
RM-G19 A, B, C Steam Line	Steam Line High Range Gamma Monitor	Ion Chamber - Gamma 0.1 to 10^{7} mr/hr	Bus B

(1) Associated sample pump powered from diesel backed 480 volt bus.

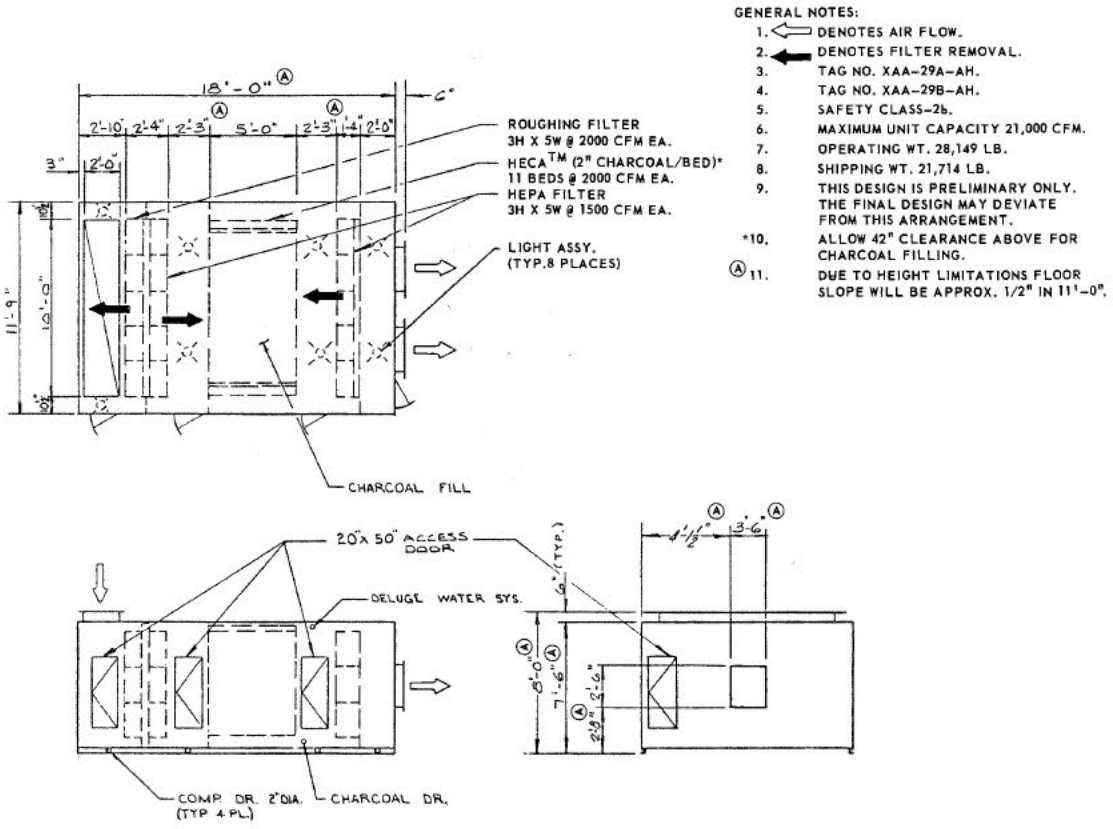
Table 12.2-4
Estimated Detection Time for
I-131 and Cs-137 in the Fuel Handling Building

Fuel Handling Building Area [1]	Exhaust Flow (cfm)	Dilution Factor	Detection Time (Minutes)	
			I-131	Cs-137
Spent Fuel Area	15,320	0.567	0.8	0.7
General Flow Area	1,840	0.068	7.0	5.5
Railroad Area	3,020	0.112	4.3	3.4
Personnel Cleanup [2]	242	0.009	53.6	42.0
Emergency Personnel Hatch	1,750	0.065	7.4	5.8
412 South West	1,470	0.054	8.8	6.9
Decontamination	1,120	0.041	11.6	9.1
Excess Waste Holdup Tank	950	0.035	13.6	10.7
Decontamination Pit Collection Tank	686	0.025	18.9	14.8

(1) Small areas, access to which is controlled due to potentially high activity levels, are not included since access is under administrative control.
(2) The personnel cleanup area is listed although it is not considered as a source of activity.

Figure 12.2-1

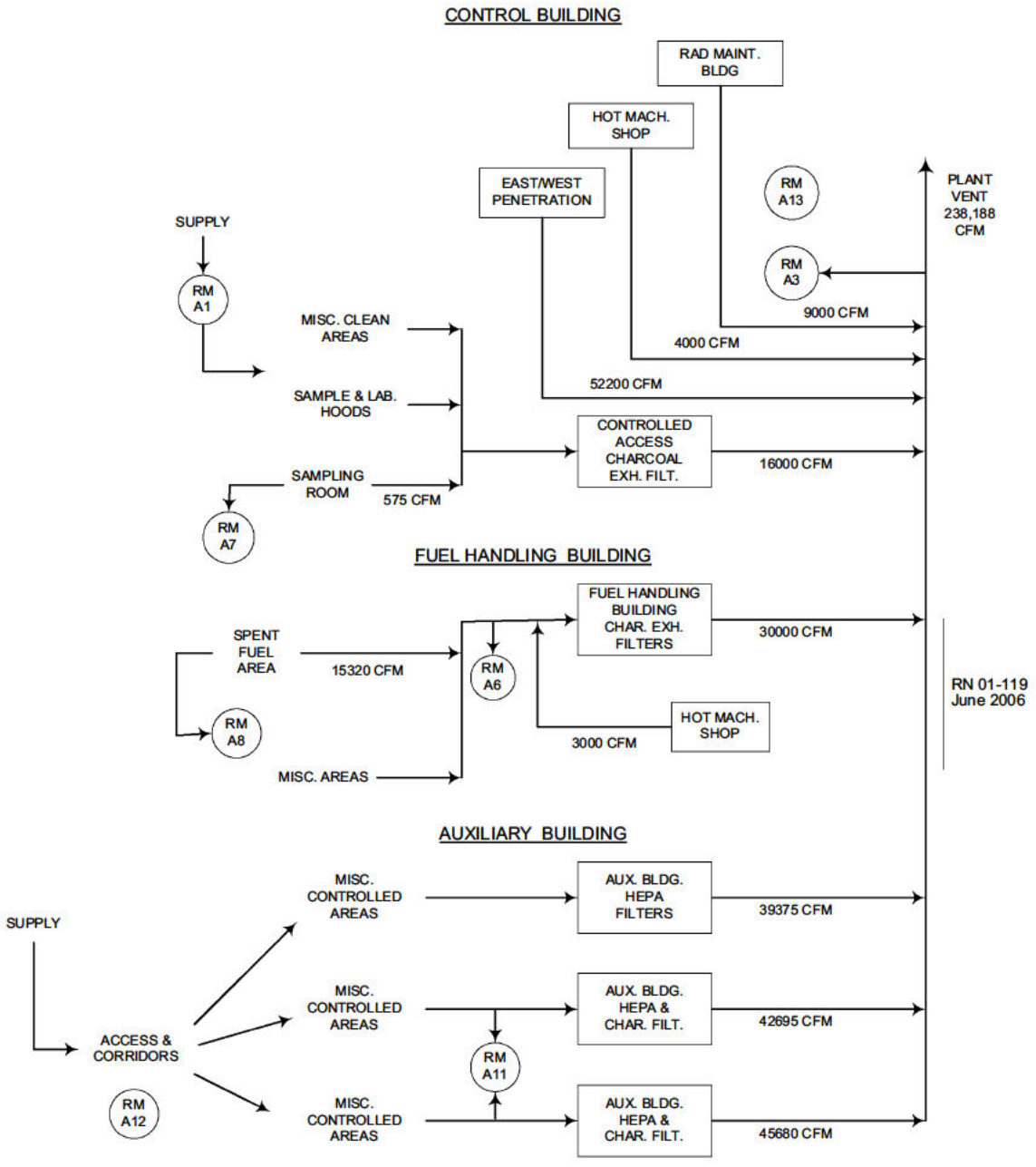
CONTROL ROOM EMERGENCY CHARCOAL FILTER PLENUM



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Control Room Emergency Charcoal Filter Plenum
Figure 12.2-1

AMENDMENT 0
AUGUST 1984

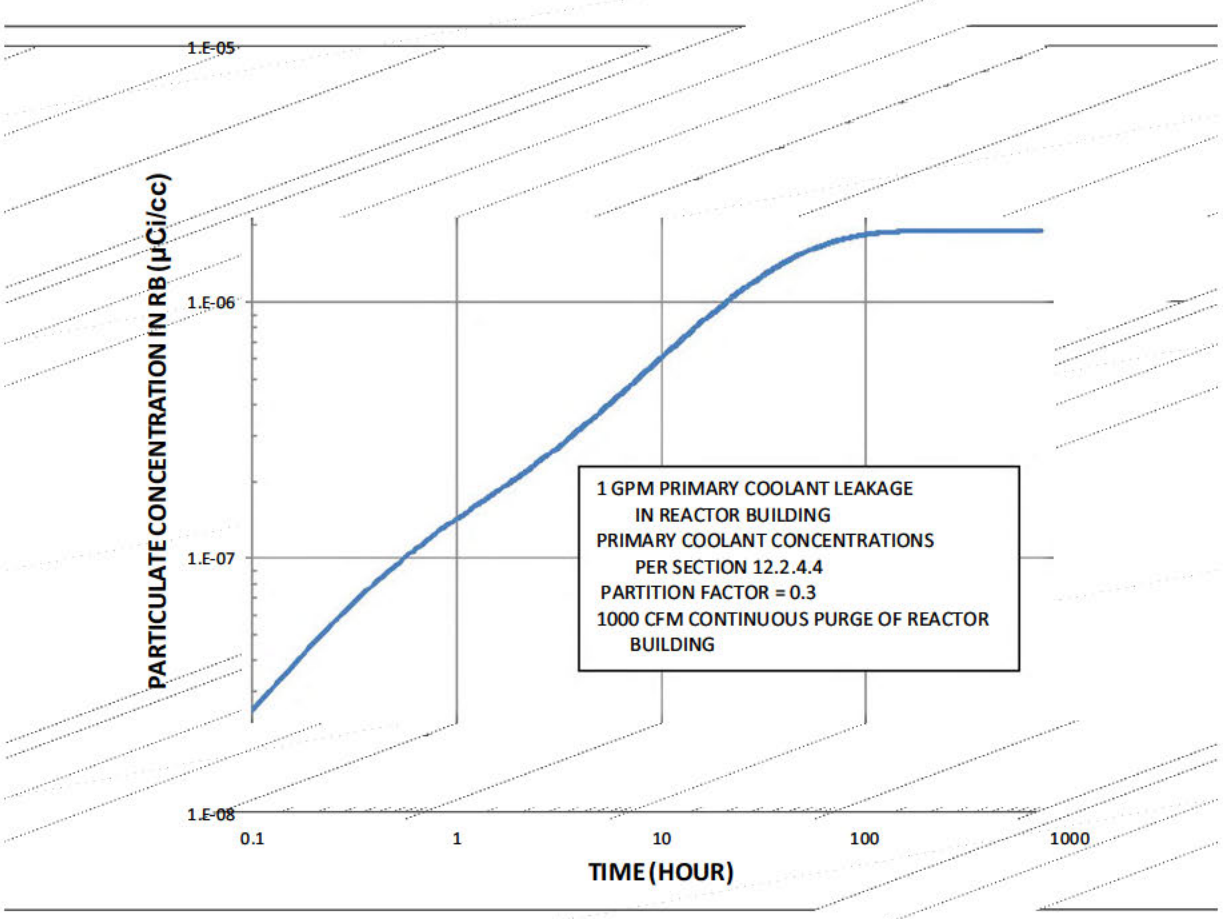
Figure 12.2-2
AIRBORNE ACTIVITY MONITORING



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Airborne Activity Monitoring ASSOCIATED WITH FSAR FIGS 9.4-4, 9.4-7, 9.4-8, 9.4-9, 9.4-10a, 9.4-11, 9.4-26a Figure 12.2-2 Rev. 2

Figure 12.2-3

BUILDUP OF PREDOMINATE PARTICULATES IN REACTOR BUILDING FROM 1 GPM REACTOR COOLANT LEAK AS A FUNCTION OF TIME AFTER LEAKAGE BEGINS



RN 13-011

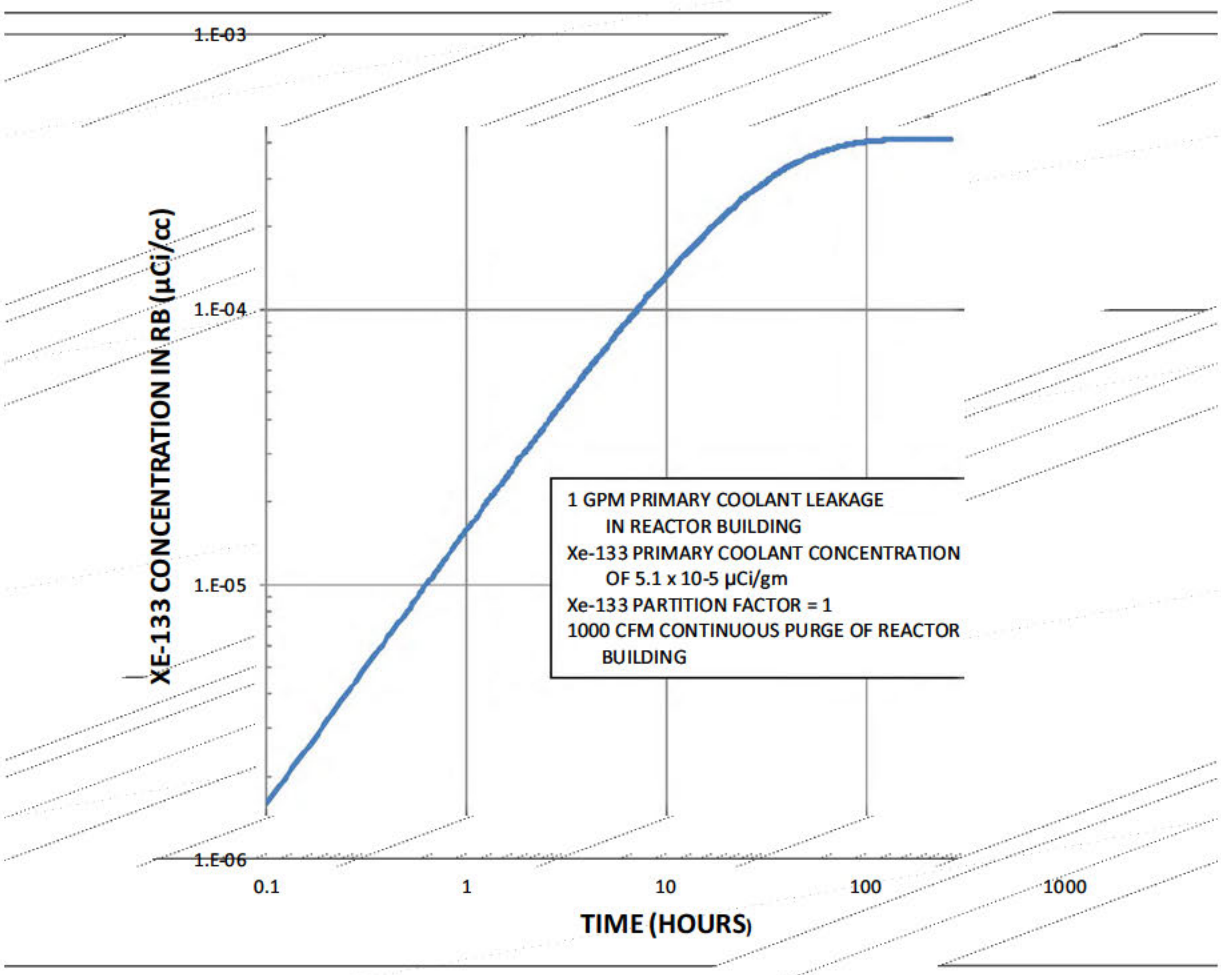
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Buildup of Predominate Particulates in Reactor Building From 1 gpm Reactor Coolant Leak as a Function of Time After Leakage Begins

Figure 12.2-3

Figure 12.2-4

BUILDUP OF XE-133 IN REACTOR BUILDING FROM 1 GPM REACTOR COOLANT LEAK AS A FUNCTION OF TIME AFTER LEAKAGE BEGINS



RN 13-011

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Buildup of Xe-133 in Reactor Building
From 1 gpm Reactor Coolant Leak as a
Function of Time After Leakage Begins

Figure 12.2-4

12.3 HEALTH PHYSICS PROGRAM

12.3.1 Objectives and Organization

12.3.1.1 Program Objectives

12.3.1.1.1 As Low as Reasonably Achievable (ALARA): Policy Considerations

It is the policy of the management of South Carolina Electric and Gas Company (SCE&G) that the Virgil C. Summer Nuclear Station is operated in such a manner that occupational radiation exposures of plant personnel are as low as reasonably achievable (ALARA). This policy is implemented by the Manager, Radiological Protection and Chemistry, who is directly responsible for the ALARA aspects of plant operation, and who also has the authority to prevent operations which are not consistent with the ALARA policy. The Manager, Radiological Protection and Chemistry, is responsible to the Plant Manager, who has overall responsibility for the implementation of the ALARA policy. The ALARA program is subject to the review and audit process described in Section 13.4.2.

The Plant Manager, has familiarized plant personnel with the commitment to keep occupational exposures ALARA by providing appropriate instructions, policy statements, and training. The Plant Manager, determines if modifications to operating and maintenance procedures and to plant equipment and facilities should be made, where practicable to minimize exposures and where unresolved safety problems are not involved.

12.3.1.1.2 ALARA: Operational Considerations

Procedural guidance in exposure reduction has been established for all systems that contain, collect, store, or transport radioactive liquids, gases, and solids, for all operating conditions. The following are examples of specific exposure-reduction techniques for operations such as maintenance, inservice inspection, radwaste handling, and refueling:

1. During initial startup, neutron and gamma-ray dose rate surveys are performed to verify the adequacy of shielding.
2. During normal operations, dose rate, surface contamination, and airborne radioactivity surveys are performed periodically throughout the plant and areas are zoned accordingly. These surveys ensure that data is available for planning operation and maintenance activities in accordance with the ALARA objective of minimizing exposures.
3. Areas are conspicuously posted in accordance with 10 CFR 20, as appropriate.
4. A radiation work permit (RWP) system is employed to ensure proper administrative control over work in restricted areas. The RWP is designed to ensure that the radiological conditions are defined and that appropriate measures are taken to minimize the dose received by personnel. Section 12.3.2.3.7 explains the use of the RWP.
5. Extension tools are used when practicable to increase the distance between the radiation source and the worker.

6. Equipment is moved to areas with lower radiation fields for maintenance when practicable.
7. Portable shielding such as lead bricks, lead sheets, lead shot, high density concrete block, or steel plates are used as practicable for assuring ALARA doses.
8. A personnel dosimetry program as described in Section 12.3.3 is administered by the Health Physics group to ensure compliance with 10 CFR 20.

Administrative controls have been established to assure that all procedures and requirements relating to radiation protection are followed by all plant personnel. The procedures that control radiation exposure are subject to review and approval as outlined in Section 13.4.

In general, the plant procedures are designed to keep occupational radiation exposures ALARA and follow the recommendations of Regulatory Guides 8.8 and 8.10. These procedures are organized and revised by the Manager, Radiological Protection and Chemistry, in cooperation with the Maintenance or Operations Director, such that operations proceed within the framework of the ALARA policy.

Independent technical and quality oversight is provided by Quality Assurance. This organization, through audits, surveillances, and reviews as described in the Dominion Energy Nuclear Facility Quality Assurance Program Description (QAPD), provides input to the Management Safety Review Committee. Since Quality Assurance maintains a reporting chain independent of plant operations, continuing implementation of and adherence to the operational ALARA program is assured.

12.3.1.2 Program Organization

The Manager, Radiological Protection and Chemistry, has the authority for developing and implementing company policy for radiation protection and contamination control. The administration of the Health Physics program is also the responsibility of the Manager, Radiological Protection and Chemistry, whose minimum qualifications are as presented in Section 13.1.3. The Manager, Radiological Protection and Chemistry, reports directly to the Plant Manager, on radiological protection issues.

The Manager, Radiological Protection and Chemistry is responsible for keeping plant staff informed of radiation hazards and conditions related to potential exposure, contamination of plant equipment or contamination of site and environs (see Figure 12.3-1). As the administrator of the health physics program, the responsibilities of the Manager, Radiological Protection and Chemistry include:

1. Training and supervision of the Health Physics staff.
2. Planning and scheduling Health Physics activities.
3. Establishing and maintaining data on plant, environmental and laboratory radiation and contamination levels, personnel exposures, and work or effluent release restrictions.
4. Maintaining a current Health Physics manual which contains the standards and procedures to implement the ALARA policy for radiation exposures and effluent releases.

5. Ensuring that plant operations comply with applicable regulations pertaining to radiation and environmental radiological protection.
6. Assessing radiological conditions/issues for normal operations and emergencies and advising plant management or the emergency director.
7. Developing, implementing, directing, controlling, and supervising all aspects of the RWP, ALARA, Effluent Control, Radiological Environmental, Radwaste, Dosimetry, Radiological Respiratory Protection, Equipment CAL/Contamination Control, Surveillance, RCA Access, and Radiological Data Base Programs.
8. Controlling the receipt, shipment, and storage of all radioactive materials.
9. Providing radiological engineering expertise and assessing events, occurrences, program performance, and data while developing and implementing solutions and enhancements.
10. Reviewing radiation safety-related operating procedures.

The Manager, Radiological Protection and Chemistry is responsible for developing a radiation protection training program, a radiation surveillance program, and an effluent control program to ensure that radiation exposures of all personnel are kept as far below the limits of 10 CFR 20 as is reasonable achievable. He also develops policy and specific procedural guidance as necessary to implement the ALARA policy.

In order to carry out his responsibilities, the Manager, Radiological Protection and Chemistry is in charge of the Health Physics groups. These groups are made up of technicians, supervisors, and professional Health Physicists who meet the qualifications presented in Section 13.1.3.

The Health Physics groups are organized to provide the following services:

1. Establish and maintain a radiological surveillance program to routinely collect, post, and record data concerning radiation and contamination levels, both surface and airborne, throughout the plant.
2. Perform radiation monitoring for special plant operations and specific maintenance activities as required and maintain records of the surveys performed.
3. Establish and implement the ALARA and RWP/planning programs for RCA work/exposure control.
4. Provide for effective access control by establishing zones throughout the plant, based on radiation and contamination levels.
5. Provide, maintain, and instruct plant personnel in the proper use of protective clothing and respiratory equipment for plant operation and maintenance.
6. Provide procedures for dealing with radiation hazards in performing day to day operations and maintenance and verify the effectiveness of such procedures.
7. Develop and implement the personnel dosimetry and respiratory protection programs.

8. Assist in the plant personnel training and emergency preparedness programs by providing specialized training in radiation protection and expertise/manpower for emergency response and scenario development.
9. Make recommendations for performing equipment, area, and personnel decontamination.
10. Receive and ship radioactive materials, including special nuclear, source, and by-product material to ensure compliance with Federal and State regulations.
11. Calibrate and maintain Health Physics, laboratory, and dosimetry equipment and facilities.
12. Sample, analyze, and perform calculations necessary to ensure that radioactivity discharged to the environment in effluents is kept as far below established limits as is reasonably achievable.
13. Assess internal exposures and maintain official dose records.
14. Provide oversight and direction to the chosen dosimetry processor in processing Radiological Environmental and site personnel TLDs.
15. Develop, direct, and implement the Radwaste Process and Minimization program.
16. Develop and maintain the ODCM, serve as member of FSRC, and as Radiation Safety Officer for various DHEC rad material licenses.

The Health Physics section supervises the implementation of the procedures specified by the Manager, Radiological Protection and Chemistry, for personnel and environment exposure reduction during normal operations, maintenance, inservice inspection, radwaste handling, and refueling in accordance with ALARA policy.

12.3.2 Facilities, Equipment, and Procedures

12.3.2.1 Facilities

12.3.2.1.1 Health Physics Facilities

The Health Physics facilities consist of:

1. A Health Physics room and instrument storage area, sampling room, counting room, personnel decontamination area, locker room, and laundry area on the 412’ elevation of the Control Building.
2. Health Physics station(s), containing protection clothing, portable survey equipment, and other Health Physics materials at locations around the plant, as specified by the Manager, Radiological Protection and Chemistry to be of strategic importance for contamination and exposure control.
3. A Health Physics facility for Dosimetry, Whole Body Counting, and Radiological Respiratory Protection.

4. An offsite Radiological Support facility located at the Environmental Lab which provides laboratory and equipment resources necessary for the radiological, environmental, and emergency response programs.

The relevant areas of the Control Building at elevation 412’ are shown in Figures 12.1-19 and 12.1-20 to illustrate the layout of the access control area Health Physics facilities.

12.3.2.1.2 Instrument Storage, Calibration, and Maintenance Facilities

Portable instruments for routine Health Physics surveys are stored in the Health Physics areas around the CB412 HP Lab, RCA Access Control Point, and AB412 HP Instrument Calibration Facility. Other portable instruments are located at Health Physics stations around the plant (see Section 12.3.2.2.2) and at the Environmental Lab. Portable instruments for emergency use are stored at strategic locations around the plant, Environmental Lab, and other approved offsite locations.

Portable instruments and laboratory equipment are routinely maintained and calibrated by Health Physics personnel or by returning the instruments to the manufacturer for repair.

12.3.2.1.2.1 Personnel Contamination Control Facilities

The primary contamination control facility for personnel is the access control area, which is illustrated in Figure 12.1-19. Additional contamination control points are established in the immediate vicinity of known contaminated areas, as necessary, to prevent the spread of contamination. These points provide a controlled interface between the clean and contaminated areas. The personnel decontamination showers are shown in Figure 12.1-19. Additionally, emergency showers are located around the plant in areas with a high potential for personnel contamination. Personnel are checked for contamination with the equipment described in Table 12.3-1.

12.3.2.1.2.2 Equipment Contamination Control Facilities

An equipment decontamination area is located adjacent to the radwaste processing area of the Auxiliary Building. This facility contains installed and portable decontamination equipment. A decontamination area for spent fuel shipping casks is also provided, and is located in the Fuel Handling Building.

12.3.2.2 Equipment

12.3.2.2.1 Selection Criteria

The equipment and instrumentation used in the Health Physics program for the assessment of radioactivity and personnel exposures are selected according to the following criteria:

1. Ability to measure the quantity of interest to an acceptable degree of precision and accuracy.

2. Ease of operation, maintenance, and calibration.
3. Appropriate sensitivity and range for various operational situations, including normal operations, anticipated operational occurrences, and accident conditions, as determined by the requirements of applicable regulations pertaining to each measurement situation.

These criteria apply to portable instrumentation for radiation and contamination surveys, laboratory technical equipment, inplant airborne radioactivity monitoring and sampling equipment, area monitors, and personnel monitoring equipment.

12.3.2.2.2 Protective Clothing and Equipment

The following respiratory protection devices are made available at the plant:

1. Full face particulate filter masks.
2. Full face masks with air line respirator.
3. Hoods or suits with air line respirator.
4. Full-face masks with self contained breathing apparatus of the bottle air or chemox type.

Protective clothing is required in contaminated areas or in areas where the potential for radioactive material contamination exists. Protective clothing available at the plant includes the following:

1. Coveralls.
2. Laboratory coats.
3. Plastic suits.
4. Disposable caps.
5. Hoods.
6. Plastic and rubber shoe covers.
7. Plastic, rubber, and cotton gloves.
8. Disposable protective clothing.

This protective clothing and equipment is located in strategic locations around the plant, as specified by the Manager, Radiological Protection and Chemistry. The protective clothing and equipment is readily available at key location(s) throughout the plant, without the need to return to the protective clothing storage and issue area to obtain this equipment. Also, protective clothing and equipment is provided in the emergency kits located around, and outside, the plant.

12.3.2.2.3 Technical Equipment and Instrumentation

The equipment and instrumentation necessary to measure radioactivity, radiation fields, and exposures falls into two major categories:

1. Fixed or installed.
2. Portable.

The fixed equipment includes the Radiation Monitoring System, access-control contamination monitors, radiochemistry laboratory equipment, personnel dosimetry readout equipment, and the counting room radioactivity analysis instrumentation. The portable equipment includes radiation and contamination survey instruments, airborne radioactivity samplers, movable airborne radioactivity monitor, and personnel dosimeters.

The Radiation Monitoring System is described in Sections 11.4, 12.1.4, and 12.2.4. The access-control contamination monitors are described in Table 12.3-1. The sensitivity of these monitors is a function of the background level at the location of the monitor; the monitors are shielded to the extent practicable in order to increase their sensitivity. The radiochemistry laboratory equipment includes fume hoods, analytical balances, glassware, reagents, and other materials and equipment as required to perform analyses for personnel protection, radioactivity surveys, and related health physics functions. The counting room instrumentation is described in Table 12.3-2.

The portable Health Physics equipment is described in Table 12.3-3. These devices are calibrated at least annually and also after any major maintenance is performed on an instrument. These calibrations are performed using a source of the appropriate type directly or indirectly traceable to the National Institute of Standards and Technology.

12.3.2.2.4 Accident Radiation Monitoring

In-plant accident radiation monitoring combines the use of fixed radiation monitoring equipment and the use of portable monitoring instrumentation.

Area gamma radiation monitors and atmospheric radiation monitors are described in Sections 12.1.4 and 12.2.4. Portable monitoring instrumentation is tabulated in Table 12.3-3.

The fixed radiation monitors (area and airborne) are supplied with diesel backed power and are designed to operate in the normal and anticipated operational environment (see Tables 12.1-20 and 3.11-3), except that the area monitors in the Reactor Building are not required to withstand LOCA environment. This function is performed by area monitor, RM-G7, as described in Section 12.1.4.

In the event of an unplanned gas release involving high concentrations of noble gases, silver zeolite filter cartridges will be used for sampling atmospheres as conditions dictate. Silver zeolite cartridges do not significantly absorb noble gases, enabling a more accurate determination of the radioiodine collected. Fixed process radiation monitors, portable continuous air monitors, and grab samplers can utilize silver zeolite cartridges. Table 12.3-3 outlines the types and quantities of portable air samplers available. Table 11.4-1 lists the fixed process radiation monitors which detect radioiodine.

Normal laboratory instrumentation, i.e., Intrinsic Germanium detectors and a gas flow proportional counter, will be utilized to determine the quantity of radioiodine collected on a filter cartridge. Counting equipment is available at the Environmental Lab if normal laboratory instrumentation is inoperable.

Health Physics procedures include provisions for determining iodine concentrations in noble gas environments. Health Physics personnel are trained on action levels requiring the use of silver zeolite cartridges and the use of portable single channel analyzers and NaI detectors. This meets the requirements of NUREG-0578 Section 2.1.8.C.

12.3.2.3 Health Physics Program: Procedures

It is the intent of SCE&G that the Health Physics Procedures discussed in this section will conform with 10 CFR 20 and follow the recommendations contained in Regulatory Guides 8.7, 8.8, 8.9, and 8.10.

12.3.2.3.1 Radiation Surveys

12.3.2.3.1.1 Radiation Field Surveys

The Health Physics group conducts routine measurements of radiation field intensities around the plant, using portable instrumentation appropriate for the type(s) of radiation present, on a schedule which is determined by:

1. The level of radiation exposure rate.
2. The variability of radiation level.
3. The occupancy factor of the location.

Routine radiation field survey frequencies could increase or decrease due to plant conditions. Locations of strategic importance for ALARA (high exposure rate and occupancy) are routinely surveyed and the latest measured values are documented and available for review prior to work in these areas. Trending of specific areas, such as those containing RHR, and letdown system components is done on a routine basis to provide job planning information in such areas. Records are maintained of the results of these surveys as required by 10CFR20.

Prior to the initiation of any operation for which a RWP is required (see Section 12.3.2.3.7) a survey is made of the radiation field(s) in the vicinity where the operation is to be performed, using instrumentation appropriate for the type(s) of radiation present. The results of this survey are recorded electronically, on paper or in the RWP.

Further aspects of radiation-field surveys are discussed in Section 12.3.2.3.2, and the portable instruments are discussed in Section 12.3.2.2.3.

12.3.2.3.1.2 Surface Contamination Surveys

The Health Physics Services group conducts routine surface contamination surveys at locations around the plant, including the access control areas, administrative area, lunchrooms, control room, and main entrance security gate. All locations of importance for controlling the potential spread of contamination are surveyed at least weekly, using the “smear” technique, or an appropriate portable instrument, and the remaining locations are surveyed at least monthly. These survey frequencies could increase or decrease due to plant conditions. The results of these surveys are recorded and tabulated by locations so that trends in the data may be readily observed.

Contamination surveys are also made on personnel, equipment, and materials from time to time as necessary to ensure complete control over the levels and spread of removable contamination. Further aspects of contamination control are discussed in Sections 12.3.2.3.3 and 12.3.2.1.

12.3.2.3.1.3 Airborne Radioactivity Surveys

Levels of airborne radioactivity are assessed on a routine basis to ensure compliance with 10 CFR 20. These assessments are performed using equipment and techniques appropriate for the type(s) of radioactivity present at the sampling locations.

Any operation requiring respiratory protection will have the results of airborne radioactivity in µci/cc placed on the radiation work permit for that operation. The airborne radioactivity may be assessed prior to the operation but must be assessed during the operation.

The results of routine airborne radioactivity surveys are recorded by location so that trends in the radioactivity level can be readily identified. Air sampling surveys are performed at least daily in areas with both high occupancy factor and a high potential for the existence of airborne radioactivity. Other locations are surveyed weekly or monthly, as a function of the significance of the location as a source of occupational radiation exposure (ORE) from airborne radioactivity. These survey frequencies could increase or decrease due to the plant conditions.
Section 12.3.2.3.4 contains further discussion of airborne radioactivity surveys.

12.3.2.3.2 Radiation Area Access Control

All areas of the plant are subject to access control restrictions to an extent proportional to the potential for ORE in each area. The particular access control requirements for each area are specified by the Manager, Radiological Protection and Chemistry.

Specifically, any area of the plant in which the radiation level is at least 100 mrem/hr at 12 inches (30 cm) from a radiation source or from any surface that the radiation penetrates will be declared a “high radiation area”, and access to such areas is restricted. These areas are posted and secured in accordance with 10 CFR 20. Physical barriers to control access to high radiation areas include: locked and/or annunciated doors or gates, fences, or rope barriers. These barriers are arranged in such a manner as to allow exit from the area without a key or other special device.

Administrative measures for access control to high radiation areas include the use of an RWP for operations taking place in such areas. The estimated exposure for individuals entering such areas is based on radiation surveys made prior to, or at the start of work, and the nature of the operation to be performed. Again, depending upon the operation, a health physics technician may be assigned to supervise stay times and make appropriate surveys while the operation is in progress.

12.3.2.3.3 Contamination Control

Surveys for contamination control are performed by the Health Physics Services group on a routine basis at various locations around the plant (see Section 12.3.2.3.1.2). Nonroutine surveys are also made whenever there is a possibility of the spread of contamination by personnel, equipment, or materials.

Since the complete removal of surface contamination from parts of the plant is a practical impossibility, certain plant areas may be designated as “contamination areas”. The level of contamination and the number of these areas are reduced to the minimum practicable level, and control points are established to prevent the spread of contamination to other plant areas. Entrance to such an area requires compliance with the protective clothing and equipment requirements specified by Health Physics. These areas are conspicuously posted and roped off from normal traffic. Such areas are under the supervision of the Health Physics Services group.

Personnel shall be checked for contamination immediately after exiting a contaminated area at the nearest personnel monitor, or by standing on a “hand-and-foot” or “portal” monitor for a predetermined length of time or by portable Health Physics instrumentation. Permanent personnel contamination monitors are located so that an intercom station is close enough that help can be summoned if necessary.

Any equipment or materials leaving a potentially contaminated area, and all equipment or materials leaving the plant radiation controlled area, will be surveyed for surface contamination and nonremovable radioactivity using smears and/or portable instruments of appropriate sensitivity. Items of appropriate size may also be placed in the Tool and Equipment Monitor (TEM) for release from the plant radiation controlled area.

12.3.2.3.4 Airborne Radioactivity Assessment and Control

Airborne radioactivity is routinely assessed using local sampling, moveable air monitors, and the installed Radiation Monitoring System. Airborne radioactive materials (particulates, noble gases, halogens, tritium) are sampled and analyzed using appropriate techniques. Since local sampling will provide better estimates of airborne contamination levels existing in a work area than will a monitor reading, such special air sampling is used in the RWP program to keep ORE due to airborne radioactivity ALARA. Moveable air monitors and the installed airborne radioactivity monitors are used to provide alarm indications and additional information which is used with local sampling for the assessment of airborne radioactivity.

Airborne radioactivity is controlled by minimizing to the extent practical the sources of this radioactivity, such as surface contamination and leaking valves; and confining unavoidable or accidental releases of airborne radioactivity in plant areas through the use of the ventilation system.

12.3.2.3.5 Respiratory Protection

The respiratory protection equipment available at the plant is listed in Section 12.3.2.2.2. The issuance of this equipment is specified, when necessary, as part of the RWP program, on the basis of special air sampling conducted in areas where work is being performed. This equipment is selected and maintained by the Health Physics group. The fitting and training programs for respiratory protection equipment is the responsibility of the Manager, Radiological Protection and Chemistry. Training is required prior to the use of respiratory protection equipment. Depending on the type of respirator, a fit test and medical evaluation are required.

12.3.2.3.6 Radioactive Materials Handling

Radioactive materials, sealed or unsealed, are handled and stored in such a manner that ORE will be kept ALARA.

Examples of specific methods of handling and storage of radioactive materials to meet this objective include:

1. Minimizing the distance that radioactive samples are transported by personnel.
2. Use of shielded sample transporters as appropriate.
3. Storage of calibration sources in appropriately shielded, labeled, and secured containers.
4. Use of remote actuators or similar devices to maximize the distance of personnel from high level sources.
5. Maintenance of accurate source activity inventories on all calibration sources.

Procedures are written and implemented by the Manager, Radiological Protection and Chemistry for the handling of radioactive materials, including procedures for the safe recovery from radioactive spills or source leakage.

12.3.2.3.7 Radiation Work Permit Program

A RWP program is established as an integral part of the ALARA policy implementation, and is the responsibility of the Manager, Radiological Protection and Chemistry. A RWP may, at the discretion of the Manager, Radiological Protection and Chemistry, be required for any operation (including maintenance, adjustments, calibrations, inspections, or normal operations) which:

1. Takes place in a radiation, high radiation, or airborne radiation area, as defined in 10 CFR 20 or in a contaminated area as specified in the plant administrative procedures.
2. Involves maintenance or other adjustments to any system or component which contains, stores, transports, or collects radioactive materials.
3. In the judgment of the Manager, Radiological Protection and Chemistry warrants the issuance of a RWP prior to initiating the operations.

The primary objectives of the RWP program are:

1. To ensure that the radiological conditions associated with operations involving radioactive materials, directly or indirectly, are known as accurately as possible.
2. To ensure that appropriate and adequate protective measures are taken against these conditions.
3. To ensure that the personnel involved in these operations are aware of the radiological conditions and required protective measures associated with the operation.
4. To ensure that the Manager, Radiological Protection and Chemistry, Health Physicist, Field Operations, or the HP Shift Leader are aware of such operations, and approves of the required protective measures. This approval will be indicated by the signature of any of the previously mentioned individuals on the RWP form.
5. Provides a means for tracking radiation dose by group, job, location, and component.

The assessment of the radiological conditions associated with operations requiring the issuance of a RWP is performed by the Health Physics Services group. The protective measures taken to mitigate these conditions will be subject to the approval of the Manager, Radiological Protection and Chemistry.

Examples of such measures include:

1. Requiring the use of personnel protective clothing and equipment, as appropriate, for the conditions involved.
2. Limitation of stay time in radiation/radioactivity areas.
3. The use of temporary shielding, temporary containments, remote handling devices, or other techniques to minimize the conditions in the operation area.

The RWP form is used to record the total estimated exposure received as derived from the personnel dosimetry readings in order to acquire a total estimated man-rem figure. The actual stay time and estimated exposure of each individual in the RWP-controlled area is recorded electronically via computer or on a dose card. At the discretion of a Health Physicist, Health Physics group personnel may be assigned to supervise the implementation of RWP's and/or to make special surveys during the course of the operation. Personnel involved in the operation acknowledge (by their signature on the RWP form or other appropriate documents) their commitment to the ALARA policy and their obligation to abide by the radiological protection decisions of the Health Physics group personnel.

12.3.2.3.8 Radiation Protection Program Review

The Manager, Radiological Protection and Chemistry is responsible for conducting an ongoing review of the plant radiation protection program, with the primary objective of finding means to reduce ORE as far below the limits of 10 CFR 20 as reasonably achievable. This review includes an analysis of the following aspects of the program:

1. Personnel exposures, as indicated by RWP data and periodic dosimetry readings, to identify trends and identify groups or individuals that are receiving large doses.
2. Radiation survey data, to identify trends in exposure or contamination levels for various locations around the plant.
3. Methods and procedures, to determine means of further reducing ORE's, when practical.
4. Equipment and facilities, to determine where improvements are practical.

In addition to these reviews, management provides independent audit functions as described in Section 12.3.1.1.1.

12.3.2.3.9 Radiation Protection Training

Plant personnel, both permanently assigned and temporary, receive training in the principles of radiation protection commensurate with the degree of hazard associated with their respective work assignments. Such training encompass at least the following topics:

1. Properties of radiation and radioactivity.
2. Biological effects of radiation on humans.
3. Measurement of radiation and radioactivity.
4. Principles and techniques of radiation protection.
5. General regulatory and specific facility license radiation protection requirements.
6. Specific procedures appropriate for particular work assignments.
7. ALARA concept and management commitment thereto.

Personnel who are reassigned to positions involving a greater degree of radiation hazard are retrained and tested at the higher level of radiation protection proficiency required for that assignment. The Manager, Radiological Protection and Chemistry approves the content of the radiation protection training program.

12.3.3 Personnel Dosimetry

12.3.3.1 External Radiation Exposure

Plant employees, visitors, and support personnel who enter the radiation controlled area are required to wear personnel dosimetry. The type of dosimetry issued is based upon expected radiological conditions. Neutron exposure is tracked using staytime and exposure rate calculations and/or is measured (for record) using neutron sensitive dosimetry or calculations, as appropriate. Beta and gamma exposure is tracked/controlled using pocket dosimeters, electronic dosimeters, calculations, or secondary thermoluminescent dosimeters (TLDs) as appropriate. Beta and gamma exposure is measured (for record) by TLD or by calculation/investigation in unusual circumstances. TLDs are processed periodically, not to exceed annually, by a NVLAP accredited processor. TLDs may be processed more frequently during outages, refueling, or when an

individual’s exposure status is in question. Records of exposure are kept for each individual in accordance with the recommendations of Regulatory Guide 8.7. The results of the personnel dosimetry measurements are periodically analyzed to find trends in exposures, identify groups or individuals whose exposures are consistently high, and to find methods of reducing these exposures.

12.3.3.2 Internal Radiation Exposure

Internal radiation exposure is assessed using whole body counting and bioassay techniques and estimated where appropriate by calculational methods. The concepts, models, equations, and assumptions used for the assessment of internal radiation exposure follow the recommendations of Regulatory Guide 8.9 or those regulations/regulatory guides in effect at the time. All personnel who regularly enter areas where the potential exists for inhalation, ingestion, or absorption of radioactive materials are routinely assessed for internal contamination. Nonroutine internal radioactivity assessments are made whenever there is reasonable chance that personnel have inhaled, ingested, or absorbed radioactive materials.

Table 12.3-1
Contamination Control Monitors

Instrument Type	Remarks
Portal Monitor	Alarm sounds on high activity or insufficient length of count. Controls egress from potentially contaminated areas.
“Frisker”	“Pancake” type detector for quick contamination checks of personnel or equipment.

Table 12.3-2
Fixed Laboratory Instrumentation

Instrument	Detector	Sensitivity (1)	Number	Location	Remarks
Low Background Gas Flow Proportional Counter	Proportional Counter	200 dpm	2	412' CB	Used for counting alpha/beta smears, residue from evaporated water and radiochemistry samples; equipped with automatic sample chamber.
Spectroscopy System	Intrinsic Germanium	As per the Technical Specifications	2	412' CB	Spectroscopy system with low-level shield; used primarily for effluent sample analysis.
Liquid Scintillation	--	As per the Technical Specifications	1	412' CB	Used for tritium determination in water, air (freeze out or gel), and urine.
Shielded GM Counting System	GM	200 dpm	2	412' CB	High-level sample counting; backup for low background system.

Table 12.3-2 (continued)
Fixed Laboratory Instrumentation

Instrument	Detector	Sensitivity (1)	Number	Location	Remarks
Laboratory Monitor	GM	N/A	1	412' CB	Check potentially high-level samples before placing in low-level system; monitor background in counting room, warn of changes.
Self-Reading Pocket Dosimeter Chargers	N/A	N/A	2	Various	Used for charging and/or zeroing pocket chamber-type dosimeters.
Electronic Dosimeter Readers	N/A	N/A	2	412’ CB	Used for programming and turning electronic dosimeters on/off.

(1) Instruments will be calibrated as part of the counting laboratory quality control program, using NBS-traceable sources appropriate for each counting system.

Table 12.3-3
Portable Health Physics Instruments

Instrument	Radiation Detected	Range	Accuracy	Number (1)	Location	Remarks
GM Survey Meter	beta gamma	0-200 mr/hr	± 10% full Scale	6	Refer to Section 12.3.2.1.2	Equipped with end window, side window, or pancake probe.
GM Survey Meter	gamma	0-1000 R/hr	± 10%	14	Refer to Section 12.3.2.1.2	Fishing pole type with extendable probe; 20 in to 13 ft.
GM Survey Meter-Friskers	beta gamma	0-50,000 cpm	± 10%	50	Refer to Section 12.3.2.1.2	Primarily personnel monitoring usage.
GM Survey Meter-Remote Monitoring Gamma	gamma	0-1000 mr/hr	± 10% full scale	13	Refer to Section 12.3.2.1.2	Provide remote area monitoring capability.
Ionization Survey Meter	beta gamma	0-5000 mr/hr	± 10% full Scale	33	Refer to Section 12.3.2.1.2	Air ionization chamber.
High Range Survey Meter	beta gamma	0.1-≥500 R/hr	± 10% full Scale	1	Refer to Section 12.3.2.1.2	Air ionization chamber.
Neutron Rem Counter	thermal through fast neutrons	0-5 Rem/hr	± 10% full Scale	3	Refer to Section 12.3.2.1.2	A BF_3, helium or equivalent tube inside a moderator for detection of neutrons up to 10 MeV.
Scintillation Counter	alpha	0-1M cpm	± 10% full Scale	1	Refer to Section 12.3.2.1.2	An alpha scintillation crystal covered with a thin mylar window.
Pocket Dosimeter	gamma x-ray	0-500 mr	± 10%	360	Various	
Pocket Dosimeter	gamma x-ray	1500 mr	± 10%	120	Various	

Table 12.3-3 (continued)
Portable Health Physics Instruments

Instrument	Radiation Detected	Range	Accuracy	Number (1)	Location	Remarks
Electronic Dosimeters	gamma	-	± 5%	400	Various	Used for personnel exposure tracking. They are rate and integrating. Number is based on having sufficient in stock to support operational and E-kit needs.
Thermoluminescent Dosimeters	gamma, beta, neutron	-	± 20%	variable	Vendor Supplied	Used personnel exposure monitoring as dose of legal record. Integrating.
Job Site Air Samplers	-	-	-	14	Various	Particulate and iodine sampler; may have extendable sample head (tygon); normally used at job sites for longer or continuous sampling.
Hand Held Air "Grab" Samplers	-	-	-	17	Various	Particulate and iodine sampler; normally used for quick grab samples or short duration jobs.
Tritium Samplers	-	-	-	2	Various	
Noble-Gas Samplers	-	-	-	5	Various	

(1) The number of instruments is based on the minimum number that should be in inventory (not necessarily in calibration or in service) to support normal operational needs and in some cases, emergency kits; exceptions are noted in the remarks.

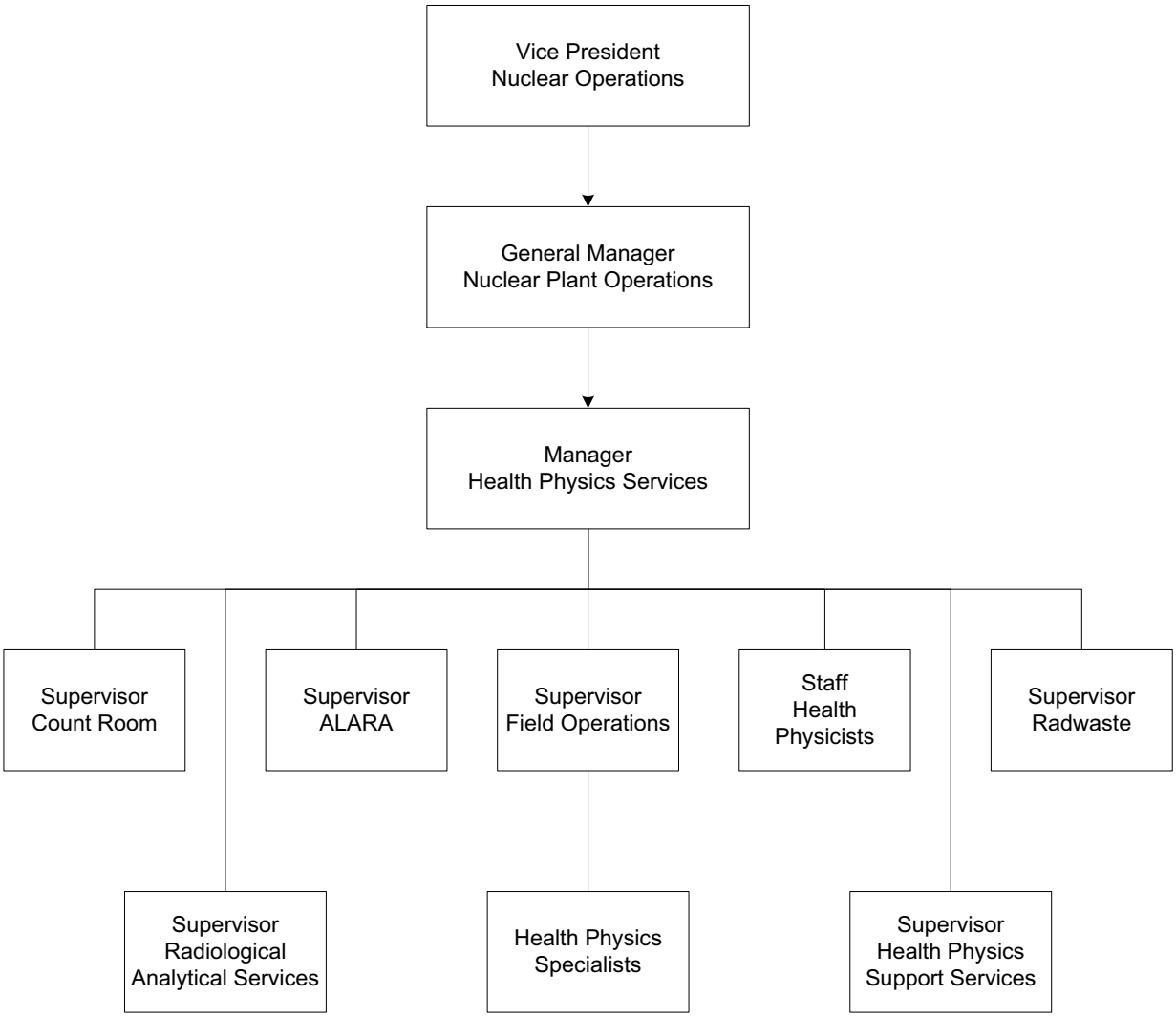
Table 12.3-4
Respiratory Protection Equipment

Dedicated To:	Type	Quantity
Normal Operations and Major Outages	Full Face Particulate Respirator.	100
	Full Face Continuous Air Flow Respirator.	40
	Continuous Air Flow Hood.	6
	Self-Contained Breathing Apparatus (30 Min. Air Supply).	10
Emergency Use	Full Face Particulate Respirator.	20
	Self-Contained Breathing Apparatus (30 Min. Air Supply).	14
	Air Supplied Suit or Hood	4

All respiratory devices available for emergency and non-emergency conditions as required.

Figure 12.3-1
HEALTH PHYSICS ORGANIZATION CHART

NOTE FIGURE 12.3-1
Figure 12.3-1 is being retained for historical purposes per NEI 98-03, Revision 1.



SOUTH CAROLINA ELECTRIC & GAS CO,
VIRGIL C. SUMMER NUCLEAR STATION

Health Physics
Organization Chart

Figure 12.3-1

Amendment 00-01
Decmeber 2000

Appendix 12A

DESIGN REVIEW OF PLANT SHIELDING AND ENVIRONMENTAL QUALIFICATION OF EQUIPMENT FOR SPACES/SYSTEMS WHICH MAY BE USED IN POST ACCIDENT OPERATIONS OUTSIDE THE REACTOR BUILDING AT THE VIRGIL C. SUMMER NUCLEAR STATION

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12A DESIGN REVIEW OF PLANT SHIELDING AND ENVIRONMENTAL QUALIFICATION OF EQUIPMENT FOR SPACES/SYSTEMS WHICH MAY BE USED IN POST ACCIDENT OPERATIONS OUTSIDE THE REACTOR BUILDING AT THE VIRGIL C. SUMMER NUCLEAR STATION

12A.1 INTRODUCTION

This report has been prepared in response to the September 13, 1979, letter from Darrel G. Eisenhut of the NRC to all operating nuclear power plants. This letter presented an implementation schedule for the recommendations presented in "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations" (NUREG-0578). The requirements defined in the September 13th letter were subsequently clarified in a letter from Harold R. Denton to all operating nuclear power plants dated October 30, 1979.

Among the requirements defined in the two NRC letters is a review to determine whether post-accident radiation fields unduly limit personnel access to areas necessary for mitigation of or recovery from an accident or unduly degrade the proper operation of safety equipment. Corrective actions for problems identified as a result of the review are also to be determined. This report presents the results of such a review for the Virgil C. Summer Nuclear Station.

The review was based on the following guidelines:

a. The post-accident dose rate in areas requiring continuous occupancy should not exceed 15 mr/hr.

b. The post-accident dose rate in areas which do not require continuous occupancy should be such that the dose to an individual during a required access period is less than 5 Rem whole body or its equivalent, in order to maintain compliance with General Design Criterion 19.

c. The integrated dose to safety equipment as a result of the accident should be less than the dose for which the equipment has been qualified to ensure that the capability of the equipment to perform its safety function has not been degraded, in order to maintain compliance with General Design Criterion 4.

d. The minimum radioactive source term used in the evaluation should be equivalent to the source terms recommended in Regulatory Guides 1.3 and 1.4 (Reference 4).

12A.2 SUMMARY

This report provides a review of the Virgil C. Summer Nuclear Power Plant to determine whether post-accident radiation fields unduly limit personnel access to areas necessary for mitigation of or recovery from an accident, or unduly degrade the proper operation of safety

equipment. This review was accomplished using the recommendations and guidelines of NUREG-0578 and subsequent clarifications as provided by the NRC.

A detailed discussion of the evaluation of plant vital areas and equipment qualification for post-accident conditions is presented in Sections 4.0 and 5.0. Results indicated that certain areas of the plant required additional radiation shielding to reduce the post-accident radiation fields. These areas and the shielding modifications utilized are described in the following paragraphs.

Area “A” is the location of the residual heat removal (RHR) pumps, reactor building spray pumps, and the pump room cooling units. The RHR/Spray piping is adequately shielded and does not restrict post-accident access to this area. However, a significant potential source of exposure to plant personnel can result from the RHR/Spray pump room sump line. This line was unshielded and located in the hallway between pump room B and the waste holdup tank, and resulted in a potentially high radiation area during both normal and accident operating conditions. The resultant dose levels in the subject area have been reduced to acceptable values by the re-routing and venting of the line to permit the line to drain during sump pump shutdown periods, and the placement of lead shielding to prevent streaming to the operating floor 374’-0". The new pipe configuration and radiation shielding allows personnel access in accordance with the occupancy requirements of Table 12A.4-2, and the resultant integrated dose meets the dose requirements of 10CFR50, Appendix A, General Design Criterion 19 as outlined in NUREG-0737.

Following an accident, personnel access to the Auxiliary Building is controlled at the 412’-0" elevation from the Control Building. As a result, the use of the stairway and elevator located in cubicle 12-09 as an access route to vital areas above and below the 412’-0" elevation is important. A 10-inch RHR line penetrates the south and east shield walls of cubicle 12-09 at elevation 429’-6" resulting in significant doses to workers in this area. Shortly after the accident, the integrated dose to a worker transversing this area would be of the order of 1 rem. The resultant dose levels in the subject area have been reduced to acceptable values by the addition of lead shielding. The new configuration allows personnel access in accordance with the occupancy requirements of Table 12A.4-2, and the resultant integrated dose meets the dose requirements of 10CFR50, Appendix A, General Design Criterion 19 as outlined in NUREG-0737.

Area “I” is the location of the charging/safety injection pump room cooling units. This area was found to contain high radiation levels due to unshielded CVCS piping located at several places within the area. In order to permit the required occupancy time in the area for manual valve alignment or maintenance, the resultant dose levels in the area have been reduced to acceptable values by the addition of lead and concrete shielding. The new configuration allows personnel access in accordance with the occupancy requirements of Table 12A.4-2, and the resultant integrated dose meets the dose requirements of 10CFR50, Appendix A, General Design Criterion 19 as outlined in NUREG-0737.

In the area of the Intermediate Building between the east and west penetration access areas there were several RHR, safety injection, and CVCS lines which were routed above the sides of an open pipe chase at elevation 422’-3". This permitted direct streaming from the piping to reach the floor area of Intermediate Building floor elevation 412’-0" which contains safety related equipment. The resultant dose levels in this area of the Intermediate Building have been reduced to acceptable values by the modification of the pipe chase as follows: (1) extension of the pipe chase side above the 12" RHR line, (2) addition of 6" concrete shielding to the existing 1 foot concrete shielding, (3) re-location of an access ladder to prevent streaming through a concrete cutout. The new configuration allows personnel access in accordance with the occupancy requirements of Table 12A.4-2, and the resultant integrated dose meets the dose requirements of 10CFR50, Appendix A, General Design Criterion 19 as outlined in NUREG-0737.

12A.3 SOURCE TERMS AND CALCULATIONAL METHODOLOGY

12A.3.1 Source Terms

12A.3.1.1 Basis for the Source Terms

The activity releases assumed in this review are based on the assumptions and regulatory positions contained in the Regulatory Guides 1.4 (Reference 4) and 1.7 (Reference 5). The activity assumed for liquid source term calculation is based on 100 percent of the noble gas inventory, 50 percent of the halogen core inventory, and 1 percent of all other nuclides in the core inventory. The activity assumed for gaseous source term calculation is based on 100 percent of the noble gas core inventory and 25 percent of the halogen core inventory.

12A.3.1.2 Liquid Source Terms

Two liquid sources are considered in the design review: (1) the undiluted fluid as found within the reactor coolant system, and (2) the diluted fluid as found within the reactor building recirculation sump. The first source term, undiluted reactor coolant, is required in the examination of those systems whose flow originates from either the Reactor Coolant System or an auxiliary system containing the undiluted primary fluid. The source terms are based on the dilution of the liquid activity inventory discussed in the first paragraph with the fluid volume of the Reactor Coolant System. This source is used for the examination of the reactor coolant fluid sampling section of the Nuclear Sampling System, and those portions of the Chemical and Volume System associated with the degasification of the reactor coolant fluid.

In the second liquid source term, consideration is given for the dilution of the liquid activity inventory discussed in the first paragraph with the fluid volume contained in the reactor building recirculation sump. The minimum fluid volume expected in the sump, and the individual contributors to that volume, are given in Table 12A.3-1. These source terms are utilized in the examination of those systems which receive their fluid supply from the reactor building recirculation sump. Those systems which are considered in the review are:

Residual Heat Removal System

Reactor Building Spray System

Safety Injection System

Nuclear Sampling System (RHR process fluid sample)

12A.3.1.3 **Gas Source Terms**

The gaseous source terms were determined for containment and the waste gas system using the activity releases described in Section 12A.3.1.1.

The containment airborne source term was based on the dilution of the gaseous activity inventory by the containment free volume atmosphere.

Although not designed for reactor coolant degasification under post-accident conditions, the waste gas system was evaluated for the exposures emitted and received under the post-accident conditions. The waste gas system is designed to remove the fission product gases from the reactor coolant contained in the Volume Control Tank (VCT). The amount of fission gases removed from the reactor coolant in the VCT and collected by the waste gas system can be related to the amount entering the VCT as follows:

(1) Stripping Efficiency (SE):

$$SE = \frac{C_R - C_L}{C_R - C_{L_{eq}}}$$

2) Stripping Fraction (SF):

$$SF = \frac{C_R - C_L}{C_R}$$

where C_R = the gas concentration in the reactor coolant liquid entering the Volume Control Tank,

C_L = the gas concentration in the reactor coolant liquid leaving the Volume Control Tank,

$C_{L_{eq}}$ = the gas concentration in the reactor coolant liquid leaving the Volume Control Tank, assuming the ratio of the gas concentration in the liquid and gas phases in the Volume Control Tank follows Henry's Law.

The waste gas system source terms were determined for the degasification of the reactor coolant liquid by calculation of the quantity of activity entering the Volume Control Tank via the normal letdown path. For the sake of conservatism, the stripping efficiency of this process is assumed to be 100 percent. Therefore, in the previous equation of the stripping fraction, $C_L = C_{L_{eq}}$, and the stripping fraction is:

$$SF = \frac{C_R - C_{L_{eq}}}{C_R}$$

Thus, the separation of the fission gases from the reactor coolant liquid in the VCT will follow Henry's Law. This results in the maximum theoretical gas concentration in the vapor phase of the VCT and, hence, the maximum quantity of gas enters the waste gas system.

12A.3.2 Methodology

12A.3.2.1 Calculation of Dose Rates

Dose rates for the areas of interest in this review were calculated by determining the potential contributing sources at a representative location and using the appropriate source term from Table 12A.3-2 adjusted for decay as required. The dose rate at the representative location was used as the general area dose rate for the area. The SDC computer code (Reference 1) was used in performing the dose rate calculations. Energy groups required as input to the computer code were determined using the gamma ray energy and intensity data in References. 2 and 3 for the nuclides in Table 12A.3-2.

MicroShield (Reference 7) was used to determine gamma energy, intensities, and dose rates for the waste gas sources and the containment sump sources.

12A.3.2.2 Calculation of Doses to Personnel During Post Accident Access to Vital Areas

Personnel doses received in performing a specific task in a given vital area are calculated as the sum of the doses received during travel to and from the vital area and the dose received while performing the given operation in the vital area.

The doses received during travel are determined by calculating dose rates at selected locations (or at a single location if the dose rate along the travel route is relatively uniform) along the travel route using the methodology discussed in Section 12A.3.2.1 and multiplying the dose rates by the appropriate travel time for each selected location along the travel route.

Doses received while performing a given operation are determined by multiplying the dose rate for the given area by the time required to perform the operation. Dose rates for the given vital area are determined using the methodology discussed in Section 12A.3.2.1.

12A.3.2.3 Calculation of Integrated Doses to Safety Equipment

The integrated dose to a given item of safety equipment is determined by integrating the dose rate appropriate for the given item over the time period that it is required to be available to perform its safety function. Dose rates are calculated using the methodology discussed in Section 12A.3.2.1.

Table 12A.3-1
CONTAINMENT SUMP MINIMUM LIQUID INVENTORY

Liquid Source	Liquid Volume (ft^3)
Refueling Water Storage Tank	44,483 [(a)]
Safety Injection Accumulators	3,052 [(b)]
Sodium Hydroxide Storage Tank	406 [(c)]
Reactor Coolant System	6,623
Containment Sump Extension [(d)]	1,159
Minimum Containment Sump Volume =	55,723 ft^3

a. Refueling Water Storage Tank at minimum operating water level at start of drawdown of the tank. The tank drawdown will be terminated at LO-LO level upon the automatic initiation of recirculation via the RHR system.
b. The total volume attributed to the accumulators includes the minimum tank volumes plus the volume of the injection lines.
c. The minimum usable volume of liquid in the Sodium Hydroxide Storage Tank.
d. Containment Sump Extension refers to the fluid volume contained in systems that recirculate sump fluid during the recirculation phase of LOCA.

Table 12A.3-2
V.C. SUMMER
SHIELDING SOURCE TERMS (T = 0)

Isotope	Liquid [1] Source Activity (Ci)	Gaseous [2] Source Activity (Ci)	Containment Sump Concentration (μCi/cc)	Reactor Coolant Concentration (μCi/cc)	Containment Airborne Concentration (μCi/cc)	Waste Gas [3] Concentration (μCi/cc)
Br-84	7.5 + 6	3.75 + 6	4.80 + 3	2.90 + 4	7.20 + 1	1.40 + 4
Kr-87	3.70 + 7	3.70 + 7	3.10 + 4	1.43 + 5	7.10 + 2	2.79 + 6
Te-133	4.40 + 5	-	2.80 + 2	1.70 + 3	-	-
Cs-134	1.70 + 5	-	1.10 + 2	6.56 + 2	-	-
Cs-136	4.70 + 4	-	3.00 + 1	1.81 + 2	-	-
Cs-137	7.03 + 4	-	4.40 + 1	2.71 + 2	-	-
Ba-139	1.50 + 6	-	9.50 + 2	5.79 + 3	-	-
Br-83	3.20 + 6	1.60 + 6	2.00 + 3	1.24 + 4	3.07 + 1	8.33 + 3
Kr-83m	6.30 + 6	6.30 + 6	6.00 + 3	2.43 + 4	1.21 + 2	6.31 + 5
Kr-85m	1.90 + 7	1.90 + 7	1.70 + 4	7.34 + 4	3.65 + 2	1.30 + 6
Kr-85	7.42 + 5	7.42 + 5	5.30 + 2	2.86 + 3	1.42 + 1	4.20 + 4
Kr-88	5.50 + 7	5.50 + 7	4.30 + 4	2.12 + 5	1.06 + 3	3.59 + 6
Rb-88	5.41 + 5	-	3.40 + 2	2.09 + 3	-	-
Rb-89	6.80 + 5	-	4.30 + 2	2.63 + 3	-	-
Sr-89	7.40 + 5	-	5.30 + 2	2.86 + 3	-	-
Sr-90	5.00 + 4	-	3.20 + 1	1.93 + 2	-	-
Y-90	5.00 + 4	-	3.20 + 1	1.93 + 2	-	-
Sr-92	9.10 + 5	-	7.00 + 2	3.51 + 3	-	-
Y-92	1.00 + 6	-	7.20 + 2	3.86 + 3	-	-
Sr-93	1.10 + 6	-	7.00 + 2	4.25 + 3	-	-
Y-93	1.10 + 6	-	8.10 + 2	4.25 + 3	-	-
Mo-99	1.50 + 6	-	9.50 + 2	5.79 + 3	-	-
Tc-99m	1.30 + 6	-	8.20 + 2	5.02 + 3	-	-
Ru-103	1.10 + 6	-	7.00 + 2	4.25 + 3	-	-
Rh-103m	1.10 + 6	-	7.00 + 2	4.25 + 3	-	-
Ru-106	4.10 + 5	-	2.60 + 2	1.58 + 3	-	-

Table 12A.3-2 (continued)
V.C. SUMMER
SHIELDING SOURCE TERMS (T = 0)

Isotope	Liquid [1] Source Activity (Ci)	Gaseous [2] Source Activity (Ci)	Containment Sump Concentration (μCi/cc)	Reactor Coolant Concentration (μCi/cc)	Containment Airborne Concentration (μCi/cc)	Waste Gas [3] Concentration (μCi/cc)
Rh-106	4.10 + 5	-	2.60 + 2	1.58 + 3	-	-
Te-132	1.10 + 6	-	7.00 + 2	4.25 + 3	-	-
I-132	5.90 + 7	2.95 + 7	3.80 + 4	2.28 + 5	5.66 + 2	1.06 + 5
Te-134	1.60 + 6	-	1.00 +3	6.18 + 3	-	-
I-134	8.90 + 7	4.45 + 7	5.70 + 4	3.44 + 5	8.54 + 2	1.59 + 5
Xe-138	1.50 + 8	1.50 + 8	9.50 + 4	5.79 + 5	2.88 + 3	1.08 + 7
Cs-138	1.50 + 6	-	9.50 + 2	5.79 + 3	-	-
Ba-140	1.40 + 6	-	9.50 + 2	5.41 + 3	-	-
La-140	1.50 + 6	-	9.50 + 2	5.79 + 3	-	-
Ce-143	1.20 + 6	-	8.20 + 2	4.63 + 3	-	-
Pr-143	1.20 + 6	-	8.20 + 2	4.63 + 3	-	-
Ce-144	9.20 + 5	-	5.80 + 2	3.55 + 3	-	-
Pr-144	1.20 + 6	-	7.60 + 2	4.63 + 3	-	-
Sr-91	9.20 + 5	-	7.00 + 2	3.55 + 3	-	-
Y-91	9.60 + 5	-	6.50 + 2	3.71 + 3	-	-
Zr-95	1.30 + 6	-	8.20 + 2	5.02 + 3	-	-
Nb-95m	-	-	-	-	-	-
Nb-95	1.30 + 6	-	8.20 + 2	5.02 + 3	-	-
Zr-97	1.30 + 6	-	8.60 + 2	5.02 + 3	-	-
Ru-105	8.60 + 5	-	5.40 + 2	3.32 + 3	-	-
Rh-105m	8.60 + 5	-	5.40 + 2	3.32 + 3	-	-
Rh-105	5.50 + 5	-	3.50 + 2	2.12 + 3	-	-
Te-131	7.20 + 5	-	4.60 + 2	2.78 + 3	-	-
I-131	4.10 + 7	2.05 + 7	2.60 + 4	1.58 + 3	3.93 + 2	7.26 + 4
Xe-131m	6.51 + 5	6.51 + 5	4.10 + 2	2.51 + 5	1.25 + 1	2.33 + 4
I-133	7.80 + 7	3.90 + 7	5.40 + 4	3.01 + 5	7.49 + 2	1.49 + 5
Xe-133m	3.80 + 6	3.80 + 6	1.50 + 4	1.47 + 4	7.29 + 1	1.04 + 6

Table 12A.3-2 (continued)
V.C. SUMMER
SHIELDING SOURCE TERMS (T = 0)

Isotope	Liquid [1] Source Activity (Ci)	Gaseous [2] Source Activity (Ci)	Containment Sump Concentration (μCi/cc)	Reactor Coolant Concentration (μCi/cc)	Containment Airborne Concentration (μCi/cc)	Waste Gas [3] Concentration (μCi/cc)
Xe-133	1.50 + 8	1.50 + 8	1.10 + 5	5.79 + 5	2.88 + 3	7.23 + 6
I-135	6.90 + 7	3.45 + 7	4.90 + 4	2.66 + 5	6.62 + 2	1.36 + 5
Xe-135m	4.20 + 7	4.20 + 7	2.70 + 4	1.62 + 5	8.06 + 2	2.80 + 6
Xe-135	2.90 + 7	2.90 + 7	2.30 + 4	1.12 + 5	5.57 + 2	1.80 + 6
Ba-141	1.30 + 6	-	8.20 + 2	5.02 + 3	-	-
La-141	1.30 + 6	-	8.90 + 2	5.02 + 3	-	-
Ce-141	1.40 + 6	-	8.90 + 2	5.41 + 3	-	-

(1) Based on 100% noble gas core inventory, 50% halogen core inventory, and 1% of all others core inventory.
(2) Based on 100% noble gas core inventory and 25% halogen core inventory.
(3) Source concentrations are for the VCT gas space and inlet line up to the waste gas compressor.

12A.4 REVIEW OF AREAS REQUIRING ACCESS FOR POST ACCIDENT OPERATIONS

A vital area is defined as any area which will or may require occupancy to permit an operator to aid in the mitigation of or recover from an accident. Vital areas for the Virgil C. Summer Nuclear Station are shown in Figures Figure 12A.4-1 through Figure 12A.4-7. Calculated exposure rates as a function of time after the accident are given in Table 12A.4-1. Vital area occupancy and access dose are summarized in Table 12A.4-2. Access routes to the vital areas are described in Table 12A.4-3.

12A.4.1 Area A: RHR/Spray Pump Rooms and Cooling Units

Area “A” as identified on Figure 12A.4-1 is the location of the residual heat removal (RHR) pumps, reactor building spray pumps and the common pump room cooling units. Failure of an RHR or Spray pump following an accident will result in a minimum safeguard condition and access to this area may be required to ensure that more than one pump is available for long term cooling of the reactor core. Under these circumstances, plant personnel may require access to this area for operations such as pump seal replacement or minor maintenance. Tasks such as these require that three individuals spend approximately 4 hours in the pump rooms or at the cooling units.

Sources of exposure in this area are the RHR and spray system piping in the system train that is operating. This piping is located in the adjacent pump room and in the valve and piping area located above at elevation 397’- 0". Piping in the train requiring maintenance or repair is assumed to be flushed and drained. Access to this area is not required immediately since only long term operation need be considered. One day after the accident, the exposure rate is 383 mr/hr in the pump rooms and 614 mr/hr at the cooling units. The calculated dose to an individual for 4 hours of occupancy is 1.41 rem and 2.25 rem, respectively. Table 12A.4-2 shows that 4 hours occupancy in this area is possible prior to one day following the accident.

The access route to area “A” is route “1” described in Table 12A.4-3. This access route will add a total of 0.024 rem to the worker dose if the task is started one day after the accident.

12A.4.2 Area B: Charging/SI Pump Rooms

Area “B” is the location of the charging/safety injection (SI) pumps and is identified on Figure 12A.4-2. Failure of one of these pumps following an accident will result in a minimum safeguards condition and access to this area may be required to ensure that all pumps are available for long term cooling of the reactor core. Under these circumstances, plant personnel may require access to this area for operations such as pump seal replacement or minor maintenance. Tasks such as these require that three individuals spend approximately 4 hours in the pump rooms.

Sources of exposure in this area are from the charging/SI pump piping for the pumps that are operational and are located in the adjacent pump rooms. Piping in the pump room where

maintenance or repair is required is assumed to be flushed and drained. Access to this area is not required immediately since only long term operation need be considered. Two days after the accident, the exposure rate is 630 mr/hr. The calculated dose of occupancy is 2.39 rem. Table 12A.4-2 shows that 4 hours occupancy in this area is possible prior to two days following the accident.

The access routes to area “B” are routes “3” and “8” and are described in Table 12A.4-3. These access routes will add 0.02 rem and 0.05 rem to the dose if the task is started two days after the accident.

12A.4.3 Area C: Charging/SI Pump C Auxiliaries Local Control Panel

Area “C” as identified on Figure 12A.4-2 is the location of charging/safety injection pump C auxiliaries local control panel. Failure of one of the charging/SI pumps will result in minimum safeguards condition and access to this area may be required for manual switching of the charging/SI pumps. This task would require that two workers spend approximately 2 minutes at the control panels.

The major source of exposure in this area is a 3 inch safety injection line located inside the shield labyrinth at the entrance to cubicles 88-23 and 88-24. A direct line of sight is possible from this source to the immediate vicinity of the pump C transfer switch. This line will not become a source of exposure until recirculation of containment sump liquid is initiated. Additional exposure in this area results from charging/SI piping in pump room 88-23.

Access to this area could be required immediately after the accident. Access at 30 minutes is assumed in order to evaluate the worst case of containment sump liquid in the 3 inch safety injection line at the start of recirculation. Assuming that the workers are in a direct line of sight with the unshielded safety injection line, the exposure rate in the area is 82.6 rem/hr which results in an occupancy dose of 2.75 rem for the 2 minute time period.

The access route to area “C” is route “7” described in Table 12A.4-3. This access route will add a total of 1.40 rem to the worker dose if the task is started 30 minutes after the accident.

12A.4.4 Area D: Spent Fuel Pit Heat Exchanger

Area “D” is the location of the spent fuel pit heat exchangers (see Figure 12A.4-2). Access to this area is not required to aid in the mitigation of or recovery from an accident, but should conditions dictate, access may be needed to service the heat exchanger to maintain cooling of the spent fuel. Under these circumstances, post-accident operations in this area require only long-term periodic surveillance.

The exposure rate in this area following an accident is negligible since there are no post-accident sources of activity in the vicinity of the heat exchangers. This permits unlimited access (40 hours/week) in this area.

The access route to area “D” is route “9” described in Table 12A.4-3. This access route will add a total of 0.02 rem to the worker dose if the task is started one day after the accident.

12A.4.5 Area E: Radwaste Gas Handling Control Panels

Area “E” as identified in Figure 12A.4-2 is the location of the radwaste gas recombiner analyzer and control panels. Access to this area is not required following an accident since it is not planned to start-up the radwaste gas handling system. If degassing of the primary coolant system becomes necessary following an accident, the operation will be accomplished by utilizing the reactor head vent system.

12A.4.6 Area F: Spent Fuel Pit Cooling Pumps and Local Control Panels

Area “F” as identified on Figure 12A.4-3 is the location of the spent fuel pit cooling pumps and local control panels. Access to this area is not required to aid in the mitigation of or recovery from an accident, but should conditions dictate, access to this area may be needed in order to maintain cooling of the spent fuel. Under these circumstances, plant personnel may require access to this area for operations such as pump seal replacement or minor maintenance. Tasks such as these require that three individuals spend approximately 4 hours at the pumps.

Dose contributors in this area are the containment building and a 3 inch safety injection line located approximately 20 feet away above the shield slab at elev. 426’-6". The time at which access to this area is required is based on the minimum time it takes to reach maximum spent fuel pool temperature with loss of both cooling pumps. This time is 12.5 hours. Eight hours after the accident, the exposure rate is 1.16 rem/hr. The calculated dose to an individual for 4 hours of occupancy is 3.03 rem.

The access route to area “F” is route “6” described in Table 12A.4-3. This access route will add a total of 0.11 rem to the worker dose if the task is started 8 hours after the accident.

12A.4.7 Area G: Engineered Safety Feature Motor Control Center

Area “G” is the location of the Engineered Safety Feature (ESF) Motor Control Center 1DA2Y and is identified on Figure 12A.4-3. It is not expected that access to this area would be required since all ESF control functions are performed from the control room. However, access may be required in the unlikely event that a safety-related component loses remote control power. Should such a component lose remote control power and fail in the unsafe position, in conjunction with a simultaneous failure of its redundant counterpart, it may be deemed necessary to gain

access to this area for manual control of the component. This task would require that two workers spend approximately 2 to 5 minutes in this area.

Dose contributors to this area are spray system, safety injection system, and chemical and volume control system piping located below and adjacent to this area. Access to this area could be required immediately after the accident. Access at 30 minutes is assumed in order to evaluate the worst case which is the initiation of the recirculation of containment sump liquid in the spray and safety injection systems. The exposure rate in this area is 24.1 rem/hr resulting in estimated exposures to an individual of 0.80 rem and 2.01 rem for occupancy times of 2 minutes and 5 minutes, respectively.

The access route to area “G” is route “4” described in Table 12A.4-3. This access route will add a total of 0.28 rem to the worker dose if access is required 30 minutes after the accident.

12A.4.8 Area H: Waste Processing System Control Panel

Area “H” is the location of the waste processing system panel (see Figure 12A.4-3). The waste gas system is not intended to be used for degassing the primary coolant system in post-accident conditions. Access to this area may be needed since the waste gas compressor are controlled from this panel. This task will require two persons to occupy this area for one minute.

Sources of exposure in this area are the containment building, and a 2 inch CVCS line located approximately 10 feet away and above the 2 foot thick concrete shield slab at elevation 426’-0". Immediately after the accident, the dose rate from these sources in area “H” is 3.74 rem/hr. The calculated dose for the one minute occupancy time is 0.06 rem.

The access route to area “H” is route “5” described in Table 12A.4-3. This route will add a total of 0.98 rem to the worker dose in this area for access immediately after the accident.

12A.4.9 Area I: Charging/safety Injection Pump Cooling Units

Area “I” is the location of the charging/safety injection pump room cooling units and is identified on Figure 12A.4-4. Although not a vital access area required for the mitigation of or recovery from an accident, the access may be established so as to ensure that more than one of the charging/safety injection pumps are available for the long term cooling of the reactor core. By this action, undesirable minimum safeguards condition that would result upon failure of one of these cooling units can be avoided. Under these circumstances, plant personnel may require access to one of the areas for operations such as manual switchover, maintenance, or repair. Tasks such as these require that two persons spend five minutes at the cooling units for manual switchover, or three persons spend four hours for the maintenance or repair of a cooling unit.

The major sources of exposure in this area are the charging/safety injection pump cubicle piping, the piping area immediately west of the cooling units on elevation 400’-0", and a 3-inch

chemical and volume control system (CVCS) pipe located inside the room containing cooling units 1 and 2.

The access route to Area "I" is route "10" described in Table 12A.4-3. For the manual valve switchover procedure, the access route will add a total of 1.03 rem to the worker dose at the time of the accident (i.e., 0 hr.). For the maintenance and repair activities after the accident, the access route will contribute 0.02 rem one day after the accident to the worker dose, and becomes negligible five days after the accident.

The resultant dose levels in this area have been reduced to the acceptable values shown in Table 12A.4-2 by the addition of concrete and lead shielding around the charging/safety injection and CVCS piping located within the charging/safety injection pump cooling unit cubicle. The new configuration allows personnel access in accordance with the occupancy requirements of Table 12A.4-2 and the occupancy guidelines for vital access areas requiring infrequent occupancy as contained in NUREG-0737.

12A.4.10 Area J: Engineered Safety Feature Substation Bus and Motor Control Center

Area "J" is the location of the engineered safety feature 480 volt unit substation bus 1DB1 and motor control center, 1DB2Y (see Figure 12A.4-6). Occupancy in this area following an accident will be the same as explained for area "G".

Dose contributors to this area are the volume control tank (cubicle 63-02), and valve gallery located in cubicle 63-03.

Access to this area could be required immediately after the accident. With the assumption that zero hour entry occurs, the exposure rate in this area will result in calculated exposures of 3.85 and 9.62 rem to an individual for the occupancy periods of 2 and 5 minutes, respectively. However, the resultant dose levels in this area are reduced to acceptable levels quickly as shown in Table 12A.4-2, and the resultant integrated doses meet the dose requirements of 10CFR50, Appendix A, General Design Criteria 19 as outlined in NUREG-0737.

The access route to area "J" is route "14" described in Table 12A.4-3. This access route will add 2.80 rem to a worker's dose immediately after the accident.

12A.4.11 Area K: Hydrogen Recombiner Control and Power Supply Panels

Area "K" as identified on Figure 12A.4-6 is the general location of the hydrogen recombiner control and power supply panels. Post-accident hydrogen formation in the Reactor Building may require operation of the hydrogen recombiner system. The system is started and controlled by operator action at the recombiner control panel. This task requires that two workers spend 10 minutes in this area per hour over a 3 hour period.

Dose contributors in this area are the personnel access hatch and a 3 inch chemical and volume control system pipe located below at elevation 450’6". Access to the control panels could be required shortly after an accident. The exposure rate 2 hours after the accident in this area is 16 rem/hr. The calculated dose to an individual in this area for 10 minutes of occupancy is 2.67 rem. If occupancy is required at one day after the accident, the exposure rate is calculated to be 1.14 rem/hr which results in a 10 minute dose of 0.19 rem.

The access route to area “K” is route “13” described in Table 12A.4-3. The calculated dose to an individual traveling this route is 0.92 rem 2 hours after the accident and 0.03 rem 1 day after the accident.

12A.4.12 Area L: Hydrogen Recombiner Control and Power Supply Panels

Area “L”, as identified on Figure 12A.4-6, is the general location of the hydrogen recombiner control and power supply panels. Occupancy in this area following an accident will be the same as explained for area “K”.

Dose contributors in this area are the Reactor Building located approximately 40 feet away and a 10 inch spray line located below the 2 ft. concrete floor at elevation 436’-0". Access to the control panels could be required shortly after an accident. The exposure rate 2 hours after the accident in this area is 0.74 rem/hr. The calculated dose to an individual in this area for 10 minutes of occupancy is 0.12 rem. If occupancy is required at one day after the accident, the exposure rate is calculated to be 16.0 mrem/hr which results in a 10 minutes dose of 0.003 rem.

The access route to area “L” is route “11” described in Table 12A.4-3. This access route will add a total of 0.52 rem to the worker dose 2 hours after the accident and 0.02 rem 1 day after the accident.A

12A.4.13-1 Area M1: Reactor Building Atmosphere Sample Collection Point and Hydrogen Gas Analyzer

Area “M1” as identified in Figure 12A.4-6 is the location where a reactor building air sample will be collected following an accident. It is also the location of the reactor building atmosphere hydrogen analyzer. The hydrogen analyzers are designed to continuously monitor the reactor building atmosphere following an accident. Access to the analyzer is not required since they are redundant (the other analyzer is located at elevation 463’-0" of the Auxiliary Building in cubicle 63-17) and all necessary functions are controlled remotely from the Control Room. However, access to this area is required to collect a reactor building air sample. The time required to collect the air sample has been estimated to be 10 minutes.

Dose contributors to this area are the Reactor Building located approximately 10 ft away, 3/8” gas sample lines for the sample cylinder and the hydrogen analyzer, and the gas sample cylinder itself. Access to this area could be required shortly after the accident. Access at 30

minutes is assumed. The exposure rate in this area 30 minutes after the accident is 12.9 rem/hr. This results in a calculated dose of 2.15 rem for 10 minutes of occupancy.

The access route to area “M” is route “12” described in Table 12A.4-3. This access route will add a total of 1.14 rem to the worker dose for access to and from this area 30 minutes after the accident.

12A.4.13-2 **Area M2: Reactor Building Atmosphere Sample Collection Point and Hydrogen Gas Analyzer**

Area “M2” as identified in Figure 12A.4-6 is the location where a reactor building air sample will be collected following an accident. It is also the location of the reactor building atmosphere hydrogen analyzer. The hydrogen analyzers are designed to continuously monitor the reactor building atmosphere following an accident. Access to the analyzer is not required since they are redundant (the other analyzer is located at elevation 463’-0” of the Fuel Handling Building) and all necessary functions are controlled remotely from the Control Room. However, access to this area is required to collect a reactor building air sample. The time required to collect the air sample has been estimated to be 10 minutes.

Dose contributors to this area are the Reactor Building located approximately 30 ft. away, 3/8-inch gas sample lines for the sample cylinder and the hydrogen analyzer, and the gas sample itself. Access to this area could be required shortly after the accident. Access at 30 minutes is assumed. The exposure rate in this area 30 minutes after the accident is 13.0 rem/hr. This results in a calculated dose of 2.17 rem for 10 minutes of occupancy.

The access route to area “M2” is route “13” described in Table 12A.4-3. This access route will add a total of 1.96 rem to the worker dose for access to and from this area 30 minutes after the accident.

12A.4.14 Area N: Technical Support Center

Area “N” as identified in Figure 12A.4-7 is the location of the technical support center. The technical support center is located adjacent to the control room on elevation 463’-0" of the Control Building. Continuous occupancy is required in this area following an accident.

A complete analysis of post-accident radiation doses in the control room and technical support center is presented in Section 15.4.1.

12A.4.15 Area O: Control Room

Area “O” as identified in Figure 12A.4-7 is the location of the control room. Continuous occupancy is required in this area following an accident.

A complete analysis of post-accident radiation doses in the control room is presented in Section 15.4.1.

12A.4.16 Area P: Sample Room

Area “P” as identified in Figure 12A.4-7 is the location of the sample room. Access to this area is required to place a primary system liquid sample on recirculation using the nuclear sampling system following an accident for assessing the extent of fuel damage using the measured recirculation radiation dose rate. The sample shall consist of fluid taken from the primary coolant hot leg, the pressurizer liquid, or residual heat removal loop.

The nuclear sampling system provides the means for the collection of post-accident samples in the sample room. The system has been designed to reduce the activity concentration of the samples to a level that will result in dose rates within the range of values normally associated with the 1% failed fuel design criteria.

In addition to the use of minimum activity concentrations, the resultant dose levels in this area have been reduced by the addition of 4-inch lead shielding between the sample rack in the chase area and the sink area of the sample room.

The access route to area “P” is route “15” described in Table 12A.4-3.

12A.4.17 Area Q: Radiochemistry Lab

Area “Q” as identified in Figure 12A.4-7 is the location of the radiochemistry laboratory. Access to this area provides for the radiological and chemical analyses of the post-accident samples following their transfer to this location.

Since the existing radiation shield design and sample analysis procedures in this area were designed for 1% failed fuel sources, the nuclear sampling system has been designed to reduce the activity concentration of the samples to a level that will result in dose rates in the radiochemistry lab within the range of values normally associated with the 1% failed fuel design criteria (< 2.5 mrem/hr).

The access route to area “Q” is route “15” as described in Table 12A.4-3.

12A.4.18 Area R: Count Room

Area “R” as identified in Figure 12A.4-7 is the location of the count room. Access to this area provides for the radiological analysis of the post-accident samples prepared in the radiochemistry laboratory.

The nuclear sampling system design criteria to provide post-accident sources with a radioisotope activity level comparable to that of the 1% failed fuel design criteria results in insignificant increases in personnel exposure above those received in the count room under normal operating conditions (<1 mrem/hr). The need for additional shielding has been reduced to make provisions for the availability of temporary personnel.

The access route to area “R” is route “15” as described in Table 12A.4-3.

12A.4.19 Intermediate Building

The Intermediate Building was reviewed to identify post-accident radiation sources, access requirements, and the location of safety related equipment. It was found that the only area of the Intermediate Building where exposure to post-accident radiation sources is possible is at the 412’-0" elevation adjacent to the east and west penetration access areas as shown in Figure 12A.4-8. At this elevation, residual heat removal (RHR), safety injection (SI), and chemical and volume control system (CVCS) piping containing post-accident sources is located in the east and west penetration access areas. The areas adjacent to the penetration access areas contain component cooling pumps, motor driven emergency feedwater pumps, and miscellaneous safety related valves and instrumentation which may require access. All other areas of the Intermediate Building are not exposed to post-accident sources and receive a negligible increase in dose.

The Intermediate Building at elevation 412’-0" is shielded from the radioactive piping located in the penetration access areas by a 2 foot concrete wall. This shield wall reduces the dose rates in this general area of the Intermediate Building to a level which permits limited access approximately 15 minutes immediately after the accident, 3 hours of access 8 hours following the accident, and 20 hours of access 1 day after the accident.

In the area between the east and west penetration access areas, several pipes containing post-accident sources were found to be located above the sides of a pipe chase located at elevation 422’-3". This allowed direct streaming of a 12-inch RHR pipe to the Intermediate Building floor elevation 412’-0". The resultant dose levels in this area of the Intermediate Building have been reduced to acceptable values by the modification of the pipe chase as follows: (1) extension of the pipe chase side above the 12" RHR line, (2) addition of 6" concrete shielding to the existing 1 foot concrete shielding, (3) relocation of access ladder to prevent streaming through concrete cutout. The new configuration allows personnel access in accordance with the occupancy requirements of Table 12A.4-2, and the resultant integrated doses meet the dose requirements of 10CFR50, Appendix A, General Design Criteria 19 as outlined in NUREG-0737.

12A.4.20 Emergency Operations Facility

The EOF is located beyond the 10-mile EPZ. Therefore there are no regulatory shielding requirements or ventilation isolation/HEPA filter requirements for the facility. The EOF is required to be “well engineered for design life of the plant” per NUREG-0696. The EOF is designed to the standards of the International Building Code, and as such resists the applicable loadings (wind, snow, earthquake, etc.) defined in ASCE 7, Minimum Design Loads for Buildings and Other Structures.

Table 12A.4-1
EXPOSURE RATES FOR VITAL AREAS AS A FUNCTION OF
TIME EXPOSURE RATE (MR/HR)

		Time after Accident									
	Vital Area	0	30 minutes	1 hour	8 hours	1 day	5 days	10 days	30 days	90 days	6 months
A	RHR/Spray Pump Rooms	(1)	2.15 + 4	1.70 + 4	2.79 + 3	3.83 + 2	8.31 + 1	6.19 + 1	2.30 + 1	3.84 + 0	1.94 + 0
	RHR/Spray Pump Room Cooling Units	1.46 + 4	1.67 + 4	1.33 + 4	2.33 + 3	6.14 + 2	7.82 + 1	5.80 + 1	2.26 + 1	4.89 + 0	2.46 + 0
B	Charging/SI Pump Rooms	5.57 + 4	4.46 + 4	3.46 + 4	6.33 + 3	1.54 + 3	1.92 + 2	1.44 + 2	5.56 + 1	1.27 + 1	5.95 + 0
C	Auxiliaries Local Control Panel										
	Source Shielded	(1)	3.10 + 2	2.47 + 2	4.57 + 1	7.50 + 0	1.62 + 0	1.20 + 0	4.85 - 1	1.24 - 1	6.30 - 2
	Source Unshielded	(1)	8.26 + 4	6.70 + 4	1.83 + 4	7.35 + 3	2.30 + 3	1.50 + 3	5.19 + 2	1.80 + 2	9.11 + 1
D	Spent Fuel Pit Heat Exchanger	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
E	Waste Gas System Control Panels	Access Not Required									
F	Spent Fuel Pit Cooling Pumps and Local Control Panels	5.63 + 3	1.05 + 4	6.42 + 3	1.16 + 3	1.15 + 2	2.65 + 1	1.97 + 1	7.62 + 0	2.68 + 0	7.91 - 1
G	Engineered Safety Feature Motor Control Center	1.46 + 4	2.41 + 4	1.92 + 4	3.37 + 3	7.76 + 2	1.13 + 2	8.36 + 1	3.27 + 1	7.19 + 0	3.63 + 0
H	Waste Processing System Control Panel	3.74 + 3	2.30 + 3	1.37 + 3	1.89 + 2	1.88 + 1	4.27 + 0	3.20 + 0	1.20 + 0	3.10 - 1	1.02 - 1

Table 12A.4-1 (CONTINUED)
EXPOSURE RATES FOR VITAL AREAS AS A FUNCTION OF
TIME EXPOSURE RATE (MR/HR)

		Time after Accident									
	Vital Area	0	30 minutes	1 hour	8 hours	1 day	5 days	10 days	30 days	90 days	6 months
I	Charging/SI Pump Room Cooling Units										
	Cooling Unit 1	3.19 + 5	2.48 + 5	1.87 + 5	3.16 + 4	7.62 + 3	1.61 + 3	1.15 + 3	4.81 + 2	1.61 + 2	8.05 + 1
	Cooling Unit 2	1.06 + 5	8.34 + 4	6.31 + 4	1.16 + 4	2.57 + 3	4.52 + 2	3.27 + 2	1.32 + 2	4.04 + 1	1.94 + 1
	Cooling Unit 3	8.07 + 4	6.32 + 4	4.96 + 4	8.82 + 3	2.36 + 3	2.76 + 2	2.05 + 2	7.94 + 1	1.71 + 1	8.31 + 0
J	Engineered Safety Feature Substation Bus and Motor Control Center	1.15 + 5	5.39 + 4	4.05 + 4	3.91 + 3	1.01 + 2	4.39 + 0	3.12 + 0	1.14 + 0	1.93 - 1	(1)
K	Hydrogen Recombiner Control and Power Supply Panels	6.32 + 4	3.66 + 4	2.49 + 4	4.10 + 3	1.14 + 3	2.50 + 2	1.73 + 2	7.31 + 1	2.82 + 1	1.29 + 1
L	Hydrogen Recombiner Control and Power Supply Panels	5.63 + 3	2.85 + 3	1.57 + 3	1.12 + 2	1.67 + 1	3.71 + 0	2.77 + 0	9.77 - 1	1.59 - 1	(1)
M1	Reactor Building Air Sample Collection Point “B”	2.43 + 4	1.29 + 4	7.35 + 3	6.80 + 2	1.60 + 2	3.67 + 1	2.36 + 1	5.77 + 0	5.70 - 1	2.93 - 1
M2	Reaction Building Air Sample Collection Point “A”	1.90 + 4	1.30 + 4	9.65 + 3	6.59 + 3	1.12 + 3	3.79 + 2	2.37 + 2	6.70 + 1	2.25 + 1	1.20 + 1
N	Technical Support Center	Refer to Section 15.4.1									

Table 12A.4-1 (CONTINUED)
EXPOSURE RATES FOR VITAL AREAS AS A FUNCTION OF
TIME EXPOSURE RATE (MR/HR)

		Time after Accident									
	Vital Area	0	30 minutes	1 hour	8 hours	1 day	5 days	10 days	30 days	90 days	6 months
O	Control Room	Refer to Section 15.4.1									
P	Sample Room										
	At Sample Sink	1.70 + 2	1.10 + 2	8.30 + 1	1.10 + 1	1.30 + 0	3.40 - 1	2.20 - 1	7.70 - 2	(1)	(1)
	At Control Panel	2.30 + 1	1.50 + 1	1.10 + 1	1.50 + 0	1.70 - 1	4.60 - 2	(1)	(1)	(1)	(1)
Q	Radiochemistry Lab	(3)									
R	Count Room	(3)									
	Intermediate Building	4.45 + 4	3.28 + 4	2.54 + 4	4.58 + 3	5.23 + 2	1.73 + 2	1.27 + 2	5.95 + 1	1.40 + 1	7.03 + 0

(1) Negligible
(2) Not Calculated
(3) Increase of Personnel Total Dose Insignificant From Current Considerations.

Table 12A.4-2
VITAL AREA RADIATION DOSE SUMMARY

	Vital Area	Occupancy Requirements	Time After Accident	Occupancy Dose (Rem/Person)	Access Dose To and From Area (Rem/Person)	Total Dose (Rem/Person)	Total Dose Man-Rem
A	RHR/Spray Pump Rooms	3 persons for 4 hours	1 day	1.41	0.024	1.43	4.29
A	RHR/Spray Pump Room Cooling Units	3 persons for 4 hours	1 day	2.25	0.024	2.27	6.81
B	Charging/SI Pump Rooms	3 persons for 4 hours	2 days	2.39	0.05	2.44	7.32
C	Charging/SI Pump C Auxiliaries Local Control Panel	2 persons for 2 minutes	1/2 hour 1 hour	2.75 2.23	1.40 1.04	4.15 3.27	8.30 6.54
D	Spent Fuel Pit Heat Exchanger	Long term periodic surveillance	1 hour 8 hours 24 hours	(1) (1) (1)	0.72 0.14 0.02	0.72 0.14 0.02	1.44 0.28 0.04
E	Waste Gas System Control Panels	Not Required					
F	Spent Fuel Pit Cooling Pumps and Local Control Panels	3 persons for 4 hours	8 hours 12 1/2 hours 1 day	3.03 1.36 0.42	0.11 0.06 0.02	3.14 1.42 0.44	9.42 4.26 1.32
G	Engineered Safety Feature Motor Control Center	2 persons for 2-5 minutes	0 1/2 hour 1 hour 8 hours 1 day	0.49 - 1.22 0.80 - 2.01 0.64 - 1.60 0.11 - 0.28 0.03 - 0.06	0.20 0.28 0.22 0.04 0.01	0.69 - 1.42 1.08 - 2.28 0.86 - 1.82 0.15 - 0.32 0.03 - 0.07	1.38 - 2.84 2.16 - 4.57 1.72 - 3.64 0.30 - 0.64 0.07 - 0.14

Table 12A.4-2 (CONTINUED)
VITAL AREA RADIATION DOSE SUMMARY

	Vital Area	Occupancy Requirements	Time After Accident	Occupancy Dose (Rem/Person)	Access Dose To and From Area (Rem/Person)	Total Dose (Rem/Person)	Total Dose Man-Rem
H	Waste Processing System Control Panel	2 persons for 1 minute	0	0.06	0.98	1.04	2.08
			1/2 hour	0.04	0.86	0.90	1.80
			1 hour	0.02	0.66	0.68	1.36
			8 hours	0.003	0.12	0.12	0.24
I	Charging/SI Pump Room Cooling Units						
	Cooling Unit I (Manual Switch Over)	2 persons for 5 minutes	8 hours	2.62	0.14	2.77	5.54
			1 day	0.63	0.02	0.66	1.32
	Cooling Unit 2 (Manual Switch Over)	2 persons for 5 minutes	8 hours	0.97	0.14	1.10	2.20
			1 day	0.21	0.02	0.23	0.46
	Cooling Unit 3 (Manual Switch Over)	2 persons for 5 minutes	1 hour	4.13	0.72	4.85	9.70
			8 hours	0.73	0.14	0.87	1.74
			1 day	0.20	0.02	0.22	0.44
	Cooling Unit 1 (Maintenance or Repair)	3 persons for 4 hours	10 days	4.59	(1)	4.59	13.77
			30 days	1.92	(1)	1.92	5.76
			90 days	0.64	(1)	0.65	1.95
	Cooling Unit 2 (Maintenance or Repair)	3 persons for 4 hours	5 days	1.80	(1)	1.80	5.40
			10 days	1.30	(1)	1.30	3.90
			30 days	0.53	(1)	0.53	1.59
			90 days	0.16	(1)	0.17	0.51
	Cooling Unit 3 (Maintenance or Repair)	3 persons for 4 hours	5 days	1.10	(1)	1.10	3.30
			10 days	0.81	(1)	0.82	2.46
			30 days	0.32	(1)	0.32	0.96
			90 days	0.07	(1)	0.07	0.21

Table 12A.4-2 (CONTINUED)
VITAL AREA RADIATION DOSE SUMMARY

	Vital Area	Occupancy Requirements	Time After Accident	Occupancy Dose (Rem/Person)	Access Dose To and From Area (Rem/Person)	Total Dose (Rem/Person)	Total Dose Man-Rem
J	Engineered Safety Feature Substation Bus and Motor Control Center	2 persons for 2-5 minutes	1 hour	1.35 - 3.38	1.47	2.82 - 4.85	5.64 - 9.90
			8 hours	0.13 - 0.33	0.17	0.30 - 0.50	0.60 - 1.00
			1 day	0.003 - 0.008	0.023	0.030 - 0.033	0.06 - 0.08
K	Hydrogen Recombiner Control and Power Supply Panels	2 persons for 10 minutes per hour over a 3 hour period	2 hours	2.67	0.92	3.59	7.18
			3 hours	1.67	0.67	2.34	4.68
			4 hours	1.33	0.52	1.85	3.70
			5 hours	1.02	0.43	1.44	2.88
			24 hours	0.19	0.03	0.22	0.44
			25 hours	0.18	0.03	0.21	0.42
			26 hours	0.18	0.02	0.20	0.40
			27 hours	0.16	0.02	0.18	0.36
L	Hydrogen Recombiner Control and Power Supply Panels	2 persons for 10 minutes per hour over a 3 hour period	2 hours	0.12	0.52	0.64	1.28
			3 hours	0.07	0.38	0.45	0.90
			4 hours	0.05	0.30	0.35	0.70
			5 hours	0.04	0.24	0.28	0.56
			24 hours	0.0027	0.02	0.0227	0.0454
			25 hours	0.0026	0.0196	0.0222	0.0444
			26 hours	0.0025	0.018	0.0205	0.041
			27 hours	0.0023	0.017	0.0193	0.0386
M1	Reactor Building Air Sample Collection Point “B”	2 persons for 10 minutes	1/2 hour	2.15	1.14	3.29	0.58
			1 hour	1.23	0.82	2.05	4.10
			8 hours	0.11	0.14	0.25	0.50
			1 day	0.03	0.02	0.05	0.10
M2	Reactor Building Air Sample Collection Point “A”	2 persons for 10 minutes	1/2 hour	2.17	1.96	4.13	8.16
			1 hour	1.60	1.47	3.07	6.14
			8 hours	1.08	0.17	1.25	2.50
			1 day	0.19	0.03	0.22	0.44
N	Technical Support Center	Continuous	30 days	-	-	Refer to Section 5.4.1.	

Table 12A.4-2 (CONTINUED)
VITAL AREA RADIATION DOSE SUMMARY

	Vital Area	Occupancy Requirements	Time After Accident	Occupancy Dose (Rem/Person)	Access Dose To and From Area (Rem/Person)	Total Dose (Rem/Person)	Total Dose Man-Rem
O	Control Room	Continuous	30 days	-	-	Refer to Section 5.4.1.	
P	Sample Room		0	(3)	(1)	(3)	(3)
Q	Radiochemistry Lab		0	(3)	(1)	(3)	(3)
R	Count Room		0	(3)	(1)	(3)	(3)

(1) Negligible
(2) Not Calculated
(3) Increase of Personnel Total Dose Insignificant from Current Considerations.

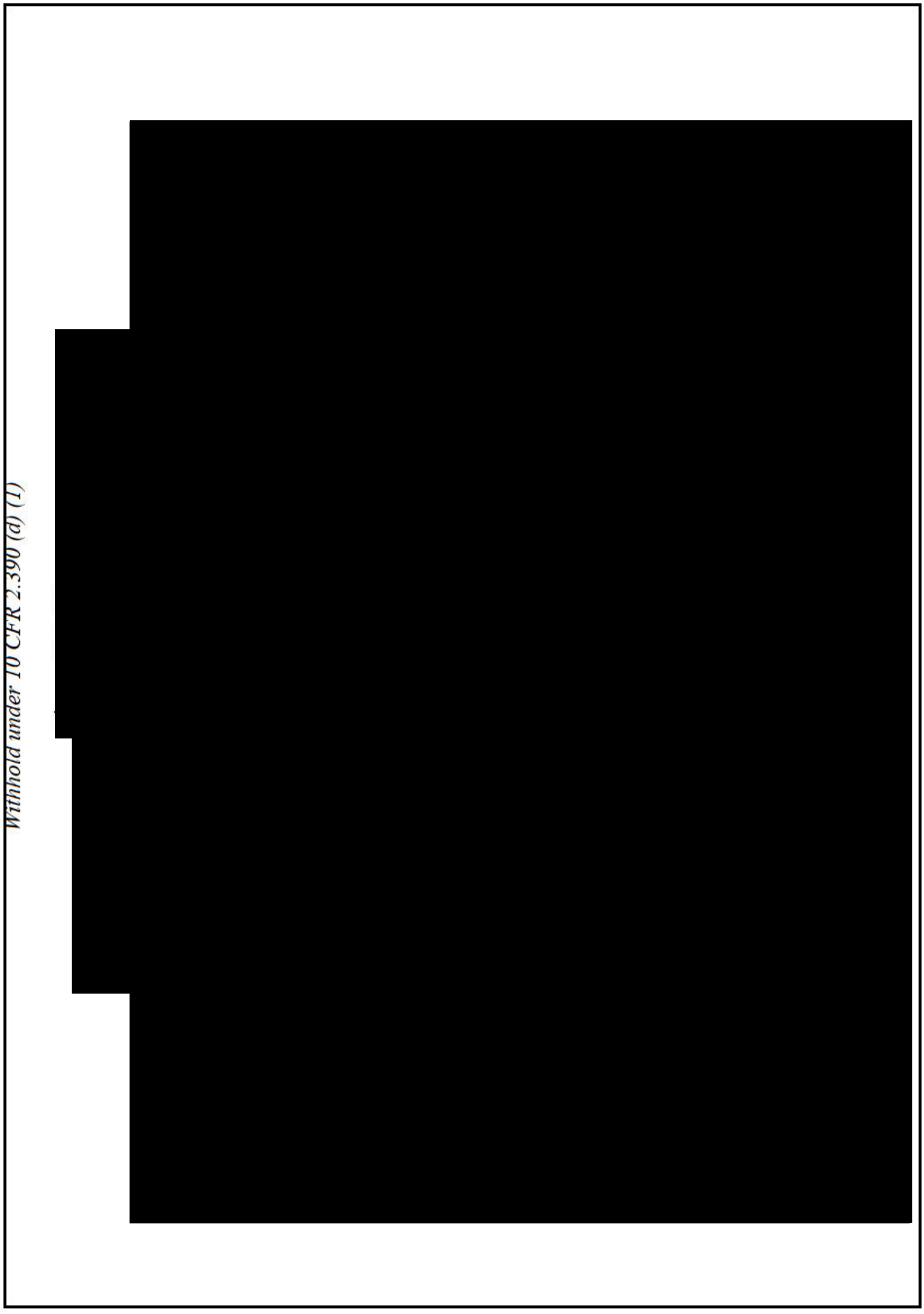
Table 12A.4-3
ACCESS ROUTES TO VITAL AREAS

Access Routes	Description
1.	From Control Building (C.B.), 463’ elev., down either stairway to 412’ elev. through 412’ elev. to north corridor. From C.B., 412’ elevation, enter Auxiliary Building (A.B.) at stairway tower 1, down stairway to 374’ elev., through hallways 74-01 and 74-09 W (formerly 74-09) to rooms 74-16 and 74-17. For cooling units, ladder up from hallway 74-09 to 385’ elev. to rooms 85-01 and 85-02.
2.	From C.B., 463’ elev., down either stairway to 412’ elev., through 412’ elev. to north corridor. From C.B., 412’ elev. enter A.B. at hallway 12-11, through hallways 12-11 and 12-09 to stairway tower 2, down stairway to 397’ elev. and through room 97-01 to stairs at column lines M and 9.5. Down stairs to 388’ elev. to room 88-13 S.
3.	Same as “2” but through room 88-13S to room 88-25.
4.	From C.B., 463’ elev., down either stairway to 412’ elev., through 412’ elev. to north corridor. From C.B., 412’ elev., enter A.B. at hallway 12-11, north through hallway 12-11 to room 12-28.
5.	Same as “4” but continues through hallway 12-11 to room 12-15.
6.	Same as “4” but north through hallway 12-11 and east through hallway 12-11 N to room 12-18.
7.	From C.B., 463’ elev., down either stairway to 412’ elev., through 412’ elev. to north corridor. From C.B., 412’ elev., enter A.B. at hallway 12-11, north through hallway 12-11 and east through hallway 12-11 N to stairway tower 3. Down stairway to 388’ elev. to room 88-13 NE.
8.	Same as “7” but through room 88-13 NE to rooms 88-23 and 88-24
9.	Same as “7” but through room 88-13 NE to room 88-13 N.
10	Same as “7” but continues through room 88-13 NE to room 88-13 N. Ladder up to 400’ elev.
11.	From C.B., 463’ elev., down either stairway to 412’ elev., through 412’ elev. to north corridor. From C.B., 412’ elev., enter A.B. at hallway 12-11, north through hallway 12-11 and east through hallway 12-11 N to stairway tower 3. Up stairway to 463’ elev. to room 63-09 at column line 7.7.
12.	Same as “11” but from room 63-09 enter Fuel Building (F.B.) 463’ elev., through room 63-01 S to column lines P.4-P.9 and 3.3-4.0.

Table 12A.4-3 (CONTINUED)
ACCESS ROUTES TO VITAL AREAS

Access Routes	Description
13.	From C.B., 463’ elev., down either stairway to 412’ elev. through 412’ elev. to north corridor. From C.B., 412’ elev. enter A.B. at hallway 12-11, through hallways 12-11 and 12-09 to stairway tower 2. Up stairway to 463’ elev., through hallway 63-04 and south through hallway 63-16 to room 63-19.
14.	Same as “13” but through room 63-09 to room 63-01.
15.	From C.B., 463’ elev., down either stairway to 412’ elev. to rooms 12-09, 12-10 and 12-11.

Withhold under 10 CFR 2.390 (d) (1)



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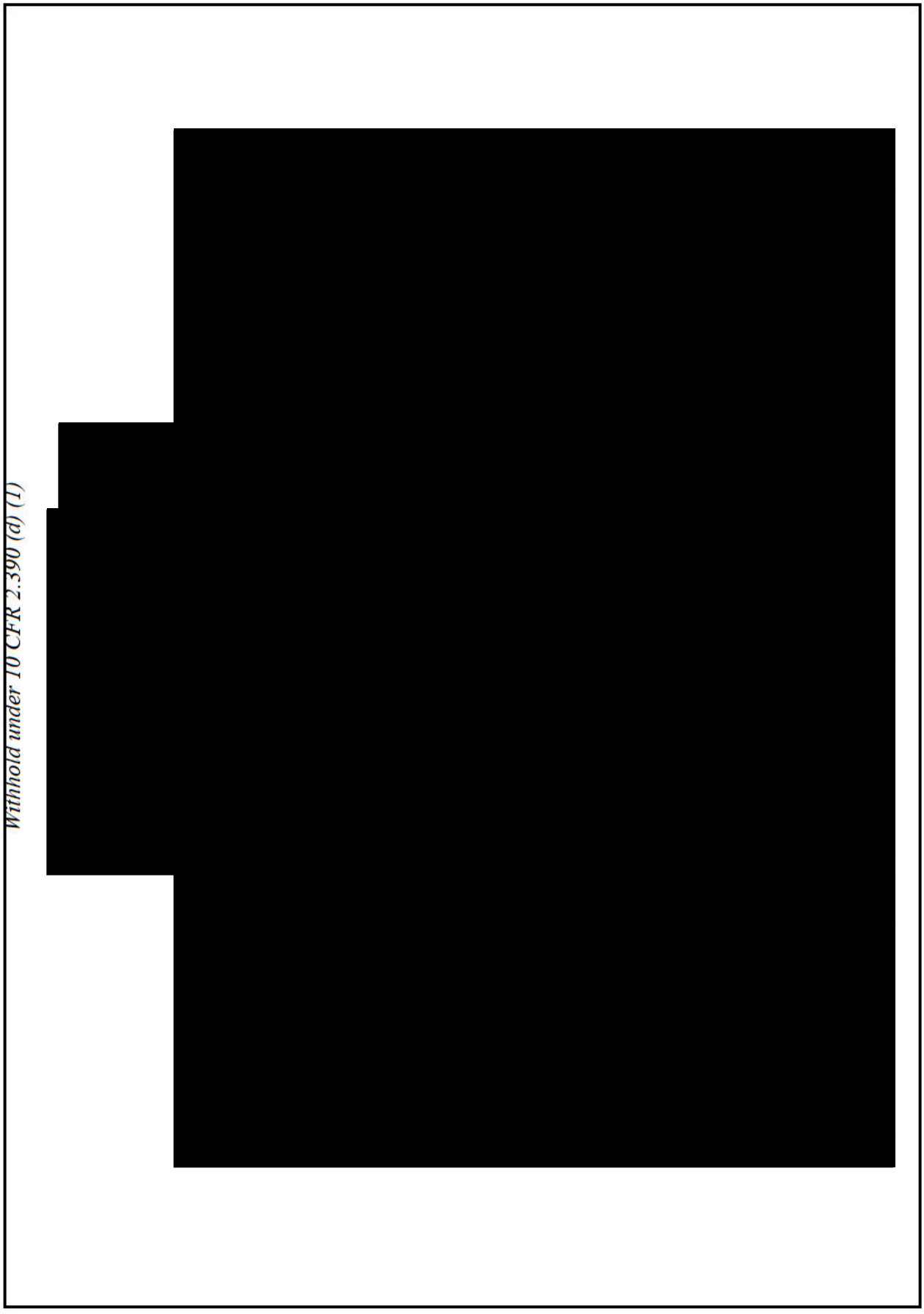

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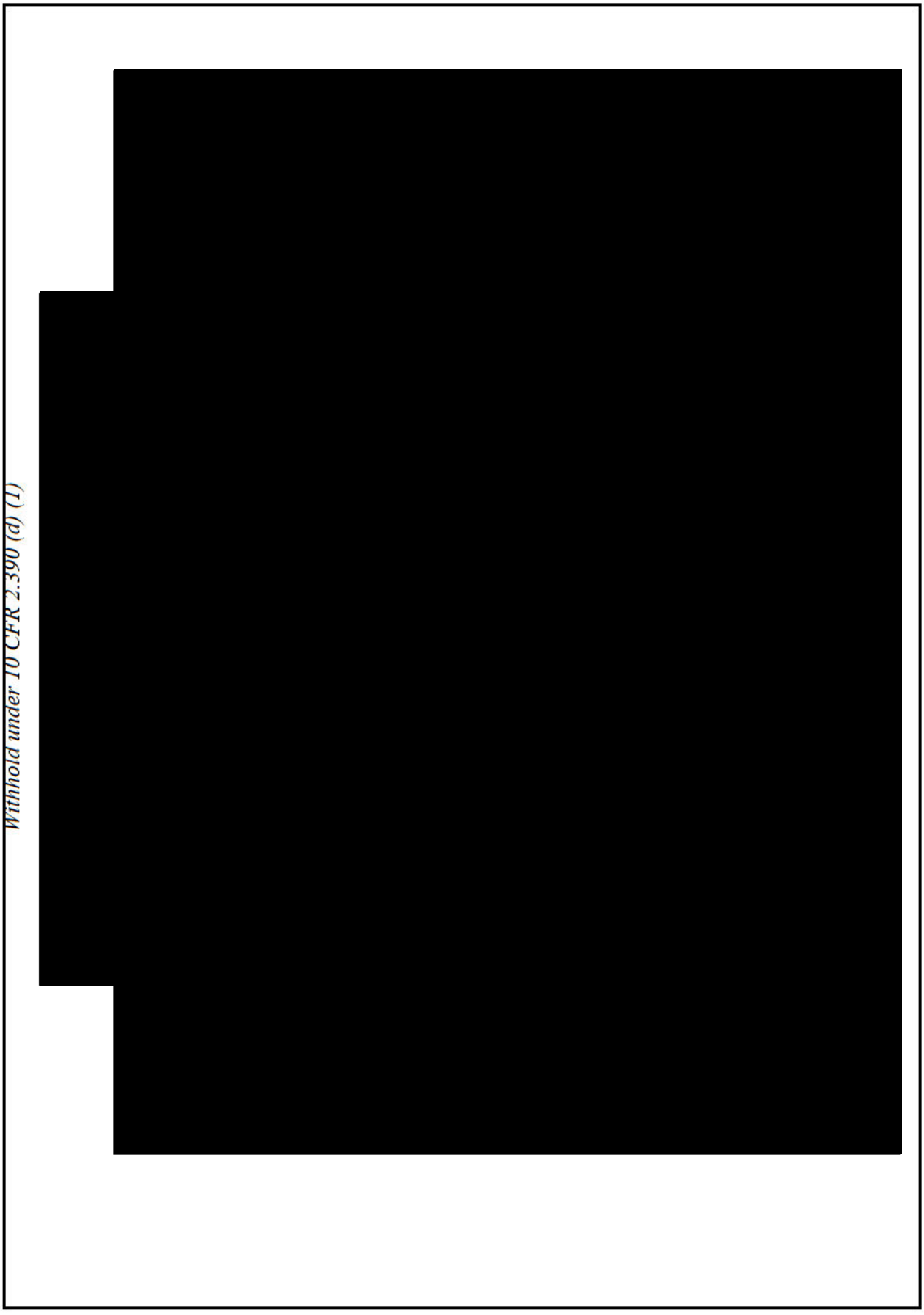

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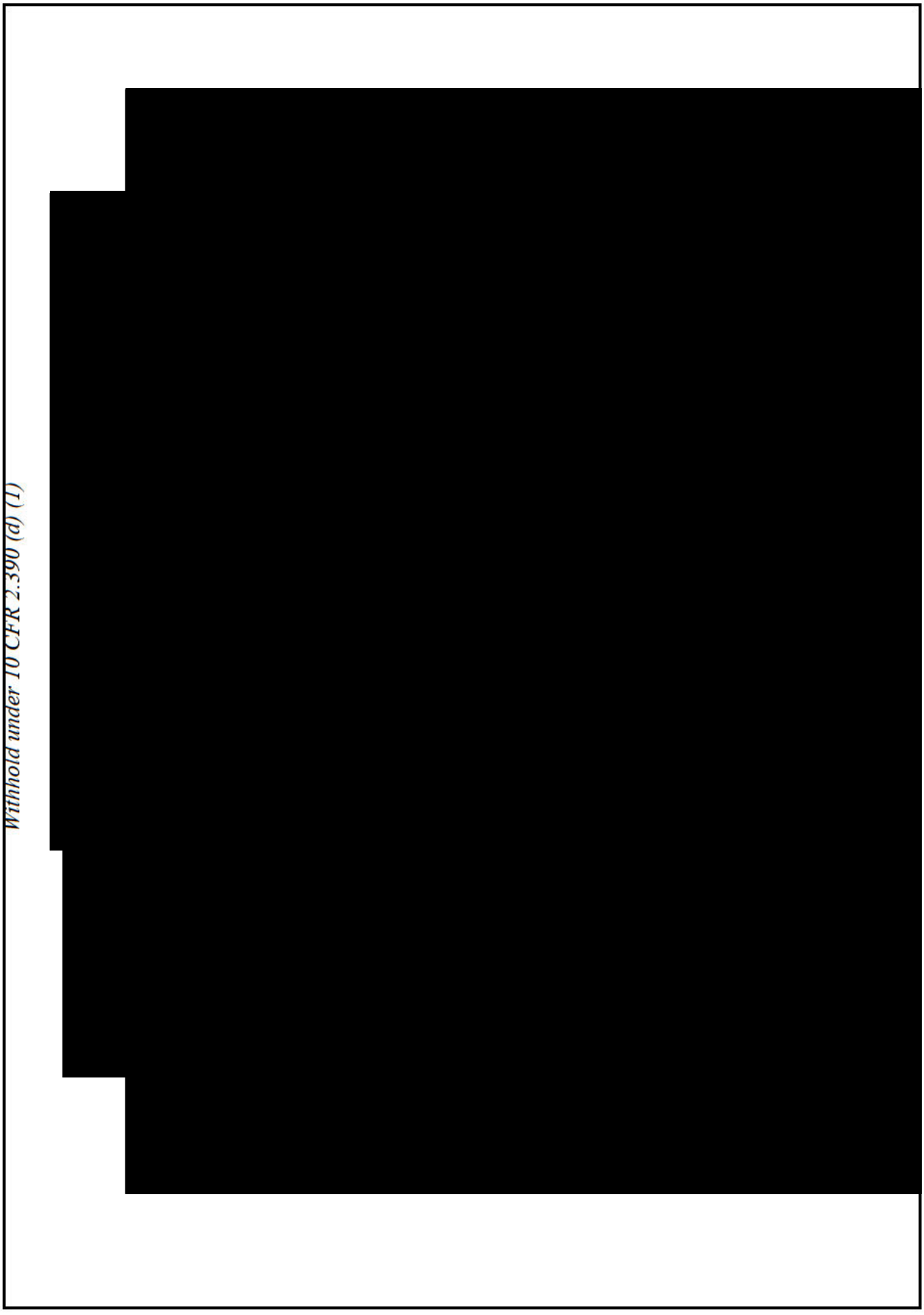
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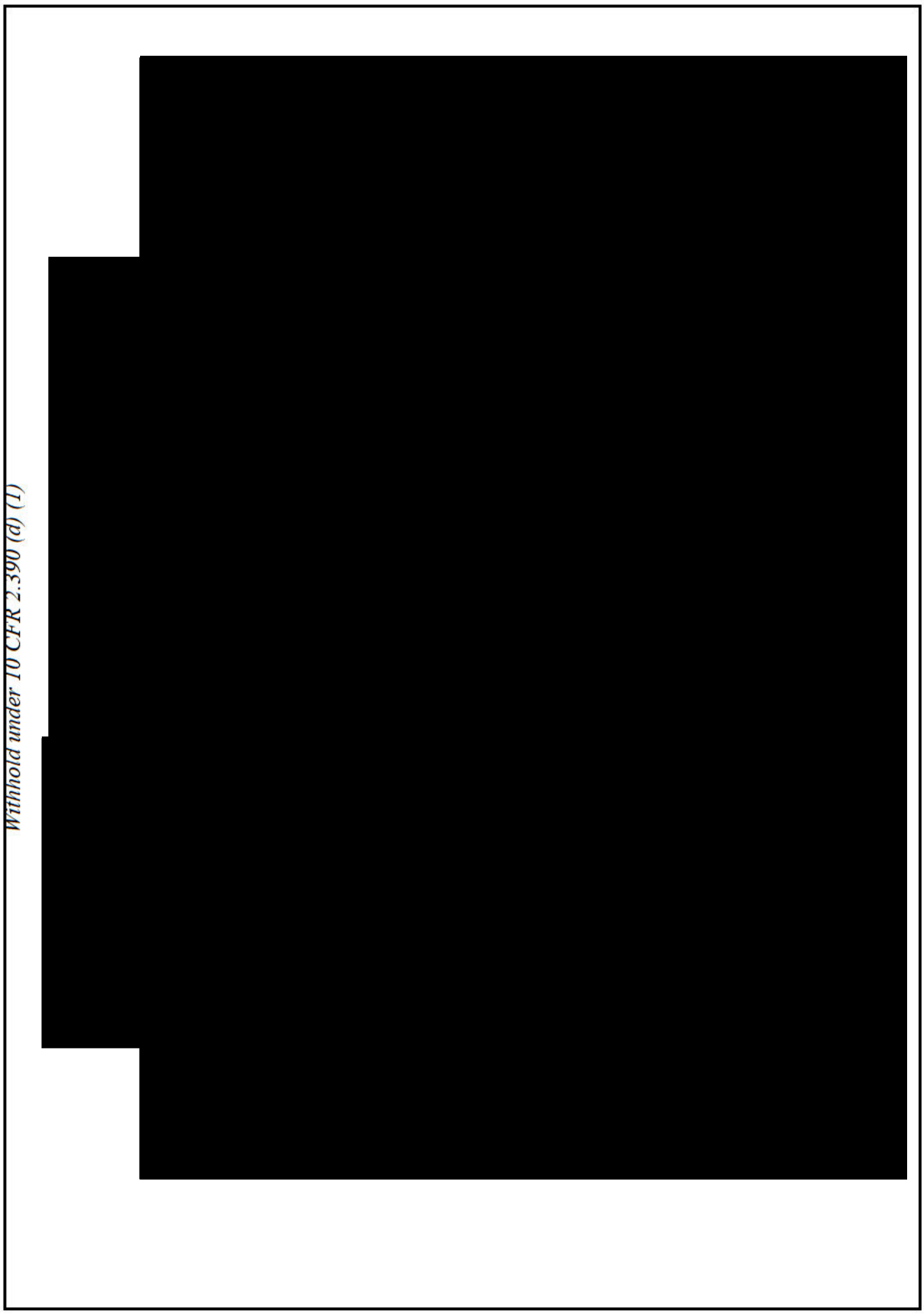

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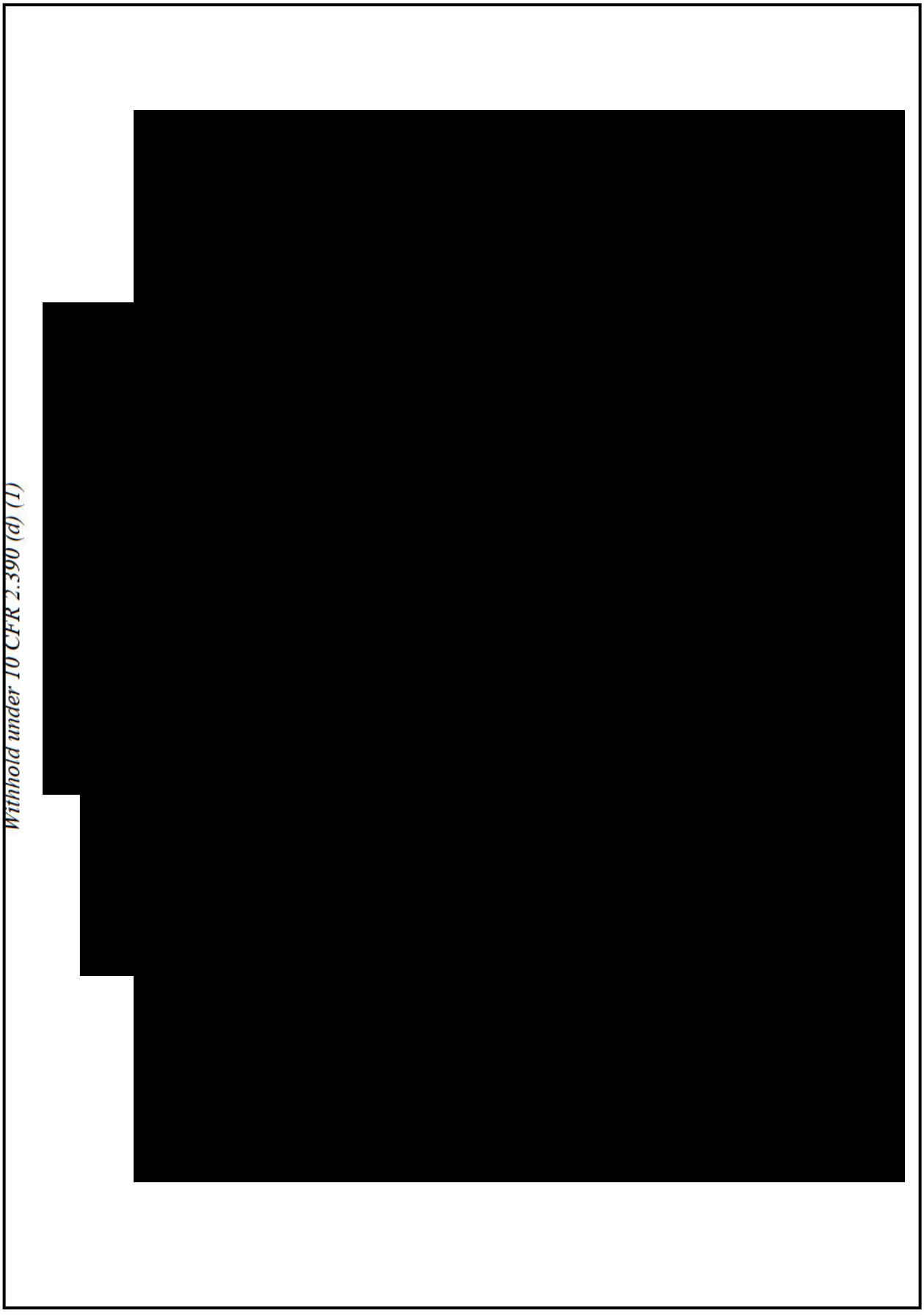

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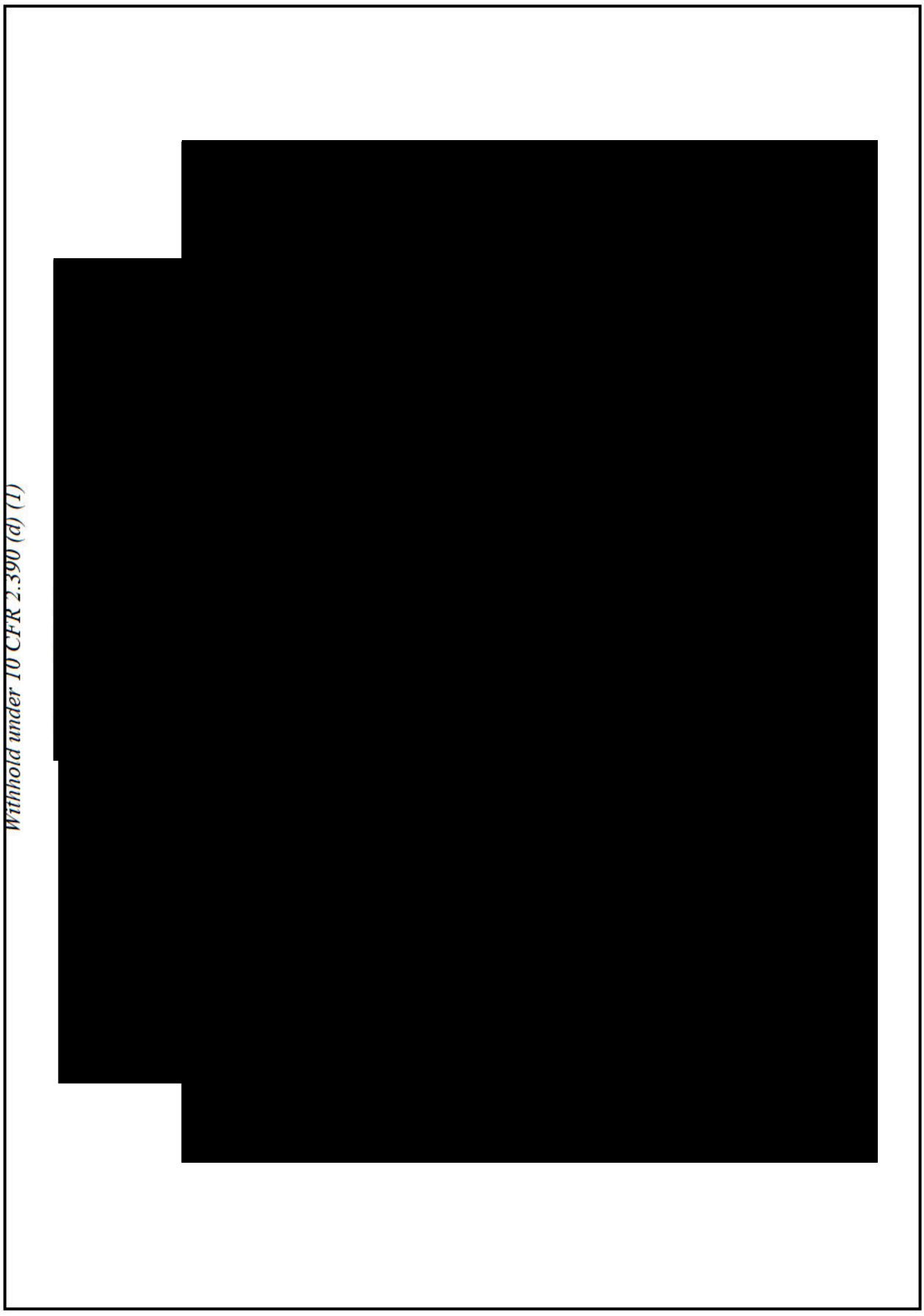

Withhold under 10 CFR 2.390 (d) (1)

12A.5 REVIEW OF RADIATION QUALIFICATION OF SAFETY RELATED EQUIPMENT

Radiation qualification of safety-related equipment is provided in the applicable equipment qualification documentation packages. Refer to Section 3.11 for further discussion.

12A.6 REFERENCES

1. E. D. Arnold and B. F. Maskervitz, *SDC - A Shield Design Calculation Code for Fuel Handling Facilities*, ORNL-3041, March 1966.
2. C. M. Lederer, J. M. Hollander, and J. Perlman, *Table of Isotopes*, Sixth Edition, John Wiley and Sons, Inc., 1967.
3. A. Tobias, *Data for the Calculation of Gamma Radiation Spectra and Beta Heating from Fission Products* (Revision 3), RD/B/M2669, June 1973.
4. Regulatory Guide 1.4, Revision 2 (6/74).
5. Regulatory Guide 1.7, Revision 2 (11/78).
6. Source Term Data for Westinghouse Pressurized Water Reactors, WCAP-8253 (May 1974).
7. Grove Engineering, *MicroShield,* Version 5, 1998.

V.C. Summer Nuclear Station
Safety Analysis Report

Conduct of Operations

Chapter 13

Revision 26--06/25/26

This Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 13 - CONDUCT OF OPERATIONS

13.1 Organizational Structure of South Carolina Electric and Gas Company

NOTE 13.1.1
Section 13.1.1 is being retained for historical purposes only.

13.1.1 Corporate Organization

This section describes the structure and qualifications of the South Carolina Electric and Gas Company (SCE&G) corporate organization and the corporate organizations of the principal contractors: Gilbert/Commonwealth (Gilbert), Westinghouse Electric Corporation (Westinghouse), and Daniel International Corporation (Daniel).

13.1.1.1 Corporate Functions, Responsibilities and Authorities

SCE&G owns and operates an integrated electric generation, transmission, and distribution system which serves approximately 304,000 customers in a 12,000 square mile service area. This area, stretching from the central region to the coastal plains, includes Columbia, the State capitol, and Charleston, South Carolina's principal seaport. SCE&G's transmission system is part of the interconnected grid extending over a large part of the central and eastern portion of the nation.

SCE&G's net generating capacity as of August 1983 was in excess of 3,950,000 kW. The South Carolina Public Service Authority (SCPSA), by joint ownership of the Virgil C. Summer Nuclear Station, owns one-third interest (300 MW) in the facility.

SCE&G, acting as its own general contractor, has constructed generating facilities which provide most of their present generating capacity. For the construction of the Virgil C. Summer Nuclear Station, SCE&G has engaged qualified contractors to construct the facility. SCE&G acted as construction manager.

SCE&G is a partner with Carolina Power and Light Company, Duke Power Company, and Virginia Electric and Power Company in Carolinas Virginia Nuclear Power Associates, Inc. (CVNPA). CVNPA was formed in 1956 to build and operate a 17,000 kWe nuclear steam generating plant at Parr, S. C., for research, operating, and engineering experience. The Carolinas Virginia Tube Reactor (CVTR) was constructed and operated under license granted by the Atomic Energy Commission. The CVTR was decommissioned in 1967 after completion of a successful operating and research program. SCE&G actively participated in the CVTR project at the planning, management, training, research, technical, and operational levels.

SCE&G has maintained active participation in the fast breeder programs of both Westinghouse and Atomics International. SCE&G also participated in the Savannah River Nuclear Study Group which examined the feasibility of developing power from a production reactor.

SCE&G was the sole applicant for the construction permit and operating license for the Virgil C. Summer Nuclear Station. As Applicant, SCE&G was responsible for the design, construction, quality assurance, and operation of this station. Figures 13.1-1 and 13.1-2 together show the SCE&G corporate organizational structure from the Board of Directors to the managerial level at the plant site. Figure 13.1-2 includes the organizational interfaces with the outside consultants and contractors; Gilbert, Westinghouse, and Daniel. Figure 13.1-3, exclusive of outside constraints, shows the SCE&G post commercial organizational operation.

Gilbert was retained by SCE&G as architect engineer for the entire project, including plant layouts and system arrangements, and design of balance of plant equipment. Engineering efforts by Gilbert were coordinated with construction by the SCE&G Nuclear Engineering Department.

SCE&G has contracted with Westinghouse for the design and manufacture of the complete nuclear steam supply system (NSSS). In addition, Westinghouse provided technical consultation in areas such as construction, initial fuel loading, testing, and initial startup. Westinghouse was also involved in the training of SCE&G operating personnel.

Daniel was under contract by SCE&G to act as general constructor for the Virgil C. Summer Nuclear Station construction activities.

13.1.1.2 In-House Pre-Commercial Organization

This section, which is historical in nature, describes the pre-commercial SCE&G corporate management, including technical support staffing and in-house organizational relationships, established for design, procurement, construction, and quality assurance functions. The responsibilities and authorities of in-house personnel are included. In addition, specific responsibilities and activities are included in order to show the accomplishments and plans for work in certain areas.

13.1.1.2.1 Corporate Management

The SCE&G corporate organization was responsible for handling all matters pertaining to the Virgil C. Summer Nuclear Station, including design, procurement, construction, quality assurance, testing, training, and operation, is shown in Figure 13.1-2. The departments primarily involved with plant activities and their relationships are described below.

The Vice President and Group Executive, Engineering and Construction, was responsible for the construction of power facilities. The Construction Department was separated into the Production Engineering Department and the Construction and Quality Control Department, each headed by a Group Manager. The Group Manager, Production Engineering and the Group Manager, Construction and Quality Control reported directly to the Senior Vice President, and Group Executive, Engineering and Construction.

The Vice President, Nuclear Operations, was responsible for the quality assurance, engineering, licensing, training, and operation of SCE&G nuclear power generating facility.

The General Manager, Nuclear Plant Operations, was responsible for station operations including start-up and test, power ascension, commercial power operation, nuclear security, and emergency planning. He was assisted in accomplishing his responsibilities by the Manager of Nuclear Protection Services, the Emergency Planning Coordinator, and the Manager, Virgil C. Summer Nuclear Station.

The Group Manager, Nuclear Engineering and Licensing, had the responsibility for plant and equipment design; plant licensing; and corporate health physics and environmental programs, geologic and hydrologic studies relating to plant sitting, design, construction and support to plant operations. This department was divided into four functional areas; Nuclear Engineering, Nuclear Licensing, the Independent Safety Engineering Group, and Corporate Health Physics and Environmental Programs. The Group Manager, Nuclear Engineering and Licensing, reported directly to the Vice President, Nuclear Operations.

The Group Manager, Nuclear Services, was responsible for the areas of Nuclear Fuel Management, incore technical support fuel cycle requirements, and quality assurance relating to design, construction and operation, and nuclear quality control relating to the operation and modification of the Virgil C. Summer Nuclear Station. Details of the quality assurance and nuclear quality control programs are found in Chapter 17.

The Group Manager, Nuclear Education and Training, was responsible for the development, implementation, and evaluation of operating and technical training programs for the Nuclear Operations Department in coordination with or upon recommendation of the General Manager, Nuclear Plant Operations; the Group Manager, Nuclear Engineering and Licensing; or the Group Manager, Nuclear Services. The Group Manager, Nuclear Education and Training, reported directly to the Vice President, Nuclear Operations.

The General Manager, Purchasing, had the company-wide responsibility for procurement of equipment and materials. This included procurement of safety-related items during design, construction, and operations of SCE&G power facilities. Purchase requisitions for the Virgil C. Summer Nuclear Station were initiated by personnel of the plant staff, nuclear engineering, or purchasing. Additional information pertaining to procurement is found in Chapter 17.

13.1.1.2.2 Specific Responsibilities and Activities

Specific responsibilities and activities in which SCE&G was engaged included:

1. Design and Construction Activities (Project Phase)

   The SCE&G Nuclear Engineering function within the Nuclear Engineering and Licensing Department had the responsibility for the design and engineering of the Virgil C. Summer Nuclear Station during the design and construction phase of the project. The Nuclear Engineering Group was responsible for coordinating and approving plant design and engineering, and geological, hydrological, and seismological studies related to the plant design and environmental effects.

Westinghouse was responsible to SCE&G for the design, engineering, procurement, and fabrication, including quality assurance, of the NSSS.

Gilbert had the responsibility for the overall design and engineering of the balance of the plant systems (nuclear and non-nuclear not within the NSSS scope of supply) and the coordination of all plant design and engineering activities. Gilbert design documents were submitted to the SCE&G Nuclear Engineering Department for review and approval. Westinghouse engineering drawings, specifications, and related design and engineering documents were submitted to Gilbert and SCE&G for review, comment, and interface information.

The final decision for procurement of materials and equipment, except those under the Westinghouse NSSS scope of supply, was made by the SCE&G purchasing committee. The vendor proposals were received by Gilbert and SCE&G and were evaluated for compliance by engineering, quality assurance, and purchasing for acceptable responses to the specification requirements in accordance with approved Gilbert and SCE&G evaluation and purchasing procedures. The SCE&G quality assurance group had to concur with the purchasing committee's decision of the selected vendor for safety-related purchases.

Site layout with respect to environmental effects and development of Safety Analysis Reports was done by Gilbert through coordination of the efforts of Westinghouse, Dames and Moore, and SCE&G.

Security during construction was the direct responsibility of the SCE&G Construction Department. Gilbert provided planning for the inclusion of security requirements in the design of the Virgil C. Summer Nuclear Station for the operations phase. The latter security planning and design documents were subject to the review and approval of the SCE&G Nuclear Engineering Department, but were reviewed by all affected SCE&G organizations.

Construction management was the responsibility of the SCE&G Construction Department under the direction of the Nuclear Site Manager who reported to the Group Manager, Construction and Control. Daniel was the constructor. Construction activities were directed by the Daniel Project Manager who reported to the SCE&G Nuclear Site Manager. Project Managers for other site contractors, performing safety-related construction activities, reported to the SCE&G Nuclear Site Manager administratively and to the Daniel Project Manager for scheduling and coordination of work activities.

Quality control activities were the direct responsibility of the SCE&G Quality Control Manager who reported to the SCE&G Group Manager, Construction and Quality Control. Site quality control activities were performed by, or under the direction of, the SCE&G Quality Control Manager, except for those contractors which had quality control responsibility. SCE&G had quality control responsibility for the Daniel scope of construction except for the ASME Boiler and Pressure Vessel Code related activities.

The SCE&G quality assurance section had the primary responsibility for surveillance and audit of site construction activities; however, Daniel had quality assurance responsibility for

the scope of work under its ASME Boiler and Pressure Vessel Code Certificates of Authorization. Several other contractors also performed surveillance and audit of their work onsite. The SCE&G quality assurance group performed surveillance and audit of all site activities including those for which contractors had quality assurance within their scope of activities. Further detail can be found in Section 17.1.

2. Preoperational Activities

The preoperational activities at the Virgil C. Summer Nuclear Station which were being accomplished included the following:

a. Development of human engineering design objectives and design phase review of proposed control room layouts

A coordinated effort had been placed on the design of the control room to best meet the needs of the plant operator during normal operation and emergency situations.

A practical review of the physical dimensions of the control board to suit the operator and the types and arrangement of controls, instrumentation, displays, and alarms required for safe operation and shutdown was performed by the plant staff. Consideration was given to the fact that certain systems normally require more attention from the operator and the controls for these systems were grouped accordingly.

Computers were used to provide supplementary information to the operator and are designed to be an effective tool in the operation of the plant. The design included adequate instrumentation to provide the operator with sufficient information for proper and safe system operation, irrespective of the availability of the computer system. The computer system obtained data by scanning analog and digital sensors. It logged data on typewriters, sequentially logged trip and post trip data, and alarmed various off-normal and abnormal conditions. Monitoring programs were also included for surveillance of reactor control and protection system operations, and for nuclear process calculations.

The computer readout and plant operator’s console are located in the control room. The control room was designed to ensure habitability under anticipated operational transients (see Section 9.4 for a discussion of control room ventilation systems).

b. Development and implementation of staff recruiting and training programs

SCE&G had developed a "Plan for Staffing the Virgil C. Summer Nuclear Station," designed for staff selection, training, and recruiting. This plan referenced ANSI N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel," as the basis for determining the minimum experience and education requirements for plant personnel. The recommendations of the NRC in WASH-1130, "Utility Staffing and Training for Nuclear Power Plants," were also used in developing this plan. Details pertaining to experience and education requirements are found in Section 13.1.3 and training details are found in Section 13.2 although both are now based on the requirements of ANS 3.1-1981.

c. Development of plans for initial testing

The plans for the preoperational and startup testing of the Virgil C. Summer Nuclear Station were developed by the plant staff. Outside consulting services were used for guidance in establishing these plans. The Manager, Virgil C. Summer Station had the overall responsibility for the development and implementation of this program. Additional details regarding plans for preoperational and startup testing are found in Chapter 14.

d. Development of plant maintenance programs

The plant maintenance program was designed to implement good practices in preventative and corrective maintenance. Such practices assured that the plant would function reliably during its lifetime. This program was designed to control maintenance of equipment and associated controls in an orderly fashion by use of approved procedures.

3. Technical Support for Operations

This section describes the technical services and backup support for operations in the following areas:

a. Nuclear, mechanical, structural, electrical, thermal-hydraulic, plant chemistry, health physics, metallurgy and materials, and instrumentation and controls

The Manager, Virgil C. Summer Nuclear Station had available to him the plant Technical Staff and the offsite Nuclear Engineering Group to support engineering activities of the station. The plant could contact offsite suppliers and consultants to secure information or guidance as required. If offsite engineering was needed to provide support services, the Manager, Nuclear Engineering, determined whether the required work would be performed by the SCE&G nuclear engineering staff, or contracted to a qualified outside organization. A coordinator in the nuclear engineering group was to follow progress and coordinate work.

b. Fueling and refueling operations support

The Manager, Virgil C. Summer Nuclear Station had the option of selecting the qualified personnel for directing fueling and refueling operations.

These personnel could come from the plant staff, other company personnel (especially from nearby SCE&G power facilities), and qualified outside contractors.

c. Maintenance support

The Manager, Virgil C. Summer Nuclear Station had the option to utilize the plant maintenance staff, other company personnel (especially from nearby SCE&G power facilities, company wide maintenance personnel, and construction support), or outside contractors for special support in maintaining the plant.

13.1.1.3 Interrelationships with Contractors

SCE&G Nuclear Engineering Department was responsible for the overall coordination and final approval of plant design and engineering activities during the design and construction phases of the project. During the operating phase, the Nuclear Engineering Department in conjunction with the onsite technical support group was to be responsible for providing technical support services to the Station. The interface between these two Departments was further described in Chapter 17. The SCE&G Nuclear Engineering Department's technical staff and the onsite technical support group were described in Sections 13.1.1.4 and 13.1.2.2, respectively.

Westinghouse design documents which would have an effect on that portion of the plant (BOP) designed by either Gilbert or SCE&G were forwarded to Gilbert or SCE&G for their respective review and comment. Likewise, SCE&G and Gilbert design documents which had an effect on the Westinghouse or other suppliers' scopes of supply were forwarded to these other organizations for their review and comment as appropriate. Specified Gilbert design documents were reviewed and approved by SCE&G Nuclear Engineering. Final acceptance by the SCE&G Nuclear Engineering Department of design concepts, documents, and equipment suppliers was based on recommendations from the responsible Gilbert engineers along with recommendations from within SCE&G Construction, Purchasing, Quality Assurance, and power supply organizations, as appropriate.

Interrelationships and interfaces among various organizations during preoperational and startup testing were described in Section 14.2.2. These relationships for the plant operational phase were described in Chapter 14.

The responsibility for ensuring that equipment suppliers and contractors conform to the approved engineering specifications was the responsibility of Gilbert and/or SCE&G even though equipment was procured by SCE&G Purchasing Department.

Conformance with the approved specifications was verified through implementation of the quality assurance program, and was described in Chapter 17.

13.1.1.3.1 Gilbert Associates, Inc.

The professional qualifications and the organizational structure of Gilbert Associates were presented in Section 1.4.2 and in Chapter 17. During the design and construction phases of the project, the Gilbert Project Manager had the responsibility of coordinating the plant design activities of Gilbert under the overall supervision and direction of the SCE&G Manager, Nuclear Engineering. Upon completion of the plant, Gilbert was to continue to perform engineering services as needed. During the operational phase, the same basic organization which was used during design and construction was to continue with qualifications and structure. (The current organization is shown in Section 1.4.2 and Chapter 17.)

The Gilbert Technical Support Group, working in direct support of the Virgil C. Summer Nuclear Station, would be smaller in size than that required to design the plant. The Project Manager and principal engineers in this continuing engineering services group were to be physically located in

a project island configuration which was designed to enhance a more effective internal interface with the Gilbert organization. The individuals assigned to the continuing services group would, for the most part, be the same personnel who were involved in the original design of the Summer Station. Changes of the Project Manager or principal engineers assigned to this group had to receive approval of the SCE&G Manager, Nuclear Engineering.

The Gilbert project island was to keep and maintain the following records and documents:

1. Project correspondence
2. Project design documents, e.g., layouts, system diagrams, system design descriptions
3. As-built drawings (Gilbert and vendor)
4. Purchase orders
5. Updated FSAR and ER
6. Equipment, valve, instrument, and electrical feeder lists
7. Design calculations
8. Other documents deemed necessary for proper technical support.

A direct telephone line was installed between the Gilbert project office and SCE&G engineering offices. Telecopiers were also available in each location. Home telephone numbers of the principal Gilbert personnel assigned to the project office were available to the SCE&G Nuclear Engineering Department on a continuous and updated basis.

In addition to the personnel assigned to the Gilbert Technical Support Group, Gilbert management was committed to provide its corporate resources as needed.

The Project Manager and principal engineers assigned to the Gilbert continuing services group visited the plant site at least annually for refamiliarization and update on the engineering status and condition of the plant.

13.1.1.3.2 Westinghouse Electric Corporation

The qualifications and structure of Westinghouse were presented in Section 1.4.3 and in Chapter 17. The Westinghouse Project Manager, Pressurized Water Reactors Division, coordinated the design and manufacturing information supplied by Westinghouse with the SCE&G Manager, Nuclear Engineering during the design and construction phase. Upon completion of construction, a Westinghouse Project Manager from the Nuclear Service Division was assigned to the Virgil C. Summer Nuclear Station and was to report to the SCE&G Site Manager, as shown in Figure 13.1-2.

13.1.1.3.3 Daniel International Corporation

The qualifications and structure of Daniel are presented in Section 1.4.4 and Chapter 17. The Daniel Project Manager reported to the SCE&G Site Manager as shown on Figure 13.1-2. This arrangement gave SCE&G the managerial control of all construction activity at the plant site.

13.1.1.3.4 Interrelationshps

The present working interrelationships among the contractor organizations mentioned above are described as follows:

SCE&G Engineering Services is responsible for coordinating and approving plant engineering and design.

Westinghouse design documents that have an effect on that part of the plant design performed by Gilbert and SCE&G are forwarded to Gilbert and SCE&G for review and comment. SCE&G and Gilbert design documents which have an effect on the Westinghouse or other suppliers scope of supply are, likewise, sent to Westinghouse and other suppliers for their review and comment. All Gilbert design documents must be reviewed and approved by SCE&G.

Final acceptance by SCE&G Engineering Services of design concepts, documents, and equipment suppliers was based on recommendations from the responsible designers and consultation with SCE&G organizations as appropriate.

The interrelationships and interfaces among various organizations during preoperational and startup testing are described in Section 14.2.2.

The responsibility for ensuring that equipment suppliers and contractors conform to approved specifications is the responsibility of SCE&G. Conformance is verified through implementation of the quality assurance program described in Chapter 17.

13.1.1.4 South Carolina Electric & Gas Company Corporate Technical Staff

The SCE&G corporate technical staff supporting the Virgil C. Summer Nuclear Station was composed of experienced engineers in the Technical Services and Nuclear Regulatory and Developmental Support Services organizations as shown on Figure 13.1-3. This organizational structure functioned until early 1988 wherein the present Nuclear Operations Division was re-organized with all supporting staff located at the Virgil C. Summer Nuclear Station as shown on Figure 13.1-4.

13.1.2 Operating Organization

The nuclear organization and key individuals’ responsibilities are described in the Quality Assurance Program Description (QAPD) referred to in FSAR Chapter 17.2. Additionally, station personnel will meet the qualification requirements as specified in the station Technical Specifications and the QAPD.

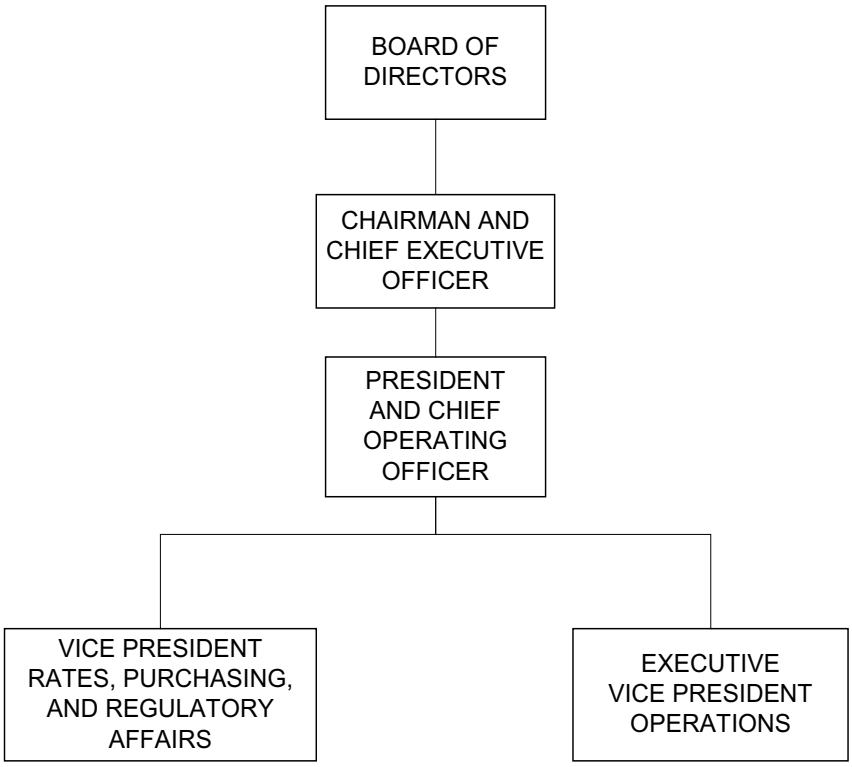
Table 13.1-1
Deleted Amendment 98-01

Figure 13.1-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ORGANIZATION CHART

This figure is being retained for historical purposes only.

South Carolina Electric & Gas
Company Organization Chart
General Management



AMENDMENT 02-01
MAY 2002

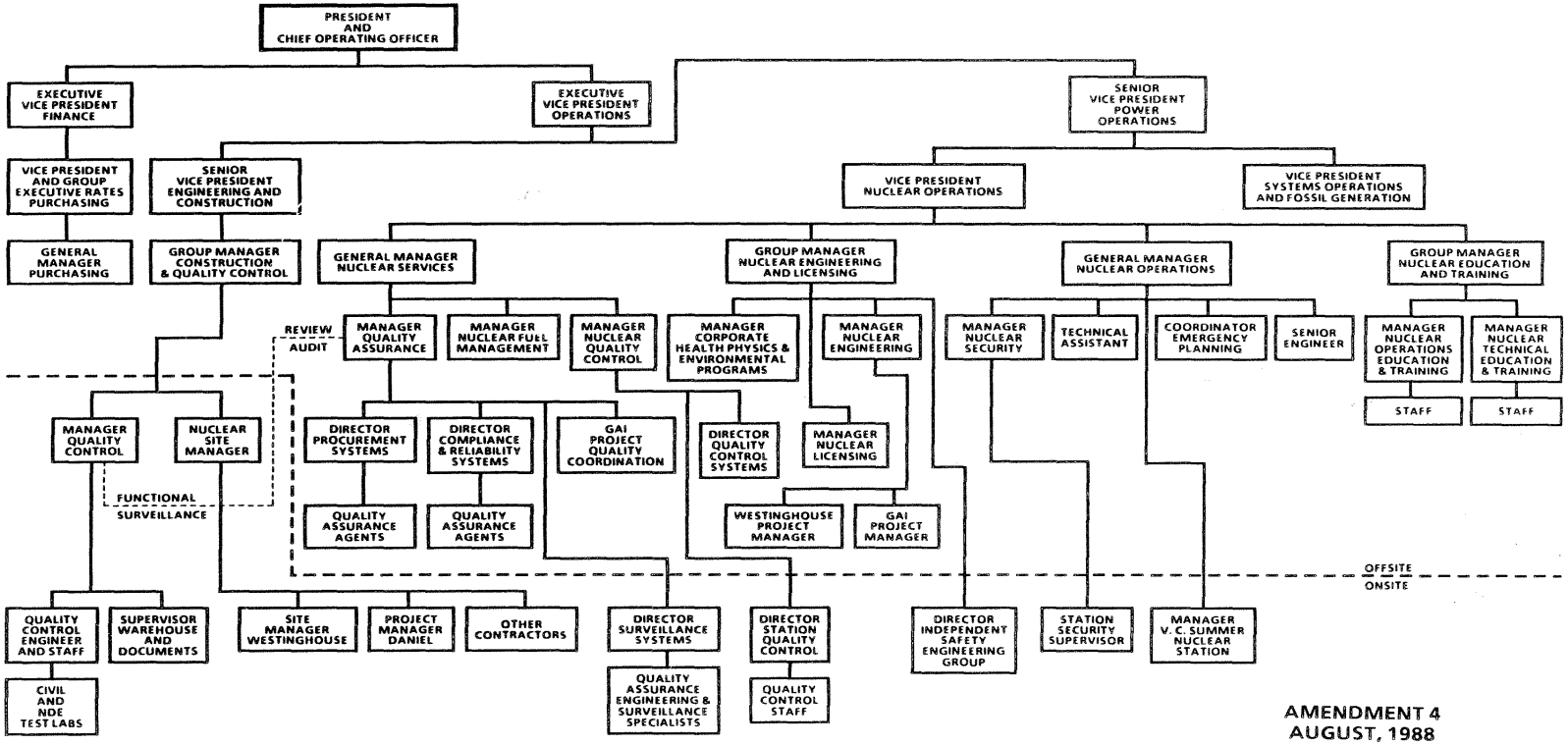
SOUTH CAROLINA ELECTRIC & GAS CO
VIRGIL C. SUMMER NUCLEAR STATION

South Carolina Electric & Gas Company
Organization Chart

Figure 13.1-1

Figure 13.1-2

SOUTH CAROLINA ELECTRIC & GAS COMPANY
PRECOMMERCIAL ORGANIZATION CHART



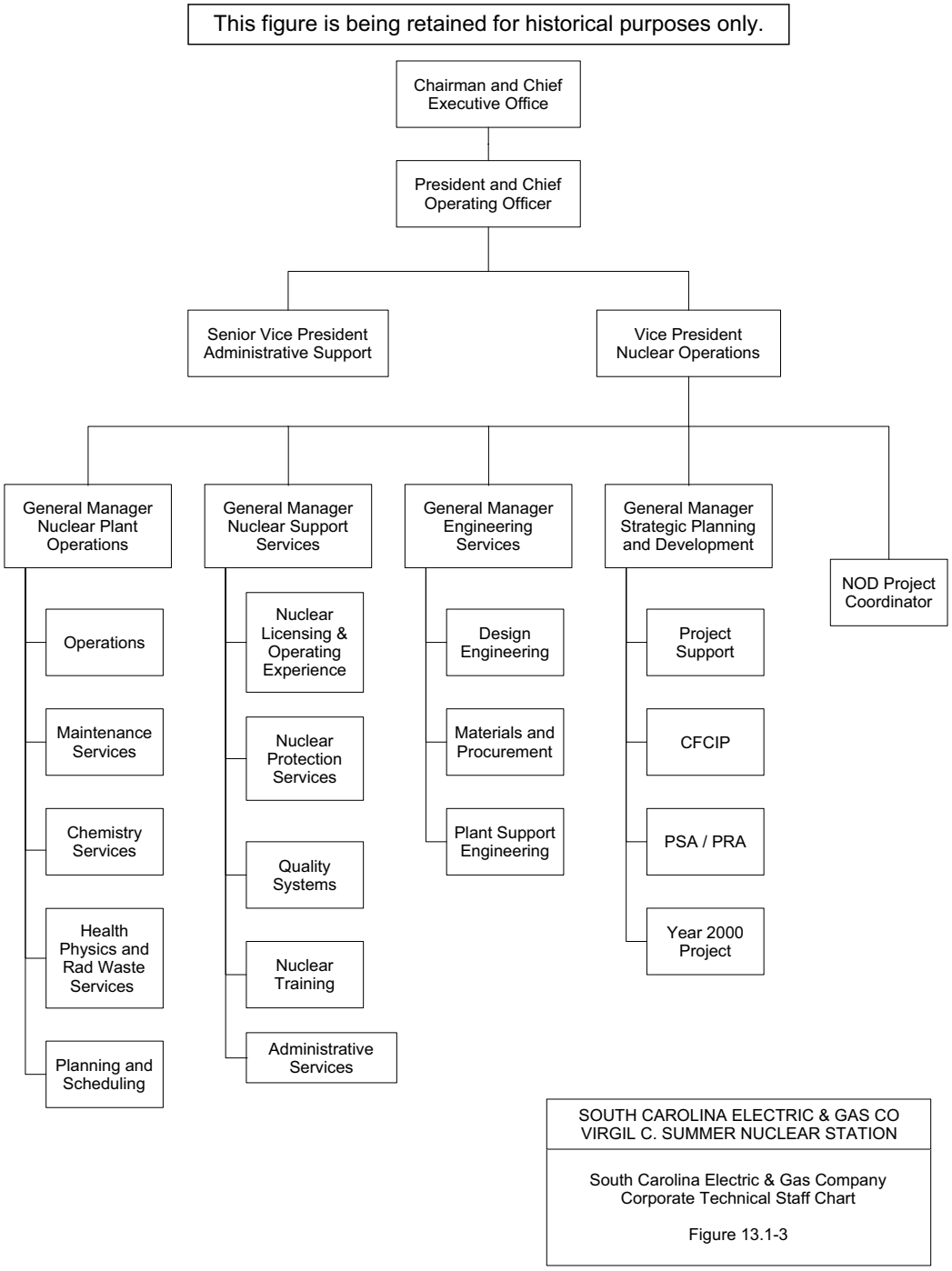
AMENDMENT 4
AUGUST, 1988

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

South Carolina Electric & Gas Company
Precommercial Organization Chart
Figure 13.1-2

Figure 13.1-3

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CORPORATE TECHNICAL STAFF CHART



AMENDMENT 02-01
MAY 2002

13.2 TRAINING PROGRAM

13.2.1 INPO Accredited Training Programs

Virgil C. Summer Nuclear Station training programs are INPO accredited. They have been developed using the INPO Principles of Training System Development guidance and are supported by a plant-specific Job and Task Analysis. The programs that are INPO accredited consist of:

1. Non-Licensed Operator Training Program
2. Reactor Operator Training Program
3. Senior Reactor Operator Training Program
4. Licensed Operator Requalification Training Program
5. Shift Technical Advisor Training Program
6. Shift Manager
7. Chemistry Specialist Personnel Training Program
8. Health Physics Technician Personnel Training Program
9. Mechanical Maintenance Personnel Training Program
10. Electrical Maintenance Personnel Training Program
11. Instrument and Control Personnel Training Program
12. Engineering Support Personnel

NOTE 13.2.2

Section 13.2.2 is being retained for historical purposes only (per RN 00-064).

13.2.2 Training Program for Specialists and Nonlicensed Personnel

13.2.2.1 General

Specialized training programs for Virgil C. Summer Nuclear Station personnel are described below. Several technical staff personnel were involved in Senior Reactor Operator's training who were not required to hold a license; however, this training was beneficial in the safe and efficient performance of their assigned duties. SCE&G took advantage of the following specialized training programs offered by Westinghouse.

13.2.2.2 PWR Station Nuclear Engineering

This is a 13 week program conducted by Westinghouse in the Pittsburgh area. Instructors in this program are Westinghouse engineering personnel knowledgeable in the areas in which they instruct. The classes will contain lecture series and problem solving sessions. A topical outline of

the program includes responsibilities and duties of the station nuclear engineer, responsibilities and relationships to federal and state regulatory agencies, plant licensing and reference documentation, basic PWR design considerations, plant testing program, reactor physics testing, plant instrumentation and control, plant computer reactivity considerations, system reliability checks, station fuel management, and emergency situations.

13.2.2.3 Additional Training

1. Mitigating Core Damage Training was taught to the Plant Manager, the Assistant Plant Manager, I&C, Health Physics, and Chemistry personnel also participated in applicable portions of this training program.
2. Any additional training deemed necessary to meet the intent and training requirements described in Quality Assurance Program Description section 2.5 was handled in conjunction with vendors or through local universities and/or other technical schools to ensure trained personnel operate the Virgil C. Summer Nuclear Station.

13.2.3 General Employee Training

13.2.3.1 Station Orientation Training

All personnel granted unescorted access onto the Virgil C. Summer Nuclear Station will be required to attend applicable portions of the station orientation training program. The subjects covered in this training program are listed below and are required on a biennial basis. Portions of the program may be waived based on exemption exams and/or waivers as justified and approved by applicable supervisory personnel.

Station Familiarization

Station Radiation Emergency Plan and Related Procedures

Industrial Safety

Station Security

Quality Assurance

Basic and Station Specific Health Physics - Principles and Practices

13.2.3.2 Temporary Personnel Training

Personnel without unescorted access will be classified as visitor personnel and shall be escorted while within the boundaries of the protected area. Visitor personnel will be trained in emergency plan procedures as appropriate to ensure the safe execution of their duties.

13.2.4 Training Program Administration

Overall responsibility for training of personnel within the Virgil C. Summer Nuclear Station rests with the Chief Nuclear Officer and President Nuclear Operations through the Site Vice President, and the Director, Plant Support. Training is implemented under the direction of the Manager, Nuclear Training.

13.2.5 Records

Records of plant personnel qualification and training are maintained in a computerized data base system with sufficient hard copy records to support the validity of the data base such as class attendance and exam results.

Summary records of plant personnel qualifications and training may be maintained for each member of the plant staff in a qualification and training folder. This folder will contain a resume of the person's qualifications and general records of training programs and courses completed. Those staff members holding an NRC Nuclear Operator's License will be enrolled in a requalification program that is required to maintain their license. For this type of training, the records maintained will be much more extensive and detailed. These records will contain such items as copies of written examinations administered and the answers given by the licensee, retraining examinations, lecture attendance, trainee's evaluations, and results of retraining in areas in which personnel have exhibited deficiencies. This will assure that records are maintained to comply with 10 CFR 55.59(c)(5).

After initial criticality, the training program effectiveness of each employee shall be evaluated by the individual scores on tests given on the lecture material presented to each employee.

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13.3 EMERGENCY PLANNING

The Virgil C. Summer Nuclear Station Radiation Emergency Plan (REP) contains the precautionary planning, delegation of authority and responsibility, and plans of action to protect the public, plant personnel, and equipment in case of an emergency. As specified in 10 CFR 50, Appendix E, this plan is for use at the local level for the control of emergencies such as fire, personal injury, tornadoes and high winds, and incidents that could result in the release of significant amounts of radioactivity. The actual Virgil C. Summer Nuclear Station REP is provided in Appendix 13A.

13.4 REVIEW AND AUDIT

A program of inplant and independent reviews and audits has been developed by SCE&G to provide a system to ensure that plant startup and operation are consistent with company policies, approved procedures, and license provisions. The review and audit program also assures that abnormal occurrences are promptly investigated and corrected in a manner which reduces the probability of recurrence of such events, and detects trends which may not be apparent to a day to day observer. Guidance provided by ANSI N18.7, "Administrative Controls and Quality Assurance for the Operating Phase of Nuclear Power Plants," (Reference 1) has been used in establishing the SCE&G review and audit program for the Virgil C. Summer Nuclear Station.

NOTE 13.4.1
Section 13.4.1 is being retained for historical purposes only.

13.4.1 Review and Audit - Construction

Review and audit during the design and construction phase of the Virgil C. Summer Nuclear Station are a part of the SCE&G quality assurance program. The review function is performed primarily by the exchange of information between SCE&G, the principal contractors, and other contractors and suppliers. Audits are conducted internally and externally in accordance with the approved quality assurance plan to ensure that design and construction are in accordance with the requirements of 10 CFR 50, Appendix B (see Chapter 17).

13.4.2 Review and Audit - Operations

Specific review and audit requirements are assigned to various committees in addition to the review and audit requirements assigned to the Virgil C. Summer quality assurance staff by the quality assurance program for station operations (see Chapter 17). The committees charged with specific review and audit functions are delineated in Dominion’s Nuclear Facility QAPD.

The Facility Safety Review Committee is charged with first-level review of station operations. The membership of the committee, committee responsibilities and authority, and quorum and meeting requirements are delineated in the QAPD. The members of this committee who are station supervisory personnel meet or exceed the qualification requirements of the QAPD.

Independent review of the safety of nuclear unit operation is performed by the Management Safety Review Committee. The organization and responsibilities of the Management Safety Review Committee are described in the QAPD.

Maintenance and modification of safety-related equipment are controlled and documented in accordance with the requirements of a formal quality control program for station operation and other administrative controls formulated by written procedures. Audits of quality control programs are periodically conducted as delineated in the operational quality assurance program. The quality assurance and quality control programs pertinent to station operation are discussed in the QAPD.

13.4.3 References

1. ANSI N18.7, "Administrative Controls and Quality Assurance for the Operating Phase of Nuclear Power Plants," February 1976.

13.5 PLANT PROCEDURES

Actions concerning structures, systems, and components of the Virgil C. Summer Nuclear Station that are safety-related are conducted in accordance with approved written procedures. Safety-related structures, systems, and components are those that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public and such structures, systems, or components that are essential for the safe shutdown of the plant.

These procedures are written in sufficient detail that a qualified individual can perform the required function without direct supervision. Some procedural steps such as immediate action steps for emergency procedures are required to be committed to memory. Routine actions are performed in accordance with approved written procedures. Plant procedures will cover the following categories:

1. Administrative Procedures
2. Control Room Operating Procedures
3. Maintenance and Modification Procedures
4. Emergency Plan Procedures
5. Chemical-Radiochemical Control Procedures
6. Plant Radiation Protection Procedures
7. Plant Security Procedures
8. Surveillance Test Procedures
9. Fire Protection Procedures

Procedures contain the following significant aspects wherever they apply to the intent of each particular procedure.

1. Title

   A concise descriptive statement describing the activity covered in the procedure.

2. Purpose

   A concise descriptive statement describing the purpose and scope of the procedure.

3. References

   Material which contains information related to the procedure, such as other plant procedures, instructions, drawings, technical manuals, reports, the FSAR, or other applicable documents.

4. Glossary

   Abbreviations and definitions used in the procedure.

5. Prerequisites

   Independent actions or procedures which shall be completed and plant conditions which shall exist prior to use of the procedures.

6. Precautions

   Actions which if not taken or events which if not avoided when performing the procedure could result in hazardous personnel conditions or damage to plant equipment. Precautions also appear in the main body of the procedure where applicable.

7. Check Off Lists

   Lists included in complex procedures requiring the person either performing or supervising the activity being performed to signify by his initials when important procedural steps have been completed.

8. Limitations

   Statements specifying limits on the parameters being controlled such as limiting safety settings and limiting conditions for operation as specified in Technical Specifications.

9. Main Body

   Statements specifying detailed steps for performing the procedure, presented in a degree of detail necessary for performing the required functions, should be identified.

10. Symptoms

    Emergency procedure symptoms shall be included to aid in the identification of the emergency. They should include significant alarms, operating conditions, and, where possible, probable magnitudes of parameter changes.

11. Automatic Actions

    The automatic actions that occur as a result of an emergency should be identified.

12. Immediate Operator Actions

    For emergencies, steps should be specified for operation of controls or confirmation of automatic actions that are required to stop the degradation of conditions and to mitigate their consequences.

13. Probable Cause

    The probable cause for alarms should be specified.

14. Acceptance Criteria

    The qualitative or quantitative criteria against which an evaluation of acceptability may be made.

15. Attachments

    Additional information that may be attached to a procedure for clarification or ease of understanding.

The Virgil C. Summer Nuclear Station Unit 1 conforms to NQA-1-1994 through Virgil C. Summer's QAPD. Operating procedures were prepared using ANSI N18.7, Revision 1, February 19, 1976 as a guide. The Plant Manager or his designated alternate has final approval before procedures are implemented.

13.5.1 Administrative Procedures

The administrative procedures as described in the administrative manual provide a clear understanding of operating philosophy and management policies to ensure safe operation of the plant within the limits set by the operating license and Technical Specifications. They provide that plant activities are conducted in a manner that will protect the general public, plant personnel, and equipment. A list of administrative procedure categories is provided in Table 13.5-1. A description of these procedure categories is as follows:

13.5.1.1 Plant Organization and Responsibility Procedures

These procedures describe the plant organization and give the responsibility of the individuals by position and authority to operate the plant in a safe and efficient manner.

13.5.1.2 Development, Review, Approval, and Control of Safety-Related Plant Procedures

These procedures describe the method by which plant procedures are written, the control process for review and approval, and the system utilized to revise the procedures where needed. Administrative procedures, security plan implementing procedures, and emergency plan implementing procedures receive final approval by the Plant Manager or his designated alternate. They are reviewed under the direction of a supervisor from a group other than the originating group before final approval by the Plant Manager.

13.5.1.3 Conduct of Plant Operations Procedures

These procedures describe the rules and instructions issued by the Plant Manager pertaining to personnel conduct and control. These rules and instructions provide a clear understanding of

operating philosophy and management policies. They delineate the authority and responsibility of the Reactor Operators and Senior Reactor Operators for the safe operation of the reactor as required by 10 CFR 50.54 (i), (j), (k), (l), and (m). They establish the rules for procedure use and the designation of the persons responsible to authorize a temporary change to an approved procedure. Additional procedures establish standard operating orders which deal with such matters as job turnover and relief, designation of the confines of the Control Room including a diagram of the Control Room that indicates the area designated as at the controls (Figure 13.5-1), transmittal of operating data, limitations on access to equipment, and other such matters. Provisions are made for periodic review and updating of standing orders. Instructions which have short time applicability such as housekeeping, publications and their distribution, and personnel actions are issued as special orders.

As required by NUREG 0578, Section 2.2.1.c, procedures define the procedural steps for relief of shift personnel. Checklists are provided for the oncoming and offgoing Control Room Supervisor and the oncoming Shift Manager to complete and sign. These checklists provide assurance that actual plant parameters are within allowable limits and that required systems are available and are in proper alignment for the prevention and mitigation of operational transients. Systems and components that are in a degraded mode of operation permitted by Technical Specifications shall be listed and time in degraded mode is compared with Technical Specification action statements. Auxiliary Operator checklists include any equipment under maintenance or test that could degrade a system or initiate an operational transient and shall include criteria for acceptable status. The Operations Supervisor will make unannounced audits of shift relief to evaluate the effectiveness of shift relief and turnover.

Also as required by NUREG 0578, Section 2.2.2.a, procedures establish the authority and responsibility of the person in charge of the Control Room to limit access.

As required by NUREG 0737, item I.A.1.3, administrative procedures establish actual work time limitations for plant shift personnel who maintain or operate any structures, systems, or components important to safety.

13.5.1.3.1 Shift Manager’s Responsibility

As required by NUREG 0578, Section 2.2.1.a, upper level management shall issue a directive that establishes the management responsibility for the Shift Manager under all plant conditions. It shall contain clear delineation of management chain of authority as to who can, and when the Shift Manager is relieved of the responsibility for direct control of the plant.

An administrative procedure is provided that gives the authority and responsibilities of the Shift Manager, Control Room Supervisor, Control Room Operator, and other shift personnel.

Both on the job training and classes emphasize responsibility for safe operation and management functions as given in the administrative procedure.

A review of administrative duties of the Shift Manager has been conducted by senior plant and corporate management. Additional administrative personnel have been added to the operating

group that relieve the Shift Manager of routine duties that distract from the management responsibility for assuring the safe operation of the plant.

NOTE 13.5.1.3.2
Section 13.5.1.3.2 is being retained for historical purposes only.

13.5.1.3.2 Westinghouse Review of Procedures

As required by NUREG 0737, item I.C.7, Westinghouse (NSSS Supplier) reviews station emergency operating procedures, power ascension procedures, and low power physics tests. Additional information on this subject has been submitted to the NRC under separate cover letter dated December 2, 1980.

13.5.1.3.3 NRC Review of Procedures

As required by NUREG 0737, item I.C.8, selected station emergency operating procedures have been demonstrated for the NRC on the Westinghouse Zion Simulator. Also, a walkthrough on the Virgil C. Summer Nuclear Station Control Board was performed as required. NRC comments on these procedures have been resolved.

13.5.1.3.4 Reporting Safety and Relief Valve Failures

Any failure of a pressurizer PORV or safety valve to close will be reported to the NRC promptly. Challenges to these valves will be documented in the annual report.

13.5.1.4 Control of Plant Documents Procedures

These procedures describe the preparation and retention of plant records. Retention periods are established to assure the ability to reconstruct significant events and satisfy statutory requirements.

13.5.1.5 Corrective Action Reporting Procedures

These procedures assure that conditions adverse to plant safety such as equipment and material malfunction, abnormal occurrences, and nonconformances are promptly identified and corrected. They ensure that the cause of the conditions is determined and reported to the appropriate level of management for corrective action.

13.5.1.6 Equipment Control Procedures

These procedures describe the control measures and actions such as locking, tagging, notification, removal of tags, and identification of equipment. They provide for control of equipment to maintain reactor and personnel safety and to avoid unauthorized operation of equipment. As required by NUREG 0737, items I.C.6 and II.K.1 (sub items 5 and 10), administrative procedures

provide instructions for verifying correct performance of operating activities. This item has been specifically addressed under separate cover letter to the NRC dated December 11, 1980.

13.5.1.7 Design Modification Control Procedures

These procedures ensure that plant modifications satisfy, at a minimum, the same design requirements as the original equipment. Regulatory Guide 1.64 was used as a guide for the preparation of these procedures.

13.5.1.8 Procurement and Materials Control Procedures

These procedures provide for the control of purchased material, equipment, and services. They provide for proper identification, quality level requirements, control, handling, storage, and shipping of materials, parts, and components. These procedures also provide for the proper documentation to ensure quality of safety-related systems, equipment, and structures after maintenance or repair.

13.5.1.9 Control and Calibration of Test Equipment and Instrumentation Procedures

These procedures ensure that testing and measuring devices are of the proper range and type and are controlled, calibrated, adjusted, and maintained at specified intervals or prior to use to assure the necessary accuracy of calibrated devices. Records are made and equipment suitably marked to indicate calibration status.

13.5.1.10 Control of Special Processes During Operations Procedures

These procedures assure that special processes are accomplished under controlled conditions in accordance with applicable codes, standards, specifications, criteria, and other special requirements using qualified personnel and procedures.

13.5.1.11 Non-Conformance Control/Deficiency Reporting Procedures

These procedures provide for control of items, services, or activities which do not conform to requirements. These procedures include instructions for identification, documentation, segregation, notification of affected organizations, and method of disposition of such items, services, or activities.

13.5.1.12 Test Control Procedures

These procedures assure that testing required to demonstrate that an item will perform satisfactorily in service is accomplished properly. Test procedures incorporate or reference the requirements and acceptance limits contained in applicable design documents. These test procedures may include preoperational tests, initial operational phase tests, surveillance tests, and tests during design, fabrication, and construction activities associated with plant maintenance and modification.

13.5.1.13 Feedback of Operating Experience

In accordance with NUREG 0737, item I.C.5, a program will be established for evaluating operating plant experience and providing the results of the evaluations, as necessary, to pertinent plant personnel. The services of “Industry Groups" such as INPO will be utilized to the extent possible in the performance of this function.

13.5.1.14 ECCS Outages

In accordance with NUREG-0737, item II.K.3.17, a program has been established using existing plant procedures for data collection including ECCS outage times, duration and cause of the outage, components involved in the outage, and corrective action taken. A plant procedure for removal and restoration of station equipment provides measures for data collection. The ECCS data taken by this procedure will be reviewed by appropriate plant personnel to determine if improvements to availability of ECCS are needed.

13.5.2 Control Room Operating Procedures

Control Room operating procedures are those procedures that are performed by the licensed Control Room Operator or under his direction and control. They are a preplanned method for the conduct of operations to minimize reliance on memory. These procedures include anticipated operating conditions, the normal method of control, means for and limits on operation of the plant, or plant systems that affect the safety of the plant and the public. These procedures address the areas discussed in Sections 13.5.2.1 through 13.5.2.6. As stated in NUREG-0660, item I.C. the applicant will incorporate changes into station operating procedures resulting from "Owners Group participation" as deemed necessary. A list of these procedure categories can be found in Table 13.5-2.

13.5.2.1 General Operating Procedures

General Operating Procedures (GOP) provide for the integrated operation of the plant. These procedures provide the sequence of plant operations to take the plant from a given initial condition to a final expected condition. Associated system operating procedures are referenced as applicable. Necessary precautions are inserted at critical points.

13.5.2.2 Emergency Operating Procedures

Emergency Operating Procedures (EOP) are written so that a trained operator and crew will be able to identify an emergency from the symptoms available to them and take immediate action on the expected course of events to place the plant in a known safe condition and to mitigate the consequence of a serious condition should it occur. Since emergencies may not follow anticipated patterns, these procedures provide sufficient flexibility to accommodate variations. Those sections of the procedure that require immediate response action from the operating crew are committed to memory. Considerable judgment on the part of competent personnel is exercised before departure from these procedures.

13.5.2.3 System Operating Procedures

System Operating Procedures (SOP) provide instructions for energizing, starting up, shutting down, changing modes of operation, and other instructions for operations of systems related to the safety of the plant.

These procedures are concerned with systems only and include valve and switch lineups, control operations, and instrumentation within the system boundaries. They are subdivided into normal operations, infrequent operations, and off normal conditions in the main body.

13.5.2.4 Annunciator Response Procedures

Annunciator Response Procedures (ARP) are written to instruct the operator on the proper action to be taken in response to annunciators on the Main Control Board. They contain annunciator identification, inputs into the annunciator, and logical operator responses to be taken to ensure proper corrective action. The ARPs are identified by panel number. An illustration in the beginning of the ARP depicts the annunciator panel. In the case of computer alarms, each alarm's unique identifier is listed.

When use of the ARP is required, the operator selects the proper tab by an alarm panel number.

13.5.2.5 Fuel Handling Procedures

Fuel Handling Procedures (FHP) are written to specify actions and philosophy for core alterations and partial or complete refueling operations. They include requirements for continuous monitoring of neutron flux throughout core loading and audible annunciation of abnormal flux increases. The duties of personnel assigned to refueling, such as periodic data taking, response actions to alarms during refueling, and criteria for stopping the refueling are specified. Also, instructions for proper sequence of events, verification, and frequency of sampling to ensure shutdown margin, communications between the control room and the fuel loading station, documentation of final fuel component serial numbers and location, containment integrity requirements, and rules for periods when refueling is interrupted are included. System operating procedures are referenced as required.

13.5.2.6 Special Procedures

Special procedures are written and issued to direct operations during testing, refueling, maintenance, and modifications. These procedures provide guidance in unusual situations not covered by existing procedures. They ensure orderly and uniform operations for short periods when the plant, a system, or a component is not performing in a normal manner and an existing procedure does not apply. Special procedures designate the period of time during which they may be used and are subject to the same review and approval process as other operating procedures.

13.5.3 Maintenance and Modification Procedures

Maintenance and modification procedures define the policies and practices by which structures, systems, and components are kept in a condition of good repair so that they are capable of reliably performing their intended functions. This includes those activities performed by maintenance or contractor personnel to maintain, repair, or modify safety-related equipment. Additional related activities covered are those by operating personnel to ensure that a planned maintenance activity can be safely accomplished, that proper plant operating conditions exist, to authorize the release of equipment to be maintained using equipment control procedures, and to assure that the equipment has been returned to normal operating status at the completion of maintenance work, as well as verification of functional acceptability. Procedures are written to assure measurement accuracies are adequate to keep safety parameters and controls within safety and operational limits. This instrumentation includes interlocks, alarm devices, sensors, readout instruments, transmitters, signal conditioners, laboratory equipment, key recorders, and protective logic circuits. Calibration, testing, and checking of instrumentation channels are performed at the frequency specified in Technical Specifications. A list of the areas covered by maintenance procedures is given in Table 13.5-3.

13.5.4 Emergency Plan Procedures

These procedures are written in sufficient detail that a qualified individual can perform the required actions without supervision. They provide a step by step order and logical sequence in a concise manner but are flexible enough to give latitude to the user for the exercise of judgment in implementing specific actions or parts of the procedure. These instructions specify the individual or organization having authority and responsibility for performing critical tasks. The actions to be performed by support agencies and the coordination with other elements of the emergency organization are also specified. Guidelines for initiating recovery after the emergency alert is over to restore the plant to the pre-emergency conditions are given. A list of the procedure categories is given in Table 13.5-4.

13.5.5 Chemical-Radiochemical Control Procedures

These procedures provide instructions for maintaining reactor coolant, condensate, and feedwater within prescribed quality limits and include the nature and frequency of sampling and analysis. They also include laboratory instructions and instructions for calibration of laboratory equipment. Limitations on concentrations of agents that could cause corrosive attack, foul heat transfer surfaces, or become sources of radiation hazards due to activation are given. A list of the procedure categories is given in Table 13.5-5.

13.5.6 Plant Radiation Protection Procedures

These procedures cover plant personnel, other SCE&G personnel temporarily assigned, contractor and vendor personnel, and visitor protection to maintain occupational dose rate to as low as reasonably achievable. They provide coverage for all normal operations and anticipated operational occurrences. This includes refueling, purging, fuel handling and storage, also radioactive material handling, processing, use, and storage. Other areas covered are maintenance,

routine operational surveillance, inservice inspection, and calibration. A list of the areas covered by the radiation protection procedure categories is included in Table 13.5-6.

13.5.7 Plant Security Procedures

These procedures are written to supplement physical barriers and features designed to control access to the plant and as appropriate to sensitive areas and equipment within the plant. Information concerning design features and administrative provisions is protected and distribution is limited. Plans for physical protection of the Virgil C. Summer Nuclear Station are described in a separate part of the application for license, withheld from public disclosure pursuant to 10 CFR 2, Paragraph 2.790 (d) (refer to Section 13.7). A list of the areas covered by these procedures is included in Table 13.5-7.

13.5.8 Surveillance Test Procedures

These tests and inspections are performed in accordance with the Technical Specifications to ensure that the required reliability of safety systems is maintained. These surveillance test procedures contain a description of the test objectives, the acceptance criteria used to evaluate the test results, and the prerequisites for performing the test. They include any special conditions to be used to simulate normal or abnormal operating conditions, limiting conditions, the test procedure, and any special test equipment or calibrations required to conduct the test. A master surveillance schedule reflecting the status of surveillance testing is also maintained. Additional control procedures ensure timely conduct of surveillance testing, appropriate documentation, reporting, and evaluation of test results. Significant deficiencies identified by the tests are reported to management. The deficiencies will be evaluated and the condition corrected in a timely manner. A list of surveillance test procedure categories is included in Table 13.5-8.

13.5.9 Fire Protection Procedures

These associated procedures provide the necessary planning and instructions to ensure adequate fire protection for the Virgil C. Summer Nuclear Station. Included, but not limited to, are the provisions made in the Fire Protection (FP) DBD and SAP-131. The responsibilities for preparation of schedules and procedures required by the Operations, Maintenance, and Technical Groups are stated in this report and are detailed in administrative procedures.

Table 13.5-1
Administrative Procedure Categories

Plant Organization and Responsibility Procedures

Development, Review, Approval and Control of Safety-Related Plant Procedures

Conduct of Plant Operations Procedures

Control of Plant Documents Procedures

Corrective Action Reporting Procedures

Equipment Control Procedure

Design Modification Control Procedures

Procurement and Materials Control Procedures

Control and Calibration of Test Equipment and Instrumentation Procedures

Control of Special Processes During Operations Procedures

Non-Conformance Control/Deficiency Reporting Procedures

Test Control Procedures

Table 13.5-2
Control Room Operating Procedure Categories

General Operating Procedures
Emergency Operating Procedures
System Operating Procedures
Annunciator Response Procedures
Fuel Handling Procedures
Special Procedures

Table 13.5-3
Maintenance and Modification Procedure Categories

Mechanical Maintenance Procedures
Electrical Maintenance Procedures
Instrument and Control Maintenance Procedures
Instrument Calibration Test Procedures
Refueling Maintenance Procedures
Material Control Procedures
Safety-Related Structures, Systems or Components Modification Procedures

Table 13.5-4
Emergency Plan Procedure Categories

Activation and Implementation of Emergency Plan
On-Site and Off-Site Radiological Surveying
Communication and Notification
Radiation Exposure Assessment and Protective Action Recommendations
On-Site Evacuation and Personnel Accountability
Handling of Injured Personnel
Natural Emergencies
Fire Emergencies
Post-Recovery and Re-Entry
Emergency Training and Drills
Emergency Personnel Exposure Control
Emergency Facilities Activation and Organizational Responsibilities

Table 13.5-5
Chemical-Radiochemical Control Procedure Categories

Chemistry Analytical Procedures
Chemistry Reagent Preparation Procedures
Radiochemistry Analytical Procedures
Radiochemistry Carrier Preparation Procedures
Laboratory Instrumentation Operating and Calibration Procedures
Chemistry and Radiochemistry Records, Reports and Log Procedures
Procedures for Steam Generator Chemistry Control During Dry or Wet Layup
Chemistry Sampling Techniques
Radiochemistry Counting Techniques

Table 13.5-6
Plant Radiation Protection Procedure Categories

Radiological Surveys and Monitoring Procedures

Radiation Work Permit Procedures

Use and Testing of Protective Equipment and Clothing Procedures

Personnel Decontamination Procedures

Health Physics Quality Control and Instrumentation Calibration Procedures

Procedures for the Movement of Radioactive Materials Within the Plant

Contaminated Tools and Equipment Storage Procedures

Radioactive Waste Management Procedures

Control of Radioactive Calibration Source Procedure

Radiological Environmental Monitoring Procedures

Personnel Dosimetry and Radiation Exposure Control (Internal and External) Procedures

Records and Reporting Procedures

Special Nuclear Materials Accountability Procedures

Control of Personnel Conduct in Radiation and High Radiation Areas

Area and Equipment Decontamination Procedures

Table 13.5-7
Plant Security Procedure Categories

Means for Control of Plant Access Procedures

Control of Personnel Procedures

Access Control During Emergencies Procedure

Equipment Monitoring Procedures

Potential Security Threats Handling Procedures

Notification, Reports and Records

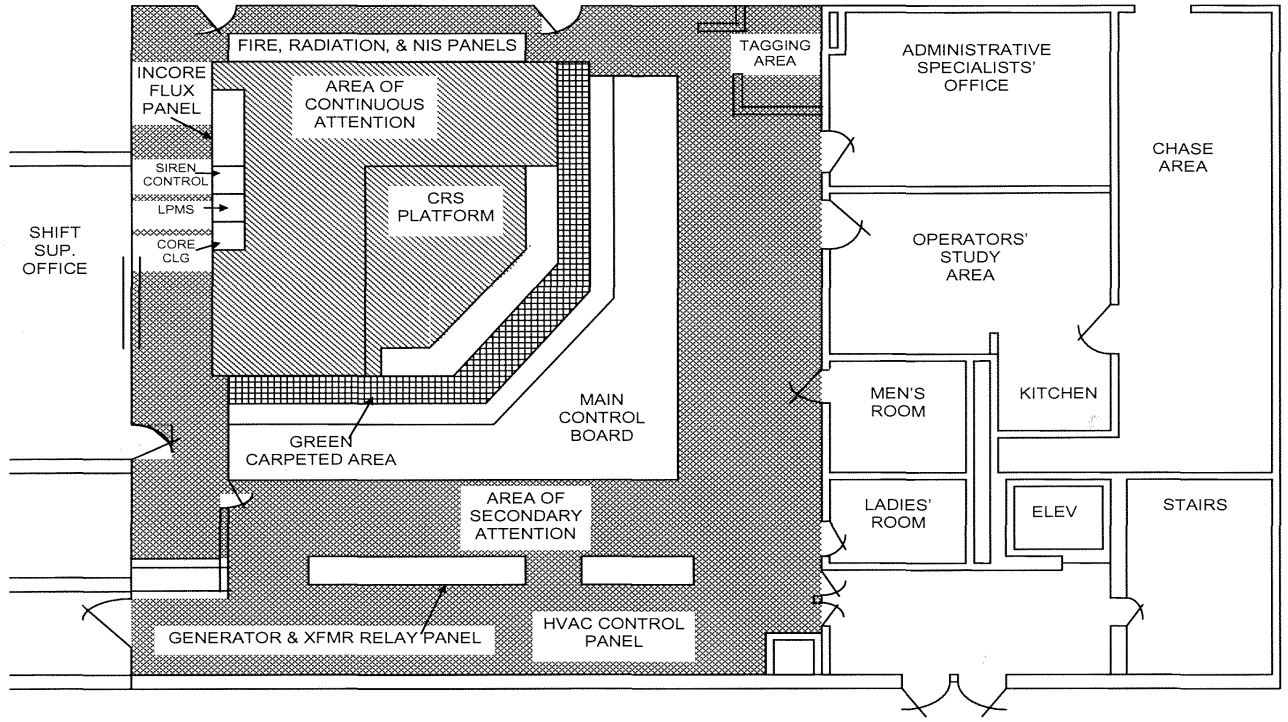
Table 13.5-8
Surveillance Test Procedure Categories

Operations Group Surveillance Procedures

Maintenance Group Surveillance Procedures

Figure 13.5-1

CONTROL ROOM AREAS DESIGNATED AS AT THE CONTROLS



Ref. Dwg. E-005-001 ASSOCIATED WITH
FSAR Figures 1.2-15, 12.1-19, and 12a.4-7

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Figure 13.5-1 Control Room Area Designated As At The Controls

Amendment 00-01
December 2000

13.6 PLANT RECORDS

Records documenting the quality of the design, construction, testing, operation, maintenance, and modification of the Virgil C. Summer Nuclear Station will be maintained to meet the requirements of Basic Requirement 17 and Supplement 17S-1 of ASME NQA-1-1994 and Regulatory Guide 1.28, Revision 3 (see Appendix 3A). The records maintained comply with the requirements of Criterion XVII of Appendix B of 10 CFR 50 and Basic Requirement 17 and Supplement 17S-1 of ASME NQA-1-1994 and Regulatory Guide 1.28, Revision 3 (see Appendix 3A).

Records are normally stored and maintained in the permanent records storage facility which provides facilities to preserve the records in a manner to preclude deterioration. Records that are not maintained in the permanent record storage facility will be duplicated and stored in a separate remote location. Electronic records will be maintained as described in Part II, Section 17.2 of the Virgil C. Summer QAPD.

Records will not normally be removed from the permanent records storage facility as specified in implementing procedures. However, under unusual circumstances, the Nuclear Records Supervisor, designee, or the Director, Plant Support may authorize temporary removal of records from the permanent records storage facility. The SCE&G quality assurance organization is responsible for auditing these quality records as described in Part II, Section 18 of the Virgil C. Summer Nuclear Station Unit 1’s QAPD.

13.6.1 Plant History

Upon completion of the plant design, construction, and construction testing, the engineering and construction departments transferred or disclosed the location of all quality documentation to the plant staff and operations quality services group. The engineering and construction departments will state that the record types necessary to document quality have been identified and that the list is complete and accurate. Records not maintained at the plant site are kept at the material suppliers due to code and standard requirements or at Parsons Power, LTD (formerly Gilbert Associates, Inc.) offices, the architect-engineer for the Virgil C. Summer Nuclear Station.

This documentation, together with the records generated during the testing program, operation, maintenance, inspection, modification, and events of the Virgil C. Summer Nuclear Station, as described in Sections 13.6.2 and 13.6.3, serves as a recorded history of plant activities.

13.6.2 Operating Records

Preoperational and startup test records generated during the testing program are kept at the plant site along with appropriate operating records. These operating records include chemistry records; manuals and procedures; operating, maintenance, and testing records; special nuclear materials records; records and reports required by regulatory agencies; and administrative records.

Operations records and logs that are kept at the plant are considered as nonpermanent and are maintained for a predetermined time as shown on the SCE&G records accumulation and retention

chart, unless a longer period is required by applicable regulations. The following are examples of these type records:

1. Startup problems and resolutions.
2. Records of normal plant operation, including power levels and period of operation at each level.
3. Records of principal safety-related maintenance activities, including inspection, repair, substitution, or replacement of principal items of equipment.
4. Records of abnormal occurrences and unusual events.
5. Records of shipment of radioactive material.

Operations records that are considered to be of a significant value in demonstrating safe operation capability, in maintaining, replacing, or repairing an item, in determining the cause of an accident or malfunction of an item, or in providing baseline data for inservice inspection are maintained for the life of the plant. The following are examples of these type records:

1. Applicable plant procedures and drawings.
2. Records of inservice inspections.
3. Records of radiation exposure of plant personnel and others, who enter radiation control areas.
4. Records of new and spent fuel inventory and assembly histories.
5. Records and drawing changes made to the plant as described in the FSAR.
6. Reactor water chemistry data.

13.6.3 Event Records

Records of occurrences such as radioactive releases and environmental surveys are maintained at the plant site. These records are considered to be of a significant value in demonstrating the safe operation capability of the plant and are therefore kept for the life of the plant. The following are examples of these type records:

1. Records of plant radiation and contamination surveys.
2. Gaseous and liquid release data.

13.7 INDUSTRIAL SECURITY

The security plans for the Virgil C. Summer Nuclear Station are submitted under separate cover pursuant to paragraph 2.790 (d), 10 CFR Part 2, "Rules of Practice."

Appendix 13A
South Carolina Electric and Gas Company
Virgil C. Summer Nuclear Station
Radiation Emergency Plan

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APPENDIX 13A
RADIATION EMERGENCY PLANNING

The Radiation Emergency Plan to support a full power operating license, which addresses the requirements of NUREG-0654, was submitted under separate cover to the NRC on June 4, 1980. Revisions to the Radiation Emergency Plan are submitted to the NRC in accordance with the requirements of 10 CFR 50.54(q).

V.C. Summer Nuclear Station
Safety Analysis Report

Initial Tests and Operation

Chapter 14

Revision 26--06/25/26

This Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

Reactor Coolant System
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CHAPTER 14 - INITIAL TESTS AND OPERATION

NOTE 14.0

Chapter 14, in its entirety, is being retained for historical purposes only.

An extensive test program is conducted by SCE&G to verify that the systems, components, and structures which make up Virgil C. Summer Nuclear Station will perform as they were designed. The overall test objective is to assure that the operation of Virgil C. Summer Nuclear Station will not endanger the health and safety of the public. The ultimate responsibility for the initial tests and operation belongs to SCE&G.

14.1 TEST PROGRAM

The initial test program of Virgil C. Summer Nuclear Station is in three phases; Phase I, component or construction tests; Phase II, acceptance and preoperational tests; and Phase III, core loading and initial startup tests.

Component or construction tests are performed to ensure that components and subsystems meet their functional requirements. The Phase I test program consists of hydrostatic test, flushing, electrical checks, initial operation of equipment, and other specific tests on individual items of equipment.

Acceptance and preoperational tests demonstrate that systems and structures can perform their intended functions. These tests start with system or subsystem turnovers from construction and continue through core loading.

Core loading and initial startup tests begin only after the plant operating license has been issued. It begins with core loading and continues through initial criticality, ascension to power, and is complete when the plant is fully licensed for commercial operation. The results of these tests show that the plant follows its predicted nuclear parameters and can be operated at rated capacity without endangering the health or safety of the public.

Some of the tests described in Regulatory Guide 1.68 are considered preoperational tests but, because of their requirements, are performed during startup testing. An example is scram performance of control rods. This can only be done after the core is loaded and the vessel head is on although this test appears in the preoperational section of the guide.

To assure quality control, procedures used in testing are written and approved in accordance with Section 14.1.1. Changes made to approved procedures are in accordance with Section 14.1.2. The use of plant procedures is discussed in Section 14.1.5. Compliance with regulatory guides is discussed in Appendix 3A.

The Manager Virgil C. Summer Nuclear Station is responsible for the development, administration, and conduct of the test program. The test program is conducted by a startup group which is organized specifically for performing the initial tests and startup of the plant. After

commercial operation, this group will be disbanded. The startup group is described in more detail in Section 14.1.1.4.

The initial test program schedule is presented as Table 14.1-81.

14.1.1 Administrative Procedures (Testing)

14.1.1.1 Development of Procedures

The preparation of Phase I, II, and III test procedures is the responsibility of the Plant Manager or his designee (qualification described in Section 13.1.3). The Startup Supervisor may assume these duties for Phase I, II, and III while the startup group is active. Procedures which are contracted to other organizations are written in accordance with the terms of the contract but are reviewed as if written by SCE&G Nuclear Operations. Phase II and III test procedures as described in this Chapter are approved by the Manager Virgil C. Summer Nuclear Station. Acceptance criteria and performance requirements are determined by SCE&G Nuclear Operations by evaluating data furnished by Westinghouse, Gilbert, other vendors, and contractors. Information received from other departments of SCE&G is given close evaluation in the determination of acceptance criteria and performance requirements.

The preparation of Phase I Test Instructions is the responsibility of the Startup Supervisor, who will designate this responsibility to the Test Supervisors. The Test Supervisor will prepare the original test instruction following the guidelines and test methods set forth in generic instructions. If more guidelines are considered necessary, the Test Supervisor will follow specified formats depending on the type of instruction being written (Hydro, Electrical, I&C, Flush). During preparation of the Phase I Test Instruction, the Test Supervisor will use the following references as applicable: Virgil C. Summer Nuclear Station, FSAR, Westinghouse System Descriptions, Gilbert Design Descriptions, Westinghouse NSSS Startup Manuals, applicable vendor Instruction Manuals, and other sources as necessary. After preparation of the test instruction is completed, the Test Supervisor will submit the instruction to the Lead Systems Supervisor, who will review and approve the test instruction.

The preparation of Phase II test procedures as described in Section 14.1.3.2 is the responsibility of the Startup Supervisor who will designate this responsibility to the Test Supervisors. The Test Supervisor(s) prepares the assigned procedure in the prescribed format and submits the procedure for distribution. Copies will be sent to the Westinghouse Startup Representative, the Gilbert Associates Startup Representative, the Startup Supervisor, and the Manager, Virgil C. Summer Nuclear Station, or their designated alternates, each having at least the qualifications of a Lead Systems Supervisor as described in Section 14.1.1.4, for review. The Startup Supervisor may also send the procedure to designated groups or persons for review. These designated groups or persons may include Nuclear Engineering personnel, Quality Assurance personnel, the Assistant Managers Operations, Maintenance Services, and/or Technical Support. Minimum qualifications for Nuclear Engineering and plant personnel assigned to review Phase II test procedures are provided in Section 13.1.

The reviewers examine the procedure for correctness and comment as necessary. The procedure with comments is then returned to the originator for resolution/incorporation of comments. When comments are resolved/incorporated, the procedure is forwarded to the Startup Supervisor. The Startup Supervisor or his designee signs the procedure recommending approval. The procedure is transmitted to the Plant Manager or his designee for his approval.

The preparation of Phase III test procedures will be the responsibility of the Assistant Manager Technical Support or his designated alternate, who will assign the responsibility for the preparation of individual test procedures to plant or support personnel. The originator(s) prepares the assigned procedure in the prescribed format and submits the procedure for distribution. The procedure(s) will be reviewed and approved as per Plant Administrative Procedures (FSAR Chapter 13 and Technical Specifications Section 6).

Test procedures are available to NRC inspection personnel 30 days prior to the scheduled performance of the activity, but not less than 90 days prior to the scheduled core loading date. NRC possession of procedures shall not impede revision, review, or refinement of the procedures.

The format for Phase II and III test procedures is as follows:

TITLE PAGE

The title page contains the station name, procedure title and number, revision number, and signature and date for approval.

1.0 PURPOSE

This section contains the general purpose and objectives of the test.

2.0 REFERENCES

This section contains the references used to develop the test procedure such as FSAR, system descriptions, operating procedures, applicable standards and codes, drawings, manufacturer’s literature, etc. Where possible, revision numbers and dates are shown.

3.0 PREREQUISITES

This section contains title and number of pertinent tests or portions of tests which must be completed prior to conducting this test and/or tests which must be carried out concurrently with this test.

This section also contains the plant status required to conduct the tests such as pressure, temperature, levels, etc. and outline of system status, such as special valve lineups, test equipment installation, temporary equipment installation, temporary equipment, and identification of any equipment that should or should not be operating for equipment or personnel safety.

4.0 SPECIAL TEST EQUIPMENT

This section lists special equipment, other than normal system equipment and instrumentation, required to conduct the test.

5.0 LIMITATIONS AND PRECAUTIONS

This section contains design and safety limits for equipment and any special limitations and precautions needed for safety of personnel or equipment needed to assure that the required results are obtained during the test.

6.0 TEST METHOD

The test method consists of one or more sections containing step-by-step instructions to accomplish the purpose of the test.

Appropriate inspection points are established to record the accomplishment of the test objectives and test requirements.

Test method ensures that the system or plant is placed in a safe condition after a test has been completed and that nonstandard arrangements are restored to their standard condition and that proper verification and records are maintained.

7.0 DATA REQUIREMENTS

This section consists of the necessary instructions to assure that the required data are obtained by outlining requirements that can clearly be associated with steps of the test method.

Preplanned data sheets are used as much as possible with provisions for name of the person responsible for recording data, type of observation performed, and acknowledgment of the acceptability of the data. The data are compared with the acceptance criteria for the test to determine acceptability.

8.0 ACCEPTANCE CRITERIA

This section lists those qualitative or quantitative requirements or limits contained in the design documents against which test results are evaluated.

14.1.1.2 Execution of Test Procedures

Prior to the start of the initial testing program, the Virgil C. Summer Nuclear Station Operations Department arranges itself into a startup group which is more suited for the initial testing program. This organization is headed by the Manager Virgil C. Summer Nuclear Station. A Startup Supervisor who reports to the Manager Virgil C. Summer Nuclear Station organizes and directs the startup program. The Startup Supervisor appoints a Test Supervisor for each test. More

than one Test Supervisor may be appointed. The Test Supervisor ensures that the test is conducted according to the test procedure. Qualified test personnel are assigned by the Startup Supervisor to perform the tests. The personnel perform the test work under the supervision of the Test Supervisor.

Prior to fuel loading, all Phase I (component and construction) tests and Phase II (preoperational and acceptance) tests are scheduled to be conducted and the results reviewed and approved in accordance with approved administrative procedures.

A limited number of test deficiencies may exist at the scheduled core loading date. These test deficiencies will be evaluated and categorized.

Appropriate hold points in the Phase III (initial startup) test program will be identified. The applicable deficiencies will be resolved prior to proceeding with the Phase III test program.

During the power ascension phase of testing, certain data are analyzed by the Test Supervisor and the results are reviewed by the Plant Manager or his designee before power is increased to the next higher plateau. Analysis of data includes checking radial flux for symmetry, verifying that axial flux is within predicted values, checking effluent radioactivity, monitoring system operation, and checking power level and nuclear instrumentation by using a heat balance. Before power is increased to a higher plateau, the high flux trip is reset to a value no greater than 20 percent beyond the next power level. Approval of the Plant Manager or his designated alternate must be obtained before increasing power to the next plateau. Approval of the completed procedure documentation is not required for continuation of the startup program or power increases.

When conducting the test, the Test Supervisor ensures that the full intent of the procedure is met. If the Test Supervisor determines the need for either a procedure or plant change, it is accomplished as outlined in Section 14.1.2. The Test Supervisor shall notify the Startup Supervisor when the test has been completed.

14.1.1.3 Review, Evaluation, and Approval of Test Results

After a Phase I test is completed and the data are compiled, the Test Supervisor will review the test results and compare them to the applicable acceptance criteria. If he is satisfied that the test results are satisfactory, he will submit the test to the Lead Systems Supervisor. The Lead Systems Supervisor will be responsible for reviewing the test results and comparing them to the applicable acceptance criteria. If he is satisfied that the test results are acceptable, he will approve the test data. If the test results are not satisfactory, the Lead Systems Supervisor will recommend to the Startup Supervisor what actions are necessary.

After a Phase II test is completed and the data are compiled, the Startup Supervisor will assign the Westinghouse Startup Representative, the Gilbert Associates Startup Representative, or their designated alternates, each having qualifications of a Lead Systems Supervisor as described in Section 14.1.1.4, to review the test results. The assigned personnel will review the test results and compare them to the applicable acceptance criteria specified in the procedure, and forward the test results to the Startup Supervisor. The Startup Supervisor or designated alternate will then review

the test results and, if acceptable, sign the test results recommending approval to the Manager Virgil C. Summer Nuclear Station. The test results are then sent to the Manager Virgil C. Summer Nuclear Station for his review and approval. If test results are not acceptable, the personnel assigned to review the data recommends to the Startup Supervisor what actions are necessary. These actions are outlined in more detail in Section 14.1.2.1.

After a Phase III test is completed and the data are compiled, the Lead Phase III Test Supervisor will place the review of the completed test procedure on the agenda of the Plant Safety Review Committee Meeting for consideration for approval of the test results. If the review of the test results during the Plant Safety Review Committee Meeting shows that the test results are acceptable, the Plant Safety Review Committee Chairman signs a procedure recommending approval, the procedure is transmitted to the Plant Manager or his designated alternate for his approval.

14.1.1.4 Personnel Responsibilities and Qualifications

Personnel who will manage, supervise, or execute any of the Phase II or III tests of the initial test program are incorporated into the Virgil C. Summer Nuclear Station startup group. This group consists of the Manager, Virgil C. Summer Nuclear Station, a Startup Supervisor, Lead Systems Supervisor, Test Supervisors, and test personnel. To the extent practical, these individuals come from the plant operating, technical, and maintenance personnel. This allows the utilization of the knowledge these persons have acquired from their training and practical experiences. Utilization of plant personnel during testing further enhances their knowledge of the plant and aids in their training.

SCE&G also utilizes qualified startup personnel from other organizations as members of the startup group. These people constitute a temporary addition to the plant staff which provides the extra people needed during startup to handle the increased work load. These additional people may be obtained from contractors for the specific purpose of starting up the Virgil C. Summer Nuclear Station.

In addition to the startup group, SCE&G may utilize vendor service personnel to provide expert advice and assistance in check out, startup, and testing of their equipment. Technical services are available from Westinghouse, Gilbert, and Daniel.

The Manager Virgil C. Summer Nuclear Station, in addition to his other duties outlined in Section 13.1.2.2, has overall responsibility for Phase II and Phase III of the initial test program. He is responsible for the development of the test procedures, the administration and conduct of the test, and the review and actions taken on the test results. The qualifications of the Plant Manager are outlined in Section 13.1.3.

The Startup Supervisor is under the supervision of the Manager Virgil C. Summer Nuclear Station and ensures effective administrative control and implementation of the test program. The Startup Supervisor meets one of the following qualifications.

1. A graduate of a four-year engineering or science college or university plus five years of experience in operation, testing, or inspection of power plant, nuclear plant, heavy industrial, or other similar equipment or facilities. At least two years of this experience should be associated with nuclear facilities; or if not, the individual shall have training sufficient to acquaint him thoroughly with the safety aspects of a nuclear facility.
2. A high school graduate or equivalent, plus 10 years of experience in operation, testing, or inspection of power plant, nuclear plant, heavy industrial, or other similar equipment or facilities. At least two years of this experience should be associated with nuclear facilities; or if not, the individual shall have training sufficient to acquaint him thoroughly with the safety aspects of a nuclear facility.

See Appendix 3A for details of compliance with Regulatory Guide 1.58.

The Startup Supervisor's duties and responsibilities include, but are not limited to the following:

1. Supervision and coordination of the activities of the startup group.
2. Responsibility for the master startup schedule.
3. Assignment for review responsibilities for individual test results of members of the startup group.
4. Review of test data and test procedure modification in accordance with established administrative procedures.
5. Recommendations to Nuclear Engineering on any request for construction or engineering changes or modifications determined to be necessary by results of a test.
6. Liaison with contractors and vendors and coordination of any activities relative to the test program.
7. The preparation and maintenance of the startup manual.
8. The review of Phase II procedures and test results.

A Lead Systems Supervisor has the responsibility of coordinating test personnel assigned to work for him. He supervises any training needed for the personnel assigned. A Lead Systems Supervisor may be assigned to be the Test Supervisor on an individual test or any number of tests. Lead Systems Supervisors shall meet the qualifications of the Startup Supervisor. Lead Systems Supervisors shall receive indoctrination on startup administrative procedures prior to beginning work.

The Lead Systems Supervisor responsibilities include, but are not limited to, the following:

1. Establish system work loads and responsibility for Test Supervisors with the Startup Organization.
2. Attend meetings with other groups (i.e., construction) as needed.
3. Coordinate turned over system work schedules.

4. Review system turnover packages for completeness of documentation.
5. Review turnover packages for closure and completeness to ensure that the system is ready for testing.
6. Coordinate activities of suppliers/contractors (when applicable) onsite.
7. Coordinate all flushing and cleaning efforts on his assigned systems.
8. Assure that all system deficiencies (design or test) are properly documented, reported, and corrected as expeditiously as possible through the Startup Supervisor.
9. Provide technical guidance for designed systems of testing and operation as required.
10. Assure that the necessary test equipment supplies are available.
11. He is responsible for coordination of the activities of the Startup Test Supervisors assigned to his group. He will assist the Startup Supervisor in scheduling tests and work completion.
12. The review of Phase II procedures and test results.
13. Assign Test Supervisors to the preparation of test procedures.

A Test Supervisor has the responsibility of coordinating the test personnel assigned to work for him. He supervises any training needed for the specific test assigned. A Test Supervisor may be assigned to be the Test Supervisor on an individual test or any number of tests. He is assigned a copy of the test procedure on which all data and acknowledgments are recorded.

Test Supervisors shall meet one of the following qualifications:

1. A graduate of a four-year engineering or science college or university, plus two years of experience in operations, testing, or inspection of power plant, nuclear plant, heavy industrial, or other similar equipment or facilities. (For Phase III, at least one of the two years of experience must be applicable nuclear power plant experience.)
2. A high school graduate or equivalent, plus four years of experience in operations, testing, or inspection of power plant, nuclear plant, heavy industrial, or other similar equipment or facilities. (For Phase III, five years of experience, at least two of which must be applicable nuclear power plant experience.) Test Supervisors shall receive indoctrination on startup administrative procedures prior to beginning work.

See Appendix 3A for details of compliance with Regulatory Guide 1.58.

A Test Supervisor’s duties and responsibilities include, but are not limited to, the following:

1. Coordinate with construction to have the necessary temporary piping installed to facilitate flushing activities and other temporary arrangements to facilitate startup.
2. Carry out system inspection and participate in walkdowns.
3. Assure that the necessary electrical, mechanical, and instrument checkouts have been completed and documented.

4. In the initial operation (if applicable), obtain and record the necessary data. Report, record, and correct deficiencies as required.
5. Present test reports and system data files to the Lead System Supervisor for inclusion in the startup files.
6. Document all deficiencies noted, corrections made, and verifications performed during testing activities.
7. Document all print changes, etc. to ensure final prints are correct and data file is complete.
8. Ensure that approved flushing procedures are implemented and allowed.
9. Calculate the approximate quantities of water required to minimize the use of water and coordinate the use of pumps and the availability of Electrical Power.
10. Walkdown the system with the cognizant personnel using the flushing P & IDs to check valve line up prior to flushing. Supervise the flushing operation.
11. Check for and document, by signing off the steps of the procedure, such as metering devices, orifice plates, valve internals, temporary strainers, blind flanges, piping, and the isolation of sensitive instruments that are removed from the system to facilitate flushing.
12. Verify that the mechanical items are being flushed in accordance with the limits and precautions specified by the procedure so that contaminants and/or flow velocities will not adversely affect subsequent operation or damage the equipment.
13. In conjunction with SCE&G Chemistry Department, verify that the proper chemicals at the designated concentration and temperature are being used in the system layup condition.

14.1.1.5 Test Records

After a test is completed and the results are approved, the master test copy and other permanent information relative to the test will be filed as part of the plant's permanent file in the permanent records room as appropriate. This gives plant personnel access to information on systems, components, etc., from plant startup to serve as a baseline for evaluating performance at any future time in the plant's life.

14.1.2 Administrative Procedures (Modifications)

When the need arises for changes in plant systems or components or in test procedures, administrative procedures are followed.

14.1.2.1 Test Initiated Changes for Systems and Components

A minor change in a system, component, or control is one which does not involve design intent of the system. If, during a test, there arises a need for a minor change in the field, the change, authorized by the Test Supervisor, is made by qualified personnel. Minor changes are indicated with the test data. These minor changes must be approved by the Lead Systems Supervisor before

the test results may be approved. The Test Supervisor initiates changes in documents which the minor change affects and notifies appropriate design organization for review.

A major change in a system, component, or control is one which could alter design intent of the system. When personnel designated to review test results, the Test Supervisor or the Startup Supervisor, indicate the necessity of major changes, the Startup Supervisor assigns qualified personnel to review the data at hand and make recommendations to SCE&G Production Engineering for resolution and approval. The Production Engineering personnel studying the necessity of a major change may seek the assistance of vendor, contractor, or others. Before resulting modifications are started, they must have the written approval of the Manager Virgil C. Summer Nuclear Station or his designee. Additional tests or retests shall be rescheduled by the Startup Supervisor. These retests shall be conducted using approved procedures. Modifications or maintenance initiated by test results and the reason they were initiated are noted by the Startup Supervisor.

The Manager Virgil C. Summer Nuclear Station is notified when test results are not acceptable. Vendors, contractors, and others as necessary are notified of any developments and followup activities concerning unacceptable test results.

14.1.2.2 Test Procedure Change and Modifications

Modifications to approved Phase II test procedures are designated either minor or major modifications. A minor modification does not involve changes in scope, intent, or acceptance limits. Minor modification may be effected with approval of the Test Supervisor. The modification must be noted on the test procedure.

Other Phase II procedure modifications are designated as major modifications. These modifications are incorporated into the test procedure by an individual designated by the Startup Supervisor. (If the startup group is not in effect, the Technical Support Engineering Supervisor assumes his duties.) The revised procedure goes through the review and approval steps of an original procedure.

Phase III procedures will be changed and modified in accordance with Technical Specifications.

14.1.3 Test Objectives and Procedures

14.1.3.1 Phase I (Construction, Component, and Subsystem Functional Tests)

NOTE: Phase I tests are generic in nature and are written to demonstrate individual components or subsystems meet their functional requirements. The test abstracts furnished below describe the general objectives, test method, and acceptance criteria for each type of component or subsystem being tested utilizing a Phase I test procedure to demonstrate that the component or subsystem meets its functional requirements.

1. Generic Flush Procedure (see Table 14.1-82).
2. Generic Hydrostatic/Pneumatic Test Procedure (see Table 14.1-83).
3. Instrument Control Procedure (see Table 14.1-84).
4. Generic Functional Test Procedure (see Table 14.1-85).

14.1.3.2 Phase II (Preoperational Tests)

1. Fire Protection System (see Table 14.1-1).
2. Containment Isolation Valves Leakage Rate Test (see Table 14.1-2).
3. Containment Penetrations Leakage Rate Test (see Table 14.1-3).
4. Containment Air Locks Leakage Rate Test (see Table 14.1-4).
5. Reactor Building Structural Acceptance Test (see Table 14.1-5).
6. Containment Integrated Leakage Rate Test (see Table 14.1-6).
7. Unit Auxiliary, Emergency Auxiliary, and Engineered Safety Features Transformers (see Table 14.1-7).
8. 7200 Volt Electrical System (see Table 14.1-8).
9. 480 Volt Buses (see Table 14.1-9).
10. 480 Volt Motor Control Centers (see Table 14.1-10).
11. 120 Volt AC (see Table 14.1-11).
12. DC System (see Table 14.1-12).
13. Plant Paging and Communication System (see Table 14.1-13).
14. Diesel Fuel Oil Transfer and Storage System (see Table 14.1-14).
15. Emergency Diesel Generators (see Table 14.1-15).
16. Response to Loss of Instrument Air (see Table 14.1-16).
17. Auxiliary Building Ventilation System (Radioactive Portion) (see Table 14.1-17).
18. Fuel Handling Building Ventilation System (Radioactive Portion) (see Table 14.1-18).
19. Process and Area Radiation Monitoring System (see Table 14.1-19).
20. Component Cooling Water System (see Table 14.1-20).
21. Service Water System (see Table 14.1-21).
22. Boric Acid Batching and Transfer System (see Table 14.1-22).
23. Heat Tracing for Boron Injection Tank and Associated Piping (see Table 14.1-23).
24. Reactor Building Ventilation Systems (see Table 14.1-24).

25. Chemical and Volume Control System (see Table 14.1-25).
26. Pressurizer Relief Tank (see Table 14.1-26).
27. Reactor Coolant System Heatup for Hot Functional Testing (see Table 14.1-27).
28. Systems Thermal Expansion (see Table 14.1-28).
29. Hot Functional Testing (see Table 14.1-29).
30. Emergency Feedwater System (see Table 14.1-30).
31. Engineered Safety Features Circuitry (see Table 14.1-31).
32. Nuclear Sampling System (see Table 14.1-32).
33. Reactor Coolant System Cooldown From Hot Functional Testing (see Table 14.1-33).
34. Residual Heat Removal System (see Table 14.1-34).
35. Nuclear Instrumentation System (see Table 14.1-35).
36. Control Building Ventilation System (see Table 14.1-36).
37. Deleted.
38. Reactor Components and Fuel Handling Tools and Fixtures (see Table 14.1-38).
39. Fuel Transfer System (see Table 14.1-39).
40. Safety Injection Pumps Operational Test (see Table 14.1-40).
41. Safety Injection Accumulator Blowdown (see Table 14.1-41).
42. Spent Fuel Cooling System (see Table 14.1-42).
43. Containment Isolation System (see Table 14.1-43).
44. Reactor Protection Operational Check (see Table 14.1-44).
45. Engineered Safety Features System Operational Check (see Table 14.1-45).
46. Integrated Engineered Safety Features Test (see Table 14.1-46).
47. Reactor Building Spray System (see Table 14.1-47).
48. Leak Detection Monitoring System (see Table 14.1-48).
49. Post Accident Hydrogen Removal System (see Table 14.1-49).
50. Radioactive Waste Disposal System (see Table 14.1-50).
51. Boron Thermal Regeneration System (see Table 14.1-51).
52. Reactor Protection System Time Response Measurement (see Table 14.1-52).
53. Emergency Lighting (see Table 14.1-79a).
54. Heat Tracing for Safety Related Outdoor Piping (see Table 14.1-79b).
55. Pressure Boundary Integrity Test (see Table 14.1-79c).

56. Seismic Instrumentation (see Table 14.1-79d).
57. Steam Generator Power Operated Relief Valve (see Table 14.1-86).
58. Condensate System (see Table 14.1-87).
59. Main Condenser Dump Valves (see Table 14.1-89).
60. Circulating Water System (see Table 14.1-90).
61. Chemical Feed System (see Table 14.1-91).
62. Nuclear Blowdown Processing System (see Table 14.1-92).
63. Control Rod Drive (see Table 14.1-93).
64. Miscellaneous Plant Drains (see Table 14.1-94).
65. Fuel Handling Building Pool Liner Leak Test (see Table 14.1-95).
66. Reactor Building Ventilation Post Accident Operation (see Table 14.1-96).
67. ESF Equipment Rooms Cooling Systems (see Table 14.1-97).
68. S. I. Accumulator Discharge Valve Functional Test (see Table 14.1-98).
69. ECCS Check Valve Leak Testing System Operational Test (see Table 14.1-99).
70. S. I. Accumulator Check Valve Hot Operational Test (see Table 14.1-100).
71. Instrument Air System (see Table 14.1-101).
72. Pressurizer Pressure and Level Control (see Table 14.1-102).
73. Process Computer (see Table 14.1-70).

14.1.3.3 Phase III (Fuel Loading and Pre-Critical Test)

These tests are listed in the order in which they are most likely to be performed:

1. Core Loading Instrumentation (see Table 14.1-37).
2. Initial Fuel Loading (see Table 14.1-53).
3. Incore Movable Detectors (see Table 14.1-54).
4. Rod Drop Time Measurement (see Table 14.1-55).
5. Rod Drive Mechanism Timing (see Table 14.1-56).
6. Rod Position Indication (see Table 14.1-57).
7. Reactor Coolant System Flow Measurement (see Table 14.1-58).
8. Reactor Coolant System Flow Coastdown (see Table 14.1-59).
9. Resistance Temperature Detector Bypass Loop Flow Verification (see Table 14.1-60).
10. Reactor Vessel O-Ring Leak Test (see Table 14.1-61).

11. Pressurizer Spray and Heater Capability and Setting Continuous Spray Flow (see Table 14.1-62).
12. Water Quality Test (see Table 14.1-63).

14.1.3.4 Phase III (Power Ascension Test)

These tests are listed in the order in which they are most likely to be performed.

1. Initial Criticality (see Table 14.1-64).
2. Low Power Test (see Table 14.1-65).
   a. Augmented Low Power Test (see Table 14.1-65a).
3. Incore Movable Detector and Thermocouple Mapping at Power (see Table 14.1-66).
4. Power Coefficient and Power Defect Measurement (see Table 14.1-67).
5. Effluent Radiation Monitor Test (see Table 14.1-68).
6. Radiation Shielding Survey (see Table 14.1-69).
7. Thermal Power Measurements and Instrument Calibration (see Table 14.1-71).
8. Automatic Control Systems Checkout (see Table 14.1-72).
9. Feedwater System (see Table 14.1-88).
10. Plant Response to Step Load Changes (see Table 14.1-73).
11. Pseudo Rod Ejection Test (see Table 14.1-74).
12. Rod Drop Test (see Table 14.1-75).
13. Below-Bank Rod Test (see Table 14.1-76).
14. Plant Loss of Electrical Load (see Table 14.1-77).
15. Loss of Offsite Power (see Table 14.1-78).
16. Shutdown from Outside the Control Room (see Table 14.1-79).

Table 14.1-80 indicates power levels at which the above tests are performed.

14.1.4 Core Loading and Initial Operation

Core loading begins when all prerequisite system tests and operations are satisfactorily completed and the NRC operating license received. Upon completion of core loading, the reactor upper internals and pressure vessel head are installed and additional mechanical and electrical tests are performed. The reactor is then ready for its initial criticality. After the initial criticality, low power tests, and power ascension test will commence. The purpose of these tests is to establish the operational characteristics of the unit and core, to acquire data for the proper calibration of setpoints, and to ensure that operation conforms to the license requirements.

14.1.4.1 Core Loading

Before starting core loading, the precore loading tests must be complete, the plant shall have a NRC operating license, and there must be an appropriately licensed operating staff. The Plant Manager is responsible for the conduct of core loading and all core loading personnel. Technical assistance will be provided by Westinghouse during the initial core loading operation. During this time, containment integrity and security must be maintained through the use of established procedures. The overall process of initial core loading is, in general, directed from the operating floor of the Reactor Building.

The as-loaded core configuration is specified as part of the core design studies conducted well in advance of plant startup and as such is not subject to change at startup. In the event that mechanical damage is sustained during core loading operations by a fuel assembly of a type for which no spare is available onsite, an alternate core scheme whose characteristics closely approximate those of the initially prescribed pattern will be determined.

The core is assembled in the reactor vessel, submerged in water containing enough dissolved boric acid to maintain a calculated core effective multiplication constant of 0.95 or lower. The refueling cavity is dry during initial core loading. Core moderator chemistry conditions (particularly boron concentration) are prescribed in the core loading procedure document and are verified periodically by chemical analysis of moderator samples taken prior to and during core loading operation.

Core loading instrumentation consists of two permanently installed source range (pulse type) nuclear channels and two temporary incore source range channels plus a third temporary channel which can be used as a spare. The permanent channels, when responding, are monitored in the Control Room by licensed plant operators; the temporary channels are installed in the containment structure and are monitored by fuel loading personnel. At least one permanent channel is equipped with an audible count rate indicator heard in the Reactor Building and the Control Room. Both plant channels have the capability of displaying the neutron flux level on strip chart recorders. The temporary channels indicate on rate meters with a minimum of one channel recorded on a strip chart recorder. Minimum count rates of 1/2 counts per second, attributable to core neutrons, are required on at least two (i.e., temporary and/or permanent source range detectors) available nuclear source channels at all times following installation of the initial nucleus of eight fuel assemblies. A response check of nuclear instruments to a neutron source shall be performed within 12 hours prior to loading of the core, or resumption of loading if delay is for more than 12 hours.

At least two neutron sources are introduced into the core loading program to ensure a neutron population of a minimum of 1/2 counts/sec for adequate monitoring of the core.

Fuel assemblies together with inserted components (control rod assemblies, burnable poison inserts, source spider, or thimble plugging devices) are placed in the reactor vessel one at a time according to a previously established and approved sequence which was developed to provide reliable core monitoring with minimum possibility of core mechanical damage. The core loading procedure documents include a detailed tabular check sheet which prescribes and verifies the

successive movements of each fuel assembly and its specified inserts from its initial position in the fuel racks to its final position in the core. Multiple checks are made of component serial numbers and types at successive transfer points to guard against possible inadvertent exchanges or substitution of components and fuel assembly status boards are maintained throughout the core loading operations.

An initial nucleus of eight fuel assemblies, the first of which contains a neutron source, is the minimum source-fuel nucleus which permits subsequent meaningful inverse count rate monitoring. This initial nucleus is determined by calculation and previous experience to be markedly subcritical ($K_{eff} \leq 0.95$) under the required conditions of loading.

Subsequent fuel additions are accompanied by detailed neutron count rate monitoring to determine that the count rate does not increase excessively and that the extrapolated inverse count rate ratio is not decreasing for unexplained reasons. The results of each loading step are evaluated by SCE&G and technical advisors before the next prescribed step is started.

Criteria for safe loading require that loading operations stop immediately if:

1. An unanticipated increase in the neutron count rates by a factor of two occurs on all responding nuclear channels during any single loading step after the initial nucleus of eight fuel assemblies is loaded (excluding anticipated change due to detector and/or source movement).
2. The neutron count rate on any individual nuclear channel increases by a factor of five during any single loading step after the initial nucleus of eight fuel assemblies is loaded (excluding anticipated changes due to detector and/or source movements).
3. A decrease in boron concentration greater than 20 ppm is determined from two successive samples of Reactor Coolant System water until the decrease is explained.

An alarm in the Reactor Building and Control Room is coupled to the source range channels with a setpoint at five times the current count rate. This alarm automatically alerts the fuel loading personnel to an indication of high count rate and requires an immediate stop of all operations until the situation is evaluated by SCE&G and technical advisors.

Core loading procedures specify alignment of fluid systems to prevent inadvertent dilution of the reactor coolant, restrict the movement of fuel to preclude the possibility of mechanical damage, prescribe the conditions under which loading can proceed, identify chains of responsibility and authority, and provide for continuous and complete fuel and core component accountability.

14.1.4.2 Postloading Tests

Upon completion of core loading, the reactor upper internals and pressure vessel head are installed and additional mechanical and electrical tests are performed prior to initial criticality. The final pressure tests are conducted after filling and venting is completed.

Mechanical and electrical tests are performed on the control rod drive mechanisms. These tests include a complete operational checkout of the mechanisms. Checks are made to ensure that the control rod assembly position indicator coil stacks are connected to rod drive mechanism coils.

Tests are performed on the reactor trip circuits to test manual trip operation and actual control rod assembly drop times are measured for each control rod assembly. By use of dummy signals, the Reactor Control and Protection System is made to produce trip signals for the various plant abnormalities that require tripping.

At all times that the control rod drive mechanisms are being tested, the boron concentration in the coolant-moderator is large enough such that the shutdown margin requirements specified in the Technical Specifications are met. During individual RCCA or RCC bank motion, source range instrumentation is monitored for unexpected changes in core reactivity.

A complete functional electrical and mechanical check is made of the incore nuclear flux mapping system at operating temperature and pressure.

14.1.4.3 Initial Criticality

Initial criticality is established by sequentially withdrawing the shutdown and control groups of control rod assemblies from the core, leaving the last withdrawn control group inserted far enough in the core to provide effective control when criticality is achieved, and then continuously diluting the heavily borated reactor coolant until the chain reaction is self-sustaining. Successive stages of control rod assembly group withdrawal and of boron concentration reduction are monitored by observing changes in neutron count rate as indicated by the regular source range nuclear instrumentation as functions of group position during rod motion and, subsequently, of reactor coolant boron concentration and primary water addition to the Reactor Coolant System during dilution. Throughout this period, samples of the primary coolant are obtained and analyzed for boron concentration.

Primary safety reliance is based on inverse count rate ratio monitoring as an indication of the nearness and rate of approach to criticality of the core during control rod assembly group withdrawal and during reactor coolant boron dilution. The rate of approach is reduced as the reactor approaches extrapolated criticality to ensure that effective control is maintained at all times.

Written procedures specify alignment of fluid systems to allow controlled starting, stopping, and adjustment of the rate of the approach to criticality. These procedures also identify chains of responsibility and authority during initial criticality.

14.1.4.4 Low Power Testing

A prescribed program of reactor physics measurements is undertaken to verify that the basic static and kinetic characteristics of the core are as expected and that the values of the kinetic coefficients assumed in the safeguards analysis are indeed conservative.

The measurements are made at low power and primarily at or near operating temperature and pressure. Measurements, to include verification of calculated values of control rod assembly group reactivity worths, of moderator temperature coefficient under various core conditions, of differential boron concentration reactivity worth, and of critical boron concentrations as functions of control rod assembly group configuration, are made. In addition, measurements of the relative power distributions are made. Concurrent tests are conducted on the instrumentation including the source and intermediate range nuclear channels.

In accordance with NUREG 0737, item I.G.1, a discussion of the special low power testing to be performed at the Virgil C. Summer Station has been submitted to the NRC under separate cover letters dated 10/31/80, 12/2/80, and 12/22/80.

Detailed procedures are prepared to specify the sequence of tests and measurements to be conducted and the conditions under which each is to be performed to ensure both safety of operation and the relevancy and consistency of the results obtained. If significant deviations from design predictions exist, unacceptable behavior is revealed, or apparent anomalies develop, a review by qualified personnel will be performed. The Plant Manager may determine that a review by the Plant Safety Review Committee is appropriate prior to increasing power to the next testing plateau.

14.1.4.5 Power Ascension

When the operating characteristics of the reactor and plant are verified by low power testing, a program of power level escalation in successive stages brings the plant to its full rated power level. Prior to starting to the next higher power plateau, as defined by the startup test program, management approval shall be obtained; also, the high flux trip shall be reset to a value no greater than 20 percent beyond the next power level. During the power escalation, a predetermined test program is followed to verify that the reactor and plant are performing as expected. The minimum test requirements for each successive stage of power escalation are specified.

Measurements are made to determine the relative power distribution in the core as functions of power level and control assembly group position.

Secondary system heat balances ensure that the several indications of power level are consistent and provide bases for calibration of the power range nuclear channels. The ability of the Reactor Control System to respond effectively to signals from primary and secondary instrumentation under a variety of conditions encountered in normal operations is verified.

At prescribed power levels, the dynamic response characteristics of the Reactor Coolant and Steam Systems are evaluated. These responses are evaluated for step load changes of 10 percent and a plant loss of electrical load from 100 percent power.

Adequacy of radiation shielding is verified by gamma and neutron radiation surveys inside the containment and throughout the station site. Periodic sampling is performed to verify coolant chemistry and activity.

The sequence of tests, measurements, and intervening operations is described in the power escalation procedure with specific details relating to the conduct of the several tests and measurements.

14.1.5 Administrative Procedures (System Operation)

Whenever the test allows, the plant operating procedures for Virgil C. Summer Nuclear Station will be incorporated into the test procedures. This will help in evaluating plant operating procedures. If during a test it is found that the operating procedure is not adequate, the test procedure will be changed in the manner described in Section 14.1.2.2; and the operating procedure shall be changed in accordance with Chapter 13. Any operating procedure, or part of one, which is referenced in a test procedure must be approved.

Table 14.1-1
Fire Protection System

1.0 Objective

Demonstrate that the Fire Protection System is capable of providing adequate fire protection under all conditions, including loss of power to the motor driven pump.

2.0 Prerequisites

Fire Protection System installation and component checks completed.

3.0 Test Methods

3.1 Align the subsystems for operation and establish normal flow paths for water systems.

3.2 Check operation of water systems and CO_2 system.

3.3 Verify pump heads and flow rates under both normal and emergency power conditions of the water systems.

3.4 Verify operation and response of detector systems.

4.0 Acceptance Criteria

4.1 Alarms, interlocks, and detection devices function as per design requirements.

4.2 System is capable of providing protection in accordance with applicable fire protection codes.

4.3 Where appropriate, flows, pressures, and spray patterns are as per design requirements.

Table 14.1-2
Containment Isolation Valves Leakage Rate Test

1.0 Objective

Demonstrate that the leakage from containment isolation valves and gasketed blind flanges required to be tested by 10 CFR 50, Appendix J is within allowable limits.

2.0 Prerequisites

2.1 Portions of the systems containing isolation valves and/or gasketed blind flanges have been successfully pressure tested.

2.2 Motor operated and air operated containment isolation valves have been functionally tested.

2.3 Portions of the systems containing isolation valves and/or gasketed blind flanges have been properly drained and vented.

2.4 Containment isolation valves have been closed using their normal mode of operation.

3.0 Test Methods

3.1 A pressure of not less than P_a is applied against the isolation valve or gasketed blind flange.

3.2 Measurement of valve leakage is made using a rotameter array or other equivalent instrumentation.

4.0 Acceptance Criteria

4.1 Containment isolation valve and gasketed blind flange leakage rates are within allowable design limits.

Table 14.1-3
Containment Penetrations Leakage Rate Test

1.0 Objective

Demonstrate that the leakage from containment penetrations required to be tested by 10 CFR 50, Appendix J is within allowable limits.

2.0 Prerequisites

2.1 Penetrations have been properly installed.

3.0 Test Methods

3.1 A pressure of not less than P_a is applied to the penetration.

3.2 Measurement of penetration leakage is made using a rotameter array or other equivalent instrumentation.

4.0 Acceptance Criteria

4.1 Containment penetration leakage rates are within allowable design limits.

Table 14.1-4
Containment Air Locks Leakage Rate Test

1.0 Objective

Demonstrate that leakage from the containment personnel air locks and equipment hatch is within allowable limits.

2.0 Prerequisites

2.1 Containment personnel air locks and equipment hatch have been properly installed.

3.0 Test Methods

3.1 A pressure of not less than P_a is applied to the seals of the containment personnel air lock and equipment hatch.

3.2 Measurement of seal leakage is made using a rotameter array or other equivalent instrumentation.

4.0 Acceptance Criteria

4.1 Containment personnel air lock and equipment hatch leakage is within allowable design limits.

Table 14.1-5
Reactor Building Structural Acceptance Test

1.0 Objective

Verify the structural integrity of the Reactor Building.

2.0 Prerequisites

2.1 Reactor Building penetrations installed and penetration leak tests (Type B test) completed.

2.2 Isolation valve leak test (Type C test) completed.

2.3 Reactor Building Ventilation Systems operable to extent required to control Reactor Building internal temperature.

3.0 Test Methods

3.1 Prior to initial fuel loading, the Reactor Building will be subjected to a pressure equivalent to 115 percent of the Reactor Building designed pressure. This test demonstrates that the Reactor Building is capable of resisting the postulated accident pressure. In addition, by measuring the structural response and comparing the results with analytical predictions, the test verifies that the structure does behave as anticipated.

3.2 Instrumentation, measuring systems, pressurization procedure, deformation, strain and temperature measurements, crack pattern mapping, and data acquisition schedules for the preoperational structural acceptance test will be in accordance with the approved test procedure.

4.0 Acceptance Criteria

The Reactor Building meets structural integrity design requirements.

Table 14.1-6
Containment Integrated Leakage Rate Test

1.0 Objective

Demonstrate that the containment leakage rate following a postulated loss of coolant accident (LOCA) is within allowable limits.

2.0 Prerequisites

2.1 Reactor Building structural acceptance test completed.

2.2 Affected systems lined up in their post accident mode.

3.0 Test Methods

3.1 The containment is pressurized at a rate of 5 psi per hour or less to P_a as defined in the approved test procedure.

3.2 Containment temperature is held essentially constant for 24 hours while the internal temperature, pressure, and dewpoint are closely monitored.

3.3 Using the perfect gas law, the change in the containment air mass is computed.

3.4 The leakage rate in percent/day is computed from the changes in containment air mass.

3.5 A known leak is superimposed on the containment to verify instrumentation accuracy.

4.0 Acceptance Criteria

4.1 Integrated leakage rate is within allowable design limits.

4.2 Instrumentation accuracy is verified to be within allowable design limits.

Table 14.1-7

Unit Auxiliary, Emergency Auxiliary, and Engineered Safety Features Transformers

1.0 Objective

1.1 Demonstrate the capability of the unit auxiliary, emergency auxiliary, and engineered safety features transformers to supply electrical power to the 7200 volt buses.

1.2 Verify operation of protection devices and functional operation of controls and interlocks.

2.0 Prerequisites

2.1 230 kV substation operational and energized.

2.2 Meters, relays, and protective devices calibrated and tested.

2.3 125 volt DC available.

2.4 Erection work on transformers and switchgear completed.

2.5 Transformer oil and fan systems tested and in service.

2.6 Isolated phase bus tested and ready for service.

2.7 Breaker controls and transfer scheme verified.

2.8 PT and CT circuits checked for polarity and continuity.

2.9 7200 volt breakers racked out.

2.10 115 kV supply line energized.

3.0 Test Methods

3.1 Simulate signals to temperature controls and verify operation of transformer oil pumps and fans.

3.2 Simulate signals to verify annunciators for transformer protective devices.

3.3 Energize transformers and verify phase rotation.

4.0 Acceptance Criteria

Transformers provide reliable source of electrical power to 7200 volt buses in accordance with design requirements and Section 8.3.

Table 14.1-8
7200 Volt Electrical System

1.0 Objective

1.1 Verify that 7200 volt buses can be energized from their respective normal and alternate sources.

1.2 Verify that electrical and mechanical interlocks function properly.

2.0 Prerequisites

2.1 Breakers in the 7200 volt buses are racked out and tagged.

2.2 Meters, relays, and protective devices calibrated and tested.

2.3 125 volt DC available.

2.4 Phase rotation checked on 7200 volt buses.

2.5 Unit auxiliary, emergency auxiliary, and ESF transformers energized.

3.0 Test Methods

3.1 Rack in and close 7200 volt breakers to energize associated 7200 volt buses.

3.2 Record voltage and verify phase relationship.

3.3 Shift buses to alternate power sources as applicable and verify phase relationship.

3.4 Verify 7200 Volt BOP buses will transfer from normal source to alternate source if a fault occurs on normal supply.

3.5 Verify 7200 Volt ESF buses will transfer from normal source to emergency diesel generator if voltage is lost on normal supply.

4.0 Acceptance Criteria

4.1 The 7200 volt buses are capable of being energized from their normal and alternate sources and that proper phase relationship is exhibited.

4.2 System interlocks and alarms function properly.

4.3 BOP buses transfer from normal source to alternate source if a fault occurs on normal supply.

Table 14.1-8 (continued)
7200 Volt Electrical System

4.4 ESF uses will transfer from normal source to emergency diesel generator if voltage is lost on normal supply,

Table 14.1-9
480 Volt Buses

1.0 Objective

1.1 Verify that 480 volt buses can be energized from their normal and alternate sources.

1.2 Verify that electrical and mechanical interlocks function properly.

2.0 Prerequisites

2.1 Breakers in the 480 volt buses are racked out and tagged.

2.2 Meters, relays, and protective devices calibrated and tested.

2.3 125 volt DC and 7.2 kV buses energized.

2.4 Phase rotation checked on 480 volt buses.

3.0 Test Methods

3.1 Close 7.2 kV breakers to energize load center transformers and buses.

3.2 Measure voltage and verify phase relationship.

3.3 Shift buses to alternate power sources as applicable and verify phase relationship.

3.4 Simulate loss of power.

4.0 Acceptance Criteria

4.1 480 volt buses are capable of being energized from their normal and alternate sources, and proper phase relationship is exhibited.

4.2 The 480 volt buses respond correctly to a loss of power.

4.3 Interlocks and alarms function properly.

Table 14.1-10
480 Volt Motor Control Centers

1.0 Objective

1.1 Verify that 480 volt motor control centers can be energized from their normal sources.

1.2 Verify that electrical and mechanical interlocks function properly.

2.0 Prerequisites

2.1 All breakers in 480 volt motor control centers are racked out and tagged.

2.2 Meters, relays, and protective devices calibrated and tested.

2.3 125 volt DC available.

2.4 480 volt buses energized.

2.5 Phase rotation checked on motor control centers.

3.0 Test Methods

3.1 Rack in and close motor control center supply breakers.

3.2 Measure voltage and verify phase relationship.

3.3 Simulate loss of power.

4.0 Acceptance Criteria

4.1 Motor control centers are capable of being energized from their normal sources, and proper phase relationship is exhibited.

4.2 The 480 volt motor control centers respond correctly to a loss of power.

4.3 System interlocks and alarms function properly.

Table 14.1-11
120 Volt AC

1.0 Objective

Demonstrate the capabilities of the 120 volt vital instrument power system and the 120 volt AC regulated instrument power system to supply power to instrumentation and control loads under normal and emergency conditions at full load.

2.0 Prerequisites

2.1 120 volt instrument power systems installation and component checks completed.

2.2 480 volt motor control centers available.

2.3 125 volt DC system operable

3.0 Test Methods

3.1 Energize 120 volt instrument power buses from their normal power sources and load to full load using a load bank.

3.2 Demonstrate ability to transfer each vital instrument bus manually to a backup instrument bus and back to its static inverter.

3.3 Trip the normal power supplies to the static inverters. Verify automatic transfer to alternate DC source. Verify transfer back to normal supply when re-energized.

3.4 Demonstrate ability to transfer each instrument panel manually to its alternate source.

4.0 Acceptance Criteria

4.1 Vital buses or panels can be manually transferred to alternate sources.

4.2 Vital inverters will transfer to the alternate 125V DC input source upon loss of normal 480V AC input source. Normal 120V AC is maintained during the transfer.

4.3 System interlocks and alarms function properly.

4.4 Vital AC inverters will supply their design load at 60 amps.

Table 14.1-12
DC System

1.0 Objective

Demonstrate the capability of the DC system to provide a source of reliable, uninterruptible DC power for normal and emergency instrumentation, control, and power loads.

2.0 Prerequisites

2.1 480 volt AC power available.

2.2 Battery Room Ventilation System operable.

2.3 Batteries, battery chargers, and DC distribution system, including protective devices, installation, and component checks completed.

2.4 DC breakers are open.

3.0 Test Methods

3.1 Energize the battery chargers and verify this normal feed to bus.

3.2 Verify alarms and interlocks.

3.3 Discharge the batteries at a controlled rate and determine ampere-hour capacity.

3.4 Adjust chargers to supply DC load and charge batteries simultaneously.

3.5 De-energize battery chargers while the applicable buses are carrying their normal station load to verify that battery will maintain load.

3.6 Verify that 125 volt bus can be fed from the backup charger upon loss of normal charger (manual transfer).

3.7 Verify ground detection by connecting variable load resistor to ground.

4.0 Acceptance Criteria

4.1 System interlocks and alarms function properly.

4.2 Batteries are capable of supplying plant DC power upon de-energization of their chargers.

Table 14.1-12 (continued)
DC System

4.3 Battery chargers are capable of maintaining normal bus loads concurrent with charging the batteries.

4.4 Bus can be supplied by backup charger.

Table 14.1-13
Plant Paging and Communication System

1.0 Objective

1.1 Demonstrate the adequacy of the plant paging systems intracommunication between all local stations in each separate system, and interconnection of the plant PABX system to the commercial telephone service and SCE&G microwave system.

1.2 Demonstrate that the radiation emergency (site evacuation) alarm can be heard from any location in the plant under all required conditions.

1.3 Demonstrate operability of Reactor Building evacuation alarm and fire alarm.

2.0 Prerequisites

2.1 Communications systems installation and component checks completed.

2.2 Sound levels established for locations where noise levels might interfere with communication.

3.0 Test Methods

3.1 Test the portable stations, page/party line phone station, and redundant communication phone stations for proper operation.

3.2 Test interconnection of the plant PABX system to the commercial telephone service, and SCE&G microwave system.

3.3 Verify alarms.

3.4 Shift PABX equipment to alternate power sources and verify operation.

4.0 Acceptance Criteria

4.1 Communication systems provide for paging, normal plant communications, shutdown communications, interconnection to SCE&G microwave system and commercial telephone service and alarm signaling in accordance with design requirements and Section 9.5.2.

4.2 Evacuation alarm can be heard from any location in the plant.

4.3 Paging systems and alarms will not produce sound pressure levels above 130 dB level where personnel will conduct normal plant communications.

Table 14.1-14
Diesel Fuel Oil Transfer and Storage System

1.0 Objective

Demonstrate that the Diesel Fuel Oil Transfer and Storage System supplies fuel oil to the diesel fuel oil day tanks and verify modes of operation.

2.0 Prerequisites

2.1 Fire protection is available.

2.2 Diesel Fuel Oil System installation and component checks completed.

3.0 Test Methods

3.1 Align system for operation and establish normal transfer flow paths.

3.2 Verify capability to transfer fuel oil to each day tank.

3.3 Verify alarms and automatic pump operations.

4.0 Acceptance Criteria

Fuel transfer capability of the system meets the design requirements.

Table 14.1-15
Emergency Diesel Generators

1.0 Objective

1.1 Demonstrate manual start and synchronization of the diesel generators.

1.2 Demonstrate load-carrying capacity of diesel generators.

1.3 Demonstrate fuel consumption of diesels.

1.4 Demonstrate proper operation of diesel auxiliaries during the load carrying capacity test.

2.0 Prerequisites

2.1 Station batteries charged and DC control power available.

2.2 Relays calibrated and all normal bus protective devices checked and in service.

2.3 Diesel engine auxiliary systems installation and component checks completed as specified.

2.4 Diesel room ventilation and fire protection available.

2.5 Diesel Fuel Oil System operable.

3.0 Test Methods

3.1 Demonstrate manual start and synchronization of each diesel generator, including synchronizing the diesel generator unit to offsite power while the unit is connected to the emergency load, isolating the diesel generator unit, and restoring it to standby status.

3.2 Verify timing of diesel generators starting sequence and available for load.

3.3 Verify capability to control diesel generators in local and remote operation.

3.4 The diesel generators will be operated at continuous rated load for 22 hours. The load will then be increased to the two hour rating and held at this condition for a period of two hours. During this 24 hour period, the indicated readings from supervisory instrumentation will be recorded to establish base line operating conditions.

3.5 Conduct load-carrying duration test.

Table 14.1-15 (continued)
Emergency Diesel Generators

3.6 Verify load rejection and overspeed trip.

3.7 Demonstrate diesel generator reliability by performing 69/N starts (where N is the number of diesel generator units).

4.0 Acceptance Criteria

4.1 Diesel generators function in maintaining the 7200 volt ESF buses as designed.

4.2 Diesel generators do not overspeed when load is removed.

4.3 Each redundant onsite power source and its load group can function without any dependence upon any other redundant load group or portion thereof.

4.4 Diesel auxiliaries perform their design requirements.

4.5 Diesel generators demonstrate required reliability.

Table 14.1-16
Response to Loss of Instrument Air

1.0 Objective

Demonstrate that pneumatically operated “Active” valves fail to their safe position on a loss of instrument air.

2.0 Prerequisites

2.1 Instrument Air System installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow conduct of this test.

2.3 System has been blown down and cleanliness requirements met.

3.0 Test Methods

Note: Specific valves and systems may be tested individually.

3.1 Align system for normal operation.

3.2 Reduced instrument air pressure to zero psig.

3.3 Observe the response of pneumatically operated “Active” valves during loss of air pressure and record the position to which each valve fails.

3.4 Air operated valves equipped with safety related volume tanks will be isolated from the instrument air header and stroked to verify their operability.

4.0 Acceptance Criteria

4.1 Pneumatically operated “Active” valves fail to their “safe” position on loss of instrument air.

4.2 Components with “safety related” air volume tanks operate in accordance with design.

Table 14.1-17
Auxiliary Building Ventilation System (Radioactive Portion)

1.0 Objective

1.1 Demonstrate the capabilities of the Auxiliary Building Ventilation System to provide for control and disposal of airborne radioactivity.

1.2 Confirm the proper operation of system interlocks and controls.

2.0 Prerequisites

2.1 Auxiliary Building Ventilation System installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Align system for normal operation.

3.2 Verify building internal negative pressure differential with respect to atmosphere.

3.3 Test positioning on pneumatically operated dampers.

3.4 Simulate isolation actuation signal and observe system response.

3.5 Verify fan and damper, interlocks and permissives.

4.0 Acceptance Criteria

4.1 System provides for control and disposal of airborne radioactivity in accordance with design requirements and Section 9.4.

4.2 Fans and dampers function as per design.

4.3 Auxiliary Building internal pressure is less than atmospheric.

Table 14.1-18
Fuel Handling Building Ventilation System (Radioactive Portion)

1.0 Objective

Demonstrate the capabilities of the Fuel Handling Building Ventilation System to provide for control and disposal of airborne radioactivity.

2.0 Prerequisites

2.1 Fuel Handling Building Ventilation System installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Align system for normal operation.

3.2 Verify fan and damper, interlocks, and permissives.

3.3 Test positioning on pneumatically operated dampers.

3.4 Simulate isolation actuation signal and observe system response.

3.5 Verify building internal negative pressure differential with respect to atmosphere.

4.0 Acceptance Criteria

4.1 System provides for control and disposal of airborne radioactivity in accordance with design requirements and Section 9.4.

4.2 Fans and dampers function as per design.

4.3 Building internal pressure with respect to atmospheric pressure is per design.

Table 14.1-19
Process and Area Radiation Monitoring System

1.0 Objective

Demonstrate the capability of the Process and Area Radiation Monitoring Systems to monitor effectively the levels of radiation in the plant or its effluents and to initiate isolation and alarms as required.

2.0 Prerequisites

2.1 Process and Area Radiation Monitoring Systems installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow the conduct of this test.

3.0 Test Methods

3.1 Align system for normal operation. Position valves in associated systems as necessary to allow response to isolation signals.

3.2 Verify proper functioning of system detectors by utilizing test sources and other procedures as appropriate.

3.3 Verify proper system response to simulated alarm conditions by monitoring controller outputs, alarm indications, and the operation of isolation valves where possible.

4.0 Acceptance Criteria

System effectively monitors and responds to levels of radiation in the plant areas and effluents in accordance with design requirements and Sections 11.4, 12.1.4, and 12.2.4.

Table 14.1-20
Component Cooling Water System

1.0 Objective

Demonstrate the capability of the Component Cooling System to supply design flow to system components.

2.0 Prerequisites

2.1 Component Cooling (CC) System installation and component checks completed.

2.2 Adequate supply of demineralized water available.

2.3 Associated systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Verify the ability of the CC pumps to deliver design low and high speed flows to system components.

3.2 Verify the ability of the CC system to perform its design functions for SI and recirculation modes of operation.

3.3 Verify CC system controls operate as designed.

4.0 Acceptance Criteria

4.1 System flows, pressures, and automatic functions are in accordance with design requirements identified on the applicable flow diagrams.

4.2 System interlocks, instrumentation, and alarms function properly.

Table 14.1-21
Service Water System

1.0 Objective

Demonstrate the capability of the Service Water System to provide adequate cooling water.

2.0 Prerequisites

2.1 Service Water System installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Align system for normal operation.

3.2 Verify system flow rates and system control.

4.0 Acceptance Criteria

4.1 System flows, pressures, and automatic functions are in accordance with design requirements of Section 9.2.1.

Table 14.1-22
Boric Acid Batching and Transfer System

1.0 Objective

Verify proper functioning of equipment and instrumentation utilized in batching, storage, transfer, and recirculation of boric acid solutions.

2.0 Prerequisites

2.1 Boric Acid System installation and component checks completed.

2.2 Adequate supply of Grade A water available.

2.3 Steam supply available to batching tank jacket heater.

2.4 Associated systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Align system for normal operation.

3.2 Verify boric acid tank and batching tank level setpoints, controller functions, and steam delivery to batching tank heaters.

3.3 Verify capability of boric acid transfer pumps to deliver water from the batching tank to the boric acid tanks and to recirculate each boric acid tank.

3.4 Verify capability of supplying the charging pump suction header.

4.0 Acceptance Criteria

4.1 System provides for batching, storage, transfer, and recirculation flow paths in accordance with Section 9.3.4.

4.2 Interlocks, automatic functions, alarms, flows, and pressures are within design limits.

Table 14.1-23
Heat Tracing for Boron Injection Tank and Associated Piping

1.0 Objective

Demonstrate the ability of the Heat Tracing System to maintain proper temperature control in the various piping systems involved with the boron injection tank.

2.0 Prerequisites

2.1 Heat Tracing System installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow the conduct of this test.

3.0 Test Methods

3.1 Energize Heat Tracing System.

3.2 Monitor temperatures maintained by each heat tracing circuit with the system in a static condition.

3.3 Place boron injection recirculation pump in operation and establish transfer flow path.

3.4 Monitor temperatures maintained by each heat tracing circuit.

4.0 Acceptance Criteria

Each heat tracing circuit maintains temperature within allowable design limits.

Table 14.1-24
Reactor Building Cooling System

1.0 Objective

1.1 Demonstrate the operation of the Reactor Building cooling equipment for normal plant operating conditions.

1.2 Demonstrate the capacity of the Reactor Building cooling units to maintain area temperatures within design limits during normal operating conditions.

2.0 Prerequisites

2.1 Reactor Building Cooling System installation and component checks completed.

2.2 Service Water and Industrial Cooling Water Systems operable.

2.3 Associated systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Align system for normal operation.

3.2 Verify fan, damper, and cooling unit controls, interlocks, and permissives.

3.3 With the plant at, or near, normal operating conditions, survey various areas to verify that temperatures do not exceed design limits.

4.0 Acceptance Criteria

4.1 System interlocks and controls function properly.

4.2 Temperature survey does not show any hot spots or exceed design limits.

Table 14.1-25
Chemical and Volume Control System

1.0 Objective

Demonstrate that the Chemical and Volume Control System (CVCS) performs as required during plant operation.

2.0 Prerequisites

2.1 CVCS installation and component checks completed.

2.2 Reactor Coolant System at the condition specified in the approved test procedure.

2.3 Adequate supply of Grade A water available in refueling water storage tank or reactor makeup tank.

2.4 Associated systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Align CVCS for normal operation and establish normal flow paths.

3.2 Verify capacities of letdown orifices and pressure drop of reactor coolant filter.

3.3 Check operation of the letdown line temperature and pressure controllers with the demineralizers bypassed.

3.4 Verify operation of excess letdown and seal water subsystems.

3.5 Verify flow rates and pressure drops of demineralizers.

3.6 Verify charging pumps' flow rates and the seal water flow rate for each reactor coolant pump.

3.7 Verify volume control tank level controller operation. Check reactor makeup control system response to inventory changes of volume control tank.

4.0 Acceptance Criteria

System performance, interlocks, and automatic functions are in accordance with Section 9.3.4.

Table 14.1-26
Pressurizer Relief Tank

1.0 Objective

Verify that the pressurizer relief tank provides for adequate control of the discharge from the primary reliefs and safety valves.

2.0 Prerequisites

2.1 Hydrostatic test of pressurizer relief tank completed.

2.2 Pressurizer relief tank installation checks completed.

2.3 Radioactive waste disposal system completed to the extent necessary to allow conduct of this test.

2.4 Adequate supply of Grade A water available.

2.5 Adequate supply of nitrogen available.

3.0 Test Methods

3.1 Verify alarms, interlock operations, and spray flow control.

3.2 Demonstrate ability to maintain nitrogen blanket in pressurizer relief tank.

3.3 Verify transfer flow paths from pressurizer relief tank.

4.0 Acceptance Criteria

Pressurizer relief tank provides disposal of primary plant coolant discharge in accordance with design requirements and Section 5.5.11.

Table 14.1-27
Reactor Coolant System Heatup for Hot Functional Testing

1.0 Objective

Perform functional checks on the Reactor Coolant System and associated systems components and instrumentation required to bring the plant from a cold shutdown condition to normal operating temperature and pressure.

2.0 Prerequisites

2.1 Reactor Coolant System and supporting systems valve lineups for normal operation completed and normal flow paths established.

2.2 Reactor Coolant System cold hydrostatic test completed.

2.3 Preoperational and acceptance tests completed as necessary.

2.4 Instrumentation and control checkouts and calibrations completed as necessary.

2.5 Secondary system ready to receive steam and return feedwater to the steam generators.

2.6 Diesel generators fully operable. Batteries and battery chargers are in service.

2.7 Systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Establish specified charging and letdown flow rate and seal water flow to the reactor coolant pumps.

3.2 Operate reactor coolant pumps.

3.3 Energize pressurizer heaters and conduct solid system pressure control demonstration.

3.4 Perform chemistry adjustment demonstrations.

3.5 Form pressurizer steam bubble.

3.6 At approximately 100°F intervals, stabilize system parameters and record required data, measurements, and observations for incore thermocouple and RTD cross calibration, reactor coolant pump vibration measurements, and Reactor Coolant System thermal expansion measurements.

Table 14.1-27 (continued)
Reactor Coolant System Heatup for Hot Functional Testing

3.7 Verify ability to maintain steam generator levels by operation of the atmospheric steam dump and the Emergency Feedwater System.

3.8 Check operability of pressurizer power operated relief valves, spray valves, and steam generator atmospheric steam dump valves by either placing in service or performing functional check.

3.9 Main steam power operated relief valves are functionally checked.

4.0 Acceptance Criteria

Systems, components, instrumentation, and controls function within allowable design limits.

Table 14.1-28
Systems Thermal Expansion

1.0 Objective

1.1 Verify that the applicable systems piping can expand without obstruction during initial heatup to normal operating conditions.

1.2 Confirm that systems piping and components return to their approximate baseline cold position after cooldown to ambient conditions.

2.0 Prerequisites

2.1 To commence with the Reactor Coolant System heatup for hot functional testing.

2.2 Hanger lock pins removed and expansion clearances set to the proper cold values.

2.3 Reference points for measurements established.

2.4 Piping supports are verified for proper installation prior to heatup for thermal expansion measurements.

3.0 Test Methods

3.1 Record cold baseline data.

3.2 Obtain a set of measurements during Reactor Coolant System heatup at approximately 250, 350, 450, and 550°F.

3.3 Upon completion of Reactor Coolant System cooldown, obtain a set of measurements.

4.0 Acceptance Criteria

4.1 Piping movements do not cause piping rubs or interference with other equipment.

4.2 Piping movements do not cause undue stresses as determined by inspection.

4.3 Piping and components return to approximate baseline position on cooldown.

Table 14.1-29
Hot Functional Testing

1.0 Objective

Perform functional checks on the Reactor Coolant System and associated systems components and instrumentation required during normal hot plant operation.

2.0 Prerequisites

2.1 Reactor Coolant System heatup completed, Reactor Coolant System conditions of 525-557°F and 2235 psig being maintained.

2.2 Systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Check the response, stability, and general control characteristics of the pressure control system.

3.2 Perform other tests which required the Reactor Coolant System to be at normal operating no-load temperature and pressure as outlined in the hot functional testing procedures.

4.0 Acceptance Criteria

Systems, components, instrumentation, and controls function within allowable design limits.

Table 14.1-30
Emergency Feedwater System

1.0 Objective

Demonstrate that the Emergency Feedwater System is capable of providing adequate quantities of feedwater for the removal of decay heat.

2.0 Prerequisites

2.1 Emergency Feedwater System installation and component checks completed.

2.2 Condensate storage tank adequately filled to supply the required water for the duration of the test.

3.0 Test Methods

3.1 Verify flow rates of the pumps and system control.

3.2 Verify that the turbine driven emergency feedwater pump cold starts successfully five successive times.

4.0 Acceptance Criteria

4.1 Emergency flow capability of the system meets the design requirements.

4.2 System interlocks and alarms function within allowable design limits.

4.3 The turbine driven emergency feedwater pump cold starts successfully five successive times.

Table 14.1-31
Engineered Safety Features Circuitry

1.0 Objective

1.1 Verify proper operation of motor and air operated valves to the different ESF signals and various interlocks.

1.2 Verify proper operation of breakers to ESF signals.

2.0 Prerequisites

2.1 Associated systems have been checked.

2.2 Necessary breakers are racked out and other conditions are as outlined in test.

3.0 Test Methods

Simulate various ESF signals and note component responses to signals.

4.0 Acceptance Criteria

Valves and breaker respond properly to actuation signals.

Table 14.1-32
Nuclear Sampling System

1.0 Objective

Verify that a quantity of representative fluid can be obtained from each sampling point.

2.0 Prerequisites

2.1 Reactor Coolant System at operating pressure and temperature.

2.2 Installation checks complete.

3.0 Test Methods

3.1 From each nuclear sampling point take a sample.

3.2 Check operation of remotely and manually operated valves.

4.0 Acceptance Criteria

Flows are adequate for gathering samples. Remote valve actuation signals get proper response.

Table 14.1-33
Reactor Coolant System Cooldown from Hot Functional Testing

1.0 Objective

Perform functional checks on the Reactor Coolant System and associated systems components and instrumentation required to bring the plant to the cooled-down, depressurized condition.

2.0 Prerequisites

2.1 Reactor Coolant System hot functional testing completed, Reactor Coolant System conditions of 525-557°F and 2235 psig being maintained.

2.2 Reactor makeup water storage tank contains sufficient quantity of Grade A water to accommodate the contraction of the primary coolant during cooldown.

2.3 Specified systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Demonstrate the Reactor Coolant System degassing procedure.

3.2 Secure two reactor coolant pumps and commence plant cooldown by decreasing the set pressure of the steam dump valves.

3.3 Record data as required for incore thermocouple and RTD cross calibration.

3.4 When reactor coolant temperature and pressure are below 350°F and 425 psig, place the Residual Heat Removal System in operation.

3.5 Collapse the steam bubble.

3.6 Continue pressurizer and Reactor Coolant System cooldown to 140°F and reduce pressure to 50 psig.

3.7 Establish conditions for Reactor Coolant System draining.

4.0 Acceptance Criteria

Systems, components, instrumentation, and controls function within allowable design limits.

Table 14.1-34
Residual Heat Removal System Flow Tests

1.0 Objective

1.1 To record actual RHR pump data (flow versus head) and compare this to the manufacturer's pump curve.

1.2 To demonstrate proper flow rates in the cold leg injection, cold leg recirculation, and hot leg recirculation modes.

1.3 To demonstrate that motor operated valves in the LHSI system stroke properly against maximum differential pressure.

1.4 Verify proper operation of flow control valves (603A & B, 605A & B).

1.5 To verify the friction loss in the sump suction lines to the RHR pumps and verify vortex control.

1.6 To demonstrate the automatic opening of the RHR sump isolation valves (8811A & B, 8812A & B) on receipt of a RWST lo-lo level signal coincident with a safety injection signal.

1.7 To demonstrate proper RHR system flow rate in the cooldown lineup (RHR pumps taking suction from the Reactor Coolant System loops and discharging back into the Reactor Coolant System cold legs with the reactor vessel head removed).

1.8 To demonstrate that interlocks associated with the following valves operate properly; 8701A, 8701B, 8702A, 8702B, 8706A, and 8706B.

2.0 Prerequisites

2.1 Reactor vessel head is not installed and the internals are not in the vessel.

2.2 Sufficient water available in the RWST to conduct the test.

3.0 Test Methods

3.1 Each RHR pump will be run at various flow rates to record pressure and flow data (motor currents and vibration data will be recorded at full flow).

3.2 Each RHR pump will be run in the cold leg injection, cold leg recirculation (with suction from the RWST instead of the containment sump), and hot leg recirculation (with suction from the RWST instead of the containment sump) modes to record flow rates.

Table 14.1-34 (continued)
Residual Heat Removal System Flow Tests

3.3 Each motor operated valve in the low head safety injection system will be stroked against maximum differential pressure.

3.4 The RHR pumps will be run at various flow rates using flow control valves 603A & B, and 605A & B.

3.5 Each RHR recirculation sump will be flooded with water and each RHR pump will be operated taking suction from its respective sump to verify friction losses in each sump suction line and to demonstrate vortex control.

3.6 Each of the sump isolation valves (8811A & B and 8812A & B) will receive a lo-lo RWST level coincident with a safety injection signal to verify that each of the four valves open.

3.7 Each of the RHR pumps will take a suction from the Reactor Coolant System (with the level in the vessel at least one foot above the nozzles) and discharge back into the Reactor Coolant System cold legs.

3.8 Demonstrate that the interlocks associated with valves 8701A, 8701B, 8702A, 8702B, 8706A, and 8706B operate properly.

4.0 Acceptance Criteria

4.1 Pump performance characteristics and required flow rates in the injection and recirculation modes will be in accordance with design requirements.

4.2 Each motor operated valve will be observed locally for proper operation and timed to verify the valve strokes in less than the maximum allowable time.

4.3 Flow control valves will be monitored to verify no abnormal system flow oscillations.

4.4 Actual friction loss in the sump suction lines will be compared to the calculated friction losses for acceptability. Each sump will be monitored during pump operation to verify that no vortices are formed.

4.5 RHR system flow rate in the cooldown lineup will be in accordance with design requirements.

4.6 Valve interlocks operate as required by design.

Table 14.1-35
Nuclear Instrumentation System

1.0 Objective

Verify that the Nuclear Instrumentation System performs the required indication and control functions through the source, intermediate, and power ranges of operation.

2.0 Prerequisites

2.1 Nuclear Instrumentation System installed with calibration and initial alignments completed.

2.2 System energized for stabilization prior to commencing this test.

2.3 Systems complete as required for conducting this test.

3.0 Test Methods

Using the installed test facilities, verify proper performance of instrumentation, including output signals to the Reactor Protection System, and remote indications.

4.0 Acceptance Criteria

System performance is in accordance with Section 7.2.

Table 14.1-36
Control Building Ventilation Systems

1.0 Objective

1.1 Demonstrate the operation of the following Control Building HVAC systems during normal and abnormal plant operating conditions.

1.1.1 Control Room Ventilation

1.1.2 Relay Room Ventilation

1.1.3 Computer Room Ventilation

1.1.4 Controlled Access Ventilation

1.2 Confirm the proper operation of system equipment interlocks and controls.

1.3 Measure the total Control Room boundary leak rate.

2.0 Prerequisites

2.1 Individual Control Building Ventilation systems installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow conduct of this test.

2.3 Control Room pressure boundaries are sealed properly.

3.0 Test Methods

3.1 Verify fan, damper, heater, humidifier, and cooling unit controls, interlocks, and permissives for all systems.

3.2 Verify isolation damper operation on applicable systems.

3.3 Verify actuations from radiation monitors and safety injection signals on applicable systems.

3.4 Verify that Control Room internal pressure is greater than atmospheric pressure with a maximum of 400 cfm admitted from outside air.

Table 14.1-36 (continued)
Control Building Ventilation Systems

4.0 Acceptance Criteria

4.1 The dampers and fans respond to recirculation signals in accordance with Sections 6.5.1 and 9.4 for applicable systems.

4.2 Fans, dampers, heaters, humidifiers, and cooling units function correctly for each system.

4.3 Control Room is maintained at positive (1/8”) differential pressure with respect to atmosphere in the normal and emergency modes of operation.

4.4 Control Room leak rate does not exceed its maximum design value.

Table 14.1-37
Core Loading Instrumentation

1.0 Objective

Verify proper operation of the source range instrumentation channels prior to fuel loading operations.

2.0 Prerequisites

2.1 Temporary source range instrumentation installation checks completed.

2.2 Permanent source range channels operable.

3.0 Test Methods

3.1 Perform calibration of each source range channel.

3.2 Verify response of each channel to a neutron source.

3.3 Verify audible signal from at least one permanent channel available in Control Room and Reactor Building.

4.0 Acceptance Criteria

Instrumentation provides monitoring of source range neutron level for loading fuel as required by the Technical Specifications.

Table 14.1-38
Reactor Components and Fuel Handling Tools and Fixtures

1.0 Objective

Verify the adequacy of the special equipment required for refueling operations.

2.0 Prerequisites

Equipment to be checked out is onsite and inspected in accordance with the routine receiving inspection.

3.0 Test Methods

3.1 Check each tool for smooth performance and complete actuation.

3.2 Check adequacy of locating devices, guides, and chambers.

3.3 Verify operation of interlocks and/or safety devices.

3.4 Verify load test lifting devices.

4.0 Acceptance Criteria

Equipment provides for safe handling of fuel assemblies and reactor components.

NOTES:

1. Test may be conducted with a dummy fuel element when a fuel element is necessary for test.

2. Testing was conducted on the polar crane in accordance with standard crane testing procedures during the construction of the station. This test included:

   a. Hoists upper and lower limit switches verified.

   b. Load test to 125 percent.

   c. Operational performance under load.

   The polar crane is under the administrative controls of the nuclear operations department.

Table 14.1-39
Fuel Transfer System

1.0 Objective

Provide functional demonstration of the Fuel Transfer System and fuel handling tools prior to initial core load.

2.0 Prerequisites

2.1 Reactor components and fuel handling tools and fixtures test completed.

2.2 Fuel Transfer System installation and component checks completed.

2.3 Reactor vessel head and upper internals stored in the refueling positions.

2.4 Dummy fuel assembly stored in a new fuel storage rack.

3.0 Test Methods

With canal drained, conduct the various fuel handling evolutions with the dummy fuel assembly.

4.0 Acceptance Criteria

System provides for storage, transfer, and handling of fuel assemblies as designed.

NOTE: Test may be conducted with a dummy fuel element when an element is needed.

Table 14.1-40
Safety Injection High Head Flow Balancing Test

1.0 Objective

1.1 To establish proper positioning of the high head cold leg injection and recirculation throttle valve (8996A, B, C, 9884A, B, C) to balance injection flows to each loop and to limit charging pump runout flow.

1.2 To establish proper positioning of the high head hot leg recirculation throttle valves (8989A, B, C, 8991A, B, C) to balance injection flows to each loop and to limit charging pump runout flow.

1.3 To record actual charging pump data (flow versus head) and compare this to manufacturer's pump curve.

1.4 To demonstrate that motor operated valves in the high head S. I. System stroke properly against maximum expected differential pressure.

1.5 To demonstrate that the charging pumps are capable of taking a suction from the RHR pumps.

2.0 Prerequisites

2.1 Reactor vessel head is not installed and the internals are not in the vessel.

2.2 Sufficient water available in RWST to conduct test.

3.0 Test Methods

3.1 Each charging pump will be run through the cold leg injection path. Throttle valves will be adjusted to provide the minimum required branch line flows from the pump whose flow path has the highest resistance (lowest flow) to the throttle valves. The throttle valves will then be locked in position and flow from each pump will be run through the branch lines to verify that minimum flow rates are still met and charging pump runout flow is limited. This method of testing will also be used for positioning throttle valves in the cold leg recirculation and hot leg recirculation flow paths.

3.2 Each charging pump will be run at various flow rates through the high head injection lines to record pressure and flow data (motor currents and vibrations data will be recorded at full flow).

Table 14.1-40 (continued)
Safety Injection High Head Flow Balancing Test

3.3 Each charging pump will be operated while taking suction from an RHR pump. The charging pumps will be lined up to provide flow through one of the four high head safety injection flow paths.

4.0 Acceptance Criteria

Pump performance characteristics and minimum required flow rates in the injection and recirculation flow paths will be in accordance with design requirements. Each motor operated valve will be observed locally for proper operation and timed to verify the valve strokes in less than the maximum allowable time. Each charging pump will be observed for any abnormal vibration under full flow when taking suction from the RHR pumps.

Table 14.1-41
S. I. Accumulator Blowdown Test

1.0 Objective

1.1 To demonstrate accumulator blowdown and verify that the accumulator blowdown data are within the acceptable L/D range for each accumulator.

1.2 Time the opening of each accumulator discharge valve (8808A, B, & C) under flow conditions.

2.0 Prerequisites

2.1 The reactor vessel head is not installed and the internals are not in the vessel.

3.0 Test Methods

3.1 Fill each accumulator to a level consistent with vendor supplied accumulator blowdown prerequisites.

3.2 Connect a brush recorder to accumulator pressure and level instrumentation and to the accumulator discharge valve indication circuitry.

3.3 Pressurize each accumulator to 100 psig.

3.4 Start the brush recorder and then open the accumulator discharge valve.

3.5 Using data obtained during accumulator blowdowns, calculate the L/D for each accumulator discharge line.

4.0 Acceptance Criteria

The L/D values for each accumulator discharge line are within design limits and that each accumulator discharge valve opens in less than the maximum allowable stroke time.

4.1 Pressure and level alarm setpoints are proper.

4.2 Valve opening times and blowdown rates satisfy design requirements.

Table 14.1-42
Spent Fuel Cooling System

1.0 Objective

Demonstrate flow capabilities of the Spent Fuel Cooling System.

2.0 Prerequisites

2.1 Spent Fuel Cooling System installation and component checks completed.

2.2 Adequate supply of Grade B water available.

2.3 No fuel is stored in the spent fuel pool.

3.0 Test Methods

3.1 Demonstrate filling and draining of the spent fuel pool, fuel transfer canal, cask loading area, and the refueling water storage tank.

3.2 Demonstrate circulation through demineralizer loop, heat exchangers, and skimmer loop.

4.0 Acceptance Criteria

System provides for filling, draining, and/or purification of the water in the spent fuel pool, fuel transfer canal, the cask loading area, and refueling water storage tank in accordance with Section 9.1.3.

Table 14.1-42a
Spent Fuel Cooling System

1.0 Objective

Demonstrate flow capabilities of the Spent Fuel Cooling System.

2.0 Prerequisites

2.1 Spent Fuel Cooling System installation and component checks.

2.2 Reactor coolant drain tank and pumps installation and component checks completed.

2.3 Adequate supply of Grade B water available.

3.0 Test Methods

3.1 Demonstrate filling and draining of the refueling canal and refueling cavity.

3.2 Demonstrate circulation through demineralizer loop and skimmer loop.

4.0 Acceptance Criteria

System provides for filling, draining, and/or purification of the water in the refueling canal and refueling cavity, in accordance with Section 9.1.3.

Table 14.1-43
Containment Isolation System

1.0 Objective

Demonstrate the capability of the containment isolation system to respond properly to an isolation signal.

2.0 Prerequisites

2.1 Containment isolation system installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow the conduct of this test.

2.3 Containment isolation system and the applicable isolation valves in associated systems aligned for normal operation.

3.0 Test Methods

3.1 Verify component response to Phase A containment isolation by manually initiating a Phase A containment isolation signal from the MCB.

3.2 Verify component response to Phase B containment isolation by manually initiating a spray actuation signal from the MCB.

4.0 Acceptance Criteria

System response to containment isolation actuation signals is in accordance with Section 6.2.4.

Table 14.1-44
Reactor Protection Operational Check

1.0 Objective

Verify the correct installation and proper operation of the reactor trip portion of the Reactor Protection System.

2.0 Prerequisites

2.1 Reactor plant in cold shutdown condition.

2.2 Instrumentation and Reactor Protective Systems installation checks and calibrations completed.

3.0 Test Methods

3.1 Utilizing the appropriate train test panels, conduct individual tests of each train's tripping logic.

3.2 Conduct overall logic test for both trains.

4.0 Acceptance Criteria

System performance is in accordance with Section 7.2 and the approved test procedure.

Table 14.1-45
Engineered Safety Features System Operational Check

1.0 Objective

Verify the operation of the ESF logic systems for all conditions of trip logic.

2.0 Prerequisites

2.1 Instrumentation and ESF systems installation checks and calibration completed.

2.2 Reactor plant in cold shutdown condition prior to core loading.

3.0 Test Methods

3.1 Conduct individual train logic tests.

3.2 Conduct overall logic test for both trains.

3.3 Verify redundant tripping of each ESF channel through to the relay or controller that actuates the ESF device.

4.0 Acceptance Criteria

System performance is in accordance with Section 7.3.

Table 14.1-46
Integrated Engineered Safety Features Test

1.0 Objective

Demonstrate the capability of the ESF equipment during a simulated accident condition to function in the proper sequence of manner within acceptable parameters.

2.0 Prerequisites

2.1 ESF systems checks and component checks completed.

2.2 Emergency diesel generators are fully operational.

2.3 Systems to be tested are filled and aligned in recirculation with the appropriate storage tanks.

3.0 Test Methods

3.1 Verify the train A ESF load group assignment and component response to an ESF signal by defeating the automatic start of the train B diesel generator and de-energizing the train B ESF 7200 volt bus 1DB, then manually initiating a safety injection and spray actuation from the MCB.

3.2 Verify the train B ESF load group assignment and component response to an ESF signal by defeating the automatic start of the train A diesel generator and de-energizing the train A ESF 7200 volt bus 1DA, then manually initiating a safety injection and spray actuation signal from the MCB.

3.3 Verify the train A & B ESF component response to ESF signals with offsite power by manually initiating a safety injection and spray actuation signal from the MCB.

3.4 Verify the train A & B ESF component response to ESF signals with only onsite power by simultaneously de-energizing offsite power and manually initiating a safety injection and spray actuation signal from the MCB. Diesel generator starting time and loading sequence will be recorded.

4.0 Acceptance Criteria

4.1 Emergency diesel generators respond within acceptable design limits.

4.2 ESF systems and components respond as required.

Table 14.1-47
Reactor Building Spray System

1.0 Objective

1.1 To record actual Reactor Building Spray pump data (flow vs. head) and compare this to the manufacturer's pump curve.

1.2 To demonstrate that motor operated valves in the Reactor Building Spray System stroke properly against maximum differential pressure.

1.3 To determine the friction loss in the sump suction lines to each Reactor Building Spray pump and verify vortex control.

1.4 To demonstrate that the spray ring nozzles are free of obstructions.

1.5 To record the NaOH drawdown rates using various combinations of ECCS pumps.

2.0 Prerequisites

2.1 Reactor Building Spray System installation and component checks completed.

2.2 Sufficient Grade A water available in the refueling water storage tank and sodium hydroxide storage tank.

3.0 Test Methods

3.1 Each Reactor Building Spray pump will be run at various flow rates to record pressure and flow data (motor currents and vibration data will be recorded at full flow).

3.2 Each motor operated valve in the Reactor Building Spray System will be stroked against maximum differential pressure.

3.3 Each Reactor Building Spray pump recirculation sump will be flooded with water and each Reactor Building Spray pump will be run taking a suction from its respective sump to determine friction losses in each pump suction line and to demonstrate vortex control.

3.4 Air will be forced through each spray nozzle to verify that nozzles are free of obstructions.

3.5 Various combinations of ECCS pumps will be run and the NaOH drawdown rates will be recorded for each combination.

Table 14.1-47 (continued)
Reactor Building Spray System

4.0 Acceptance Criteria

4.1 Actual pump performance characteristics will be in accordance with design requirements.

4.2 Each motor operated valve will be observed locally for proper operation and timed to verify the valve strokes in less than the maximum allowable time.

4.3 Actual friction loss in the sump suction lines will be compared to the calculated friction losses for acceptability. Each sump will be monitored during pump operation to verify no vortexes are formed.

4.4 Each spray nozzle will be checked to ensure it passes air.

4.5 Actual NaOH drawdown rates will be analyzed for acceptability.

Table 14.1-48
Leak Detection Monitoring System

1.0 Objective

Demonstrate system capability of detecting the presence of significant leakage from the reactor coolant loops to the Reactor Building atmosphere during normal operations.

2.0 Prerequisites

2.1 Leak Detection Monitoring System installation and component checks completed.

2.2 Associated system completed to the extent necessary to allow the conduct of this test.

3.0 Test Methods

3.1 Verify proper functioning of containment air particulate monitor and radioactive gas monitor detectors by exposure to standard test sources.

3.2 Verify monitor's flow rates and associated controls, indications, and alarms.

3.3 Verify proper functioning of leak detection instrumentation associated with the system.

4.0 Acceptance Criteria

System provides for monitoring of Reactor Coolant System leakage within design acceptance limits.

Table 14.1-49
Post Accident Hydrogen Removal System

1.0 Objective

Demonstrate the capability of the Post Accident Hydrogen Removal System to provide adequate flow and heat for removal of combustible gases.

2.0 Prerequisites

Post Accident Hydrogen Removal System installation and component checks completed.

3.0 Test Methods

3.1 Verify remote actuation.

3.2 Demonstrate ability to obtain atmospheric samples from each sample point.

3.3 Verify proper operation of each hydrogen recombiner.

4.0 Acceptance Criteria

Hydrogen recombiners function as designed.

Table 14.1-50
Radioactive Waste Disposal System

1.0 Objective

Demonstrate the ability of the Radioactive Waste Disposal System to provide controlled handling and disposal of solid, liquid, and gaseous radioactive wastes.

2.0 Prerequisites

2.1 Solid Waste Processing, Liquid Waste Processing, and Gaseous Waste Processing Systems installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow the conduct of this test.

3.0 Test Methods

3.1 The system will be tested in a series of functional Phase I tests as described in Table 14.1-85 for the following subsystems:

a. Reactor coolant drain tank and pumps

b. Waste evaporator feed pump and holdup tank

c. Floor drain tank and pump

d. Waste evaporator condensate tank and pump

e. Waste evaporator

f. Chemical drain tank and pump

g. Spent resin storage and transfer

h. Laundry and hot shower tank and pump

i. Waste monitor tank and pump

j. Waste evaporator concentrates tank and pump

k. Radwaste solidification module

l. Excess waste holdup tank and pump

Table 14.1-50 (continued)
Radioactive Waste Disposal System

m. Decontamination pit collection tank and pump

n. Nuclear drain sump pumps

o. Waste gas compressors and control valves

p. Waste gas hydrogen recombiners

q. Waste gas decay tank drain pump

4.0 Acceptance Criteria

System provides controlled handling and disposal of radioactive wastes in accordance with Sections 11.2, 11.3, and 11.5.

Table 14.1-51
Boron Thermal Regeneration System

1.0 Objective

Operationally checkout the Boron Thermal Regeneration System (BTRS) and operate the system with letdown flow.

2.0 Prerequisites

2.1 BTRS installation and component checks completed.

2.2 The Reactor Coolant System at normal operating temperature and pressure.

2.3 Associated systems completed to the extent necessary to allow the conduct of this test.

3.0 Test Methods

3.1 Align the system for normal operation.

3.2 Operate the system in the dilution and the boration modes.

4.0 Acceptance Criteria

System flow, pressures, and temperatures are within design limits.

Table 14.1-52
Reactor Protection System Time Response Measurement

1.0 Objective

Verify the Reactor Protection System response times and function of each trip path including sensor response time. Response time measurements will be verified for all sensors for which response time measurements are required by Technical Specifications, Tables 3.3-2 and 3.3-5.

2.0 Prerequisites

2.1 To be performed prior to initial fuel loading.

2.2 Instrumentation and Reactor Protective System installation checks and calibrations completed.

3.0 Test Methods

3.1 Utilizing test panels and temporary instrumentation as required, measure the time response and verify the functioning of each trip path in the reactor protective circuitry by simulating the sensor input to the process protection cabinets.

For ESF trip paths, the time response measured will include the sensor input to the process protection cabinets through the energization of the slave relay in the solid state protection cabinets.

Component response times (i.e., the valves travel to their required position, pump discharge pressures reach their required values, etc.) will be obtained from the preoperational test performed on the systems for which the component is a part.

Diesel generator starting and sequence loading delays will be obtained from the Integrated Engineered Safety Features Test (Table 14.1-46).

Sensors response times will be obtained by vendor testing, by onsite bench testing, or by in-place testing.

The response times measured by this test and those sensor time responses obtained as outlined above and the component time response obtained from preoperational tests will be algebraically summed to obtain an overall response time for each trip path.

Delays in sensing lines will be determined analytically.

Table 14.1-52 (continued)
Reactor Protection System Time Response Measurement

4.0 Acceptance Criteria

Response times of the individual "trip paths" including process to sensor coupling delay are less than the maximum allowable times specified in the Technical Specifications, Tables 3.3-2 and 3.3-5.

Table 14.1-53
Initial Fuel Loading

1.0 Objective

To accomplish initial fuel loading in a safe, orderly manner.

2.0 Prerequisites

2.1 All the tests required to be performed before fuel loading is completed.

2.2 The Residual Heat Removal System is maintaining the coolant in constant recirculation.

2.3 Boron concentration is sufficient to maintain $K_{eff} \leq .95$.

2.4 Five source range neutron detectors are installed; two permanently installed, two temporary incore, and a third temporary to act as a spare.

2.5 Containment integrity has been established.

3.0 Test Methods

3.1 An initial nucleus of eight fuel assemblies with a source is loaded.

3.2 Using an inverse neutron count rate plot as a guide to ensure safe loading, fuel assemblies are placed in the core until core loading is complete.

4.0 Acceptance Criteria

The core is loaded in the specified configuration barring mechanical damage to an assembly.

Table 14.1-54
Incore Movable Detectors

1.0 Objective

Verify proper response of the individual channels of instrumentation and the ability to accurately position the detectors of the Incore Movable Detector System.

2.0 Prerequisites

2.1 Incore Movable Detector System installation and component checks completed.

2.2 “Manual local” operation has been checked using a dummy cable.

2.3 Core installed.

2.4 Gas Purge System and Leak Detection System installation and component checks completed.

3.0 Test Methods

3.1 Align system for normal operation.

3.2 Verify proper operation of all transfer devices, isolation valves, safety and limit switches, and readout and control equipment.

3.3 Compare position readouts with observed position of detectors.

4.0 Acceptance Criteria

4.1 System provides mapping capability as described in Section 7.7.

Table 14.1-55
Rod Drop Time Measurement

1.0 Objective

Determine the drop time for each full length control rod at no flow cold conditions and at full flow hot conditions. Also, the slowest rod and the fastest rod are tripped 10 times at no flow/cold conditions and at full flow/hot conditions.

2.0 Prerequisites

2.1 Core installed and reactor vessel head in place.

2.2 Boron concentration equal to or greater than that required for refueling shutdown.

2.3 Rod Position Indication System operable.

2.4 Both source range protection channels available in the control room.

3.0 Test Methods

3.1 Withdraw selected bank to the fully withdrawn position.

3.2 Conduct individual rod drop tests, recording rod drop time, rod travel time, and other specified data.

3.3 Repeat for all banks of full length rods in required conditions of flow and temperature.

3.4 Drop the slowest rod and the fastest rod 10 times at the required flow and temperature conditions.

4.0 Acceptance Criteria

4.1 Drop time for all rods is less than the maximum value specified in the Technical Specifications.

4.2 Operation of the dashpot for all rods, as indicated by recorder traces, will be verified.

Table 14.1-56
Rod Drive Mechanism Timing

1.0 Objective

Verify proper timing of each Rod Control System slave cycler and conduct an operational check of each full length control rod drive mechanism.

2.0 Prerequisites

2.1 All full length control rod drive mechanism equipment installed with rod control cluster assemblies attached.

2.2 Reactor Coolant System filled and vented.

2.3 Boron concentration equal to or greater than that required for refueling shutdown.

2.4 Baseline count rates established for each source range channel.

2.5 Test is to be performed at cold and hot standby conditions.

3.0 Test Methods

3.1 Verify the timing of each power cabinet's slave cycler.

3.2 Conduct individual mechanism operational checks by withdrawing and inserting each mechanism a specified number of steps while obtaining an oscillograph trace.

4.0 Acceptance Criteria

Mechanism timing and operational checks verified to be within acceptable design limits.

Table 14.1-57
Rod Position Indication

1.0 Objective

1.1 Demonstrate that the Rod Position Indication System performs the required indication and alarm functions for each full length rod control cluster assembly.

1.2 Demonstrate performance of the full length rod control cluster assemblies over their full range of travel.

2.0 Prerequisites

2.1 Reactor Coolant System at normal operating no load temperature and pressure.

2.2 Boron concentration equal to or greater than that required for refueling shutdown.

2.3 Cold shutdown alignment and adjustments of Rod Position Indication System completed.

3.0 Test Methods

3.1 The rods are withdrawn in groups and their indicated positions are compared with the group step counters.

4.0 Acceptance Criteria

4.1 Indicators and alarms function in accordance with Section 7.7.

Table 14.1-58
Reactor Coolant System Flow Measurement

1.0 Objective

Obtain the data to compute actual Reactor Coolant System flow rates as they relate to the design flow rates.

2.0 Prerequisites

2.1 Core installed.

2.2 Reactor plant is in hot standby condition with all control rods fully inserted.

2.3 Reactor coolant pumps operable.

3.0 Test Methods

3.1 Measure loop temperatures, loop elbow tap Δp's, and reactor coolant pump input power and speed for various configurations of reactor coolant pumps.

3.2 Compute actual Reactor Coolant System flow rate. Density variation of cold leg fluid will be accounted for in the data reduction method to provide direct comparison to full power conditions.

4.0 Acceptance Criteria

4.1 Reactor Coolant System flow rates are determined to be greater than or equal to the thermal design minimum less than or equal to the mechanical design maximum as per FSAR Table 5.1-1.

4.2 If the criteria as described in 4.1 are not met, the power level will be restricted to the rated thermal power which the measured Reactor Coolant System flow rate will support.

Table 14.1-59
Reactor Coolant System Flow Coastdown

1.0 Objective

1.1 Measure the rate at which Reactor Coolant System flow changes subsequent to reactor coolant pump stops and starts.

1.2 Measure time delays associated with the loss of flow accident.

2.0 Prerequisites

2.1 Core installed.

2.2 Reactor plant is in hot standby condition with all control rods fully inserted.

3.0 Test Methods

3.1 Selectively trip reactor coolant pumps from various configurations of pump operation.

3.2 Measure required flow data and response times for each configuration of pump operation.

4.0 Acceptance Criteria

4.1 Time delays associated with the loss of flow accident are within the design values.

4.2 Rate of change of reactor coolant flow is within the design limits for the various pump configurations.

Table 14.1-60
Resistance Temperature Detector Bypass Loop Flow Verification

1.0 Objective

To ensure the flow necessary to achieve the design objective for reactor coolant transport time in each resistance temperature detector (RTD) bypass loop and to verify flow setpoint.

2.0 Prerequisites

2.1 The Reactor Coolant System is at normal operating no load temperature and pressure.

2.2 Installed pipe measurements have been made and necessary construction and tests are finished.

3.0 Test Methods

3.1 Measure flow in RTD bypass loops.

3.2 Reduce flow to verify alarm setpoints.

3.3 Increase flow and verify alarm setpoints.

4.0 Acceptance Criteria

4.1 Flow gives a transport time of 1 second or less in the RTD bypass loops such that the total time response given in Technical Specification Table 3.3-2, item 7, is not exceeded.

4.2 Alarms actuate and clear at proper setpoints.

Table 14.1-61
Reactor Vessel O-Ring Leak Test

1.0 Objective

Verify that there is no leakage past the reactor vessel head and vessel seal following installation of the reactor vessel head after core loading.

2.0 Prerequisites

2.1 Core installed, reactor vessel head installed, and reactor vessel head studs torqued.

2.2 Reactor Coolant System pressure integrity verified in accordance with ASME Code prior to core loading.

3.0 Test Methods

3.1 Establish normal operating no load temperature and pressure conditions for Reactor Coolant System.

3.2 Increase system pressure to 100 psi above operating pressure and check for leakage past the head and vessel seal.

4.0 Acceptance Criteria

Acceptable leakage past reactor vessel head and vessel seal is determined.

Table 14.1-62
Pressurizer Spray and Heater Capability and Setting Continuous Spray Flow

1.0 Objective

1.1 Establish proper continuous spray flow rates.

1.2 Verify pressurizer normal control spray effectiveness.

1.3 Verify pressurizer heater effectiveness.

2.0 Prerequisites

2.1 Core installed.

2.2 Plant is in shutdown condition at approximately the normal operating no load temperature and pressure.

3.0 Test Methods

3.1 Adjust continuous spray flow rates such that ΔT between the pressurizer and spray lines is less than or equal to 200°F and the spray line low-temperature alarms are clear.

3.2 Check normal control spray effectiveness by spraying down to approximately 2000 psig.

3.3 Check heater effectiveness by energizing heaters with power operated relief valves in “close” and spray and level controls in manual. Allow pressure to increase to approximately 2300 psig.

4.0 Acceptance Criteria

4.1 Continuous spray flow adjusted in accordance with design requirements.

4.2 Heater and normal control spray effectiveness are in accordance with design requirements.

Table 14.1-63
Water Quality Test

1.0 Objective

Verify acceptable water quality of Reactor Coolant System fill and makeup water prior to initial criticality.

2.0 Prerequisites

2.1 Reactor Coolant System filled and vented in preparation for initial criticality.

2.2 Reactor makeup water storage tank at operating level.

3.0 Test Methods

3.1 Sample Reactor Coolant System and analyze for chlorides, conductivity, total dissolved solids, pH, clarity, and fluorides.

3.2 Sample Reactor Makeup Water System and analyze for the above.

4.0 Acceptance Criteria

Analyses are within the limits specified in the Technical Specifications.

Table 14.1-64
Initial Criticality

1.0 Objective

To bring the reactor critical.

2.0 Prerequisites

2.1 All tests to be performed before the initial criticality have been performed.

2.2 Reactor Coolant System is at normal operating temperature and pressure.

3.0 Test Methods

3.1 Withdraw shutdown bank.

3.2 Withdraw control banks leaving the last bank far enough in to provide effective control.

3.3 Dilute the reactor coolant until critical.

3.4 Achieve steady-state hot zero power by using control rod movement.

4.0 Acceptance Criteria

The reactor achieves criticality in an orderly, safe manner.

Table 14.1-65
Low Power Test

1.0 Objective

1.1 Verify nuclear instrumentation overlap.

1.2 Verify point of adding heat.

1.3 Measure rods out boron concentration.

1.4 Determine moderator temperature coefficient.

1.5 Determine integral and differential worths for sequenced control banks.

1.6 Determine differential boron worth.

1.7 Measure ejected control cluster assembly worth at hot zero power.

2.0 Prerequisites

2.1 The Reactor Coolant System is in the hot zero power condition with the reactor critical.

2.2 Reactor Coolant System temperature is being maintained.

2.3 Required signals for data collection and recording are available.

3.0 Test Methods

3.1 The neutron flux level will be increased by outward control rod motion and the nuclear instrumentation overlap recorded. Adjustments will be made as necessary to ensure minimum overlap as described in the Technical Specifications.

3.2 The neutron flux level will be increased by outward control rod motion until temperature feedback effects are noted. The upper limit for zero power physics testing is defined as approximately one decade below this level.

3.3 The all rods out, critical boron concentration is determined by measuring the just critical boron concentration with bank D near the fully withdrawn position. The amount of reactivity held down by bank D is then dynamically determined by withdrawal of bank D, noting the amount of reactivity inserted and converting this value to an equivalent amount of boron.

Table 14.1-65 (continued)
Low Power Test

3.4 The moderator temperature coefficient for various boron concentrations is obtained by dynamically measuring the reactivity change due to a temperature change in the primary system.

3.5 The sequenced bank differential rod worth is determined by either borating the Reactor Coolant System while withdrawing the control banks or by diluting the Reactor Coolant System while inserting the control banks to maintain nominal system criticality. Integral worth is then determined from the differential reactivity data.

3.6 Differential boron worth at hot zero power is determined by obtaining and analyzing reactor coolant samples for boron content in conjunction with control bank movement to maintain nominal criticality during boration. Boron concentration as a function of time in combination with integrated reactivity as a function of time is used to plot reactivity versus boron concentration, the slope of which yields differential boron worth.

3.7 Ejected rod cluster control assembly worth at hot zero power is determined by obtaining a critical configuration with the sequenced rod banks at their insertion limit as defined in the Technical Specifications. The most reactive inserted rod is withdrawn to maintain nominal criticality during boration. The reactivity addition is determined by summing the differential reactivity insertions as the rod is withdrawn to its withdrawal limit.

4.0 Acceptance Criteria

4.1 Nuclear instrumentation overlap meets the minimum requirements.

4.2 The all rods out, critical boron concentration is within ± 50 ppm of design prediction.

4.3 The moderator temperature coefficient is negative under the allowed conditions of normal critical operation.

4.4 Measured integral worths for control banks are within 10 percent of predicted worths and total worth of all rods less the most reactive rod exceeds the shutdown reactivity requirements throughout the fuel cycle.

4.5 Differential boron worth, over the range measured, is within ± 10 percent of the predicted value.

Table 14.1-65 (continued)
Low Power Test

4.6 The measured integral reactivity worth of the RCCA withdrawn during the rod ejection test, and the resultant hot channel factor, F_Q, are less than or equal to the values used in the safety analysis with adequate allowance for measurement uncertainty.

Table 14.1-65a
Augmented Low-Power Test

1.0 Objective

1.1 Demonstrate decay heat removal capability of natural circulation.

1.2 Determine the depressurization rate following a loss of pressurizer heaters for evaluation of the loss of all AC emergency procedure.

1.3 Demonstrate to the plant operators the effect of increased charging flow and reduced steam generator pressure on the saturation margin.

1.4 Demonstrate under simulated loss of offsite power conditions that decay heat can be removed via the steam generators by maintaining steam generator level with the Emergency Feedwater System.

1.5 Demonstrate under simulated loss of onsite and offsite power conditions that decay heat can be removed via the steam generators by maintaining steam generator level with the Emergency Feedwater System.

1.6 Demonstrate boron mixing and Reactor Coolant System cooldown using natural circulation (credit for this objective may be taken for testing completed on a similar plant).

1.7 Train Operators on a simulator in:

a. Natural circulation operations

b. The use of auxiliary pressurizer spray

c. Loss of offsite, and loss of offsite and onsite AC power

2.0 Prerequisites

2.1 The Reactor Coolant System and all emergency and auxiliary systems are at the conditions specified in the appropriate approved test procedure.

2.2 Required signals for data collection and recording are available.

2.3 Reactor Power is maintained less than or equal to 5 percent.

Table 14.1-65a (continued)
Augmented Low-Power Test

3.0 Test Methods

3.1 In hot standby with the reactor coolant pumps supplying heat input to the secondary side, simulate removal of onsite AC power sources and operate the plant utilizing manual control and the steam driven emergency feedwater pump. HVAC to the pump room is isolated to verify pump operability in this environment.

3.2 After fuel loading, but prior to Initial Criticality, establish stable condition at T_{no} Load and 2235 psig with RCP B in operation. Reduce pressure by turning off pressurizer heaters noting depressurization rate. Re-establish heaters and reduce pressure by use of auxiliary spray noting depressurization rate and effect on margin to saturation temperature. At reduced pressure, observe the effects of changes in charging flow and steam flow on margin to saturation temperature.

3.3 With the reactor critical at approximately 3 percent reactor power, place the plant in natural circulation mode observing the length of time for plant to stabilize, flow distribution, power distribution, and ability to maintain cooling mode.

3.4 Perform Loss-of-Offsite Power/Station Blackout Test with plant trip from 10-20 percent Rated Thermal Power. Operate Plant establishing stable conditions in natural circulation using batteries and emergency diesels.

3.5 Referencing boration and cooldown tests performed at Sequoyah I, North Anna II, Farley II, and Diablo Canyon I, verify similar plant response by parameter and plant comparison. Operator training for cooldown on natural circulation provided on a simulator.

4.0 Acceptance Criteria

4.1 Natural circulation was established and maintained under steady state conditions in all cases.

4.2 Operator training during natural circulation was accomplished.

4.3 Adequate boron mixing during Reactor Coolant System cooldown on natural circulation has been proven at Virgil C. Summer Nuclear Station or credit has been taken for this test performed on a similar plant.

Table 14.1-66
Incore Movable Detector and Thermocouple Mapping at Power

1.0 Objective

To obtain and analyze core power distributions for various control rod configurations at each major power plateau.

2.0 Prerequisites

2.1 The reactor is critical at a steady-state power level.

2.2 Incore Instrumentation System functional test is complete and the system is operable.

2.3 Computer systems are operable as necessary for incore map processing.

3.0 Test Methods

Reactor power level is stabilized and complete incore flux maps are obtained and processed.

4.0 Acceptance Criteria

Core peaking factors are within acceptable limits as defined in the Technical Specifications.

Table 14.1-67
Power Coefficient and Power Defect Measurement

1.0 Objective

To determine the differential power coefficient of reactivity and the integral power defect.

2.0 Prerequisites

2.1 The reactor is in the hot zero power condition with rods in the specified maneuvering band.

2.2 The instrumentation necessary for collection of data is installed, calibrated, and operable.

3.0 Test Methods

Reactor power is maintained congruent with turbine load demand by control bank adjustment throughout the range of each load change from the hot zero power condition to the hot full power condition. Reactivity increments due to periodic control bank steps are determined and recorded throughout each load change. At selected power levels, conditions are stabilized and a heat balance obtained to accurately determine core power. Power coefficient and power defect are calculated with data obtained over the range from hot zero power to hot full power.

4.0 Acceptance Criteria

4.1 The best estimate of the measured power coefficient as a function of power, derived from experimental data, is equal to or more conservative than that used in the accident analysis.

4.2 The measured power defect is compatible with design predictions.

Table 14.1-68
Effluent Radiation Monitor Test

1.0 Objective

To verify the performance of the effluent monitors under actual discharge conditions. This test is to be performed at each major power plateau.

2.0 Prerequisites

2.1 The reactor has been operating for a time sufficient to generate representative effluents.

2.2 The effluent monitors have been checked against known sources.

3.0 Test Methods

Following standard procedures, the suitability of effluents for discharge is verified by radiochemical analysis. Discharge is commenced and the response of effluent monitors is observed and recorded. Effluent is sampled in accordance with established procedures and effluent monitor performance is verified through radiochemical analysis.

4.0 Acceptance Criteria

The installed effluent monitors perform in accordance with design standards and properly indicate the radioactive content of the effluent.

Table 14.1-69
Radiation Shielding Survey

1.0 Objective

To measure radiation dose levels at preselected points throughout the plant to verify shielding effectiveness.

2.0 Prerequisites

2.1 Radiation survey instruments to be used are calibrated against known sources.

2.2 The reactor is critical at a steady-state power.

3.0 Test Methods

In accordance with procedures for radiation surveys, dose levels are measured at points throughout the station.

4.0 Acceptance Criteria

Measured radiation levels are within the limits for the zone designation of each area surveyed.

Table 14.1-70
Process Computer

1.0 Objective

Verify the output value printout of the nonsafety related process computer for computer inputs.

2.0 Prerequisites

Computer has been functionally checked out.

3.0 Test Methods

Data comparisons are made between simulated process signals and the printout of the process computer.

4.0 Acceptance Criteria

4.1 Errors between simulated process signals and computer output are within acceptable design limits.

4.2 Alarm functions are within acceptable design limits.

Table 14.1-71
Thermal Power Measurements and Instrument Calibration

1.0 Objective

To determine the power output of the core at major power plateaus for nuclear instrumentation calibration.

2.0 Prerequisites

2.1 The plant is in a steady-state condition.

2.2 Necessary process instruments have been checked and calibrated.

2.3 Steam generator blowdown has been stopped.

3.0 Test Methods

3.1 For each loop, check to ensure steam flow and feed flow are equal, then record the mass flow rate.

3.2 Record steam pressure and find steam enthalpy of saturated liquid conditions.

3.3 Record feedwater temperature and find feedwater enthalpy for saturated liquid conditions.

3.4 Using the proper equation, determine thermal output.

3.5 Calibrate nuclear instrumentation to agree with core thermal output.

4.0 Acceptance Criteria

Instrumentation is calibrated to indicate core output.

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Table 14.1-72
Automatic Control Systems Checkout

1.0 Objective

To demonstrate that the automatic control systems for pressurizer pressure and level control, rod control, steam generator level control, and turbine generator control respond properly to changes in controlling parameters.

2.0 Prerequisites

2.1 The reactor and turbine generator are at approximately 25 percent power with normal operating parameters.

2.2 Related instrumentation has been checked and calibrated.

3.0 Test Methods

3.1 Using manual control of pressure control devices (sprays, reliefs, and heaters), increases and decreases are made in system pressure. The controls are placed in automatic and the responses noted.

3.2 Using manual control of pressurizer level control, changes are made from the normal level. The controller is placed in automatic and the responses to high and low levels are noted.

3.3 Using manual rod control, errors in Reactor Coolant System average temperature are initiated. The rod control is placed in automatic and the responses to high and low average temperatures are noted.

3.4 Using manual control of the various controllers (three main feedwater valve controllers and the master feed pump controller), steam generator level and feedwater pressure changes are made. The controllers are placed in automatic and the responses noted.

3.5 With turbine control in automatic, changes in steam pressure are made by manual manipulations of control rods. Closing of a stop and control valve is used to change steam conditions. The turbine generator responses to these manipulations are noted.

4.0 Acceptance Criteria

4.1 Automatic controllers return plant parameters to normal values without excessive overshoot.

4.2 The recorded process variables are not more limiting than stated in the setpoint study document.

Table 14.1-73
Plant Response to Step Load Changes

1.0 Objective

To demonstrate satisfactory plant response to a 10 percent load change from various power levels.

2.0 Prerequisites

2.1 The various control systems have been tested and are in automatic.

2.2 All pressurizer and main steam relief and safety valves are operable.

2.3 The control rods are in the maneuvering band for the power level existing at the commencement of the test.

2.4 Plant conditions are stabilized and pertinent parameters to be measured are connected to high speed recorders.

3.0 Test Methods

3.1 Output is manually reduced at a rate sufficient to simulate a step load change equivalent to approximately a 10 percent load decrease.

3.2 After stabilization of systems, output is manually increased at a rate sufficient to simulate a step load change equivalent to approximately a 10 percent load increase.

3.3 Pertinent parameters affected by a load change are measured and recorded.

3.4 At various power levels, as required by the test procedure, the test is repeated.

4.0 Acceptance Criteria

4.1 Neither the turbine nor the reactor trips, and no initiation of safety injection is experienced.

4.2 No pressurizer or main steam relief or safety valves lift.

4.3 No operator action is required to restore conditions to steady state.

4.4 Control systems maintain their parameters within their design transient limits per NSSS Supplier Setpoint Study Document.

Table 14.1-74
Pseudo Rod Ejection Tests

1.0 Objective

To verify the rod worth and hot channel factors assumed in the safety analysis.

2.0 Prerequisites

2.1 The reactor is critical and at a steady-state power level of greater than or equal to 10 percent but no more than 50 percent.

2.2 All of the excore instrumentation channels are operable.

2.3 The incore detectors and thermocouples are operable.

3.0 Test Methods

3.1 The affected rod bank is placed at the full power insertion limit.

3.2 Single rod motion is accomplished by disconnecting the lift coils on all the rods in the affected bank except the coil on the selected rod.

3.3 The selected rod is withdrawn from the core while power and reactor coolant temperature are held constant by boron concentration changes.

3.4 Data are gathered by use of the incore detectors and thermocouples and boron concentration.

4.0 Acceptance Criteria

The measured worth of the pseudo ejected rod and the associated hot channel factors is more conservative than that assumed in the safety analyses.

Table 14.1-75
Rod Drop Test

1.0 Objective

To demonstrate the operations of the negative rate trip circuitry in detecting the simultaneous insertion of two cluster control assemblies.

2.0 Prerequisites

2.1 All power range nuclear instrumentation channels are operable.

2.2 The reactor is at the steady-state power level specified in the procedure with the controlling bank near the full power insertion limit.

2.3 Pertinent parameters to be measured are connected to recording devices.

3.0 Test Methods

3.1 All four power range nuclear instrumentation channel positive and negative rate trips are defeated with instrumentation set up to monitor the negative rate trip bistables.

3.2 Two rods from a common group most difficult to detect by excore detectors due to low worth and core location are simultaneously dropped by removing voltage to both the movable and stationary gripper coils of the designated rod.

3.3 Following the transient, recorded data are evaluated for system and instrumentation response.

4.0 Acceptance Criteria

4.1 The negative rate trip circuitry is initiated on a minimum of three power range nuclear instrumentation channels as a result of simultaneously dropping two control rods.

Table 14.1-76
Below-Bank Rod Test

1.0 Objective

To demonstrate the response of the nuclear and incore instrumentation to a rod cluster control assembly below the nominal bank position and to determine hot channel factors associated with this misalignment.

2.0 Prerequisites

2.1 All power range nuclear instrumentation channels are operable.

2.2 The moveable incore detectors are operable.

2.3 Power escalation testing is completed to approximately the 50 percent reactor power level.

3.0 Test Methods

3.1 Single rod movement is accomplished by disconnecting the lift coils of all rods in the affected bank except the selected rod.

3.2 During rod cluster control assembly insertion, power range detector currents, thermocouple maps, and moveable incore detector traces are periodically recorded to demonstrate sensitivity to RCCA misalignment. The power range detector data provide information to relate core quadrant tilt to rod cluster control assembly position. With the RCCA fully misaligned, a moveable detector flux map is obtained to verify resultant core hot channel factors.

4.0 Acceptance Criteria

4.1 The measured radial hot channel factor resultant from a single RCCA fully misaligned from its bank is less than or equal to the value assumed in the safety analysis (Table 15.2-2) and does not exceed the Technical Specification limit for the power level at which the test is performed.

4.2 Incore and/or nuclear instrumentation is demonstrated to detect any significant power maldistribution caused by the misaligned rod cluster control assembly.

Table 14.1-77
Plant Trip from 100% Power

1.0 Objective

1.1 To demonstrate the ability of the primary and secondary plant and the plant automatic control systems to sustain a trip from 100 percent power and to bring the plant to a stable condition following the transient.

1.2 To determine the overall response time of the reactor coolant hot leg resistance temperature detectors.

1.3 To obtain data which are to be evaluated to determine if changes in the control system setpoints are warranted to improve transient response based on actual plant operation.

2.0 Prerequisites

2.1 The various control systems are in the automatic mode and functioning properly.

2.2 The reactor is steady state of 100 percent power, with the rods in the maneuvering band.

2.3 Pressurizer and main steam safety and relief valves are in service and operable.

2.4 Pertinent parameters to be measured are connected to recording devices.

3.0 Test Methods

3.1 Initiate a plant trip by manually initiating a turbine generator trip.

3.2 Pertinent parameters are recorded on recording devices.

3.3 Following the transient, recorded data are evaluated for system and controller response and possible abnormalities.

4.0 Acceptance Criteria

4.1 The parameters recorded are not more limiting than those in the setpoint study document.

Table 14.1-78
Loss of Offsite Power

1.0 Objective

To demonstrate that the necessary equipment, controls, and indication are available following the isolation of the Offsite Power Distribution System to remove decay heat from the core using only emergency power supplies.

2.0 Prerequisites

The plant is at a steady-state condition with greater than 10 percent generator output.

3.0 Test Methods

3.1 Simulate loss of power by manually de-energizing the offsite power supplies to all 7.2 kV buses, and initiating a turbine generator trip.

3.2 Using approved operating procedures, bring the plant to a hot standby condition and maintain the plant in a hot standby condition for at least 30 minutes using the only emergency onsite power sources.

4.0 Acceptance Criteria

The hot standby condition is achieved and maintained for at least 30 minutes using only emergency onsite power sources.

Table 14.1-79
Shutdown from Outside the Control Room

1.0 Objective

The purpose of this test is to demonstrate the following:

1.1 That the plant can be taken off the line from power operations and maintained in hot standby from outside the control room.

1.2 That cooldown from hot standby can be initiated and maintained from outside the control room by reducing the Reactor Coolant System temperature approximately 50°F without exceeding the cooldown rate.

1.3 That the Residual Heat Removal System can be initiated and controlled from outside the control room by placing the Residual Heat Removal System in service and reducing the Reactor Coolant System temperature approximately 50°F without exceeding the cooldown rate.

2.0 Prerequisites

2.1 The plant is at some power level greater than or equal to 10 percent output on the generator.

2.2 Two shifts of operators are onsite, one observes from control room, the other performs the test.

3.0 Test Methods

3.1 The plant is tripped off the line from outside the control room.

3.2 Using switchgear, manual operators on valves, local indicators, and local panels of controls and indicators, hot standby (approximately no load temperature) is maintained through the assistance of the plant communication system for a period of at least 30 minutes.

3.3 The plant is cooled from approximately no-load temperature approximately 50°F without exceeding the cooldown rate.

3.4 Residual Heat Removal System is initiated from outside the control room and the plant is cooled approximately 50°F without exceeding the cooldown rate.

4.0 Acceptance Criteria

Hot standby is maintained by the members of one shift from outside the control room for at least 30 minutes.

The plant is cooled approximately 50°F below the approximately no-load Reactor Coolant System temperature without exceeding the cooldown rate.

The RHR system is initiated from outside the control room and is used to reduce the Reactor Coolant System temperature approximately 50°F.

Note: Steps 3.3 and 3.4 may be performed during hot functional testing.

Table 14.1-79a
Emergency Lighting

1.0 Objective

Verify that the Emergency DC Lighting System meets design requirements.

2.0 Prerequisites

All construction checks have been completed.

3.0 Test Methods

3.1 Interrupt the standby lighting sources to provide illumination solely from the emergency system.

3.2 Record foot-candle level data at selected locations.

4.0 Acceptance Criteria

Emergency Lighting System meets requirements of Section 9.5.3.3.

Table 14.1-79b
Heat Tracing for Safety Related Outdoor Piping

1.0 Objective

Demonstrate the ability of the Heat Tracing System to maintain proper temperature control in safety related outdoor piping.

2.0 Prerequisites

2.1 Heat Tracing System installation and component checks completed.

2.2 Associated systems completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Energize Heat Tracing System.

3.2 Monitor temperatures maintained by each heat tracing circuit with the system in a static condition.

4.0 Acceptance Criteria

Each heat tracing circuit maintains temperature within design limits.

Table 14.1-79c
Pressure Boundary Integrity Test

1.0 Objective

Demonstrate pressure boundary integrity conforms to applicable codes.

2.0 Prerequisites

2.1 Reactor vessel internals, head, and studs installed.

2.2 Required weld non-destructive testing is complete and accepted.

3.0 Test Methods

3.1 The Reactor Coolant System is filled with Grade “A” water.

3.2 The Reactor Coolant System is brought to hydrostatic test temperature utilizing the system pumps.

3.3 The Reactor Coolant System is brought to the required test pressure utilizing the Chemical Volume Control System.

4.0 Acceptance Criteria

4.1 The pressure boundary satisfactorily withstands the test pressure as required by applicable ASME codes.

Table 14.1-79d
Seismic Instrumentation

1.0 Objective

Verify operability of the seismic instrumentation.

2.0 Prerequisites

Installation and calibration of the seismic instrumentation is complete.

3.0 Test Methods

3.1 Verify system response to a simulated signal.

3.2 Verify operability of system alarms.

4.0 Acceptance Criteria

4.1 System response to a simulated signal meets design intent.

4.2 System alarms function as designed.

Table 14.1-80
Power Ascension Test Program

Test	Low Power	30%	50%	75%	90%	100%
Initial Criticality	N/A					
Low Power Test	X					
Incore Moveable Detector and Thermocouple Mapping at Power	X	X	X	X	X	X
Power Coefficient and Power Defect Measurement	X	X	X	X		X
Effluent Radiation Monitor Test	X	X	X	X	X	X
Radiation Shielding Survey	X		X			X
Thermal Power Measurements and Instrument Calibration		X	X	X	X	X
Automatic Control Systems Checkout		X				
Plant Response to Step Load Changes		X		X		X
Pseudo Rod Ejection Test			To be specified in the test			
Rod Drop Test			To be specified in the test			
Below-Bank Rod Test			X			
Plant Loss of Electrical Load						X
Loss of Offsite Power		Greater than or equal to 10% gen. load				
Shutdown from Outside the Control Room		Greater than or equal to 10% gen. load				

X - To be performed

Note: Tests at each given power test plateau will be reviewed before increasing power to the next test plateau.

Table 14.1-81
Initial Test Program Schedule

Startup Activity	Months Before Commercial Operation	Approximate Duration Weeks
Reactor Coolant System Cold Hydro	15	1
Hot Functional Testing	10	3
Core Loading	6	2
Low Power Test	5	4
Power Ascension	3	8

Startup group staffing will begin approximately 30 months prior to commercial operation. The startup group will be completely staffed and trained approximately 20 months prior to commercial operation.

Table 14.1-82
Generic Flush Procedure

1.0 Objective

Flush plant systems to the appropriate level class of cleanliness.

2.0 Prerequisites

2.1 Construction is completed and the system is turned over to the point to allow flushing.

2.2 Adequate source of clean water is available.

2.3 Permanent plant equipment, i.e., pump or temporary flush equipment, i.e., Hydrolaser, is available for the flush.

3.0 Test Methods

3.1 Align the system valves to flush the system.

3.2 Using permanent plant equipment or Hydrolaser, flush the system.

4.0 Acceptance Criteria

4.1 By flush cloth or visual observation, verify that the system meets the desired cleanliness class.

Table 14.1-83
Generic Hydrostatic/Pneumatic Test

1.0 Objective

Prove structural integrity of the systems being tested to the design requirements as specified in the particular design specification.

2.0 Prerequisites

2.1 The system to be tested must be completed sufficiently enough by construction to alleviate the need for system boundary re-entry and test invalidity.

2.2 The system is to be flushed, if practical, before the test is to be conducted.

2.3 The document research and quality control requirements must be completed before testing can begin.

3.0 Test Methods

3.1 Calibrated test gages are installed at selected locations for test pressure verification.

3.2 The system is filled with the appropriate hydrostatic or pneumatic test medium at a temperature higher than the minimum specified in the design specification.

3.3 By use of test pumps, compressors, or other appropriate means, the system is pressurized to the test pressure and held for the specified time limit, then lowered to the inspection pressure and structural integrity is verified.

3.4 After the test, the system is drained or vented, then it is put in the proper layup condition.

4.0 Acceptance Criteria

4.1 No external leakage is allowed except at (1) temporary connections, installed for the purpose of making the test, (2) at gaskets, seals, leak offs, etc., on previously tested components, (3) items noted on the test report as being permitted by specification.

4.2 The leakage shall not exceed the capacity of the pressure source to maintain the required test pressure.

Table 14.1-84
Instrument Control Procedure

1.0 Objective

1.1 Verify and, if required, re-establish the accuracies and control functions of the channel sensors, associated signal processing equipment, indicating equipment, and alarms associated with the analog process signals.

2.0 Prerequisites

2.1 Process control cabinets are installed and energized.

2.2 Process control sensors are installed and connected to the process control cabinets.

2.3 Interconnection between the process control cabinets and the main control board is complete.

3.0 Test Methods

3.1 Using test equipment to simulate the process parameter, the correction conversion, by the sensor, of the process parameter to an analog signal will be verified.

3.2 Using a signal simulator to simulate an analog signal from the sensor, the correct processing of the analog signal by the process equipment, setpoints of comparators, and operation of indicating equipment will be verified.

4.0 Acceptance Criteria

4.1 The process instrumentation provides intolerance conversion of the process parameter and performs its as-designed indication and control functions.

Table 14.1-85
Functional Test

1.0 Objective

To test the operability of subsystems and non-safety related systems to demonstrate their ability to meet their functional requirements.

2.0 Prerequisites

2.1 Specify any tests or portions of tests which must be completed prior to conduct of this test.

2.2 Specify plant status necessary to start the test.

3.0 Test Methods

3.1 Step by step method to accomplish the test.

3.2 Specify data to be taken during the test such as; vibration, bearing temperatures, pressure and flow characteristics, automatic control functions, valve open and closing under actual pressure conditions.

3.3 Restore the system to a safe post test condition.

4.0 Acceptance Criteria

4.1 Specify those qualitative or quantitative requirements that demonstrate the system's ability to meet its functional requirements.

Table 14.1-86
Steam Generator Power Operated Relief Valve

1.0 Objective

1.1 Demonstrate that the steam generator power operated relief valves respond as designed to control Reactor Coolant System temperature utilizing steam pressure as the input signal.

1.2 Demonstrate that the steam generator power operated relief valves respond as designed to control Reactor Coolant System temperature utilizing T_{avg} as the input signal.

2.0 Prerequisites

2.1 Phase I testing complete on steam generator power operated relief valves and associated process instrumentation control loops.

3.0 Test Methods

3.1 During hot functional testing, verify proper operation of the power operated relief valves in the pressure control mode at Reactor Coolant System temperatures of 350°F, 450°F, and approximately 557°F.

3.2 Verify the proper operation of the steam generator power operated relief valves in the temperature control mode by inducing a simulated T_{avg} signal in the process control racks.

4.0 Acceptance Criteria

4.1 Visual observation of the valves stroking to full flow at a reactor coolant temperature of approximately 557°F detects no abnormal movement of valves or associated piping.

4.2 Steam generator power operated relief valves respond as required to simulated inputs of T_{avg}.

Table 14.1-87
Condensate System

1.0 Objective

1.1 Demonstrate that the Condensate System delivers condensed steam from the main condenser hotwell through the low pressure feedwater heaters to the deaerator.

1.2 Demonstrate that the Hotwell Level Control System automatically makes up and rejects water to the condensate storage tank.

1.3 Demonstrate the system interlocks and automatic devices perform their intended functions.

2.0 Prerequisites

2.1 Condensate System installation is complete and component checks are completed.

2.2 Deaerator and hotwell are capable of receiving water.

3.0 Test Methods

3.1 System is aligned for operation.

3.2 Check operation of condensate pump speed controls.

3.3 Verify pump head and flow rates.

3.4 Verify that the Hotwell Level Control System functions to maintain hotwell level.

3.5 Check operation of pump trips and interlocks.

4.0 Acceptance Criteria

4.1 Pump flow capabilities meet or exceed design requirements.

4.2 Interlocks, pump trips, and protective devices function per design requirements.

4.3 Verify control system function per design requirements.

Table 14.1-88
Feedwater System

1.0 Objective

1.1 Demonstrate that the Feedwater System provides heated and deaerated water to the steam generators during normal and transient plant conditions.

1.2 Demonstrate that plant and component protection devices perform their intended functions.

2.0 Prerequisites

2.1 Feedwater System installation is complete and component checks are completed.

2.2 Steam generators are capable of receiving water.

3.0 Test Methods

3.1 System is aligned for operation.

3.2 Check operation of feedwater pump turbine speed controls to provide programmed differential pressure between the steam generator and feedwater pump.

3.3 Verify pump head and flow rates.

3.4 Check operation of pump trips and interlocks.

4.0 Acceptance Criteria

4.1 Pump flow capabilities meet or exceed design requirements.

4.2 Interlocks, pump trips, and protective devices function per design requirements.

4.3 Verify control system function per design requirements.

Table 14.1-89
Main Condenser Dump Valves

1.0 Objective

1.1 Demonstrate that the main condenser dump valves respond properly to simulated temperature and pressure input signals.

1.2 During hot functional testing, cycle each steam dump valve full open.

2.0 Prerequisites

2.1 Phase I testing complete on main condenser dump valves and associated process instrumentation control loops.

3.0 Test Methods

3.1 Simulate temperature and pressure inputs to the control circuitry for the main steam dump valves and verify proper system response.

3.2 During hot functional testing, cycle each steam dump valve fully open and fully closed and verify no abnormal valve or pipe movement.

4.0 Acceptance Criteria

4.1 Main condenser dump valves respond properly to simulated temperature and pressure inputs.

4.2 Each main steam dump valve cycles fully open and closed with no abnormal valve or pipe movement.

Table 14.1-90
Circulating Water System

1.0 Objective

1.1 Demonstrate the capability of the Circulating Water System to provide adequate cooling water.

2.0 Prerequisites

2.1 Circulating Water System installation, piping flushes, and component checks are completed.

2.2 Associated systems are completed to the extent necessary to allow conduct of this test.

3.0 Test Methods

3.1 Align the system for operation.

3.2 Verify system protective interlocks.

3.3 Verify flows and pressures for normal operations.

4.0 Acceptance Criteria

4.1 System flows, pressures, and automatic functions are in accordance with design requirements.

4.2 System interlocks function in accordance with design.

Table 14.1-91
Chemical Feed System

1.0 Objective

1.1 Demonstrate that the Condensate Chemical Injection System can maintain established limits of pH and dissolved oxygen in the Condensate and Feedwater Systems.

1.2 Demonstrate that the Steam Generator Standby Chemical Injection System can maintain established limits of pH and dissolved oxygen in the secondary side of the steam generators during wet layup.

2.0 Prerequisites

2.1 Chemical Injection System installation and component checks are complete.

3.0 Test Methods

3.1 Align systems for normal operation and establish flow paths.

3.2 Check operation of metering controls for injection systems.

4.0 Acceptance Criteria

4.1 Condensate System delivers calibrated volume to the Condensate System.

4.2 Steam Generator Standby Chemical Injection System delivers a calibrated volume to the steam generator.

Table 14.1-92
Nuclear Blowdown Processing System

.0 Objective

1.1 Demonstrate flow capabilities of the Nuclear Blowdown Processing System.

2.0 Prerequisites

2.1 Nuclear Blowdown Processing System installation and component checks are completed.

3.0 Test Methods

3.1 Demonstrate circulation through different loops of the Nuclear Blowdown Processing System and verify ability to demineralize water to Condensate System grade water.

4.0 Acceptance Criteria

4.1 System provides the capability to demineralize steam generator nuclear blowdown to Condensate System cleanliness criteria.

Table 14.1-93
Control Rod Drive

1.0 Objective

1.1 Demonstrate that the circuitry and components comprising the Control Rod Drive System will perform their design requirements without control rod drives installed.

2.0 Prerequisites

2.1 Wiring and component installation complete.

3.0 Test Methods

3.1 Initially energize the rod position indication system and verify proper signal response from the detection coils to the indication display.

3.2 Verify proper control rod drive mechanism polarity and coil currents.

3.3 Verify proper control rod drive M-G set operation.

3.4 Verify proper control rod drive mechanism magnetic coil sequencing.

4.0 Acceptance Criteria

4.1 Control rod drive components and circuitry function as required by design.

Table 14.1-94
Miscellaneous Plant Drains

1.0 Objective

1.1 Demonstrate the ability of Miscellaneous Plant Drains System to remove water from the plant.

2.0 Prerequisites

2.1 Miscellaneous Plant Drains System installation and component checks are completed as necessary.

3.0 Test Methods

3.1 Verify capability of the sump pumps to remove water form the sumps.

3.2 Verify sump level interlocks to applicable plant equipment.

4.0 Acceptance Criteria

4.1 Sump level interlocks to plant equipment function as designed.

4.2 System provides for water removal in accordance with design requirements.

Table 14.1-95
Fuel Handling Building Pool Liner Leak Test

1.0 Objective

1.1 Demonstrate watertight integrity of spent fuel pit, fuel transfer canal, and cask loading pit.

1.2 Demonstrate watertight integrity of the fuel transfer tube isolation valve and blind flange.

1.3 Demonstrate watertight integrity of spent fuel pit gate and cask loading pit gate.

1.4 Demonstrate airtight integrity of the inflatable seals on the spent fuel pit and cask loading pit gates.

2.0 Prerequisites

2.1 Pool liners have been installed and cleaned.

2.2 Spent fuel racks are not installed.

2.3 Adequate source of water is available.

3.0 Test Methods

3.1 Fill pools with water and monitor liner leakage.

3.2 Install transfer canal isolation gates, drain canal and monitor leakage through the gates.

4.0 Acceptance Criteria

4.1 Total leakage for liner is less than design maximums.

4.2 Fuel transfer tube isolation valve.

4.2.1 Blind flange and valve is less than design maximums.

4.2.2 Valve stem is less than design maximums.

4.3 Isolation gates.

4.3.1 Inflatable seal on gates - no visible bubbles.

4.3.2 Spent fuel pit gate is less than design maximums.

4.3.3 Cask loading pit gate is less than design maximums.

Table 14.1-96
Reactor Building Ventilation "Post Accident Operation"

1.0 Objective

1.1 Demonstrate that the Reactor Building cooling units have the capacity to cool the Reactor Building within the design load during the worst postulated accident conditions.

1.2 Demonstrate during the integrated leak rate test that the Reactor Building cooling fan motor over current protection will allow operation of the motors under the maximum load.

1.3 Demonstrate during the integrated leak rate test that the Reactor Building cooling unit bypass damper closes.

2.0 Prerequisites

2.1 Installation of components and support systems is complete and operational.

2.2 The integrated leak rate test is in progress for objective 1.2.

2.3 Adjusts fan pitch settings to accommodate increased containment air density (for ILRT).

3.0 Test Methods

3.1 Align the Reactor Building coolers for system operation in the "post-accident" mode.

3.2 Measure the flow rate and temperature drop across the cooling coil air and water sides at ambient conditions.

3.3 Calculate the heat removal capacity and extrapolate for worst conditions using the coil data sheets and measured data.

3.4 Align system for operation during the containment integrated leak rate test and monitor the fan motor operation.

3.5 During the integrated leak rate test, reposition the Reactor Building cooling unit dampers from the bypass to the closed position.

4.0 Acceptance Criteria

4.1 The cooling units are shown to have the capacity to remove the designed heat load at the worst postulated conditions.

4.2 The fan motor operates in accordance with design requirements during the integrated leak rate test.

4.3 Reactor Building cooling unit dampers operate from the bypass to the closed position.

Table 14.1-97
ESF Equipment Rooms Cooling Systems

1.0 Objective

1.1 Demonstrate that the cooling systems for the following ESF Equipment Rooms have the capacity to cool the areas within design loads during the worst postulated conditions.

1.1.1 Reactor Building Cooling Units (Normal Mode)

1.1.2 Charging Pump Room Cooling Unit

1.1.3 RHR-Spray Pump Room Cooling Units

1.1.4 Safety Related MCC Switchgear Cooling Units

1.1.5 Relay Room Cooling System (Recirc. Mode)

1.1.6 Control Room Ventilation System (Recirc. Mode)

1.1.7 ESF Switchgear Room Cooling

1.1.8 Speed Switch Room Cooling

1.1.9 Service Water Booster Pump Cooling Units

1.1.10 Emergency Feedwater Pump Cooling Units

2.0 Prerequisites

2.1 Installation of components and support systems is complete and operational.

3.0 Test Methods

3.1 Align the cooler for system operation and measure the flow rate and temperature drop across the cooling coil air and water sides at ambient conditions.

3.2 Calculate the heat removal capacity at ambient conditions. Verify that the coils are operating on their characteristic curve by comparing test data results to manufacturer’s design program data.

4.0 Acceptance Criteria

4.1 The cooling units are shown to operate on their characteristic curve, thereby verifying that they have the capacity to remove the design heat load at the worst postulated conditions for each of their respective areas.

Table 14.1-98
S. I. Accumulator Discharge Valve Functional Test

1.0 Objective

1.1 To demonstrate that each accumulator isolation valve (8808A, B, & C) will open under the maximum differential pressure conditions of zero Reactor Coolant System pressure and maximum expected accumulator precharge pressure upon receipt of a safety injection signal by each valve.

1.2 To verify the actual accumulator level matches the indicated accumulator level at the minimum technical specification level.

1.3 To demonstrate that each accumulator isolation valve (8808A, B, & C) will open on an increasing Reactor Coolant System pressure signal.

2.0 Prerequisites

2.1 The Reactor Coolant System is depressurized and adequately vented.

2.2 A source of nitrogen is available to pressurize the accumulators.

2.3 A tygon hose is connected to the accumulator for level indication.

3.0 Test Methods

3.1 Close valves 8808A, B, & C and then fill each accumulator with Grade A water. As each accumulator fills, compare the accumulator actual level with the indicated level when actual level reaches the minimum technical specification level. Isolate the tygon hose before pressurizing the accumulators.

3.2 Pressurize each accumulator to the maximum expected accumulator precharge pressure.

3.3 Initiate a safety injection signal to the control circuitry of each valve.

3.4 Increase the Reactor Coolant System pressure signal to each valve.

4.0 Acceptance Criteria

4.1 That each accumulator isolation valve will open in less than the maximum allowable stroke time under maximum differential pressure conditions.

4.2 That indicated accumulator level is within tolerance at the actual minimum technical specification level in the accumulator.

Table 14.1-98 (continued)
S. I. Accumulator Discharge Valve Functional Test

4.3 That each accumulator isolation valve will open when required on an increasing RCS pressure signal.

Table 14.1-99
ECCS Check Valve Leak Testing System Operational Test

1.0 Objective

1.1 Demonstrate proper functioning of the ECCS Check Valve Leak Testing System and perform a backleakage test on each check valve monitored by the ECCS Check Valve Leak Testing System.

2.0 Prerequisites

2.1 Instrumentation in the ECCS Check Valve Leak Testing System has been calibrated.

2.2 Hot functional testing is in progress.

3.0 Test Methods

3.1 Perform a leak test on each check valve in the ECCS normally checked using the ECCS Check Valve Leak Testing System.

4.0 Acceptance Criteria

4.1 System operates satisfactorily during leak check tests.

Table 14.1-100
S. I. Accumulator Check Valve Hot Operational Test

1.0 Objective

1.1 To demonstrate that the accumulator discharge check valves (8948A, B & C and 8956A, B & C) will function under normal operating temperature and pressure conditions.

2.0 Prerequisites

2.1 Hot functional testing is in progress.

3.0 Test Methods

3.1 Inject or pump water through each check valve during hot functional testing.

4.0 Acceptance Criteria

4.1 That each check valve passes water into the RCS during hot functional testing.

Table 14.1-101
Instrument Air System

1.0 Objective

1.1 Demonstrate the ability of the Instrument Air System to supply instrument and service air.

2.0 Prerequisites

2.1 Instrument Air System installation and component checks are completed as necessary.

2.2 System has been blown down and cleanliness requirements met.

3.0 Test Methods

3.1 Verify operability of system alarms.

3.2 Verify operability of system interlocks.

3.3 Verify ability of air compressors to maintain system pressure.

3.4 Verify start of standby compressor on reduction of air pressure.

3.5 Verify isolation of service air on reduction of air pressure.

3.6 Verify backup supply to Reactor Building header on reduction of pressure.

3.7 Verify operability of dryers.

4.0 Acceptance Criteria

4.1 System interlocks and alarms function as designed.

4.2 Instrument Air System supplies air to Reactor Building instrument air services on loss of Reactor Building instrument air.

4.3 Service air is isolated on loss of instrument air.

4.4 Air compressors and dryers function as designed.

Table 14.1-102
Pressurizer Pressure and Level Control

1.0 Objective

1.1 To demonstrate the response, stability, and control characteristics of the Pressurizer Pressure and Level Control System.

1.2 To demonstrate the operation of the pressurizer power relief valves.

2.0 Prerequisites

2.1 The Reactor Coolant System is at hot no-load conditions as required by hot functional testing.

2.2 The pressurizer relief tank is operable.

2.3 Pressurizer pressure and level process instrumentation has been calibrated.

3.0 Test Methods

3.1 Place the pressurizer pressure control in manual and increase (decrease) the setpoint of the automatic controller 50 psig. Switch the pressurizer pressure control back to automatic control and observe the system response as pressure increases (decreases) to the new setpoint.

3.2 Using manual control, increase the system pressure to the pressurizer high pressure reactor trip value, then lower the pressure to the pressurizer low pressure reactor trip value, and verify the operation of the alarms and interlocks associated with the Pressurizer Pressure Control System.

3.3 Place the pressurizer level control in manual and decrease (increase) the pressurizer level 5 percent. Switch the pressurizer level control to automatic and observe the system response as pressurizer level increases (decreases) to the normal setpoint.

3.4 Using manual control, increase pressurizer level to the high level reactor trip, then lower the pressurizer level to the low level heater cutout and letdown isolation value, and verify the operation of alarms and interlocks associated with the Pressurizer Level Control System.

3.5 Verify the operation and response time of the pressurizer power relief valves by opening and closing the valves from the MCB and allowing a blowdown for 10 seconds or until 1900 psig is reached.

Table 14.1-102 (continued)
Pressurizer Pressure and Level Control

3.6 Verify the operation of the pressurizer backup heaters from the control room evacuation panel.

4.0 Acceptance Criteria

4.1 System operation is in accordance with design requirements.

14.2 Augmentation of Staff for Initial Test and Operation

During the initial test program at Virgil C. Summer Nuclear Station, SCE&G is using a special startup organization. In addition to the plant operating staff, the startup organization is augmented by representatives from Westinghouse, Gilbert, and other contractors and vendors as required. Competent technical personnel from other SCE&G departments may be called upon to assist and advise the startup organization as necessary.

14.2.1 Organizational Functions, Responsibilities, and Authorities

The functions, responsibilities, and authorities of organizations participating in the startup program are discussed in Sections 14.2.1.1 through 14.2.1.3.

14.2.1.1 Plant Operating Staff

Under the direction of the Manager, Virgil C. Summer Nuclear Station qualified plant personnel to assist in preparation of test procedures and performance of tests. Test procedure preparation includes writing and review of the procedure and approval of the procedure by the Manager, Virgil C. Summer Nuclear Station. Test performance includes checking of prerequisites, operation of equipment, and recording of data. All functions requiring an NRC license are performed by licensed personnel.

Prior to receiving nuclear fuel at the plant site, SCE&G will establish industrial security and health physics programs under the control and administration of the Manager, Virgil C. Summer Nuclear Station. Also, under the direction of the Manager, Virgil C. Summer Nuclear Station, plant operating and maintenance personnel will assume responsibility for operation and maintenance of tested and accepted systems.

14.2.1.2 Westinghouse Electric Corporation

Westinghouse provides onsite technical assistance to SCE&G during the installation, startup, testing, and initial operation of each nuclear steam supply system (NSSS). In this manner, Westinghouse aids the owner and assures that each NSSS is installed, started, tested, and operated in conformance with design intent. Westinghouse onsite personnel provide direct assistance and act as technical liaison with Westinghouse headquarters to resolve problems within the Westinghouse scope. Personnel assignments are made as required by site activities.

14.2.1.3 Gilbert Associates, Inc.

Gilbert provides experienced personnel to assist in the startup activities. Liaison is maintained between the Gilbert Reading, PA, offices and field personnel to facilitate resolution of problems related to test specifications and system operation for which Gilbert has design responsibility.

14.2.2 Interrelationships and Interfaces

Onsite representatives of Westinghouse, Gilbert, and other contractors and vendors are responsible to the Manager, Virgil C. Summer Nuclear Station. If any of the above personnel participate in the performance of a test, they will be responsible to the person above them in the startup organization, that is a Test Supervisor or the Startup Supervisor. For activities related to construction, they will be responsible to the SCE&G Manager of Construction.

14.2.3 Personnel Functions, Responsibilities, and Authorities

The functions, responsibilities, and authorities of major augmenting personnel are as discussed in Sections 14.2.3.1 through 14.2.3.3.

14.2.3.1 Plant Staff

Members of the Virgil C. Summer Nuclear Station operating, maintenance, and technical groups who meet the requirements for Test Supervisor or test personnel are utilized in these capacities. Their functions, responsibilities, and authorities are described in Section 14.1.1.4.

14.2.3.2 Westinghouse Electric Corporation

Westinghouse startup specialists assigned to the Virgil C. Summer Nuclear Station act as technical advisors to the Plant Manager and assist him in NSSS startup activities. Their function and responsibilities include, but are not limited to, assisting the startup group in procurement of procedures, system checkout, functional testing, and coordination of the test program. Resolution of technical problems within the Westinghouse scope of supply shall be resolved by the startup specialists by direct liaison with Westinghouse headquarters.

14.2.3.3 Gilbert Associates, Inc.

Gilbert personnel assigned to the Virgil C. Summer Nuclear Station site assist in startup activities. Liaison is maintained between the site personnel and the Gilbert home office to facilitate resolution of problems and questions which may arise during startup and testing and are related to Gilbert design activities. Gilbert site personnel may assist SCE&G in actual performance of startup and testing of the plant.

14.2.4 Personnel Qualifications

Personnel who manage, supervise, or perform preoperational or startup tests shall satisfy the qualifications stated in Section 14.1.1.4.

V.C. Summer Nuclear Station
Safety Analysis Report

Accident Analysis

Chapter 15

Revision 26-- 06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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15.0 ACCIDENT ANALYSIS

Since 1970 Westinghouse has been using the ANS classification of plant conditions which divides plant conditions into four categories in accordance with anticipated frequency of occurrence and potential radiological consequences to the public. The four categories are as follows:

1. Condition I:Normal Operation and Operational Transients
2. Condition II:Faults of Moderate Frequency
3. Condition III:Infrequent Faults
4. Condition IV:Limiting Fault

The basic principle applied in relating design requirements to each of the conditions is that the most probable occurrences should yield the least radiological risk to the public and those extreme situations having the potential for the greatest risk to the public shall be those least likely to occur. Where applicable, Reactor Trip System and Engineering Safety Features functioning is assumed to the extent allowed by considerations such as the single failure criterion, in fulfilling this principle.

In the evaluation of the radiological consequences associated with initiation of a spectrum of accident conditions, numerous assumptions must be postulated. In many instances, these assumptions are a product of extremely conservative judgments. This is due to the fact that many physical phenomena, in particular fission product transport under accident conditions, are not understood to the extent that accurate predictions can be made. Therefore, the set of assumptions postulated would predominantly determine the accident classification.

The specific accident sequences analyzed in this chapter include those required by Revision 1 of Regulatory Guide 1.70, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, and others considered significant for V. C. Summer. Because the V. C. Summer design differs from other plants, some of the accidents identified in Table 15-1 of Regulatory Guide 1.70, Revision 1, are not applicable to this plant. Some comments on these items are as follows:

(Item 10) - There are no pressure regulators or regulating instruments in the Westinghouse PWR design whose failure could cause heat removal greater than heat generation.

(Item 11) - Reactor coolant flow controller is not a feature of the Westinghouse PWR designs. Treatment of the performance of the reactivity controller in a number of accident conditions is offered in this chapter.

(Item 12) - The analysis of specific effects of internal and external events such as major and minor fires, floods, storms, or earthquakes are generally discussed in Chapter 3. Refer to Section 3.1.2.1 for guidance on which FSAR sections specifically address GDCs 2, 3, and 4.

(Item 22) - No instrument lines from the Reactor Coolant System boundary in the Westinghouse PWR design penetrate the Reactor Building (1).

(Item 26) - Control room habitability is discussed. Chapter 7 contains an analysis showing that the plant can be brought to, and maintained in, the hot shutdown condition from outside the control room.

(Item 27) - Overpressurization of the Residual Heat Removal System is not considered credible due to the isolation valve interlocks described in Section 7.6.

(Item 28) - Loss of condenser vacuum is covered by the analyses of <hot spots>Section 15.2.7, Loss of External Electric Load and/or Turbine Trip.

(Item 29) - Turbine trip is covered by the analyses of <hot spots>Section 15.2.7, Loss of External Electric Load and/or Turbine Trip.

(Item 30) - Loss of the Service Water System is discussed in Section 9.2.

(Item 31) - Loss of one D-C system is discussed in Chapter 8.

(Item 33) - Turbine trip with failure of generator breakers to open is discussed in Chapter 10. The effect of turbine trip on the Reactor Coolant System are presented in <hot spots>Section 15.2.7.

(Item 34) - Loss of the Instrument Air System is discussed in Chapter 9.

(Item 35) - Loss of the turbine gland seal is of no significance for PWRs.

(1) For the definition of the Reactor Coolant System boundary, refer to ANSI-N18.2, "Nuclear Safety Criteria for the Design of Stationary PWR Plants," Section 5, 1973.

The Nuclear Steam Supply System (NSSS) is designed to afford proper protection against the possible effects of natural phenomena, postulated environmental conditions, and dynamic effects. In addition, the design incorporates features which minimize the probability and effects of fires and explosions. Chapter 17 discusses the Quality Assurance Program which has been implemented to assure that the NSSS will satisfactorily perform its assigned safety functions. The incorporation of these features in the NSSS, coupled with the reliability of the design, ensures that the normally operating systems and components listed in <hot spots>Table 15.0-1 will be available for mitigation of the events discussed in Chapter 15. In determining which systems are necessary to mitigate the effects of these postulated events, Westinghouse utilizes the classification system of ANSI-N18.2, 1973. The design of "systems important to safety" (including protection systems) is consistent with IEEE Standard 379-1972 and Regulatory Guide 1.53 in the application of the single failure criterion.

TABLE 15.0-1
Equipment Available for Transient and Accident Conditions

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
1.	Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition	Power range high flux (low s.p.), manual	-	-	-
2.	Uncontrolled RCCA Bank Withdrawal at Power	Power range high flux, OTΔT, hi pressurizer pressure, manual	-	Pressurizer safety valves, steam generator safety valves	-
3.	RCCA Misalignment	Manual	-	-	-
4.	Uncontrolled Boron Dilution	Source range high flux, power range high flux, OTΔT, manual	Low insertion limit annunciators for boration	-	-
5.	Startup of an Inactive Reactor Coolant Loop	Power range high flux, manual	-	-	-
6.	Loss of External Electrical Load and/or Turbine Trip	High pressurizer pressure, OTΔT, manual	-	Pressurizer safety valves, steam generator safety valves	-
7.	Loss of Normal Feedwater	Steam generator lo-lo level, manual	Steam generator lo-lo level	-	One motor driven emergency feedwater pump

TABLE 15.0-1 (CONTINUED)
Equipment Available for Transient and Accident Conditions

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
8.	Loss of Offsite Power to the Station Auxiliaries	Same as 7	Same as 7	Same as 7	Same as 7
9.	Excess Heat Removal due to Feedwater System Malfunctions	Power range high flux, high steam generator level, OTΔT, OPΔT, manual	High Steam generator level, low pressurizer pressure	Feedwater isolation valves, turbine trip	-
10.	Excessive Load Increase Incident	Power range high flux, OTΔT, OPΔT, manual	-	Pressurizer safety valves, steam generator safety valves	-
11.	Accidental Depressurization of the RCS	Pressurizer low pressure, OTΔT, manual	-	-	-
12.	Major Rupture of Main Steam Line	SIS, manual	Low pressurizer pressure, low compensated steam line pressure, hi-1 containment pressure, manual	Feed line isolation valves, steam line isolation valves	Emergency feedwater system, SI equipment minus either one SI charging pump, or one diesel generator
13.	Complete Loss of Forced Reactor Coolant Flow	Low flow, underpower, underfrequency, manual	-	-	-

TABLE 15.0-1 (CONTINUED)
Equipment Available for Transient and Accident Conditions

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
14.	Rupture of a Control Rod Drive Mechanism Housing	Power range high flux, manual	-	-	-
15.	Single RCCA Withdrawal at Full Power	OTΔT, manual	-	-	-
16.	Major Rupture of a Main Feedwater Line	Low steam generator level plus steam/feed mismatch, SIS, manual	High containment pressure, high pressurizer pressure, steam generator low-low water level, low compensated steam line pressure	Steam line isolation valves, feed line isolation, pressurizer safety valves, steam generator safety valves	Emergency feedwater pumps
17.	Large Break LOCA	Reactor Trip system	Engineered safety features actuation system	Service water system, component cooling water system	Emergency core cooling system, containment heat removal system, emergency power system.
18.	Small Break LOCA	Reactor trip system	Engineered safety features actuation system	Service water system, component cooling water system, generator safety and/or relief valves	Emergency core cooling system, emergency feedwater system, containment heat removal system, emergency power system.

TABLE 15.0-1 (CONTINUED)
Equipment Available for Transient and Accident Conditions

	Incident	Reactor Trip Functions	ESF Actuation Functions	Other Equipment	ESF Equipment
19.	Steam Generator Tube Rupture	Reactor trip system	Engineered safety features actuation system	Service water system, component cooling water system, steam generator shell side fluid operating system, steam generator safety and/or relief valve, steam line isolation valves.	Emergency core cooling system, emergency feedwater system, emergency power system

15.1 CONDITION I - NORMAL OPERATION AND OPERATIONAL TRANSIENTS

Condition I occurrences are those which are expected frequently or regularly in the course of power operation, refueling, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Since Condition I occurrences occur frequently or regularly, they must be considered from the point of view of affecting the consequences of fault conditions (Conditions II, III, and IV). In this regard, analysis of each fault condition described is generally based on a conservative set of initial conditions corresponding to the most adverse set of conditions which can occur during Condition I operation.

A typical list of Condition I events follows:

1. Steady state and shutdown operations

   Mode 1 - Power operation (> 5% of rated thermal power)
   Mode 2 - Startup ($K_{eff} \geq 0.99$, ≤ 5% of rated thermal power)
   Mode 3 - Hot standby ($K_{eff} < 0.99$, $T_{avg} \geq 350°F$
   Mode 4 - Hot shutdown (subcritical, residual heat removal system in operation, $K_{eff} < 0.99$, $200°F < T_{avg} \leq 350°F$
   Mode 5 - Cold shutdown (subcritical, residual heat removal system in operation, $K_{eff} < 0.99$, $T_{avg} \leq 200°F$
   Mode 6 - Refueling ($K_{eff} \leq 0.95$, $T_{avg} \leq 140°F$)

2. Operation with permissible deviations

   Various deviations which may occur during continued operation as permitted by the plant Technical Specifications (Reference 1) must be considered in conjunction with other operational modes. These include:

   a. Operation with components or systems out of service
   b. Leakage from fuel with clad defects
   c. Leakage from fuel with clad defects
      (1) Fission products
      (2) Corrosion products
      (3) Tritium
   d. Operation with steam generator leaks up to the maximum allowed by the Technical Specifications
   e. Testing as allowed by the Technical Specifications

3. Operational transients

a. Plant heatup and cooldown (up to 100°F/hour for the Reactor Coolant System; 200°F/hour cooldown for the pressurizer, 100°F/hour heatup for the pressurizer)

b. Step load changes (up to ± 10 percent)

c. Ramp load changes (up to 5 percent/minute)

d. Load rejection up to and including design load rejection transient

15.1.1 Optimization of Control Systems

A control system setpoint study (Reference 2) has been performed in order to simulate performance of the reactor control and protection systems. Emphasis was placed on the development of a control system which will automatically maintain prescribed conditions in the plant, even under the most conservative set of reactivity parameters with respect to both system stability and transient performance.

For each mode of plant operation, a group of optimum controller setpoints is determined. In areas where the resultant setpoints are different, compromises based on the optimum overall performance are made and verified. A consistent set of control system parameters is derived satisfying plant operational requirements throughout the core life and for power levels between 15 and 100 percent.

The study comprised an analysis of the following control systems: rod cluster control assembly, steam dump, steam generator level, pressurizer pressure and pressurizer level.

Due to the revised parameters associated with replacement steam generators, the control system setpoint study described in (Reference 2) was reviewed for applicability. Several of the setpoints required revision in order to provide acceptable control system performance for the entire core life and over the entire design range of Reactor Coolant System operating conditions. The control systems requiring revision included the steam generator level control (due to the replacement steam generator), rod control, steam dump, and pressurizer level control systems (due to the revised range of the full power T_{avg}).

15.1.2 Initial Power Conditions Assumed In Accident Analyses

15.1.2.1 Power Rating

Table 15.1-1 lists the principal power rating values which are assumed in analyses performed in this section. This rating is the guaranteed Nuclear Steam Supply System (NSSS) thermal power output. This power output includes the thermal power generated by the reactor coolant pumps.

Where initial power operating conditions are assumed in accident analyses, the “guaranteed nuclear steam supply system thermal power output” (plus allowance for errors in steady-state power determination for some accidents) is assumed. The thermal power values used for each transient analyzed are given in Table 15.1-4.

15.1.2.2 Initial Conditions

For most accidents which are Departure from Nucleate Boiling limited, nominal values of initial conditions are assumed. The allowances on power, temperature, and pressure are determined on a statistical basis and are included in the limit Departure from Nucleate Boiling Ratio, as described in (Reference 3). This procedure is known as the “Revised Thermal Design Procedure” (RTDP) and these accidents utilize the WRB-1 and WRB-2 Departure from Nucleate Boiling correlations (References 4 and 5). RTDP allowances may be more restrictive than non-RTDP allowances. The initial conditions for other key parameters are selected in such a manner to maximize the impact on Departure from Nucleate Boiling Ratio. Minimum measured flow is used in all RTDP transients. For accident evaluations that are not Departure from Nucleate Boiling-limited, or for which the Revised Thermal Design Procedure is not employed, the initial conditions are obtained by adding maximum steady state errors to rated values. The following steadystate errors are considered.

(1) Core power	± 2.0% allowance calorimetric error
(2) Average RCS temperature	+ 6.3 / - 5.3 allowance for deadband and measurement error
(3) Pressurizer pressure	+54 / -65 psi allowance for steady state fluctuations and measurement error
(4) RCS Flow	2.1% allowance on flow measurement error

15.1.2.3 Power Distribution

The transient response of the reactor system is dependent on the initial power distribution. The nuclear design of the reactor core minimizes adverse power distribution through the placement of control rods and operating instructions. The power distribution may be characterized by the radial factor ($F_{\Delta H}$) and the total peaking factor F_Q. The peaking factor limits are given in the Technical Specifications and the Core Operating Limits Report (COLR).

For transients which may be DNB limited, the radial peaking factor is of importance. The radial peaking factor increases with decreasing power level due to rod insertion. This increase in $F_{\Delta H}$ is included in the core limits illustrated in (Figure 15.1-1). All transients that may be DNB limited are assumed to begin with a $F_{\Delta H}$ consistent with the initial power level defined in the Technical Specifications.

The axial power shape used in the DNB calculation is discussed in Section 4.4.3.

For transients that may be overpower-limited, the total peaking factor (F_Q) is of importance. The value of F_Q may increase with decreasing power level so that the full power hot spot heat flux is not exceeded, i.e., F_Q x Power = design hot spot heat flux. All transients that may be overpower-

limited are assumed to begin with a value of F_Q consistent with the initial power level as defined in the Technical Specifications.

The value of peak kW/ft can be directly related to fuel temperature using steady state fuel rod performance predictions. For transients that are slow with respect to the fuel rod thermal time constant (approximately 5 seconds), the fuel temperatures follow the steady state predictions. For transients that are fast with respect to the fuel rod thermal time constant (for example, rod ejection), a detailed heat transfer calculation is made.

15.1.3 Trip Points and Time Delays to Trip Assumed in Accident Analysis

A reactor trip signal acts to open 2 trip breakers, connected in series, feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the rod cluster control assemblies which then fall by gravity into the core. There are various instrumentation delays associated with each trip function, including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall. Limiting trip setpoints assumed in accident analyses and the time delay assumed for each trip function are given in Table (Figure 15.1-2).

Reference is made in that table to the overtemperature and overpower ΔT trip shown on (Figure 15.1-1). This figure presents the allowable reactor coolant loop average temperature and ΔT for the design flow and the NSSS Design Thermal Power distribution as a function of primary coolant pressure. The boundaries of operation defined by the Overpower ΔT trip and the Overtemperature ΔT trip are represented as “protection lines” on this diagram. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions, a trip would occur well within the area bounded by these lines. The utility of this diagram is in the fact that the limit imposed by any given DNBR can be represented as a line. The DNB lines represent the locus of conditions for which the DNBR equals the safety analysis limit values (1.43 and 1.42 for typical cell, and thimble cell respectively) for RTDP accidents. All points below and to the left of a DNB line for a given pressure have a DNBR greater than the limit values. The diagram shows that DNB is prevented for all cases if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR line at any point.

The area of permissible operation (power, pressure and temperature) is bounded by the combination of reactor trips: high neutron flux (fixed setpoint); high pressurizer pressure (fixed setpoint); low pressurizer pressure (fixed setpoint); Overpower and Overtemperature ΔT (variable setpoints).

The limit values, which were used as the DNBR limits for all accidents analyzed with the Revised Thermal Design Procedure, are conservative compared to the actual design DNBR values required to meet the DNB design basis.

The difference between the limiting trip point, assumed for the analysis, and the normal trip point represents an allowance for instrumentation channel error and setpoint error. During startup tests,

it is demonstrated that actual instrument errors and time delays are equal to or less than the assumed values.

15.1.4 Instrumentation Drift and Calorimetric Errors - Power Range Neutron Flux

The instrumentation drift and calorimetric uncertainties used in establishing the Technical Specification power range neutron flux (High) reactor trip setpoint are included in the report "Westinghouse Setpoint Methodology for Protection Systems -Virgil C. Summer", WCAP-11770 (Class 2) (Reference 19) and WCAP-11814 (Class 3) (Reference 20). These uncertainties are based on the installed instrumentation, on the calibration limits, and on the calibration methods for the power range neutron flux channels. The Technical Specification Power Range Neutron Flux (High) reactor trip setpoint preserves the analyzed limit used in the safety analysis.

The calorimetric uncertainty is the uncertainty determined for the core thermal power measurement as obtained from secondary side plant measurements. The power range neutron flux channels (sum of the top and bottom sections) are required by Technical Specifications to be calibrated (set equal) to the measured power on a daily basis. The calorimetric (power measurement) uncertainty is included in the report "Westinghouse Revised Thermal Design Procedure Instrument Uncertainty Methodology - Virgil C. Summer", WCAP-13812 (Class 2) (Reference 21) and WCAP-13813 (Class 3) (Reference 22).

A high accuracy calorimetric Reactor Coolant System flow measurement is performed at the beginning of each fuel cycle to calibrate (set equal to) the Reactor Coolant System elbow tap flow channels. This calibration or normalization allows a simplified periodic Reactor Coolant System flow measurement that is independent of feedwater venturi fouling. For the high accuracy Reactor Coolant System flow measurement, feedwater venturi fouling is accounted for by inspecting and cleaning (if necessary) each venturi at each refueling outage.

15.1.5 Rod Cluster Control Assembly Insertion Characteristics

The negative reactivity insertion following a reactor trip is a function of the acceleration of the rod cluster control assemblies and the variation in rod worth as a function of rod position. With respect to accident analyses, the critical parameter is the time of insertion up to the dashpot entry or approximately 85 percent of the rod cluster travel. For accident analyses the insertion time to dashpot entry is conservatively taken as 2.7 seconds. The rod cluster control assembly position versus time assumed in accident analyses is shown in Figure 15.1-2.

Figure 15.1-3 shows the fraction of total negative reactivity insertion versus rod position for a core where the axial distribution is skewed to the lower region of the core. This curve is used to compute the negative reactivity insertion versus time following a reactor trip which is input to all point kinetics core models used in transient analyses.

There is inherent conservatism in the use of this curve in that it is based on a skewed flux distribution which would exist relatively infrequently. For cases other than those associated with xenon oscillations, significant negative reactivity would have been inserted due to the more favorable axial distribution existing prior to trip.

The normalized rod cluster control assembly negative reactivity insertion versus time is shown in Figure 15.1-4. The curve shown in this figure was obtained from Figure 15.1-2 and Figure 15.1-3. A total negative reactivity insertion following a trip of 4.8 percent ΔK is assumed in the transient analyses except where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available as shown in Tables 4.3-2 and 4.3-3.

The normalized rod cluster control assembly negative reactivity insertion versus time curve for an axial power distribution skewed to the bottom (Figure 15.1-4) is used in those transient analyses for which a point kinetics core model is used. Where special analyses require use of three dimensional or axial one dimensional core models, the negative reactivity insertion resulting from the reactor trip is calculated directly by the reactor kinetics code and is not separable from the other reactivity feedback effects. In this case, the rod cluster control assembly position versus time of Figure 15.1-2 is used as code input.

15.1.6 Reactivity Coefficients

The transient response of the reactor system is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient. These reactivity coefficients and their values are discussed in detail in Chapter 4.

In the analysis of certain events, conservatism requires the use of large reactivity coefficient values whereas in the analysis of other events, conservatism requires the use of small reactivity coefficient values. Some analyses such as loss of reactor coolant from cracks or ruptures in the reactor coolant system do not depend on reactivity feedback effects. The values used are given in Table 15.1-4. Reference is made in that table to Figure 15.1-5 which shows the upper and lower bound Doppler power coefficients as a function of power, used in the transient analysis. The justification for use of conservatively large versus small reactivity coefficient values are treated on an event by event basis.

15.1.7 Fission Product Inventories

15.1.7.1 Radioactivity in the Core

The fission product inventories for all isotopes, which are important from a health hazards standpoint, were calculated using the ORIGEN code (Reference 17) and are given in Table 15.1-5. This code uses a data base of fission product yields, cross sections, and decay constants taken from the ENDFB IV/V fission product library. The calculation of the core iodine fission product inventory is consistent with TID 14844 (Reference 18). The ORIGEN code takes into account fuel burnup as well as fission product buildup and decay. Continuous operation at full power is assumed during the fuel residence time to provide an upper limit estimate of the fission product inventory. The isotopes included in Table 15.1-5 are the isotopes controlling from considerations of inhalation dose (iodines) and from direct dose due to immersion (noble gases).

The isotopic yields used in the calculations are from the data of APED 5398 (Reference 23), utilizing the isotopic yield data for thermal fissioning of U 235 as the sole fissioning source. The

change in fission product inventory resulting from the fissioning of other fissionable atoms has been reviewed. The results of this review indicated that inclusion of all fission source data would result in small (less than 10 percent) change in the isotopic inventories due to the overall conservatism.

15.1.7.2 Radioactivity in the Fuel Pellet Clad Gap

This section was deleted by Amendment 96-02.

15.1.8 Residual Decay Heat

Residual heat in a subcritical core consists of:

1. Fission product decay energy,
2. Decay of neutron capture products, and
3. Residual fissions due to the effect of delayed neutrons.

These constituents are discussed separately in the following paragraphs.

15.1.8.1 Fission Product Decay Energy

Transient-specific decay heat curves are calculated in the LOCA analyses based on the 1979 ANS decay heat standard (Reference 11) as described in Section 9 of Reference 6. For the non-LOCA analyses the 1979 ANS decay heat curve is used (Reference 15). Figure 15.1-7 presents this curve as a function of time after shutdown for non-LOCA analyses.

15.1.8.2 Decay of U-238 Capture Products

Betas and gammas from the decay of U-239 (23.5 minute half life) and Np-239 (2.35 day half life) contribute significantly to the heat generation after shutdown. The cross section for production of these isotopes and their decay schemes are relatively well known. For long irradiation times their contribution can be written as:

$$\frac{P_1}{P_0} = \frac{E_{\gamma 1} + E_{\beta 1}}{200\text{Mev}} c(1+\alpha) e^{-\lambda_1 t} \text{ watts/watt}$$

$$\frac{P_2}{P_0} = \frac{E_{\gamma 2} + E_{\beta 2}}{200\text{Mev}} c(1+\alpha) \left[\frac{\lambda_2}{\lambda_1 - \lambda_2} \left(e^{-\lambda_2 t} - e^{-\lambda_1 t} \right) + e^{-\lambda_2 t} \right] \text{watts/watt}$$

Where:

P_1/P_o = the energy from U-239 decay

P_2/P_o = the energy from Np-239 decay

t = the time after shutdown (seconds)

c (1+α) = the ratio of U-238 captures to total fissions = 0.6 (1+0.2)

$\lambda 1$ = the decay constant of U-239 = 4.91×10^{-4} seconds^{-1}

$\lambda 2$ = the decay constant of Np-239 = 3.41×10^{-6} seconds^{-1}

$E\gamma_1$ = total γ-ray energy from U-239 decay = 0.06 Mev

$E\gamma_2$ = total γ-ray energy from Np-239 decay = 0.30 Mev

$E_{\beta 1}$ = total β-ray energy from U-239 decay = 1/3 x 1.18 Mev

$E_{\beta 2}$ = total β-ray energy from NP-239 decay = 1/3 x 0.43 Mev

(Two-thirds of the potential β-energy is assumed to escape by the accompanying neutrinos).

For the LOCA analyses, the heat from the radioactive decay of U-239 and Np-239 is calculated as described in Section 9 of Reference 6. The decay of other actinides is neglected, as justified in Section 9.9.1 of Reference 6. The effect of neutron capture in fission products is included, as discussed in Reference 11. For the non-LOCA analysis, the decay of U-238 capture products is included as an integral part of the 1979 decay heat curve presented as Figure 15.1-7.

15.1.8.3 Residual Fissions

The time dependence of residual fission power after shutdown depends on core properties throughout a transient under consideration. Core average conditions are more conservative for the calculation of reactivity and power level than actual local conditions as they would exist in hot areas of the core. Thus, unless otherwise stated in the text, static power shapes have been assumed in the analyses and these are factored by the time behavior of core average fission power calculated by a point model kinetics calculation with 6 delayed neutron groups.

For the LOCA analyses, the residual fission energy is calculated using a point kinetics model as described in Section 9 of Reference 6. Fission product decay heat is calculated using the 1979 ANS decay heat standard (Reference 11). Implementation of the model includes consideration of the spatial distribution, and uncertainty of the decay heat itself.

15.1.8.4 Distribution of Decay Heat Following Loss of Coolant Accident

For the LOCA analyses, the energy deposition modeling is performed as described in Section 9 of Reference 6. The LOCA analyses model the energy sources within the reactor fuel in three distinct categories. These categories are prompt fission, fission product decay, and actinide nuclide decay.

The energy from fission events appears in varying forms with large differences in spatial transport characteristics. The degree to which a radiation source will propagate through a medium is strongly related to whether the radiation is expressed as a charged particle (e.g., fission fragment or beta particle), an uncharged particle (e.g., neutron), or a photon, (e.g., gamma-ray). Charged particles emitted from within a nuclear fuel material are, from a practical viewpoint, unable to penetrate the confines of the fuel rod and, therefore, deposit essentially all of their energy within the fuel rod as heat. The vast majority of the total energy released due to a fission event is expressed as the kinetic energy of the fission products. The fission fragments are emitted as highly charged particles, essentially instantaneously after the fission event, and are deposited almost exclusively within the fuel pin in which they are generated. The beta particle energy from both the decay of fission fragments and the transmutation of the actinide activation products are also charged particles which are, like the fission fragments, deposited almost exclusively within the fuel pin in which they are generated. The beta particle energy is released as a result of the radioactive decay process, which is not directly related to the fission rate; rather it is related to the concentration of the various radio-nuclides which compose the source. The LOCA analyses explicitly model the spatial distribution and temporal relationships which describe all heat sources and deposits the energy from non-penetrating radiation sources. The fraction of the total heat source which is deposited in this manner is independent of coolant conditions.

The balance of the energy released as a result of the fission event is expressed as uncharged particles, i.e., neutrons and gamma photon energy. These penetrating radiation sources, due to their lack of charged particles, easily escape the confines of the fuel rod. The LOCA analyses model the spatial deposition of spatially varying penetrating radiation sources using a generalized energy deposition model (GEDM).

15.1.9 Computer Codes Utilized

Summaries of some of the principal computer codes used in transient analyses are given below. Other codes, in particular, very specialized codes in which the modeling has been developed to simulate one given accident, and which consequently have a direct bearing on the analysis of the accident itself, are summarized in their respective accident analyses sections. The codes used in the analyses of each transient have been listed in Table 15.1-4.

15.1.9.1 FACTRAN

FACTRAN calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod (see Figure 15.1-8) and the transient heat flux at the surface of the clad using as input the nuclear power and the time dependent coolant parameters (pressure, flow, temperature, and density). The code uses a fuel model which exhibits the following features simultaneously:

1. A sufficiently large number of finite difference radial space increments to handle fast transients such as rod ejection accidents.
2. Material properties which are functions of temperature and a sophisticated fuel to clad gap heat transfer calculation.

3. The necessary calculations to handle post DNB transients: film boiling heat transfer correlations, Zircaloy water reaction, and partial melting of the materials.

The gap heat transfer coefficient is calculated according to an elastic pellet model. The thermal expansion of the pellet is calculated as the sum of the radial (one dimensional) expansions of the rings. Each ring is assumed to expand freely. The clad diameter is calculated based on thermal expansion and internal and external pressures.

If the outside radius of the expanded pellet is smaller than the inside radius of the expanded clad, there is no fuel clad contact and the gap conductance is calculated on the basis of the thermal conductivity of the gas contained in the gap. If the pellet outside radius so calculated is larger than the clad inside radius (negative gap), the pellet and the clad are pictured as exerting upon each other a pressure sufficient to reduce the gap to zero by elastic deformation of both. This contact pressure determines the heat transfer coefficient.

FACTRAN is further discussed in Reference 12

15.1.9.2 LOFTRAN

The LOFTRAN program is used for studies of transient response of a pressurized water reactor system to specified perturbations in process parameters. LOFTRAN simulates a multiloop system by modeling the reactor core and vessel, hot and cold leg piping, steam generator (tube and shell sides), reactor coolant pumps, and the pressurizer with up to 4 reactor coolant loops. The pressurizer heaters, spray, relief, and safety valves are also considered in the program. Point model neutron kinetics, and reactivity effects of the moderator, fuel, boron and rods are included. The secondary side of the steam generator utilizes a homogeneous, saturated mixture for the thermal transients and a water level correlation for indication and control. The reactor protection system is simulated to include reactor trips on neutron flux, overpower and overtemperature reactor coolant delta T, high and low pressure, low flow, and high pressurizer level. Control systems are also simulated including rod control, steam dump, feedwater control and pressurizer pressure control. The Safety Injection System, including the accumulators, is also modeled.

LOFTRAN is a versatile program which is suited to both accident evaluation and control studies as well as parameter sizing.

LOFTRAN also has the capability of calculating the transient value of DNBR based on the input from the core limits illustrated on Figure 15.1-7. The core limits represent the minimum value of DNBR as calculated for typical or thimble cell.

LOFTRAN is further discussed in Reference 13.

15.1.9.3 LEOPARD

The LEOPARD computer program determines fast and thermal neutron spectra, using only basic geometry and temperature data. The code optionally computes fuel depletion effects for a dimensionless reactor and recomputes the spectra before each discrete burnup step.

LEOPARD is further described in Reference 14.

15.1.9.4 TURTLE

TURTLE is a two group, two dimensional neutron diffusion code featuring a direct treatment of the nonlinear effects of xenon, enthalpy, and Doppler. Fuel depletion is allowed.

TURTLE was written for the study of azimuthal xenon oscillations, but the code is useful for general analysis. The input is simple, fuel management is handled directly, and a boron criticality search is allowed.

TURTLE is further described in Reference 15.

15.1.9.5 TWINKLE

The TWINKLE program is a multi dimensional spatial neutron kinetics code, which was patterned after steady state codes presently used for reactor core design. The code uses an implicit finite difference method to solve the two group transient neutron diffusion equations in 1, 2, and 3 dimensions. The code uses 6 delayed neutron groups and contains a detailed multi region fuel clad coolant heat transfer model for calculating point wise Doppler and moderator feedback effects. The code handles up to 8000 spatial points, and performs its own steady state initialization. Aside from basic cross section data and thermal hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. Various edits are provided, e.g., channel wise power, axial offset, enthalpy, volumetric surge, point wise power, and fuel temperatures.

The TWINKLE Code is used to predict the kinetic behavior of a reactor for transients which cause a major perturbation in the spatial neutron flux distribution.

TWINKLE is further described in Reference 16.

15.1.9.6 THINC

The THINC Code is described in Section 4.4.3.

15.1.9.7 WCOBRA/TRAC-TF2

WCOBRA/TRAC-TF2 is the principal thermal-hydraulics code for FSLOCA and is described in Reference 6.

15.1.10 References

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Table 15.1-1
Nuclear Steam Supply System Power Ratings

Licensed Core Thermal Power	2900 MWt
Analyzed Core Thermal Power (unless otherwise noted)	2900 MWt
Thermal power generated by the reactor coolant pumps	12 MWt
Nuclear steam supply system thermal power output	2912 MWt

Table 15.1-2
Trip Points and the Time Delays to Trip Assumed in Accident Analyses

Trip Function	Limiting Trip Point Assumed in Analysis	Time Delay (Seconds)
Power Range High Neutron Flux, High Setting	118%	0.5
Power Range High Neutron Flux, Low Setting	35%	0.5
Overtemperature ΔT	Variable see Figure 15.1-1.	8.5(1)
Overpower ΔT	Variable see Figure 15.1-1.	8.5(1)
High pressurizer pressure	2455 psig	2.0
Low pressurizer pressure	1775 psig	2.0
Low reactor coolant flow (from loop flow detectors)	87% loop flow	1.0
Undervoltage Trip	(2)	1.5
Underfrequency Trip	57 Hz	0.6
Turbine Trip	Not applicable	1.0
Low-low steam generator level	16.7% of narrow range span	2.0
High-high steam generator level trip of the feedwater pumps and closure of the feedwater system valves *, and turbine trip	100% of narrow range span	2.0 * 13.0 (for Feedwater isolation)

(1) Total time delay (including RTD time response, and trip circuit channel electronics delay) from the time the temperature difference in coolant loops exceeds the trip setpoint until the rods are free to fall.
(2) A specific undervoltage setpoint was not assumed in the safety analysis.

Table 15.1-4
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Utilized	Assumed Reactivity Coefficients: MTC[a] pcm/°F[d]	Assumed Reactivity Coefficients: MDC[a] Δk/gm/cc	Assumed Reactivity Coefficients: Doppler [b]	Initial NSSS Thermal Power Output Assumed, [c] MWt
CONDITION II					
Uncontrolled RCCA Bank Withdrawal from a subcritical Condition	TWINKLE FACTRAN THINC	+7	-	955 pcm	0
Uncontrolled RCCA bank Withdrawal at power	LOFTRAN	+7	0.50	Lower and upper	2915
RCCA Misoperation	LOFTRAN THINC	-	-	-	2912
Uncontrolled Boron Dilution					0 and 2912
Partial Loss of Forced Reactor Coolant Flow	LOFTRAN FACTRAN THINC	0	-	Upper	2915
Startup of an Inactive Reactor Coolant Loop	LOFTRAN FACTRAN THINC	-	0.50	Lower	1805

Table 15.1-4 (continued)
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Utilized	Assumed Reactivity Coefficients MTC[a] pcm/°F[d]	Assumed Reactivity Coefficients MDC[a] Δk/gm/cc	Assumed Reactivity Coefficients Doppler [b]	Initial NSSS Thermal Power Output Assumed, [c] MWt
CONDITION II, Continued					
Loss of External Electrical Load and/or Turbine Trip	LOFTRAN	+7	0.50	Lower and Upper	2912
Loss of Normal Feedwater	LOFTRAN	0	-	Upper	2915
Loss of Offsite Power to the Station Auxiliaries	LOFTRAN	0	-	Upper	2915
Excessive Heat Removal due to Feedwater System Malfunctions	LOFTRAN THINC	-	0.50	Lower	0 and 2912
Excessive Load Increase	LOFTRAN	-	0 and 0.50	Lower and Upper	2912
Accidental Depressurization of the Reactor Coolant System	LOFTRAN	+7	-	Lower	2915
Accidental Depressurization of the Main Steam System	LOFTRAN	-	Function of the moderator density. See Sec. 15.2.13 (Fig. 15.2-46)	See Fig. 15.4-75	0 (subcritical)

Table 15.1-4 (continued)
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Utilized	Assumed Reactivity Coefficients MTC[a] pcm/°F[d]	MDC[a] Δk/gm/cc	Doppler [b]	Initial NSSS Thermal Power Output Assumed, [c] MWt
CONDITION II, Continued					
Spurious Operation of the SIS at power	LOFTRAN	+7	0.50	Lower and Upper	2915
CONDITION III					
Complete Loss of Forced Reactor Coolant Flow	LOFTRAN FACTRAN THINC	0	-	Upper	2915
Inadvertent loading of a fuel assembly into an improper position	LEOPARD, TURTLE	-	-	-	2915[e]
Single RCCA withdrawal at full power	TURTLE, THINC, LEOPARD	-	-	-	2915[e]
Loss of reactor coolant from small ruptured pipes or from cracks in large pipe which actuate emergency core cooling	WCOBRA/ TRAC-TF2	Function of moderator density	-	Function of fuel temp	2900[e]

Table 15.1-4 (continued)
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Utilized	Assumed Reactivity Coefficients: MTC[a] pcm/°F[d]	Assumed Reactivity Coefficients: MDC[a] Δk/gm/cc	Assumed Reactivity Coefficients: Doppler [b]	Initial NSSS Thermal Power Output Assumed, [c] MWt
CONDITION IV					
Major rupture of pipes containing reactor coolant up to and including double-ended rupture of the largest pipe in the Reactor Coolant System (loss-of-coolant accident)	WCOBRA/TRAC-TF2	Function of moderator density	-	Function of fuel temp	2900[e]
Major Secondary System Pipe Ruptures up to and including Double-Ended-Rupture (rupture of a steam pipe)	LOFTRAN THINC	-	Function of the moderator density see Section15.2.13 (Fig. 15.2-46)	See Fig. 15.4-75	0 (subcritical)
Major Secondary System Pipe Ruptures up to and including Double-Ended-Rupture (rupture of a feedline)	LOFTRAN	-	0.50	Upper	2915
Single Reactor Coolant Pump Locked Rotor	LOFTRAN FACTRAN THINC	0	-	Upper	2915

Table 15.1-4 (continued)
Summary of Initial Conditions and Computer Codes Used

Event	Computer Codes Utilized	Assumed Reactivity Coefficients: MTC[a] pcm/°F[d]	Assumed Reactivity Coefficients: MDC[a] Δk/gm/cc	Assumed Reactivity Coefficients: Doppler [b]	Initial NSSS Thermal Power Output Assumed, [c] MWt
CONDITION IV, Continued					
Rupture of a Control Rod Mechanism Housing (RCCA Ejection)	TWINKLE FACTRAN	+7 (BOL-HZP) 0 (BOL-HFP) -16.8 (EOL-HZP) -22.9 (EOL-HFP)	-	955 pcm (BOL) 893 pcm (EOL)	0 and 2900 [e]

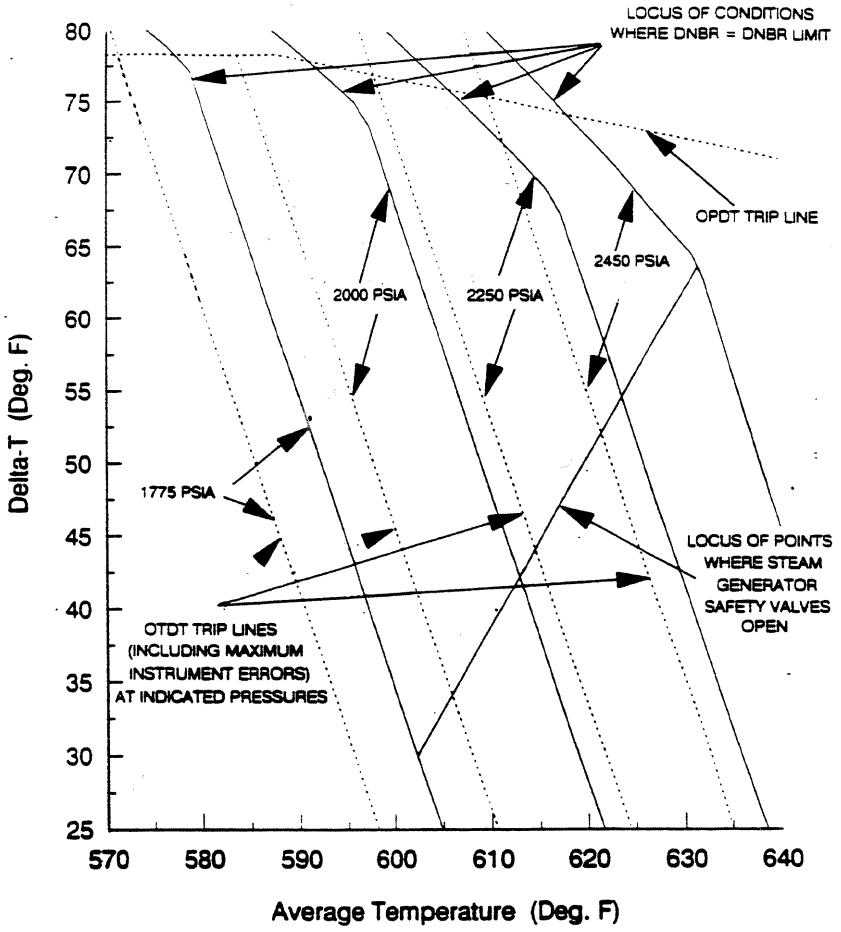
a. Only one is used in analysis, i.e., either moderator temperature or moderator density coefficient.
b. Reference Figure 15.1-5.
c. Appropriate calorimetric error considered where applicable.
d. pcm means percent mille.
e. Core power.

Table 15.1-5
Core Activities (Iodine and Noble Gases)
Based on Full Power Operation for 480 Days

Isotope	Curies in Core (x 10^7)	Curies in Core (x 10^6)
I-131	8.2	8.2
I-132	12.0	12.0
I-133	16.8	17.0
I-134	18.0	18.0
I-135	15.4	15.0
Xe-131m	0.056	0.056
Xe-133	17.0	17.0
Xe-133m	2.4	2.4
Xe-135	3.7	3.7
Xe-135m	3.4	3.4
Xe-138	13.0	13.0
Kr-83m	0.95	0.95
Kr-85	0.083	0.25
Kr-85m	2.1	2.1
Kr-87	3.8	3.8
Kr-88	5.4	5.4
Kr-89	6.6	6.6

Figure 15.1-1

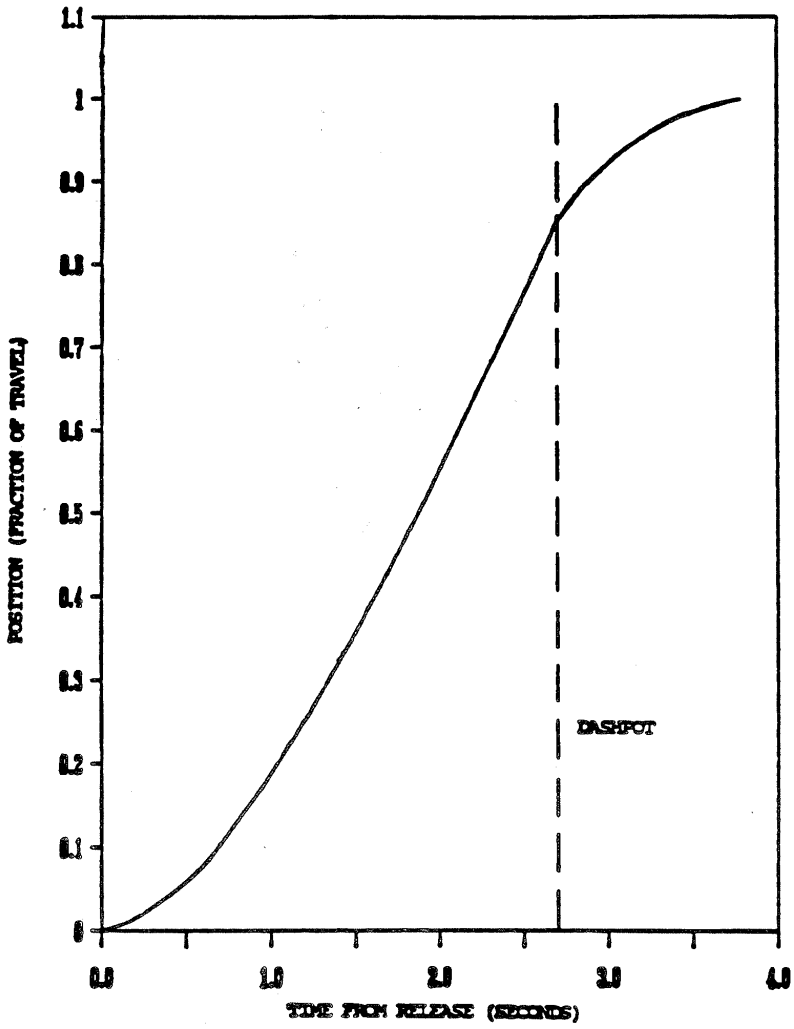
OVERPOWER DELTA-T PROTECTION



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Overtemperature and Overpower Delta-T Protection Figure 15.1-1

AMENDMENT 96-02
July 1996

Figure 15.1-2
ROD POSITION VS.
TIME ON REACTOR TRIP



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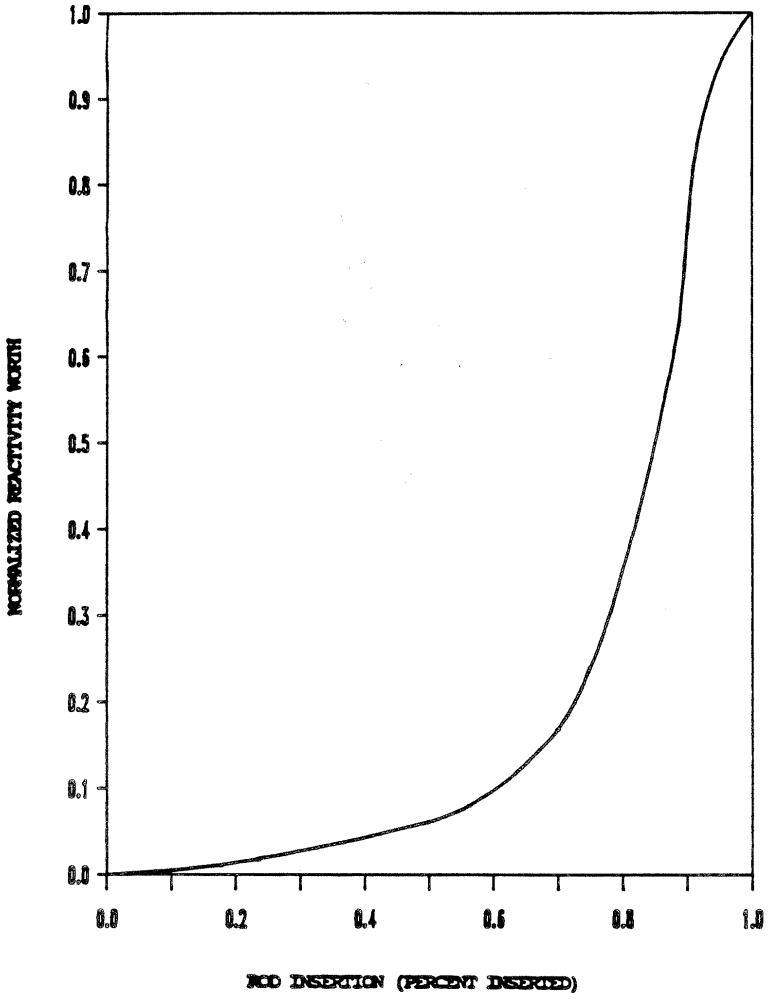
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Rod Position vs. Time On Reactor Trip Figure 15.1-2

Figure 15.1-3
NORMALIZED KRCCA REACTIVITY WORTH VS. PERCENT INSERTION



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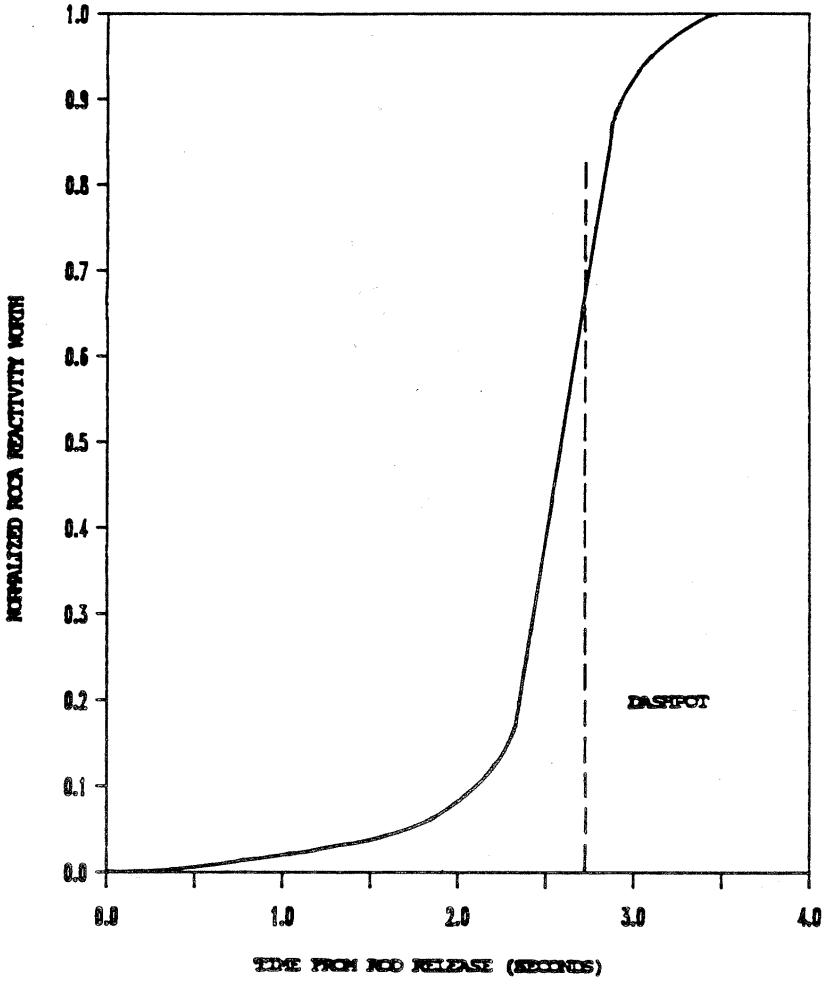
Normalized RCCA Reactivity
Worth vs. Percent Insertion

Figure 15.1-3

Figure 15.1-4
NORMALIZED RCCA BANK WORTH VS. TIME AFTER TRIP



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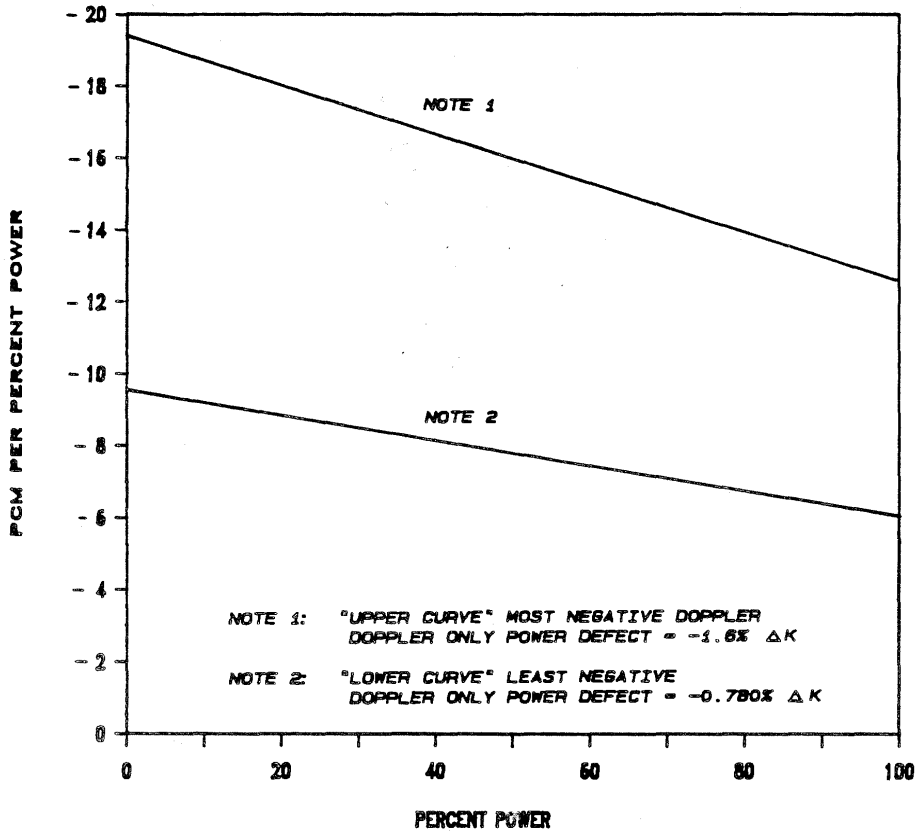
Normalized RCCA Bank Worth vs. Time After Trip Figure 15.1-4

Figure 15.1-5
DOPPLER POWER COEFFICIENT
USED IN ACCIDENT ANALYSIS



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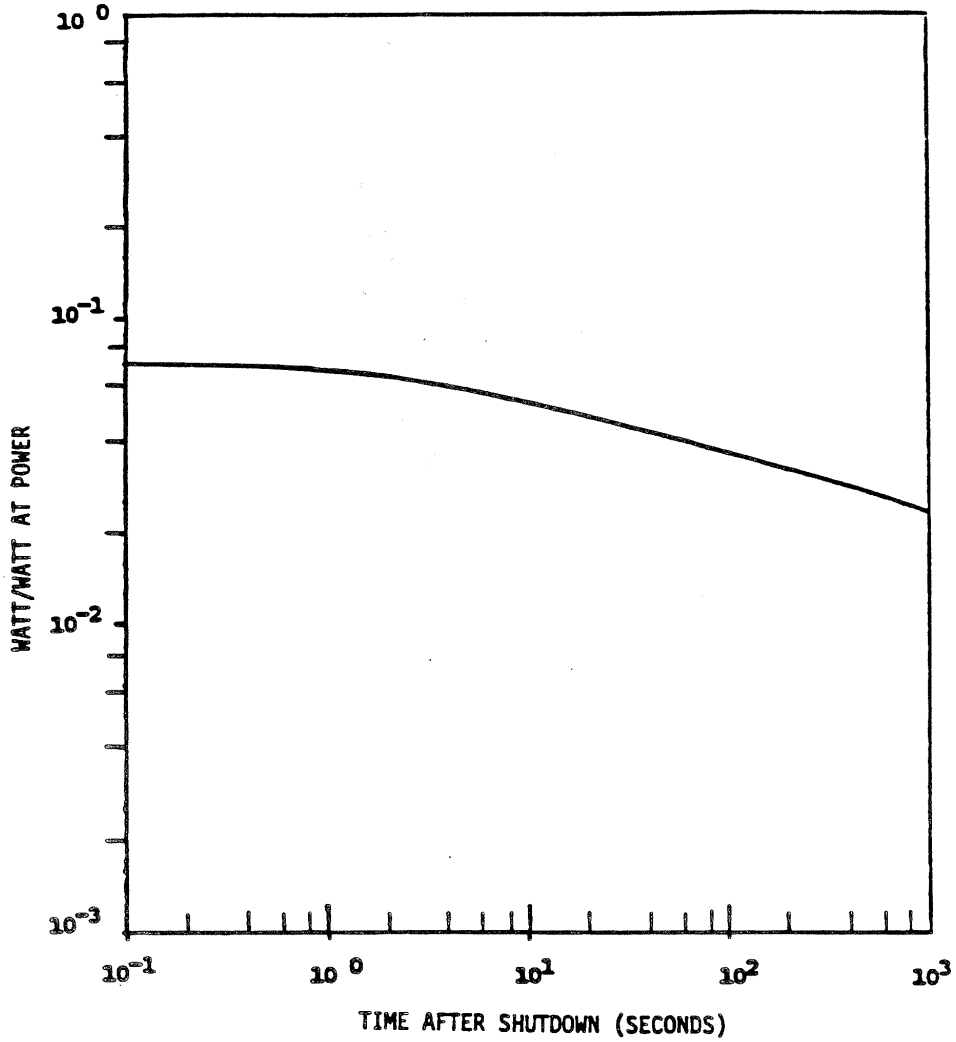
Doppler Power Coefficient Used
In Accident Analysis

Figure 15.1-5

Figure 15.1-6
DELETED

Figure 15.1-7
1979 ANS DECAY HEAT



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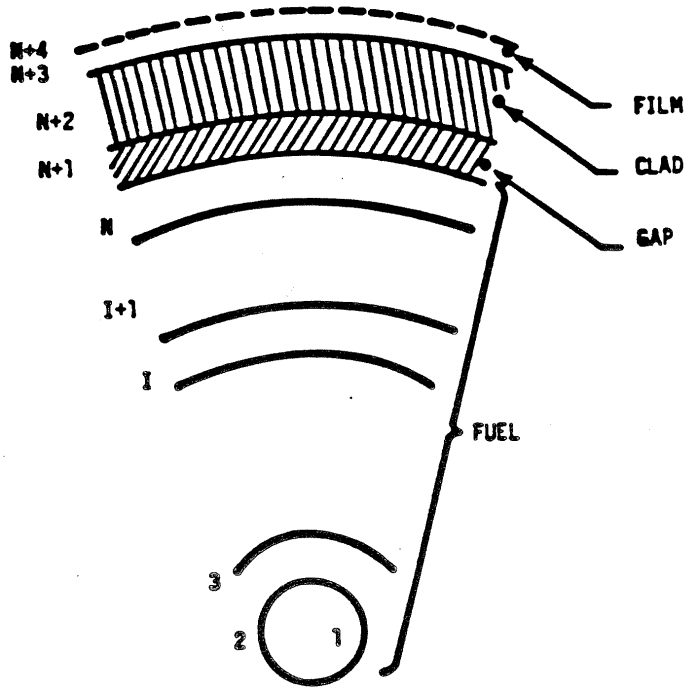
.SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
1979 ANS Decay Heat Figure 15.1-7

Figure 15.1-8
FUEL ROD CROSS SECTION



AMENDMENT 6
AUGUST, 1990

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Fuel Rod Cross Section Figure 15.1-8

15.2 CONDITION II - FAULTS OF MODERATE FREQUENCY

These faults, at worst, result in a reactor trip with the plant being capable of returning to operation. By definition, these faults (or events) do not propagate to cause a more serious fault (i.e., Condition III or IV category). In addition, Condition II events are not expected to result in fuel rod failures or Reactor Coolant System overpressurization. For the purposes of this report, the following faults have been grouped into this category:

1. Uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition.
2. Uncontrolled rod cluster control assembly bank withdrawal at power.
3. Rod cluster control assembly misalignment.
4. Uncontrolled boron dilution.
5. Partial loss of forced reactor coolant flow.
6. Startup of an inactive reactor coolant loop.
7. Loss of external electrical load and/or turbine trip.
8. Loss of normal feedwater.
9. Loss of offsite power to the station auxiliaries.
10. Excessive heat removal due to feedwater system malfunctions.
11. Excessive load increase incident.
12. Accidental depressurization of the Reactor Coolant System.
13. Accidental depressurization of the Main Steam System.
14. Inadvertent operation of the Safety Injection System (SIS) during power operation.

Each of these faults of moderate frequency are analyzed in this section. In general, each analysis includes an identification of causes and description of the accident, an analysis of effects and consequences, a presentation of results, and relevant conclusions.

An evaluation of the reliability of the Reactor Protection System actuation following initiation of Condition II events has been completed and is presented in Reference 1 for the relay protection logic. Standard reliability engineering techniques were used to assess likelihood of the trip failure due to random component failures. Common-mode failures were also qualitatively investigated. It was concluded, from the evaluation, that the likelihood of no trip following initiation of Condition II events is extremely small (2×10^{-7} derived for random component failures).

The Solid State Protection System design has been evaluated by the same methods as used for the relay system and the same order of magnitude of reliability is provided.

In order to satisfy the positions set forth in WASH-1270, Appendix A, Part 11.13, anticipated transients without trip have been analyzed for Westinghouse Pressurized Water Reactors (PWR's).

The results of these analyses are presented in References 11, 12, and 13 and demonstrate that a Westinghouse PWR is inherently self-limiting within well defined safety limits.

The time sequence of events during applicable Condition II events is shown in Table 15.2-1.

15.2.1 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition

15.2.1.1 Identification of Causes and Accident Description

Branch Technical Position (BTP), ICSB 14, discusses spurious withdrawals of control rods in Pressurized Water Reactors General Design Criteria (Appendix A to 10CFR50) 20 and 25 require protection systems which at all times limit the consequences of anticipated operational occurrences or malfunctions, and for reactivity control systems the fuel design limits may not be exceeded. The following discussion provides evidence that the Rod Control System in conjunction with the Reactor Protection System at VCSNS assures the GDC requirements are met. This BTP is also applicable to Section 15.2.2 and 15.3.6.

A rod cluster control assembly (RCCA) withdrawal accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of RCCAs resulting in a power excursion. Such a transient could be caused by a malfunction of the reactor control or rod control systems. This could occur with the reactor either subcritical, hot zero power, or at power. The “at power” case is discussed in Section Section 15.2.2.

Although the reactor is normally brought to power from a subcritical condition by means of RCCA withdrawal, initial startup procedures with a clean core, call for boron dilution. The maximum rate of reactivity increase in the case of boron dilution, is less than that assumed in this analysis (see Section 15.2.4).

The RCCA drive mechanisms are wired into preselected bank configurations, which are not altered during reactor life. These circuits prevent the RCCAs from being automatically withdrawn in other than their respective banks. Power supplied to the banks is controlled such that no more than 2 banks can be withdrawn at the same time. The RCCA drive mechanisms are of the magnetic latch type and coil actuation is sequenced to provide variable speed travel. The maximum reactivity insertion rate analyzed in the detailed plant analysis is that occurring with the simultaneous withdrawal of the combination of 2 control banks having the maximum combined worth at maximum speed.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast rise terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the power excursion is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous RCCA withdrawal accident occur, the transient will be terminated by the following automatic features of the Reactor Protection System:

1. Source Range Neutron Flux Reactor Trip

   The source range high neutron flux reactor trip is actuated when either of 2 independent source range channels indicates a neutron flux level above a preselected manually adjustable setpoint. This trip function may be manually bypassed only after an intermediate range flux channel indicates a flux level above a specified level. It is automatically reinstated when both intermediate range channels indicate a flux level below a specified level.

2. Intermediate Range High Neutron Flux Reactor Trip

   The intermediate range high neutron flux reactor trip is actuated when either of 2 independent intermediate range channels indicates a flux level above a preselected manually adjustable setpoint. This trip function may be manually bypassed only after 2 of the 4 power range channels are reading above approximately 10% of full power and is automatically reinstated when 3 of the 4 channels indicate a power level below this value.

3. Power Range High Neutron Flux Reactor Trip (Low Setting)

   The power range high neutron flux trip (low setting) is actuated when 2 out of the 4 power range channels indicate a power level above approximately 25% of full power. This trip function may be manually bypassed when 2 of the 4 power range channels indicate a power level above approximately 10% of full power and is automatically reinstated only after 3 of the 4 channels indicate a power level below this value.

4. Power Range High Neutron Flux Reactor Trip (High Setting)

   The power range high neutron flux reactor trip (high setting) is actuated when 2 out of the 4 power range channels indicate a power level above a preset setpoint. This trip function is always active.

5. High Positive Neutron Flux Rate Trip

   In addition, control rod stops on high intermediate range flux level (1 of 2) and high power range flux level (1 out of 4) serve to discontinue rod withdrawal and prevent actuation of the intermediate range flux level trip and the power range flux level trip, respectively.

15.2.1.2 Analysis of Effects and Consequences

15.2.1.2.1 Method of Analysis

The analysis of the uncontrolled rod withdrawal from subcritical accident is performed in 3 stages: first a core average nuclear power transient calculation is performed, followed by an average core heat transfer calculation, and finally a DNBR calculation. The core average nuclear power transient calculation is performed using a spatial neutron kinetics code, TWINKLE (Reference 2) , to determine the average power generation with time including the various total core feedback effects, i.e., Doppler and moderator reactivity. The average

heat flux and temperature transients are determined by performing a fuel rod transient heat transfer calculation in FACTRAN (Reference 3). Note that the effects of fuel thermal conductivity degradation with burnup, consistent with the PAD5 fuel performance code (Reference 19), were accounted for in the core hot spot FACTRAN calculations.The average heat flux is next used in THINC (Reference 9) for the transient DNBR calculation.

The core axial power distribution is severely peaked to the bottom of the core for the limiting transient. The W-3 DNB correlation is used to evaluate DNBR in the span between the lower non-mixing vane grid and the first mixing vane grid. The WRB-2 correlation remains applicable for the rest of the fuel assembly.

In order to give conservative results for a startup accident, the following assumptions are made concerning the initial reactor conditions:

1. Since the magnitude of the power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler coefficient, conservative values (low absolute magnitude) as a function of temperature are used. See Section 15.1.6 and Table 15.1-4.
2. Contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time between the fuel and moderator is much longer than the neutron flux response time. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. A conservative value, given in Table 15.1-4, is used in the analysis to yield the maximum peak heat flux.
3. The reactor is assumed to be at hot zero power. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-water heat transfer coefficient, larger specific heats, and a less negative (smaller absolute magnitude) Doppler coefficient, all of which tend to reduce the Doppler feedback effect, thereby, increasing the neutron flux peak. The initial effective multiplication factor is assumed to be 1.0 since this results in the worst nuclear power transient.
4. Reactor trip is assumed to be initiated by power range high neutron flux (low setting). The most adverse combination of instrument and setpoint errors, as well as delays for trip signal actuation and rod cluster control assembly release, is taken into account. A 10% increase is assumed for the power range flux trip setpoint, raising it from the nominal value of 25% to 35%. Previous results, however, show that rise in the neutron flux is so rapid that the effect of errors in the trip setpoint on the actual time at which the rods are released is negligible.
5. The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the combination of the 2 control banks having the greatest combined worth at maximum speed (45 inches/minute). Control rod drive mechanism design is discussed in Section 4.2.3.
6. The initial power level was assumed to be below the power level expected for any shutdown condition. The combination of highest reactivity insertion rate and lowest initial power produces the highest peak heat flux.
7. Two (2) reactor coolant pumps are assumed to be operating.

8. A 1% core flow statepoint reduction was applied to incorporate the effects of asymmetric loop flow, assuming a maximum RCS loop-to-loop flow asymmetry of 5%.

15.2.1.2.2 Results

The calculated sequence of events for this accident is shown on Table 15.2-1.

Figure 15.2-1 and Figure 15.2-2 show the transient behavior for the indicated reactivity insertion rate with the accident terminated by reactor trip at 35% nominal power. This insertion rate is greater than that for the 2 highest worth control banks, both assumed to be in their highest incremental worth region.

Figure 15.2-1 shows the nuclear power transient. The nuclear power overshoots the full power nominal value but this occurs for only a very short time period. Hence, the energy release and the fuel temperature increases are relatively small. The heat flux response, of interest for DNB considerations, is shown in Figure 15.2-1. The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux less than the full power nominal value.

Figure 15.2-2 shows the response of the hot spot average fuel and clad temperature. The average fuel temperature increases to a value lower than the nominal full power value.

15.2.1.3 Conclusions

In the event of an RCCA withdrawal accident from the subcritical condition, the core and the Reactor Coolant System are not adversely affected, since the combination of thermal power and the coolant temperature result in a departure from nucleate boiling ratio (DNBR) greater than the design limit value. Thus, no fuel or clad damage is predicted as a result of DNB.

15.2.2 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power

15.2.2.1 Identification of Causes and Accident Description

Uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power results in an increase in the core heat flux. Since the heat extraction from the steam generator lags behind the core power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in the reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise would eventually result in DNB. Therefore, in order to avert damage to the cladding, the Reactor Protection System is designed to terminate any such transient before the DNBR falls below the safety analysis limit value.

The automatic features of the Reactor Protection System, which prevent core damage following the postulated accident, include the following:

1. Power range neutron flux instrumentation actuates a reactor trip if 2 out of 4 channels exceed a high flux setpoint, or a high positive flux rate setpoint.

2. Reactor trip is actuated if any 2 out of 3 ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with axial power imbalance, coolant temperature, and pressure to protect against DNB.
3. Reactor trip is actuated, if any 2 out of 3 ΔT channels exceed an overpower ΔT setpoint, to ensure that the allowable heat generation rate (kW/ft) is not exceeded.
4. A high pressurizer pressure reactor trip actuated from any 2 out of 3 pressure channels that are set at a fixed point. This set pressure is less than the set pressure for the pressurizer safety valves.
5. high pressurizer water level reactor trip, actuated from any 2 out of 3 level channels, is set at a fixed point.

In addition to the above listed reactor trips, there are the following RCCA withdrawal blocks:

1. High neutron flux (1 out of 4)
2. Overpower ΔT (2 out of 3)
3. Overtemperature ΔT (2 out of 3)

The manner in which the combination of overpower and overtemperature ΔT trips provide protection over the full range of Reactor Coolant System conditions is described in Chapter 7. Figure 15.1-1 presents allowable reactor coolant loop average temperature and ΔT for the design power distribution and flow as a function of primary coolant pressure. The boundaries of operation defined by the overpower ΔT trip and the overtemperature ΔT trip are represented as “protection lines” on this diagram. The protection lines are drawn to include all adverse instrumentation and setpoint errors so that under nominal conditions the trip would occur well within the area bounded by these lines. The utility of this diagram is in the fact that the limit imposed by any given DNBR can be represented as a line. The DNB lines represent the locus of conditions for which the DNBR equals the safety analysis limit value. All points below and to the left of a DNB line for a given pressure have a DNBR greater than the limit. The diagram shows that DNB is prevented for all cases if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR line at any point.

The area of permissible operation (power, pressure, and temperature) is bounded by the combination of reactor trips: high neutron flux (fixed setpoint); high pressure (fixed setpoint); low pressure (fixed setpoint); overpower and overtemperature ΔT (variable setpoints).

15.2.2.2 Analysis of Effects and Consequences

The analyses described below demonstrate conformance to fuel design limits. A conservative analysis has also been performed that verifies that the RCS overpressure limit will not be exceeded.

15.2.2.2.1 Method of Analysis

This transient is analyzed by the LOFTRAN (Reference 4) Code. This code simulates the neutron kinetics, Reactor Coolant System, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. The core limits as illustrated in Figure 15.1-1 are used as input to LOFTRAN to determine the minimum DNBR during the transient.

In order to obtain conservative results, the following assumptions are made:

1. To analyze the accident for DNB concerns, the accident is analyzed using the Revised Thermal Design Procedure. Therefore, the initial reactor power, pressure, and RCS temperatures are assumed to be at their nominal values. Uncertainties in the initial conditions are included in the limit DNBR. To analyze the accident for maximum RCS pressure, uncertainties in the initial conditions are applied to produce limiting RCS pressures.
2. Reactivity Coefficients - Both minimum and maximum reactivity conditions are considered.
   e. Minimum reactivity feedback. A positive moderator coefficient of reactivity of + 7 pcm/°F is assumed. A variable Doppler power coefficient with core power is used in the analysis. A conservatively small (in absolute magnitude) value is assumed.
   f. Maximum reactivity feedback. A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler power coefficient are assumed.
3. The reactor trip on high neutron flux is assumed to actuate at a conservative value of 118% of nominal full power. The DT trips include all adverse instrumentation and setpoint errors. The reactor trip on high pressurizer pressure actuates when the pressurizer pressure exceeds a setpoint of 2455 psia. The delays for the trip signal actuations for all of the trips are assumed at conservatively high values.
4. The RCCA trip insertion characteristics is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.
5. The maximum positive reactivity insertion rate is greater than that which would be obtained for the simultaneous withdrawal of the 2 control banks having the maximum combined worth at maximum speed.
6. The overtemperature ΔT setpoint used in the analyses is higher than the safety analysis limit used in the setpoints study to account for a 4°F allowance for temperature related effects.

The effect of RCCA movement on the axial core power distribution is accounted for by causing a decrease in overtemperature and overpower ΔT trip setpoints proportional to decrease in margin to DNB.T trip setpoints proportional to decrease in margin to DNB.

15.2.2.2.2 Results

The calculated sequence of events for the cases analyzed for DNB concerns is shown on Table 15.2-1.

Figure 15.2-3 and Figure 15.2-4 show the transient response to a rapid RCCA withdrawal starting from full power. Reactor trip on high neutron flux occurs shortly after the start of the accident. Since this is rapid with respect to the thermal time constants of the plant, small changes in T_{avg} and pressure result and a large margin to DNB is maintained.

The transient response for a slow control rod assembly withdrawal from full power is shown on Figure 15.2-5 and Figure 15.2-6. Reactor trip on overtemperature ΔT occurs after a longer period and the rise in temperature and pressure is consequently larger than for rapid RCCA withdrawal. Again, the minimum DNBR is never less than the safety analysis limit values.

Figure 15.2-7, Figure 15.2-8, and Figure 15.2-9 illustrate the minimum DNBR calculated for minimum and maximum reactivity feedbacks.

Figure 15.2-7 shows the minimum DNBR as a function of reactivity insertion rate from initial full power operation for minimum and maximum reactivity feedback. It can be seen that 2 reactor trip channels provide protection over the whole range of reactivity insertion rates. These are the high neutron flux and overtemperature ΔT trip channels. The minimum DNBR is never less than the safety analysis limit values.

Figure 15.2-8 and Figure 15.2-9 show the minimum DNBR as a function of reactivity insertion rate for RCCA withdrawal incidents starting at 60 and 10% power respectively. The results are similar to the 100% power case, except as the initial power is decreased, the range over which the overtemperature ΔT trip is effective is increased. In neither case does the DNBR fall below the safety analysis limit values.

The shape of the curves of minimum DNBR versus reactivity insertion rate in the referenced figures is due both to reactor core and coolant system transient response and to protection system action in initiating a reactor trip.

Referring to Figure 15.2-9, for example, it is noted that:

1. For high reactivity insertion rates of about ~5 pcm/sec, reactor trip is initiated by the high neutron flux trip for the minimum reactivity feedback cases. The neutron flux level in the core rises rapidly for these insertion rates while core heat flux and coolant system temperature lag behind due to the thermal capacity of the fuel and coolant system fluid. Thus, the reactor is tripped prior to significant increase in heat flux or water temperature with resultant high minimum DNBR's during the transient. As the reactivity insertion rate decreases, core heat flux and coolant temperatures can remain more nearly in equilibrium with the neutron flux; minimum DNBR during the transient thus decreases with decreasing insertion rate.

2. The overtemperature ΔT reactor trip circuit initiates a reactor trip when measured coolant loop ΔT exceeds a setpoint based on measured Reactor Coolant System average temperature and pressure. This trip circuit is described in detail in Chapter 7; however, it is important to note that the average temperature contribution to the circuit is lead-lag compensated in order to decrease the effect of the thermal capacity of the Reactor Coolant System in response to power increases.
3. For reactivity insertion rate below ~ 15 pcm/sec the overtemperature ΔT trip terminates the transient for the minimum reactivity feedback cases.

   For reactivity insertion rates below ~ 20 pcm/sec the effectiveness of the overtemperature ΔT trip increases (in terms of increased minimum DNBR) due to the fact that with lower insertion rates the power increase rate is slower, the rate of rise of average coolant temperature is slower, and the system lags and delays become less significant.

Referring to Figure 15.2-8, it is noted that:

For reactivity insertion rates less than ~ 50 pcm/sec, the rise in the reactor coolant temperature is sufficiently high so that the steam generator safety valve setpoint is reached prior to trip. Opening of these valves, which act as an additional heat load on the Reactor Coolant System, sharply decreases the rate of increase of Reactor Coolant System average temperature. This decrease in rate of increase of the average coolant system temperature during the transient is accentuated by the lead-lag compensation causing the overtemperature ΔT trip setpoint to be reached later with resulting lower minimum DNBR.

For transients initiated from higher power levels (for example, see Figure 15.2-7) the effect described above, which results in the sharp peak in minimum DNBR at approximately 50 pcm/sec, does not occur since the steam generator safety valves are not actuated prior to trip.

Since the RCCA withdrawal at power incident is an overpower transient, the fuel temperatures rise during the transient until after reactor trip occurs. For high reactivity insertion rates, the overpower transient is fast with respect to the fuel rod thermal time constant, and the core heat flux lags behind the neutron flux response. Due to this lag, the peak core heat flux does not exceed 118% of its nominal value (i.e., the high neutron flux trip setpoint assumed in the analysis). Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature will still remain below the fuel melting temperature.

For slow reactivity insertion rates, the core heat flux remains more nearly in equilibrium with the neutron flux. The overpower transient is terminated by the overtemperature ΔT reactor trip before a DNB condition is reached. The peak heat flux again is maintained below 118% of its nominal value. Taking into account the effect of the RCCA withdrawal on the axial core power distribution, the peak fuel centerline temperature will remain below the fuel melting temperature.

Since DNB does not occur at any time during the RCCA withdrawal at power transient, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

The calculated sequence of events for the cases analyzed for DNB concerns is shown on Table 15.2-1. With the reactor tripped, the plant eventually returns to a stable condition. The plant may subsequently be cooled down further by following normal plant shutdown procedures.

15.2.2.3 Conclusions

The high neutron flux, overtemperature ΔT, and high pressurizer pressure reactor trip functions provide adequate protection against DNB or overpressure over the entire range of possible reactivity insertion rates. The minimum value of DNBR is always larger than the safety analysis limit value and the RCS pressure is maintained below 110% of the design pressure. Therefore, the results of the analysis show that an uncontrolled RCCA bank withdrawal at power does not adversely affect the core or the RCS.

15.2.3 Rod Cluster Control Assembly Misoperation

This section discusses RCCA misoperation that can result from system malfunction or operator error.

15.2.3.1 Identification of Causes and Accident Description

Rod cluster control assembly (RCCA) misalignment accidents include:

1. One (1) or more dropped RCCAs within the same group;
2. A dropped RCCA bank;
3. Statically misaligned RCCA.

Each RCCA has a position indicator channel which displays position of the assembly. The displays of assembly positions are grouped for the operator’s convenience. Fully inserted assemblies are further indicated by a rod bottom signal, which actuates a local alarm and a control room annunciator. Group demand position is also indicated. RCCAs are always moved in preselected banks, and the banks are always moved in the same preselected sequence. Each bank of RCCAs is divided into 2 groups. The rods comprising a group operate in parallel through multiplexing thyristors. The 2 groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism) is required to withdraw the RCCA attached to the mechanism. Since the stationary gripper, movable gripper, and lift coils associated with the 4 RCCAs of a rod group are driven in parallel, any single failure that would cause rod withdrawal would affect a minimum of one group. Mechanical failures are in the direction of insertion, or immobility.

A dropped RCCA or RCCA bank is detected by:

1. A sudden drop in the core power level as seen by the nuclear instrumentation system;
2. Asymmetric power distribution as seen on excore neutron detectors or core exit thermocouples;

3. Rod at bottom signal;
4. Rod deviation alarm;
5. Rod position indication.

Misaligned assemblies are detected by:

1. Asymmetric power distribution as seen on excore neutron detectors or core exit thermocouples;
2. Rod deviation alarm;
3. Rod position indicators.

The deviation alarm alerts the operator whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. If the rod deviation alarm is not operable, the operator is required to take action as required by the Technical Specifications (Reference 6).

If 1 or more rod position indicator channels should be out of service, detailed operating instructions are followed to ensure the alignment of the nonindicated RCCAs. The operator is also required to take action as required by the Technical Specifications.

15.2.3.2 Analysis of Effects and Consequences

15.2.3.2.1 Method of Analysis

1. One (1) or more dropped RCCAs from the same group.
   For evaluation of the dropped RCCA event, the transient system response is calculated using the LOFTRAN (Reference 4) code. The code simulates the neutron kinetics, Reactor Coolant System, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

   Statepoints are calculated and nuclear models are used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met using the THINC code (Reference 9). The transient response, nuclear peaking factor analysis, and DNB design basis confirmation are performed in accordance with the methodology described in Reference 10

2. Dropped RCCA Bank

   A dropped RCCA bank results in a symmetric power change in the core. As discussed in Reference 10, assumptions made for the dropped RCCA(s) analysis provide a bounding analysis for the dropped RCCA bank.

3. Statically Misaligned RCCA

Steady state power distributions are analyzed using the computer codes as described in Table 4.1-2. The peaking factors are then used as input to the THINC code to calculate the DNBR.

15.2.3.2.2 Results

1. One (1) or more Dropped RCCAs

   Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion. The core is not adversely affected during this period since power is decreasing rapidly. Either reactivity feedback or control bank withdrawal will re-establish power.

   Following a dropped rod event in manual control, the plant will establish a new equilibrium condition. Without control system interaction, a new equilibrium is achieved at a reduced power level and reduced primary temperature. Thus, the automatic rod control mode of operation is the limiting case.

   For a dropped RCCA event in the automatic rod control mode, the Rod Control System detects the drop in power and initiates control bank withdrawal. Power overshoot may occur due to this action by the automatic rod controller after which the control system will insert the control bank to restore nominal power. Figure 15.2-10 and Figure 15.2-11 show a typical transient response to a dropped RCCA (or RCCAs) in automatic control. In all cases, the minimum DNBR remains above the safety analysis limit value

2. Dropped RCCA Bank

   A dropped RCCA bank results in a negative reactivity insertion greater than 500 pcm. The core is not adversely affected during the insertion period, since power is decreasing rapidly. The transient will proceed as described in Part 1; however, the return to power will be less due to the greater worth of the entire bank. The power distribution during a dropped bank transient is symmetric. Following plant stabilization, normal procedures are followed.

3. Statically Misaligned RCCA

   The most severe misalignment situations with respect to DNBR at significant power levels arise from cases in which 1 RCCA is fully inserted, or where bank D is fully inserted with 1 RCCA fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the postulated conditions are approached. The bank can be inserted to its insertion limit with any one assembly fully withdrawn without the DNBR falling below the safety analysis limit value.

   The insertion limits in the Technical Specifications may vary from time to time depending on a number of limiting criteria. It is preferable, therefore, to analyze the misaligned RCCA case at full power for a position of the control bank as deeply inserted as the criteria on minimum DNBR and power peaking factor will allow. The full power insertion limits on control bank D must then be chosen to be above that position and will usually be dictated by other criteria. Detailed results will vary from cycle to cycle depending on fuel arrangements.

For this RCCA misalignment, with bank D inserted to its full power insertion limit and one RCCA fully withdrawn, DNBR does not fall below the safety analysis limit value. This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values but with the increased radial peaking factor associated with the misaligned RCCA.

DNB calculations have not been performed specifically for RCCAs missing from other banks; however, power shape calculations have been done as required for the fully withdrawn analysis. Inspection of the power shapes shows that the DNB and peak kw/ft situation is less severe than the bank D case discussed above, assuming insertion limits on the other banks equivalent to a bank D full-in insertion limit.

For RCCA misalignments with 1 RCCA fully inserted, the DNBR does not fall below the limit value. This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values, but with the increased radial peaking factor associated with the misaligned RCCA.

DNB does not occur for the RCCA misalignment incident and thus the ability of the primary coolant to remove heat from the fuel rod is not reduced. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation is well below that which would cause fuel melting.

Following the identification of a RCCA group misalignment condition by the operator, the operator is required to take action as required by the plant Technical Specifications and operating instructions.

15.2.3.3 Conclusions

It is shown for all cases of dropped RCCAs or dropped banks that the DNBR remains greater than the safety analysis limit value and, therefore, the DNB design basis is met.

For all cases of any RCCA fully inserted, or bank D inserted to its rod insertion limits with any single RCCA in that bank fully withdrawn (static misalignment), the DNBR remains greater than the safety analysis limit value. Therefore, the DNB design basis is met.

15.2.4 Uncontrolled Boron Dilution

15.2.4.1 Identification of Causes and Accident Description

Reactivity can be added to the core by feeding primary grade water into the Reactor Coolant System (RCS) via the reactor makeup portion of the Chemical and Volume Control System (CVCS). Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water during normal charging to that in the RCS. The CVCS is designed to limit, even under various

postulated failure modes, the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

The opening of the primary water makeup control valve provides makeup to the RCS which can dilute the reactor coolant. Inadvertent dilution from this source can be readily terminated by closing the control valve. In order for makeup water to be added to the RCS at pressure, at least 1 charging pump must be running in addition to a primary makeup water pump.

The rate of addition of unborated makeup water to the RCS is limited by a flow limiting orifice between the reactor makeup water pumps and the boric acid blender. As demonstrated by tests at the plant, flow is within the bounds of unborated water used in analyses in this section.

The boric acid from the boric acid tank is blended with primary grade water in the blender and the composition is determined by the preset flow rates of boric acid and primary grade water on the control board. In order to dilute 2 separate operations are required:

1. The operator must switch from the automatic makeup mode to the dilute mode.
2. The start/stop switch is placed in the start position.

Omitting either step would prevent dilution.

The status of the RCS makeup is continuously available to the operator by:

1. Indication of the boric acid and blended flow rates,
2. CVCS and RMWS pump status lights,
3. Deviation alarms if the boric acid or blended flow rates deviate by more than 10% from the preset values.

Indication of a dilution event is available to the operator by:

1. Source Range Neutron Flux - when the reactor is subcritical:
   a. High flux at shutdown alarm. A separate main control board (MCB) and computer generated alarm is provided for each channel.
   b. Indicated source range neutron flux count rates.
   c. Audible source range neutron flux count rate.
2. With the reactor critical:
   a. Axial flux difference alarm (reactor power ≥ 50% RTP),
   b. Control rod insertion limit low and low-low alarms,
   c. Overtemperature ΔT alarm (at power),
   d. Overtemperature ΔT turbine runback (at power),

e. Overtemperature ΔT reactor trip, and

f. Power range neutron flux - High, both high and low setpoint reactor trips.

15.2.4.2 Analysis of Effects and Consequences

To cover all phases of the plant operation, boron dilution during refueling, cold shutdown, hot standby, startup, and power operation are considered in this analysis. Table 15.2-1 contains the time sequence of events for this accident.

1. Dilution During Refueling

   An uncontrolled boron dilution accident based on a failure in the primary water makeup system cannot occur during refueling. This accident is prevented by administrative controls which isolate the RCS from the potential source unborated water.

   Valves 8454, 8441, 8430, and 8439 will be locked closed during refueling operations. These valves will block the flow paths which could allow unborated makeup water to reach the RCS. Any makeup which is required during refueling will be added to the Reactor Coolant System by unlocking these valves as appropriate and initiating the required blended makeup water flow. After the required volume of blended makeup flow has been added, these valves will again be locked closed. An alternate source of borated water that could be used is from the refueling water storage tank to the charging pump suction.

   Demineralized water may be used to decontaminate the refueling cavity walls while draining the refueling cavity. When the cavity water level is above the RV flange, water is pumped back to the refueling water storage tank through the Residual Heat Removal System. Administrative controls preclude an uncontrolled boron dilution accident by limiting the amount of demineralized water used such that the boron concentrations within the refueling cavity, Reactor Coolant System, and refueling water storage tank remain above minimum Technical Specification limits.

   The most limiting alternate source of unborated water is from the Boron Thermal Regeneration System (BTRS). For this case, highly borated RCS water is depleted of boron as it passes through the BTRS and is returned via the volume control tank. The following conditions are assumed for an uncontrolled boron dilution during refueling.

   Technical Specifications require the reactor to be borated to at least 2,000 ppm or shutdown by at least 5.0% Δk at refueling.

   If an inadvertent dilution from the BTRS occurs during refueling, with the reactor vessel head off, and the refueling cavity filled with borated water (i.e., in a condition to move fuel), the maximum dilution capability of the BTRS is insufficient to cause a return to criticality.

The maximum dilution capability of the BTRS at these conditions is conservatively estimated to be 250 ppm. However, the minimum change in boron concentration necessary to bring the reactor critical at these conditions is conservatively estimated to be 590 ppm. An initial boron concentration of 2000 ppm is assumed. Therefore, a dilution to criticality from the BTRS at these refueling conditions cannot occur.

The most limiting conditions for an inadvertent boron dilution from the BTRS during refueling occur when the reactor coolant level is at the vessel/head junction. The dilution capability of the BTRS at these conditions is sufficient to cause a return to criticality. The minimum volume in the Reactor Coolant System corresponding to this condition is conservatively estimated to be 3075 ft^3. The critical boron concentration is conservatively estimated to be 1410 ppm.

2. Dilution During Cold Shutdown

Technical Specifications specify the required shutdown margin as a function of RCS boron concentration during cold shutdown. The specified shutdown margin ensures sufficient time for the operator to terminate the dilution. If the reactor is in cold shutdown and on the Residual Heat Removal System with RCS piping filled and vented, the following conditions are assumed for an uncontrolled boron dilution. Dilution flow is assumed to be a maximum of 150 gpm, which is the capability of 1 primary water makeup pump to deliver unborated water to the RCS. Mixing of the reactor coolant is accomplished by the operation of 1 residual heat removal pump.

A volume of 5240.5 ft^3 in the Reactor Coolant System is used. This corresponds to the active volume of the Reactor Coolant System minus the pressurizer volume, while on the Residual Heat Removal System.

If the reactor is in cold shutdown and the RCS water level is drained down from a filled and vented condition while on RHR, an inadvertent dilution is prevented by administrative controls which isolate the RCS from the potential source of unborated water. Valves 8454, 8441, 8430, and 8439 will be locked closed during operation in these conditions. These valves block all flow paths that could allow unborated makeup water to reach the RCS. Any makeup, which is required, will be added to the Reactor Coolant System by unlocking these valves, as appropriate, and initiating the required blended makeup water flow. After the required volume of blended makeup flow has been added, these valves will again be locked closed. An alternate source of borated water which may be used is from the refueling water storage tank to the charging pump suction.

3. Dilution During Hot Shutdown

   Technical Specifications specify the required shutdown margin as a function of RCS boron concentration. The analysis assumes that the RCS is filled and vented on the Residual Heat Removal System. This is more conservative than if 1 or more reactor coolant pumps are assumed operating. The following conditions are assumed for a continuous boron dilution during hot standby. Dilution flow is assumed to be a maximum of 150 gpm, which is the capacity of 1 primary water makeup pump to deliver unborated water to the RCS. A minimum water volume of 5240.5 ft^3 in the Reactor Coolant System is used. This corresponds to the active volume of the Reactor Coolant System minus the pressurizer volume, while on the Residual Heat Removal System.

4. Dilution During Hot Standby

   Technical Specifications specify the required shutdown margin as a function of RCS boron concentration. The following conditions are assumed for a continuous boron dilution during hot standby. Dilution flow is assumed to be a maximum of 150 gpm, which is the capability of one primary water makeup pump to deliver unborated water to the RCS. A minimum RCS water volume of 8126 ft^3 is assumed. This is a conservative estimate of the active RCS volume with one reactor coolant pump operating.

5. Dilution During Startup

   Prior to startup, the RCS is filled with borated water at a boron concentration of 2200 ppm. This is a conservative estimate with the reactor at a 1.77% Δk shutdown margin at 557°F. Dilution flow is assumed to be a maximum of 150 gpm, which is the capability of one primary water makeup pump to deliver unborated water to the RCS. A minimum volume of 8126 ft^3 in the Reactor Coolant System is used. This is a conservative estimate of the active volume of the RCS excluding the pressurizer.

6. Dilution During Full Power Operation

   During power operation, the plant may be operated 2 ways, under manual operator control or under automatic T_{avg}/rod control. The Technical Specifications require 3 reactor coolant pumps operating and a shutdown margin of at least 1.77% Δk. The RCS is conservatively assumed to be filled with borated water at a boron concentration of 2200 ppm. While the plant is in manual control, the dilution flow is assumed to be a maximum of 150 gpm, which is the capacity of one reactor makeup water pump to deliver unborated water to the RCS. When in automatic control, the dilution flow is limited by the maximum letdown flow (approximately 125 gpm). A minimum RCS water volume of 8126 ft^3 is used. This is a conservative estimate of the active volume of the RCS excluding the pressurizer.

15.2.4.3 Results

Dilution During Refueling

During refueling, an inadvertent dilution from the Reactor Makeup Water System is prevented by administrative controls which isolate the RCS from the potential source of unborated makeup water. The most limiting conditions for an inadvertent dilution from the BTRS occur when the reactor vessel head is unbolted and the vessel water level is at the vessel/head junction. The high flux at shutdown alarm, set at twice the background flux level measured by the source range nuclear instrumentation, is available at these conditions to alert the operator that a dilution event is in progress. For this case, the operator has more than 30 minutes from the high flux at shutdown alarm to recognize and terminate the dilution before shutdown margin is lost and the reactor becomes critical.

Dilution During Cold Shutdown

While in cold shutdown the high flux at shutdown alarm, set at twice the background flux level measured by the source range nuclear instrumentation, is available to alert the operator that a dilution event is in progress. During the cold shutdown mode while operating on the Residual Heat Removal System (RHRS) with the RCS piping filled and vented, the shutdown margin requirement ensures that the operator has at least 13.6 minutes from the high flux at shutdown alarm to recognize and terminate the uncontrolled reactivity insertion before shutdown margin is lost. During the cold shutdown mode, while operating on the RHRS with the RCS drained down from a filled and vented condition, an inadvertent dilution is precluded by administrative controls which isolate the RCS from the potential source of unborated water.

Dilution During Hot Shutdown

While in hot shutdown, the high flux at shutdown alarm, set at twice the background flux level measured by the source range nuclear instrumentation, is available to alert the operator that a dilution event is in progress. During hot shutdown, the shutdown margin requirement ensures that the operator has at least 13.6 minutes from the high flux at shutdown alarm to recognize and terminate the uncontrolled reactivity insertion before shutdown margin is lost.

Dilution During Hot Standby

While in hot standby, the high flux at shutdown alarm, set at twice the background flux level measured by the source range nuclear instrumentation, is available to alert the operator that a dilution event is in progress. During hot standby, the shutdown margin requirement ensures that the operator has at least 13.4 minutes from the high flux at shutdown alarm to recognize and terminate the uncontrolled reactivity insertion before shutdown margin is lost.

Dilution During Startup

In the event of an unplanned approach to criticality or dilution during power escalation while in the startup mode, the operator is alerted to an uncontrolled reactivity insertion by a reactor trip at

the Source Range High Neutron Flux Setpoint. After reactor trip there is more than 15 minutes for operator action prior to return to criticality.

Dilution at Power

During the at power mode with manual control, the operator is alerted to an uncontrolled reactivity insertion by an overtemperature ΔT trip. More than 15 minutes are available from the trip for the operator to recognize and terminate the uncontrolled dilution before shutdown margin is lost. The sensitivity and alarm thresholds are already assumed to be degraded to the maximum extent allowable for the overtemperature ΔT trip function (see Section 15.2.2).

During the at power mode with automatic control, the operator is alerted to an uncontrolled reactivity insertion by the rod insertion limit alarms. Two (2) insertion limit alarms are available: The first occurs when the rods are 10 steps above the insertion limit (Lo Insertion Limit Alarm) and the second occurs at the insertion limit (Lo-Lo Insertion Limit Alarm). The analysis assumed that the operator is alerted to the need for action by the Lo-Lo alarm although action would be taken when the first alarm occurs. Thus the analysis already assumes a 10 step allowance for rod position indicator inaccuracies. Even with this conservatism, more than 15 minutes are available from the time of alarm until all shutdown margin is lost. In addition to the above, other indications are available. The main indication would be a violation of the axial offset control band which could result in a reactor trip (reduction in overtemperature ΔT setpoint).

15.2.4.4 Event Detection Immediately Following Reactor Shutdown

Following a reactor trip or shutdown, the high flux at shutdown alarms for the MCB are implemented via a manual calibration of the alarm bistable based on the existing source range counts. Following the initial calibration, the MCB alarms are recalibrated at approximately 12, 24, and 48 hours after shutdown to compensate for the anticipated decrease in source range counts to stable levels. Consistent with Generic Letter 85-05, computer generated alarms, which account for decreasing source range counts, and administrative controls are also utilized to provide increased assurance that an inadvertent dilution event, should it occur, will be terminated prior to a loss of shutdown margin.

15.2.4.5 Conclusions

The analysis presented above shows that, for an inadvertent boron dilution, the operator has sufficient time to recognize and terminate the dilution before shutdown margin is lost and the reactor becomes critical.

15.2.5 Partial Loss of Forced Reactor Coolant Flow

15.2.5.1 Identification of Causes and Accident Description

A partial loss of coolant flow accident can result from a mechanical or electrical failure in a reactor coolant pump, or from a fault in the power supply to the pump or pumps. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase

in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor is not tripped promptly.

The necessary protection against a partial loss of coolant flow accident is provided by the low primary coolant flow reactor trip which is actuated by 2 out of 3 low flow signals in any reactor coolant loop. Above approximately 38% power (Permissive 8), low flow in any loop will actuate a reactor trip. Between approximately 10% power (Permissive 7) and power level corresponding to Permissive 8, low flow in any 2 loops will actuate a reactor trip. Reactor trip on low flow is blocked below Permissive 7.

A reactor trip signal from the pump breaker position is also provided. When operating above Permissive 7, a breaker open signal from any 2 pumps will actuate a reactor trip. This serves as a backup to the low flow trip. Reactor trip on reactor coolant pump breakers open is blocked below Permissive 7.

Normal power for each pump is supplied through individual buses connected to the isolated phase bus duct between the generator circuit breaker and the main transformer. Faults in the substation may cause a trip of the main transformer high side circuit breaker leaving the generator to supply power to the reactor coolant pumps. When a generator circuit breaker trip occurs because of electrical faults, the pumps are automatically transferred to an alternate power supply and the pumps will continue to supply coolant flow to the core. Following any turbine trip where there are no electrical faults the generator circuit breaker is tripped and the reactor coolant pumps remain connected to the network through the transformer high side breaker. Continuity of power to the pump buses is achieved without motoring the generator since means are provided to isolate the generator without isolating the pump buses from the external power lines (e.g., a generator output breaker is provided as well as station output breaker).

15.2.5.2 Analysis of Effects and Consequences

15.2.5.2.1 Method of Analysis

The following case has been analyzed:

All loops operating, one loop coasting down.

This transient is analyzed by 3 digital computer codes. First the LOFTRAN code is used to calculate the loop and core flow during the transient. The LOFTRAN code is also used to calculate the time of reactor trip, based on the calculated flows and the nuclear power transient following reactor trip. The FACTRAN code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC code (Reference 9) is used to calculate the minimum DNBR during the transient based on the heat flux from FACTRAN and the flow from LOFTRAN.

1. Initial Conditions

   Initial operating conditions assumed are the most adverse with respect to the margin to DNB (i.e., nominal steady-state power level, nominal steady-state pressure, and nominal steady-state coolant average temperature). See Section 15.1.2 for an explanation of initial conditions. The accident is analyzed using the Revised Thermal Design Procedure as described in Reference 5.

2. Reactivity Coefficients

   A conservatively large absolute value of the Doppler-only power coefficient is used (see Table 15.1-4). The total integrated Doppler reactivity from 0 to 100% power is assumed to be -0.016 ΔK.

   The least negative moderator temperature coefficient for full power conditions (0 pcm/°F) is assumed since this results in the maximum core power during the initial part of the transient when the minimum DNBR is reached.

3. Flow Coastdown

   The flow coastdown analysis is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, and the pump characteristics and is based on high estimates of system pressure losses to calculate the flow coastdown.

15.2.5.2.2 Results

The calculated sequence of events is shown in Table 15.2-1. Figure 15.2-12 and Figure 15.2-13 show the vessel flow coastdown, the faulted loop flow coastdown, the nuclear power, and heat flux transient. The minimum DNBR is not less than the safety analysis limit value. (See Figure 15.2-14).

15.2.5.3 Conclusions

The analysis shows that the DNBR will not decrease below the safety analysis limit value at any time during the transient. Thus, no core safety limit is violated.

15.2.6 Startup of an Inactive Reactor Coolant Loop

In accordance with Technical Specification 3/4.4.1, V. C. Summer operation during startup and power operation with less than 3 loops operating is not permitted. Therefore, this section is not applicable.

15.2.7 Loss of External Electrical Load and/or Turbine Trip

15.2.7.1 Identification of Causes and Accident Description

A major load loss on the plant can result from loss of external electrical load or from a turbine trip. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps. The case of loss of offsite power to the station auxiliaries is analyzed in Section 15.2.9.

For a turbine trip, the reactor would be tripped directly (unless below approximately 50% power) from a signal derived from the turbine autostop oil pressure and turbine stop valves.

The automatic steam dump system would accommodate the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the main condenser was not available, the excess steam generation would be dumped to the atmosphere. Additionally, main feedwater flow would be lost if the main condenser was not available. For this situation, steam generator level would be maintained by the Emergency Feedwater System.

For a loss of external electrical load without subsequent turbine trip, a direct reactor trip signal may be generated. However, with full load rejection capability the plant may be expected to continue without a reactor trip. A continued steam load of approximately 5% would exist after total loss of external electrical load because of the steam demand of plant auxiliaries.

Onsite power supplies plant auxiliaries during plant operation, e.g., the reactor coolant pumps. Engineered safety features (ESF) loads are supplied from offsite power or, alternately, from emergency diesels. Reactor Protection System equipment is supplied from the 120V a-c instrument power supply system, which in turn is supplied from the inverters; the inverters are supplied from a d-c bus energized from batteries or rectified a-c from ESF buses. Thus, for postulated loss of load and subsequent turbine generator overspeed, any overfrequency condition is not seen by safety-related pump motors, Reactor Protection System equipment, or other ESF loads. Any increased frequency to the reactor coolant pump motors will result in slightly increased flowrate and subsequent additional margin to safety limits.

Should a safety limit be approached following the loss of load, protection would be provided by high pressurizer pressure and overtemperature ΔT trips. Power and frequency relays associated with the reactor coolant pump provide no additional safety function for this event. Following a complete loss of load the maximum turbine overspeed would be approximately 8 to 9%, resulting in an overfrequency of less than 6 Hz. This resulting overfrequency is not expected to damage the sensors (non-NSSS). However, it is noted that frequent testing of this equipment is required by the Technical Specifications. Any degradation in their performance could be ascertained at that time.

In the event the steam dump valves fail to open following a large loss of load, the steam generator safety valves may lift and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, or the overtemperature ΔT signal. The steam generator shell side pressure and reactor coolant temperatures will increase rapidly. The pressurizer safety valves

and steam generator safety valves are, however, sized to protect the Reactor Coolant System (RCS) and steam generator against overpressure for all load losses without assuming the operation of the steam dump system, pressurizer spray, pressurizer power operated relief valves, automatic control of the rod cluster control assembly nor direct reactor trip on turbine trip.

The steam generator safety valve capacity is sized to remove the steam flow at the ESF rating (104.5% steam flow at rated power) from the steam generator without exceeding 110% of the steam system design pressure. The pressurizer safety valve capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load (along with operation of the steam generator safety valves). The pressurizer safety valves are then able to maintain the RCS pressure within 110% of the RCS design pressure without direct or immediate reactor trip action.

A more complete discussion of overpressure protection can be found in Reference 8.

15.2.7.2 Analysis of Effects and Consequences

15.2.7.2.1 Method of Analysis

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from full power without a direct reactor trip. This is done to show the adequacy of the pressure-relieving devices and to demonstrate core protection margins. The reactor is not tripped until conditions in the RCS result in a trip. The turbine is assumed to trip without actuating all the turbine stop valve limit switches. This assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst case transient. In addition, no credit is taken for steam dump. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for emergency feedwater (except for long-term recovery) to mitigate the consequences of the transient.

The total loss of load transients are analyzed with the LOFTRAN computer program (see Section 15.1). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

Major assumptions are summarized below:

1. Initial Operating Conditions

   This accident is analyzed using the Revised Thermal Design Procedure (RTDP). For the DNB (pressure control) case, initial core power, reactor coolant temperature, and pressurizer pressure are assumed to be at their nominal fullpower values consistent with steady-state full power operation. Uncertainties in initial conditions and instrument errors are included in the limit departure from nucleate boiling ratio (DNBR) as described in Reference 5 For the pressure transient case, the initial core power and reactor coolant temperature are assumed to be at their nominal full-power values plus uncertainty. The initial pressurizer pressure is assumed to be the nominal full-power value minus uncertainty.

2. Moderator and Doppler Coefficients of Reactivity

   The turbine trip is analyzed with minimum reactivity feedback which assumes a moderator temperature coefficient of zero and the least negative Doppler coefficient.

3. Reactor Control

   From the standpoint of the maximum pressures attained and DNBR, it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

4. Steam Release

   No credit is taken for the operation of the steam dump system or steam generator power operated relief valves. The steam generator pressure rises to the safety valve setpoint where steam release through safety valves limits secondary steam pressure at the setpoint value.

5. Pressurizer Spray and Power Operated Relief Valves
   a. For evaluating the minimum DNBR, full credit is taken for the effect of pressurizer spray and power operated relief valves in reducing or limiting the coolant pressure. Safety valves are also available.
   b. For evaluating the maximum RCS and steam generator pressures, no credit is taken for the effect of pressurizer spray and power operated relief valves in reducing or limiting the coolant pressure. Safety valves are available.
6. Feedwater Flow

   Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for emergency feedwater flow since a stabilized plant condition will be reached before emergency feedwater initiation is normally assumed to occur; however, the emergency feedwater pumps would be expected to start on a trip of the main feedwater pumps. The emergency feedwater flow would remove core decay heat following plant stabilization.

7. Reactor trip is actuated by the first Reactor Protection System trip setpoint reached with no credit taken for the direct reactor trip on the turbine trip. Trip signals are expected due to high pressurizer pressure and overtemperature ΔT.
8. The overtemperature ΔT setpoint used in the analyses is higher than the safety analysis limit used in the setpoints study to account for a 4°F allowance for temperature related effects.

15.2.7.2.2 Results

The transient responses for a total loss of load from full power operation are shown for 2 cases for the beginning of core life; 1 case for DNBR and 1 case for peak pressure, in Figures 15.2-19

through 15.2-21 and Figure 15.2-25 through Figure 15.2-27. The calculated sequence of events for the accident is shown in Table 15.2-1.

Figure 15.2-19, Figure 15.2-20, and Figure 15.2-21 show the transient responses for the total loss of steam load at beginning of life assuming full credit for the pressurizer spray and pressurizer power operated relief valves. No credit is taken for the steam dump. The reactor is tripped by the high pressurizer pressure trip channel. The minimum DNBR is well above the limit value. The pressurizer safety valves are actuated for this case and maintain system pressure below 110% of the design value. The steam generator safety valves open and limit the secondary steam pressure increase.

The total loss of load accident was also studied assuming the plant to be initially operating at full power with no credit taken for the pressurizer spray, pressurizer power operated relief valves, or steam dump. The reactor is tripped on the high pressurizer pressure signal. Figure 15.2-25, Figure 15.2-26, and Figure 15.2-27 show the beginning of life transients. The neutron flux remains constant at full power until the Reactor is tripped. In this case, the pressurizer safety valves are actuated and maintain system pressure below 110% of the design value.

Reference 8 presents additional results of analysis for a complete loss of heat sink including loss of main feedwater. This analysis shows the overpressure protection that is provided by the pressurizer and steam generator safety valves.

15.2.7.3 Conclusions

Results of the analyses, including those in Reference 8, show that the plant design is such that a total loss of external electrical load without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. Pressure relieving devices incorporated in the 2 systems are adequate to limit the maximum pressures to within the design limits.

The integrity of the core is maintained by operation of the Reactor Protection System, i.e., the DNBR will be maintained above the safety analysis limit values. Thus, no core safety limit will be violated.

15.2.8 Loss of Normal Feedwater

15.2.8.1 Identification of Causes and Accident Description

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of offsite power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during this accident, core damage would possibly occur from a sudden loss of heat sink. If an alternative supply of feedwater were not supplied to the plant, residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer occurs. Significant loss of water from the Reactor Coolant System (RCS) could conceivably lead to core damage. Since the plant is tripped well before the steam generator heat transfer capability is significantly reduced, the primary system variables never approach a DNB condition.

The following provides the necessary protection against a loss of normal feedwater:

1. Reactor trip on low-low water level in any steam generator.
2. Reactor trip on steam flow-feedwater flow mismatch in coincidence with low generator water level.
3. Two (2) motor driven emergency feedwater (EFW) pumps which are started on:
   a. Low-low level in any steam generator.
   b. Trip of all main feedwater pumps.
   c. Any safety injection signal.
   d. Loss of offsite power (automatic transfer to diesel generator).
   e. Manual actuation.
4. One (1) turbine driven emergency feedwater pump is started on:
   a. Low-Low level in any 2 steam generators.
   b. Loss of offsite power.
   c. Manual actuation.

   The motor driven emergency feedwater pumps are connected to vital buses and are supplied by Class 1E electric power from the diesels if a loss of offsite power occurs. The turbine driven pump utilizes steam from the safety class portions of the Main Steam System and exhausts it to the atmosphere. Both the motor driven and turbine driven emergency feedwater pumps are designed to start within 1 minute even if a loss of offsite power occurs simultaneously with the loss of normal feedwater. The emergency feedwater pumps take suction from the condensate storage tank for delivery to the steam generators.

   The analysis shows that following a loss of normal feedwater, the Emergency Feedwater System is capable of removing the stored and residual heat, thus preventing either overpressurization of the RCS or loss of water from the reactor core.

15.2.8.2 Analysis of Effects and Consequences

15.2.8.2.1 Method of Analysis

A detailed analysis using the LOFTRAN (Reference 4) Code is performed in order to obtain the plant transient following a loss of normal feedwater. The code describes the plant thermal kinetics, RCS including the natural circulation, pressurizer, steam generators and feedwater system, and computes pertinent variables including the steam generator level, pressurizer water level, pressurizer pressure, and reactor coolant average temperature.

Major assumptions are:

1. Reactor trip occurs on steam generator low-low level at 17.5% of narrow range span.

2. The plant is initially operating at 102% of the NSSS design rating.
3. Conservative core residual heat generation based on long-term operation at the initial power level preceding the trip is assumed. The 1979 decay heat ANSI 5.1 +2 SIGMA was used for calculation of residual decay heat levels.
4. The Emergency Feedwater System is actuated by the low-low steam generator water level signal.
5. The worst single failure in the Emergency Feedwater System occurs (turbinedriven pump) and 1 motor-driven pump is assumed to be unavailable. The emergency feedwater system is assumed to supply a total of 400 gpm equally split to all 3 steam generators from the motor-driven pump.
6. The pressurizer sprays are assumed operable while the pressurizer PORVs are assumed inoperable. This maximizes the peak transient pressurizer water volume.
7. Secondary system steam relief is achieved through the self-actuated safety valves. Note that steam relief will, in fact, be through the power-operated relief valves or condenser dump valves for most cases of a loss of normal feedwater. However, these have been assumed unavailable.
8. The initial reactor coolant average temperature is 6.3°F higher than the nominal value to allow for uncertainty on nominal temperature. The initial pressurizer pressure is 65 psi lower than the nominal value to allow for uncertainty on nominal pressure.

15.2.8.2.2 Results

Figure 15.2-31 and Figure 15.2-32 show the significant plant parameters following a loss of normal feedwater.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to the reduction of steam generator void fraction and because steam flow through the safety valves continues to dissipate the stored and generated heat. One (1) minute following the initiation of the low-low level trip, the motor driven EFW pump is automatically started, reducing the rate of water level decrease.

The capacity of the motor driven EFW pump is such that the water level in the steam generator being fed does not recede below the lowest level at which sufficient heat transfer area is available to dissipate core residual heat without water relief from the RCS relief or safety valves.

From Figure 15.2-32 it can be seen that at no time is there water relief from the pressurizer. If the emergency feed delivered is greater than that of 1 motor driven pump, the initial reactor power is less than 102% of the NSSS design rating, or if the steam generator water level in 1 or more steam generators is above the low-low level trip point at the time of trip, then the result for this transient will be less limiting.

The calculated sequence of events for this accident is listed in Table 15.2-1. As shown in Figure 15.2-31 and Figure 15.2-32, the plant approaches a stabilized condition following reactor

trip and emergency feedwater initiation. Plant procedures may be followed to further cool down the plant.

15.2.8.3 Conclusions

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the RCS, or the steam system since the emergency feedwater capacity is such that the reactor coolant water is not relieved from the pressurizer relief or safety

15.2.9 Loss of Offsite Power to the Station Auxiliaries

15.2.9.1 Identification of Causes and Accident Description

During a complete loss of offsite power and a turbine trip there will be a loss of power to the plant auxiliaries, i.e., the reactor coolant pumps, condensate pumps, etc.

The events following a loss of offsite power with turbine and reactor trip are described in the sequence listed below:

1. Plant vital instruments are supplied from emergency power sources.
2. As the steam system pressure rises following the trip, the steam generator power operated relief valves are automatically opened to the atmosphere. Steam dump to the condenser is assumed not to be available. If the power relief valves are not available, the steam generator self-actuated safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.
3. As the no load temperature is approached, the steam generator power operated relief valves (or the self-actuated safety valves, if the power operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot standby condition.
4. The emergency diesel generators start on loss of voltage on the plant ESF buses and begin to supply plant vital loads.

The Emergency Feedwater System is started automatically as discussed in the loss of normal feedwater analysis. The steam driven emergency feedwater pump utilizes steam from the safety class portions of the Main Steam System and exhausts to the atmosphere. The 2 motor driven emergency feedwater pumps are supplied by power from the diesel generators. The pumps take suction directly from the condensate storage tank for delivery to the steam generators.

Upon the loss of power to the reactor coolant pumps, coolant flow necessary for core cooling and the removal of residual heat is maintained by natural circulation in the reactor coolant loops.

15.2.9.2 Analysis of Effects and Consequences

A detailed analysis using the LOFTRAN code (Reference 4) is performed in order to determine the plant transient following Loss of Offsite Power. The code describes the plant thermal kinetics,

RCS including natural circulation, pressurizer, steam generators, and feedwater system, and computes pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature. Major assumptions differing from those in a loss of normal feedwater are:

1. No credit is taken for immediate response of control rod drive mechanisms caused by a loss of offsite power.
2. A heat transfer coefficient in the steam generator associated with RCS natural circulation is assumed following the reactor coolant pump coastdown.
3. The pressurizer PORVs are assumed operable.
4. The initial reactor coolant average temperature is 6.4°F lower than the nominal value to allow for uncertainty on nominal temperature.

The time sequence of events for the accident is given in Table 15.2-1. The first few seconds after the loss of power to the reactor coolant pumps will closely resemble a simulation of the complete loss of flow incident (see Section 15.3.4); i.e., core damage due to rapidly increasing core temperatures is prevented by promptly tripping the reactor. After the reactor trip, stored and residual heat must be removed to prevent damage to either the RCS or the core. The LOFTRAN code results show that the natural circulation flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

15.2.9.3 Conclusions

Results of the analysis show that, for the loss of offsite power to the station auxiliaries event, all safety criteria are met. EFW capacity is sufficient to prevent water relief through the pressurizer relief and safety valves; this assures that the RCS is not overpressurized.

Analysis of the natural circulation capability of the RCS demonstrates that sufficient long-term heat removal capability exists following reactor coolant pump coastdown to prevent fuel or clad damage.

It is assumed that there is leakage from the RCS to the secondary system in the steam generators and that radioactivity will be released to the atmosphere through the relief or safety valves. Parameters used in determining the amount of radioactivity released are given in Table 15.2-5.

15.2.9.4 Environmental Consequences of a Postulated Loss of Offsite Power to the Station Auxiliaries

The postulated incidents involving release of steam from the secondary system will not result in a release of radioactivity unless there is leakage from the RCS to the secondary system within the steam generators. A realistic and conservative analysis of the potential offsite doses resulting from this accident is presented.

These analyses incorporate assumptions for operating with defective fuel and steam generator leakage for a sufficient time prior to the postulated accident to establish equilibrium specific

activity levels in the secondary system. Parameters used in both the realistic and conservative analyses are listed in Table 15.2-5.

The assumptions used to determine the equilibrium concentrations of isotopes in the secondary system are as follows:

1. Primary to secondary leakage in steam generators occurs when the reactor is started and the leakage remains constant during the plant operation. For the conservative analysis, the Technical Specification limit on leakage rate of 1 gpm is used whereas 100 lbs/day is used in the realistic analysis.
2. Primary to secondary leakage is evenly distributed in the steam generators.
3. For the unconservative analysis, the reactor coolant activity is 1% defective fuel (see Table 11.1-2). For the realistic analysis, 12% of these values are used.
4. No noble gas is dissolved or contained in the steam generator water, i.e., all noble gas leaked to the secondary system is continuously released with steam from the steam generators through the condenser air removal system.
5. The blowdown rate from steam generators is continuous at 12,756 and 42,000 lbs/hr per steam generator for the conservative and realistic cases, respectively.

Secondary system equilibrium concentrations are provided in Table 15.2-6.

The following additional assumptions and parameters are used to calculate the activity releases and offsite doses for the postulated loss of offsite power to plant auxiliaries:

1. Offsite power is lost; main condensers are not available for steam dump.
2. Eight (8) hours after the accident the Residual Heat Removal System commences operation to cooldown the plant.
3. After 8 hours following the accident, no steam and activity are released to the environment.
4. No condenser air removal system release and no steam generator blowdown during the accident.
5. No noble gas is dissolved in steam generator water.
6. The iodine partition factor in the steam generators is 0.01 between the steam generator steam and water phases.
7. During the postulated accident, iodine carryover from the primary side is uniformly mixed with the water in the steam generators and is diluted by the incoming feedwater.
8. The steam release for cooling down the plant is equally contributed by all steam generators.
9. The 0-2 and 2-8 hour atmospheric diffusion factors, given in Appendix 15A, and the 0-8 hour breathing rate of 3.47×10^{-4} m^3/sec are applicable.
10. Dose model used to evaluate the environmental consequence of this accident is given in Appendix 15A.

11. Steam releases to the atmosphere for the loss of offsite power are given by Table 15.2-5.

Using the previously listed assumptions, isotopic releases to the environment are summarized by Table 15.2-7 and Table 15.2-8 for realistic and conservative analyses, respectively.

Gamma, beta, and thyroid doses in the first 2 hours of the loss of offsite power to plant auxiliaries for the realistic analysis at the site boundary are 9.51×10^{-7} rem, 1.85×10^{-6} rem and 1.77×10^{-5} rem, respectively. The corresponding doses at the low population zone are 2.20×10^{-7} rem, 4.30×10^{-7} rem, and 3.11×10^{-6} rem, respectively.

The gamma, beta, and thyroid doses in the first 2 hours of the loss of offsite power to plant auxiliaries for the conservative analysis at the site boundary are 9.69×10^{-4} rem, 1.86×10^{-3} rem, and 4.68×10^{-2} rem, respectively. Corresponding doses at the low population zone are 2.23×10^{-4} rem, 4.31×10^{-4} rem and 7.91×10^{-3} rem, respectively, for the duration of the accident.

The doses for this accident are well within the limits defined in 10 CFR 100 (25 Rem, whole body and 300 Rem, thyroid).

15.2.10 Excessive Heat Removal Due to Feedwater System Malfunction

15.2.10.1 Identification of Causes and Accident Description

Excessive feedwater additions or reductions in feedwater enthalpy are a means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the secondary plant and of the RCS. The overpower and overtemperature protection (high neutron flux, overtemperature ΔT, and overpower ΔT trips) prevent any power increase that could lead to fuel melting or a DNBR that is less than the DNBR limit.

An example of excessive feedwater flow would be a full opening of a feedwater control valve due to a feedwater control system malfunction or an operator error. At power this excess flow causes a greater load demand on the RCS due to increased subcooling in the steam generator. With the plant at no-load conditions, the addition of cold feedwater may cause a decrease in RCS temperature and thus a reactivity insertion due to the effects of the negative moderator coefficient of reactivity. Continuous addition of excessive feedwater is prevented by the steam generator high-high level trip, which closes the feedwater valves.

An example of a reduction in feedwater enthalpy is the transient associated with a postulated failure of the feedwater digital control system that causes the loss of feedwater heating. This results in a sudden reduction in feedwater temperature at the inlet to the steam generators and a consequential greater load demand on the RCS due to increased subcooling in the steam generator. In the presence of a negative moderator temperature coefficient, positive reactivity will be inserted causing an increase in power.

15.2.10.2 Analysis of Effects and Consequences

15.2.10.2.1 Method of Analysis

The excessive heat removal due to feedwater system malfunction transient is analyzed with the LOFTRAN code. This code simulates a multi-loop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. The detailed thermal-hydraulic THINC code is used for the limiting case to calculate the DNBR using transient information from LOFTRAN.

The system is analyzed to evaluate plant behavior in the event of a feedwater system malfunction.

Excessive feedwater addition due to a control system malfunction or operator error which allows a feedwater control valve to open fully is considered. Evaluations have shown that an excessive feedwater addition event from no-load conditions is less limiting than one from full power conditions due to the large DNBR margin that exists at subcooled conditions. Therefore, two (2) cases are analyzed as follows:

1. Accidental opening of one (1) feedwater control valve with the reactor in manual control at full power.
2. Accidental opening of one (1) feedwater control valve with the reactor in automatic control at full power.

The transient response following an excessive feedwater addition event is calculated with the following assumptions:

1. For the feedwater control valve accident at full power, one (1) feedwater control valve is assumed to malfunction resulting in a step increase to 250% of nominal feedwater flow to one (1) steam generator.
2. No credit is taken for the heat capacity of the RCS and steam generator thick metal in attenuating the resulting plant cooldown.
3. No credit is taken for the heat capacity of the steam and water in the unaffected steam generators.
4. The feedwater flow resulting from a fully open control valve is terminated by the steam generator high-high level signal that closes all feedwater control valves, closes all feedwater bypass valves, trips the main feedwater pumps, and shuts the feedwater isolation valves. The steam generator high-high level signal also produces a signal to trip the turbine.

A bounding feedwater enthalpy reduction due to loss of all feedwater heaters is considered. Two (2) cases are analyzed as follows:

1. Loss of all feedwater heaters with the reactor in manual control at full power.
2. Loss of all feedwater heaters with the reactor in automatic control at full power.

The failure of the digital control system is limiting at full power; thus, a zero load case is not analyzed.

The transient response following a feedwater enthalpy reduction event is calculated with the following assumptions:

1. The feedwater temperature cooldown profile resulting from the failure of the feedwater digital control system is conservatively modeled with two successive step changes. The first step decrease from the nominal full power feedwater temperature to the nominal outlet temperature of the deaerator downstream of the low pressure feedwater heater string, occurs at time zero. The second step decrease to the nominal outlet temperature of the condensate system (inlet to the low pressure heaters) occurs after the water downstream of the low pressure feedwater heaters at the time of the event has been purged.
2. The feedwater flow rate to the steam generators remains at the nominal full power value throughout the transient.
3. The transient is terminated by a reactor trip from an overpower ΔT signal, and by a low pressurizer pressure safety injection system actuation signal, which closes all feedwater control valves, closes all feedwater bypass valves, trips the main feedwater pumps, and shuts the feedwater isolation valves.
4. No credit is taken for the heat capacity of the RCS and steam generator thick metal in attenuating the resulting plant cooldown.

Normal reactor control systems and engineered safety systems are not required to function. The reactor protection system will actuate to trip the reactor due to an overpower condition (feedwater enthalpy reduction) or trip the turbine (excessive feedwater addition). No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

15.2.10.2.2 Results

Excessive Feedwater Addition

The full power excessive feedwater flow case with the reactor in manual control results in the greatest power increase. Assuming the reactor to be in the automatic control mode results in a slightly less severe transient. The rod control system is not required to function for an excessive feedwater flow event. A turbine trip and feedwater isolation are actuated when the steam generator level reaches the high-high level setpoint. For convenience, reactor trip is assumed to be initiated upon turbine trip. However, this function is not necessary for core protection. Should turbine trip not initiate a reactor trip signal, reactor trip will eventually occur on low-low steam generator level following feedwater isolation.

For excessive feedwater flow cases, continuous addition of cold feedwater is prevented by closure of feedwater control valves, a trip of the feedwater pumps, and closure of the feedwater pump bypass and isolation valves on steam generator high-high level signal.

Transient results (see Figure and Figure) show the core heat flux, pressurizer pressure, core T_{avg}, and DNBR, as well as the increase in nuclear power and loop ΔT associated with the increased thermal load on the reactor. Steam generator level rises until the feedwater is terminated as a result of the high-high steam generator level trip. The DNBR does not drop below the safety analysis limit DNBR value.

Feedwater Enthalpy Reduction

For the feedwater enthalpy reduction cases, the manual reactor control case results in the greatest power increase. This case is also more severe than the limiting excessive feedwater addition case. The reduction in feedwater temperature caused by the failure of the feedwater digital control system increases the thermal load on the primary system. The resultant temperature and power transients cause a reactor trip on an overpower ΔT signal. When the pressurizer pressure reaches the safety injection low pressure setpoint, the feedwater control and isolation valves are closed and feedwater isolation occurs. Following reactor trip and feedwater isolation, the plant will approach a stabilized condition at which point normal operating procedures may be followed.

Transient results (see Figure 15.2-33 and Figure 15.2-33a) show the core heat flux, pressurizer pressure, core T_{avg}, and DNBR, as well as the increase in nuclear power and loop ΔT associated with the increased thermal load on the reactor. Since the power level increases during the feedwater enthalpy reduction event, the fuel temperature will also increase until reactor trip occurs. However, the peak linear heat rate produced in the fuel rods remains below a value which would result in exceeding the fuel melting temperature. Hence, fuel melting is precluded for this event. The transient results also show that the DNBR does not fall below the safety analysis DNBR limit value.

15.2.10.3 Conclusion

The DNBRs encountered for the full power cases (excessive feedwater addition and feedwater enthalpy reduction cases) are above the safety analysis limit DNBR value and fuel melting is precluded.

15.2.11 Excessive Load Increase Incident

15.2.11.1 Identification of Causes and Accident Description

An excessive load increase incident is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10% step load increase or a 5% per minute ramp load increase in the range of 15 to 100% of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the Reactor Protection System.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

During power operation, steam dump to the condenser is controlled by reactor coolant condition signals; i.e., high reactor coolant temperature indicates a need for steam dump. A single controller malfunction does not cause steam dump; an interlock is provided which blocks the opening of the valves unless a large turbine load decrease or a turbine trip has occurred.

Protection against an excessive load increase accident is provided by the following Reactor Protection System signals:

1. Overpower ΔT.
2. Overtemperature ΔT.
3. Power range high neutron flux.

15.2.11.2 Analysis of Effects and Consequences

15.2.11.2.1 Method of Analysis

This accident is analyzed using the LOFTRAN (Reference 4) Code. The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator safety valves, and feedwater system. The code computes pertinent plant variables including temperatures, pressures, and power level.

Four (4) cases are analyzed to demonstrate the plant behavior following a 10% step load increase from rated load. These cases are as follows:

1. Reactor control in manual with BOL minimum moderator reactivity feedback,
2. Reactor control in manual with EOL maximum moderator reactivity feedback,
3. Reactor control in automatic with BOL minimum moderator reactivity feedback,
4. Reactor control in automatic with EOL maximum moderator reactivity feedback.

For the BOL minimum moderator feedback cases, the core has the least negative moderator temperature coefficient of reactivity and the least negative Doppler only power coefficient curve; therefore the least inherent transient response capability. For the EOL maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its highest absolute value and the most negative Doppler only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

A conservative limit on the turbine valve opening is assumed, and all cases are studied without credit being taken for pressurizer heaters.

This accident is analyzed with the Revised Thermal Design Procedure as described in Reference 5. Initial reactor power, RCS pressure and temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 5.

Plant characteristics and initial conditions are further discussed in Section 15.1.

15.2.11.2.2 Results

The calculated sequence of events for the excessive load increase incident are shown on Table 15.2-1.

Figure 15.2-35 through Figure 15.2-38 illustrate the transient with the reactor in the manual control mode. As expected, for the BOL minimum moderator feedback case there is a slight power increase, and the average core temperature shows a large decrease. This results in a DNBR which increases above its initial value. For the EOL maximum moderator feedback manually controlled case there is a much larger increase in reactor power due to the moderator feedback. A reduction in DNBR is experienced but DNBR remains above the limit value.

Figure 15.2-39 through Figure 15.2-42 illustrate the transient assuming the reactor is in the automatic control mode. Both the BOL minimum moderator feedback and the EOL maximum moderator feedback cases show that core power increases, thereby reducing the rate of decrease in coolant average temperature and pressurizer pressure. For both the beginning of life and end of life cases, the minimum DNBR remains above the limit value.

For all cases, the plant rapidly reaches a stabilized condition at the higher power level. Normal plant operating procedures would then be followed to reduce power.

The excessive load increase incident is an overpower transient for which the fuel temperatures will rise. Reactor trip does not occur for any of the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

Since DNB does not occur at any time during the excessive load increase transients, the ability of the primary coolant to remove heat from the fuel rod is not reduced. Thus, the fuel cladding temperature does not rise significantly above its initial value during the transient.

15.2.11.3 Conclusions

The analysis presented above shows that for a 10% step load increase, the DNBR remains above the safety analysis limit value, thereby precluding fuel or clad damage. The plant reaches a stabilized condition rapidly, following the load increase.

15.2.12 Accidental Depressurization of the Reactor Coolant System

15.2.12.1 Identification of Causes and Accident Description

An accidental depressurization of the Reactor Coolant System could occur as a result of an inadvertent opening of a pressurizer relief or safety valve. Since a safety valve is sized to relieve approximately twice the steam flowrate of a relief valve, and will therefore allow a much more rapid depressurization upon opening, the most severe core conditions resulting from an accidental depressurization of the RCS are associated with an inadvertent opening of a pressurizer safety

valve. Initially, the event results in a rapidly decreasing RCS pressure, which could reach hot leg saturation conditions without Reactor Protection System intervention.If saturated conditions are reached, the rate of depressurization is slowed considerably. However, the pressure continues to decrease throughout the event. The effect of the pressure decrease is to increase power via moderator density feedback. However, if the plant is in the automatic mode, the rod control system functions to maintain the power essentially constant throughout the initial stages of the transient. The average coolant temperature remains approximately the same, but the pressurizer level increases until reactor trip because of the decreased reactor coolant density.

The reactor will be tripped by the following Reactor Protection System signals:

1. Overtemperature ΔT.
2. Pressurizer low pressure

15.2.12.2 Analysis of Effects and Consequences

15.2.12.2.1 Method of Analysis

The accidental depressurization transient is analyzed with the LOFTRAN code (Reference 4). The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

This accident is analyzed with the Revision Thermal Design Procedure as described in Reference 5.

In calculating the DNBR the following conservative assumptions are made:

1. Plant characteristics and initial conditions are discussed in Section 15.1. Uncertainties and initial conditions are included in the limit DNBR as described in Reference 5.
2. A positive moderator temperature coefficient of reactivity for BOL operation in order to provide a conservatively high amount of positive reactivity feedback due to changes in moderator temperature. The spatial effect of voids due to local or subcooled boiling is not considered in the analysis with respect to reactivity feedback or core power shape. These voids would tend to flatten the core power distribution.
3. A low (absolute value) Doppler coefficient of reactivity such that the resultant amount of negative feedback is conservatively low in order to maximize any power increase due to moderator reactivity feedback.

15.2.12.2.2 Results

Figure 15.2-43 illustrates the nuclear power transient following the RCS depressurization accident. The flux increases until the time reactor trip occurs on overtemperature ΔT, thus resulting in a rapid decrease in the nuclear flux. The time of reactor trip is shown in Table 15.2-1.

The pressure decay transient following the accident is given on Figure 15.2-44. The resulting DNBR never goes below the safety analysis limit value as shown on Figure 15.2-45.

15.2.12.3 Conclusion

The pressurizer low pressure and the overtemperature ΔT Reactor Protection System signals provide adequate protection against this accident, and the minimum DNBR remains in excess of the safety analysis limit value.

15.2.13 Accidental Depressurization of the Main Steam System

NOTE: Section 15.2.13 is being retained for historical purposes only. The DNB results for Section 15.2.13 events are bounded by those presented in Section 15.4.7 which show that the minimum DNBR remains above the limit value for ruptures of the main steam line.

15.2.13.1 Identification of Causes and Accident Description

The most severe core conditions resulting from an accidental depressurization of the Main Steam System are associated with an inadvertent opening of a single steam dump, relief or safety valve. The analyses performed assuming a rupture of a main steam line are given in Section 15.4.

The steam release as a consequence of this accident results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the Reactor Coolant System causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin.

The analysis is performed to demonstrate that the following criterion is satisfied:

Assuming a stuck rod cluster control assembly and a single failure in the engineered safety features, the limit DNBR value will be met after reactor trip for a steam release equivalent to the spurious opening, with failure to close, of the largest of any single steam dump, relief or safety valve.

The following systems provide the necessary mitigation of an accidental depressurization of the main steam system.

1. Safety injection system actuation from any of the following:
   a. Two (2) out of 3 low pressurizer pressure signals.
   b. Two (2) out of 3 high-1 containment pressure signals.
2. The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the safety injection signal.

3. Redundant isolation of the main feedwater lines: Sustained high feedwater flow would cause additional cooldown. Therefore, a safety injection signal will rapidly close all feedwater control valves, trip the main feedwater pumps, and close the feedwater isolation valves.

15.2.13.2 Analysis of Effects and Consequences

15.2.13.2.1 Method of Analysis

The following analyses of a secondary system steam release are performed for this section based on methodologies documented in Reference 16.

1. A full plant digital computer simulation (LOFTRAN (Reference 4)) to determine Reactor Coolant System temperature and pressure during cooldown, and the effect of safety injection.
2. An analysis to ascertain that the reactor does not exceed the limit DNBR value.

The following conditions are assumed to exist at the time of a secondary steam system release.

1. End of life shutdown margin at no load, equilibrium xenon conditions, and with the most reactive rod cluster control assembly stuck in its fully withdrawn position. Operation of rod cluster control assembly banks during core burnup is restricted in such a way that addition of positive reactivity in a secondary system steam release accident will not lead to a more adverse condition than the case analyzed.
2. A negative moderator coefficient corresponding to the end of life rodded core with the most reactive rod cluster control assembly in the fully withdrawn position. The variation of the coefficient with temperature and pressure is included. The K_{eff} versus temperature at 1150 psia corresponding to the negative moderator temperature coefficient plus the Doppler temperature effect used is shown in Figure 15.2-46.
3. Minimum capability for injection of high concentration boric acid solution corresponding to the most restrictive single failure in the Safety Injection System. The injection curve is shown on Figure 15.2-47. This corresponds to the flow delivered by 1 charging pump delivering its full contents to the cold leg header. No credit has been taken for the low concentration boric acid that must be swept from the safety injection lines downstream of the refueling water storage tank (RWST) isolation valves prior to the delivery of high concentration boric acid (2300 ppm) to the reactor coolant loops.
4. The case studied is an initial steam flow of 255 pounds per second at 1100 psia from 1 steam generator with offsite power available. This is the maximum capacity of any single steam dump, relief or safety valve. Initial hot shutdown conditions at time 0 are assumed since this represents the most conservative initial condition.

   Should the reactor be just critical or operating at power at the time of a steam release, the reactor will be tripped by the normal overpower protection when power level reaches a trip point. Following a trip at power, the Reactor Coolant System contains more stored energy than at no load, the average coolant temperature is higher than at no load, and there is appreciable energy stored in the fuel.

Thus, the additional stored energy is removed via the cooldown caused by the steam release before the no load conditions of Reactor Coolant System temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis which assumes no load condition at time zero. However, since the initial steam generator water inventory is greatest at no load, the magnitude and duration of the Reactor Coolant System cooldown are less for steam line release occurring at power.

5. In computing the steam flow, the Moody Curve for fl/D = 0 is used.
6. Perfect moisture separation in the steam generator is assumed.
7. No credit was taken for secondary side safety injection actuation on low steam pressure.

15.2.13.2.2 Results

This calculated time sequence of events for this accident is listed in Table 15.2-1.

The results presented are a conservative indication of the events which would occur assuming a secondary system steam release since it is postulated that all of the conditions described above occur simultaneously.

Figure 15.2-48 and Figure 15.2-49 show the transient arising as the result of an initial steam flow of 255 lbs/second at 1100 psia with steam release from 1 safety valve. The assumed steam release is the maximum capacity of any single steam dump or safety valve. In this case safety injection is initiated automatically by low pressurizer pressure. Operation of 1 centrifugal charging pump is considered. Boron solution at 2300 ppm from the refueling water storage tank enters the Reactor Coolant System providing sufficient negative reactivity to terminate the transient. The reactivity transient for the case shown in Figure 15.2-49 is more severe than the case of a failed steam generator safety or relief valve, which is terminated by steam line differential pressure, or a failed condenser dump valve that is terminated by low pressurizer pressure and level.

The transient is quite conservative with respect to cooldown, since no credit is taken for the energy stored in the system metal other than that of the fuel elements or the energy stored in the other steam generators. Since the transient occurs over a period of about 5 minutes, the neglected stored energy is likely to have a significant effect in slowing the cooldown.

15.2.13.3 Conclusions

The analysis has shown that the criteria stated earlier in this section are satisfied. For an accidental depressurization of the Main Steam System, the DNB design basis is met. This case is less limiting than the rupture of a main steam pipe case presented in Section 15.4.

15.2.14 Inadvertent Operation of the Emergency Core Cooling System During Power Operation

15.2.14.1 Identification of Causes and Accident Description

Spurious Emergency Core Cooling System (ECCS) operation at power could be caused by operator error or a false electrical actuating signal. A spurious signal in any of the following channels could cause this accident:

1. High containment pressure.
2. Low pressurizer pressure.
3. High steam line differential pressure.
4. Low steam line pressure.
5. Manual actuation.

Following the actuation signal, the suction of the coolant charging pumps is diverted from the volume control tank to the refueling water storage tank. The charging pumps then force highly concentrated (2300 ppm) boric acid solution from the RWST, through the header and injection line, and into the cold legs of each loop. The low head safety injection pumps also start automatically but provide no flow when the Reactor Coolant System is at normal pressure.

A Safety Injection System signal normally results in a reactor trip followed by a turbine trip. However, it cannot be assumed that any single fault that actuates the safety injection system will also produce a reactor trip. Therefore, 2 different courses of events are considered.

Case A - Trip occurs at the same time spurious injection starts.

Case B - The Reactor Protection System produces a trip later in the transient.

1. Case A

   For Case A, the operator should determine if the spurious signal was transient or steady state in nature, i.e., an occasional occurrence or a definite fault. The operator will determine this by following approved procedures. In the transient case, the operator would stop the safety injection and bring the plant to the hot shutdown condition. If the SIS must be disabled for repair, boration should continue and the plant brought to cold shutdown.

2. Case B

   For Case B, the Reactor Protection System does not produce an immediate trip and the reactor experiences a negative reactivity excursion due to the injected boron causing a decrease in the reactor power. At beginning of life, the power mismatch causes a drop in T_{avg} and consequent coolant shrinkage, and pressurizer pressure and level drop. Load will decrease due to the effect of reduced steam pressure on load when the turbine throttle valve is fully open. If automatic rod control is used, these effects will be lessened until the rods have moved out of the core. The transient is eventually terminated by the Reactor Protection System low-pressure trip or by manual trip.

   Results at end of life are similar except that moderator feedback effects result in a slower transient. he pressurizer pressure and level increase slowly and the coolant T_{avg} decreases slowly. The transient is eventually terminated by the Reactor Protection System high pressurizer pressure or high pressurizer level trip or by manual trip.

   The time to trip is affected by initial operating conditions including core burnup history which affects initial boron concentration, rate of change of boron concentration, Doppler and moderator coefficients.

   Recovery from this incident for Case B is made in the same manner described for Case A. The only difference is the lower T_{avg} and pressure associated with the power mismatch during the transient. The time at which reactor trip occurs is of no concern for this occurrence. At lower loads coolant contraction will be slower resulting in a longer time to trip.

15.2.14.2 Analysis of Effects and Consequences

15.2.14.2.1 Method of Analysis

The spurious operation of the Safety Injection System is analyzed with the LOFTRAN (Reference 4) code. The code simulates the neutron kinetics, reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator safety valves, and the effect of the safety injection system. The program computes pertinent plant variables including temperatures, pressures, and power level.

Because of the power and temperature reduction during the transient, operating conditions do not approach the core limits. Analysis of several cases shows that the results are relatively independent of time to trip.

A typical transient is considered representing conditions at beginning of core life. This accident is analyzed with the Revised Thermal Design Procedure as described in Reference 5. The assumptions made in the analysis are:

1. Initial Operating Conditions

   The initial reactor power, pressure, and reactor coolant system temperatures are assumed at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in Reference 5.

2. Moderator and Doppler Coefficients of Reactivity

   A positive beginning of life moderator temperature coefficient was used. A low absolute value Doppler power coefficient was assumed.

3. Reactor Control

   The reactor was assumed to be in manual control.

4. Pressurizer Heaters

   Pressurizer heaters were assumed to be inoperable in order to increase the rate of pressure drop.

5. Boron Injection

   At time 0, 2 charging pumps inject 2300 ppm borated water into the cold legs of each loop.

6. Turbine Load

   Turbine load was assumed constant until the governor drives the throttle valve wide open. Then turbine load drops as steam pressure drops.

7. Reactor Trip

   Reactor trip was initiated by low pressurizer pressure. The trip was conservatively assumed to be delayed until the pressure reached 1775 psia.

15.2.14.2.2 Results

The calculated time sequence of events for this accident is listed in Table 15.2-1.

The transient response for the minimum feedback case is shown in Figure 15.2-50 and Figure 15.2-51. Nuclear power starts decreasing immediately due to boron injection, but steam flow does not decrease until 36 seconds into the transient when the turbine throttle valve goes wide open. The mismatch between load and nuclear power causes T_{avg}, pressurizer water level, and pressurizer pressure to drop. The low pressure trip setpoint is reached at 52 seconds and rods start moving into the core at 54 seconds.

15.2.14.3 Conclusions

Results of the analysis show that spurious safety injection with or without immediate reactor trip presents no hazard to the integrity of the Reactor Coolant System.

DNBR is never less than the initial value. Thus, there will be no cladding damage and no release of fission products to the reactor coolant system.

If the reactor does not trip immediately, the low pressure reactor trip will be actuated. This trips the turbine and prevents excess cooldown thereby expediting recovery from the incident.

15.2.15 Anticipated Transients Without Trip

The worst common mode failure which is postulated to occur is the failure to scram the reactor after an anticipated transient has occurred. A series of generic studies (Reference 11 and Reference 14) on Anticipated Transients Without Scram (ATWS) showed acceptable consequences would result provided that the turbine trips and emergency feedwater flow is initiated in a timely manner. The effects of ATWS events are not considered as part of the design basis for transients analyzed in Chapter 15. The final NRC ATWS rule (Reference 15) requires that Westinghouse designed plants install ATWS Mitigation System Actuation Circuitry (AMSAC) to initiate a turbine trip and actuate emergency feedwater flow independent of the Reactor Protection System. The V. C. Summer AMSAC design is described in Section 7.8 of the FSAR.

15.2.16 References

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11. Westinghouse Anticipated Transients Without Trip Analysis, WCAP-8330, August, 1974.

12. Letter NS-CE-559, dated February 21, 1975, from C. Eicheldinger (Westinghouse) to D. B. Vassallo (NRC).

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14. Anderson, T. M., *ATWS Submittal*, Westinghouse letter NS-TMA-2182 to S. H. Hanauer of the NRC, December, 1979.

15. ATWS Final Rule - Code of Federal Regulations, Title 10, Part 50.62 and Supplementary Information Package, *Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light Water Cooled Nuclear Power Plants.*

16. *Reactor Core Response to Excessive Secondary Steam Releases*, WCAP-9226-P-A, Rev. 1, February 1998.

17. Deleted (RN VCS-UCR-2020-01).

18. Deleted (RN VCS-UCR-2020-01).

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Table 15.2-1
Time Sequence of Events For Condition II Events

Accident	Event	Time, sec
Uncontrolled RCCA Withdrawal from a Subcritical Condition	Initiation of uncontrolled rod withdrawal 82.5 pcm/sec reactivity insertion rate from 10^{-9} fraction of nominal power	0.0
	Power range high neutron flux setpoint reached	9.6
	Peak nuclear power occurs	9.7
	Rods begin to fall into core	10.1
	Peak heat flux occurs	11.9
	Peak hot spot average clad temperature occurs	12.1
	Peak hot spot average fuel temperature occurs	12.4
	Peak hot spot fuel centerline temperature occurs	13.1
Uncontrolled RCCA Withdrawal at Power		
1. Minimum Reactivity Feedback	Initiation of uncontrolled RCCA withdrawal at a high reactivity insertion rate (70 pcm/sec)	0.0
	Power range high neutron flux high trip setpoint reached	1.6
	Rods begin to fall into core	2.1
	Minimum DNBR occurs	3.1

Table 15.2-1 (continued)
Time Sequence of Events For Condition II Events

Accident	Event	Time, sec
2. Minimum Reactivity Feedback	Initiation of uncontrolled RCCA withdrawal at a low reactivity insertion rate (5 pcm/sec)	0.0
	Overtemperature ΔT reactor trip signal initiated	271.1
	Rods begin to fall into core	273.1
	Minimum DNBR occurs	273.1
Uncontrolled Boron Dilution		
1. Dilution during refueling	Dilution begins	0
	Operator receives high flux at shutdown alarm, set at twice background	2123
	Operator isolates source of dilution; minimum margin to criticality occurs	3923
2. Dilution during cold shutdown	Operator receives high flux at shutdown alarm set at twice background	0
	Operator isolates source of dilution; shutdown margin is lost	816
3. Dilution during hot shutdown	Operator receives high flux at shutdown alarm set at twice background	0
	Operator isolates source of dilution; shutdown margin is lost	816
4. Dilution during hot standby	Operator receives high flux at shutdown alarm set at twice background	0
	Operator isolates source of dilution; shutdown margin is lost	804

Table 15.2-1 (continued)
Time Sequence of Events For Condition II Events

Accident	Event	Time, sec
5. Dilution during startup	Source Range High Neutron Flux	0
	Shutdown margin lost (if dilution continues after trip)	1356
6. Dilution during full power operation		
a. Automatic reactor control	Operator receives lo-lo rod insertion limit alarm due to dilution	0
	Shutdown margin is lost	1548
b. Manual reactor control	Overtemperature ΔT reactor trip due to dilution	0
	Shutdown margin lost (if dilution continues after trip)	1224
Partial Loss of forced Reactor Coolant Flow		
All loops operating, one pump coasting down		
	Coastdown begins	0.0
	Low flow reactor trip	1.8
	Rods begin to drop	2.8
	Minimum DNBR occurs	3.7
Loss of External Electrical Load		
1. With pressure control	Loss of electrical load	0.0
	Initiation of steam release from steam generator safety valves	7.7
	Overtemperature ΔT trip setpoint reached	10.3
	Rods begin to drop	11.8
	Minimum DNBR occurs	13.1

Table 15.2-1 (continued)
Time Sequence of Events For Condition II Events

Accident	Event	Time, sec	
2. Without pressure control	Loss of Electrical load		0.0
	High pressurizer pressure trip setpoint reached		5.5
	Rods begin to drop		7.5
	Peak RCS pressure occurs		8.8
	Initiation of steam release from steam generator safety valves		9.0
	Minimum DNBR occurs		(a)
		w/power	w/o power
Loss of Normal Feedwater and Loss of Offsite Power to the Station Auxiliaries	Main feedwater flow stops	10	10
	Low-low steam generator water level reactor trip setpoint	65.8	65.7
	Rods begin to drop	67.8	67.7
	Reactor coolant pumps begin to coast down	-	69.7
	All steam generators begin to receive emergency feedwater from one motor driven emergency feedwater pump	125.9	125.7
	Cold emergency feedwater is delivered to the steam generators	142.8	142.6
	Peak water level in pressurizer occurs	3232.8	354.4

(a) DNBR does not decrease below its initial value

Table 15.2-1 (continued)
Time Sequence of Events For Condition II Events

Accident	Event	Time, sec	
	Core decay heat plus pump heat decreases to emergency feedwater heat removal capacity	~3250	-
	Core decay heat decreases to emergency feedwater heat removal capacity	-	~375
Excessive Feedwater Flow at Full Load	One main feedwater control valve fails fully open		0
	High-high steam generator level signal generated		32.0
	Turbine trip occurs due to high-high steam generator level		34.0
	Minimum DNBR occurs		34.5
	Reactor trip due to turbine trip (1)		36.0
	Feedwater isolation valves fully closed		45.0
Feedwater Enthalpy Reduction at Full Load	Feedwater digital control system fails and a loss of all feedwater heaters occurs		0.0
	Overpower ΔT reactor trip setpoint reached		53.6
	Rod motion occurs		55.1
	Minimum DNBR occurs		56.0
	Peak linear heat rate occurs		56.0
	Low pressurizer pressure safety injection setpoint reached		72.0
	Feedwater isolation occurs		97.3

(1) Not a required safety function.

Table 15.2-1 (continued)
Time Sequence of Events For Condition II Events

Accident	Event	Time, sec
Excessive Load Increase		
1. Manual reactor control (BOL minimum moderator feedback)	10% step load increase	0.0
	Equilibrium conditions reached (approximate times only)	125
2. Manual reactor control (EOL maximum moderator feedback)	10% Step load increase	0.0
	Equilibrium conditions reached (approximate times only)	50
3. Automatic reactor control (BOL minimum moderator feedback)	10% Step load increase	0.0
	Equilibrium conditions reached (approximate times only)	150
4. Automatic reactor control (EOL maximum moderator feedback)	10% Step load increase	0.0
	Equilibrium conditions reached (approximate times only)	75
Accidental Depressurization of the Reactor Coolant System	Inadvertent opening of one RCS safety valve	0.0
	Overtemperature ΔT trip setpoint reached	25.2
	Rods begin to drop	26.7
	Minimum DNBR occurs	27.2
Accidental Depressurization of the Main Steam System	Inadvertent opening of one main steam safety or relief valve	0.0
	Pressurizer empties	189
	Boron from the RWST reaches RCS loops	253

Table 15.2-1 (continued)
Time Sequence of Events For Condition II Events

Accident	Event	Time, sec
Inadvertent Operation of the ECCS During Power Operation	Charging pumps begin injecting borated water	0.0
	Low-pressure trip setpoint reached	52
	Rods begin to drop	54

Table 15.2-5
Parameters Used in Loss of Offsite Power Analysis

	Realistic Analysis	Conservative Analysis
Core thermal power	2958 MWt	2958 MWt
Steam generator tube leak rate prior to and during accident	100 lbs/day (1)	1.0 gpm
Fuel defects	0.12% (1)	1%
Iodine partition factor in steam generators prior to and during accident	0.01	0.01
Blowdown rate per steam generator prior to accident	42,000 lbs/hr	12,756 lbs/hr
Duration of plant cooldown by secondary system after accident	8 hr.	8 hr.
Steam release from three steam generators	447,900 lbs (0-2hr) 868,300 lbs (2-8hr)	447,900 lbs (0-2hr) 868,300 lbs (2-8hr)
Feedwater flow to three steam generators	375,500 lbs (0-2hr) 841,800 lbs (2-8hr)	375,500 lbs (0-2hr) 841,800 lbs (2-8hr)
Meteorology	Annual average	Accident

(1) American National Standards Institute, “Source Term Specification”, ANS/ANSI 18.1-1984.

Table 15.2-6
Secondary System Equilibrium Concentration (μCi/lb)

Isotopes	Realistic	Conservative
I-131	1.57×10^{-2}	4.87×10^{1}
I-132	4.94×10^{-3}	6.29×10^{0}
I-133	1.96×10^{-2}	4.35×10^{1}
I-134	4.55×10^{-4}	5.05×10^{-1}
I-135	7.07×10^{-3}	1.14×10^{1}

Table 15.2-7
Loss of Offsite Power Accident Isotopic Release to Environment Realistic Analysis

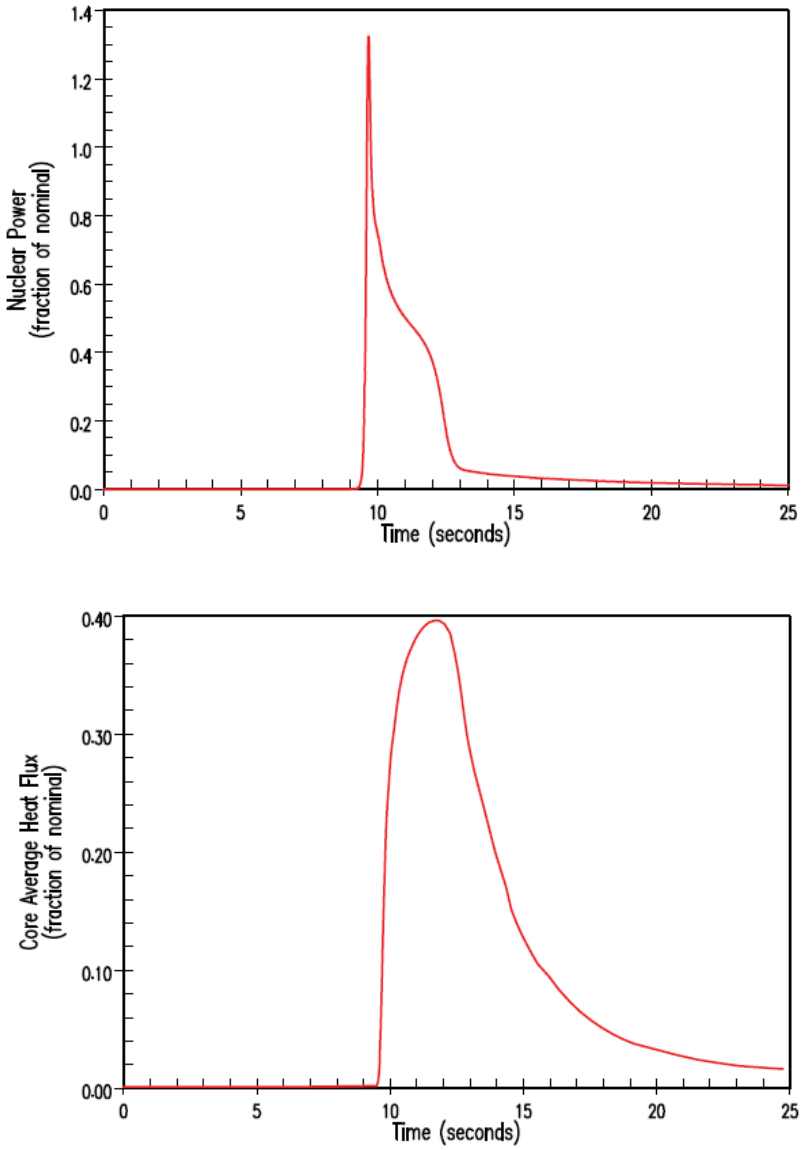
Isotope	Activity Released to Environment by Accident (Ci) (0-2 hr)	(2-8 hr)
I-131	9.3×10^{-5}	1.9×10^{-4}
I-132	3.9×10^{-5}	8.8×10^{-5}
I-133	1.2×10^{-4}	2.4×10^{-4}
I-134	5.0×10^{-6}	1.2×10^{-5}
I-135	4.7×10^{-5}	9.8×10^{-5}
Xe-131m	1.0×10^{-3}	3.1×10^{-3}
Xe-133	1.3×10^{-1}	3.9×10^{-1}
Xe-133m	8.6×10^{-3}	2.6×10^{-2}
Xe-135	3.9×10^{-3}	1.2×10^{-2}
Xe-135m	2.4×10^{-4}	7.1×10^{-4}
Xe-138	2.9×10^{-4}	8.7×10^{-4}
Kr-83m	2.0×10^{-4}	5.9×10^{-4}
Kr-85	3.5×10^{-3}	1.0×10^{-2}
Kr-85m	8.2×10^{-4}	2.5×10^{-3}
Kr-87	5.0×10^{-4}	1.5×10^{-3}
Kr-88	1.5×10^{-3}	4.4×10^{-3}
Kr-89	4.0×10^{-5}	1.2×10^{-4}

Table 15.2-8
Loss of Offsite Power Accident
Isotopic Release to Environment
Conservative Analysis

Isotope	Activity Released to Environment by Accident (Ci) (0-2 hr)	(2-8 hr)
I-131	2.6×10^{-1}	4.9×10^{-1}
I-132	4.2×10^{-2}	1.0×10^{-1}
I-133	2.4×10^{-1}	4.7×10^{-1}
I-134	5.3×10^{-3}	1.3×10^{-2}
I-135	6.8×10^{-2}	1.4×10^{-1}
Xe-131m	1.0×10^{0}	3.1×10^{0}
Xe-133	1.3×10^{2}	4.0×10^{2}
Xe-133m	8.6×10^{0}	2.6×10^{1}
Xe-135	3.9×10^{0}	1.2×10^{1}
Xe-135m	2.4×10^{-1}	7.1×10^{-1}
Xe-138	2.9×10^{-1}	8.7×10^{-1}
Kr-83m	2.0×10^{-1}	5.9×10^{-1}
Kr-85	3.5×10^{0}	1.0×10^{1}
Kr-85m	8.2×10^{-1}	2.5×10^{0}
Kr-87	5.0×10^{-1}	1.5×10^{0}
Kr-88	1.5×10^{0}	4.4×10^{0}
Kr-89	4.0×10^{-2}	1.2×10^{-1}

Figure 15.2-1

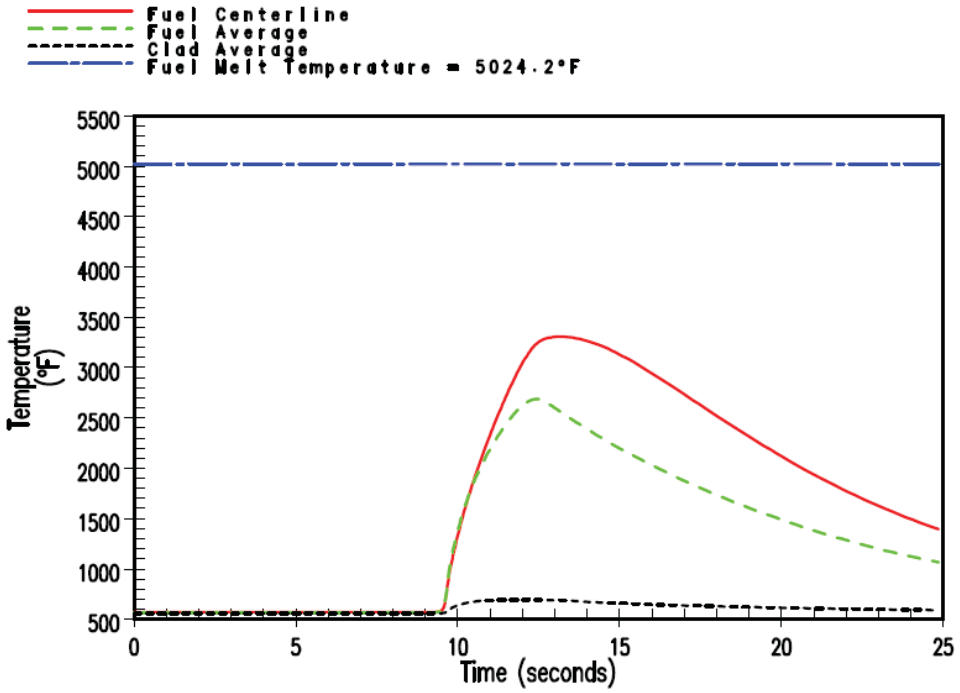
UNCONTROLLED RCCA WITHDRAWAL FROM SUBCRITICAL: NUCLEAR POWER AND CORE HEAT FLUX VS. TIME



South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
Uncontrolled RCCA Withdrawal from Subcritical: Nuclear Power and Core Heat Flux vs. Time
Figure 15.2-1

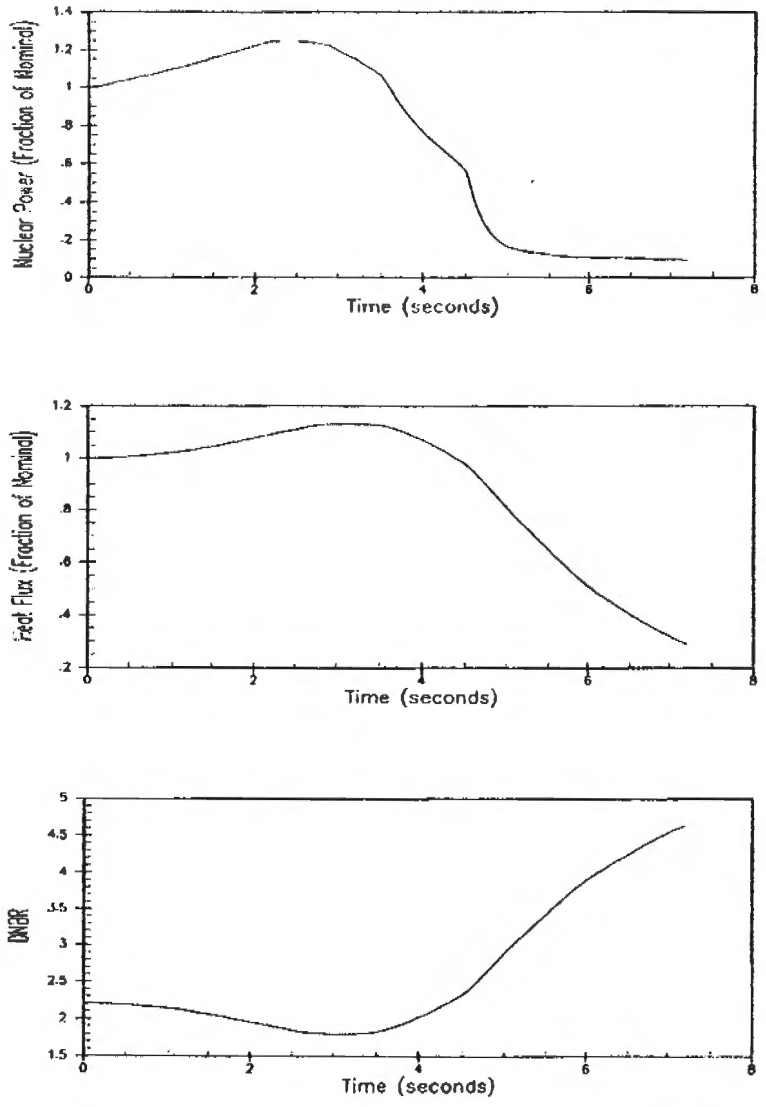
Figure 15.2-2

UNCONTROLLED RCCA WITHDRAWAL FROM SUBCRITICAL: FUEL CENTERLINE, AVERAGE, AND CLAD TEMPERATURE VS. TIME



South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
Uncontrolled RCCA Withdrawal from Subcritical: Fuel Centerline, Average, and Clad Temperature vs. Time
Figure 15.2-2

Figure 15.2-3
UNCONTROLLED ROD WITHDRAWAL FROM 100% POWER TERMINATED BY HIGH NEUTRON FLUX TRIP NUCLEAR POWER, HEAT FLUX, AND DNBR VS. TIME



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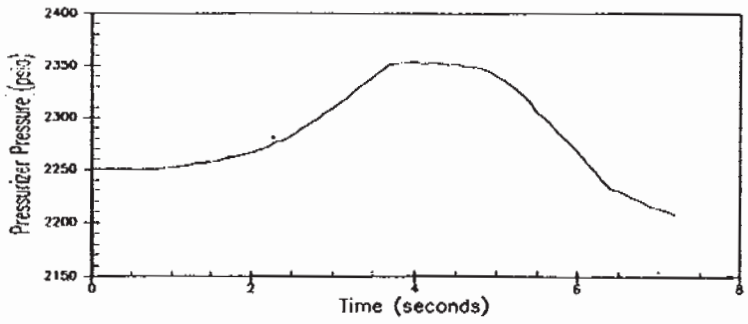
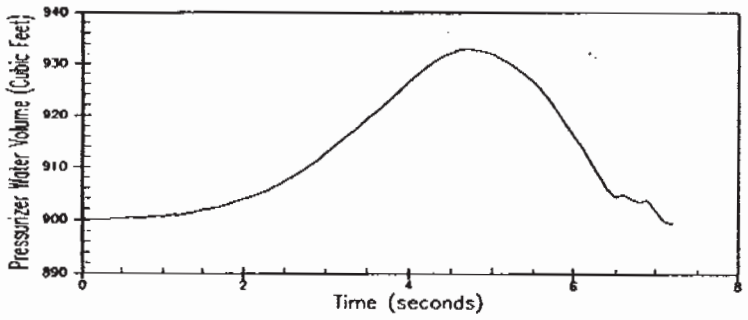
VIRGIL C. SUMMER NUCLEAR STATION

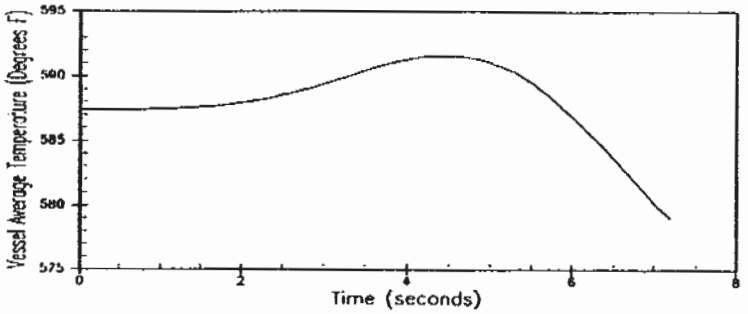
Uncontrolled Rod Withdrawal From
100% Power Terminated by
High Neutron Flux Trip
Nuclear Power, Heat Flux and DNBR vs. Time
Figure 15.2-3

Figure 15.2-4

UNCONTROLLED ROD WITHDRAWAL FROM 100% POWER TERMINATED BY HIGH NEUTRON FLUX TRIP PRESSURIZER PRESS, WATER VOLUME, AND T_{AVG} VS. TIME



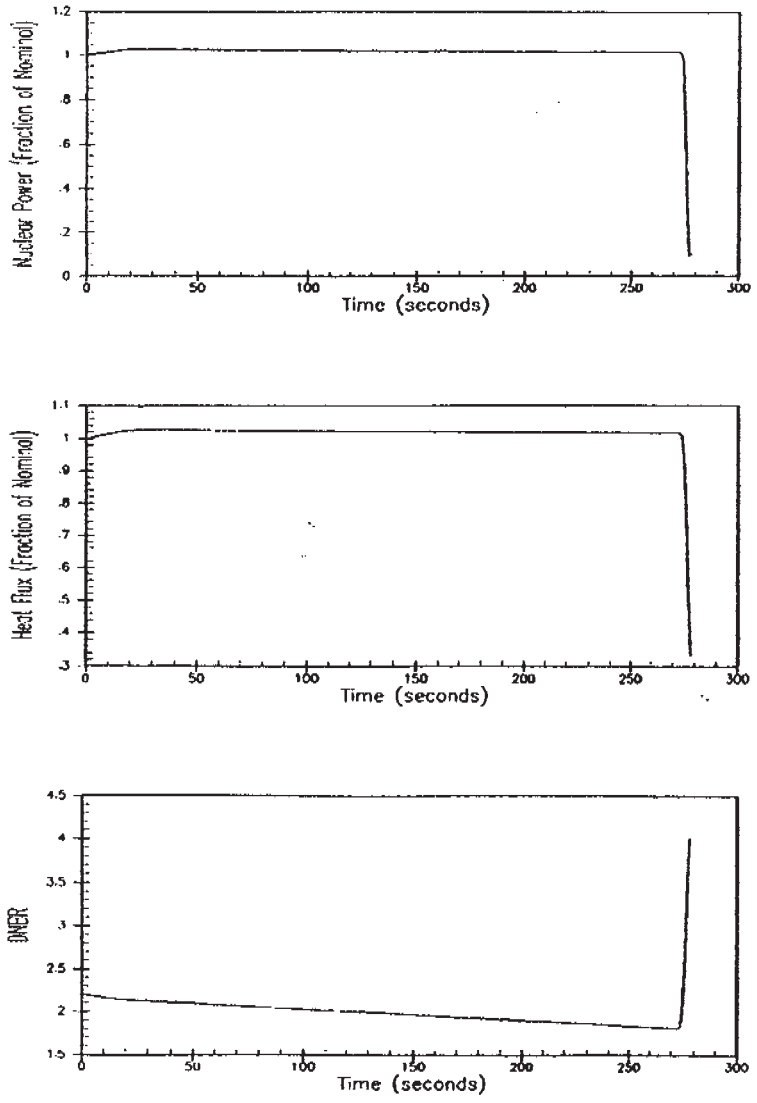




SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Uncontrolled Rod Withdrawal From 100% Power Terminated by High Neutron Flux Trip Pressurizer Press, Water Volume and Tavg vs. Time Figure 15.2-4

Figure 15.2-5

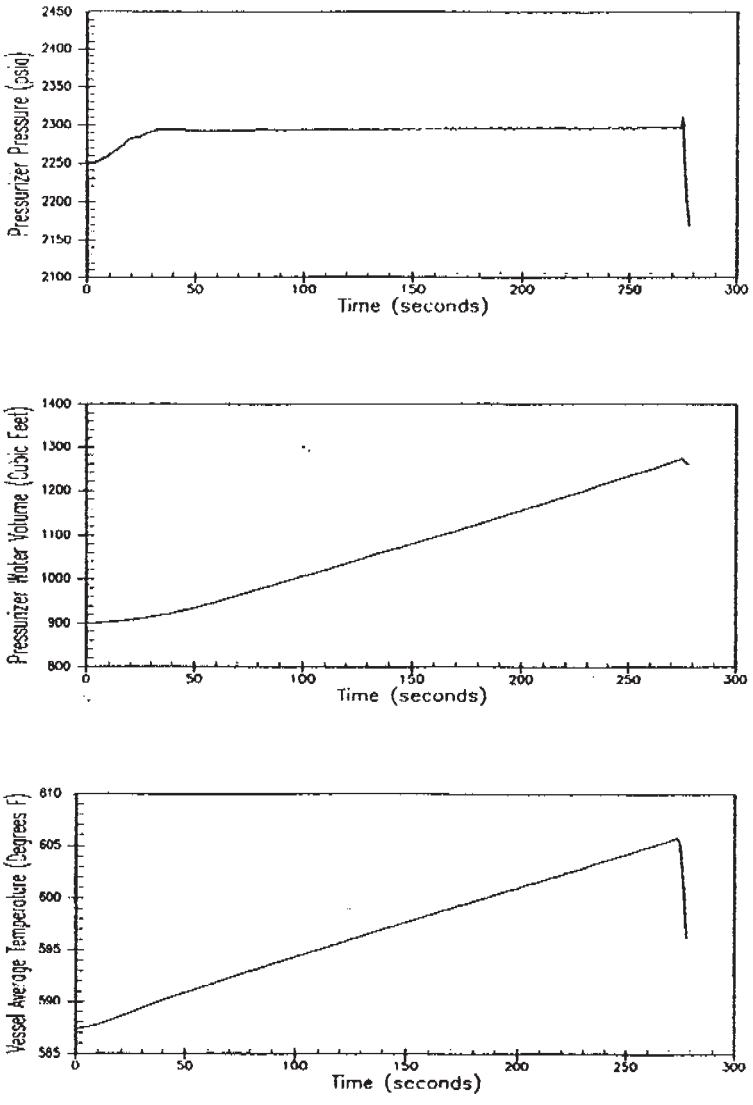
UNCONTROLLED ROD WITHDRAWAL FROM 100% POWER TERMINATED BY OVERTEMPERATURE ΔT TRIP NUCLEAR POWER, HEAT FLUX, AND DNBR VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Uncontrolled Rod Withdrawal From 100% Power Terminated by Overtemperature ΔT Trip Nuclear Power, Heat Flux and DNBR vs. Time Figure 15.2-5

Figure 15.2-6

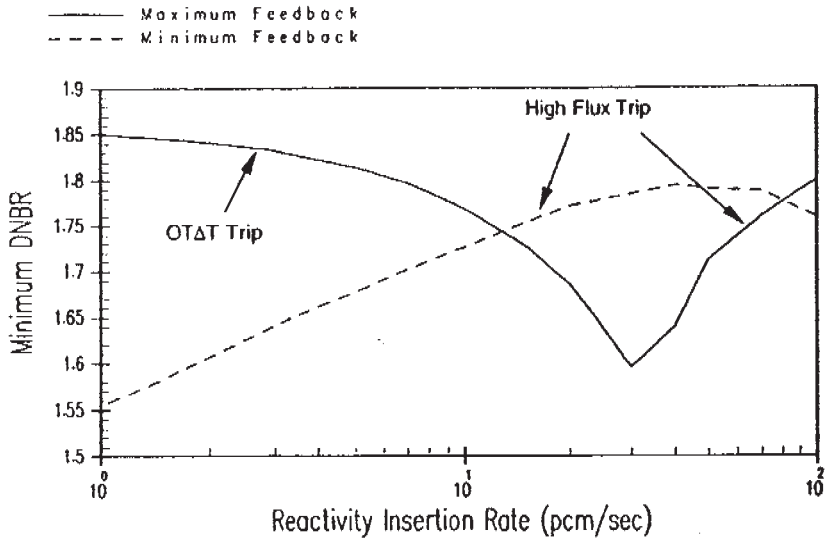
UNCONTROLLED ROD WITHDRAWAL FROM 100% POWER TERMINATED BY OVERTEMPERATURE ΔT TRIP PRESSURIZER PRESS, WATER VOLUME, AND T_{AVG} VS.TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Uncontrolled Rod Withdrawal From 100% Power Terminated by Overtemperature ΔT Trip Pressurizer Press, Water Volume and Tavg vs. Time Figure 15.2-6

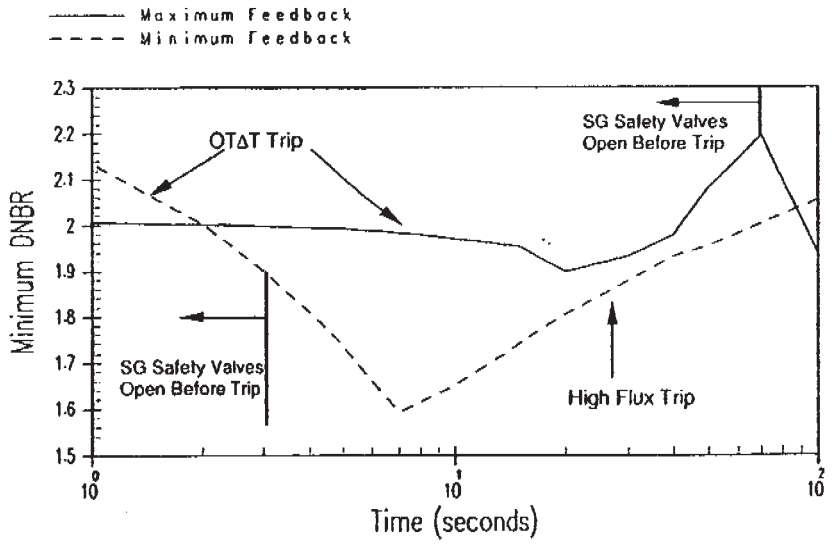
Figure 15.2-7

EFFECT OF REACTIVITY INSERTION RATE ON MINIMUM DNBR FOR A ROD WITHDRAWAL ACCIDENT AT 100% POWER



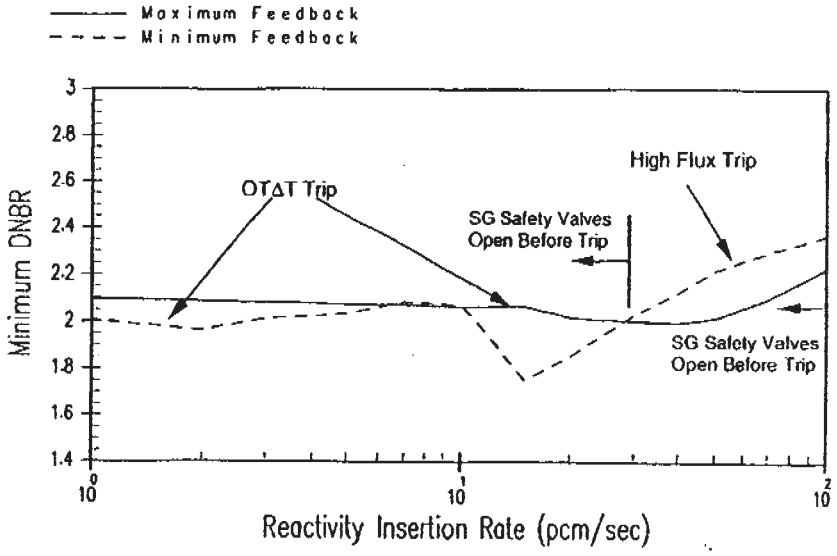
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Effect of Reactivity Insertion Rate on Minimum DNBR for a Rod Withdrawal Accident at 100% Power Figure 15.2-7

Figure 15.2-8
EFFECT OF REACTIVITY INSERTION RATE ON MINIMUM DNBR FOR A ROD WITHDRAWAL ACCIDENT AT 60% POWER



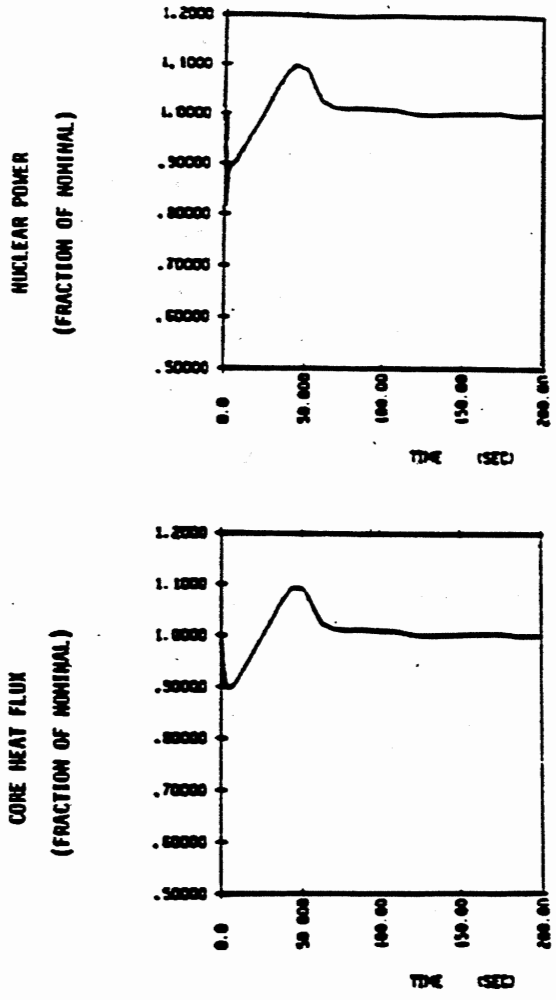
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Effect of Reactivity Insertion Rate on Minimum DNBR for a Rod Withdrawal Accident at 60% Power Figure 15.2-8

Figure 15.2-9
EFFECT OF REACTIVITY INSERTION RATE ON MINIMUM DNBR FOR A ROD WITHDRAWAL ACCIDENT AT 10% POWER



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Effect of Reactivity Insertion Rate on Minimum DNBR for a Rod Withdrawal Accident at 10% Power Figure 15.2-9

Figure 15.2-10
TRANSIENT RESPONSE TO A DROPPED RCCA
NUCLEAR POWER AND HEAT FLUX VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Transient Response To A Dropped RCCA
Nuclear Power and Heat Flux vs. Time
Figure 15.2-10

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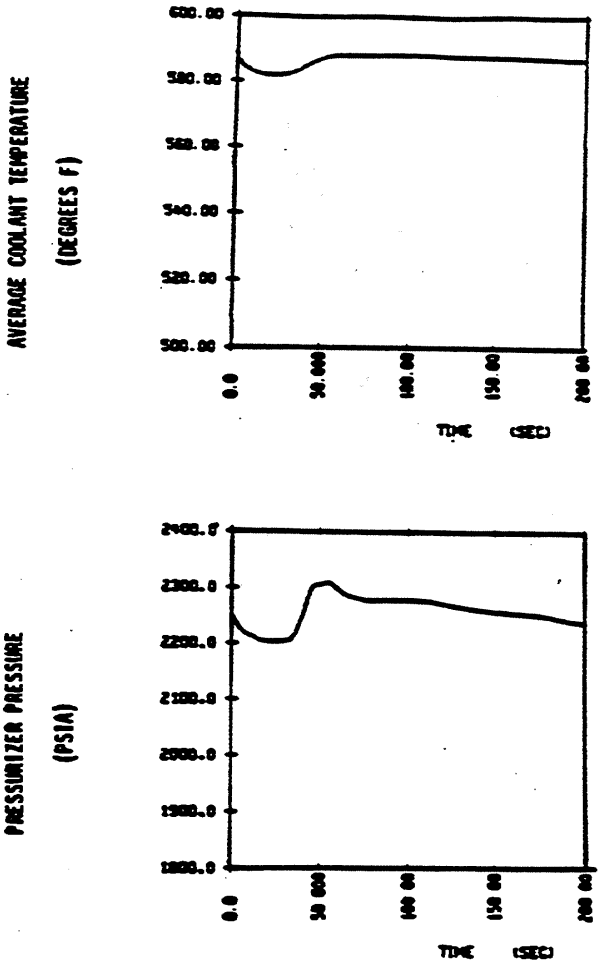
JULY 1996

Figure 15.2-11

TRANSIENT RESPONSE TO A DROPPED RCCA
T_{AVG} AND PRESSURIZER PRESSURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Transient Response To A Dropped RCCA Tavg and Pressurizer Pressure vs. Time Figure 15.2-11

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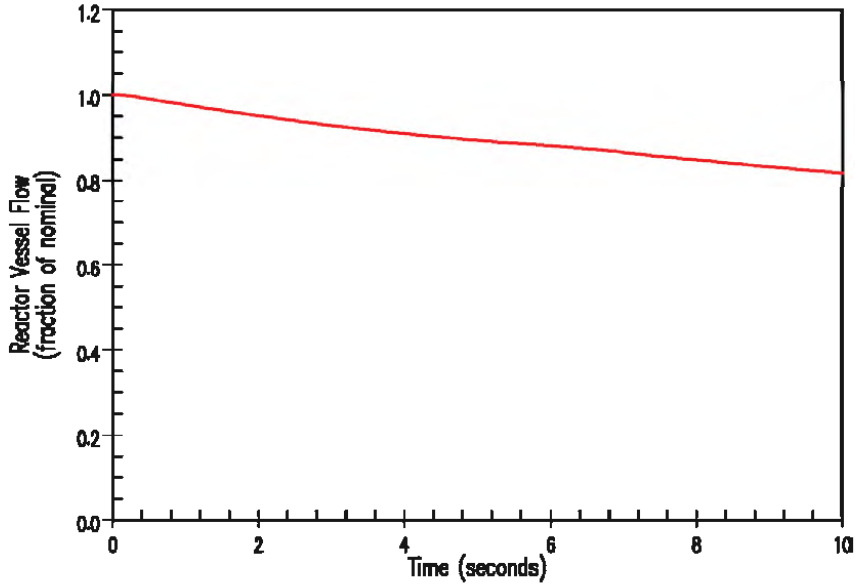
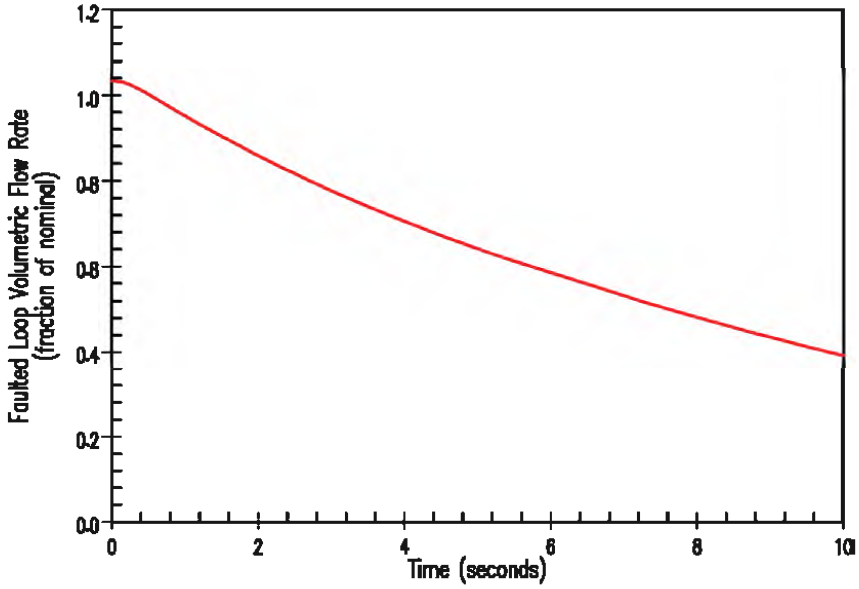
Figure 15.2-12

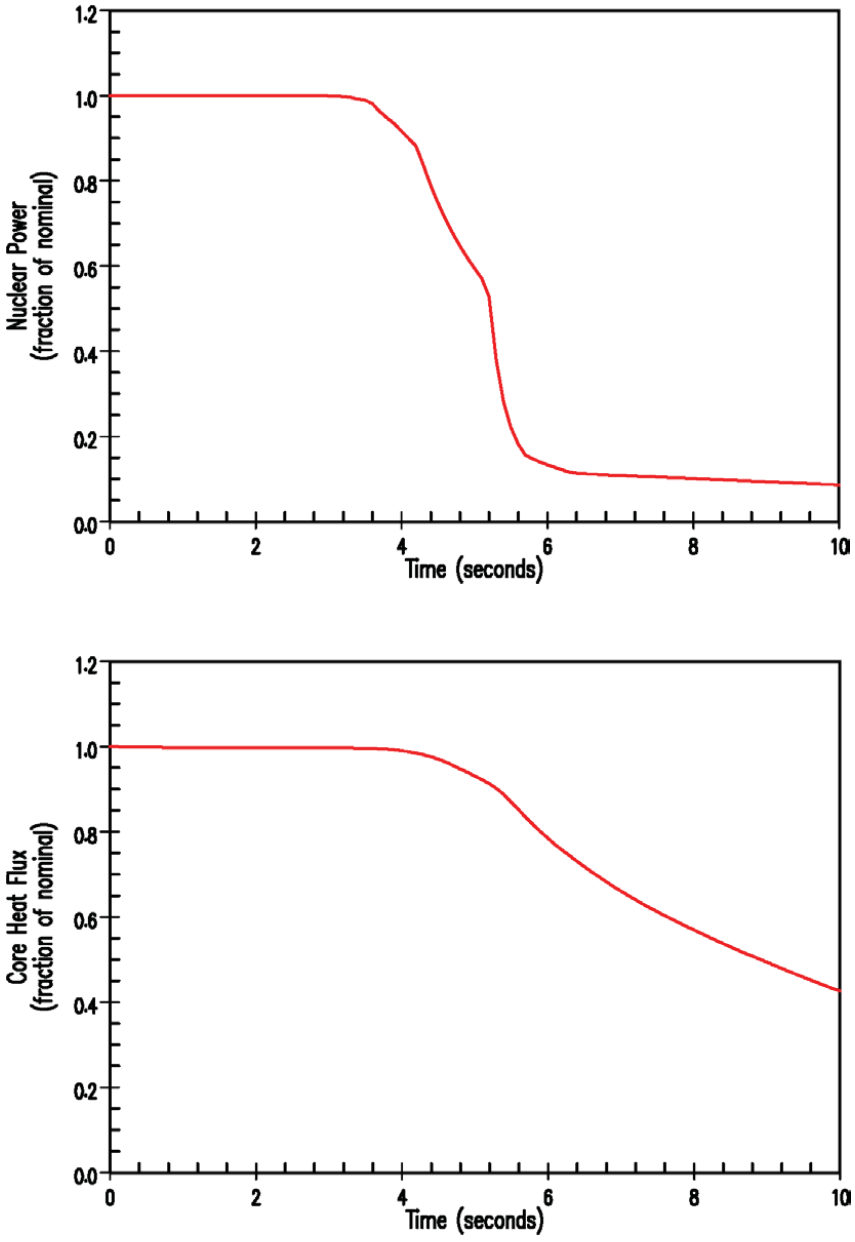
ALL LOOPS OPERATING, ONE LOOP COASTING DOWN: VESSEL FLOW AND FAULTED LOOP FLOW VS. TIME





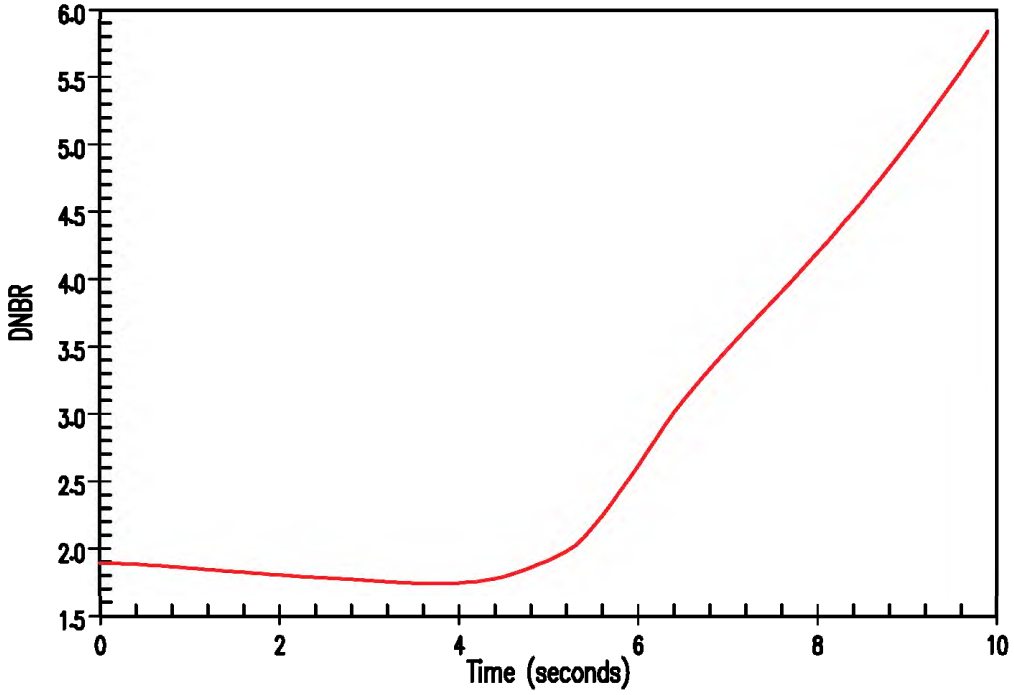
South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
All Loops Operating, One Loop Coasting Down: Vessel Flow and Faulted Loop Flow vs. Time
Figure 15.2-12

Figure 15.2-13
ALL LOOPS OPERATING, ONE LOOP COASTING DOWN: NUCLEAR POWER AND CORE HEAT FLUX VS. TIME



South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
All Loops Operating, One Loop Coasting Down: Nuclear Power and Core Heat Flux vs. Time
Figure 15.2-13

Figure 15.2-14
ALL LOOPS OPERATING, ONE LOOP COASTING DOWN: DNBR VS. TIME

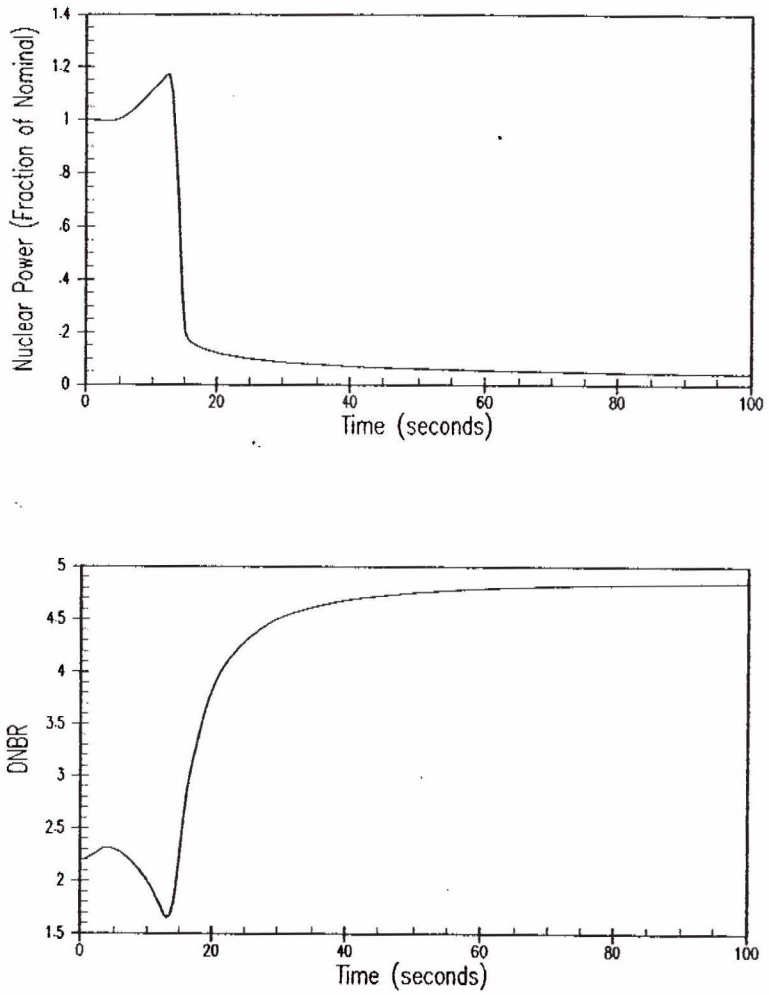


South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
All Loops Operating, One Loop Coasting Down: DNBR vs. Time
Figure 15.2-14

Figures 15.2-15 through 15.2-18
DELETED BY AMENDMENT 99-01

Figure 15.2-19

LOSS OF LOAD/TURBINE TRIP WITH AUTO PRESSURE CONTROL, MINIMUM FEEDBACK (BOL) NUCLEAR POWER AND DNBR VS. TIME



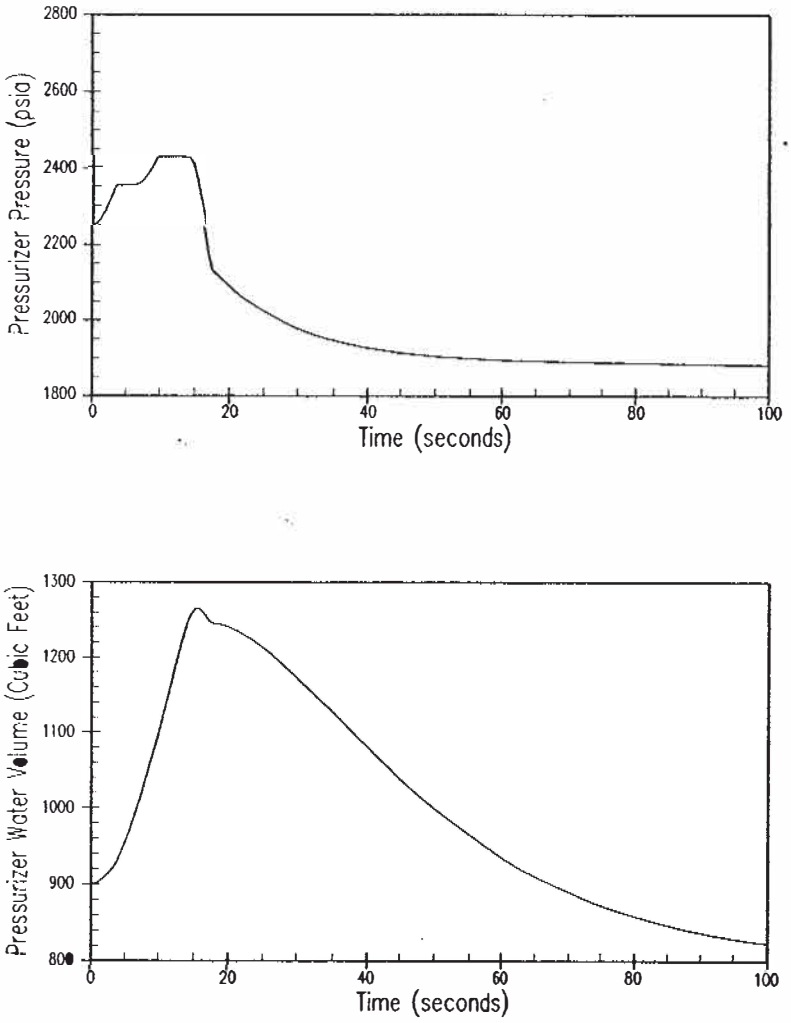
Note: A DNBR penalty of -0.087 has been assessed on the calculated minimum DNBR to account for the effects of using the PAD5 fuel rod performance code[19].

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Loss of Load / Turbine Trip with
Auto Pressure Control, Minimum Feedback (BOL)
Nuclear Power and DNBR vs. Time

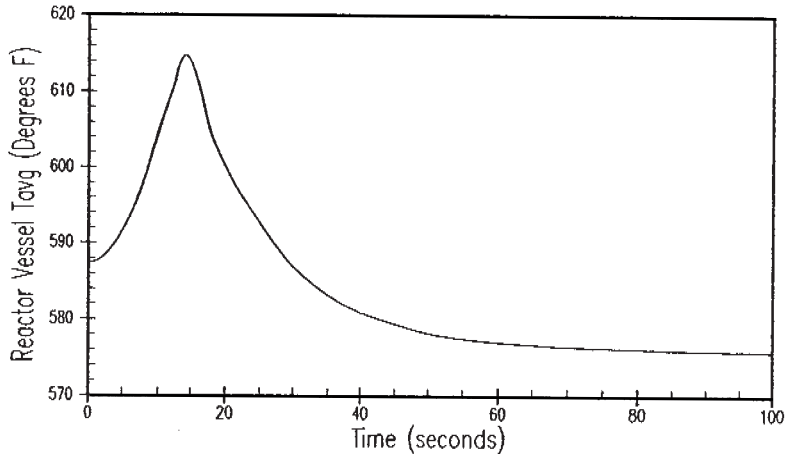
Figure 15.2-19

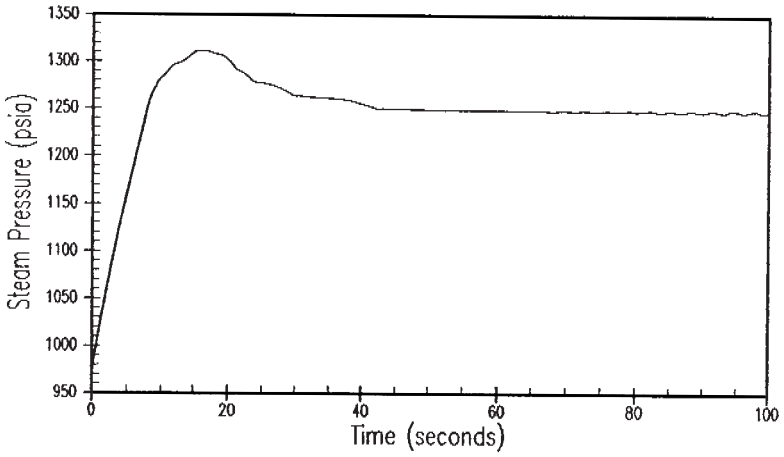
Figure 15.2-20
LOSS OF LOAD/TURBINE TRIP WITH AUTO PRESSURE CONTROL, MINIMUM FEEDBACK (BOL) PRESSURIZER PRESSURE AND WATER VOLUME VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loss of Load / Turbine Trip with Auto Pressure Control, Minimum Feedback (BOL) Pressurizer Pressure and Water Volume vs. Time Figure 15.2-20

Figure 15.2-21
LOSS OF LOAD/TURBINE TRIP WITH AUTO PRESSURE CONTROL, MINIMUM FEEDBACK (BOL) REACTOR VESSEL T_{AVG} AND STEAM PRESSURE VS. TIME

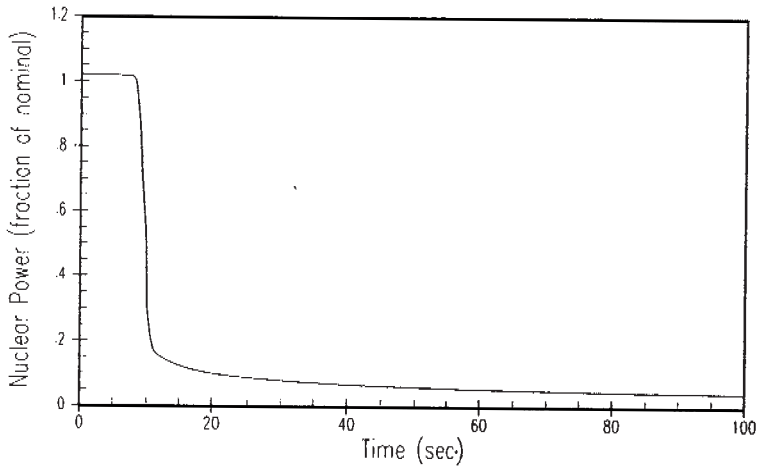


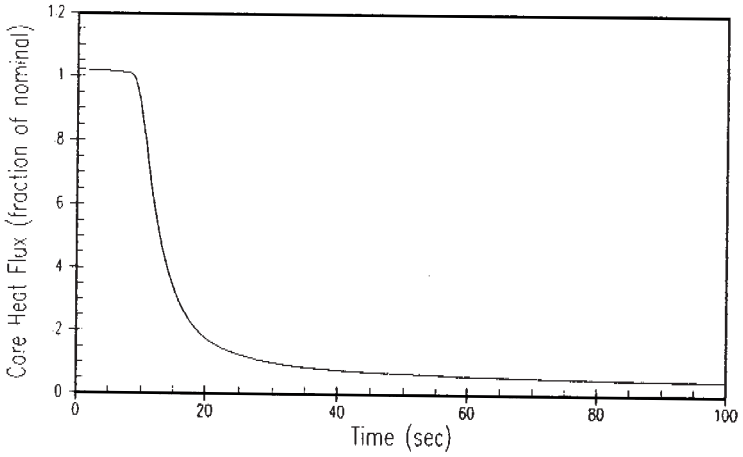


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loss of Load / Turbine Trip with Auto Pressure Control, Minimum Feedback (BOL) Reactor Vessel T_{avg} and Steam Pressure vs. Time Figure 15.2-21

Figures 15.2-22 through 15.2-24
DELETED PER RN 03-042

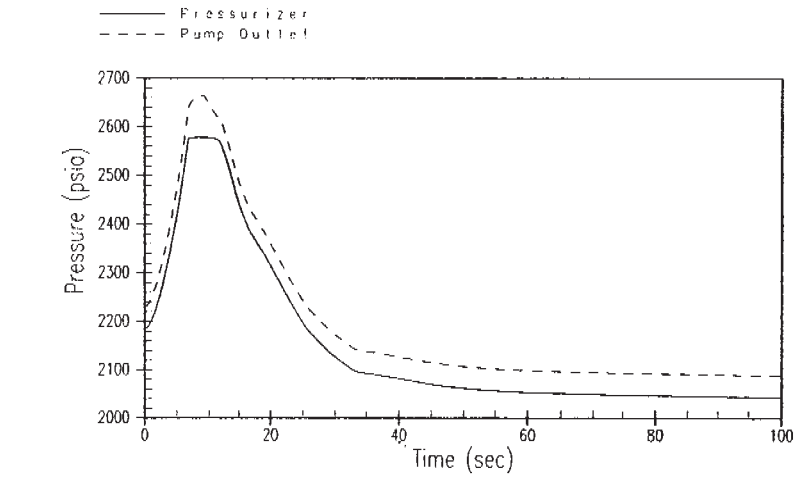
Figure 15.2-25
LOSS OF LOAD/TURBINE TRIP WITH NO PRESSURE CONTROL
NUCLEAR POWER AND CORE HEAT FLUX VS. TIME

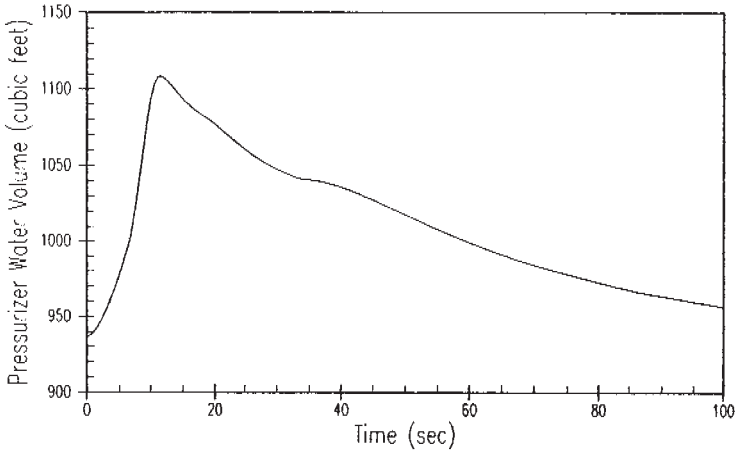




SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
Loss of Load / Turbine Trip with no Pressure Control Nuclear Power and Core Heat Flux vs. Time Figure 15.2-25

Figure 15.2-26
LOSS OF LOAD/TURBINE TRIP WITH NO PRESSURE CONTROL
RCS PRESSURE AND PRESSURIZER WATER VOLUME VS. TIME

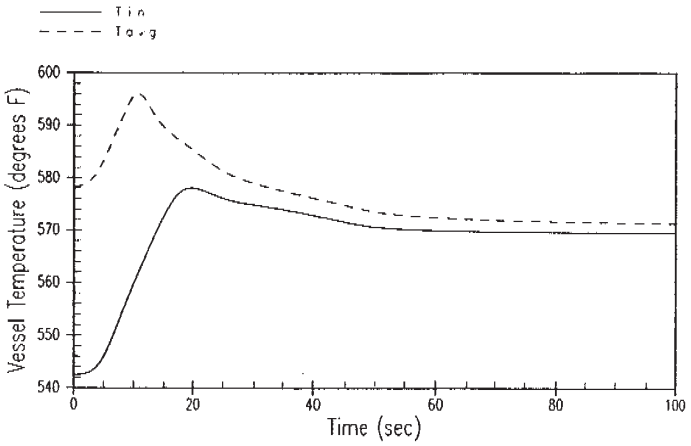


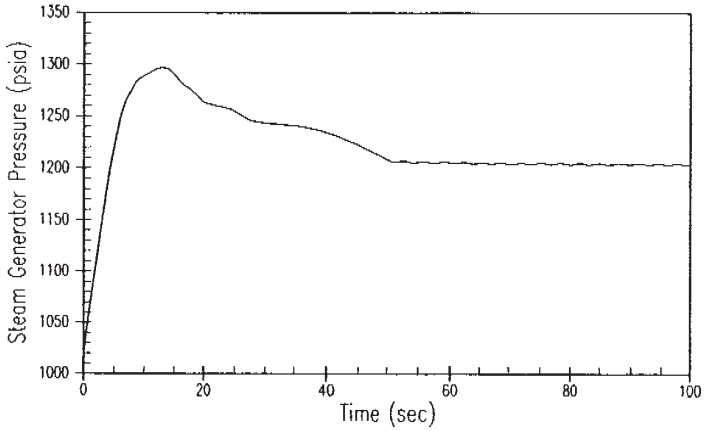


Note: A pressure penalty of +2.2 psi has been assessed on the calculated peak RCS pressure to account for the effects of using the PAD5 fuel rod performance code[19].

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
Loss of Load / Turbine Trip with no Pressure Control RCS Pressure and Pressurizer Water Volume vs. Time Figure 15.2-26

Figure 15.2-27
LOSS OF LOAD/TURBINE TRIP WITH NO PRESSURE CONTROL
REACTOR VESSEL TEMPERATURE AND STEAM PRESSURE VS. TIME



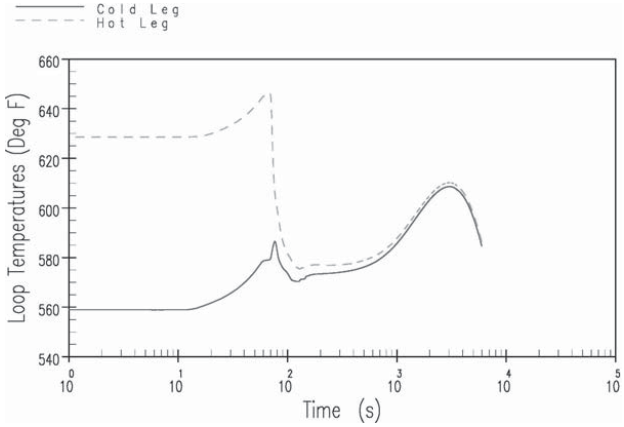


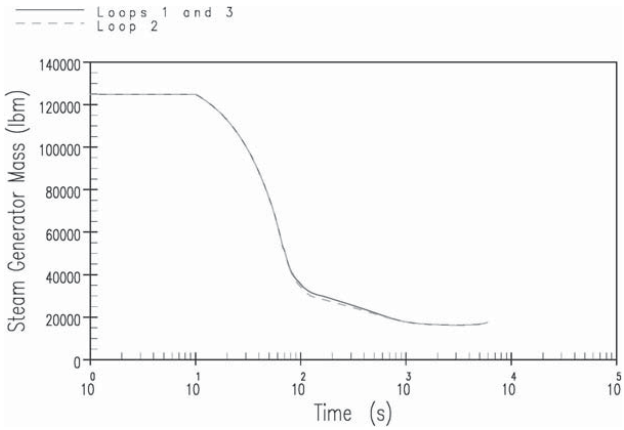
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
Loss of Load / Turbine Trip with no Pressure Control Reactor Vessel Temperature and Steam Pressure vs. Time Figure 15.2-27

Note: A pressure penalty of +1.1 psi has been assessed on the calculated peak steam generator pressure to account for the effects of using the PAD5 fuel rod performance code[19].

Figures 15.2-28 through 15.2-30
DELETED PER RN 03-042

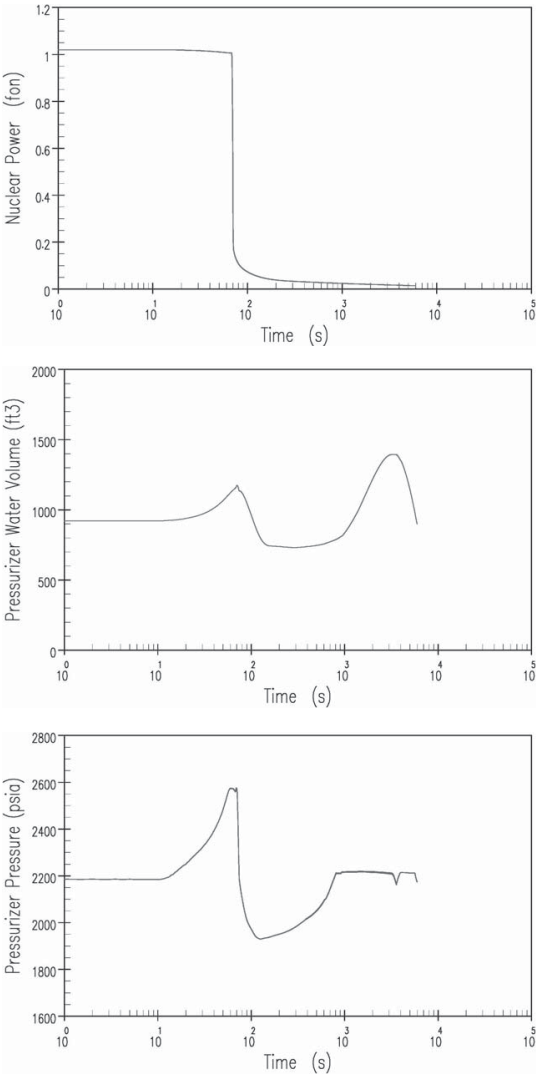
Figure 15.2-31
LOSS OF NORMAL FEEDWATER LOOP TEMPERATURE, STEAM GENERATOR WATER MASS VS. TIME





SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loss of Normal Feedwater Loop Temperatures, Steam Generator Water Mass versus Time Figure 15.2-31

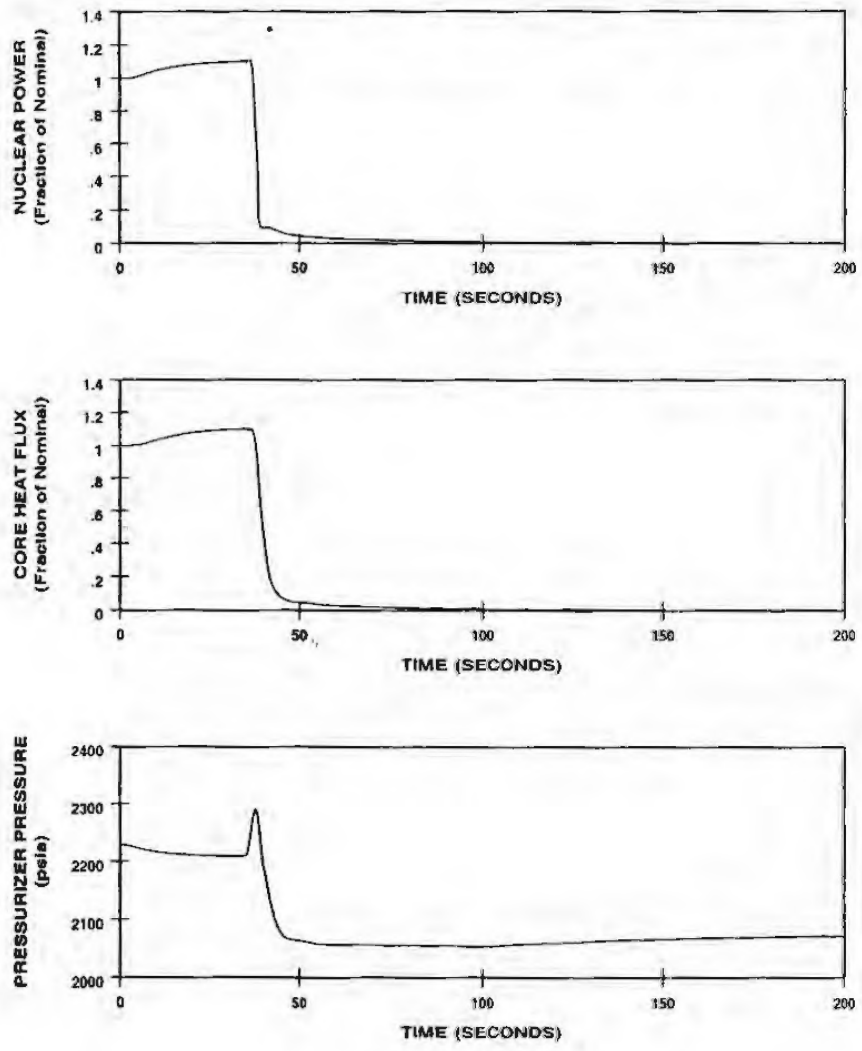
Figure 15.2-32
LOSS OF NORMAL FEEDWATER NUCLEAR POWER, PRESSURIZER WATER VOLUME, AND PRESSURIZER PRESSURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Loss of Normal Feedwater Nuclear Power, Pressurizer Water Volume and Pressurizer Pressure versus Time
Figure 15.2-32

Figure 15.2-33

FEEDWATER SYSTEM MALFUNCTION (EXCESSIVE FEEDWATER ADDITION) NUCLEAR POWER, CORE HEAT FLUX, AND PRESSURIZER PRESSURE VS. TIME



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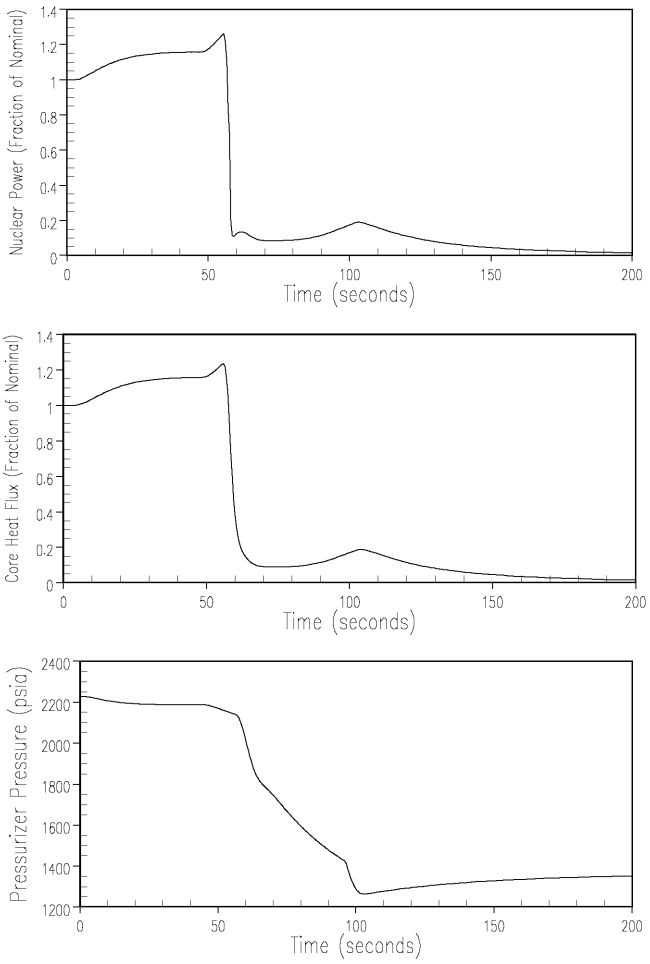
Feedwater System Malfunction (Excessive Feedwater Addition): Nuclear Power, Core Heat Flux and Pressurizer Pressure vs. Time Figure 15.2-33

Figure 15.2-33a

FEEDWATER SYSTEM MALFUNCTION (FEEDWATER ENTHALPY REDUCTION): NUCLEAR POWER, CORE HEAT AND FLUX PRESSURIZER PRESSURE VS. TIME



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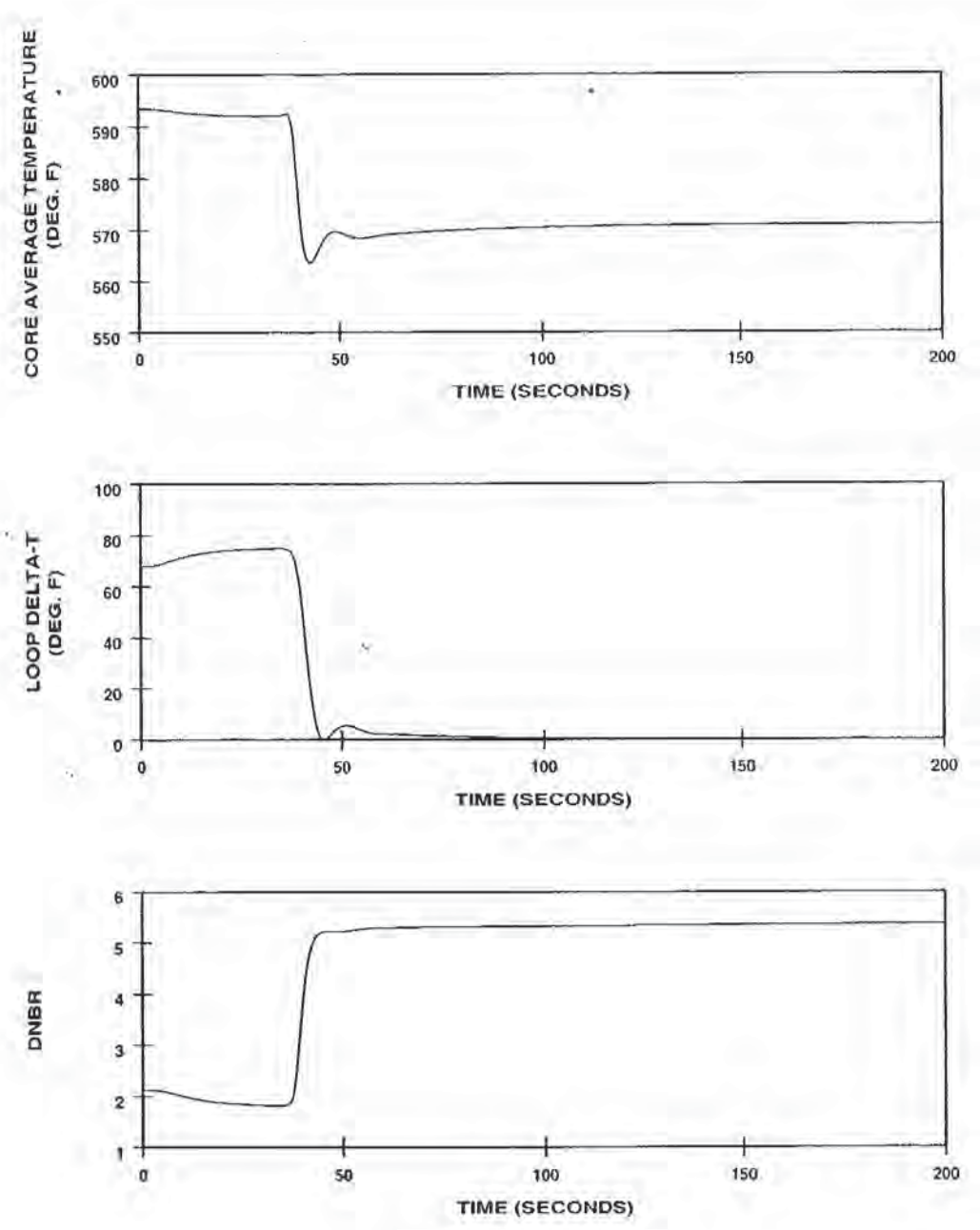
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Feedwater System Malfunction (Feedwater Enthalpy Reduction): Nuclear Power, Core Heat Flux and Pressurizer Pressure vs. Time Figure 15.2-33a

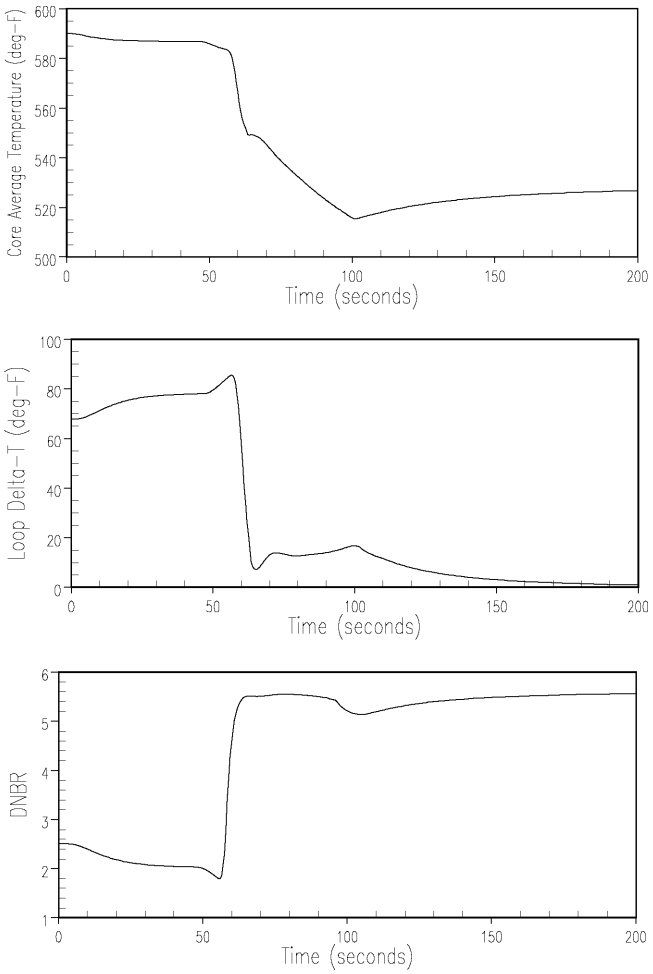
Figure 15.2-34
FEEDWATER SYSTEM MALFUNCTION
(EXCESSIVE FEEDWATER ADDITION):
LOOP DELTA-T, CORE AVERAGE TEMPERATURE AND DNBR VS. TIME



SOUTH CAROLINA ELECTRIC AND GAS VIRGIL C. SUMMER NUCLEAR STATION
Feedwater System Malfunction (Excessive Feedwater Addition):

Figure 15.2-34a

FEEDWATER SYSTEM MALFUNCTION (FEEDWATER ENTHALPY REDUCTION): LOOP DELTA-T, CORE AVERAGE TEMPERATURE, AND DNBR VS. TIME



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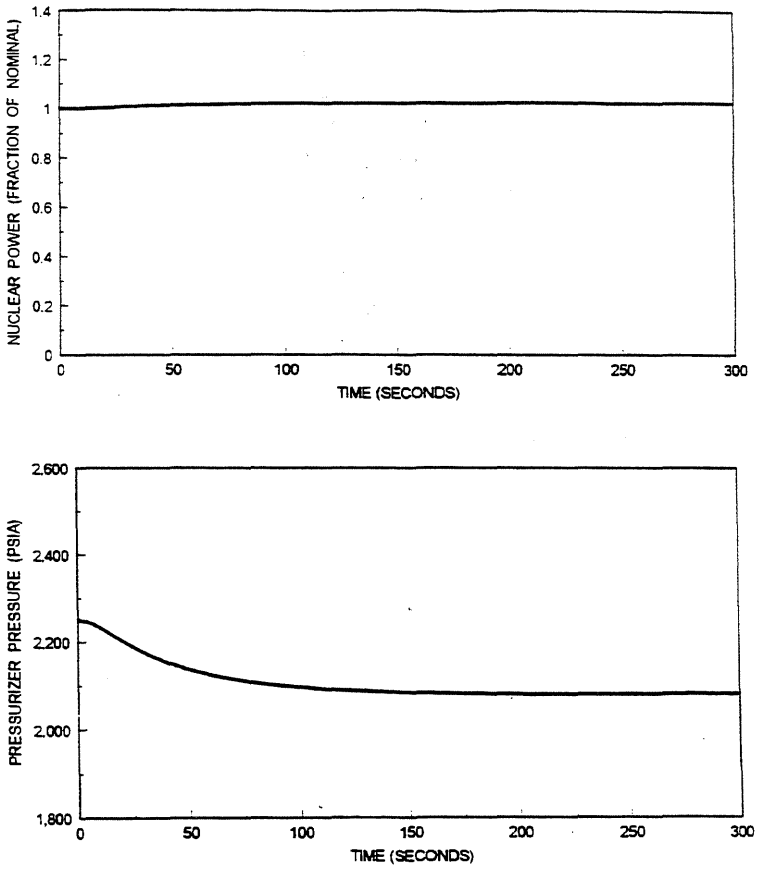
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Feedwater System Malfunction (Feedwater Enthalpy Reduction): Loop Delta-T, Core Average Temperature and DNBR vs. Time

Figure 15.2-34a

Figure 15.2-35
EXCESSIVE LOAD INCREASE W/O CONTROL, MINIMUM FEEDBACK NUCLEAR POWER AND PRESSURIZER PRESSURE VS. TIME

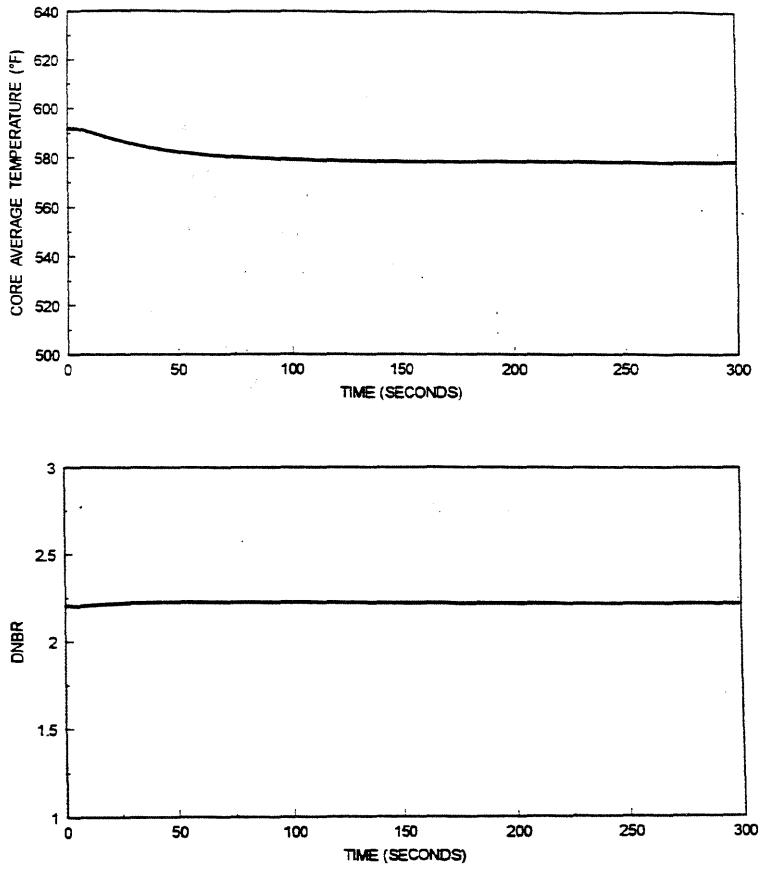


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Excessive Load Increase w/o Control, Minimum Feedback Nuclear Power and Pressurizer Pressure vs. Time

Figure 15.2-35

Figure 15.2-36
EXCESSIVE LOAD INCREASE W/O CONTROL, MINIMUM FEEDBACK CORE AVERAGE TEMPERATURE AND DNBR VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Excessive Load Increase w/o Control, Minimum Feedback Core Average Temperature and DNBR vs. Time

Figure 15.2-36

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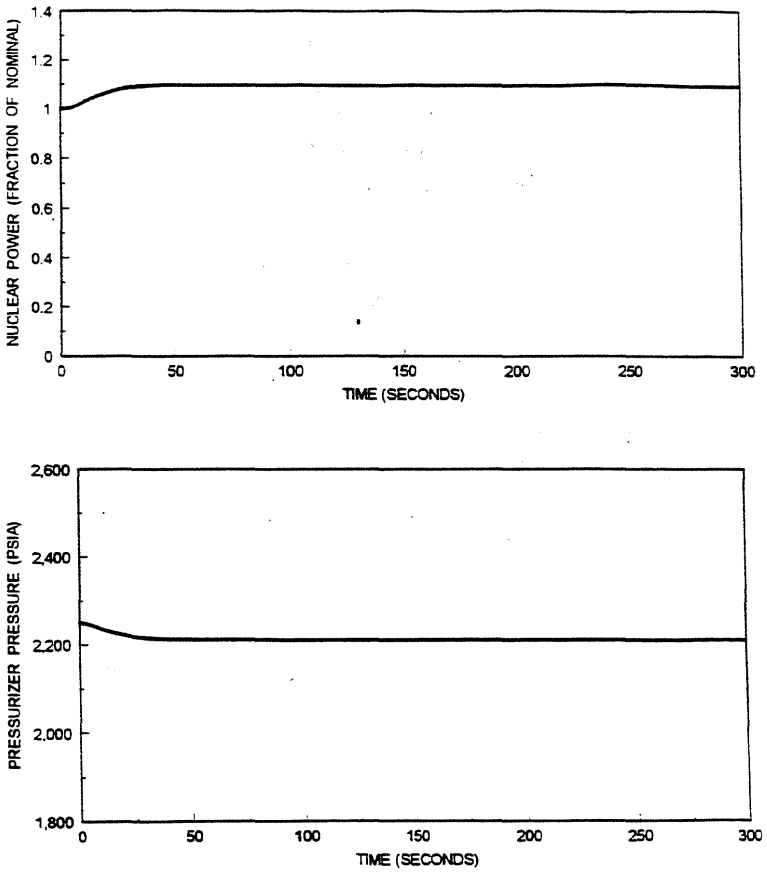
Figure 15.2-37

EXCESSIVE LOAD INCREASE W/O CONTROL, MAXIMUM FEEDBACK NUCLEAR POWER AND PRESSURIZER PRESSURE VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Excessive Load Increase w/o Control, Maximum Feedback Nuclear Power and Pressurizer Pressure vs. Time

Figure 15.2-37

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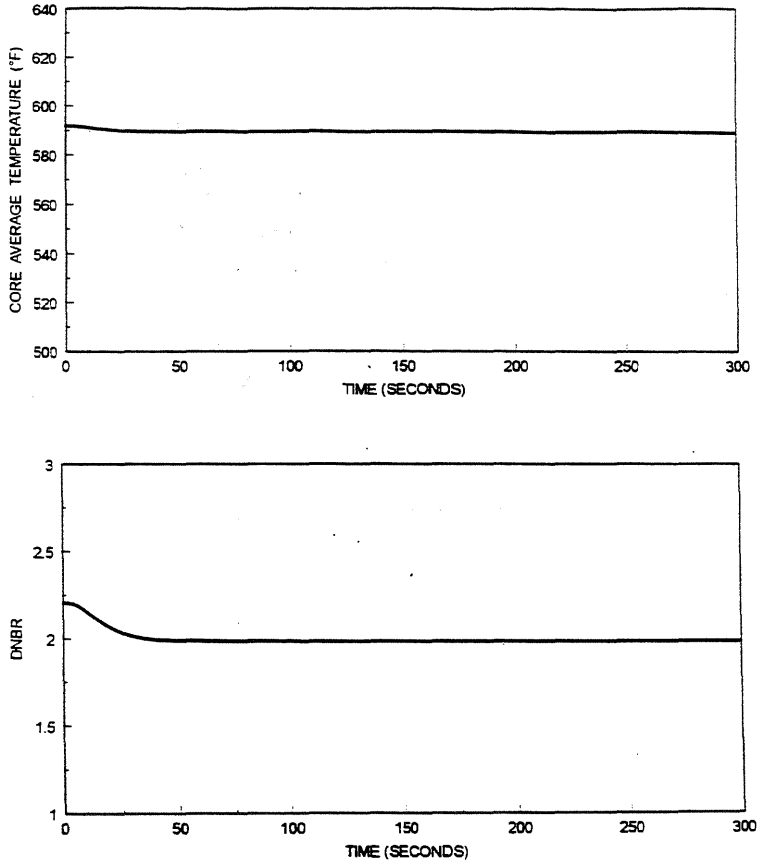
Figure 15.2-38
EXCESSIVE LOAD INCREASE W/O CONTROL, MAXIMUM FEEDBACK CORE AVERAGE TEMPERATURE AND DNBR VS. TIME



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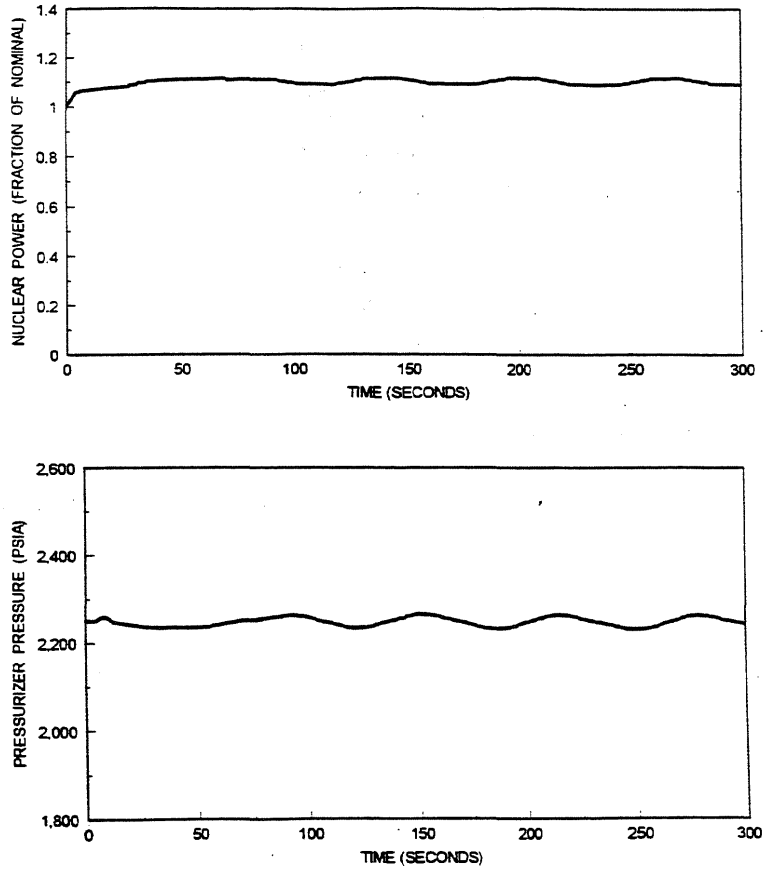
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Excessive Load Increase w/o Control.
Maximum Feedback Core Average
Temperature and DNBR vs. Time

Figure 15.2-38

Figure 15.2-39

EXCESSIVE LOAD INCREASE W/ CONTROL, MINIMUM FEEDBACK NUCLEAR POWER AND PRESSURIZER PRESSURE VS. TIME



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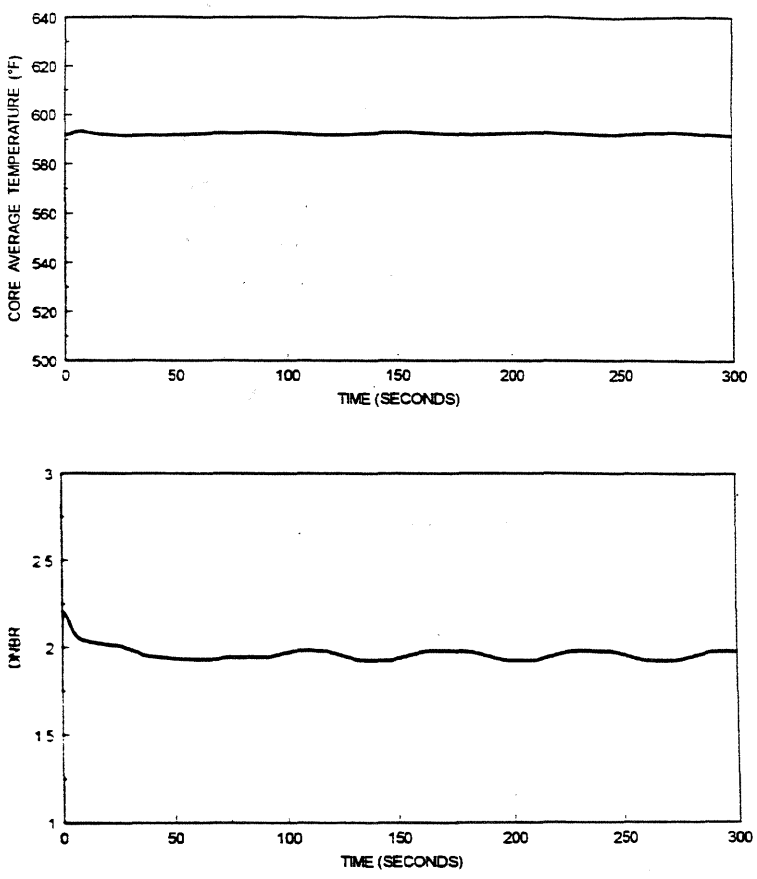
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Excessive Load Increase w/ Control, Minimum Feedback Nuclear Power and Pressurizer Pressure vs. Time

Figure 15.2-39

Figure 15.2-40

EXCESSIVE LOAD INCREASE W/ CONTROL, MINIMUM FEEDBACK CORE AVERAGE TEMPERATURE AND DNBR VS. TIME



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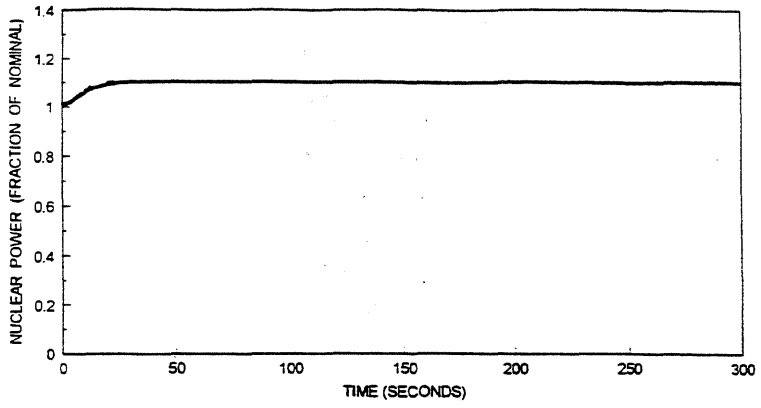
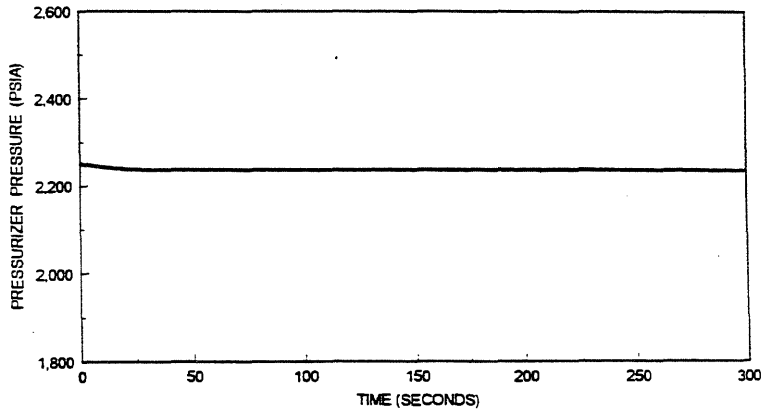
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Excessive Load Increase w/ Control, Minimum Feedback Core Average Temperature and DNBR vs. Time

Figure 15.2-40

Figure 15.2-41
EXCESSIVE LOAD INCREASE W/ CONTROL, MAXIMUM FEEDBACK NUCLEAR POWER AND PRESSURIZER PRESSURE VS. TIME





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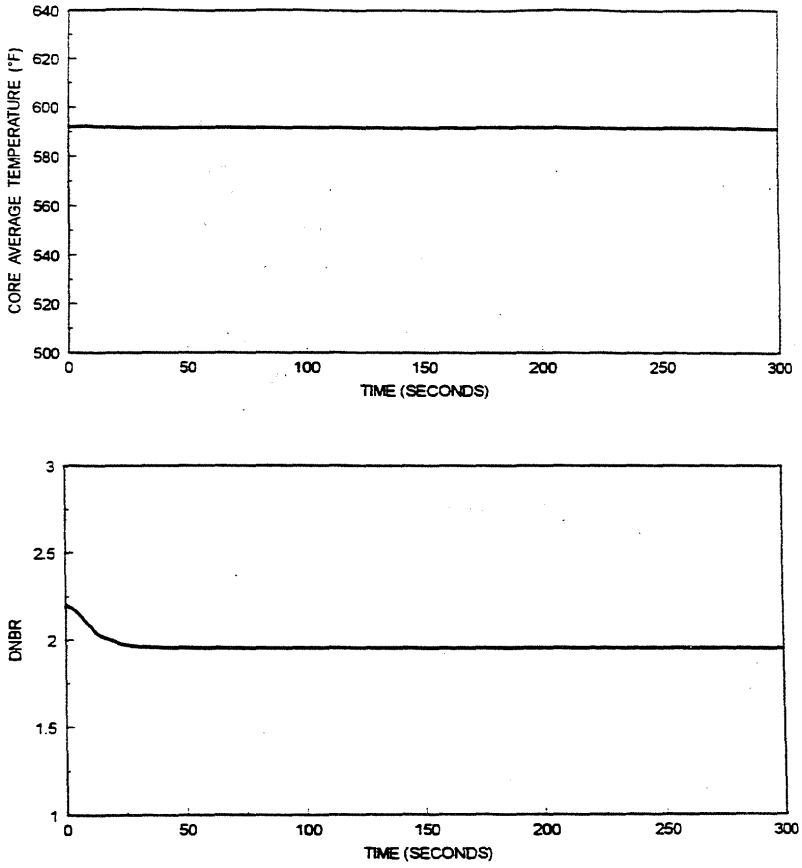
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Excessive Load Increase w/ Control, Maximum Feedback Nuclear Power and Pressurizer Pressure vs. Time

Figure 15.2-41

Figure 15.2-42

EXCESSIVE LOAD INCREASE W/ CONTROL, MAXIMUM FEEDBACK CORE AVERAGE TEMPERATURE AND DNBR VS. TIME



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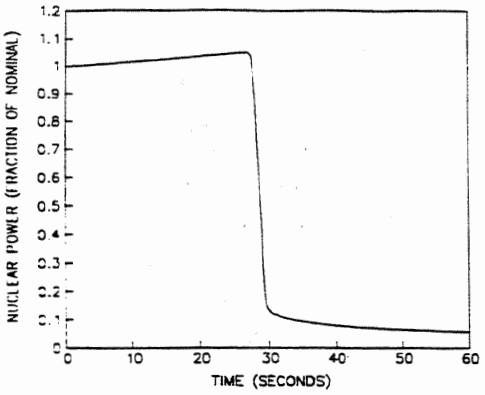
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

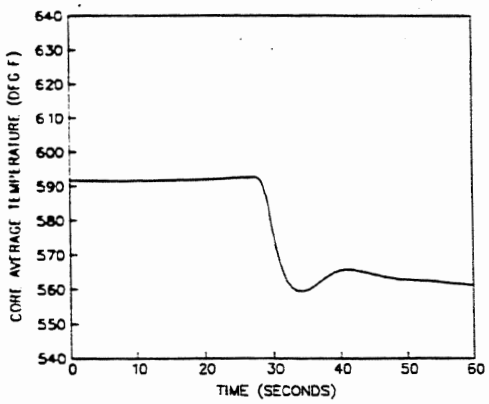
Excessive Load Increase w/ Control, Maximum Feedback Core Average Temperature and DNBR vs. Time

Figure 15.2-42

Figure 15.2-43

ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM NUCLEAR POWER AND CORE AVERAGE TEMPERATURE VS. TIME





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VIRGIL C. SUMMER NUCLEAR STATION

Accidental Depressurization of the Reactor Coolant System Nuclear Power and Core Average Temperature vs. Time

Figure 15.2-43

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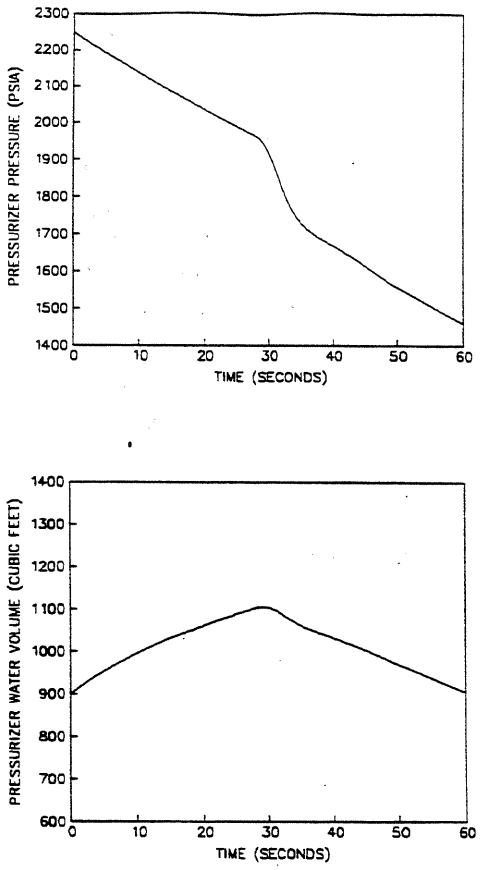
Figure 15.2-44
ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM PRESSURIZER PRESSURE AND WATER VOLUME VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Accidental Depressurization of the Reactor Coolant System Pressurizer Pressure and Water Volume vs. Time Figure 15.2-44

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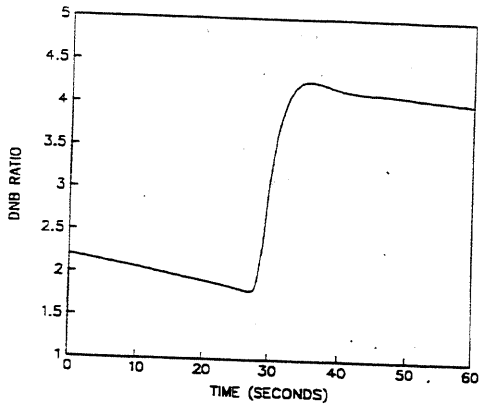
Figure 15.2-45
ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM DNBR VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Accidental Depressurization of the Reactor Coolant System DNBR vs. Time

Figure 15.2-45

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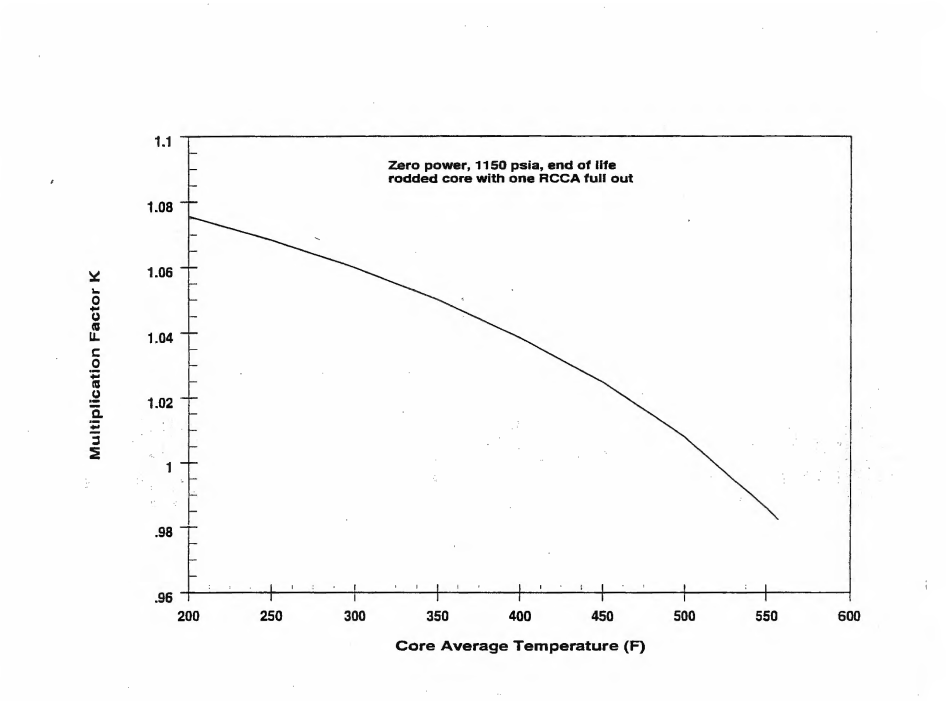
Figure 15.2-46
MAIN STEAM DEPRESSURIZATION
VARIATION OF K_{EFF} WITH CORE TEMPERATURE



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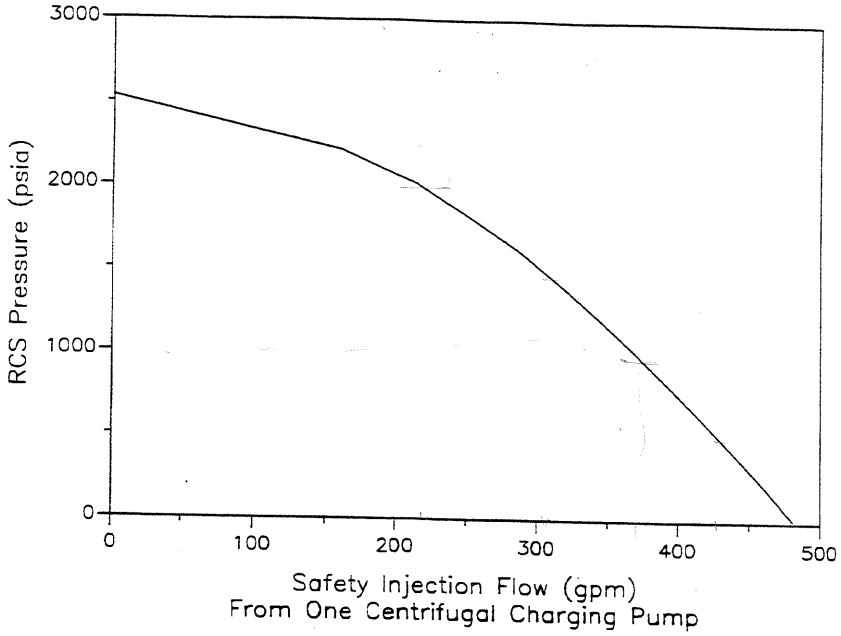
December 2000

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Depressurization Variation of Keff With Core Temperature FIGURE 15.2-46

Figure 15.2-47
MAIN STEAM DEPRESSURIZATION SAFETY INSPECTION FLOWRATE



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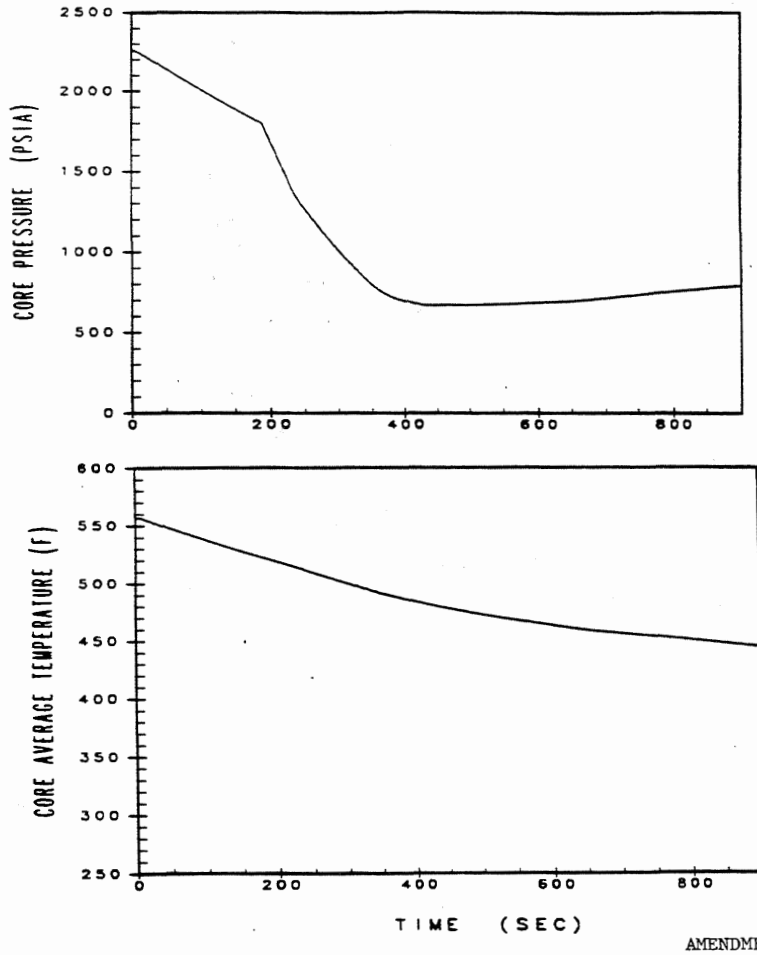
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Main Steam Depressurization Safety Injection Flowrate Figure 15.2-47

Figure 15.2-48

TRANSIENT RESPONSE FOR A STEAM LINE BREAK EQUIVALENT TO 255 LB/SEC AT 1100 PSIA W/OFFSITE POWER AVAILABLE



AMENDMENT 96-02
JULY 1996

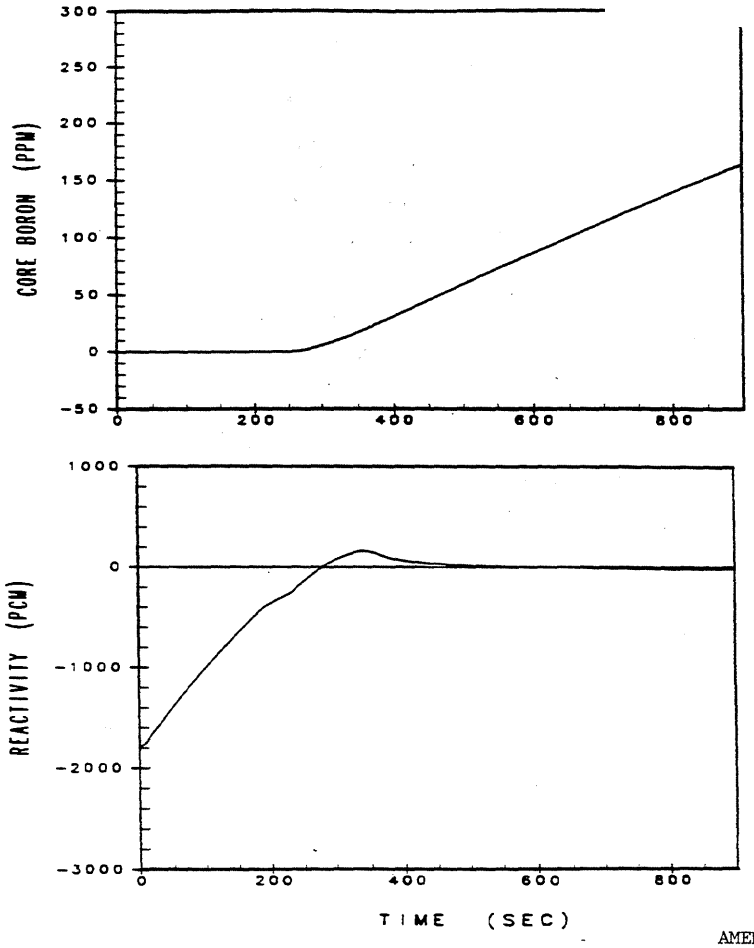
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Transient Response for a Steam Line Break Equivalent to 255 lb/sec at 1100 psia w/Offsite Power Available

Figure 15.2-48

Figure 15.2-49

TRANSIENT RESPONSE FOR A STEAM LINE BREAK EQUIVALENT TO 255 1B/SEC AT 1100 PSIA W/OFFSITE POWER AVAILABLE



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JULY 1996

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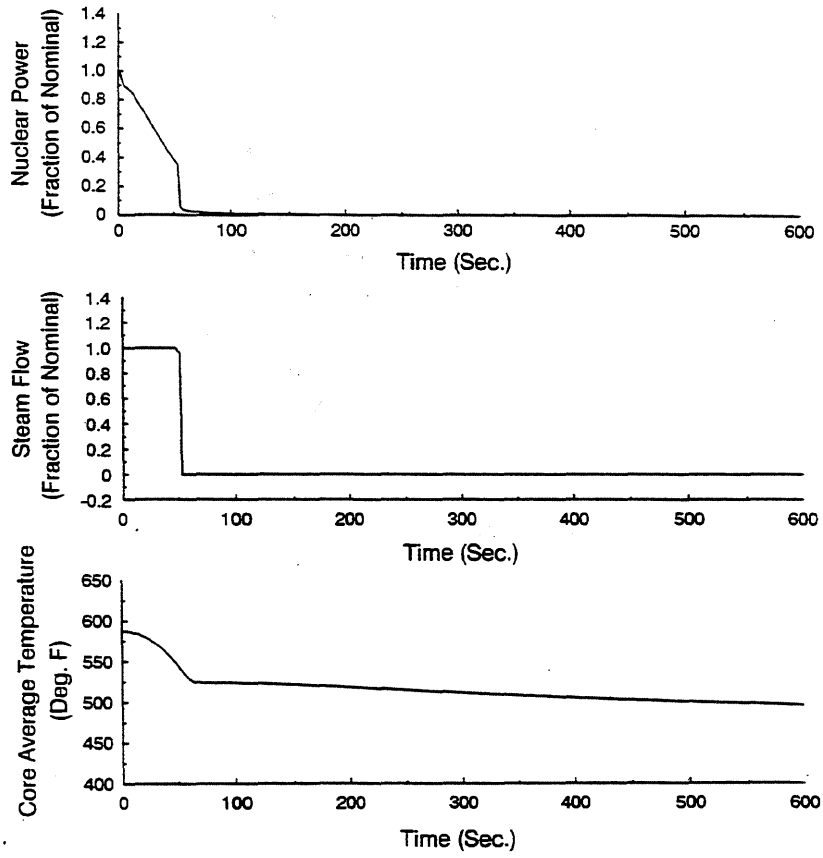
Transient Response for a Steam Line Break Equivalent To 255 lb/sec at 1100 psia w/Offsite Power Available Figure 15.2-49

Figure 15.2-50

SPURIOUS ACTUATION OF THE SAFETY INJECTION SYSTEM NUCLEAR POWER, STEAM FLOW AND CORE T_{AVG} VS. TIME



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Spurious Actuation Of The Safety Injection System Nuclear Power, Steam Flow and Core Tavg vs. Time Figure 15.2-50

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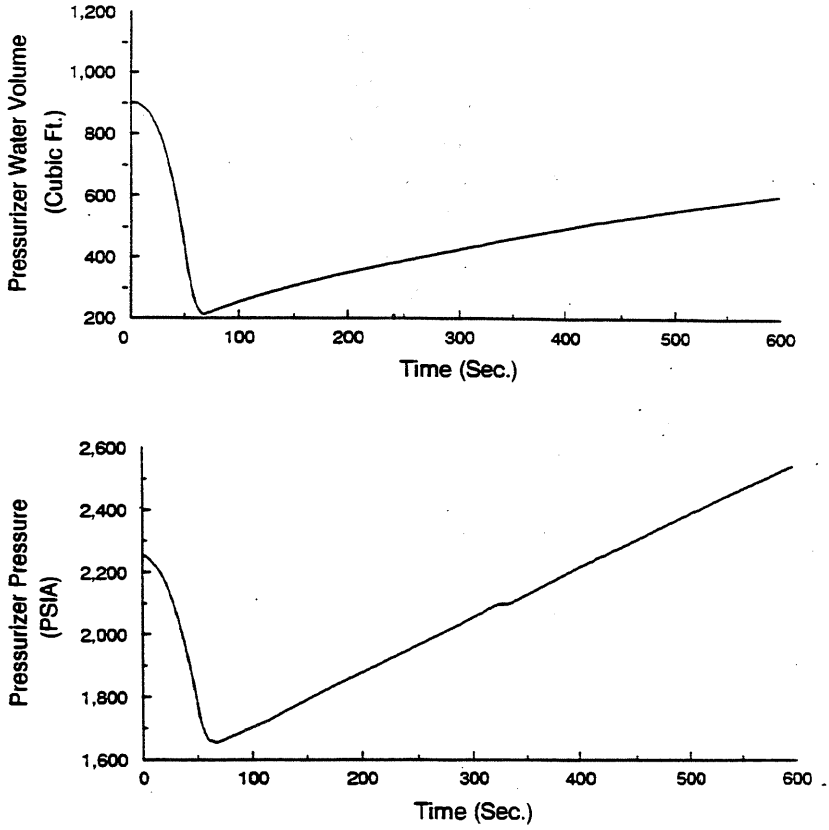
Figure 15.2-51

SPURIOUS ACTUATION OF THE SAFETY INJECTION SYSTEM PRESSURIZER WATER VOLUME AND PRESSURIZER PRESSURE VS. TIME



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Spurious Actuation Of The Safety Injection System Pressurizer Water Volume and Pressurizer Pressure vs. Time
Figure 15.2-51

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15.3 CONDITION III - INFREQUENT FAULTS

By definition Condition III occurrences are faults which may occur very infrequently during the life of the plant. They will be accommodated with the failure of only a small fraction of the fuel rods although sufficient fuel damage might occur to preclude resumption of the operation for a considerable outage time. The release of radioactivity will not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. A Condition III fault will not, by itself, generate a Condition IV fault or result in a consequential loss of function of the Reactor Coolant System or containment barriers. For the purposes of this report the following faults have been grouped into this category:

1. Loss of reactor coolant, from small ruptured pipes or from cracks in large pipes which actuates the Emergency Core Cooling System (ECCS).
2. Minor secondary system pipe breaks.
3. Inadvertent loading of fuel assembly into an improper position.
4. Complete loss of forced reactor coolant flow.
5. Waste gas decay tank rupture.
6. Single rod cluster control assembly withdrawal at full power.

Each of these infrequent faults are analyzed in this section. In general, each analysis includes an identification of causes and description of the accident, an analysis of effects and consequences, a presentation of results, and relevant conclusions.

The time sequence of events during applicable Condition III faults 1 and 4 above is shown in Table 15.4-3 and Table 15.3-3.

15.3.1 Loss of Reactor Coolant From Small Ruptured Pipes or From Cracks in Large Pipes Which Actuates the Emergency Core Cooling System

A small break loss-of-coolant accident (SBLOCA) analysis has been performed for V.C. Summer using the FULL SPECTRUM™1 loss-of-coolant accident (FSLOCA™) evaluation model (EM) (Reference 1).

The break sizes considered in the Westinghouse FSLOCA EM include what traditionally are defined as Small and Large Break LOCA (LBLOCA). The traditional SBLOCA analysis is referred to as the Region I analysis, and the traditional LBLOCA analysis is referred to as the Region II analysis.

The FSLOCA EM analysis for V.C. Summer is discussed in Section 15.4.1 since the LBLOCA (Region II) analysis is more limiting than the SBLOCA (Region I) analysis.

The FSLOCA EM methods, models, and demonstrations for 10 CFR 50.46 compliance are discussed in Section 15.4.1, which describes both Region I and Region II analyses.

15.3.1.1 Identification of Causes and Accident Description

A loss of coolant accident is defined as a rupture of the Reactor Coolant System piping or of any line connected to the system. See Section 15.2 for a more detailed description of the loss of reactor coolant accident boundary limits. Ruptures of small cross section will cause expulsion of the coolant at a rate which can be accommodated by the charging pumps which would maintain an operational water level in the pressurizer, permitting the operator to execute an orderly shutdown. The coolant which would be released to the containment contains the fission products existing in it.

The maximum break size for which the normal makeup system can maintain the pressurizer level is obtained by comparing the calculated flow from the Reactor Coolant System through the postulated break against the charging pump makeup flow at normal Reactor Coolant System pressure, i.e., 2250 psia. A makeup flow rate from one centrifugal charging pump is typically adequate to sustain pressurizer level at 2250 psia for a break through a 3/8 inch diameter hole. This break results in a loss of approximately 17.5 lb/sec.

Should a larger break occur, depressurization of the Reactor Coolant System causes fluid to flow to the Reactor Coolant System from the pressurizer, resulting in a pressure and level decrease in the pressurizer. Reactor trip occurs when the pressurizer low pressure trip setpoint is reached. The Safety Injection System is actuated when the appropriate setpoint is reached.

15.3.1.2 Additional Analysis

NUREG-0737 (Reference 12), Section II.K.3.31, required plant-specific small break LOCA analysis using an Evaluation Model revised per Section II.K.3.30 (Revised Small-Break Loss-of-Coolant-Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K). The analysis method for small break LOCA is a realistic evaluation model (EM) in compliance with 10 CFR Part 50.46(a)(1)(i). An Appendix K method is no longer used for the small break LOCA analysis, but the use of a realistic method has been approved for use in small break LOCA analyses. The methodology accounts for comparisons with experimental data, including data from the Loss-of-Fluid Test (LOFT), semiscale, and Rig-of-Safety Assessment (ROSA) test facilities.

Analyses of a LOCA in the pressurizer vapor space such as that caused by opening a pressurizer relief valve or a safety valve were provided in WCAP 9600 (Reference 11). The conclusion presented in WCAP 9600 is that these breaks are not limiting since little or no core uncovery will take place. WCAP 9600 states that the analyses reported therein apply to all Westinghouse designed plants.

RCS loop-to-loop flow imbalance of 5% was considered, to incorporate the effects of RCS Flow Asymmetry, per Westinghouse Nuclear Safety Advisory Letter (NSAL) 00 008. The results show that the effect of 5% Loop Flow Asymmetry is inconsequential for LOCA PCT calculations.

15.3.1.3 Impact of ECCS Evaluation Model Changes

The October 17, 1988, revision to 10CFR50.46 requires applicants and holders of operating licenses or construction permits to notify the NRC of errors and changes in the ECCS Evaluation Models, which are not significant, on an annual basis. Reference 19 defines a significant error or change as one which results in a calculated peak fuel cladding temperature (PCT) different by more than 50° F from the temperature calculated for the limiting transient using the last acceptable model, or is an accumulation of changes and errors such that the sum of the absolute temperature change is greater than 50° F. The current ECCS evaluation model changes for Virgil C. Summer Nuclear Station that affect the small break LOCA PCT and their effect are identified in the latest 10CFR50.46 annual or 30 day report.

15.3.2 Minor Secondary System Pipe Breaks

15.3.2.1 Identification of Causes and Accident Description

Included in this grouping are ruptures of secondary system lines which would result in steam release rates equivalent to a 6 inch diameter break or smaller.

15.3.2.2 Analysis of Effects and Consequences

Minor secondary system pipe breaks must be accommodated with the failure of only a small fraction of the fuel elements in the reactor. Since the results of analysis presented in Section 15.4.7 for a major secondary system pipe rupture also meet this criteria, separate analysis for minor secondary system pipe breaks is not required.

The analysis of the more probable accidental opening of a secondary system steam dump, relief or safety valve is presented in Section 15.2.13. These analyses are illustrative of a pipe break equivalent in size to a single valve opening.

15.3.2.3 Conclusions

The analyses presented in Section 15.4.7 demonstrate that the consequences of a minor secondary system pipe break are acceptable since a DNBR of less than the design limit does not occur even for a more critical major secondary system pipe break.

15.3.3 Inadvertent Loading of a Fuel Assembly Into An Improper Position

15.3.3.1 Acceptance Criteria

This event is classified as a Condition III event. Condition III events are defined as those events that do not cause more than a small fraction of fuel rods to fail, although sufficient fuel damage might occur to preclude immediate resumption of operation. The specific acceptance criteria for this event are as follows:

a. To meet the requirements of General Design Criteria 13, plant operating procedures should include a provision requiring that reactor instrumentation be used to search for potential fuel loading errors after fueling operations.

b. In the event the error is not detectable by the instrumentation system and fuel rod failure limits could be exceeded during normal operation, the offsite consequences should be a small fraction of the 10 CFR Part 100 guidelines.

15.3.3.2 Identification of Causes and Accident Description

The Inadvertent Loading Event comprises core misloading scenarios such as the loading of one or more fuel assemblies into improper positions, the loading of a fuel rod during manufacture with one or more pellets of the wrong enrichment, or the loading of a full fuel assembly during manufacture with pellets of the wrong enrichment. In addition to these scenarios, misloading events involving burnable absorbers are theoretically possible, scenarios such as the placement of a cluster of 20 burnable absorbers into a core location slated to have 24 burnable absorbers. All of these misloading scenarios potentially result in a core reactivity distribution that differs from the intended core reactivity distribution. As a result, the core power distribution and peaking factors may differ from predictions. Specifically, misloading errors can lead to increased local power peaking at the location of the misloading if the misloading results in a local reactivity increase relative to the intended pattern. If the misloading results in a local reactivity decrease, power peaking increases away from the location of the misloading are possible due to unintended power tilts. These kinds of increases, however, are generally distributed over a large core volume and are small relative to those where the local reactivity is increased.

Fuel misloads are prevented by the manufacturing controls employed to build the fuel and the core loading controls used to assemble the core. The manufacturing controls include checks on fuel rod weight to confirm the uranium loading in the fuel rod, active and passive gamma scans of individual fuel rods to confirm fuel enrichments, pellet stack lengths, pellet types, and the absence of pellet gaps during fuel manufacturing, and bar coding of each fuel rod to confirm its proper placement in the fuel assembly.

To reduce the probability of core loading errors during fuel loading, each fuel assembly and core component is marked with an identification number and loaded in accordance with a core loading diagram. During core loading, the identification numbers are checked before the assembly is moved into the core. Identification numbers read during fuel movement are subsequently recorded on the loading diagram as a further check on proper placement after the loading is completed. These procedures make the likelihood of core misloadings very small.

The severity and detectability of fuel misloads are influenced by several factors: the local reactivity perturbation relative to the intended core loading pattern, the core position of the misload, the local environment of the misloaded fuel assembly, and the number of operable incore detector locations and their proximity to the misload location. Should misloadings occur, the incore system of movable flux detectors, which is used to verify power distributions during startup and throughout the operating cycle, is capable of revealing enrichment errors or misloadings which would cause the kind of substantial power distribution perturbation that would

be necessary to induce large numbers of fuel rod failures. In addition, thermocouples and excore detectors can provide additional indications of power distribution anomalies. This instrumentation, along with the startup testing performed each cycle, make the detection of severe misloadings highly likely.

15.3.3.3 Evaluation

The incore moveable detector system is used to search for potential fuel misloads at the start of each operating cycle. Following fuel loading and low power physics testing, an initial core power distribution measurement is made. The core power level of this initial flux map is typically between ~30% and ~50% of rated thermal power. This initial power distribution measurement is used to confirm that the measured power distribution is consistent with the predicted power distribution. Observed flux map deviations in excess of the flux map review criteria (see Table 15.3-9) would prompt an investigation of a possible core anomaly. This satisfies the first acceptance criterion given in Section 15.3.3.1a above.

In Reference 29, a large number of misloads were evaluated for representative core designs employing current fuel types and fuel features. The simulated misloads, involving one or two fuel assemblies, covered a wide range of local reactivity perturbations and core positions. The resulting hot full power (HFP) $F\Delta H$ peaking factors ranged from benign to very severe. Severe misloads with peaking factors that exceed the $F\Delta H$ limit for DNB at normal operation conditions have the potential for fuel failure if they remain undetected. The simulated misloads were assessed with respect to severity and detectability.

The detectability assessments of Reference 29 demonstrated that the incore detector system is very robust with respect to detection of misloads severe enough to fail fuel during normal operation. By examining a large number of moveable detector thimble patterns, the detectability assessments considered the effect of inoperable moveable detector thimbles on misload detectability. Even when the minimum number of operable detector locations allowed per the plant licensing bases was assumed, the incore detector system was capable of reliably detecting misloads severe enough to fail fuel during normal operation.

Fuel misloads involving a single fuel rod or fuel pellet were not evaluated as part of Reference 29. Such misloads, in general, will not be detectable using the incore detector system due to the very small power distribution perturbation. In terms of increased peaking factors and reduced DNBR values, however, the consequences of such misloads will be very small and limited to the affected fuel rod and the immediately adjacent fuel rods.

Detection of fuel misloads is, in part, a function of the number of available incore detector locations. Reference 29 demonstrated that the flux map review criteria of Table 15.3-9 are effective in detecting fuel misloads that could lead to fuel failures during normal operation. To enhance the probability that significant misloads will be detected, tighter review criteria are employed when the number of available detector locations is reduced. These review criteria will be used for startup and subsequent at power flux maps.

The detectability assessments of Reference 29 confirm that the moveable detector system can reliably detect fuel misloads that could fail fuel during normal operation when the Table 15.3-9 review criteria are employed. Specifically, Reference 29 demonstrated that only a small fraction of 1% of misloads severe enough to fail fuel during normal operation would be undetected at startup using these limited review criteria. Furthermore, it was judged that even these “undetected” misloads would very likely be detected if other attributes of the startup power distribution measurement (e.g., tilts and reaction rate error contours) were considered along with the results of low power physics testing. Given that detection of >99% of misloads severe enough to fail fuel is expected using these review criteria, a radiological consequences analysis is deemed unnecessary. Failures in fresh fuel during startup would have negligible radiological consequences since there is only a small fission product inventory. Following startup, any fuel rod failures would occur gradually and would be detected by coolant activity monitoring. Since the number of potential fuel rod failures due to a core misload would be extremely small and such failures would occur gradually, any coolant activity releases would initially be well within the cleanup capacity of the plant. Any trend in increased coolant activity would warrant further investigation and evaluation. Therefore, the second acceptance criterion for this event would be satisfied since failures would be gradual, detectable, and the operations would be maintained within Technical Specification coolant activity guidelines.

15.3.3.4 Conclusions

Fuel misloads are prevented by manufacturing controls and core loading controls. In the unlikely event that a fuel misload should occur, the incore moveable detector system is capable of reliably detecting misloads that could fail fuel at normal operation conditions. Exceeding the review criteria herein would initiate an investigation to identify potential core anomalies. Any failures associated with an undetected fuel misload would be gradual, detectable, and the operations would be maintained within Technical Specification coolant activity guidelines.

15.3.4 Complete Loss of Forced Reactor Coolant Flow

15.3.4.1 Identification of Causes and Accident Description

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical supplies to all reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor were not tripped promptly. The following reactor trips provide necessary protection against a loss of coolant flow accident:

1. Undervoltage or underfrequency on reactor coolant pump power supply buses.
2. Low reactor coolant loop flow.

The reactor trip on reactor coolant pump bus undervoltage is provided to protect against conditions that can cause a loss of voltage to all reactor coolant pumps, i.e., Loss of Offsite Power. The reactor trip on reactor coolant pump underfrequency is provided to open the reactor coolant

pump breakers and trip the reactor for an underfrequency condition, resulting from frequency disturbances on the major power grid. The trip disengages the reactor coolant pumps from the power grid so that the pumps' flywheel kinetic energy is available for full coastdown. Both trips are blocked below approximately 10% power (Permissive 7).

The reactor trip on low primary coolant loop flow is provided to protect against loss of flow conditions that affect only one reactor coolant loop. It also serves as a backup to the undervoltage and underfrequency trips. This function is generated by two out of three low flow signals per reactor coolant loop. Above approximately 38% power (Permissive 8), low flow in any loop will actuate a reactor trip. Between approximately 10 and 39% power (Permissive 7 and Permissive 8), low flow in any two loops will actuate a reactor trip.

Normal power for each pump is supplied through individual busses connected to the isolated phase bus duct between the generator circuit breaker and the main transformer. Faults in the substation may cause a trip of the main transformer high side circuit breaker leaving the generator to supply power to the reactor coolant pumps. When a generator circuit breaker trip occurs because of electrical faults, the pumps are automatically transferred to an alternate power supply and the pumps will continue to supply coolant flow to the core. Following any turbine trip where there are no electrical faults, the generator circuit breaker is tripped and the reactor coolant pumps remain connected to the network through the transformer high side breaker. Continuity of power to the pump buses is achieved without motoring the generator since means are provided to isolate the generator without isolating the pump buses from the external power lines (e.g., a generator output breaker is provided as well as a station output breaker).

15.3.4.2 Analysis of Effects and Consequences

15.3.4.2.1 Method of Analysis

This transient is analyzed by three digital computer codes. First the LOFTRAN (Reference 17) Code is used to calculate the loop and core flow during the transient. The LOFTRAN Code is also used to calculate the time of reactor trip, based on the calculated flows, and the nuclear power transient following reactor trip. The FACTRAN (Reference 9) Code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN. Finally, the THINC (Reference 18) Code is used to calculate the minimum DNBR during the transient based on the heat flux from FACTRAN and flow from LOFTRAN.

The following case has been analyzed:

All loops operating, all loops coasting down.

The method of analysis and the assumptions made regarding initial operating conditions and reactivity coefficients are identical to those discussed in Section 15.2.5 for the partial loss of flow event, except that following the loss of supply to all pumps at power, a reactor trip is actuated by either bus undervoltage or bus underfrequency.

15.3.4.2.2 Results

The calculated sequence of events is shown in Table 15.3-3. Figure 15.3-27 and Figure 15.3-28 show the flow coastdown, nuclear power, and heat flux transients and minimum DNBR for the limiting complete loss of flow event. The reactor is assumed to trip on the undervoltage signal.

15.3.4.3 Conclusions

The analysis performed has demonstrated that for the complete loss of forced reactor coolant flow, the DNBR does not decrease below the safety analysis limit value during the transient, and thus, no core safety limit is violated.

15.3.5 Waste Gas Decay Tank Rupture

15.3.5.1 Identification of Causes and Accident Description

The Gaseous Waste Processing System, as discussed in Chapter 11, is designed to remove fission product gases from the reactor coolant. The system consists of a closed loop with waste gas compressors, hydrogen recombiners, waste gas decay tanks for service at power, and other waste gas decay tanks for service at shutdown and startup.

The maximum amount of waste gases stored occurs after a refueling shutdown at which time the gas decay tanks store the radioactive gases stripped from the reactor coolant.

The accident is defined as an unexpected and uncontrolled release of radioactive xenon and krypton fission product gases stored in a waste decay tank as a consequence of a failure of a single gas decay tank or associated piping.

15.3.5.2 Analysis of Effects

Nonvolatile fission product concentrations are greatly reduced as the coolant being let down is passed through the purification demineralizers. An iodine removal factor of 10 is expected in the mixed bed demineralizers, and an iodine partition factor of the order of 10,000 is expected between the liquid and vapor phases. Based on the above analysis and operating experience at Yankee Rowe and Saxton, activity stored in a gas decay tank consists of that from the noble gases released from the processed coolant and only negligible quantities of less volatile isotopes.

15.3.5.3 Environmental Consequences

The quantity of noble gases contained in each gas decay tank is restricted to assure that in the event of an uncontrolled release of the tank's contents, the resulting total body exposure to an individual at the nearest exclusion area boundary will not exceed 0.5 Rem. Using the methodology outline in Section 5.6.1 of NUREG-0133, the maximum allowable limit is 131,000 curies of noble gases (considered as 133Xe). The corresponding beta/gamma skin dose will also not exceed 2.05 Rem.

To supplement the above evaluation, a realistic analysis and a conservative analysis of potential environmental consequences is performed using the NUREG-0133 methodology with the maximum expected noble gas inventory shown in Table 15.3-5. These supplemental dose projections resulting from the postulated rupture of a gas decay tank are based on the following assumptions:

1. The decay tank rupture is assumed to occur immediately after isolation of the decay tank from the gaseous waste processing system, releasing the entire contents of the tank to the outside atmosphere at ground level. The assumption of the release of the noble gas inventory from only a single tank is based upon the fact that the valving of the decay tanks in the gaseous waste processing system has been designed so that a release from one decay tank by any means does not result in any additional release of radioactivity stored in any of the other decay tanks.
2. The 0-1 hour atmospheric diffusion factor given in Section 15.A is applicable for the conservative offsite dose analysis. The average annual atmospheric diffusion factors of 3.25 x 10^{-6} and 3.65 x 10^{-7} sec/m^3 at the site boundary and low population zone are used for the realistic offsite dose analysis.

The site boundary gamma whole body and gamma/beta skin doses for the realistic analysis are 2.1x 10^{-3} Rem and 1.22 x 10^{-2} Rem respectively.

The low population zone gamma whole body and gamma/beta skin doses for the realistic analysis are 2.29 x 10^{-4} Rem and 1.37 x 10^{-3} Rem respectively.

The site boundary gamma whole body and gamma/beta skin doses for the conservative analysis are 2.56 x 10^{-1} Rem and 1.54 Rem respectively.

The low population zone gamma whole body and gamma/beta skin doses for the conservative analysis are 6.34 x 10^{-2} Rem and 0.38 Rem respectively.

Since there is no significant amount of the iodine radioisotope within the gas decay tank, a thyroid dose is not calculated.

The calculated doses are well within the limits of 10CFR100 and fall below the 10CFR20 yearly instantaneous dose rate limits (≤ 00 mrem total body & ≤ 3000 mrem skin) for unrestricted areas.

15.3.6 Single Rod Cluster Control Assembly Withdrawal at Full Power

15.3.6.1 Identification of Causes and Accident Description

No single electrical or mechanical failure in the Rod Control System could cause the accidental withdrawal of a single Rod Cluster Control Assembly (RCCA) from the inserted bank at full power operation. The operator could deliberately withdraw a single RCCA in the control bank since this feature is necessary in order to retrieve an assembly should one be accidentally dropped. In the extremely unlikely event of simultaneous electrical failures which could result in single

RCCA withdrawal, rod deviation and rod control urgent failure would both be displayed on the plant annunciator, and the rod position indicators would indicate the relative positions of the assemblies in the bank. The urgent failure alarm also inhibits automatic rod motion in the group in which it occurs. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

Each bank of RCCAs in the system is divided into 2 groups of 4 mechanisms each. The rods comprising a group operate in parallel through multiplexing thyristors. The 2 groups in a bank move sequentially such that the first group is always within 1 step of the second group in the bank. A definite schedule of actuation (or deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism) is required to withdraw the RCCA attached to the mechanism. Since the 4 stationary gripper, movable gripper, and lift coils associated with the 4 RCCAs of a rod group are driven in parallel, any single failure which would cause rod withdrawal would affect a minimum of 1 group, or 4 RCCAs. Mechanical failures are in the direction of insertion or immobility.

15.3.6.2 Analysis of Effects and Consequences

15.3.6.2.1 Method of Analysis

Power distributions within the core are calculated by the ANC (Reference 21) Code based on macroscopic cross section generated by PHOENIX-P (Reference 21) or PARAGON (Reference 22). The peaking factors calculated by ANC are then used by THINC to calculate the minimum DNB for the event. The plant was analyzed for the worst rod withdrawn from Bank D inserted at the insertion limit, with the reactor initially at full power.

15.3.6.2.2 Results

Two (2) cases have been considered as follows:

1. If the reactor is in the manual control mode, continuous withdrawal of a single RCCA results in both an increase in core power and coolant temperature, and an increase in the local hot channel factor in the area of the failed RCCA. In terms of the overall system response, this case is similar to those presented in Section 15.2.2; however, the increased local power peaking in the area of the withdrawn RCCA results in lower minimum DNBR's than for the withdrawn bank cases. Depending on initial bank insertion and location of the withdrawn RCCA, automatic reactor trip may not occur sufficiently fast to prevent the minimum core DNBR from falling below the safety limit value. Evaluation of this case at the power and coolant conditions at which the overtemperature T trip would be expected to trip the plant, shows that an upper limit for the number of rods with a DNBR less than the safety limit value is 5 percent.
2. If the reactor is in automatic control mode, continuous withdrawal of a single RCCA will result in the immobility of the other RCCAs in the controlling bank. The transient will then proceed in the same manner as Case 1 described above. For such cases as above, a trip will

ultimately ensue, although not sufficiently fast, in all cases to prevent a minimum DNBR in the core of less than the safety limit.

15.3.6.3 Conclusions

For the case of one RCCA fully withdrawn, with the reactor in the automatic or manual control mode, and initially operating at full power with Bank D at the insertion limit, an upper bound of the number of fuel rods experiencing DNBR less than the design limit is 5 percent or less of the total fuel rods in the core.

For both cases discussed, the indicators and alarms mentioned would function to alert the operator to the malfunction before DNB could occur. For case 1 discussed above, the insertion limit alarms (low and low-low alarms) would also serve to alert the operator.

15.3.7 Break In Instrument Line or Other Lines From Reactor Coolant Pressure Boundary That Penetrate Containment

There are no instrument lines connected to the reactor coolant system that penetrate containment. However, grab sample lines from reactor coolant loop 2 and loop 3 hot legs, the pressurizer steam and liquid spaces, and the 3 inch chemical and volume control system (CVCS) letdown line do penetrate containment. he grab sample lines are equipped with normally closed isolation valves both inside and outside containment and are designed in accordance with General Design Criterion 55.

The most severe pipe rupture, with regard to release of radioactivity during normal plant operation, would be complete severance of the 3 inch CVCS letdown line just outside containment, upstream of the outer containment isolation valve, (see Figure 9.3 16, Sheet 1) at rated power. Complete severance of the letdown line would result in the loss of reactor coolant at the rate of up to 165 gpm based on the use of two (60 gpm) letdown orifice prior to the accident. Following such a break, the RCS pressure decreases due to the loss of reactor coolant. When the pressurizer pressure has reached the low pressure setpoint, a reactor trip is initiated. A turbine trip follows a reactor trip and results in an increase in secondary side pressure to the steam generator safety valve set pressure. The safety injection signal on low pressurizer pressure terminates the break flow by isolating the letdown line inside containment. The reactor coolant inventory is replenished by the charging pumps. Operation of these pumps ensure that the core will not be uncovered and prevents any significant increases in clad temperature. For smaller breaks within the capability of the Reactor Makeup System, Engineered Safety Features actuation would not occur. Frequent automatic operation of the Reactor Makeup System would provide some indication of reactor coolant loss to the operator.

For this event, environmental consequences are evaluated for both a realistic and a conservative case. Assumptions and parameters used to calculate the activity released and the offsite doses resulting from this event for both the realistic and conservative cases are summarized in Table 15.3-6 and are listed as follows:

1. The operator will be able to detect the rupture and isolate the break within 10 minutes by use of the following:

   a. Low flow alarm on the reactor coolant letdown monitor, RM L1 (see Section 11.4.2).

   b. Leakage greater than 45 gpm which actuates an alarm in the control room. The alarm drain system is discussed in Section 9.3.3.3 and illustrated schematically by Figure 9.3 7.

   c. Indication of letdown line flow on the main control board.

   However, for this offsite dose analysis it is conservatively assumed that the time required for the operator to identify the accident and isolate the break is 30 minutes.

2. Reactor coolant is lost through the break at a rate of 165 gpm. No activity is released from the break after the isolation time of 30 minutes.
3. The iodine partition factor for activity released from the break is 0.4.
4. The concentration of radioactive nuclides in the reactor coolant is listed in Table 11.1 2. For the realistic case these values were multiplied by a factor of 0.12. For the conservative case it is assumed that concurrent iodine spikes occur as a result of the accident.
5. For the concurrent iodine spike, the increase in the reactor coolant iodine concentration is estimated using a spiking model which assumes that the iodine release rate from the fuel rods to the coolant increases to a value 500 times greater than the release rate corresponding to the iodine concentration at the equilibrium value associated with reactor coolant activities at 1 Ci/gm dose equivalent I-131. The iodine release rate during the concurrent spike is based on a maximum letdown flow of 143 gpm which includes the maximum normal letdown of 120 gpm plus 12 gpm to account for uncertainty in flow and 11 gpm primary coolant leakage.

Using the previously listed assumptions, isotopic releases to the environment are determined to be those listed in Table 15.3-7 and Table 15.3-8 for the realistic and conservative cases, respectively.

Gamma, beta and thyroid doses at the site boundary for the realistic case are 4.27×10^{5} Rem, 7.11×10^{-5} Rem, and 3.17×10^{-3} Rem, respectively. Corresponding doses at the low population zone are 4.82×10^{-6} Rem, 8.03×10^{-6} Rem, and 3.58×10^{-4} Rem, respectively.

Gamma, beta and thyroid doses at the site boundary for the conservative case with a concurrent iodine spike are 2.31×10^{-1} Rem, 1.35×10^{-1} Rem, and $2.17 \times 10^{+1}$ Rem, respectively. Corresponding doses at the low population zone are 1.34×10^{-2} Rem, 7.83×10^{-3} Rem, and 1.26 Rem, respectively.

Doses resulting from this accident are well within the limits defined in 10 CFR 100 (25 Rem whole body and 300 Rem thyroid).

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Table 15.3-1
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Table 15.3-3
Time Sequence of Events For Condition III Events

Accident	Event	Time (sec)
Complete Loss of Forced Reactor Coolant Flow		
All loops operating, all pumps coasting down	Coastdown begins	0.0
	Reactor coolant pump underfrequency reactor trip setpoint reached	0.6
	Rod motion begins	1.2
	Minimum DNBR occurs	2.8

Table 15.3-5
Estimated Gas Decay Tank Inventory

Isotope	Gas Decay Tank Inventory (Curies)
Kr-83m	4.3
Kr-85	53000
Kr-85m	47
Kr-87	4.6
Kr-88	45
Xe-131m	530
Xe-133	56000
Xe-133m	2900
Xe-135	500
Xe-135m	2.1
Xe-138	0.13

Basis: 1% Defective Fuel and the Purge System Operation; VCT Purge Rate = 0.7 sc/m

Table 15.3-6
Parameters Used in Analysis of Chemical and Volume
Control Systems Letdown Line Rupture

Parameter	Realistic Case	Conservative Case
Core Thermal Power	2958 MWt	2958 MWt
Fuel Defects	0.12 percent (1)	1 percent (2)
Iodine Spiking Basis	None	Concurrent Spike (3)
Break Flow Rate	165 gpm	165 gpm
Break Flow Isolation Time	30 min	30 min
Partition Factors		
Iodine	0.4	0.4
Noble Gases	1.0	1.0
Meteorology	Annual Average	Accident
Dose Model	Appendix 15A	Appendix 15A

(1) American National Standards Institute, “Source Team Specification” ANS/ANSI 18.1-1984.
(2) For noble gases.
(3) Initial Reactor Coolant iodine activities based on 1 μCi/gm dose equivalent I-131.

Table 15.3-7
Chemical and Volume Control System Letdown
Line Rupture - Isotopic Release to the
Environment - Realistic Case No Iodine Spike

Isotope	Activity Released (Ci)
I-131	1.99×10^{0}
I-132	2.06×10^{0}
I-133	3.06×10^{0}
I-134	3.99×10^{-1}
I-135	1.59×10^{0}
Kr-83m	9.05×10^{-1}
Kr-85	1.60×10^{1}
Kr-85m	3.78×10^{0}
Kr-87	2.31×10^{0}
Kr-88	6.73×10^{0}
Kr-89	1.87×10^{-1}
Xe-131m	4.84×10^{0}
Xe-133	6.10×10^{2}
Xe-133m	3.99×10^{1}
Xe-135	1.81×10^{1}
Xe-135m	1.09×10^{0}
Xe-138	1.34×10^{0}

Table 15.3-8
Chemical and Volume Control System
Letdown Line Rupture - Isotopic Release
to the Environment - Conservative Case With Iodine Spike

Isotope	Activity Released (Ci)
I-131	9.87×10^{1}
I-132	4.82×10^{2}
I-133	2.01×10^{2}
I-134	1.85×10^{2}
I-135	1.80×10^{2}
Kr-83m	7.54×10^{0}
Kr-85	1.33×10^{2}
Kr-85m	3.16×10^{1}
Kr-87	1.93×10^{1}
Kr-88	5.61×10^{1}
Kr-89	1.56×10^{0}
Xe-131m	4.03×10^{1}
Xe-133	5.09×10^{3}
Xe-133m	3.33×10^{2}
Xe-135	1.51×10^{2}
Xe-135m	9.12×10^{0}
Xe-138	1.12×10^{1}

Table 15.3-9
Flux Map Review Criteria for Inadvertent Core Loading

Number of Available Incore Detector Locations	Measured vs. Predicted Detector Reaction Rate Comparison *	Symmetric Thimble Reaction Rate Comparison**
47 to 50	10%	7%
42 to 46	8%	5%
38 to 41	6%	5%

** The review criterion is the table value (%) or an absolute normalized reaction rate difference equal to the table value divided by 100% (e.g., 10% / 100% = 0.1), whichever is greater.

** Applicable to symmetric thimbles with normalized reaction rates above 0.7. The review criterion is relative to the expected reaction rate difference.

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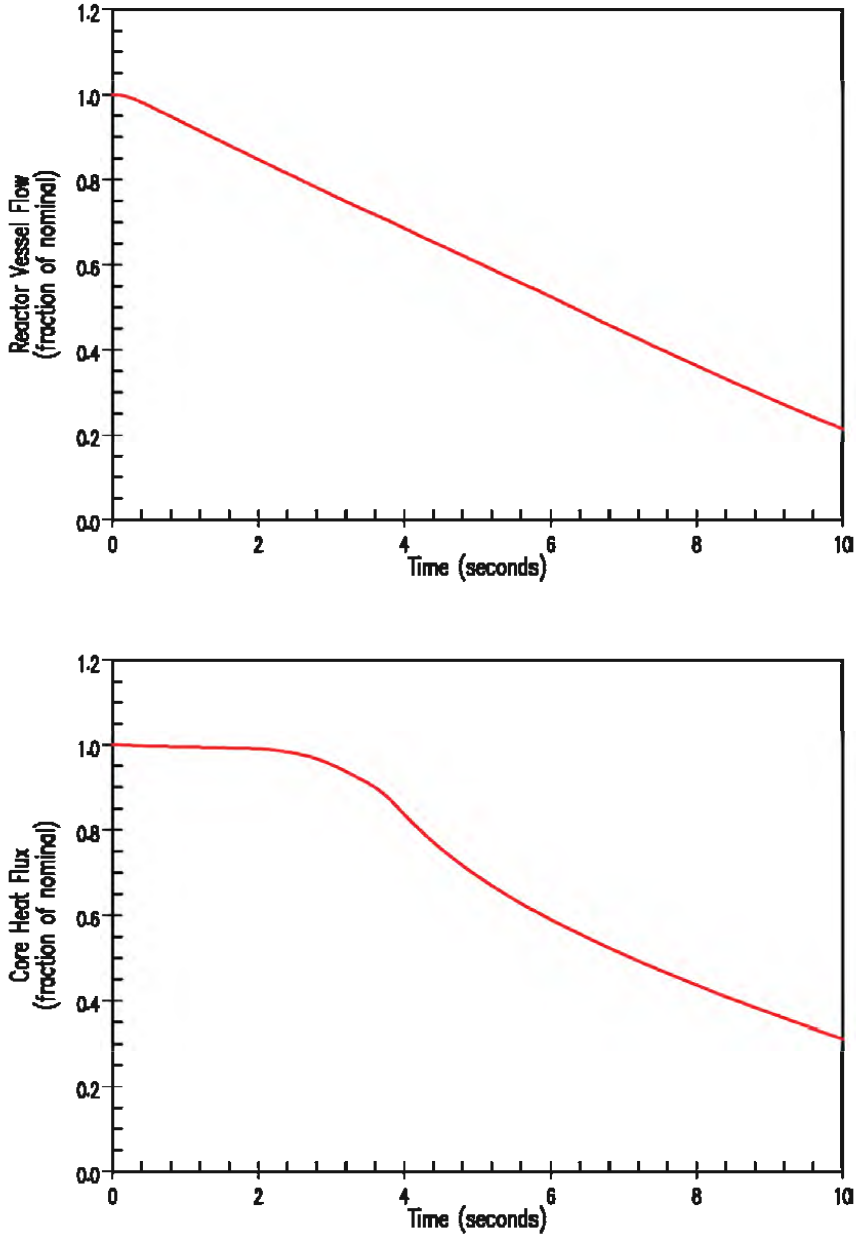
Figure 15.3-27

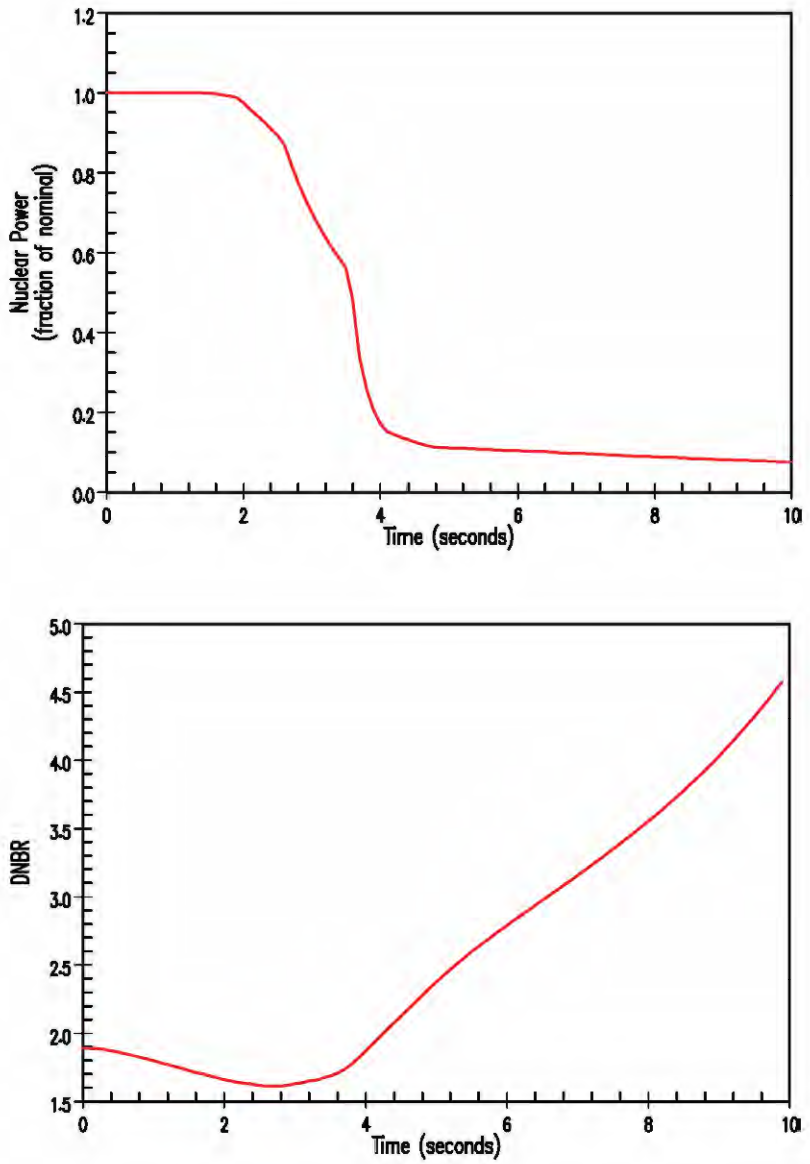
ALL LOOPS OPERATING, ALL LOOPS COASTING DOWN: VESSEL FLOW AND CORE HEAT FLUX VS. TIME



South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
All Loops Operating, All Loops Coasting Down: Vessel Flow and Core Heat Flux vs. Time
Figure 15.3-27

Figure 15.3-28

ALL LOOPS OPERATING, ALL LOOPS COASTING DOWN: NUCLEAR POWER AND DNBR VS. TIME



South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
All Loops Operating, All Loops Coasting Down: Nuclear Power and DNBR vs. Time
Figure 15.3-28

15.4 CONDITION IV - LIMITING FAULTS

Condition IV occurrences are faults which are not expected to take place, but are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. They are the most drastic which must be designed against and represent limiting design cases. Condition IV faults are not to cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of guideline values of 10 CFR 50.67. A single Condition IV fault is not to cause a consequential loss of required functions of systems needed to cope with the fault including those of the Emergency Core Cooling System and the containment. For the purposes of this report the following faults have been classified in this category:

1. Major rupture of pipes containing reactor coolant up to and including double ended rupture of the largest pipe in the Reactor Coolant System (RCS), i.e., loss-of-coolant accident (LOCA).
2. Major secondary system pipe ruptures.
3. Steam generator tube rupture.
4. Single reactor coolant pump locked rotor.
5. Fuel handling accident.
6. Rupture of a control rod drive mechanism housing (rod cluster control assembly ejection).

Each of these six limiting faults is analyzed in Section 15.4 in accordance with USNRC Regulatory Guide 1.183 guidelines. In general, each analysis includes an identification of causes and description of the accident, an analysis of effects and consequences, a presentation of results, and relevant conclusions

15.4.1 Major Reactor Coolant System Pipe Ruptures (Loss of Coolant Accident)

An analysis with the FULL SPECTRUM loss-of-coolant accident (FSLOCA) evaluation model (EM) has been completed for V.C. Summer. Sections 15.4.1.1.1 through 15.4.1.1.5 discuss the LOCA analysis.

15.4.1.1 FULL SPECTRUM LOCA Evaluation Model and Analysis

15.4.1.1.1 Introduction

The FSLOCA EM (Reference 1) was developed to address the full spectrum of loss-of-coolant accidents (LOCAs) which result from a postulated break in the reactor coolant system (RCS) of a pressurized water reactor (PWR). The break sizes considered in the Westinghouse FSLOCA EM include any break size in which break flow is beyond the capacity of the normal charging pumps, up to and including a double-ended guillotine (DEG) rupture of an RCS cold leg with a break flow area equal to two times the pipe area, including what traditionally are defined as Small and Large Break LOCAs.

The break size spectrum is divided into two regions. Region I includes breaks that are typically defined as Small Break LOCAs (SBLOCAs). Region II includes break sizes that are typically defined as Large Break LOCAs (LBLOCAs).

The FSLOCA EM explicitly considers the effects of fuel pellet thermal conductivity degradation (TCD) and other burnup-related effects by calibrating to fuel rod performance data input generated by the PAD5 code (Reference 2), which explicitly models TCD and is benchmarked to high burnup data in Reference 2. The fuel pellet thermal conductivity model in the WCOBRA/TRAC-TF2 code used for system and fuel response predictions explicitly accounts for pellet thermal conductivity degradation.

Three of the Title 10 of the Code of Federal Regulations (CFR) 50.46 criteria (peak cladding temperature (PCT), maximum local oxidation (MLO), and core-wide oxidation (CWO)) are considered directly in the FSLOCA EM. The MLO is defined as the sum of pre-transient corrosion and transient oxidation consistent with the position in Information Notice 98-29 (Reference 4). Compliance with demonstrating the maintenance of core cooling geometry and of long-term core cooling is discussed in Section 15.4.1.1.5.

10 CFR 50.46 (Reference 3) states that "[…] *uncertainty must be accounted for, so that, when the calculated ECCS cooling performance is compared to the criteria set forth in paragraph (b) of this section, there is a high level of probability that the criteria would not be exceeded*." A statistical statement which estimates or bounds the 95th percentile of the population with a 95-percent confidence level has been suggested by the NRC as acceptable to demonstrate the required "high probability." In the FSLOCA EM, the uncertainties are combined with a direct Monte Carlo simulation. A sample of the predicted short-term LOCA population is generated, and non-parametric statistical inference procedures are applied to develop probabilistic statements based on the predicted LOCA population. Upper tolerance limits for PCT, MLO, and CWO are calculated at the 95-percent confidence level to bound 95% of the population of predicted LOCA results. A "high level of probability" that 10 CFR 50.46 acceptance criteria (b)(1), (b)(2), and (b)(3) would not be exceeded is assured by confirming that the upper tolerance limits are within the acceptance criteria.

The FSLOCA EM has been generically approved by the Nuclear Regulatory Commission (NRC) for Westinghouse 3-loop and 4-loop plants with cold leg Emergency Core Cooling System (ECCS) injection (Reference 1). Since V.C. Summer is a Westinghouse designed 3-loop plant with cold leg ECCS injection, the approved method is applicable.

Sections 15.4.1.1.3 and 15.4.1.1.4 summarize the application of the Westinghouse FSLOCA EM to V.C. Summer. The application of the FSLOCA EM to V.C. Summer is consistent with the NRC-approved methodology (Reference 1), with the corrections and changes reported in Reference 5 pursuant to 10 CFR 50.46. The application of the FSLOCA EM is also applicable for the V.C. Summer plant design and operating conditions.

The major plant parameter and analysis assumptions used in the V.C. Summer analysis with the FSLOCA EM are provided in Tables 15.4-1a through 15.4-1f.

15.4.1.1.2 Method of Analysis

15.4.1.1.2.1 FULL SPECTRUM LOCA Evaluation Model Development

In 1988, the NRC Staff amended the requirements of 10 CFR 50.46 (Reference 3 and Reference 6) and Appendix K, "ECCS Evaluation Models," to permit the use of a realistic EM to analyze the performance of the ECCS during a hypothetical LOCA. Under the amended rules, best-estimate thermal-hydraulic models may be used in place of models with Appendix K features. After the rule change, Westinghouse developed and received approval for a best-estimate LBLOCA EM, which is discussed in Reference 7. The EM is referred to as the Code Qualification Document (CQD), and was developed following Regulatory Guide (RG) 1.157 (Reference 8).

When the FSLOCA EM was being developed, the NRC issued RG 1.203 (Reference 9) which expands on the principles of RG 1.157, while providing a more systematic approach to the development and assessment process of a PWR accident and safety analysis EM. Therefore, the development of the FSLOCA EM followed the Evaluation Model Development and Assessment Process (EMDAP), which is documented in RG 1.203. While RG 1.203 expands upon RG 1.157, there are certain aspects of RG 1.157 which are more detailed than RG 1.203; therefore, both RGs were used for the development of the FSLOCA EM.

15.4.1.1.2.2 WCOBRA/TRAC-TF2 Computer Code

The FSLOCA EM (Reference 1) uses the WCOBRA/TRAC-TF2 code to analyze the system thermal-hydraulic response for the full spectrum of break sizes. WCOBRA/TRAC-TF2 was created by combining a 1D module (TRAC-P) with a 3D module (based on Westinghouse modified COBRA-TF). The 1D and 3D modules include an explicit non-condensable gas transport equation. The use of TRAC-P allows for the extension of a two-fluid, six-equation formulation of the two-phase flow to the 1D loop components. This new code is WCOBRA/TRAC-TF2, where "TF2" is an identifier that reflects the use of a three-field (TF) formulation of the 3D module derived by COBRA-TF and a two-fluid (TF) formulation of the 1D module based on TRAC-P.

This best-estimate computer code contains the following features:

1. Ability to model transient three-dimensional flows in different geometries inside the reactor vessel
2. Ability to model thermal and mechanical non-equilibrium between phases
3. Ability to mechanistically represent interfacial heat, mass, and momentum transfer in different flow regimes
4. Ability to represent important reactor components such as fuel rods, steam generators (SGs), reactor coolant pumps (RCPs), etc.

A detailed assessment of the computer code WCOBRA/TRAC-TF2 was made through comparisons to experimental data. These assessments were used to develop quantitative estimates of the ability of the code to predict key physical phenomena for a LOCA. Modeling of a LOCA

introduces additional uncertainties which are identified and quantified in the plant-specific analysis. The reactor vessel and loop noding scheme used in the FSLOCA EM is consistent with the noding scheme used for the experiment simulations that form the validation basis for the physical models in the code. Such noding choices have been justified by assessing the model against large and full scale experiments.

15.4.1.1.3 Region I Analysis

Identification of Cause and Accident Description

The Region I analysis considers a spectrum of small breaks to ensure that those breaks with the likelihood of the more severe core uncovery are captured.

Before the break occurs, the plant is in an equilibrium condition, i.e., the heat generated in the core is being removed via the steam generator into the secondary system. Following the postulated break, a depressurization of the RCS and a loss of coolant would result. During the blowdown phase, heat from decay, hot reactor vessel internals, and the reactor vessel continues to be transferred to the RCS. A reactor trip occurs when the pressurizer low pressure trip setpoint is reached.

Safety injection (SI) is actuated when the low pressurizer pressure SI setpoint is reached. For a SBLOCA, the RCS pressure can remain high for an extended period, and the high pressure SI system functions to partially mitigate the RCS inventory lost through the break. The low pressurizer pressure SI signal also terminates normal feedwater flow by closing the main feedwater line isolation valves and initiates auxiliary feedwater flow by starting auxiliary feedwater pumps.

The heat transfer between the RCS and the secondary system may be in either direction depending on the relative temperatures between the RCS and the steam generator secondary side. In the case of continued heat addition to the steam generator secondary side, the pressure increases and is relieved by the main steam safety valves (MSSVs). Make-up to the steam generator secondary side is automatically provided by the auxiliary feedwater pumps.

When the RCS depressurizes below the accumulator cover pressure, the accumulators begin to inject water into the reactor coolant loops and recover the RCS inventory, effectively ending the transient.

The consequences of the accident are mitigated in two ways:

1. The reactor trip and borated water injection complement void formation in the core resulting in a rapid reduction in nuclear power to a residual level corresponding to the delayed fission and fission product decay.
2. The injection of borated water ensures sufficient flooding of the core to prevent excessive fuel rod cladding temperatures.

The availability of offsite power affects the timing of the initiation of safety injection flow and the reactor coolant pump trip following a small break LOCA. With a loss-of-offsite power (LOOP), the delayed SI results in a longer period of time when the vessel inventory is lost without being replaced by high head safety injection (HHSI) flow, although the HHSI flow is relatively small in magnitude early in the transient compared to the break flow due to the high RCS pressure. The reactor coolant pumps trip very early in the transient for LOOP, while operator action is assumed to result in an RCP trip 5 minutes after the plant-specific trip criterion is reached for offsite power available (OPA). Continued pump operation with OPA can work to pump more flow toward the break, depleting vessel inventory at a greater rate than otherwise would occur for a given break size. For small breaks, however, the continued pump operation can also maintain the positive flow in the broken cold leg, impeding flow reversal from the vessel directly to the break and reducing the total flow out the break.

15.4.1.1.3.1 Phenomenological Description of Region I LOCA

The small break LOCA transient can be divided into time periods in which specific phenomena are occurring, as discussed below.

Blowdown

The rapid depressurization of the RCS coincides with subcooled liquid flow through the break. Following the reactor trip on the low pressurizer pressure setpoint, the pressurizer drains, and safety injection is initiated on the low pressurizer pressure SI setpoint. After reaching this setpoint and applying the safety injection delays, high pressure safety injection flow begins. Phase separation begins in the upper head and upper plenum near the end of this period until the entire RCS eventually reaches saturation, ending the rapid depressurization slightly above the steam generator secondary side pressure near the modeled MSSV setpoint.

Natural Circulation

This quasi-equilibrium phase persists while the RCS pressure remains slightly above the secondary side pressure. The system drains from the top down, and while significant mass is continually lost through the break, the vapor generated in the core is trapped in the higher elevations of the RCS because of the seal formed by liquid in the crossover leg (cold leg pump suction) loop seals. Throughout this period, the core remains covered by a two-phase mixture and the fuel cladding temperatures remain at the saturation temperature.

Loop Seal Clearance

As the system drains through the break, the liquid levels in the downhill side of the pump suction (crossover leg) decrease to the lower elevations of the piping, allowing the vapor trapped during the natural circulation phase to also vent to the break. This is the loop seal clearing process. The break flow and the flow through the RCS loops become primarily vapor. Relief of a static head imbalance allows for a quick but temporary recovery of liquid levels in the core region.

Boil-Off

With a vapor vent path established after the loop seal clearance, the RCS depressurizes at a rate controlled by the critical flow, which continues to be a primarily high quality mixture of water and steam. The RCS pressure may remain high enough such that safety injection flow cannot make up for the primary system fluid inventory lost through the break in time, potentially leading to core uncovery and a fuel rod cladding temperature heatup.

Core Recovery

The RCS pressure continues to decrease, and once it reaches that of the accumulator gas pressure, the introduction of additional ECCS water from the accumulators replenishes the reactor vessel inventory and recovers the core mixture level. The accident analysis is terminated when the break flow is matched, then exceeded, by the injected flow.

15.4.1.1.3.2 Analysis Results

The V.C. Summer Region I analysis was performed in accordance with the NRC-approved methodology in Reference 1 with the corrections and changes reported in Reference 5. The transient that produced the analysis PCT result is a cold leg break with a break diameter of 2.6-inches. The most limiting ECCS single failure of one ECCS train is assumed in the analysis as identified in Table 15.4-1a. Control rod drop is modeled for breaks less than 1 square foot assuming a 2.0-second signal delay time and a 4.0-second rod drop time. RCP trip is modeled coincident with reactor trip on the low pressurizer pressure setpoint for LOOP transients. When the low pressurizer pressure SI setpoint is reached, there is a delay to account for emergency diesel generator start-up, filling headers, etc., after which safety injection is initiated into the reactor coolant system.

The results of the V.C. Summer Region I uncertainty analysis are summarized in Table 15.4-2.

Table 15.4-3 contains a sequence of events for the transient that produced the Region I analysis PCT result. Figures 15.4-2 through 15.4-13 illustrate the calculated key transient response parameters for this transient.

15.4.1.1.4 Region II Analysis

Identification of Cause and Accident Description

Before the break occurs, the reactor is assumed to be in a full power equilibrium condition, i.e., the heat generated in the core is being removed by the steam generators. The entire RCS contains sub-cooled liquid which transfers heat from the core by forced convection with some nucleate boiling. Should a large break occur, rapid depressurization of the RCS to a pressure nearly equal to the containment pressure occurs in approximately 40 seconds, with nearly a complete loss of liquid inventory.

During blowdown, heat from fission product decay and stored energy in the fuel pellets continues to be transferred to the fuel rod cladding, and departure from nucleate boiling occurs. Rapid voiding in the core shuts down the reactor. The SI system is actuated when the low pressurizer pressure setpoint (SI signal) is reached. As the RCS pressure decreases to the accumulator cover pressure, injection of accumulator liquid into the cold leg begins. However, significant accumulator inventory is lost out of the break due to the phenomenon of emergency core cooling bypass. After the initial surge of accumulator inventory is lost out of the break, core bypass breaks down and the remaining accumulator liquid refills the lower portion of the reactor vessel.

The heat transfer between the RCS and the secondary system may be in either direction, based on the progression of the transient and the relative fluid temperatures. In the case of the large break LOCA, the primary pressure rapidly decreases below the secondary system pressure, and the steam generators become an additional heat source. Reflood of the core and eventual quench of the fuel rods is accomplished by the injection of water from the refueling water storage tank (RWST).

The consequences of the accident are mitigated in two ways:

1. The borated water injection complements void formation in causing a rapid reduction in nuclear power to a residual level corresponding to fission product decay heat. The level of RCS mixed boron concentration is sufficient to ensure that the post-LOCA core remains subcritical. However, no credit is taken for the insertion of control rods to shut down the reactor in the large break analysis.
2. The injection of borated water provides core cooling and prevents excessive fuel rod cladding temperatures.

The availability of offsite power affects the timing of the initiation of safety injection flow and the reactor coolant pump trip following a large break LOCA. With a LOOP, there is an extended delay in safety injection. Also, the effect of the RCS pumps on the LOCA transient may be significantly different, depending on whether they are assumed to coast down with LOOP or continue running with OPA.

15.4.1.1.4.1 Phenomenological Description of Region II LOCA

A large-break LOCA transient can be divided into phases in which specific phenomena are occurring. A convenient way to divide the transient is in terms of the various heatup and cooldown phases that the fuel assemblies undergo. For each of these phases, specific phenomena and heat transfer regimes are important, as discussed below.

Blowdown – Critical Heat Flux (CHF) Phase

In this phase, the break flow is subcooled, the discharge rate of coolant from the break is high, the core flow reverses, the fuel rods go through departure from nucleate boiling (DNB), and the cladding rapidly heats up and the reactor is shut down due to the core voiding.

The regions of the RCS with the highest initial temperatures (upper core, upper plenum, and hot legs) begin to flash during this period. This phase is terminated when the water in the lower plenum and downcomer begins to flash. The mixture level swells and a saturated mixture is pushed into the core by the intact loop RCPs, still rotating in single-phase liquid. As the fluid in the broken cold leg reaches saturation conditions, the discharge flow rate at the break decreases significantly.

Blowdown – Upward Core Flow Phase

Heat transfer is increased as the two-phase mixture is pushed into the core. The break discharge rate is reduced because the fluid becomes saturated at the break. This phase ends as the lower plenum mass is depleted, the fluid in the loops become two-phase, and the RCP head degrades with increasing voiding.

Blowdown – Downward Core Flow Phase

The break flow begins to dominate and pulls flow down through the core as RCP head decreases, while liquid and entrained liquid flows also provide core cooling. Heat transfer in this period may be enhanced by liquid flow from the upper head. Once the system has depressurized to less than the accumulator cover pressure, the accumulators begin to inject cold water into the cold legs.

During this period, due to steam upflow in the downcomer, a portion of the injected ECCS water is lost to the break or bypasses the core around the downcomer and exits via the break due to the phenomenon of emergency core cooling bypass. After the initial surge of accumulator inventory is lost out of the break, core bypass breaks down and the remaining accumulator liquid refills the lower portion of the reactor vessel. As the system pressure continues to decrease, the break flow and consequently the downward core flow are reduced. The system pressure approaches the containment pressure at the end of this last period of the blowdown phase.

During this phase, the core begins to heat up as the system equilibrates with containment pressure, and the phase ends when the reactor vessel begins to refill with ECCS water.

Refill Phase

The core continues to heat up as the lower plenum refills with ECCS water. This phase is characterized by a rapid increase in fuel cladding temperature at all elevations due to the lack of liquid and steam flow in the core region. The water completely refills the lower plenum and the refill phase ends. As ECCS water enters the core, the fuel rods in the lower core region begin to quench and liquid entrainment begins, resulting in increased fuel rod heat transfer.

Reflood Phase

During the early reflood phase, the accumulators begin to empty and nitrogen is discharged into the RCS. The nitrogen surge forces water into the core, causing system re-pressurization and a temporary reduction of pumped ECCS flow. During this time, core cooling may increase due to

vapor generation and liquid entrainment, but conversely the early reflood pressure spike results in loss of mass out through the broken cold leg.

The pumped ECCS water aids in the filling of the downcomer throughout the reflood period. As the quench front progresses further into the core, the PCT elevation moves increasingly higher in the fuel assembly.

As the transient progresses, continued injection of pumped ECCS water refloods the core, effectively removes the reactor vessel metal mass stored energy and core decay heat, and leads to an increase in the reactor vessel fluid mass. Eventually the core inventory increases enough that liquid entrainment is able to quench all the fuel assemblies in the core.

15.4.1.1.4.2 Analysis Results

The V.C. Summer Region II analysis was performed in accordance with the NRC-approved methodology in Reference 1 with the corrections and changes reported in Reference 5. The analysis was performed assuming both LOOP and OPA, and the results of both of the LOOP and OPA analyses are compared to the 10 CFR 50.46 acceptance criteria. The most limiting ECCS single failure of one ECCS train is assumed in the analysis as identified in Table 15.4-1a. The results of the V.C. Summer Region II LOOP and OPA uncertainty analyses are summarized in Table 15.4-2.

Table 15.4-4 contains a sequence of events for the transient that produced the more limiting analysis PCT result relative to the offsite power assumption. Figures 15.4-14 through 15.4-27 illustrate the key response parameters for this transient.

The effects of containment backpressure on the LOCA analysis are determined by a containment response analysis separate from that described in Chapter 6. The containment pressure is calculated for each LOCA transient in the analysis using the COCO code (References 10 and 11). The COCO containment code is integrated into the WCOBRA/TRAC-TF2 thermal-hydraulic code. The transient-specific mass and energy releases calculated by the thermal-hydraulic code at the end of each timestep are transferred to COCO. COCO then calculates the containment pressure based on the containment model (the inputs are summarized in Tables 15.4-1b, 15.4-1c, and 6.2-60) and the mass and energy releases, and transfers the pressure back to the thermal-hydraulic code as a boundary condition at the break, consistent with the methodology in Reference 1. The containment model for COCO calculates a conservatively low containment pressure, including the effects of all the installed pressure reducing systems and processes such as assuming all trains of containment spray are operable and assuming fan cooler operation. The containment backpressure for the transient that produced the analysis PCT result is provided in Figure 15.4-21.

15.4.1.1.5 Compliance with 10 CFR 50.46

It must be demonstrated that there is a high level of probability that the following criteria in 10 CFR 50.46 are met:

(b)(1) The analysis PCT corresponds to a bounding estimate of the 95th percentile PCT at the 95-percent confidence level. Since the resulting PCT is less than 2,200°F, the analysis with the FSLOCA EM confirms that 10 CFR 50.46 acceptance criterion (b)(1), i.e., "Peak Cladding Temperature less than 2,200°F," is demonstrated.

The results are shown in Table 15.4-2 for V.C. Summer.

(b)(2) The analysis MLO corresponds to a bounding estimate of the 95th percentile MLO at the 95-percent confidence level. Since the resulting MLO is less than 17 percent when converting the time-at-temperature to an equivalent cladding reacted using the Baker-Just correlation and adding the pre-transient corrosion, the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(2), i.e., "Maximum Local Oxidation of the cladding less than 17 percent," is demonstrated.

The results are shown in Table 15.4-2 for V.C. Summer.

(b)(3) The analysis CWO corresponds to a bounding estimate of the 95th percentile CWO at the 95-percent confidence level. Since the resulting CWO is less than 1 percent, the analysis confirms that 10 CFR 50.46 acceptance criterion (b)(3), i.e., "Core-Wide Oxidation less than 1 percent," is demonstrated.

The results are shown in Table 15.4-2 for V.C. Summer.

(b)(4) 10 CFR 50.46 acceptance criterion (b)(4) requires that the calculated changes in core geometry are such that the core remains in a coolable geometry.

This criterion is met by demonstrating compliance with criteria (b)(1), (b)(2), and (b)(3), and by assuring that fuel assembly grid deformation due to combined LOCA and seismic loads is specifically addressed. Criteria (b)(1), (b)(2), and (b)(3) have been met for V.C. Summer as shown in Table 15.4-2.

It is discussed in Section 32.1 of the NRC-approved FSLOCA EM (Reference 1) that the effects of LOCA and seismic loads on the core geometry do not need to be considered unless fuel assembly grid deformation extends beyond the core periphery (i.e., deformation in a fuel assembly with no sides adjacent to the core baffle plates). Inboard grid deformation due to combined LOCA and seismic loads is not calculated to occur for V.C. Summer.

(b)(5) 10 CFR 50.46 acceptance criterion (b)(5) requires that long-term core cooling be provided following the successful initial operation of the ECCS.

Long-term cooling is dependent on the demonstration of the continued delivery of cooling water to the core. The actions that are currently in place to maintain long-term cooling are not impacted by the application of the NRC-approved FSLOCA EM (Reference 1).

Based on the analysis results for Region I and Region II presented in Table 15.4-2 for V.C. Summer, it is concluded that V.C. Summer complies with the criteria in 10 CFR 50.46.

15.4.1.1.6 Long Term Cooling

In the long term, the core remains subcritical and amenable to cooling. For the limiting cold leg break, evaluations show:

1. At initiation of cold leg recirculation, the sump boron concentration is sufficient to keep the core subcritical (K_{eff} less than 1.0) with all control rods out and no Xenon.
2. Boron levels within the core are limited to less than the precipitation level by supplying ECCS water to the hot legs within 8 hours after initiation of the LOCA.
3. At the initiation of hot leg recirculation, the sump boron concentration is sufficient to keep the core subcritical (K_{eff} less than 1.0) with N-1 rods inserted (per WCAP-15704 (Reference 50) and Xenon.

15.4.1.1.7 Impact of ECCS Evaluation Model Changes

The October 17, 1988 revision to 10CFR50.46 requires applicants and holders of operating licenses or construction permits to notify the NRC of errors and changes in the ECCS Evaluation Models, which are not significant, on an annual basis. Reference 47 defines a significant error change as one which results in a calculated peak fuel cladding temperature (PCT) different by more than 50°F from the temperature calculated for the limiting transient using the last acceptable model, or is a cumulation of changes and errors such that the sum of the absolute temperature change is greater than 50°F. The current ECCS evaluation model changes that affect the large break LOCA PCT are identified in the latest 10CFR50.46 annual or 30 day report.

15.4.1.2 Hydrogen Production and Accumulation

Hydrogen accumulation in the containment atmosphere following a design basis accident can be the result of production from several sources. The potential sources of hydrogen are the zirconium water reaction, corrosion of construction materials, and radiolytic decomposition of the emergency core cooling solution. The latter source, solution radiolysis, includes both core solution radiolysis and sump solution radiolysis.

15.4.1.2.1 Method of Analysis

Methods and assumptions used in the analysis of post-accident hydrogen generation and control are specified by Regulatory Guide 1.7 (Reference 53). In determining the amount of hydrogen generated by reaction of the core Zircaloy cladding with water, Regulatory Guide 1.7 states that the amount of hydrogen generated by zirc-water reaction should be the greater of either five times the maximum amount calculated by ECCS evaluation or the amount that would result from reaction of all the metal in the outside surfaces of the fuel cladding to a depth of 0.00023 inches. The 10CFR50.46 acceptance criteria for ECCS performance requires that total hydrogen generated by cladding oxidation be less than 0.01 times (1.0%) the amount generated by oxidation of the whole core cladding. The amount of cladding oxidation following the design basis LOCA is shown by the ECCS evaluation to be less than the 1.0% acceptance criteria (Table 15.4-2). Five times that amount, then, is 5.0%. Since 0.00023 inches is approximately 1% of the cladding thickness, the conservative assumption for Zirc-water reaction under Regulatory Guide 1.7 is 5.0% of the whole core cladding Zircaloy.

The use of aluminum inside the containment is limited, and it is not used in safety related components which are in contact with the recirculating core cooling fluid. Aluminum is much more reactive with the containment spray alkaline borate solution than other plant materials such as galvanized steel, copper, and copper nickel alloys.

By limiting the use of aluminum and zinc, the aggregate source of hydrogen over the long term is primarily due to that arising from radiolytic decomposition and can be predicted with reasonable certainty to permit the design of effective countermeasures.

It should be noted that the zirconium water reaction and aluminum zinc corrosion with containment spray are chemical reactions and thus essentially independent of the radiation field inside the containment following a loss of coolant accident. Radiolytic decomposition of water is dependent on the radiation field intensity. The radiation field inside the containment is calculated for the maximum credible accident in which the fission product activities given in TID 14844 (Reference 15) are used.

The hydrogen generation calculations are performed using the NRC model discussed in Regulatory Guide 1.7 and NRC Standard Review Plan, Section 6.2.5 with no recombiner operating; also, a calculation is made using the NRC model and recombiner operation after the first day following a LOCA. Recombiner operation is discussed in Section 6.2.5.

15.4.1.2.2 Assumptions

The following discussion outlines the assumptions used in the calculations.

1. Zirconium water reaction

   The zirconium water reaction is described by the chemical equation:

   $Zr + 2H_2O \quad Zr\,O_2 + 2H_2 + Heat$

The hydrogen generation due to this reaction will be completed during the first day following the loss of coolant accident. The quantity of hydrogen generated from the zirconium water reaction is 14,987 scf, and is based on 5% of the total zirconium mass reacted. The hydrogen generated is assumed to be released immediately to the containment atmosphere following the loss of coolant accident.

2. Hydrogen from the Reactor Coolant System

   The maximum quantity of hydrogen contained in the primary coolant system is 909 scf. This includes both hydrogen dissolved in the coolant water [35 cc (STP)/kg] and the corresponding equilibrium hydrogen in the pressurizer gas space. The 909 scf of hydrogen is assumed to be released immediately to the containment atmosphere following the loss of coolant accident.

3. Corrosion of plant materials

   Oxidation of metals in aqueous solution results in the generation of hydrogen gas as one of the corrosion products. Extensive corrosion testing has been conducted to determine the behavior of the various metals used in the containment in the

   emergency core cooling solution at design basis accident conditions. Metals tested include Zircaloy, Inconel, aluminum alloys, cupronickel alloys, carbon steel, galvanized carbon steel, and copper.

   Tests conducted at Oak Ridge National Laboratory (ORNL) (Reference 17) (Reference 18) have also verified the compatibility of the various materials (exclusive of aluminum) with alkaline borate solution. As applied to the quantitative definition of hydrogen production rates, the results of the corrosion tests have shown that only aluminum and zinc will corrode at a rate that will significantly add to the hydrogen accumulation in the containment atmosphere.

   The corrosion of aluminum may be described by the overall reaction:

   $2\,Al + 3\,H_2O \rightarrow Al_2O_3 + 3\,H_2$

   Therefore, three moles of hydrogen are produced for each two moles of aluminum oxidized. This corresponds to 20 scf hydrogen produced for each pound of aluminum corroded.

   The corrosion of zinc may be described by the overall reaction:

   $Zn + 2\,H_2O \leftrightarrows Zn(OH)_2 + H_2$

   Therefore, one mole of hydrogen is produced for each mole of zinc oxidized. This corresponds to 5.5 scf hydrogen produced for each pound of zinc corroded.

The time temperature cycle (Table 15.4-6) used in the calculation of aluminum and zinc corrosion is based on a conservative representation of the postulated post accident containment transient. The corrosion rates at the various steps were determined from the aluminum and zinc corrosion rate design curve shown in Figure 15.4-68 and Figure 15.4-69. The corrosion data points include the effects of temperature, alloy, and spray solution conditions. Based on these corrosion rates and the aluminum and zinc inventory given in Table 15.4-7, the contribution of aluminum and zinc corrosion to hydrogen accumulation in the containment following a design basis accident has been calculated. For conservative estimation, no credit was taken for protective shielding effects of insulation or enclosures from the spray, and complete and continuous immersion was assumed.

4. Radiolysis of core and sump water

   Water radiolysis is a complex process involving reactions of numerous intermediates. However, the overall radiolytic process may be described by the reaction:

   $2\ H_2O \leftrightarrows 2\ H_2 + O_2$

   Of interest here is the quantitative definition of the rates and extent of radiolytic hydrogen production following a design basis accident.

   As the emergency core cooling solution flows through the core, it is subjected to gamma radiation by decay of fission products in the fuel. This energy deposition results in solution radiolysis and the production of molecular hydrogen and oxygen. The initial production rate of these species will depend on the rate of energy absorption and the specific radiolytic yields. Another source of hydrogen for the post-accident period arises from water contained in the reactor containment sump being subjected to radiolytic decomposition by fission products.

   For the purposes of this analysis, the calculations are based on Regulatory Guide 1.7 assumptions.

   Calculations based on Regulatory Guide 1.7 assume a hydrogen yield value of 0.5 molecules per 100 ev, 10% of the gamma energy produced from fission products in the fuel rods is absorbed by the solution in the region of the core, 100% of the gamma and beta energy produced from fission products intimately mixed with coolant.

15.4.1.2.3 Results

Figure 15.4-71 and Figure 15.4-72 show the hydrogen production and accumulation in the containment following a loss of coolant accident for the NRC model. Figure 15.4-73 shows the volume percent of hydrogen in the containment for the NRC model assuming no recombiner and recombiner start at one day.

15.4.1.3 Deleted

15.4.1.4 Environmental Consequences of a Postulated Loss of Coolant Accident

The results of analyses presented in this section demonstrate that the amounts of radioactivity released to the environment in the event of a LOCA do not result in doses which exceed guideline values.

Two analyses have been performed:

1. An analysis based upon Regulatory Guide 1.183 (see Appendix 3A).
2. A realistic analysis.

15.4.1.4.1 Fission Product Release to the Containment

To evaluate the radiological consequences of a postulated LOCA, the following 2 cases of fission product releases to the containment have been analyzed.

1. Core Activity Release (Regulatory Guide 1.183 Analysis)

   Acceptable assumptions regarding core inventory and the release of radionuclides from the core are provided in Regulatory Position 3 of Regulatory Guide 1.183.

   The inventory of fission products in the reactor core available for release from the containment is based on a core thermal power of 2958 MWt. A list of the 60 isotopes used in the Regulatory Guide 1.183 analysis is given in Table 15.4-11. The release fractions and timing associated with these isotopes are taken from RG 1.183 and reproduced in Table 15.4-12.

2. Primary Coolant Activity Release (Realistic Case)

   The inventory of fission products available for release from the containment are based on the 1% failed fuel primary coolant activities. In addition, the iodines and bromines in the coolant are conservatively assumed to be increased by a factor of 50 and the noble gases by a factor of 1.5 due to the spiking phenomenon. The resulting values available for release from containment are listed in Table 15.4-13.

15.4.1.4.2 Radioactive Releases from Recirculation Loops

In addition to the fission product release to the containment, the effect of leakage of recirculating sump fluid from engineered safety features equipment located outside the Reactor Building needs to be considered in evaluating the radiological consequences of a LOCA. The following assumptions are utilized in estimating the radiological consequences of post LOCA radioactive releases from these systems (i.e., emergency core cooling and Reactor Building spray) to the Auxiliary Building.

1. With the exception of noble gases, the fission products released to the containment listed in Table 15.4-11 and Table 15.4-13 are assumed to instantaneously and homogeneously mix in the primary containment sump water.
2. The leakage from these systems is conservatively assumed to be 12,000 cc/hr which is approximately 2 times the operational leakage estimated for the RHR and RB Spray systems as indicated in Tables 6.2 52b and 6.3 4. The release from these systems is assumed to start at the earliest time that the recirculation mode is initiated and continue for the duration of the accident
3. It is conservatively assumed that the recirculation loop leakage flashes and that 10% of the iodine is released to the Auxiliary Building atmosphere.
4. No credit is taken for the holdup or filtration of this leakage in the auxiliary building, i.e., the iodine released by the recirculation loop leakage is assumed to be immediately available for release to the environs.

15.4.1.4.3 Radiological Consequences Offsite

The RADTRAD (Reference 64) computer code was used to calculate the offsite doses for the LOCA event. Schematics showing the code modeling of the activity flow paths are shown on Figure 15.4-74 and Figure 15.4-74A. Parameters and assumptions used in evaluating the offsite doses for the LOCA are summarized in Table 15.4-15.

The calculated offsite doses for LOCA are provided in Table 15.4-16. The dose limits as defined in 10 CFR 50.67 are included in Table 15.4-16. The doses resulting from this accident are well within the limits defined in 10 CFR 50.67.

15.4.1.4.4 Radiological Consequences to the Control Room

The radiological effects that could exist in the control room as a consequence of this event would be due to direct radiation from the radioactive cloud in the atmosphere which results from leakage of fission products from the containment and from the postulated recirculation loop leakage in the Auxiliary Building; direct exposure from, the containment; and exposure to radioactive materials which might leak into the control room from these sources.

For the Regulatory Guide 1.183 Case the integrated dose to the control room operators was calculated using the following methods and assumptions:

1. The RADTRAD (Reference 64.) computer code was used to calculate the control room doses for the Regulatory Guide 1.183 case. Schematics showing the code modeling of the activity flow paths are shown on Figure 15.4-74 and Figure 15.4-74A. Parameters and assumptions used in evaluating the control room doses for the LOCA are summarized in Table 15.4-17.
2. The analytical model used to calculate the direct dose from the external radioactive cloud in the atmosphere is calculated as the unprotected control room dose utilizing the RADTRAD computer code and is adjusted to reflect the shielding effects of the control building structure.

3. The direct whole body dose from the radioactivity in the reactor building is calculated utilizing the MicroShield (Reference 65) shielding computer code based on a cylindrical source model, applicable post-accident source terms, and reactor/control building shielding.
4. The atmospheric diffusion parameters for the control room are provided in Table 2.3-123. The limiting control room release point for the LOCA is the Reactor Building nearest point (intake A).
5. As described in Section 9.4.1, the Control Room Ventilation system is automatically placed in the emergency mode, with filtration of incoming and recirculated air, following receipt of a Safety Injection (SI) or high radiation signal from the gaseous activity channel of RM-A1. If both trains are operating, one train will be isolated within 30 minutes by the Operator in accordance with the Emergency Operating Procedures to minimize dose consequences. This condition is bounded by the analysis which only credits one train control room ventilation for the duration of the accident.
6. The modeling of the Control Room Ventilation assumed for the Regulatory Guide 1.183 case is shown on Figure 15.4-74 and Figure 15.4-74A. The emergency mode of operation is assumed to occur at time zero since a SI signal occurs quickly after the accident.

The resulting control room doses for this LOCA are summarized in Table 15.4-18.

15.4.2 Major Secondary System Pipe Rupture

Two (2) major secondary system pipe ruptures are analyzed in this section: rupture of a main steam line and rupture of a main feedwater pipe. The time sequence of events for each of these events is provided in Table 15.4-19.

15.4.2.1 Major Rupture of a Main Steam Line

15.4.2.1.1 Identification of Causes and Accident Description

The steam release arising from a rupture of a main steam line would result in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin. If the most reactive rod cluster control assembly (RCCA) is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam line rupture is a potential problem mainly because of the high power peaking factors which exist assuming the most reactive RCCA to be stuck in its fully withdrawn position. The core is ultimately shut down by the boric acid injection delivered by the safety injection system.

The limiting main steam line break was selected based upon the sensitivity studies performed in “Reactor Core Response to Excessive Secondary Steam Releases,” WCAP 9226, January, 1978 (Reference 42).

The analysis of a main steam line rupture is performed to demonstrate that, assuming a stuck RCCA (with and without offsite power), and a single failure in the engineered safety features (ESF) there is no consequential damage to the primary system and the core remains in place and intact.

Energy release to containment for the worst steam pipe break is discussed in FSAR Chapter 6.

Although departure from nucleate boiling (DNB) and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that no DNB occurs for any rupture assuming the most reactive assembly stuck in its fully withdrawn position.

The following functions provide the necessary protection for a steam line rupture:

1. Safety Injection System actuation from any of the following:
   a. Two (2) out of 3 low pressurizer pressure signals.
   b. Two (2) out of 3 high 1 containment pressure signals.
2. The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the safety injection signal.
3. Redundant isolation of the main feedwater lines sustained high feedwater flow would cause additional cooldown. Therefore, a safety injection signal will rapidly close all feedwater control valves and feedwater isolation valves that backup the control valves.
4. Trip of the main steam line isolation valves (See Technical Specification (Reference 24) (Table 3.3 5) on:
   a. High 2 containment pressure.
   b. High steam line flow in 2 out of 3 steam lines in coincidence with 2 out of 3 low-low RCS average temperature.
   c. Two (2) out of 3 low steam line pressure.

For breaks downstream of the isolation valves, closure of all valves would completely terminate the blowdown. For any break, in any location, no more than one steam generator would blowdown even if one of the isolation valves fails to close. A description of steam line isolation is included in Chapter 10.

Steam flow is measured by monitoring dynamic head in nozzles located in the throat of the steam generator. The effective throat area of the nozzles is 1.4 square feet, which is considerably less than the main steam pipe and thus the nozzles also serve to limit the maximum steam flow for a break at any location.

Table 15.4-21 lists the equipment required in the recovery from a high energy line rupture. Not all equipment is required for any one particular break, since it will vary depending upon postulated break location and details of balance of plant design and pipe rupture criteria. Design criteria and methods of protection of safety related equipment from the dynamic effects of postulated piping

ruptures are provided in FSAR Section 3.6.

15.4.2.1.2 Analysis of Effects and Consequences

15.4.2.1.2.1 Method of Analysis

The analysis of the steam pipe rupture has been performed based on the methodologies documented in Reference 42 to determine:

1. The core heat flux and RCS temperature and pressure resulting from the cooldown following the steam line break. The LOFTRAN (Reference 25) Code has been used.
2. The thermal and hydraulic behavior of the core following a steam line break. A detailed thermal and hydraulic digital computer code, THINC (Reference 26), has been used to determine if DNB occurs for the core conditions computed in item 1 above.

The following conditions were assumed to exist at the time of a main steam line break accident.

1. End of life shut down margin at no load, equilibrium xenon conditions, and the most reactive RCCA stuck in its fully withdrawn position. Operation of the control rod banks during core burnup is restricted in such a way that addition of positive reactivity in a steam line break accident will not lead to a more adverse condition than the case analyzed.
2. The negative moderator coefficient corresponding to the end of life rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature and pressure has been included. The k_{eff} versus temperature coefficient used is shown in Figure 15.2-46. The effect of power generation in core on overall reactivity is shown in Figure 15.4-75.

   The core properties associated with the sector nearest the affected steam generator and those associated with the remaining sector were conservatively combined to obtain average core properties for reactivity feedback calculations. Further, it was conservatively assumed that the core power distribution was uniform. These 2 conditions cause underprediction of the reactivity feedback in the high power region near the stuck rod. To verify the conservatism of this method, the reactivity as well as the power distribution was checked. These core analyses considered the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution, and non uniform core inlet temperature effects. For cases in which steam generation occurs in the high flux regions of the core, the effect of void formation was also included. It was determined that the reactivity employed in the kinetics analysis was always larger than the true reactivity. These results verified conservatism; i.e., underprediction of negative reactivity feedback from power generation.

3. Minimum capability for injection of high concentration boric acid (2300 ppm) solution corresponding to the most restrictive single failure in the Safety Injection System (SIS). The characteristics of the injection unit used are shown on Figure 15.2-47. This corresponds to the flow delivered by one charging pump delivering its full flow to the cold leg header. No

credit has been taken for the low concentration of boric acid that must be swept from the safety injection lines downstream of the refueling water storage tank (RWST) isolation valves prior to the delivery of highly concentrated boric acid to the reactor coolant loops. This effect has been allowed for in the analysis. The modeling of the SIS in LOFTRAN is described in (Reference 2).

When offsite power is available, the sequence of events in the high head injection system is the following. After the generation of the safety injection signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves begin to operate and the charging pump starts. In 27 seconds, the valves are assumed to be in their final position and the pump is assumed to be at full speed. The volume containing the low concentration borated water is swept before the 2300 ppm water from the refueling water storage tank reaches the core. This delay is inherently included in the modeling.

When offsite power is not available, an additional ten second delay is assumed to start the diesels and to load the necessary safety injection equipment onto them. That is, after a total of 37 seconds following a safety injection signal, safety injection is assumed to be capable of delivering flow to the RCS. For conservatism, both the with and without offsite power available cases were analyzed using 37 seconds.

The choice of having loss of power near the beginning of the transient is made to maximize the delay of boron reaching the core. Having full RCS flow and immediate safety injection startup during the early stage of the transient facilitates boron delivery by minimizing pump startup time, thereby immediately purging unborated water from the safety injection lines, and minimizing RCS transport time. Loss of power after the break occurs, therefore, will allow a partial or total purge of unborated water from the safety injection lines, thus reducing the amount of time before which boron can be injected into the core, and loss of power prior to the break will allow for immediate safety injection startup and thus almost immediate purging of unborated water from the safety injection lines. Furthermore, since the steamline break with loss of offsite power is less severe than the case with offsite power available, the latter will be more conservative and bound the case of loss of offsite power.

4. Since the steam generators are provided with integral flow restrictors with a 1.4 square foot throat area, any rupture with a break area greater than 1.4 square feet, regardless of location would have the same effect on the Nuclear Steam Supply System (NSSS) as the 1.4 square foot break. The following cases have been considered in determining the core power and RCS transients:

   a. Complete severance of a pipe, with the plant initially at no load conditions, full reactor coolant flow with offsite power available.

   b. Complete severance of a pipe with the plant initially at no load conditions with offsite power unavailable.

5. Power peaking factors corresponding to one stuck RCCA and non uniform core inlet coolant temperatures are determined at end of core life. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return to power

phase following the steam line break. This void in conjunction with the large negative moderator coefficient partially offsets the effect of the stuck assembly. The power peaking factors depend upon the core power, temperature, pressure, and flow, and thus, are different for each case studied.

Both the cases assume initial hot shutdown conditions at time zero since this represents the most pessimistic initial condition. Should the reactor be just critical or operating at power at the time of a steam line break, the reactor will be tripped by the normal overpower protection system when power level reaches a trip point. Following a trip at power the RCS contains more stored energy than at no load, the average coolant temperature is higher than at no load, and there is appreciable energy stored in the fuel. Thus the additional stored energy is removed via the cooldown caused by the steam line break before the no load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis which assumed no load condition at time zero.

However, since the initial steam generator water inventory is greatest at no load, the magnitude and duration of the RCS cooldown are less than steam line breaks occurring at power.

6. In computing the steam flow during a steam line break, the Moody Curve (Reference 27) for fl/D = 0 is used. The Moody Multiplier is 1 with a discharge at dry saturated steam conditions.
7. Perfect moisture separation in the steam generator is assumed. The assumption leads to conservative results since, in fact, considerable water would be discharged. Water carryover would reduce the magnitude of the temperature decrease in the core and the pressure increase in the containment.
8. No credit was taken for secondary side safety injection actuation on low steam pressure.
9. A flow imbalance of 5% between loops (faulted vs. intact) was assumed to incorporate the effects of loop-to-loop RCS flow asymmetry in the limiting steamline rupture event (with offsite power available).
10. To maximize primary-to-secondary heat transfer, 0 percent (0%) steam generator tube plugging is assumed in the limiting steamline rupture event (with offsite power available).

15.4.2.1.2.2 Results

The results presented are a conservative indication of the events which would occur assuming a steam line rupture since it is postulated that all of the conditions described above occur simultaneously. The calculated sequence of events is listed in Table 15.4-19.

Figure 15.4-76 and Figure 15.4-77 show the response of pertinent system parameters following a main steam pipe rupture. Offsite power is assumed to be available such that full reactor coolant flow exists.The transient shown assumes an uncontrolled steam release from only one steam generator, with all 3 steam generators blowing down through the break until steamline isolation.

As can be seen, the core attains criticality with RCCAs inserted (with the design shutdown assuming one stuck RCCA) before boric acid solution at 2300 ppm enters the RCS from the SIS which is drawing from the Refueling Water Storage Tank (RWST). The delay time consists of the time to receive and actuate the safety injection signal and the time to completely open valve trains in the safety injection lines. The safety injection pumps are then ready to deliver flow. At this stage, a further delay is incurred before 2300 ppm boron solution can be injected to the RCS due to the low concentration solution being swept from the safety injection lines. Should a partial loss of offsite power occur such that the power is lost to the ESF functions while the reactor coolant pumps remain in operation, an additional safety injection delay of 10 seconds would occur while the diesel generators startup and the necessary safety injection equipment is loaded onto them. This additional 10 second delay is included in the limiting analyzed case (with offsite power available). A peak core power well below the nominal full power value is attained.

The calculation assumes the boric acid is mixed with, and diluted by the water flowing in the RCS prior to entering the reactor core. The concentration after mixing depends upon the relative flow rates in the RCS and in the high head injection system. The variation of mass flow rate in the RCS due to water density changes is included in the calculation as is the variation of flow rate from the high head injection system and the accumulator due to changes in the RCS pressure. The high head injection system flow calculation includes the line losses in the system as well as the pump head curve. The accumulators provide an additional source of borated water after the RCS pressure has decreased to below 600 psia.

Should the core be critical at near zero power when the rupture occurs low steam line pressure will trip the reactor. Automatic trip of the isolation valves in the steam lines by low steam line pressure or the high steam flow signal in coincidence with low-low RCS temperature will prevent continued steam release from more than one steam generator. The steam line isolation valves are designed to be fully closed in less than 7 seconds after receipt of closure signal. The analysis assumes a 10 second closing time for conservatism.

Figure 15.4-78 and Figure 15.4-79 show the responses of the salient parameters for the case with a total loss of offsite power at the time of the rupture. This results in a coastdown of the reactor coolant pumps. In this case, the core power increases at a slower rate and reaches a lower peak value than in the cases in which offsite power is available to the reactor coolant pumps. The ability of the emptying steam generator to extract heat from the RCS is reduced by the decreased flow in the RCS.

It should be noted that following a steam line break only one steam generator blows down completely while the intact steam generators only blow down for a short time. Thus, the intact steam generators are still available for dissipation of decay heat after the initial transient is over. In the case of loss of offsite power this heat is removed to the atmosphere via the steam line safety valves.

15.4.2.1.3 Conclusions

A DNB analysis was performed for both these cases. It was found that the DNB design basis (Reference 39) is met.

15.4.2.1.4 Environmental Consequences of a Postulated Steam Line Break

The postulated accidents involving release of steam from the secondary system will not result in a release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators. A realistic and a conservative analysis based upon Regulatory Guide 1.183 of the potential offsite and control room doses resulting from a steam line break outside containment is presented below. The analyses incorporate defective fuel and steam generator leakage assumptions prior to the postulated accident for a time sufficient to establish equilibrium specific activity levels in the secondary system. In addition, the conservative analysis includes considerations of iodine spiking effects, both pre-existing and concurrent iodine spike occurrences. Parameters used in both the realistic and conservative analyses are listed in Table 15.4-23.

The RADTRAD (Reference 64) computer code was used to calculate the offsite and control room doses for the main steam line break (MSLB). A schematic showing the code modeling of the activity flow paths is shown on Figure 15.4-143.

For the conservative analysis, the primary and secondary coolant activity equilibrium concentrations, prior to the accident, are based upon 1% fuel defects with iodine activity scaled to technical specification limits for dose equivalent (DE) I 131. In addition, 2 iodine spike scenarios are addressed as follows:

a. Pre-accident Iodine Spike

A reactor transient has occurred prior to the postulated MSLB and has raised the primary coolant iodine concentration to 60 μCi/gm DE I 131. Based upon the assumed 1 gpm primary to secondary leakage, the secondary system coolant specific activity, during this iodine spike, is assumed to increase to an equilibrium value based on the 60 μCi/gm DE I 131. The RCS and secondary system coolant specific activities are provided in Table 15.4-24a.

b. Concurrent Iodine Spike

A reactor trip and/or primary system depressurization associated with the MSLB creates an iodine spike in the primary system. The increase in the reactor coolant iodine concentration is estimated using a spiking model which assumes that the iodine release rate from the fuel rods to the coolant increases to a value 500 times greater than the release rate corresponding to the iodine concentration at the equilibrium value associated with reactor coolant activities at 1 μCi/gm dose equivalent I-131.

The iodine release rate during the concurrent spike is based on a maximum letdown flow of 143 gpm which includes the maximum normal letdown of 120 gpm plus 12 gpm to account for uncertainty in flow and 11 gpm primary coolant leakage and is shown in Table 15.4-24b. The secondary system coolant specific activity is assumed to be at an equilibrium value based on 0.1 μCi/gm DE I-131.

The RCS and secondary system coolant specific activities are provided in Table 15.4-24c.

The following additional assumptions and parameters are used to calculate the activity releases and offsite doses for a steam line break:

1. The faulted steam generator was assumed to be isolated from AFW 30 minutes after the accident.
2. The primary-to-secondary leak rate in the steam generators is assumed to be the leak-rate-limiting condition for operation specified in the plant requirements of 1 gpm for all three steam generators. The leakage is apportioned between the steam generators in such a manner that the calculated dose is maximized. Prior to the accident this leakage is assumed to be distributed throughout the three steam generators. To be consistent with preferred plant procedures for shutdown, the shutdown cooling rate following this type of event is taken as 25 °F /hr. Therefore, to go from 557 °F to 212 °F would require about 14 hours. The MSLB is conservatively analyzed using 24 hours for the cooldown time. The activity associated with the 1 gpm leak is assumed to be released to the environment via the faulted steam generator at a rate of 0.35 gpm for the 24 hour duration with no credit taken for any reduction or mitigation, i.e. a partition factor of 1.0. The remaining 0.65 gpm is assumed to be released to the environment via the two intact steam generators for the 24 hour duration crediting a partition factor of 100 in accordance with Regulatory Guide 1.183, Appendix E. In addition, the secondary coolant activity initially contained in the faulted steam generator is released to the environment with a partition factor of 1.0.
3. Offsite power is lost and the main condenser is not available.
4. As a result of the accident, no fuel failures occur.
5. Steam and reactor coolant releases for the faulted and the intact steam generators are given in Table Table 15.4-23. Implementation of PAD5 does not impact the steam releases for the MSLB dose analysis because the steam releases for the dose analysis are based on a generic core stored energy value that is more conservative than the V. C. Summer specific core stored energy (3.45 fps). Therefore, the steam releases for MSLB dose analysis remain valid for use as input to the subsequent dose consequence analyses.
6. No steam generator blowdown during the accident.
7. No noble gas is dissolved in the steam generator secondary system water. Before the MSLB, all noble gases are assumed to be released via the condenser air removal system. After the MSLB occurs, all noble gases are assumed to be released to the environment without mitigation.

The RADTRAD (Reference 64) computer code was used to calculate the control room doses for the main steam line break (MSLB). The following assumptions and parameters are used to calculate the control room doses for the MSLB.

1. The atmospheric diffusion parameters for the control room are provided in Table 2.3-123. The limiting control room source-receptor pair for the MSLB is the Main Steam Safety Relief Valve “A” (Reliefs B, C, D, E), Control Room Intake B.
2. The control room emergency filtration system is credited after 30 minutes.

3. The control room ventilation system flow rates are shown on Figure 15.4-143.
4. The control room breathing rate is assumed as 3.5E-04 m^3/sec for the duration of the accident.
5. Additional control room parameters are shown on Table 15.4-17.

Isotopic releases to the environment using these assumptions are summarized by Table 15.4-25 and Table 15.4-26.

The resultant doses calculated at the site boundary, low population zone and control room for the steam line break accident, based upon the realistic and conservative analysis assumptions are given in Table 15.4-27. The doses resulting from this accident are within the limits defined by 10 CFR 50.67 and RG 1.183.

15.4.2.2 Major Rupture of a Main Feedwater Line

15.4.2.2.1 Identification of Causes and Accident Description

A major feedwater line rupture is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. (A break upstream of the feedline check valve would affect the NSSS only as a loss of feedwater. This case is covered by the evaluation in Section 15.2.8.)

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a reactor coolant system cooldown (by excessive energy discharge through the break), or a RCS heatup. Potential reactor coolant system cooldown resulting from a secondary pipe rupture is evaluated in Section 15.4.2.1. Therefore, only the RCS heatup effects are evaluated for a feedline rupture.

A feedline rupture reduces the ability to remove heat generated by the core from the RCS because of the following reasons:

1. Feedwater to the steam generators is reduced. Since feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip;
2. Liquid in the steam generator may be discharged through the break, and would then not be available for decay heat removal after trip;
3. The break may be large enough to prevent the addition of any main feedwater after trip.

An Emergency Feedwater System is provided to assure that adequate feedwater will be available such that:

1. No substantial overpressurization of the RCS shall occur; and
2. Liquid in the RCS shall be sufficient to cover the reactor core at all times.

The following provides the necessary protection for a main feedwater rupture:

1. A reactor trip on any of the following conditions:
   a. High pressurizer pressure.
   b. Overtemperature Delta T.
   c. Low low steam generator water level in any steam generator.
   d. Low steam generator level plus steam/feed flow mismatch in any steam generator.
   e. Safety injection signals from any of the following:
      (1) Low steam line pressure.
      (2) High containment pressure (Hi-1).
      (3) High steam line differential pressure.

(Refer to Chapter 7 for a description of the actuation system)

2. An emergency feedwater system to provide an assured source of feedwater to the steam generators for decay heat removal. (Refer to Section 10.4.9 for a description of the emergency feedwater system.)

15.4.2.2.2 Analysis of Effects and Consequences

15.4.2.2.2.1 Method of Analysis

A detailed analysis using the LOFTRAN (Reference 25) Code is performed in order to determine the plant transient following a feedline rupture. The code describes the plant thermal kinetics, reactor coolant system including natural circulation, pressurizer, steam generators and feedwater system, and computes pertinent variables including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

Major assumptions are:

1. The plant is initially operating at 102% of the nominal NSSS design rating.
2. Initial reactor coolant average temperature is 4.0°F above the nominal value, and the initial pressurizer pressure is 50 psi below its nominal value.
3. A conservatively high initial pressurizer level is assumed; initial steam generator water level is at the nominal value plus 5% in the faulted steam generator, and at the nominal value minus 5% in the intact steam generators.
4. No credit is taken for the pressurizer spray.
5. Cases with and without pressurizer power operated relief valves are analyzed.
6. No credit is taken for the high pressurizer pressure reactor trip.

7. Main feedwater to all steam generators is assumed to stop at the time the break occurs. (All main feedwater spills out through the break.)
8. The worst possible break area is assumed which minimizes the steam generator fluid inventory at the time of trip and maximizes the blowdown discharge rate following the time of trip, and thereby maximizes the resultant heatup of the reactor coolant.
9. Detailed iterative calculations were performed to determine the break flow and enthalpy based on transient conditions utilizing a multi-nodal transient steam generator model.
10. Reactor trip is assumed to be initiated when the low-low level trip setpoint in the ruptured steam generator is reached. A low-low level setpoint of 0% narrow range span is assumed.
11. The emergency feedwater system (EF) is actuated by the low-low steam generator water level signal and is assumed to supply 120°F EF at total of 380 gpm to the unaffected SGs within 114 seconds of the main feedwater line rupture. The assumed time delay includes the following allowances: 60 seconds to account for instrumentation delays and startup of the diesels and EF pumps, 48 seconds to automatically isolate EF flow to the faulted SG and 6 seconds to purge 5 cubic feet of hot water contained in the EF lines prior to the event. Note that after the installation of cavitating venturis per ECR50695E, automatic isolation of the faulted SG will not occur following secondary side breaks and is no longer necessary to ensure at least 380 gpm is delivered to the intact SGs following this event. The intact SGs could receive 120°F emergency feedwater beginning at 66 seconds after the event; however, the analysis conservatively continues to assume the original additional delay of 48 seconds for EF isolation. Although a substantial amount of EF will be added to the intact SGs during the 48 seconds, no credit is taken for the additional EF flow during this delay.
12. No credit is taken for heat energy deposited in RCS metal during the RCS heatup.
13. Steam generator heat transfer area is assumed to decrease as the shell side liquid inventory decreases.
14. Conservative core residual heat generation based on long term operation at the initial power level preceding the trip is assumed. The 1979 ANS 5.1 (Reference 28) decay heat standard plus uncertainty was used for calculation of residual decay heat levels.
15. No credit is taken for charging or letdown.
16. A flow imbalance of 5% between loop (faulted vs. intact) was assumed to incorporate the effects of loop-to-loop RCS flow asymmetry for the limiting cases (with PORVs only).
17. The maximum steam generator tube plugging level (10%) is assumed for the faulted loop, and the minimum steam generator tube plugging level (0%) is assumed for the intact loops.
18. A conservatively large feedwater isolation delay time was assumed.

15.4.2.2.2.2 Results

Results for two feedline break cases are presented. Results for a case in which offsite power is assumed to be available are presented in Section 15.4.2.2.2.1. Results for a case in which offsite power is assumed to be lost following reactor trip are presented in Section 15.4.2.2.2.2.2. The calculated sequence of events for both cases is listed in Table 15.4-19. Both of the presented

feedline break cases credit the power operated relief valves, because these cases were found to be the most limiting.

15.4.2.2.2.2.1 Feedline Rupture with Offsite Power Available

The system response following a feedwater line rupture, assuming offsite power is available, is presented in Figure 15.4-83 through Figure 15.4-86. Results presented in Figure 15.4-84 and Figure 15.4-86 show that pressures in the RCS and Main Steam System remain below 110% of the respective design pressures. Pressurizer pressure decreases after reactor trip on low-low steam generator water level due to the reduction of heat input. Following this initial decrease, pressurizer pressure increases to the pressurizer power operated relief valve setpoint. This increase in pressure is the result of coolant expansion caused by the reduction in heat transfer capability in the steam generators. Figure 15.4-87 shows that the water volume in the pressurizer increases in response to the heatup and pressurizer water relief begins at 2134 seconds. At approximately 3300 seconds, decay heat generation decreases to a level such that the total RCS heat generation (decay heat plus pump heat) is less than emergency feedwater heat removal capability, and RCS pressure and temperature begin to decrease.

The results show that the core remains covered at all times and that no boiling occurs in the reactor coolant loops.

15.4.2.2.2.2.2 Feedline Rupture with Offsite Power Unavailable

The system response following a feedwater line rupture without offsite power available is similar to the case with offsite power available and is presented in Figure 15.4-87 through Figure 15.4-90. However, as a result of the loss of offsite power (assumed to occur at reactor trip), the reactor coolant pumps coast down. This results in a reduction in total RCS heat generation by the amount produced by pump operation.

The reduction in total RCS heat generation produces a milder transient than in the case where offsite power is available. Results presented in Figures Figure 15.4-88 and 1Figure 15.4-90 show that pressure in the RCS and main steam system remain below 110% of the respective design pressures. Pressurizer pressure decreases after reactor trip on low-low steam generator water level due to the reduction of heat input. Following this initial decrease, pressurizer pressure increases as a result of coolant expansion caused by the reduction in heat transfer capability in the steam generators. Figure 15.4-88 shows that the water volume in the pressurizer increases in response to the heatup. At approximately 800 seconds, decay heat generation decreases to less than the emergency feedwater heat removal capability, and RCS temperatures begin to decrease. The results show that the core remains covered at all times since the pressurizer does not empty.

15.4.2.2.3 Conclusions

Results of the analysis show that for the postulated feedline rupture, the assumed Emergency Feedwater System capacity is adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core. Radioactivity doses from the postulated feedline rupture are less than those previously presented for the postulated steam line break.

15.4.3 Steam Generator Tube Rupture

15.4.3.1 Identification of Causes and Accident Description

The accident examined is the complete severance of a single steam generator tube. The accident is assumed to take place at power with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited amount of defective fuel rods. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the reactor coolant system. In the event of a coincident loss of offsite power, or failure of the condenser steam dump system, discharge of activity to the atmosphere takes place via the steam generator safety and/or power operated relief valves.

In view of the fact that the steam generator tube material is Inconel 690 and is a highly ductile material, it is considered that the assumption of a complete severance is conservative. The more probable mode of tube failure would be one or more minor leaks of undetermined origin. Activity in the steam and power conversion system is subject to continual surveillance and an accumulation of minor leaks which exceed the limits established in the Technical Specifications is not permitted during the unit operation.

The operator is expected to determine that a steam generator tube rupture has occurred, and to identify and isolate the ruptured steam generator on a restricted time scale in order to minimize contamination of the secondary system and ensure termination of radioactive release to the atmosphere from the ruptured unit. The recovery procedure can be carried out on a time scale which ensures that break flow to the secondary system is terminated before water level in the affected steam generator rises into the main steam pipe.

Sufficient indications and controls are provided to enable the operator to carry out these functions satisfactorily.

Assuming normal operation of the various plant control systems, the following sequence of events is initiated by a tube rupture:

1. Pressurizer low pressure and low level alarms are actuated and charging pump flow increases in an attempt to maintain pressurizer level. On the secondary side there is a steam flow/feedwater flow mismatch before trip as feedwater flow to the affected steam generator is reduced due to the additional break flow which is now being supplied to that unit. The steam line radiation monitor for the ruptured steam generator will alarm.
2. Continued loss of reactor coolant inventory leads to a reactor trip signal generated by low pressurizer pressure or Overtemperature Delta-T. Resultant plant cooldown following reactor trip leads to a rapid change of pressurizer level, and the safety injection signal, initiated by low pressurizer pressure, follows soon after the reactor trip. The safety injection signal automatically terminates normal feedwater supply and initiates emergency feedwater addition.
3. The steam generator blowdown liquid radiation monitor and the condenser air removal system radiation monitor will alarm, indicating a sharp increase in radioactivity in the

secondary system and will automatically divert the steam generator blowdown flow to the Nuclear Blowdown Processing System.

4. The reactor trip automatically trips the turbine and if offsite power is available the steam dump valves open permitting steam dump to the condenser. In the event of a coincident loss of offsite power, the condenser steam dump valves would automatically close to protect the condenser. The steam generator pressure would rapidly increase resulting in steam discharge to the atmosphere through the main steam safety and/or power operated relief valves.
5. Following reactor trip, the continued action of emergency feedwater supply and borated high head injection flow (supplied from the refueling water storage tank) provide a heat sink which absorbs some of the decay heat. Thus, steam bypass to the condenser, or in the case of loss of offsite power, steam relief to atmosphere, is attenuated while the recovery procedure leading to break flow termination is being carried out.
6. High head injection flow results in increasing pressurizer water level. The time after trip at which the operator can clearly see returning level in the pressurizer is dependent upon the amount of operating auxiliary equipment.

15.4.3.2 Analysis of Effects and Consequences

15.4.3.2.1 Method of Analysis

In estimating the mass transfer from the RCS through the broken tube the following assumptions are made:

1. Reactor trip occurs automatically as a result of low pressurizer pressure.
2. Following the initiation of the safety injection signal, 2 centrifugal charging pumps are actuated and continue to deliver flow for 30 minutes.
3. After reactor trip, the break flow reaches equilibrium at the point where incoming safety injection flow is balanced by outgoing break flow as shown in Figure 15.4-91. The resultant break flow persists from plant trip until 30 minutes after the accident.
4. The steam generators are controlled at the safety valve setting rather than the power operated relief valve or steam dump setting.
5. The operator identifies the accident type and terminates break flow to the ruptured steam generator within 30 minutes of accident initiation.
6. Steam relief from the ruptured steam generator ceases at 30 minutes after accident initiation.
7. Steam relief from the intact steam generators continues until the Residual Heat Removal System is put into service for decay heat removal.

Mass and energy balance calculations are performed to determine primary to secondary mass release and to determine the amount of steam vented from each of the steam generators.

Although it is recognized that the operators may not be able to identify the accident and terminate break flow within 30 minutes for all postulated steam generator tube rupture events, these

licensing basis assumptions provide a conservative estimate of the mass releases. This has been confirmed by utilizing an NRC-approved thermal hydraulic code and analysis method (Reference 66) which simulates the plant response, and models specific operator actions based on those outlined in Section 15.4.3.2.2. Consistent with the original and current licensing basis analysis, single failures were not considered in this confirmatory analysis. Overall, the analysis demonstrates that even if break flow is not terminated until almost one hour after accident initiation, the radiological consequences for a postulated steam generator tube rupture are bounded by those presented in Section 15.4.3.4 for the licensing basis analysis.

15.4.3.2.2 Recovery Procedure

Immediately apparent symptoms of a tube rupture accident such as falling pressurizer pressure and level and increased charging pump flow are also symptoms of small steam line breaks and loss of coolant accidents. It is therefore important for the operator to determine that the accident is a rupture of a steam generator tube in order that he may carry out the correct recovery procedure. The accident under discussion can be identified by the following method. In the event of a complete tube rupture, it will be clear soon after trip that the level in one steam generator is rising more rapidly than in the others. This is a unique indication of a tube rupture accident. Also this accident could be identified by either a condenser air removal system radiation alarm, or main steamline radiation alarm, or a steam generator blowdown radiation alarm.

The operator carries out procedures subsequent to reactor trip which lead to isolation of the ruptured steam generator and to unit cooldown. These actions are based on the Pressurized Water Reactor Owner's Group Emergency Response Guidelines (ERGs) for Westinghouse plants.

With Offsite Power Available:

1. Identify the ruptured steam generator by one or more of the following means: increasing steam generator water level, high radiation from any steam generator sample, high radiation from any steam generator steam line, and/or high radiation from any steam generator blowdown line.
2. Close the main steam isolation valve and isolate all other steam paths from the ruptured steam generator.
3. Minimize emergency feedwater flow to the ruptured steam generator to control secondary water level.
4. Dump steam to the condenser from the intact steam generator at a maximum rate to establish subcooling margin for subsequent RCS depressurization. The amount of RCS cooldown is determined by the ruptured steam generator pressure.
5. Decrease RCS pressure by use of normal pressurizer spray until the water level returns in the pressurizer and RCS pressure and the ruptured steam generator pressure are equal, or high pressurizer water level is attained, or minimum subcooling is attained.
6. Based on the pressurizer water level, secondary heat sink(s), RCS subcooling and increasing RCS pressure, stop all but one charging pump to minimize break flow to the secondary

system. At this point, RCS pressure and the ruptured steam generator pressure should be maintained approximately equal.

7. Continue dumping steam to the condenser from the intact steam generators and simultaneously decrease RCS pressure by use of normal pressurizer spray. Decrease pressure in the ruptured steam generator by backfill, blowdown or steam release.
8. Initiate operation of residual heat removal system at the appropriate RCS conditions.

Without Offsite Power:

1. Identify the ruptured steam generator by one or more of the following means: increasing steam generator water level, high radiation from any steam generator blowdown line, and/or high radiation from any steam generator steam line.
2. Close the main steam isolation valve and isolate all other steam paths from the ruptured steam generator.
3. Minimize emergency feedwater flow to the ruptured steam generator to control secondary water level.
4. Dump steam through the intact steam generator power relief valves at a maximum rate to establish RCS subcooling margin for subsequent RCS depressurization. The amount of RCS cooldown is determined by the ruptured steam generator pressure.
5. Open pressurizer relief valve to reduce RCS pressure until water level returns in the pressurizer and RCS pressure and the ruptured steam generator pressure are equal, or high pressurizer water level is attained, or minimum subcooling is attained.
6. Based on the pressurizer water level, secondary heat sink(s), RCS subcooling, and increasing RCS pressure, stop all but one charging pump to minimize break flow to the secondary system. At this point, RCS pressure and the ruptured steam generator pressure should be maintained approximately equal.
7. Continue dumping steam through the intact steam generator power relief valves and simultaneously decrease RCS pressure. Decrease pressure in the ruptured steam generator by backfill, blowdown or steam release.
8. Initiate operation of Residual Heat Removal System at the appropriate RCS conditions.

After the residual heat removal system is placed in operation, the condensate accumulated in the secondary system can be examined and processed as required. Table 15.4-28 presents the balance of plant equipment required for the steam generator tube rupture accident.

There is ample time available to carry out the above recovery procedures such that isolation of the affected steam generator is established before water level rises into the main steam pipes.

This has been confirmed by utilizing an NRC-approved thermal hydraulic analysis code and analysis method (Reference 66) which simulated the plant response, and models specific operator actions based on those outlined above. Critical operator actions modeled in the simulation to terminate break flow and preclude steam generator overfill include:

1. Terminating emergency feedwater flow to the ruptured steam generator.
2. Isolating the ruptured steam generator.
3. Dumping steam from the intact steam generators to cooldown the reactor coolant system.
4. Opening a pressurizer relief valve to depressurize the reactor coolant system.
5. Terminating safety injection flow.

Consistent with the original and current licensing basis analysis, single failures were not considered in this confirmatory analysis. Conservative deviations from the Reference 66 method were taken to address the issues raised by NSAL-07 -11 (Reference 67). Overall, the analysis demonstrates that break flow is terminated approximately 50 minutes after initiation of the tube rupture and that overfill of the ruptured steam generator does not occur.

15.4.3.2.3 Results

Figure 15.4-91 illustrates the flow rate that would result through the ruptured steam generator tube. For conservatism, the equilibrium break flow rate is based on the maximum safety injection flow rate with three charging pumps operating. The previous assumptions lead to a conservative estimate of 92,900 pounds for the total amount of reactor coolant transferred to the secondary side of the ruptured steam generator as a result of a tube rupture accident.

15.4.3.3 Conclusions

A steam generator tube rupture will cause no subsequent damage to the reactor coolant system or the reactor core. An orderly recovery from the accident can be completed even assuming simultaneous loss of offsite power. Parameters used in determining the radioactivity released to the atmosphere for a steam generator tube rupture are listed in Table 15.4-29.

15.4.3.4 Environmental Consequences of a Postulated Steam Generator Tube Rupture

The postulated accidents involving release of steam from the secondary system will not result in a release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators. An analysis based on Regulatory Guide 1.183 of the potential offsite and control room doses from a postulated Steam Generator Tube Rupture (SGTR) is presented below. The analysis incorporates assumptions for defective fuel and steam generator leakage prior to the postulated accident for a time sufficient to establish equilibrium specific activity levels in the secondary system. In addition, the conservative analysis includes the consideration of iodine spiking effects caused by the SGTR. Both pre-existing and concurrent iodine spikes are evaluated coincident with the postulated tube rupture. Parameters used are listed in Table 15.4-29.

In the safety analysis to evaluate the radiological consequences of a steam generator tube rupture, calculations are performed to determine the primary to secondary mass transfer and steam releases from the ruptured and intact steam generators. The RCS depressurization rate due to the primary to secondary break flow is calculated to determine the time of reactor trip and actuation of the safety injection system. The average break flow rate during the time period from the tube

rupture initiation to reactor trip and safety injection was used to calculate the integrated break flow for this period. After reactor trip and safety injection, it was assumed that the RCS stabilizes at a pressure where the incoming safety injection flow equals the flow out the broken tube, with the assumption of maximum safeguards and no spillage (which gives the highest primary to secondary flow). The resultant break flow rate is assumed to persist from reactor trip and safety injection actuation until 30 minutes after the accident. The integrated break flow values for these two time periods were then summed to yield a total primary to secondary break flow of 92,900 lb for the 30 minutes.

The steam released to the atmosphere from the ruptured and intact steam generators is calculated for 30 minutes following the event by a mass and energy balance between the primary and secondary system. It is assumed that the ruptured steam generator is isolated after 30 minutes.

For the remainder of the transient, after ruptured steam generator isolation, steam releases from the intact steam generators are obtained by an energy balance between the primary and secondary systems. The energy in the primary system is calculated, including energy of the fluid, decay heat, and metal energy. This is equated with the amount of secondary steam which must be generated and released in order to remove this energy from the primary system and decrease the primary system pressure to the desired levels.

In summary, then, although a detailed analysis is not performed, the current analysis is a conservative estimate of the radiological consequences of the steam generator tube rupture as noted in Section 15.4.3.2.1.

The RADTRAD (Reference 64)computer code was used to calculate the offsite and control room doses for the steam generator tube rupture (SGTR). A schematic showing the code modeling of the activity flow paths is shown on Figure 15.4-144.

The following additional assumptions and parameters are used to calculate the activity releases and offsite doses for the postulated steam generator tube rupture.

1. It is assumed that prior to the accident an equilibrium fission product activity exists in the primary and secondary systems due to primary to secondary leakage in the steam generators. In the conservative analyses, the activity concentrations are assumed in combination with a pre accident iodine spike as well as an accident initiated iodine spike.
2. Offsite power is not available in the analysis.
3. The reactor coolant released to the defective steam generator and associated steam releases are given in Table 15.4-29.
4. No additional fuel failure as a result of the accident.
5. No steam generator blowdown during the accident.
6. Thirty minutes after the accident, the pressure between the ruptured steam generator and primary system is equalized. The ruptured steam generator is isolated. No steam and fission product activities are released from the defective steam generator after this time.

7. The primary to secondary leak rate in the intact steam generators is conservatively assumed to be 1 gpm. The iodine and particulate activity associated with the 1 gpm leak is assumed to mix with the bulk water. The radioactivity within the bulk water is assumed to become vapor at a rate that is a function of the steaming rate and the partition coefficient. A partition coefficient of 100 is assumed. All noble gas activity in the leakage is assumed to be immediately released to the environment.
8. To be consistent with preferred plant procedures for shutdown, the shutdown cooling rate is taken as 25°F/hr. Although conditions for start-up of the Residual Heat Removal system can be achieved in approximately 8 hours, the analysis conservatively accounts for cooldown times up to 24 hours.
9. The normal operation letdown is 60 to 120 gpm.
10. RCS mass is assumed to remain constant throughout the SGTR event; i.e., flow through the ruptured tube is offset by flow from the safety injection system.
11. Except for the iodine isotopes, the initial RCS activity is based on operation with defects in fuel producing 1% of the plant power.
12. The analysis for the pre-existing iodine spike assumes a reactor transient has occurred prior to the postulated steam generator tube rupture and raised the primary coolant iodine concentration to the maximum value permitted by the technical specifications (60 μCi/gm DE I-131). No dilution from the safety injection system is considered.
13. The analysis for the accident initiated iodine spike assumes the iodine release rate from the fuel rods to the primary coolant increases to a value 335 times greater than the release corresponding to the iodine concentration at the equilibrium value (1.0 μCi/gm DE I-131) specified in the technical specifications with a spike duration of 8 hours.

Key assumptions and parameters used to calculate control room and offsite doses with the RADTRAD (Reference 64) computer code are summarized in Table 15.4-12 and Table 15.4-29. The offsite and control room doses resulting from the postulated steam generator tube rupture accident based upon the specified analysis assumptions are summarized in Table 15.4-33. The doses from this accident are within the limits defined in 10 CFR 50.67 and Regulatory Guide 1.183: 5 Rem TEDE for the control room; 25 REM TEDE for the site boundary and LPZ with a pre-existing iodine spike; and 2.5 Rem TEDE for the site boundary and low population with a concurrent iodine spike.

15.4.4 Single Reactor Coolant Pump Locked Rotor

15.4.4.1 Identification of Causes and Accident Description

The accident postulated is an instantaneous seizure of a reactor coolant pump rotor such as is discussed in Section 5.5. Flow through the affected reactor coolant loop is rapidly reduced, leading to an initiation of a reactor trip on a low flow signal.

Following initiation of the reactor trip heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the shell side of the

steam generators is reduced, first because the reduced flow results in a decreased tube side film coefficient and then because the reactor coolant in the tubes cools down while the shell side temperature increases (turbine steam flow is reduced to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the power operated relief valves, and opens the pressurizer safety valves, in that sequence.

The three power operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, their pressure reducing effect as well as the pressure reducing effect of the spray is not included in the analysis.

15.4.4.2 Analysis of Effects and Consequences

15.4.4.2.1 Method of Analysis

Two digital computer codes are used to analyze this transient. The LOFTRAN Code is used to calculate the resulting loop and core coolant flow following the pump seizure. The LOFTRAN Code is also used to calculate the time of reactor trip, based on the calculated flow, the nuclear power following reactor trip, and to determine the peak pressure. The thermal behavior of the fuel located at the core hot spot is investigated using the FACTRAN (Reference 29) Code, using the core flow and the nuclear power calculated by LOFTRAN. The FACTRAN Code includes the use of a film boiling heat transfer coefficient.

The following case is analyzed:

All loops operating, one locked rotor.

At the beginning of the postulated locked rotor accident, i.e., at the time the shaft in one of the reactor coolant pumps is assumed to seize, the plant is assumed to be in operation under the most adverse steady state operating conditions, i.e., maximum steady state power level, maximum steady state pressure, and maximum steady state coolant average temperature.

When the peak pressure is evaluated, the initial pressure is conservatively estimated as 50 psi above nominal pressure of 2250 psia to allow for errors in the pressurizer pressure measurement and control channels. This is done to obtain the highest possible rise in the coolant pressure during the transient. To obtain the maximum pressure in the primary side, conservatively high loop pressure drops are added to the calculated pressurizer pressure. A flow imbalance of 5% between loops (faulted vs. intact) was assumed to incorporate the effects of loop-to-loop RCS flow asymmetry.

15.4.4.2.2 Evaluation of the Pressure Transient

After pump seizure and reactor trip, the neutron flux is rapidly reduced by control rod insertion effect. Rod motion is assumed to begin one second after the flow in the affected loop reaches 87%

of nominal flow. No credit is taken for the pressure reducing effect of the pressurizer relief valves, pressurizer spray, steam dump or controlled feedwater flow after plant trip.

Although these operations are expected to occur and would result in a lower peak pressure, an additional degree of conservatism is provided by ignoring their effect.

The pressurizer safety valves are assumed to achieve rated flow at 2580 psia. No relief is credited prior to reaching this pressure. This conservatively accounts for uncertainties in the nominal setpoint of 2500 psia.

15.4.4.2.3 Evaluation of DNB in the Core During the Accident

For this accident, DNB is assumed to occur in the core and, therefore, an evaluation of the consequences with respect to fuel rod thermal transients is performed. Results obtained from analysis of this “hot spot” condition represent the upper limit with respect to clad temperature and zirconium water reaction.

In the evaluation, the rod power at the hot spot is conservatively assumed to be approximately 2.6 times the average rod power at the initial core power level.

15.4.4.2.4 Film Boiling Coefficient

The film boiling coefficient is calculated in the FACTRAN Code using the Bishop Sandberg Tong film boiling correlation. The fluid properties are evaluated at film temperature (average between wall and bulk temperatures). The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The neutron flux, system pressure, bulk density, and mass flow rate as a function of time are used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient since they are the most conservative with respect to clad temperature response. For conservatism, DNB was assumed to start at the beginning of the accident.

15.4.4.2.5 Fuel Clad Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and clad (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between pellet and clad. Based on investigations on the effect of the gap coefficient upon the maximum clad temperature during the transient, the gap coefficient was assumed to increase from a steady state value consistent with initial fuel temperature to 10,000 BTU/hr ft^2 °F at the initiation of the transient. Thus the large amount of energy stored in the fuel because of the small initial value is released to the clad at the initiation of the transient to maximize the cladding temperature during the transient.

15.4.4.2.6 Zirconium Steam Reaction

The zirconium steam reaction can become significant above 1800 F (clad temperature). The Baker-Just parabolic rate equation shown below is used to define the rate of the zirconium steam reaction.

$$\frac{d(w^2)}{dt} = 33.3 \times 10^6 \exp\left(-\frac{45{,}500}{1.968T}\right)$$

Where:

w	=	amount reacted, mg/cm^2.
t	=	time, sec.
T	=	temperature, ° Kelvin.

The reaction heat is 1510 cal/gm.

15.4.4.2.7 Results

Transient values of RCS flow, faulted loop flow, nuclear power, core heat flux, RCS pressure, and hot spot clad temperature are shown in Figure 15.4-95, Figure 15.4-96A, and Figure 15.4-96B.

Maximum RCS pressure, maximum clad average temperature, and amount of zirconium water reaction are contained in Table 15.4-34.

15.4.4.3 Conclusions

1. Since the peak RCS pressure reached during any of the transients is less than that which would cause stresses to exceed the faulted condition stress limits, the integrity of the primary coolant system is not endangered.
2. Since the peak clad average temperature calculated for the hot spot during the worst transient remains considerably less than the 2700°F limit for ZIRLO® material and the 2375°F limit for Optimized ZIRLOTM material, the core will remain in place and intact with no consequential loss of core cooling capability.
3. The results of the transient analysis show that less than 15.0% of the fuel rods will have DNBR's below the safety analysis limit values.

If it is assumed that there is leakage from the RCS to the secondary system in the steam generators and that offsite power is lost following the reactor coolant pump locked rotor accident, radioactivity will be released to the atmosphere through the relief or safety valves. Parameters used in determining the amount of radioactivity released are given in Table 15.4-34a.

15.4.4.4 Environment Consequences of a Postulated Reactor Coolant Pump Locked Rotor

The postulated accidents involving release of steam from the secondary system will not result in release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators. A realistic analysis and a conservative analysis based on Regulatory Guide 1.183 of the potential offsite and control room doses resulting from a reactor coolant pump locked rotor is presented. This analysis incorporates assumptions of defective fuel and steam generator leakage prior to the postulated accident for a time sufficient to establish equilibrium specific activity levels in the secondary system. Parameters used in both the realistic and conservative analyses are listed in Table 15.4-34a.

The RADTRAD (Reference 64) computer code was used to calculate the offsite and control room doses for the reactor coolant pump locked rotor accident (RCPLRA). A schematic showing the code modeling of the activity flow paths is shown on Figure 15.4-145.

The following assumptions and parameters are used to calculate the activity releases and offsite doses for a reactor coolant pump locked rotor:

1. Prior to the accident, an equilibrium activity of fission products exists in the primary and secondary systems due to primary to secondary leakage in the steam generators.
2. Offsite power is lost and the main condenser is not available for steam dump.
3. Twenty four hours after the accident the Residual Heat Removal System starts operation to cool down the plant.
4. After 24 hours following the accident, no steam and activity are released to the environment.
5. Primary to secondary leakage is 1 gpm and is evenly distributed in the steam generators.
6. Defective fuel prior to the accident is 1%.
7. As a result of the accident, 15% of the fuel rods in the core are considered to be failed and their gap activity is considered to be released to, and instantaneously mixed with, the reactor coolant. Per Regulatory Guide 1.183, Table 3, the non-LOCA fraction of fission products inventory in the gap is acceptable for use if the peak fuel burnup does not exceed 62,000 MWD/MTU and the maximum linear heat generation rate does not exceed 6.3 kw/ft. peak rod average power for burnups exceeding 54 GWD/MTU. To account for possible variation in burnup and rod power, the Table 3 non-LOCA fraction of fission products inventory in the gap is conservatively doubled. The Regulatory Guide 1.183, Table 3 gap fractions and the gap fractions used in the RCPLRA analysis are listed as follows:

Group	Regulatory Guide 1.183 Fraction	RCPLRA Analysis Fraction
I-131	0.08	0.16
Kr-85	0.10	0.20

Other Noble Gases	0.05	0.10
Other Halogens	0.05	0.10
Alkali Metals	0.12	0.24

8. No Condenser Air Removal System release and no steam generator blowdown occurs during the accident.
9. No noble gas is dissolved in the steam generator water.
10. The primary-to-secondary leak rate in the steam generators is assumed to be the leak-rate-limiting condition for operation specified in the plant requirements of 1 gpm for all three steam generators. The leakage is apportioned between the steam generators in such a manner that the calculated dose is maximized. To be consistent with preferred plant procedures for shutdown, the shutdown cooling rate following this type of event is taken as 25 °F /hr. Therefore, to go from 557 °F to 212 °F would require about 14 hours. The RCPLRA is conservatively analyzed using 24 hours for the cooldown time. The activity associated with the 1 gpm leak is assumed to be released to the environment via the steam generators for the 24 hour duration with a partition factor of 100 for iodine and particulates and 1.0 for noble gases. In addition, the secondary coolant activity initially contained in the steam generators is released to the environment with a partition factor of 100.

Steam releases to the atmosphere for the reactor pump locked rotor accident are given in Table 15.4-34a. Assumptions for the realistic analysis are also presented in Table 15.4-34a. Isotopic releases to the environment using these assumptions are summarized by Table 15.4-34b through Table 15.4-34c.

In addition, the following assumptions and parameters are used to calculate the control room doses for the RCPLRA:

1. The atmospheric diffusion parameters for the control room are provided in Table 2.3-123. The limiting control room release point for the LRA is the Main Steam Safety Relief Valve “A” (Reliefs B, C, D, E), Control Room Intake B.
2. The control room emergency filtration system is credited after 120 minutes.
3. The control room ventilation system flow rates are shown on Figure 15.4-145.
4. The control room breathing rate is assumed as 3.47E-04 m^3/sec for the duration of the accident.
5. Additional control room parameters are shown on Table 15.4-17.

The offsite and control room doses resulting from the RCPLRA are listed in Table 15.4-34d.

15.4.5 Fuel Handling Accidents

A fuel handling accident (FHA) during refueling could release a fraction of the fission product inventory in the plant to the environment. Two (2) accident scenarios are considered: (1) a

refueling accident occurring inside containment and (2) a refueling accident occurring outside containment.

The RADTRAD (Reference 64) computer code was used to calculate the offsite and control room doses for both of the fuel handling accident (FHA) scenarios. A schematic showing the code modeling of the activity flow paths is shown on Figure 15.4-146.

15.4.5.1 Fuel Handling Accident Inside of Containment

The postulated fuel handling accident inside containment is the dropping of a spent fuel assembly onto the core during refueling which results in damage to the fuel assemblies. For this postulated accident, two analyses bases are evaluated: (1) a realistic case and (2) a conservative case. The conservative case analysis is based on Regulatory Guide 1.183 assumptions. The assumed analysis parameters and radiological consequences associated with these cases are discussed below.

15.4.5.1.1 Identification of Causes and Accident Description

There are numerous administrative controls and physical limitations which are imposed to prevent a fuel handling accident from occurring during refueling operations. Nevertheless, an accident sequence has been postulated with the objective of assessing the potential risk to the public health and safety.

It is postulated that a spent fuel assembly is dropped onto the core during refueling resulting in breaching of the fuel rod cladding. As a result of the damage, a portion of the volatile fission gases are released to the water pool covering the core. Subsequently, a fraction of the water soluble gases are absorbed in the pool with the remainder being transported through the water and into the Reactor Building atmosphere. The escaped gases are assumed to be released instantaneously to the environment via the Reactor Building Purge System and dispersed into the atmosphere.

15.4.5.1.2 Analysis of Effects and Consequences

15.4.5.1.2.1 Method of Analysis

The following assumptions are postulated in the calculation of the radiological consequences of a fuel handling accident inside containment:

Realistic Analyses

1. The accident occurs at 100 hours after reactor shutdown, which is the minimum time after shutdown that refueling operations could commence. Radioactive decay of the fission product inventory for this time period is taken into account.

2. A total of 314 pins are assumed to be damaged as a result of this event. All 264 pins in the dropped spent fuel assembly and 50 pins in the impacted assembly are assumed to be ruptured.
3. The assembly damaged is the highest powered assembly in the core region to be discharged. The values for individual fission product inventories in the damaged assembly are calculated assuming full power operation at the end of core life immediately preceding shutdown.
4. All activity in the clad gap of the damaged fuel, as given in Table 15.4-36, is released to the reactor cavity pool.
5. The minimum water depth between the top of the damaged fuel rods and the reactor cavity pool surface is 23 feet.
6. Noble gases released to the reactor cavity pool are immediately released to the reactor building atmosphere.
7. The pool water retains a large fraction of the iodine species activity by virtue of their solubility and hydrolysis. An iodine/pool decontamination factor of 500 is used for this analysis, and is based upon the results of an experimental test program (Reference 40) conducted to evaluate the extent of the removal of iodines released from a damaged irradiated fuel assembly. The iodine/pool decontamination factor is discussed in Section 15.4.5.1.2.2.

Conservative Analysis

1. The accident occurs at 72 hours after reactor shutdown, which is a conservative minimum time after shutdown. Radioactive decay of the fission product inventory for this time period is taken into account.
2. A total of 314 pins are damaged as a result of this event. This includes all 264 pins in the dropped spent fuel assembly and 50 pins in the impacted fuel assembly. This is equivalent to 1.19 assemblies.
3. The assembly damaged is the highest-powered assembly in the core region to be discharged. The values for individual fission product inventories in the fuel are calculated using ORIGEN-S/ARP program (Reference 54) and the calculation assumes full power operation at the end of core life immediately preceding shutdown. The fission product inventory in the highest-rated assembly for the conservative case is given in Table 15.4-37 and is based on a peaking factor of 1.7. Per Regulatory Guide 1.183, Table 3, the non-LOCA fraction of fission products inventory in the gap is acceptable for use if the peak fuel burnup does not exceed 62,000 MWD/MTU and the maximum linear heat generation rate does not exceed 6.3 kw/ft. peak rod average power for burnups exceeding 54 GWD/MTU. To account for possible variation in burnup and rod power, the Table 3 non-LOCA fraction of fission products inventory in the gap is conservatively doubled. The Regulatory Guide 1.183, Table 3 gap fractions and the gap fractions used in the FHA analyses are listed as follows:

Group	Regulatory Guide 1.183 Fraction	FHA Analysis Fraction
I-131	0.08	0.16
Kr-85	0.10	0.20
Other Noble Gases	0.05	0.10
Other Halogens	0.05	0.10
Alkali Metals	0.12	0.24

4. All activity in the clad gap of the damaged fuel is released to the reactor cavity pool.
5. Noble gases released to the reactor cavity pool are immediately released to the reactor building atmosphere.
6. Per Regulatory Guide 1.183, Appendix B.1.3, the chemical form of radioiodine released from the fuel is 95% aerosol (Csl), 4.85% elemental and 0.15% organic. Due to the low pH of the water, Csl instantaneously disassociates and the iodine re-evolves as elemental, resulting in 99.85% elemental (4.85% + 95%) and 0.15% organic iodine within the water. The minimum fuel depth over the reactor core when handling fuel and over the spent fuel in the FHB is 23 feet. Therefore, consistent with Regulatory Guide 1.183, Appendix B.2, the overall effective iodine decontamination factor is 200, for the reactor core pool, with a resulting chemical species released from the water of 57% elemental and 43% organic iodine.

15.4.5.1.2.2 Iodine Decontamination Factors

An experimental test program (Reference 40) was performed to evaluate the extent of removal of iodine released from a damaged irradiated fuel assembly. Iodine removal from the released gas takes place as the gas rises through the body of solution in the fuel storage area to the pool surface. The extent of iodine removal is determined by mass transfer from the gas phase to the surrounding liquid and is controlled by the bubble diameter and contact time of the bubble in the solution.

In order to obtain all the necessary information regarding this mass transfer process, a number of small scale tests were conducted, using trace iodine and carbon dioxide in an inert carrier gas. Iodine testing was performed at the design basis solution conditions (temperature and chemistry) and data were collected for various bubble diameters and solution depths. This work resulted in the formulation of a mathematical expression for iodine decontamination factor in terms of bubble size and bubble rise time.

Similar tests were conducted with carbon dioxide in an inert carrier, except that the solution temperature and chemistry were patterned after that of a deep pool where large scale tests were also performed with carbon dioxide. The small scale carbon dioxide tests also resulted in a

mathematical expression for decontamination factor in terms of bubble size and bubble rise time through the solution.

To complete the experimental program, a full size fuel assembly simulator was fabricated and placed in a deep pool for testing, where gas released would be typical of that from the postulated damaged assembly. Tests were conducted with trace carbon dioxide in an inert carrier gas and overall decontamination factors were measured as a function of the total gas volume released. These measurements, combined with the analytical expression derived from small scale tests with carbon dioxide, permitted an in situ measurement of both the effective bubble diameter and rise time, both as a function of the volume of gas released. Having measured the characteristics of large scale gas releases, the decontamination factor for iodine was obtained, using the analytical expression from small scale iodine testing.

$$\text{Decontamination Factor} = 7.3\ e^{0.313\ t/d}$$

Where:

t = rise time

d = effective bubble diameter

The overall test results clearly indicate that iodine will be readily removed from the gas rising through the spent fuel pool and that the efficiency of removal will depend on the volume of gas released instantaneously from the full void space.

With consideration given to the total quantity of gas released from a fuel assembly, i.e., 6.9 scf for the 17 x 17 array, the pool decontamination factor for iodine is indicated to be a minimum of 760 for the 26 foot depth. Thus, a decontamination factor of 760 constitutes one parameter of the expected case. In the realistic case presented here, a lower decontamination factor is selected to provide for reasonable deviation in the factors that control iodine absorption by the pool water. For the realistic analysis, a decontamination factor value of 500 is used, which is a reduction of 66% of the expected value. For the conservative analysis, the decontamination factor is further reduced to a value of 200, or less than 30% of the value that would be expected.

15.4.5.1.3 Conclusions

A summary of the parameters and assumptions used to evaluate the consequences of a fuel handling accident are given in Table 15.4-38 for both the realistic and conservative analyses.

Activities released to the environment as a result of this event, are given in Table 15.4-40 for both the realistic and conservative cases.

15.4.5.1.4 Environmental Consequences of a Postulated Fuel Handling Accident Inside Containment

Following the postulated accident inside the Reactor Building, the activity released to the Reactor Building atmosphere is assumed to be released over a two hour duration to the environment

through the Reactor Building Purge System. In both the realistic and conservative analyses, no credit is taken for a reduction in the amount of activity released due to filtration or radioactive decay due to holdup in the containment. A summary of the pertinent parameters used to evaluate the consequences are presented in Table 15.4-38.

The following additional assumptions and parameters are used to calculate the control room doses for the FHA inside containment.

1. The atmospheric diffusion parameters for the control room are provided in Table 2.3-123. The limiting control room release point for the FHA inside of containment is the nearest point to the reactor building control room intake “A”.
2. The control room emergency filtration system is credited after 30 minutes.
3. The control room ventilation system flow rates are shown on Figure 15.4-146.
4. The control room breathing rate is assumed as 3.47E-04 m^3/sec for the duration of the accident.
5. Additional control room parameters are shown on Table 15.4-17.

The offsite and control room radiation doses resulting from both the realistic and conservative analyses of a postulated fuel handling accident inside containment are presented in Table 15.4-41.

15.4.5.2 Fuel Handling Accident Outside Containment

The fuel handling accident outside containment is postulated as the dropping of a spent fuel assembly into the Spent Fuel Pool which results in damage to the fuel assemblies and the release of the volatile gaseous fission products. Similar to the evaluation of the FHA inside containment, realistic and conservative analyses are performed for this postulated accident.

The identification of causes and description of this accident is identical to the FHA inside containment with the exception that the escaped gaseous fission products are released to the spent fuel pool and subsequently to the Fuel Handling Building. These gases are released to the environment via the fuel handling building charcoal exhaust system.

The conditions and parameters assumed in analyzing the effects and consequences of this accident are identical to those utilized in the FHA inside containment except that the activity released to the environment is treated by the HEPA and charcoal filters of the Fuel Handling Building Exhaust System. No credit is taken for these filters in the analysis of the environmental doses. Accordingly, the activity released to the environment is identical to that presented for the FHA inside containment and shown in Table 15.4-40 for the realistic and conservative cases respectively.

15.4.5.2.1 Environmental Consequences of a Postulated Fuel Handling Accident Outside of Containment

Following a postulated FHA outside containment, a quantity of airborne radioactivity would be released to the environment via the fuel handling building charcoal exhaust system.

In both the realistic and conservative analyses, no credit is taken for the mixing of the activity released with the fuel building atmosphere nor for radioactive decay due to holdup in the building or transit time after release to the environs. A summary of the pertinent parameters used to evaluate the consequences are presented in Table 15.4-38. Isotopic releases to the environment are presented in Table 15.4-40.

The following additional assumptions and parameters are used to calculate the control room doses for the FHA outside containment.

1. The atmospheric diffusion parameters for the control room are provided in Table 2.3-123. The limiting control room release point for the FHA outside of containment is the Main Plant Vent.
2. The control room emergency filtration system is credited after 30 minutes.
3. The control room ventilation system flow rates are shown on Figure 15.4-146.
4. The control room breathing rate is assumed as 3.47E-04 m^3/sec for the duration of the accident.
5. Additional control room parameters are shown on Table 15.4-17.

The offsite and control room radiation doses resulting from both the realistic and conservative analyses of the postulated fuel handling accident outside containment are presented in Table 15.4-50.

15.4.6 Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

15.4.6.1 Identification of Causes and Accident Description

This accident is defined as the mechanical failure of a control rod mechanism pressure housing resulting in the ejection of a rod cluster control assembly (RCCA) and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

15.4.6.1.1 Design Precautions and Protection

Certain features in Westinghouse Pressurized Water Reactors are intended to preclude the possibility of a rod ejection accident, or to limit the consequences if the accident were to occur. These include a sound, conservative mechanical design of the rod housings, together with a thorough quality control (testing) program during assembly, and a nuclear design which lessens

the potential ejection worth of RCCAs and minimizes the number of assemblies inserted at high power levels.

15.4.6.1.1.1 Mechanical Design

The mechanical design is discussed in FSAR Section 4.2. Mechanical design and quality control procedures intended to preclude the possibility of a RCCA drive mechanism housing failure are listed below:

1. The mechanism and travel housings were hydrotested after they were attached to the head adapters in the reactor vessel head, and checked during the hydrotest of the Replacement Reactor Vessel Closure Head.
2. Stress levels in the mechanism are not affected by anticipated system transients at power, or by the thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress range specified by the ASME Code, Section III, for Class 1 components.
3. The latch mechanism housing and rod travel housing are each a single length of forged Type 304 stainless steel. This material exhibits excellent notch toughness at all temperatures which will be encountered.

A significant margin of strength in the elastic range together with the large energy absorption capability in the plastic range gives additional assurance that gross failure of the housing will not occur. The latch mechanism housing and head adapter are connected by a full penetration weld joint. The latch mechanism housing and rod travel housing, are connected by threaded joints, reinforced by canopy type seal welds, which are subject to periodic inspections.

15.4.6.1.1.2 Nuclear Design

Even if a rupture of a RCCA drive mechanism housing is postulated, the operation of a plant utilizing chemical shim is such that the severity of an ejected RCCA is inherently limited Reactivity changes caused by core depletion and xenon transients are compensated by boron changes. Further, the location and grouping of control RCCA banks are selected during the nuclear design to lessen the severity of a RCCA ejection accident. Therefore, should a RCCA be ejected from its normal position during full power operation, only a minor reactivity excursion, at worst, could be expected to occur.

However, it may be occasionally desirable to operate with larger than normal insertions. For this reason, a rod insertion limit is defined as a function of power level. Operation with the RCCAs above this limit guarantees adequate shutdown capability and acceptable power distributions. The position of all RCCAs is continuously indicated in the control room. An alarm will occur if a bank of RCCAs approaches its insertion limit or if one RCCA deviates from its bank. There are low and low-low level insertion monitors with visual and audio signals. Operating instructions require boration at low level alarm and emergency boration at the low-low alarm.

15.4.6.1.1.3 Reactor Protection

The reactor protection in the event of a rod ejection accident has been described in (Reference 30). The protection for this accident is provided by high neutron flux trip (high and low setting) and high rate of neutron flux increase trip. These protection functions are described in detail in Section 7.2.

15.4.6.1.1.4 Effects on Adjacent Housings

Disregarding the remote possibility of the occurrence of a RCCA mechanism housing failure, investigations have shown that failure of a housing due to either longitudinal or circumferential cracking would not cause damage to adjacent housing leading to an increase in severity of the initial accident.

The operating coil stack assembly of this mechanism has a 10.718 inch by 10.718 cross section and 39.875 inch length. The position indicator coil stack assembly is located above the operating coil stack assembly. It surrounds the rod travel housing over nearly its entire 163.24 inch length. The rod travel housing outside diameter is 3.75 inches and the position indicator coil stack assembly inside and outside diameters are 3.75 inches and 7.0 inches, respectively. This assembly consists of a steel tube surrounded by a continuous stack of copper wire coils. The assembly is held together by two end plates, an outer sleeve, and four axial tie rods.

15.4.6.1.1.5 Effects of Rod Travel Housing Longitudinal Failures

If a longitudinal failure of the rod travel housing should occur, the region of the position indicator assembly opposite the break would be stressed by the reactor coolant pressure of 2250 psia. The most probable leakage path would be provided by the radial deformation of the position indicator coil assembly, resulting in the growth of axial flow passages between the rod travel housing and the steel tube.

If failure of the position indicator coil assembly should occur, the resulting free radial jet from the failed housing could cause it to bend and contact adjacent rod housings. If the adjacent housings were on the periphery, they might bend outward from their bases. The housing material is quite ductile; plastic hinging without cracking would be expected. Housings adjacent to a failed housing, in locations other than the periphery, would not be bent because of the rigidity of multiple adjacent housings.

15.4.6.1.1.6 Effect of Rod Travel Housing Circumferential Failures

If circumferential failure of a rod travel housing should occur, the broken off section of the housing would be ejected vertically because the driving force is vertical and the position indicator coil stack assembly and the drive shaft would tend to guide the broken off piece upwards during its travel. Travel is limited by the missile shield, thereby limiting the projectile acceleration. When the projectile reached the missile shield it would partially penetrate the shield and dissipate its kinetic energy. The water jet from the break would continue to push the broken off piece against the missile shield.

If the broken off piece of the rod travel housing were short enough to clear the break when fully ejected, it would rebound after impact with the missile shield. The top end plates of the position indicator coil stack assemblies would prevent the broken piece from directly hitting the rod travel housing of a second drive mechanism. Even if a direct hit by the rebounding piece were to occur, the low kinetic energy of the rebounding projectile would not be expected to cause significant damage.

15.4.6.1.1.7 Possible Consequences

From the above discussion, the probability of damage to an adjacent housing must be considered remote. However, even if damage is postulated, it would not be expected to lead to a more severe transient since RCCAs are inserted in the core in symmetric patterns, and control rods immediately adjacent to worst ejected rods are not in the core when the reactor is critical. Damage to an adjacent housing could, at worst, cause that RCCA not to fall on receiving a trip signal, however this is already taken into account in the analysis by assuming a stuck rod adjacent to the ejected rod.

15.4.6.1.1.8 Summary

The considerations given above lead to the conclusion that failure of a control rod housing, due either to longitudinal or circumferential cracking, would not cause damage to adjacent housings that would increase severity of the initial accident.

15.4.6.1.2 Limiting Criteria

Due to the extremely low probability of a RCCA ejection accident, some fuel damage could be considered an acceptable consequence.

Comprehensive studies of the threshold of fuel failure and of the threshold of significant conversion of the fuel thermal energy to mechanical energy, have been carried out as part of the SPERT project by the Idaho Nuclear Corporation (Reference 31). Extensive tests of UO2 zirconium clad fuel rods representative of those in Pressurized Water Reactor type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design have exhibited failures as low as 225 cal/gm. These results differ significantly from the TREAT (Reference 32) results, which indicated a failure threshold at 280 cal/gm. Limited results have indicated that this threshold decreases by about 10% with fuel burnup. The clad failure mechanism appears to be melting for zero burnup rods and brittle fracture for irradiated rods. Also important is the conversion ratio of thermal to mechanical energy. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods and 200 cal/gm for irradiated rods; catastrophic failure, (large fuel dispersal, large pressure rise) even for irradiated rods, did not occur below 300 cal/gm.

In view of the above experimental results, conservative criteria (Reference 49) are applied to ensure that there is little or no possibility of fuel dispersal in the coolant, gross lattice distortion, or severe shock waves. These criteria are:

1. Average fuel pellet enthalpy at the hot spot below 225 cal/gm for unirradiated fuel and 200 cal/gm for irradiated fuel.
2. Peak reactor coolant pressure less than that which would cause stresses to exceed the faulted condition stress limits;
3. Fuel melting will be limited to less than 10% of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of criterion 1 above.

15.4.6.2 Analysis of Effects and Consequences

15.4.6.2.1 Method of Analysis

The analysis of the RCCA ejection accident is performed in two stages, first an average core nuclear power calculation and then a hot spot heat transfer calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients in the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient. A detailed discussion of the method of analysis can be found in Reference (Reference 33).

15.4.6.2.2 Average Core Analysis

The spatial kinetics computer code, TWINKLE (Reference 34), is used for the average core transient analysis. This code solves the 2 group neutron diffusion theory kinetic equation in one, two or three spatial dimensions (rectangular coordinates) for 6 delayed neutron groups and up to 8000 spatial points. The computer code includes a detailed multiregion, transient fuel clad coolant heat transfer model for calculation of pointwise Doppler and moderator feedback effects.

In this analysis, the code is used as a 1 dimensional axial kinetics code since it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement. However, since the radial dimension is missing, it is still necessary to employ very conservative methods (described below) of calculating the ejected rod worth and hot channel factor. Further description of TWINKLE appears in Section 15.1.9.

15.4.6.2.3 Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal times the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the transient value in 0.1 second, the time for full ejection of the rod. Therefore, the assumption is made that the hot spot before and after ejection are coincident. This is very conservative since the peak after ejection will occur in or adjacent to the assembly with the ejected rod, and prior to ejection the power in this region will necessarily be depressed.

The hot spot analysis is performed using the detailed fuel and clad transient heat transfer computer code, FACTRAN (Reference 29). This computer code calculates the transient temperature distribution in a cross section of a metal clad UO2 fuel rod, and the heat flux at the surface of the rod, using as input the nuclear power versus time and the local coolant conditions. The zirconium water reaction is explicitly represented, and all material properties are represented as functions of temperature. A parabolic radial power distribution is used within the fuel rod. Also, consistent with the PAD5 fuel performance code (Reference 68), the effects of fuel thermal conductivity degradation with burnup are accounted for in the analysis.

FACTRAN uses the Dittus-Boelter (Reference 35) or Jens-Lottes (Reference 36) correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation (Reference 37) to determine the film boiling coefficient after DNB. The DNB heat flux is not calculated, instead the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted in order to force the full power steady state pellet temperature distribution to agree with the fuel heat transfer design codes.

For full power cases, the design initial hot channel factor (F_Q) is input to the code. The hot channel factor during the transient is assumed to increase from steady state design value to the maximum transient value in 0.1 seconds, and remain at the maximum for the duration of the transient. This is conservative, since detailed spatial kinetics models show that the hot channel factor decreases shortly after the nuclear power peak due to power flattening caused by preferential feedback in the hot channel. Further description of FACTRAN appears in Section 15.1.9.

15.4.6.2.4 System Overpressure Analysis

Because safety limits for fuel damage specified earlier are not exceeded, there is little likelihood of fuel dispersal into the coolant. The pressure surge may therefore be calculated on the basis of conventional heat transfer from the fuel and prompt heat generation in the coolant.

The pressure surge is calculated by first performing the fuel heat transfer calculation to determine the average and hot spot heat flux versus time. Using this heat flux data, a THINC calculation is conducted to determine the volume surge. Finally, the volume surge is simulated in a plant transient computer code. This code calculates the pressure transient taking into account fluid transport in the RCS and heat transfer to the steam generators. No credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing. (Reference 38)

15.4.6.2.5 Calculation of Basic Parameters

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The more important parameters are discussed below. Table 15.4-42 presents the parameters used in this analysis.

15.4.6.2.6 Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using three dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculations.

Appropriate margins are added to the results to allow for calculational uncertainties.

15.4.6.2.7 Reactivity Feedback Weighting Factors

The largest temperature rises, and hence the largest reactivity feedbacks occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple single channel analysis. Physics calculations have been carried out for temperature changes with a flat temperature distribution, and with a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which when applied to single channel feedbacks correct them to effective whole core feedbacks for the appropriate flux shape. In this analysis, since a one dimensional (axial) spatial kinetics method is employed, the axial weighting is not necessary. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative compared to 3 dimensional analysis.

15.4.6.2.8 Moderator and Doppler Coefficient

The critical boron concentrations at the beginning of life and end of life are adjusted in the nuclear code in order to obtain moderator density coefficient curves which are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using a one dimensional steady state computer code with a Doppler weighting factor of 1. The resulting curve is conservative compared to design predictions for this plant. The Doppler weighting factor should be larger than 1.0 (approximately 1.2), just to make the present calculation agree with design predictions before ejection. This weighting factor will increase under accident conditions, as discussed above. The Doppler defect used as an initial condition is 955 pcm at the beginning of life (BOL) and 893 pcm at the end of life (EOL).

15.4.6.2.9 Delayed Neutron Fraction

Calculations of the effective delayed neutron fraction (β_{eff}) typically yield values of 0.70% at beginning of life and 0.50% at end of life for the first cycle. The accident is sensitive to β_{eff} if the

ejected rod worth is nearly equal to or greater than β_{eff} as in zero power transients. In order to allow for future cycles, pessimistic estimates of β_{eff} of 0.54% at beginning of cycle and 0.44% at end of cycle were used in the analysis.

15.4.6.2.10 Trip Reactivity Insertion

The trip reactivity insertion assumed is given in Table 15.4-42 and includes the effect of one stuck RCCA. These values are reduced by the ejected rod reactivity. The shutdown reactivity was simulated by dropping a rod of the required worth into the core. The start of rod motion occurred 0.5 seconds after the high neutron flux trip point is reached. This delay is assumed to consist of 0.2 seconds for the instrument channel to produce a signal, 0.15 seconds for the trip breaker to open and 0.15 seconds for the coil to release the rods. The analyses presented are applicable for a rod insertion time of 2.7 seconds from coil release to entrance to the dashpot. The choice of such a conservative insertion rate means that there is over one second after the trip point is reached before significant shutdown reactivity is inserted into the core. This is a particularly important conservatism for hot full power accidents.

The minimum design shutdown margin available for this plant at hot zero power (HZP) may be reached only at end of life in the equilibrium cycle. This value includes an allowance for the worst stuck rod, and adverse xenon distribution, conservative Doppler and moderator defects, and an allowance for calculational uncertainties. Physics calculations for this plant have shown that the effect of 2 stuck RCCAs (one of which is the worst ejected rod) is to reduce the shutdown by about an additional 1% Δk. Therefore, following a reactor trip resulting from an RCCA ejection accident, the reactor will be subcritical when the core returns to HZP.

Depressurization calculations have been performed for the Virgil C. Summer Nuclear Station assuming the maximum possible size break (2.75 inch diameter) located in the reactor pressure vessel head. The results show a rapid pressure drop and a decrease in system water mass due to the break. The safety injection system is actuated on low pressurizer pressure within one minute after the break. The RCS pressure continues to drop and reaches saturation (1100 to 1300 psi depending on the system temperature) in about 2 to 3 minutes. Due to the large thermal inertia of primary and secondary system, there has been no significant decrease in the RCS temperature below no load by this time, and the depressurization itself has caused an increase in shutdown margin by about 0.2% Δk due to the pressure coefficient. The cooldown transient could not absorb the available shutdown margin until more than ten minutes after the break. The addition of borated safety injection flow starting one minute after the break is much more than sufficient to ensure that the core remains subcritical during the cooldown.

15.4.6.2.11 Results

The values of the parameters used in the analysis, as well as the results of the analysis, are presented in Table 15.4-42 and discussed below.

1. Beginning of Cycle, Full Power

Control bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor were conservatively assumed to be 0.20% Δk and 4.5 respectively. The peak hot spot clad average temperature was 2158°F. The peak hot spot fuel center temperature exceeded the BOL melting temperature of 5024.2°F. However, melting was restricted to less than 10% of the pellet.

2. Beginning of Cycle, Zero Power

   For this condition, control bank D was assumed to be fully inserted and bank C was at its insertion limit. The worst ejected rod is located in control bank D and was conservatively assumed to have a worth of 0.855% Δk and a hot channel factor of 13. The peak hot spot clad average temperature reached 2680°F. The peak hot spot fuel center temperature was 4468°F.

3. End of Cycle, Full Power

   Control bank D was assumed to be inserted to its insertion limit. The ejected rod worth and hot channel factors were conservatively assumed to be 0.21% Δk and 5.0, respectively. This resulted in a peak hot spot clad average temperature of 2136°F. The peak hot spot fuel center temperature exceeded the EOL melting temperature of 5024.2°F. However, melting was restricted to less than 10% of the pellet.

4. End of Cycle, Zero Power

   Control Bank D was assumed to be fully inserted and C was at its insertion limit. The ejected rod worth and hot channel factor were conservatively assumed to be 0.91% Dk and 22.5, respectively. The peak clad average and fuel center temperatures were 2839°F and 4402°F, respectively.

   A summary of the cases presented above is given in Table 15.4-42. The nuclear power and hot spot fuel and clad temperature transients are presented in Figure 15.4-100 through Figure 15.4-103.

15.4.6.2.12 Fission Product Release

It is assumed that fission products are released from the gaps of all rods entering DNB. In all cases considered, less than 10% of the rods entered DNB based on a detailed three dimensional THINC analysis. Although limited fuel melting at the hot spot was predicted for the full power cases, in practice melting is not expected since the analysis conservatively assumed that the hot spots before and after ejection were coincident.

15.4.6.2.13 Pressure Surge

A detailed calculation of the pressure surge for an ejection reactivity worth of one dollar at beginning of life, hot full power, indicates that the peak pressure does not exceed that which would cause stress to exceed the faulted condition stress limits. Since the severity of the present

analysis does not exceed this “worst case” analysis, the accident for this plant will not result in an excessive pressure rise or further damage to the reactor coolant system.

15.4.6.2.14 Lattice Deformations

A large temperature gradient will exist in the region of the hot spot. Since the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods may produce a force tending to bow the midpoint of the rods toward the hot spot. Physics calculations indicate that the net result of this would be a negative reactivity insertion. In practice, no significant bowing is anticipated, since the structural rigidity of the core is more than sufficient to withstand the forces produced. Boiling in the hot spot region would produce a net flow away from that region. However, the heat from the fuel is released to the water relatively slowly, and it is considered inconceivable that cross flow will be sufficient to produce significant lattice forces. Even if massive and rapid boiling, sufficient to distort the lattice, is hypothetically postulated, the large void fraction in the hot spot region would produce a reduction in the total core moderator to fuel ratio, and a large reduction in this ratio at the hot spot. The net effect would therefore be a negative feedback. It can be concluded that no conceivable mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analysis.

15.4.6.3 Conclusions

Even on a conservation basis, the analyses indicate that the described fuel and limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the reactor coolant system. The analyses have demonstrated that upper limit in fission product release as a result of a number of fuel rods entering DNB amounts to 10% (Reference 38).

15.4.6.4 Environmental Consequences of a Postulated Rod Ejection Accident

Two analyses of a postulated rod ejection accident are performed: a realistic analysis and a conservative Regulatory Guide 1.183 analysis. The parameters used for each of these analyses are listed in Table 15.4-43.

The realistic analysis of the doses resulting from a rod ejection accident is based upon the release to the containment of all volatile fission products in the RCS.

Prior to the accident it is assumed that the plant has been operating with 0.12% fuel defects and steam generator tube leakage of 100 lb./day for a sufficient period of time to establish equilibrium levels of activity in the primary and secondary systems. Release from contaminated steam dumped to the condenser is considered negligible.

For the conservative Regulatory Guide 1.183 analysis, it is assumed that the plant is operating at equilibrium levels of radioactivity in the primary and secondary systems prior to the postulated

rod ejection accident as a result of coincident fuel defects (1%) and steam generator tube leakage (1 gpm). Following a postulated rod ejection accident, two activity release paths are considered. The first release path is via containment leakage of activity released to the containment from the reactor coolant. The second path is via the contaminated steam from the secondary system which is released through the relief valves since it is assumed that offsite power is lost.

15.4.6.4.1 Model

The RADTRAD (Reference 64) computer code was used to calculate the offsite and control room doses for the control rod ejection accident (CREA). Schematics showing the code modeling of the activity flow paths are provided on Figure 15.4-147 (steam generator release path) and Figure 15.4-148 (containment release path). Parameters and assumptions used in evaluating offsite doses for this event are summarized in Table 15.4-43.

Prior to the accident it is assumed that the plant has been operating with simultaneous fuel defects and steam generator tube leakage for a sufficient period of time to establish equilibrium levels of activity in the primary and secondary systems.

Following a postulated rod ejection accident, the activity released is assumed to be instantaneously mixed uniformly throughout the reactor coolant. Thus, the total activity released from the fuel rod gaps is assumed to be immediately available for release from the RCS.

Of the activity released with the reactor coolant to the containment by the postulated failure of the RCCA mechanism pressure housing, 100% is assumed to be mixed instantaneously throughout the containment and to be available for leakage from the containment at the design leak rate. The only removal processes considered within containment are radioactive decay and leakage from the containment.

The model for the activity available for release to the atmosphere from the relief valves assumes that the release consists of the activity in the secondary coolant prior to the accident plus that fraction of the activity leaking from the reactor coolant through the steam generator tubes following the accident. The leakage of reactor coolant to the secondary side of the steam generators is assumed to continue at its initial rate, i.e., the same leakage rate that existed prior to the accident, until primary and secondary system pressure is equalized. No mass transfer from the primary to the secondary system through steam generator tube leakage is assumed after system pressures are equalized.

15.4.6.4.2 Assumptions for Conservative Analysis

The following conservative assumptions were used in the analysis of the release of radioactivity to the environment in the event of a postulated rod ejection accident. A summary of parameters used in the analysis is given by Table 15.4-43.

1. The primary-to-secondary leak rate in the steam generators is assumed to be the leak-rate-limiting condition for operation specified in the plant requirements of 1 gpm for all three steam generators. To be consistent with preferred plant procedures for shutdown, the

shutdown cooling rate following this type of event is taken as 25 °F /hr. Therefore, to go from 557 °F to 212 °F would require about 14 hours. The CREA is conservatively analyzed using 24 hours for the cooldown time. The activity associated with the 1 gpm leak is assumed to be released to the environment via the intact steam generators for the 24 hour duration with a partition factor of 100 for iodine and particulates and 1.0 for noble gases. In addition, the secondary coolant iodine and particulate activity initially contained in the secondary system is released to the environment with a partition factor of 100.

2. Per Regulatory Guide 1.183, Table 3, the non-LOCA fraction of fission products inventory in the gap is acceptable for use if the peak fuel burnup does not exceed 62,000 MWD/MTU and the maximum linear heat generation rate does not exceed 6.3 kw/ft. peak rod average power for burnups exceeding 54 GWD/MTU. To account for possible variation in burnup and rod power, the Table 3 non-LOCA fraction of fission products inventory in the gap is conservatively doubled. The Regulatory Guide 1.183, Table 3 gap fractions and the gap fractions used in the CREA analysis are listed as follows:

Group	Regulatory Guide 1.183 Fraction	CREA Analysis Fraction
Noble Gases	0.10	0.20
Halogens	0.10	0.20
Alkali Metals	0.12	0.24

3. Instantaneous mixing of all activity released from the reactor coolant into the containment is assumed.
4. No credit is assumed for removal of iodine within containment by the reactor building sprays.

Design criteria applied to ensure that fuel dispersal into the reactor coolant will not occur include:

“Fuel melting limited to less than the innermost10% of the fuel pellet at the hot spot” (Reference 38)

Even though centerline melting in a small fraction of the core is not expected, a conservative upper limit of fission product release from the core as a result of a postulated rod ejection accident can be estimated. This limit would include the release of 100% of the noble gases and 50% of the iodines from that portion of the fuel which could experience centerline melting under the above criteria.

The upper limit of fission product release from the core for this very conservative case is determined using the following assumptions:

1. It is assumed that 100% of the noble gases and iodines in the clad gaps of the fuel rods experiencing clad damage (assumed to be 10% of the rods in the core (Reference 38) is assumed to be released to the reactor coolant.

2. It is assumed that 50% of the iodines and 100% of the noble gases in the fuel that melts are released to the reactor coolant. This is a very conservative assumption since only centerline melting could occur for a maximum time period of six seconds.
3. The fraction of fuel melting is conservatively assumed to be one quarter of one percent of the core, determined by the following method:
   a. A conservative upper limit of 50% of the rods experiencing clad damage may experience centerline melting (a total of 5% of the core).
   b. Of rods experiencing centerline melting, only a conservative maximum of the innermost 10% of the rod volume will actually melt (equivalent to 0.5% of the core that could experience melting).
   c. A conservative maximum of 50% of the axial length of the rod will experience melting due to the power distribution (0.5 of the 0.5% of the core equals 0.25% of the core).

The release fraction from the melted fuel is based on Attachment H and Regulatory Position 3.2, Table 2 of Regulatory Guide 1.183, 100% for the nobles, 25% for the iodines, and 30% for the alkali metals for the containment release pathway and 100% for the nobles, 50% for the iodines, and 50% for the alkali metals for the steam generator release pathway.

The following additional assumptions and parameters are used to calculate the control room doses for the CREA.

1. The atmospheric diffusion parameters for the control room are provided in Table 2.3-123. The limiting CR release point for the CREA is the RB nearest point - Control Room Intake A for the containment release pathway and the Main Steam Safety Relief Valve “A” (Reliefs B, C, D, E), Control Room Intake B for the SG release pathway.
2. The control room emergency filtration system is credited after 30 minutes for the containment release case and 120 minutes for the SG release case.
3. The control room ventilation system flow rates are shown on Figure 15.4-147 and Figure 15.4-148.
4. The control room breathing rate is assumed as 3.47E-04 m^3/sec for the duration of the accident.
5. Additional control room parameters are shown on Table 15.4-17.

The remainder of the assumptions and parameters used to calculate the activity release from the plant and the subsequent offsite doses for the ultraconservative analysis are identical to those used for the conservative analysis.

15.4.6.4.3 Results

Isotopic releases are summarized in Table 15.4-44 through Table 15.4-46. The calculated offsite and control room doses are provided in Table 15.4-47.

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Table 15.4-1a
Plant Operating Range Analyzed and Key Parameters for V.C. Summer

Parameter	As-Analyzed Value or Range
1.0 Core Parameters	
a. Core power	≤ 2900 MWt ± 2% Uncertainty
b. Fuel type	17x17 OFA fuel, **Optimized ZIRLO ™** cladding material, Intermediate Flow Mixers (IFMs), Integral Fuel Burnable Absorbers (IFBA) or Non-IFBA
c. Maximum total core peaking factor (F_Q), including uncertainties	2.50
d. Maximum hot channel enthalpy rise peaking factor ($F_{\Delta H}$), including uncertainties	1.70
e. Axial flux difference (AFD) band at 100% power	-12% / +10%
2.0 Reactor Coolant System Parameters	
a. Thermal design flow (TDF)	92,600 gpm/loop
b. Vessel average temperature (T_{AVG})	572.0 - 5.4°F ≤ T_{AVG} ≤ 587.4 + 6.3°F
c. Pressurizer pressure (P_{RCS})	2250 - 65 psia ≤ P_{RCS} ≤ 2250 + 54 psia
d. Reactor coolant pump (RCP) model and power	Model 93A, 7000 hp
3.0 Containment Parameters	
a. Containment modeling	Region I: Constant pressure equal to initial containment pressure Region II: Calculated for each transient using transient-specific mass and energy releases and the information in Tables 15.4-1b, 15.4-1c, and 6.2-60
4.0 Steam Generator (SG) and Secondary Side Parameters	
a. Steam generator tube plugging level	≤ 10%
b. Main steam safety valve (MSSV) nominal set pressures, uncertainty and accumulation	Table 15.4-1f
c. Main feedwater temperature	Nominal (440°F)

Table 15.4-1a (continued)
Plant Operating Range Analyzed and Key Parameters for V.C. Summer

Parameter	As-Analyzed Value or Range
d. Auxiliary feedwater temperature (T_{AFW})	$32°F \leq T_{AFW} \leq 95°F$
e. Auxiliary feedwater flow rate	133.3 gpm/SG
5.0 Safety Injection (SI) Parameters	
a. Single failure configuration	ECCS: Loss of one train of pumped ECCS Region II containment pressure: All containment spray trains are available
b. Safety injection temperature (T_{SI})	$40°F \leq T_{SI} \leq 95°F$
c. Low pressurizer pressure safety injection safety analysis limit	1715 psia
d. Initiation delay time from low pressurizer pressure SI setpoint to full SI flow	≤ 27 seconds (OPA) or ≤ 37 seconds (LOOP)
e. Safety injection flow	Minimum flows in Table 15.4-1d (Region I) or Table 15.4-1e (Region II)
6.0 Accumulator Parameters	
a. Accumulator temperature (T_{ACC})	$75°F \leq T_{ACC} \leq 120°F$
b. Accumulator water volume (V_{ACC})	$994\ ft^3 \leq V_{ACC} \leq 1034\ ft^3$
c. Accumulator pressure (P_{ACC})	$585\ psia \leq P_{ACC} \leq 701\ psia$
d. Accumulator boron concentration	≥ 2200 ppm
7.0 Reactor Protection System Parameters	
a. Low pressurizer pressure reactor trip signal processing time	≤ 2 seconds
b. Low pressurizer pressure reactor trip setpoint	1835 psia

Table 15.4-1b
Containment Data Used for Region II Calculation of
Containment Pressure for V.C. Summer

Parameter	Value
Maximum containment net free volume	1.91×10^6 ft^3
Minimum initial containment temperature at full power operation	75°F
RWST temperature for containment spray (T_{RWST})	$40°F \leq T_{RWST} \leq 95°F$
Minimum RWST temperature for broken loop spilling SI	40°F
Minimum containment outside air / ground temperature	-5°F
Minimum initial containment pressure at normal full power operation	14.6 psia
Minimum containment spray pump initiation delay from containment high pressure signal time	≥ 32 seconds (OPA) or ≥ 38 seconds (LOOP)
Maximum containment spray flow rate from all pumps	6600 gpm
Maximum number of containment fan coolers in operation during LOCA transient	2
Minimum fan cooler initiation delay time	≥ 33 seconds (OPA) or ≥ 40seconds (LOOP)
Maximum heat removal rate per fan cooler as a function of containment temperature	Table 15.4-1c
Maximum number of containment venting lines (including purge lines, pressure relief lines or any others) which can be OPEN at onset of transient at full power operation	1
Maximum effective valve diameter of each containment venting line	6.065 inches
Maximum containment pressure setpoint for venting valve closure	3.6 psig
Maximum delay time between reaching containment pressure setpoint and start of venting valve closure	1.6 seconds
Maximum venting valve closure time at normal full power operation	5.4 seconds
Containment walls / heat sink properties	Table 6.2-60
SI spilling flows	256.5 lbm/sec

Table 15.4-1c
Fan Cooler Performance Data Used for Region II Calculation of
Containment Pressure for V.C. Summer

Containment Temperature (°F)	**Heat Removal Rate (BTU/hr)**	**Heat Removal Rate (BTU/sec)**
148.5	44,592,834	12,387
170.1	68,015,125	18,893
181.7	82,961,400	23,045
190.8	95,496,000	26,527
200.7	109,945,231	30,540
211.0	125,463,080	34,851
220.2	140,202,609	38,945
227.1	151,025,483	41,952
234.2	162,115,201	45,032
254.0	192,871,878	53,576

Table 15.4-1d
Safety Injection Flow Used for Region I Calculation for V.C. Summer

Pressure (psia)	High Head Safety Injection (HHSI) Flow (gpm)
14.7	327.1
114.7	335.8
214.7	331.8
314.7	323.9
414.7	315.9
514.7	307.8
614.7	299.5
714.7	291.2
814.7	282.7
914.7	274.2
1014.7	265.5
1114.7	256.6
1214.7	247.5
1314.7	237.9
1414.7	228.1
1514.7	218.1
1614.7	208.1
1714.7	197.8
1814.7	185.0
1914.7	171.8
2014.7	158.0
2114.7	143.7
2214.7	126.3
2314.7	102.9
2414.7	77.4

Table 15.4-1d (continued)
Safety Injection Flow Used for Region I Calculation for V.C. Summer

Pressure (psia)	High Head Safety Injection (HHSI) Flow (gpm)
2414.71	0.0
2514.7	0.0

Table 15.4-1e
Safety Injection Flow Used for Region II Calculation for V.C. Summer

Pressure (psia)	High Head Safety Injection (HHSI) Flow (gpm)	Low Head Safety Injection (LHSI) Flow (gpm)
14.7	327.1	2414.3
34.7	328.4	1993.3
54.7	329.7	1537.0
74.7	331.1	1024.4
94.7	332.4	412.4
94.71	332.4	0.0
114.7	333.7	0.0
214.7	325.5	
314.7	313.6	
414.7	301.4	
514.7	288.9	
614.7	276.2	
714.7	263.2	
814.7	249.8	
914.7	236.1	
1014.7	222.0	
1114.7	207.4	
1214.7	192.3	
1314.7	176.9	
1414.7	160.7	
1514.7	143.6	
1614.7	125.3	
1714.7	106.0	
1814.7	85.3	
1914.7	63.3	
2014.7	37.5	

Table 15.4-1e (continued)
Safety Injection Flow Used for Region II Calculation for V.C. Summer

Pressure (psia)	High Head Safety Injection (HHSI) Flow (gpm)	Low Head Safety Injection (LHSI) Flow (gpm)
2114.7	2.6	
2114.71	0.0	
2514.7	0.0	

Table 15.4-1f
Steam Generator Main Steam Safety Valve Parameters for V.C. Summer

Stage	Set Pressure (psig)	Uncertainty (%)	Accumulation (%)
1	1176	1	3
2	1190	3	3
3	1205	3	3
4	1220	3	3
5	1235	3	3

Table 15.4-1g
(Deleted)
Table 15.4-1h
(Deleted)
Table 15.4-1i
(Deleted)

Table 15.4-2
V.C. Summer Analysis Results with the FSLOCA EM

Outcome	Region I Value	Region II Value (LOOP)	Region II Value (OPA)
95/95 PCT	1,108°F	1,879°F	1,868°F
95/95 MLO	8.43%	9.13%	9.06%
95/95 CWO	0.00%	0.36%	0.33%

Table 15.4-3
V.C. Summer Sequence of Events for the Region I Analysis PCT Case

Event	Time after Break (sec)
Start of Transient	0.0
Reactor Trip Signal	14.9
Safety Injection Signal	26.8
Safety Injection Begins	63.8
Loop Seal Clearing Occurs	680
Top of Core Uncovered	1,208
Accumulator Injection Begins	1,894
PCT Occurs	1,921
Top of Core Recovered	2,976

Table 15.4-4
V.C. Summer Sequence of Events for the Region II Analysis PCT Case

Event	Time after Break (sec)
Start of Transient	0.0
Fuel Rod Burst Occurs	4.3
Safety Injection Signal	4.6
Accumulator Injection Begins	11.1
End of Blowdown	15.5
Safety Injection Begins	41.6
Accumulator Empty	45.0
PCT Occurs	95.4
All Rods Quenched	266

Table 15.4-6
Post Accident Containment Temperature Transient Used in the
Calculation of Aluminum and Zinc Corrosion

Time Interval (seconds)	Temperature (°F)
0	278.0
1,996	278.0
4,000	251.6
8,001	245.7
9,996	225.5
20,002	206.9
40,003	194.2
79,998	189.2
99,999	181.0
199,999	166.8
399,997	156.1
800,004	156.1
999,994	153.1
3,400,016	140.3
3,879,965	130.0
8,640,000	130.0

Table 15.4-7
Parameters Used To Determine Hydrogen Generation

Core Thermal Power	2958 MWt
Containment Free Volume	1.84×10^6 ft^3
Containment Temperature at Accident	120°F
Weight Zirconium (Active Fuel Clad)	35,244 lb
Hydrogen Generated Zirconium-Water Reaction Based on 5.0% value	14,987 SCF
Hydrogen from Reactor Coolant System	909 SCF
Corrodable Metal	Aluminum and Zinc

Inventory of Aluminum and Zinc In Containment

	Weight (lbs)	Surface Area (ft^2)
Aluminum	2,286	1,281
Zinc	32,747	87,386

Table 15.4-11
Activity Available For Release Core
Release Case (Regulatory Guide 1.183)

Isotope	Curies	Isotope	Curies	Isotope	Curies
Co-58	7.55E+05	Ru-103	1.06E+08	Cs-136	3.08E+06
Co-60	5.78E+05	Ru-105	6.92E+07	Cs-137	5.66E+06
Kr-85	8.30E+05	Ru-106	2.42E+07	Ba-139	1.47E+08
Kr-85m	2.72E+07	Rh-105	4.79E+07	Ba-140	1.46E+08
Kr-87	4.96E+07	Sb-127	6.53E+06	La-140	1.49E+08
Kr-88	6.71E+07	Sb-129	2.31E+07	La-141	1.37E+08
Rb-86	4.43E+04	Te-127	6.31E+06	La-142	1.32E+08
Sr-89	8.41E+07	Te-127m	8.35E+05	Ce-141	1.32E+08
Sr-90	4.54E+06	Te-129	2.17E+07	Ce-143	1.29E+08
Sr-91	1.08E+08	Te-129m	5.72E+06	Ce-144	7.98E+07
Sr-92	1.13E+08	Te-131m	1.10E+07	Pr-143	1.26E+08
Y-90	4.87E+06	Te-132	1.09E+08	Nd-147	5.65E+07
Y-91	1.02E+08	I-131	8.20E+07	Np-239	1.51E+09
Y-92	1.13E+08	I-132	1.20E+08	Pu-238	8.58E+04
Y-93	1.28E+08	I-133	1.68E+08	Pu-239	1.94E+04
Zr-95	1.29E+08	I-134	1.80E+08	Pu-240	2.44E+04
Zr-97	1.35E+08	I-135	1.54E+08	Pu-241	4.11E+06
Nb-95	1.22E+08	Xe-133	1.70E+08	Am-241	2.72E+03
Mo-99	1.43E+08	Xe-135	3.70E+07	Cm-242	1.04E+06
Tc-99m	1.23E+08	Cs-134	1.01E+07	Cm-244	6.08E+04

Table 15.4-12
Fraction of Fission Product Inventory Released

Group	Isotopes	Gap Release Phase	Early In-Vessel Phase	Total
Noble Gases	Xe, Kr	0.05	0.95	1.00
Halogens	I, Br	0.05	0.35	0.40
Alkali Metals	Cs, Rb	0.05	0.25	0.30
Tellurium Metals	Te, Sb, Se	0.00	0.05	0.05
Ba, Sr	Ba, Sr	0.00	0.02	0.02
Noble Metals	Ru, Rh, Pd, Mo, Tc, Co	0.00	0.0025	0.0025
Cerium Group	Ce, Pu, Np	0.00	0.0005	0.0005
Lanthanides	La, Zr, Nd, Eu, Nb, Pm, Pr, Sm, Y, Cm, Am	0.00	0.0002	0.0002

LOCA Release Phases

Phase	Onset	Duration
Gap Release	30 seconds	0.5 hours
Early In-Vessel	0.5 hours	1.3 hours

Table 15.4-13
Primary Coolant Activity Available For Release
Realistic Case

Isotope	Curies	Isotope	Curies	Isotope	Curies
H-3	6.30E+02	Y-90	1.03E-02	I-130	2.97E+02
Cr-51	9.90E-01	Y-91	9.72E-02	I-131	2.70E+04
Mn-54	7.38E-02	Y-91m	5.22E-01	I-132	2.79E+04
Mn-56	3.96E+00	Y-92	1.98E-01	I-133	4.14E+04
Fe-59	9.36E-02	Y-93	6.84E-02	I-134	5.40E+03
Co-58	2.52E+00	Zr-95	1.21E-01	I-135	2.16E+04
Co-60	2.34E-01	Nb-95	1.21E-01	Xe-131m	6.21E+02
Br-83	8.01E+02	Mo-99	1.42E+02	Xe-133	7.83E+04
Br-84	3.78E+02	Tc-99m	1.51E+02	Xe-133m	5.13E+03
Kr-83m	1.16E+02	Ru-103	1.15E-01	Xe-135	2.32E+03
Kr-85	2.05E+03	Ru-106	3.78E-02	Xe-135m	1.40E+02
Kr-85m	4.86E+02	Ag-110m	5.40E-01	Cs-134	7.92E+02
Kr-87	2.97E+02	Te-125m	8.46E-02	Cs-136	8.10E+02
Kr-88	8.64E+02	Te-127	2.70E+00	Cs-137	3.78E+02
Rb-86	6.48E+00	Te-127m	6.48E-01	Cs-138	1.75E+02
Rb-88	6.84E+02	Te-129	3.60E+00	Ba-140	7.92E-01
Rb-89	3.24E+01	Te-129m	3.78E+00	La-140	2.52E-01
Sr-89	7.20E-01	Te-131	2.88E+00	Ce-141	1.24E-01
Sr-90	3.60E-02	Te-131m	5.22E+00	Ce-143	9.36E-02
Sr-91	9.54E-01	Te-132	5.22E+01	Ce-144	8.46E-02
Sr-92	2.16E-01	Te-134	5.04E+00	Pr-143	1.12E-01

Table 15.4-15
Parameters Used to Evaluate Offsite Doses
For the Loss of Coolant Accident

Parameter	Core Release Case	Realistic Case
Core Thermal Power	2958 MWt	2958 MWt
Fuel Damaged	100%	0%
Activity Available for Release from Containment	Table 15.4-11	Table 15.4-13
Form of Containment Iodine Release		
Particulate Iodine	95% as CsI	95% as CsI
Elemental Iodine	4.85%	4.85%
Organic Iodine	0.15%	0.15%
Activity Available for Release from Recirculation Loop Leakage	Table 15.4-11	Table 15.4-13
Activity Released to Environment from Recirculation Loop Leakage	10% of the Iodine Activity in Table 15.4-11	10% of the Iodine Activity in Table 15.4-13
Form of Recirculation Loop Iodine Release		
Elemental Iodine	97%	97%
Organic Iodine	3%	3%
Number of Spray Pumps Operating	1 of 2	1 of 2
Spray Removal Coefficients		
Elemental Iodine	20 hr^{-1}	20 hr^{-1}
Particulates	5.68 hr^{-1} (0-98% removal) 0.568 hr^{-1} (98-100% removal)	5.68 hr^{-1} (0-98% removal) 0.568 hr^{-1} (98-100% removal)

Table 15.4-15 (continued)
Parameters Used to Evaluate Offsite Doses
For the Loss of Coolant Accident

Parameter	Core Release Case	Realistic Case
Effective Decontamination Factor for Elemental Iodine Spray Removal	200	200
Containment Free Volume	1.84E+06 ft^3	1.84E+06 ft^3
Containment Leak rate	0.2% per day (0-24hr) 0.1% per day (1-30 days)	0.2% per day (0-24hr) 0.1% per day (1-30 days)
Containment Recirculation Flow	54,200 cfm	54,200 cfm

The following parameters are common to both cases:

Offsite Atmospheric Dispersion Factors

Time Period	Site Boundary	Low Population Zone
0 -2 hours	1.24E-04	-
0 - 8 hours		2.42E-05
2 - 8 hours		-
8 -24 hours		1.68E-05
1 - 4 days		7.55E-06
4 - 30 days		2.40E-06

Offsite Breathing Rate for EAB and LPZ
(common to all accidents)

Time	Breathing Rate (m^3/sec)
0-8 hr	3.5E-04
8-24 hr	1.8E-04
1-30 days	2.3E-04

Table 15.4-16
Offsite Doses From Loss of Coolant Accident

	Doses in rem TEDE	
	Site Boundary (1) 1609 meters	Low Population Zone (0-30 days) 4827 meters
Core Release Case	1.5E+00	8.3E-01
Realistic Case	5.3E-04	9.1E-04
10 CFR 50.67 Limit	25	25

(1) Core Release Case – Dose for time 0.4 – 2.4 hr (worst 2 hour time period) Realistic Case – Dose for time 0 – 2 hr

Table 15.4-17
Parameters Used in Analysis of Control Room Dose
Following Design Basis Accidents

	Parameters
Control Room Free Volume	226,040 ft^3
Filtered Recirculation Flow	19,125 cfm(1)
Recirculation Filter Efficiencies	95% for all species of iodine
Maximum Control Room Filtered Air Infiltration Rate per Operating Train	1265 cfm
Control Room Unfiltered Air infiltration Rate	243 cfm including 10 cfm for ingress/egress
Maximum Control Room Outleakage	Equal to total inleakage (1508 cfm)
Meteorology	Table 2.3-123
Percent of Time Operator Is in Control Room Following Accident	0-24 hrs 100% 1-4 days 60% 4-30 days 40%
Duration of Accident	30 days
Breathing Rate of Operators in Control Room	3.47×10^{-4} m^3/sec
Activity Release Parameters	Table 15.4-15
Method of Dose Calculation	RADTRAD (Reference 64)
Time to Initiate Control Room Emergency Ventilation System (2,3)	
Loss of Coolant Accident	0
Fuel Handling Accidents	30 minutes
Main Steam Line Break	30 minutes
Steam Generator Tube Rupture	30 minutes
Reactor Coolant Pump Locked Rotor	120 minutes
Control Rod Ejection	
Steam Generator Release Case	120 minutes
Containment Release Case	30 minutes

Notes:

Table 15.4-17 (CONTINUED)
Parameters Used in Analysis of Control Room Dose
Following Design Basis Accidents

Parameters

(1) 90% of 21,250 cfm.
(2) The Control Room Ventilation system is automatically placed in the emergency mode, with filtration of incoming and recirculated air, following receipt of a Safety Injection or high radiation signal from the gaseous activity channel of RM-A1. If both trains are operating, one train will be isolated within 30 minutes by the Operator in accordance with the Emergency Operating Procedures to minimize dose consequences. This condition is bounded by the analysis which only credits one train control room ventilation for the duration of the accident.
(3) Within the analysis, the emergency mode of operation is assumed to occur at the following times by either automatic isolation or manual initiation.

Table 15.4-18
Control Room Doses Following a LOCA

	Doses in rem TEDE
Core Release Case	
Containment Leakage	7.0E-01
Containment Shine	2.4E-03
External Cloud from Containment Leakage	2.0E-02
Recirculation Loop Leakage	2.7E-01
External Cloud from Recirculation Loop-Leakage	1.4E-02
Total	1.0E+00
Realistic Case	
Containment Leakage	1.2E-04
Containment Shine	4.6E-08
External Cloud from Containment Leakage	3.9E-06
Recirculation Loop Leakage	7.5E-04
External Cloud from Recirculation Loop-Leakage	4.0E-05
Total	9.1E-04
10 CFR 50.67 Limit 5	5

Table 15.4-19
Time Sequence of Events for
Major Secondary System Pipe Ruptures

Accident	Event	Time (sec)
Major Steam Line Rupture		
Offsite Power available	Steam line ruptures	0
	Criticality attained	25
	Boron from RWST reaches core	57
	Accumulators actuate	74
	Peak heat flux attained	76
	Core becomes subcritical	~ 108
Without offsite power	Steam line ruptures	0
	Criticality attained	22
	Boron from RWST reaches core	72
	Peak heat flux attained	~ 261
	Core becomes subcritical	~ 313
Rupture of Main Feedwater Pipe		
(Offsite Power Available)	Feedline rupture occurs	10
	Low-low SG water level setpoint reached	28.3
	Rods begin to drop	30.3
	Low steamline pressure setpoint reached	47.8
	Steamline isolation occurs	57.8
	Feedline isolation occurs	60.8
	Emergency Feedwater is started	136.3
	Feedwater lines are purged and emergency feedwater is delivered to two intact SGs	148.2
	First steam generator safety valve lifts in intact loop	217.5
	Pressurizer water relief begins	2134

Table 15.4-19 (CONTINUED)
Time Sequence of Events for
Major Secondary System Pipe Ruptures

Accident	Event	Time (sec)
Rupture of Main Feedwater Pipe (Continued)	Total RCS heat generation (decay heat + pump heat) decreases to emergency feedwater heat removal capability	~ 3300
(Offsite Power Unavailable)	Feedline rupture occurs	10
	Low-low SG water level setpoint reached	27.4
	Rods begin to drop	29.4
	Reactor coolant pump coastdown	31.4
	Low steamline pressure setpoint reached	45.8
	Steamline isolation occurs	55.8
	Feedwater isolation occurs	58.8
	Emergency Feedwater is started	135.4
	Feedwater lines are purged and emergency feedwater is delivered to two intact SGs	147.3
	First steam generator safety valve lifts in intact loop	304.4
	Total RCS heat generation (decay heat + pump heat) decreases to emergency feedwater heat removal capability	~ 800

Table 15.4-21
Equipment Required Following a High Energy Line Break

Short Term (Required For Mitigation of Accident)	Hot Standby	Required For Cooldown
Reactor trip and safeguards actuation channels including sensors, circuitry, and processing equipment (the protection circuits used to trip the reactor on undervoltage, underfrequency, and turbine trip may be excluded)	Emergency Feedwater System including pumps, water supply, and system valves and piping (Emergency Feedwater System automatically supplies water, see section 10.4.9).	Steam generator power operated relief valves (can be manually operated locally).
Safety Injection System including the pumps, the refueling water storage tank, and the systems valves and piping	Reactor Building emergency cooling units. Capability for obtaining a Reactor Coolant System sample	Controls for defeating automatic safety injection actuation during a cooldown and depressurization.
Diesel generators and emergency power distribution equipment	Capability for obtaining a Reactor Coolant System sample	Residual Heat Removal System including pumps, heat exchanger, and system valves and piping necessary to cool and maintain the Reactor Coolant System in a cold shutdown condition.
Service Water System		
Reactor Building emergency cooling units.		
Emergency Feedwater System including pumps, water supplies, piping, valves		
Main feedwater control valves(1) (trip closed feature)		
Primary and secondary safety valves		

Table 15.4-21 (continued)
Equipment Required Following a High Energy Line Break

Short Term (Required For Mitigation of Accident)	Hot Standby	Required For Cooldown
Circuits and/or equipment required to trip the main feedwater pumps(1)		
Main feedwater isolation valves(1) (trip closed feature)		
Main steam line isolation valves(1) (trip closed feature)		
Main steam line isolation valve bypass valves(1) (trip closed feature)		
Steam generator blowdown isolation valves (automatic closure feature)		
Batteries (Class IE)		
Control room ventilation		
Control room equipment must not be damaged to an extent where any equipment will be spuriously actuated or any of the equipment contained elsewhere in this list cannot be operated.		
Emergency lighting		
Post Accident Monitoring System(2)		

Table 15.4-21 (continued)
Equipment Required Following a High Energy Line Break

Short Term (Required For Mitigation of Accident)	Hot Standby	Required For Cooldown
Wide range T_{hot} or T_{cold} (preferably T_{hot}) for each reactor coolant loop		
Pressurizer water level		
Wide range Reactor Coolant System pressure		
Steam line pressure for each steam generator		
Wide range or narrow range steam generator level for each steam generator		
Containment pressure		

(1) Require for steam line, feed line, and steam generator blowdown line break only.
(2) See Section 7.5 for a discussion of the Post Accident Monitoring System.

Table 15.4-23
Parameters Used in Steam Line Break Analysis

Parameter	Conservative Case	Realistic Case
Core thermal power	2958 MWt	2958 MWt
Fuel defects	1%	0.12%
Fuel damaged	0%	0%
Steam generator tube leak	1,0 gpm	100 lb/day
Iodine spiking basis	Pre-accident/concurrent	None
Noble gas partition factor faulted and intact steam generator	1	1
Iodine and particulate partition factor faulted steam generator	1	1
Iodine and particulate partition factor intact steam generator	100	100
Form of iodine release		
Particulate iodine	97%	97%
Organic iodine	3%	3%

The following parameters are common to both cases:

Integrated Mass of Steam and Reactor Coolant Release Rates

Time Period	Integrated Steam Release from Faulted SG (lbm)	Integrated Steam Release from Intact SGs (lbm)	Reactor Coolant Release to Faulted SG (gpm) [1]	Reactor Coolant Release to Intact SGs (gpm)
0 -3 0 min	406,000		0.35	0.65
0 - 2 hours		390,000	0.35	0.65
2 - 8 hours		830,000	0.35	0.65

Table 15.4-23 (continued)
Parameters Used in Steam Line Break Analysis

Parameter	Conservative Case		Realistic Case	
Integrated Mass of Steam and Reactor Coolant Release Rates (continued)				
	Integrated Steam Release from Faulted SG	Integrated Steam Release from Intact SGs	Reactor Coolant Release to Faulted SG	Reactor Coolant Release to Intact SGs
Time Period	(lbm)	(lbm)	(gpm) (1)	(gpm)
8-24 hours		1,200,000	0.35	0.54

(1) For the realistic case the 100 lb/day reactor coolant release is assumed to be released to the faulted steam generator.

Offsite Atmospheric Dispersion Factors

Time	Site Boundary	Low Population Zone
0 - 2 hours	1.24E-04	-
0 - 8 hours		2.42E-05
8 - 24 hours		1.68E-05

Table 15.4-24a
Reactor Coolant and Secondary System Equilibrium
Concentration For Pre-Accident Iodine Spike

Isotope	Reactor Coolant Concentration (μCi/gm)	Secondary System Concentration (μCi/gm)
Kr-85m	1.80E+00	0
Kr-85	7.90E+00	0
Kr-87	1.10E+00	0
Kr-88	3.20E+00	0
I-131	4.69E+01	7.62E+02
I-132	7.61E+01	1.54E+02
I-133	7.61E+01	7.20E+02
I-134	1.67E+01	1.41E+01
I-135	5.17E+01	2.46E+02
Xe-131m	3.40E+00	0
Xe-133m	1.90E+01	0
Xe-133	2.90E+02	0
Xe-135m	5.20E-01	0
Xe-135	8.60E+00	0
Xe-138	6.40E-01	0
Cs-134	4.40E+00	7.82E+01
Cs-136	4.50E+00	7.57E+01
Cs-137	2.10E+00	3.74E+01
Cs-138	9.70E-01	4.87E-01
Rb-88	6.50E+00	1.83E+00
Br-83	5.34E+00	1.82E-01
Br-84	2.52E+00	2.09E-02

Table 15.4-24b
Post Accident Iodine Release Rate Concurrent Iodine Spike

Isotope	Iodine Release Rate (Ci/Sec)	500 x Iodine Release Rate (Ci/Sec)
I-131	7.21×10^{-3}	3.61
I-132	3.33×10^{-2}	16.64
I-133	1.39×10^{-2}	6.93
I-134	1.53×10^{-2}	7.66
I-135	1.29×10^{-2}	6.46

Table 15.4-24c
Reactor Coolant and Secondary System Equilibrium
Concentrations For Concurrent Iodine Spike

Isotope	Reactor Coolant Concentration (μCi/gm)	Secondary System Concentration (μCi/gm)
Kr-85m	1.80E+00	0
Kr-85	7.90E+00	0
Kr-87	1.10E+00	0
Kr-88	3.20E+00	0
I-131	7.82E+01	3.93E+02
I-132	1.27E+01	5.08E+02
I-133	1.27E+01	3.51E+02
I-134	2.79E+01	4.07E+01
I-135	8.62E+01	9.21E+02
Xe-131m	3.40E+00	0
Xe-133m	1.90E+01	0
Xe-133	2.90E+02	0
Xe-135m	5.20E-01	0
Xe-135	8.60E+00	0
Xe-138	6.40E-01	0
Cs-134	4.40E+00	7.82E+01
Cs-136	4.50E+00	7.57E+01
Cs-137	2.10E+00	3.74E+01
Cs-138	9.70E-01	4.87E-01
Rb-88	6.50E+00	1.83E+00
Br-83	5.34E+00	1.82E-01
Br-84	2.52E+00	2.09E-02

Table 15.4-25
Steam Line Break Isotopic Release
To Environment Realistic Analysis

Isotope	Activity Released to Environment (Ci) (0 - 2 hr)	(0 - 24 hr)
Kr-85m	8.16E-04	9.83E-03
Kr-85	3.58E-03	4.31E-02
Kr-87	4.99E-04	6.01E-03
Kr-88	1.45E-03	1.75E-02
I-131	7.81E-03	2.30E-02
I-132	3.42E-03	1.90E-02
I-133	1.01E-02	3.33E-02
I-134	4.51E-04	3.46E-03
I-135	3.99E-03	1.61E-02
Xe-131m	1.54E-03	1.86E-02
Xe-133m	8.62E-03	1.04E-01
Xe-133	1.32E-01	1.58E+00
Xe-135m	2.36E-04	2.84E-03
Xe-135	3.90E-03	4.70E-02
Xe-138	2.90E-04	3.50E-03
Cs-134	1.17E-02	3.40E-02
Cs-136	1.18E-02	3.46E-02
Cs-137	5.60E-03	1.62E-02
Cs-138	6.27E-04	5.49E-03
Rb-88	3.67E-03	3.62E-02
Br-83	9.92E-05	5.46E-04
Br-84	2.71E-05	2.38E-04

Table 15.4-26
Steam Line Break Isotopic Release to Environment
Conservative Analysis

	Pre-Accident Iodine Spike (Ci)	
Isotope	(0 - 2 hr)	(0 - 24 hr)
Kr-85m	8.17E-01	9.81E+00
Kr-85	3.59E+00	4.30E+01
Kr-87+	4.99E-01	5.99E+00
Kr-88	1.45E+00	1.74E+01
I-131	3.20E+02	4.12E+02
I-132	7.54E+01	2.16E+02
I-133	3.07E+02	4.53E+02
I-134	8.48E+00	3.92E+01
I-135	1.09E+02	2.06E+02
Xe-131m	1.54E+00	1.85E+01
Xe-133m	8.63E+00	1.04E+02
Xe-133	1.32E+02	1.58E+03
Xe-135m	2.36E-01	2.83E+00
Xe-135	3.90E+00	4.69E+01
Xe-138	2.91E-01	3.49E+00
Cs-134	3.28E+01	4.15E+01
Cs-136	3.18E+01	4.06E+01
Cs-137	1.57E+01	1.98E+01
Cs-138	3.57E-01	2.14E+00
Rb-88	1.80E+00	1.37E+01
Br-83	9.39E-01	1.07E+01
Br-84	4.16E-01	5.03E+00

Table 15.4-26 (CONTINUED)
Steam Line Break Isotopic Release to Environment
Conservative Analysis

	Concurrent Iodine Spike (Ci)	
Isotope	(0 - 2 hr)	(0 - 24 hr)
Kr-85m	8.17E-01	9.81E+00
Kr-85	3.59E+00	4.30E+01
Kr-87	4.99E-01	5.99E+00
Kr-88	1.45E+00	1.74E+01
I-131	2.98E+01	1.09E+03
I-132	5.43E+01	8.71E+02
I-133	4.02E+01	1.58E+03
I-134	1.84E+01	1.52E+02
I-135	2.67E+01	8.49E+02
Xe-131m	1.54E+00	1.85E+01
Xe-133m	8.63E+00	1.04E+02
Xe-133	1.32E+02	1.58E+03
Xe-135m	2.36E-01	2.83E+00
Xe-135	3.90E+00	4.69E+01
Xe-138	2.91E-01	3.49E+00
Cs-134	3.28E+01	4.15E+01
Cs-136	3.18E+01	4.06E+01
Cs-137	1.57E+01	1.98E+01
Cs-138	3.57E-01	2.14E+00
Rb-88	1.80E+00	1.37E+01
Br-83	8.90E-02	2.53E-01
Br-84	1.54E-02	9.24E-02

Table 15.4-27
Offsite and Control Room (CR) Doses
Main Steam Line Break Accident

	Dose (rem TEDE)		
Case	EAB	LPZ	CR
Pre-existing Iodine Spike Design CR Leakage	0.70	0.20	1.40
Concurrent Iodine Spike Design CR Leakage	0.40	0.30	0.50
Realistic Design CR Leakage	0.00006	0.00003	0.0002

The dose acceptance criteria provided in 10 CFR 50.67 and Regulatory Guide 1.183 are given as follows:

Pre-existing Iodine Spike MSLB – 25rem TEDE for the EAB and LPZ and 5 Rem TEDE for the CR.
Concurrent Iodine Spike MSLB – 2.5rem TEDE for the EAB and LPZ and 5 Rem TEDE for the CR.

Table 15.4-28
Plant Equipment Required For Recovery From Steam
Generator Tube Rupture Accident

1. Emergency Feedwater System including pumps, water supply, and system valves and piping.
2. Steam generator shell side fluid sampling system.
3. Steam generator safety valves.
4. Steam generator power operated relief valves (can be manually operated locally).
5. Refueling Water Storage Tank.
6. Main steam line isolation and bypass valves.
7. Diesel generators and emergency power distribution equipment.
8. Residual Heat Removal System.
9. Pressurizer power operated relief valves.
10. Charging system including pumps and system valves.
11. RCS and steam generator instrumentation including RCS temperature and pressure, pressurizer and SG water level instrumentation.
12. Diesel driven air compressor.

Note: Range of acceptable values are discussed in the recovery procedure.

Table 15.4-29
Parameters Used In Steam Generator Tube Rupture Analysis

Core thermal power	2958 MWt
Steam generator tube leak rate prior to and during accident	1.0 gpm
Offsite power	Lost
Fuel defects	1% for Noble Gases and other nuclides modeled except iodines
Iodine Spiking Basis	Pre-accident / Concurrent
Failed Fuel	0.0
Initial RC Iodine Activities	60 µCi/gm and 1 µCi/gm Dose Equivalent I-131 for Pre-accident /Concurrent Spike
Iodine partition factors in steam generators	100 except for flashed break flow
Time to isolate defective steam generator	30 min
Duration of plant cooldown by secondary system after accident	24 hrs
Steam release from defective steam generator	56,800 lbs (0-30 min)
Steam release from 2 unaffected steam generators	381,400 lbs (0-2 hrs) 924,900 lbs (2-8 hrs) 1,200,000 lbs (8-24 hrs)
Reactor coolant released to defective steam generator	92,900 lbs
Flashed Break Flow	3880 lbs (0-385 sec) 9188 lbs (385 sec-30 min)
Meteorology (Atmospheric Dispersion Factors)*	
Site Boundary	1.25E-04 (0-2 hr)
Low Population Zone	5.97E-05 (0-2 hr) 2.91E-05 (2-8 hr) 2.03E-05 (> 8 hr)

Table 15.4-29 (CONTINUED)
Parameters Used In Steam Generator Tube Rupture Analysis

Control Room	1.50E-3 (0-2 hrs) 1.12E-3 (2-8 hrs) 1.12E-3 (0-8 hrs) 5.24E-3 (8-24 hrs) 3.61E-3 (1-4 days) 2.33E-3 (4-30 days)

*The atmospheric dispersion factors reflect the 2012-2014 monitoring period, and were found to be acceptable because dose values in <hot spots 9 pt>Table 15.4-43 reflect a penalty of + 25%. However, these atmospheric dispersion values may not be considered acceptable for use in other dose assessments or other meteorological applications without further NRC review and approval.

Table 15.4-30
Deleted per RN 16-019
Table 15.4-31
Deleted per RN 16-019
Table 15.4-32
Deleted per RN 16-019

Table 15.4-33
Offsite and Control Room Doses
Steam Generator Tube Rupture Accident

Case	Dose (Rem TEDE) Exclusion Area Boundary (EAB)	Low Population Zone (LPZ)	Control Room (CR)
Pre-existing Iodine Spike	0.85	0.35	1.63
Concurrent Iodine Spike	0.39	0.18	0.63

Table 15.4-34
Summary of Results For Locked Rotor Transient

	Three Loops Operating Initially 1 Locked Rotor
Maximum Reactor Coolant System pressure (psia)	< 2742 (1)
Maximum clad average temperature at core hot spot (°F)	2069 (2)
Amount of Zr-H_20 reaction at core hot spot (% by weight)	1.1(3)

(1) Includes a +41 psi allowance to account for a maximum initial pressurizer level (Reference 63) and a +41 psi allowance to account for the effects of using the PAD5 fuel rod performance code (Reference 68).
(2) Includes a +98°F allowance to account for the effects of using the PAD5 fuel rod performance code (Reference 68).
(3) Includes a +0.6% by weight allowance to account for the effects of using the PAD5 fuel rod performance code (Reference 68).

Table 15.4-34a
Parameters Used In Reactor Coolant Pump
Locked Rotor Accident Analysis

	Realistic Analysis	Conservative Analysis
Core thermal power	2958 MWt	2958 MWt
Steam Generator Tube Leak Rate Prior to Accident and for First Twenty Four Hours Following Accident	100 lbs/day (1)	1.0 gpm
Offsite power	Lost	Lost
Fuel defects	0.12 percent	1 percent
Failed Fuel	0.0	15 percent
Activity Released to Reactor Coolant from Failed Fuel	0.0	15 percent of gap inventory
Iodine and Alkali Metals Partition Factor for Steam Generators	100	100
Duration of Plant Cooldown by Secondary System After Accident	24 hours	24 hours
Steam Release from Three Steam Generators	447,900 lbs (0 - 2 hr) 868,300 lbs (2 - 8 hr) 1,200,000 lbs (8 – 24 hr)	447,900 lbs (0 - 2 hr) 868,300 lbs (2 - 8 hr) 1,200,000 lbs (8 – 24 hr)

Meteorology

The following parameters are common to both cases:

Offsite Atmospheric Dispersion Factors

Time Period	Site Boundary	Low Population Zone
0 - 2 hours	1.24E-04	-
0 - 8 hours		2.42E-05
8 - 24 hours		1.68E-05

(1) American National Standards Institute, “Source Term Specification,” ANS/ANSI 18.1 - 1984.

Table 15.4-34b
Reactor Coolant Pump Locked Rotor
Isotopic Release To Environment Realistic Analysis

	Activity Released to Environment (Ci)	
Isotope	(0 - 2 hr)	(0 - 24 hr)
Kr-85	3.45E-03	4.14E-02
Kr-85m	8.17E-04	9.81E-03
Kr-87	4.99E-04	5.99E-03
Kr-88	1.45E-03	1.74E-02
Rb-86	1.02E-06	6.80E-06
I-131	8.42E-05	5.60E-04
I-132	3.61E-05	2.93E-04
I-133	1.09E-04	7.44E-04
I-134	4.68E-06	4.37E-05
I-135	4.26E-05	3.09E-04
Xe-133	1.32E-01	1.58E+00
Xe-135	3.90E-03	4.69E-02
Cs-134	1.26E-04	8.38E-04
Cs-136	1.27E-04	8.46E-04
Cs-137	6.04E-05	4.00E-04

Table 15.4-34c
Reactor Coolant Pump Locked Rotor Accident
Isotopic Release To Environment Conservative Analysis

	Activity Released to Environment (Ci)	
Isotope	(0 - 2 hr)	(0 - 24 hr)
Kr-85	1.09E+02	1.31E+03
Kr-85m	1.74E+03	2.08E+04
Kr-87	3.17E+03	3.80E+04
Kr-88	4.28E+03	5.14E+04
Rb-86	1.38E-01	1.64E+00
I-131	1.67E+02	2.00E+03
I-132	1.52E+02	1.83E+03
I-133	2.14E+02	2.56E+03
I-134	2.29E+02	2.74E+03
I-135	1.96E+02	2.35E+03
Xe-133	1.10E+04	1.32E+05
Xe-135	2.37E+03	2.84E+04
Cs-134	3.12E+01	3.72E+02
Cs-136	9.77E+00	1.15E+02
Cs-137	1.74E+01	2.08E+02

Table 15.4-34d
Offsite and Control Room (CR) Doses
Reactor Coolant Pump Locked Rotor Accident

	Dose (Rem TEDE)		
Case	EAB	LPZ	CR
Regulatory Guide 1.183 Case	0.67	0.66	2.43
Realistic Case	0.0000008	0.0000007	0.0000032

The dose acceptance criteria provided in 10 CFR 50.67 and Regulatory Guide 1.183 are given as follows:

2.5 Rem TEDE for the EAB and LPZ.

5 Rem TEDE for the CR.

Table 15.4-35
Nuclear Characteristics of Highest Rated Discharged Assembly

Core Power, MWt	2958
Number of Assemblies	157
Core Average Assembly Power at 102% of Full power, MWt	19.22
Highest Power Discharged Assembly	
Axial Peak to Average Ratio	1.70
Radial Peak to Average Ratio	1.70

Table 15.4-36
Activities In Highest Rated Assembly At 100
Hours After Reactor Shutdown

Isotope	Percent of Activity in Gap	Curies in Gap (1)
I-131	0.16	1.38E+05
I-132	0.10	2.01E+01
I-133	0.10	9.01E+03
I-134	0.10	0
I-135	0.10	6.26E+00
Kr-85	0.20	3.37E+03
Kr-85m	0.10	6.05E-03
Kr-87	0.10	0
Kr-88	0.10	2.19E-06
Xe-131m	0.10	1.71E+03
Xe-133	0.10	1.69E+05
Xe-133m	0.10	3.16E+03
Xe-135	0.10	3.23E+02
Xe-135m	0.10	1.07E+00

(1) Gap activity in 314 fuel rods (1.19 assemblies).

Table 15.4-37
Conservative Case Activities In Highest Rated
Assembly At 72 Hours After Reactor Shutdown

Isotope	Percent of Activity in Gap	Curies in Gap (1)
I-131	0,16	1.52E+05
I-132	0.10	9.30E+04
I-133	0.10	2.29E+04
I-134	0.10	0.00E+00
I-135	0.10	1.18E+02
Kr-85	0.20	3.37E+03
Kr-85m	0.10	4.61E-01
Kr-87	0.10	0.00E+00
Kr-88	0.10	2.03E-03
Xe-131m	0.10	1.76E+03
Xe-133	0.10	1.95E+05
Xe-133m	0.10	4.39E+03
Xe-135	0.10	2.55E+03
Xe-135m	0.10	1.92E+01

(1) Gap activity in 314 fuel rods (1.19 assemblies).

Table 15.4-38
Parameters Used To Evaluate the Consequences
Of a Fuel Handling Accident

Parameter	Realistic Analysis	Conservative Regulatory Guide 1.183 Analysis
Time between plant shutdown and accident	100 hours	72 hours
Maximum fuel rod pressurization	≤ 1200 psig	≤ 1200 psig
Minimum water depth between top of damaged fuel rods and spent fuel pool surface	≥ 23 feet	≥ 23 feet
Damaged to fuel assembly	All rods ruptured in 1.19 assemblies	All rods ruptured in 1.19 assemblies
Fuel assembly activity	Highest powered fuel assembly in core region discharged	Highest powered fuel assembly in core region discharged
Activity released to fuel pool	Gap activity in ruptured rods	Gap activity in ruptured rods
Form of iodine activity released from fuel pool		
Elemental Iodine	57%	57%
Organic Iodine	43%	43%
Decontamination factor (DF) in fuel pool		
Iodine	500	500
Noble gases	1	1
Filter efficiencies in Fuel Handling and Reactor Building		
Elemental Iodine	0	0
Methyl Iodine	0	0
Meteorology		

Table 15.4-38 (CONTINUED)
Parameters Used To Evaluate the Consequences
Of a Fuel Handling Accident

The following parameters are common to both cases:

Offsite Atmospheric Dispersion Factors

Time Period	Site Boundary	Low Population Zone
0 - 2	1.24E-04	5.06E-05

Table 15.4-40
Activity Releases To the Environment
From a Fuel Handling Accident

Isotope	Activity Released Conservative (Regulatory Guide 1.183) Case (Curies)	Activity Released Realistic Case Curies
I-131	7.62E+02	2.76E+02
I-132	4.65E+02	4.02E-02
I-133	1.14E+02	1.80E+01
I-134	0	0
I-135	5.90E-01	1.25E-02
Kr-85	3.37E+03	3.37E+03
Kr-85m	4.61E-01	6.05E-03
Kr-87	0	0
Kr-88	2.03E-03	2.19E-06
Xe-131m	1.76E+03	1.71E+03
Xe-133	1.95E+05	1.69E+05
Xe-133m	4.39E+03	3.16E+03
Xe-135	2.55E+03	3.23E+02
Xe-135m	1.92E+01	1.07E+00

Table 15.4-41
Offsite and Control Room (CR) Doses
Fuel Handling Accident Inside Containment

Case	Dose (Rem TEDE)		
	EAB	LPZ	CR
Regulatory Guide 1.183 Case	1.30	0.53	0.76
Realistic Case	0.53	0.21	0.31

The dose acceptance criteria provided in 10 CFR 50.67 and Regulatory Guide 1.183 are given as follows:

6.3 Rem TEDE for the EAB and LPZ.

5 Rem TEDE for the CR.

Table 15.4-42
Parameters Used in the Analysis of the Rod
Cluster Control Assembly Ejection Accident

Time in Life	Beginning	Beginning	End	End
Power level,%	102	0.0	102	0.0
Ejected rod worth, Δk	0.20	0.855	0.21	0.91
Delayed neutron fraction,%	0.54	0.54	0.44	0.44
Feedback reactivity weighting	1.173	2.308	1.232	3.275
Trip reactivity, Δk	4	2	4	2
FQ before rod ejection	2.597	-	2.597	-
FQ after rod ejection	4.5	13	5.0	22.5
Number of operating pumps	3	2	3	2
Maximum fuel pellet average temperature, °F	4033	3815	4001	3849
Maximum fuel center temperature, °F	*	4468	*	4402
Maximum clad average temperature, °F	2158	2680	2136	2839
Maximum fuel stored energy, cal/gm	176.2	164.9	174.5	166.7

*Less than 10% fuel melt.

Table 15.4-43
Parameters Used In Rod Ejection Accident Analysis

Parameter	Conservative Case Containment Release Path	Conservative Case Steam Generator Release Path	Realistic Case
Core Thermal Power	2958 MWt	2958 MWt	2958 MWt
Fuel Defects	1%	1%	0.12%
Fuel Damaged			0
Activity Available for Release from Containment	Table 15.4-45	Table 15.4-46	Table 15.4-44
Form of Iodine Release			
Particulate Iodine	95% as Csl	0%	95% as Csl
Elemental Iodine	4.85%	97%	4.85%
Organic Iodine	0.15%	3%	0.15%
Containment Leak Rate	0.2% per day (0-24 hours) 0.1% per day (1-30 days)	N/A	0.2% per day (0-24 hr) 0.1% per day (1-30 days)
SG Release Rate	N/A	447,900 lbs (0-2 hours) 868,300 lbs (2-8 hours) 1,200,000 lbs (8-24 hours)	N/A

Table 15.4-43 (CONTINUED)
Parameters Used In Rod Ejection Accident Analysis

The following parameters are common to the above cases:

Offsite Atmospheric Dispersion Factors

Time Period	Site Boundary	Low Population Zone
0 - 2 hours	1.24E-04	-
0 - 8 hours		2.42E-05
2 - 8 hours		-
8 - 24 hours		1.68E-05
1 - 4 days		7.55E-06
4 - 30 days		2.40E-06

Table 15.4-44
Control Rod Ejection Accident Isotopic
Release to Containment Realistic Analysis

Isotope	Activity Released to Containment (Ci)
Kr-85	1.66E+02
Kr-85m	3.92E+01
Kr-87	2.40E+01
Kr-88	6.97E+01
Rb-86	7.85E-01
I-131	6.54E+01
I-132	6.76E+01
I-133	1.00E+02
I-134	1.31E+01
I-135	5.23E+01
Xe-133	6.32E+03
Xe-135	1.87E+02
Cs-134	9.59E+01
Cs-136	9.81E+01
Cs-137	4.58E+01

Table 15.4-45
Control Rod Ejection Accident Isotopic
Release to Containment Conservative Analysis

Isotope	Activity Released to Containment (Ci)
Kr-85	3.31E+04
Kr-85m	1.04E+06
Kr-87	1.90E+06
Kr-88	2.57E+06
Rb-86	1.87E+03
I-131	2.88E+06
I-132	4.21E+06
I-133	5.89E+06
I-134	6.31E+06
I-135	5.40E+06
Xe-133	6.56E+06
Xe-135	1.42E+06
Cs-134	4.26E+05
Cs-136	1.30E+05
Cs-137	2.39E+05

Table 15.4-46
Control Rod Ejection Accident Isotopic Release To
Steam Generator Conservative Analysis

	Activity Released to Environment (Ci)	
Isotope	(0 - 2 hr)	(0 - 24 hr)
Kr-85	8.29E+01	9.95E+02
Kr-85m	2.60E+03	3.13E+04
Kr-87	4.75E+03	5.70E+04
Kr-88	6.42E+03	7.71E+04
Rb-86	9.78E-02	1.16E+00
I-131	1.48E+02	1.77E+03
I-132	2.16E+02	2.59E+03
I-133	3.02E+02	3.63E+03
I-134	3.24E+02	3.89E+03
I-135	2.77E+02	3.33E+03
Xe-133	1.64E+04	1.97E+05
Xe-135	3.55E+03	4.25E+04
Cs-134	2.20E+01	2.62E+02
Cs-136	6.96E+00	8.14E+01
Cs-137	1.23E+01	1.46E+02

Table 15.4-47
Offsite and Control Room (CR) Doses
Control Rod Ejection Accident

Case	Dose (Rem TEDE)		
	EAB	LPZ	CR
Regulatory Guide 1.183 Containment Release	1.31	1.46	1.71
Regulatory Guide 1.183 SG PORV Release	0.77	0.68	2.38
Realistic Containment Release	0.000072	0.000091	0.000108

The dose acceptance criteria provided in 10 CFR 50.67 and Regulatory Guide 1.183 are given as follows:

6.3 Rem TEDE for the EAB and LPZ.

5 Rem TEDE for the CR.

Table 15.4-50
Offsite and Control Room (CR) Doses
Fuel Handling Accident Outside Containment

	Dose (Rem TEDE)		
Case	EAB	LPZ	CR
Regulatory Guide 1.183 Case	1.30	0.53	0.41
Realistic Case	0.53	0.21	0.17

The dose acceptance criteria provided in 10 CFR 50.67 and Regulatory Guide 1.183 are given as follows:

6.3 Rem TEDE for the EAB and LPZ.

5 Rem TEDE for the CR.

Figure 15.4-1a
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Figure 15.4-1b
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Figure 15.4-1c
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Figure 15.4-1d
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Figure 15.4-1e
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Figure 15.4-1f
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Figure 15.4-1g
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Figure 15.4-1h
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Figure 15.4-1i
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Figure 15.4-1j
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Figure 15.4-1k
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Figure 15.4-11
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Figure 15.4-1m
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Figure 15.4-1n
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Figure 15.4-1o
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Figure 15.4-1p
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Figure 15.4-1q
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Figure 15.4-1
V.C. SUMMER BREAK FLOW VOID FRACTION FOR THE REGION I ANALYSIS PCT CASE

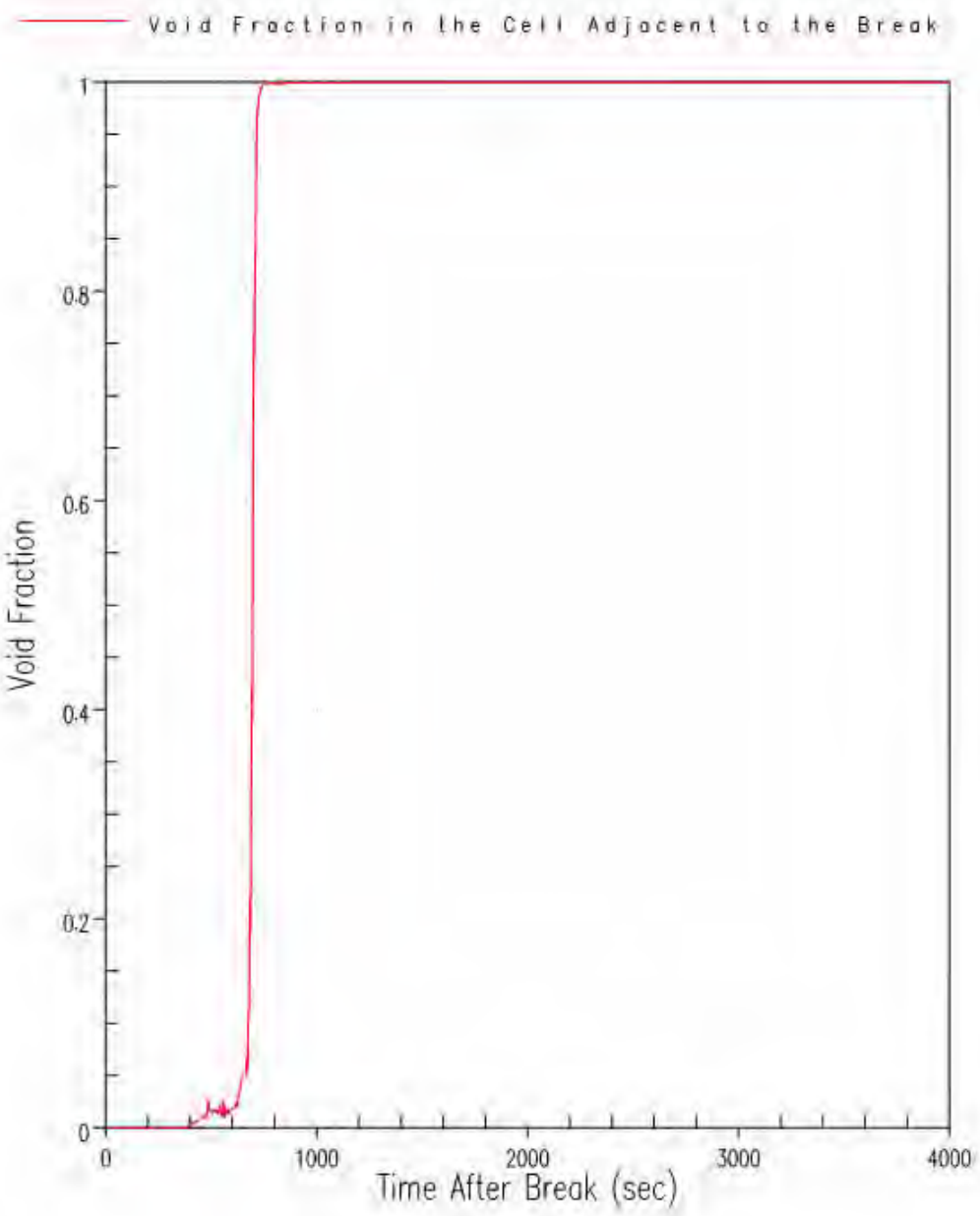


Figure 15.4-1: V.C. Summer Break Flow Void Fraction for the Region I Analysis PCT Case

Figure 15.4-2

V.C. SUMMER TOTAL SAFETY INJECTION FLOW (NOT INCLUDING ACCUMULATOR FLOW) AND TOTAL BREAK FLOW FOR THE REGION I ANALYSIS PCT CASE

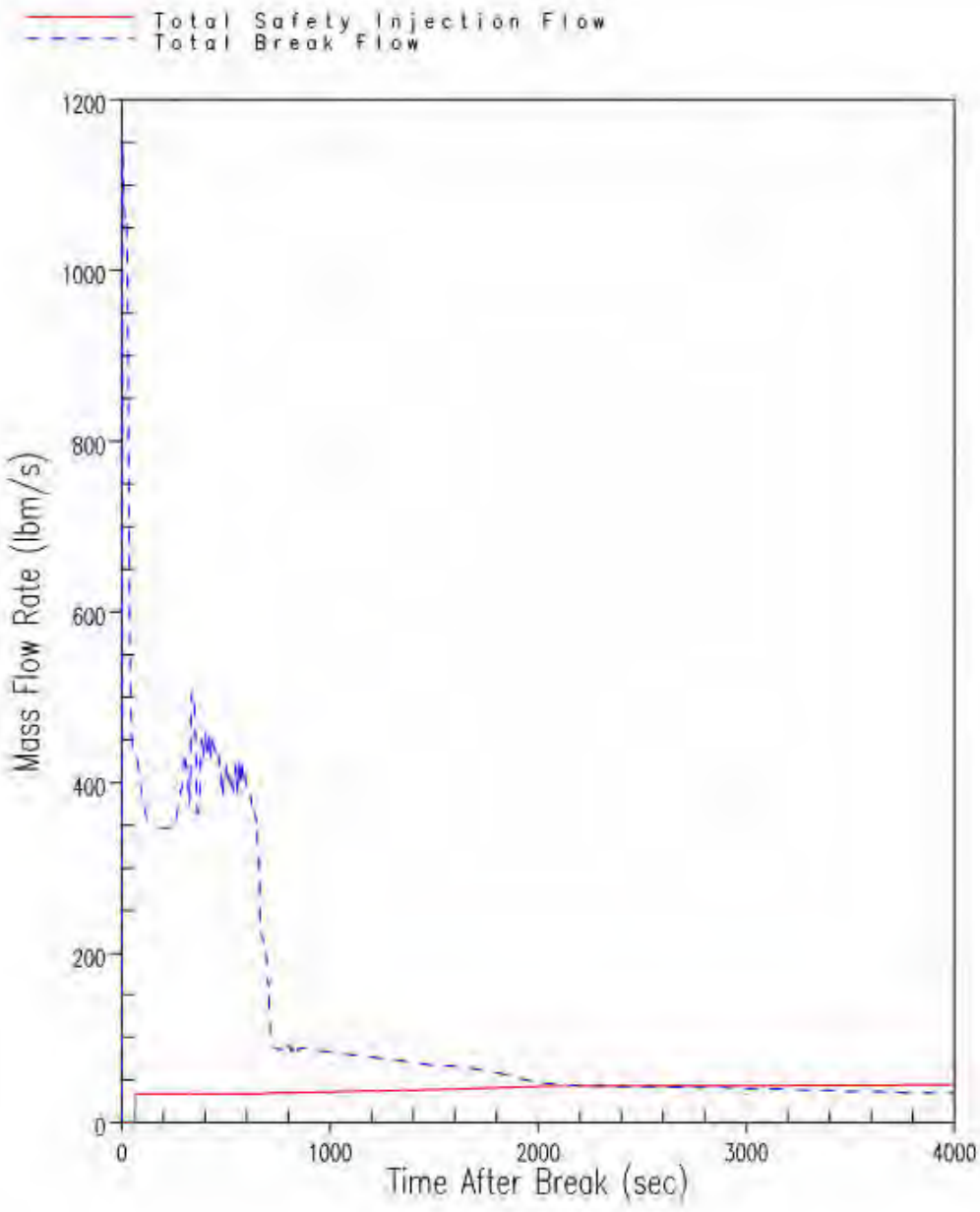


Figure 15.4-2: V.C. Summer Total Safety Injection Flow (not Including Accumulator Flow) and Total Break Flow for the Region I Analysis PCT Case

Figure 15.4-3

V.C. SUMMER RCS PRESSURE FOR THE REGION I ANALYSIS PCT CASE

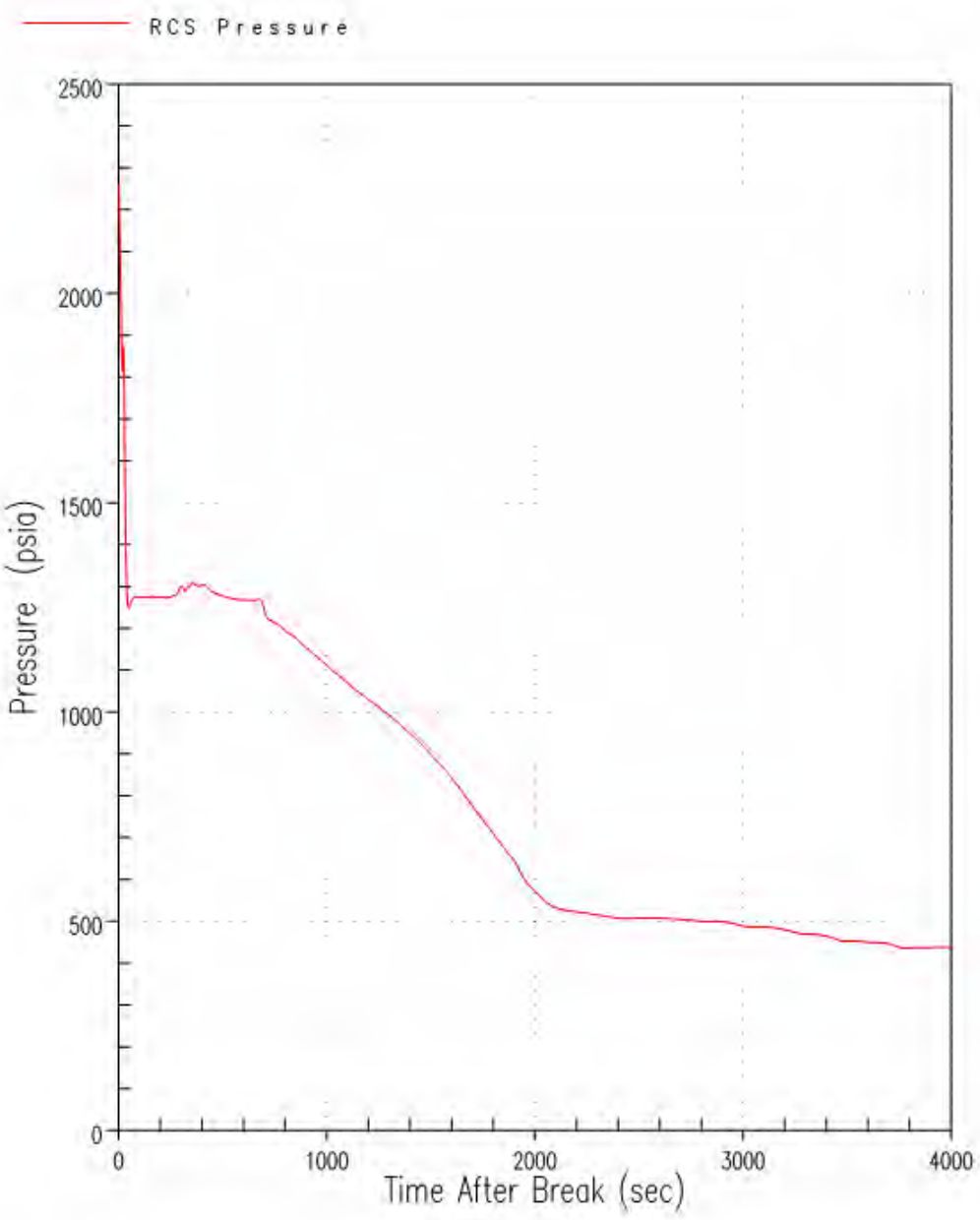


Figure 15.4-3: V.C. Summer RCS Pressure for the Region I Analysis PCT Case

Figure 15.4-4
V.C. SUMMER HOT ASSEMBLY TWO-PHASE MIXTURE LEVEL

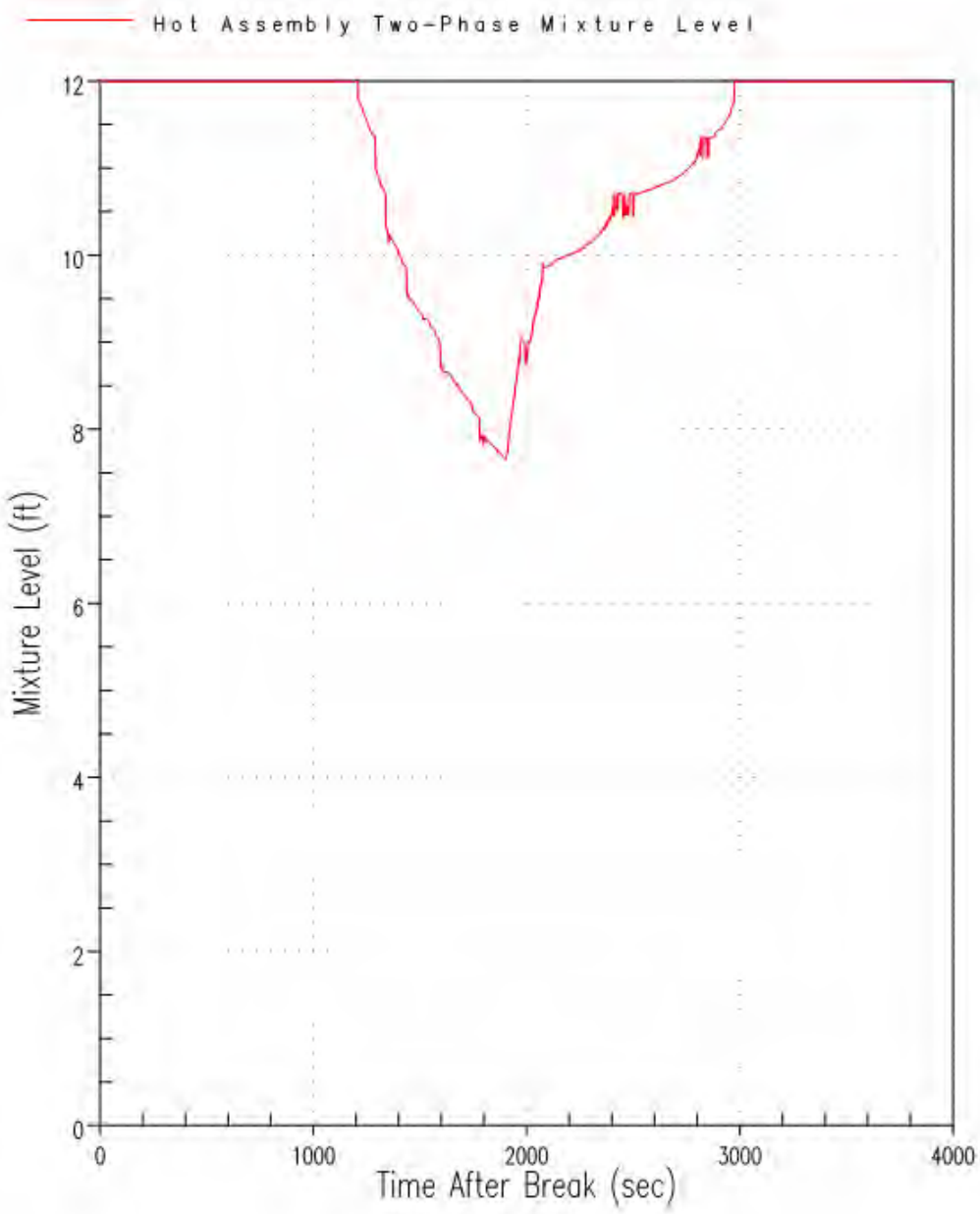


Figure 15.4-4: V.C. Summer Hot Assembly Two-Phase Mixture Level (Relative to Bottom of Active Fuel) for the Region I Analysis PCT Case

Figure 15.4-5
V.C. SUMMER PEAK CLADDING TEMPERATURE FOR ALL RODS FOR THE REGION I ANALYSIS PCT CASE

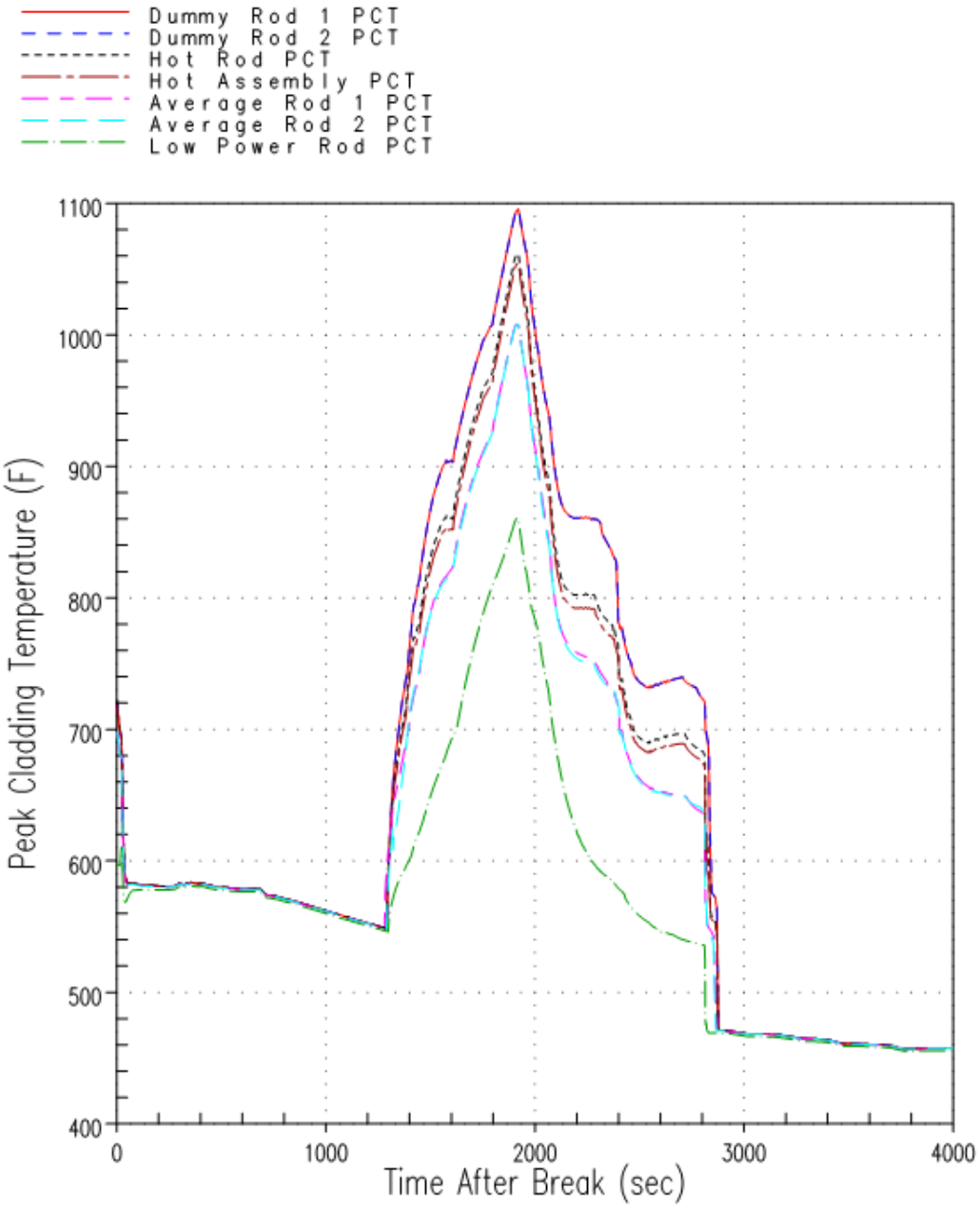


Figure 15.4-5: V.C. Summer Peak Cladding Temperature for all Rods for the Region I Analysis PCT Case

Figure 15.4-6

V.C. SUMMER VAPOR MASS FLOW RATE THROUGH THE CROSSOVER LEGS FOR THE REGION I ANALYSIS PCT CASE

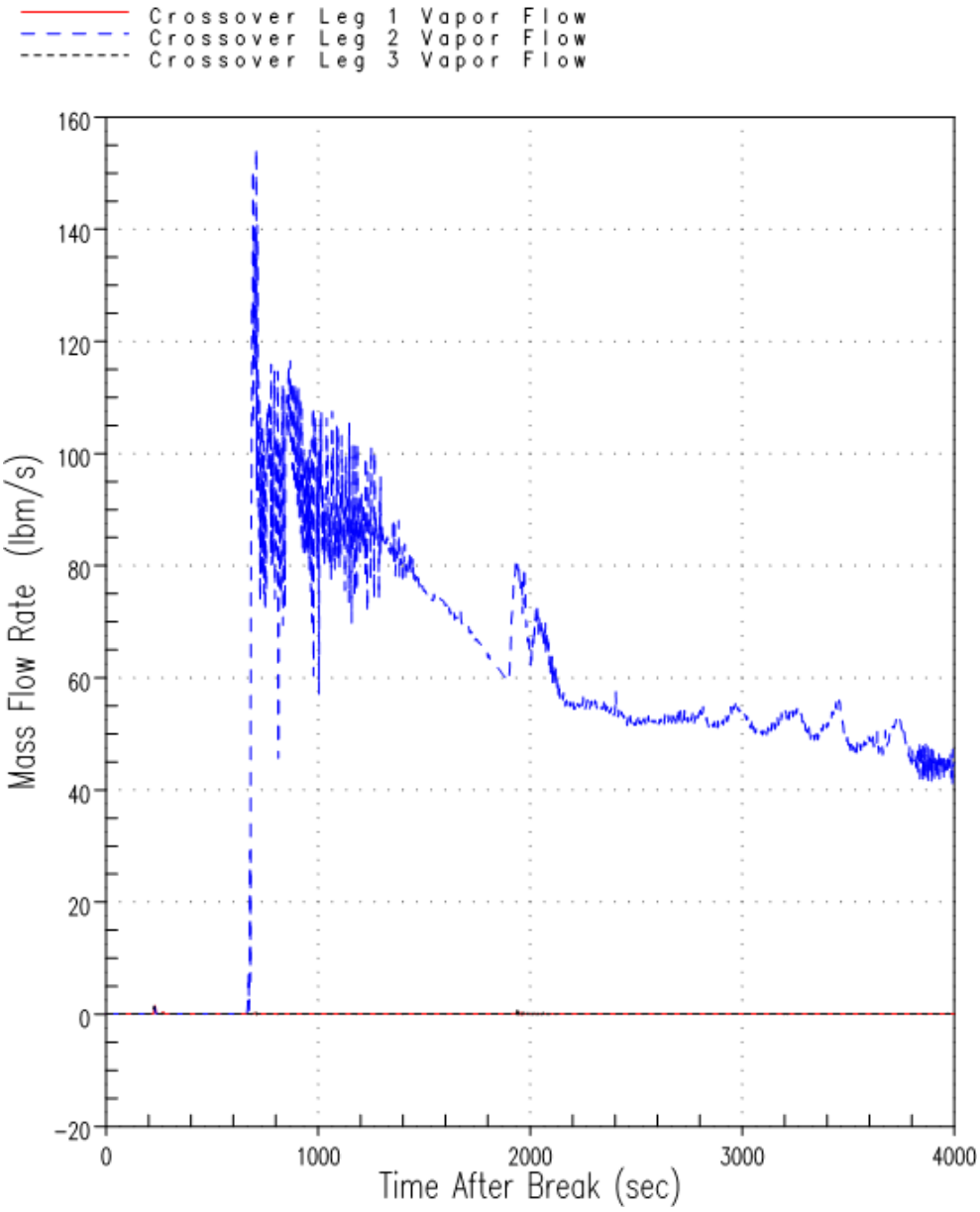


Figure 15.4-6: V.C. Summer Vapor Mass Flow Rate through the Crossover Legs for the Region I Analysis PCT Case

Figure 15.4-7
V.C. SUMMER CORE COLLAPSED LIQUID LEVELS

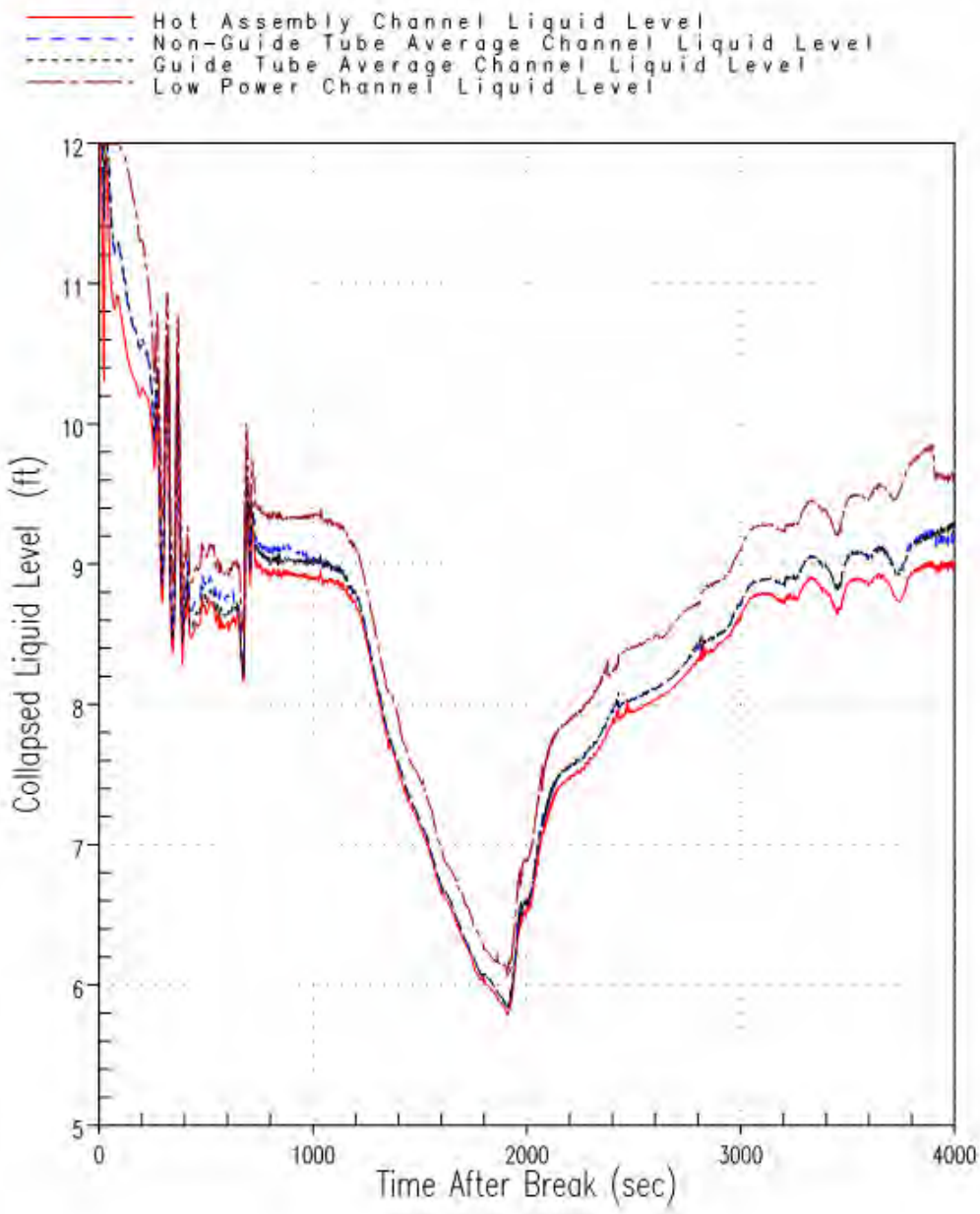


Figure 15.4-7: V.C. Summer Core Collapsed Liquid Levels (Relative to Bottom of Active Fuel) for the Region I Analysis PCT Case

Figure 15.4-8
V.C. SUMMER ACCUMULATOR INJECTION FLOW FOR THE REGION I ANALYSIS PCT CASE

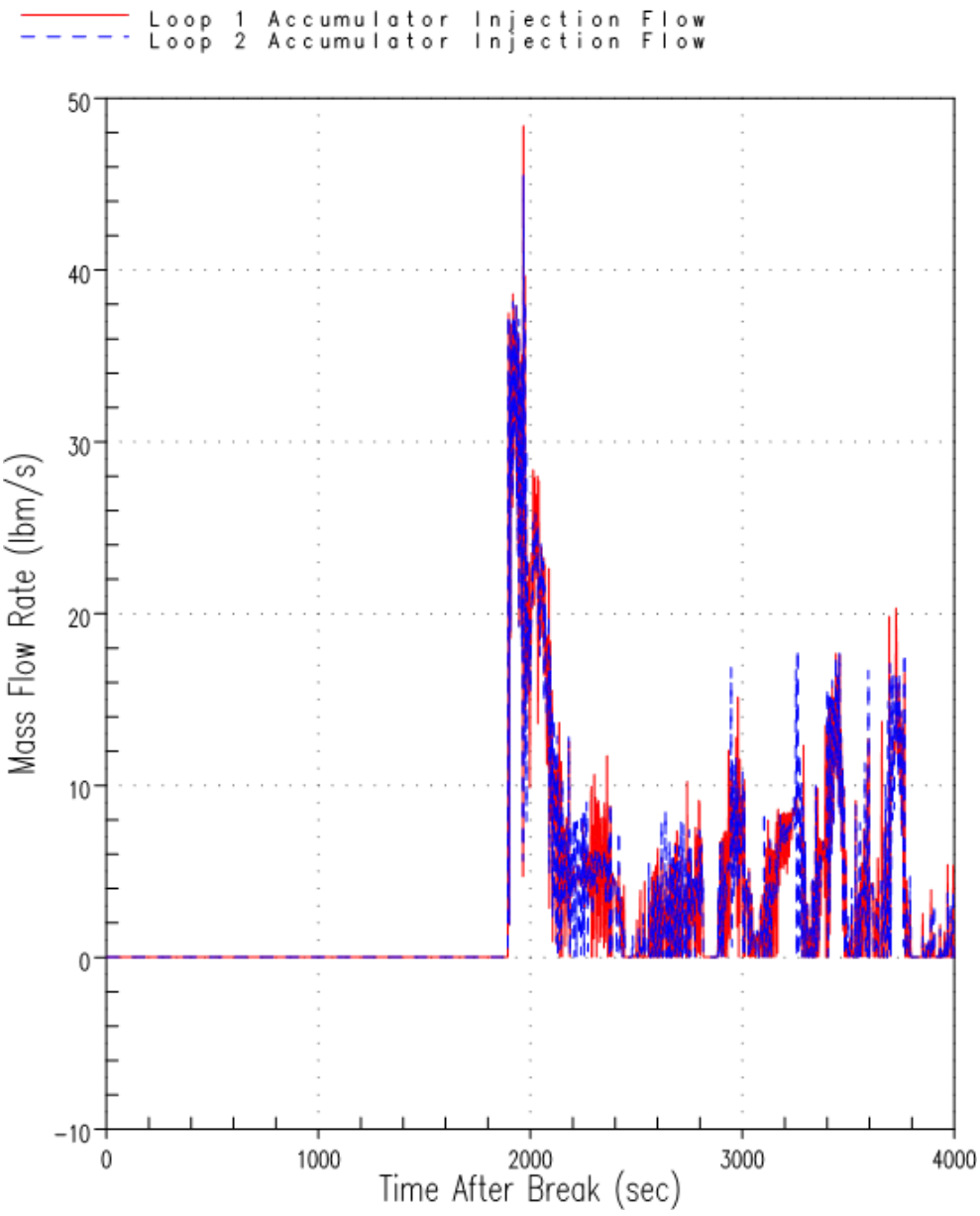


Figure 15.4-8: V.C. Summer Accumulator Injection Flow for the Region I Analysis PCT Case

Figure 15.4-9
V.C. SUMMER VESSEL FLUID MASS FOR THE REGION I ANALYSIS PCT CASE

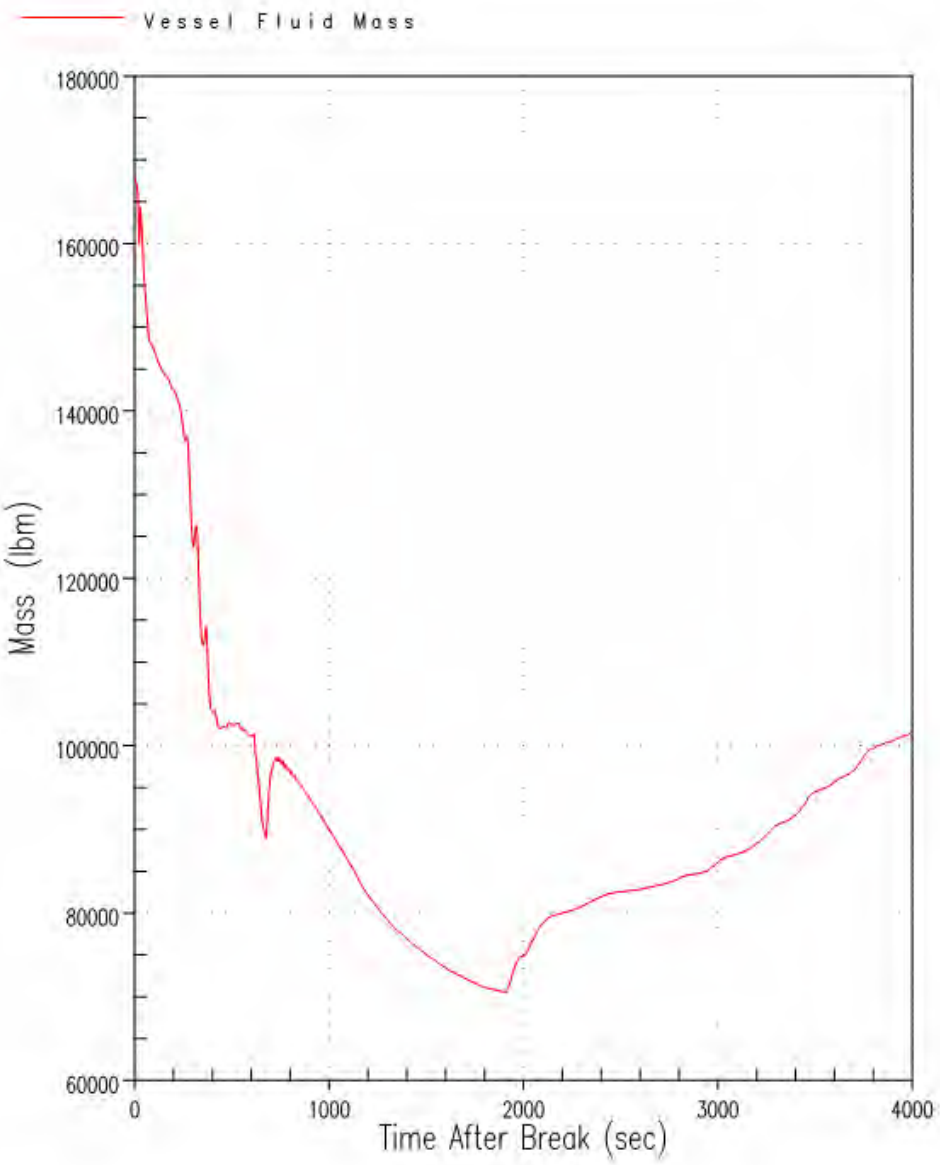


Figure 15.4-9: V.C. Summer Vessel Fluid Mass for the Region I Analysis PCT Case

Figure 15.4-10

V.C. SUMMER STEAM GENERATOR SECONDARY SIDE PRESSURE FOR THE REGION I ANALYSIS PCT CASE

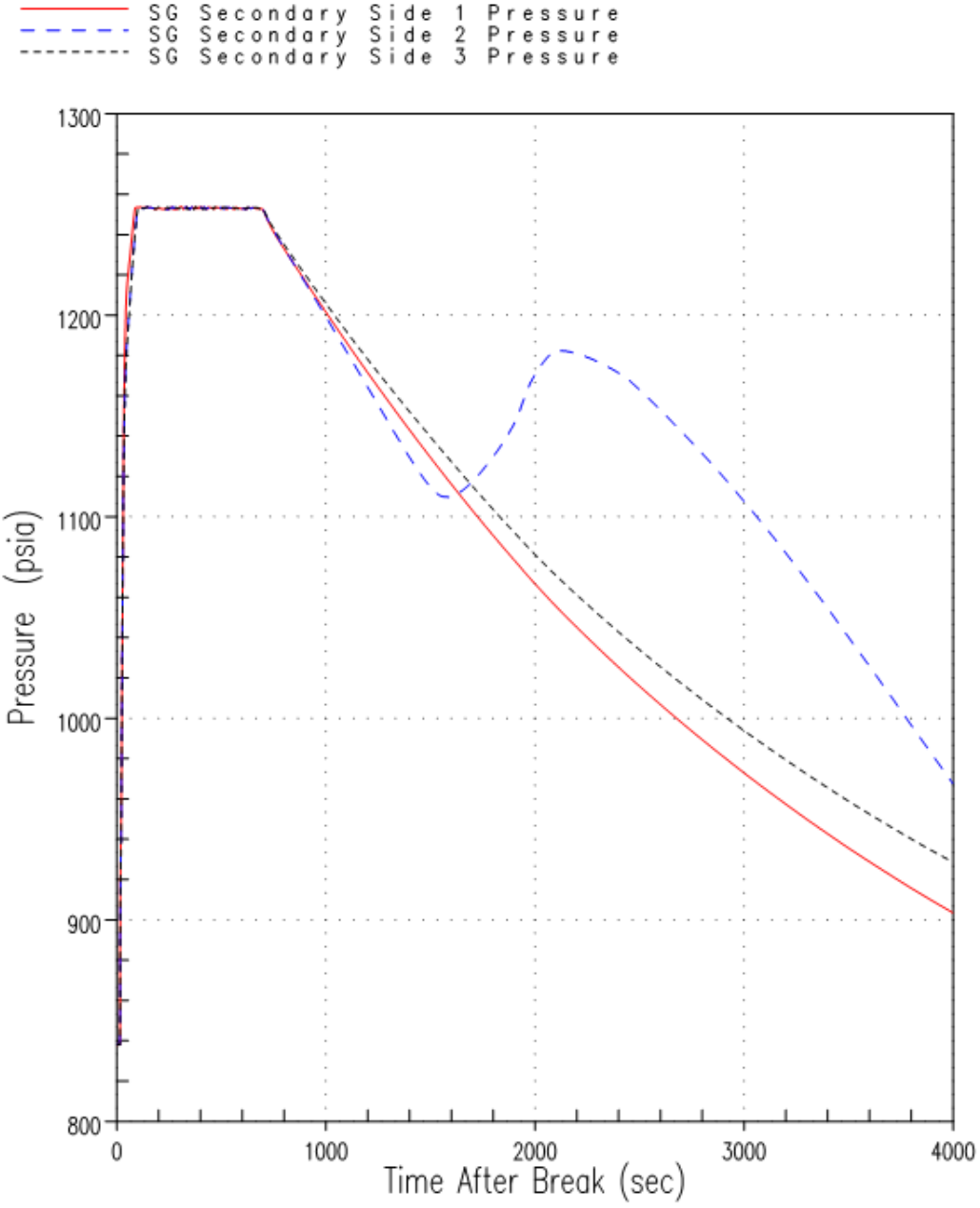


Figure 15.4-10: V.C. Summer Steam Generator Secondary Side Pressure for the Region I Analysis PCT Case

Figure 15.4-11
V.C. SUMMER NORMALIZED CORE POWER SHAPES FOR THE REGION I ANALYSIS PCT CASE

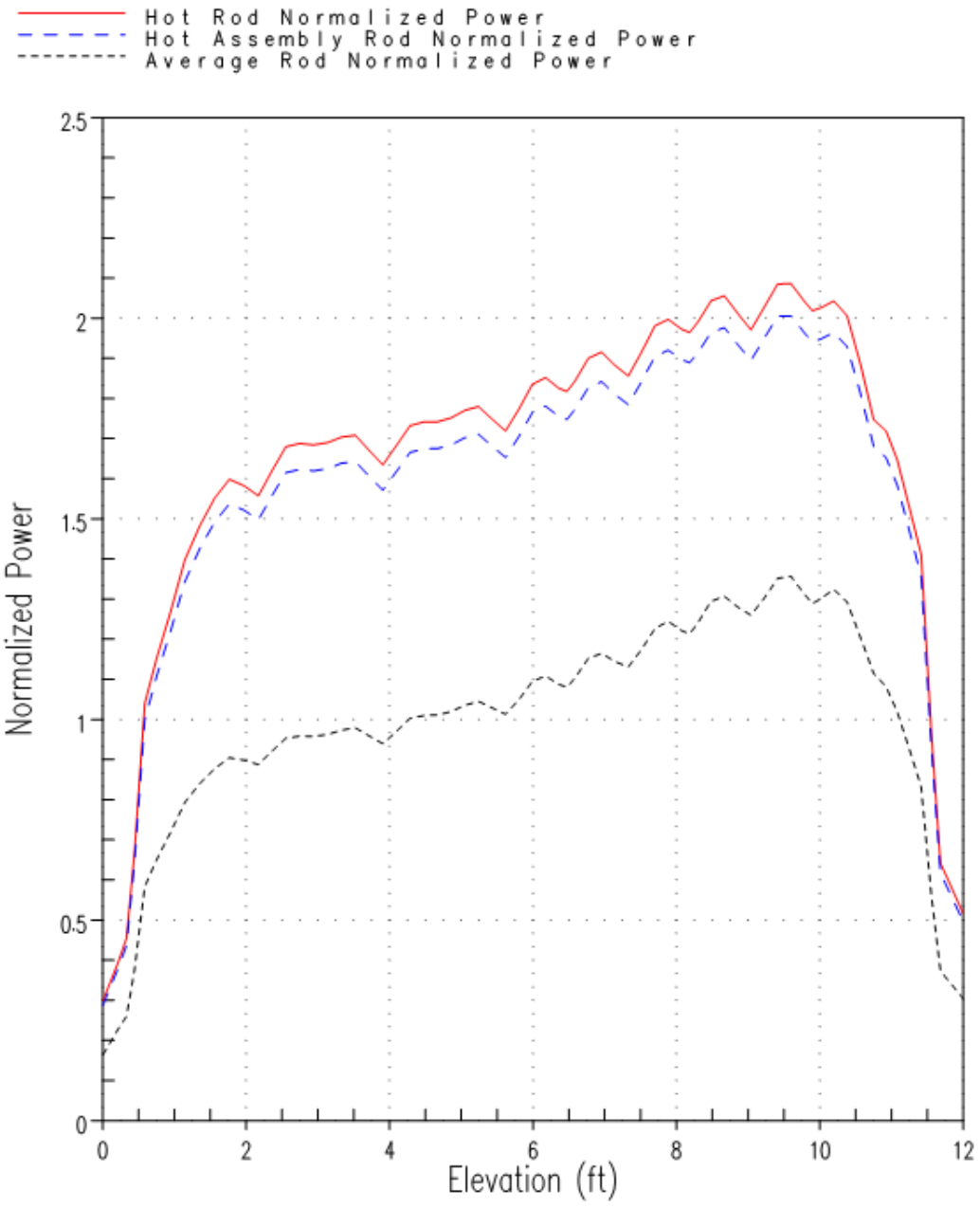


Figure 15.4-11: V.C. Summer Normalized Core Power Shapes for the Region I Analysis PCT Case

Note: The localized power decreases occur at grid elevations.

Figure 15.4-12
V.C. SUMMER RELATIVE CORE POWER FOR THE REGION I ANALYSIS PCT CASE

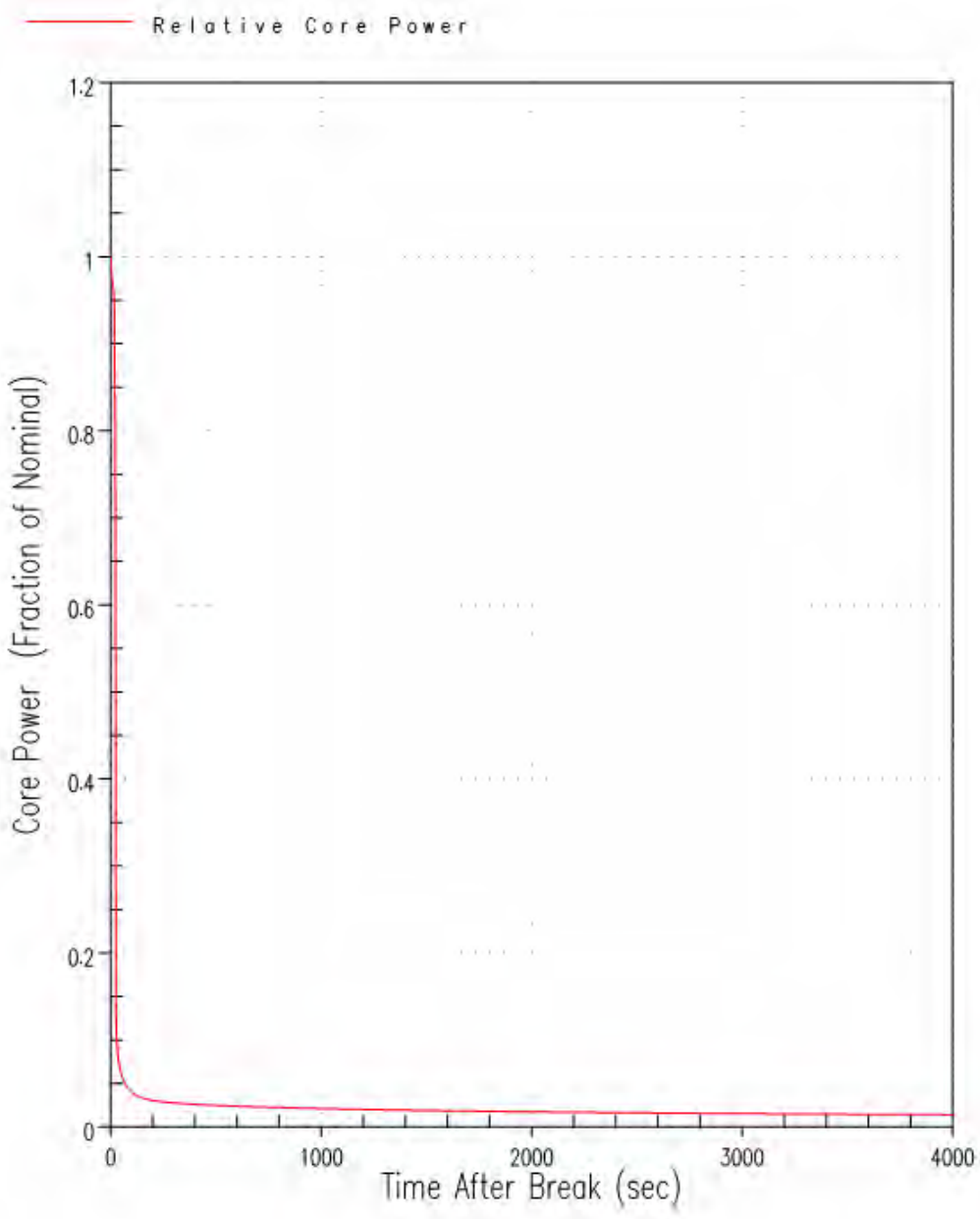


Figure 15.4-12: V.C. Summer Relative Core Power for the Region I Analysis PCT Case

Figure 15.4-13

V.C. SUMMER VAPOR TEMPERATURE AND VOID FRACTION AT CORE OUTLET FOR THE REGION I ANALYSIS PCT CASE

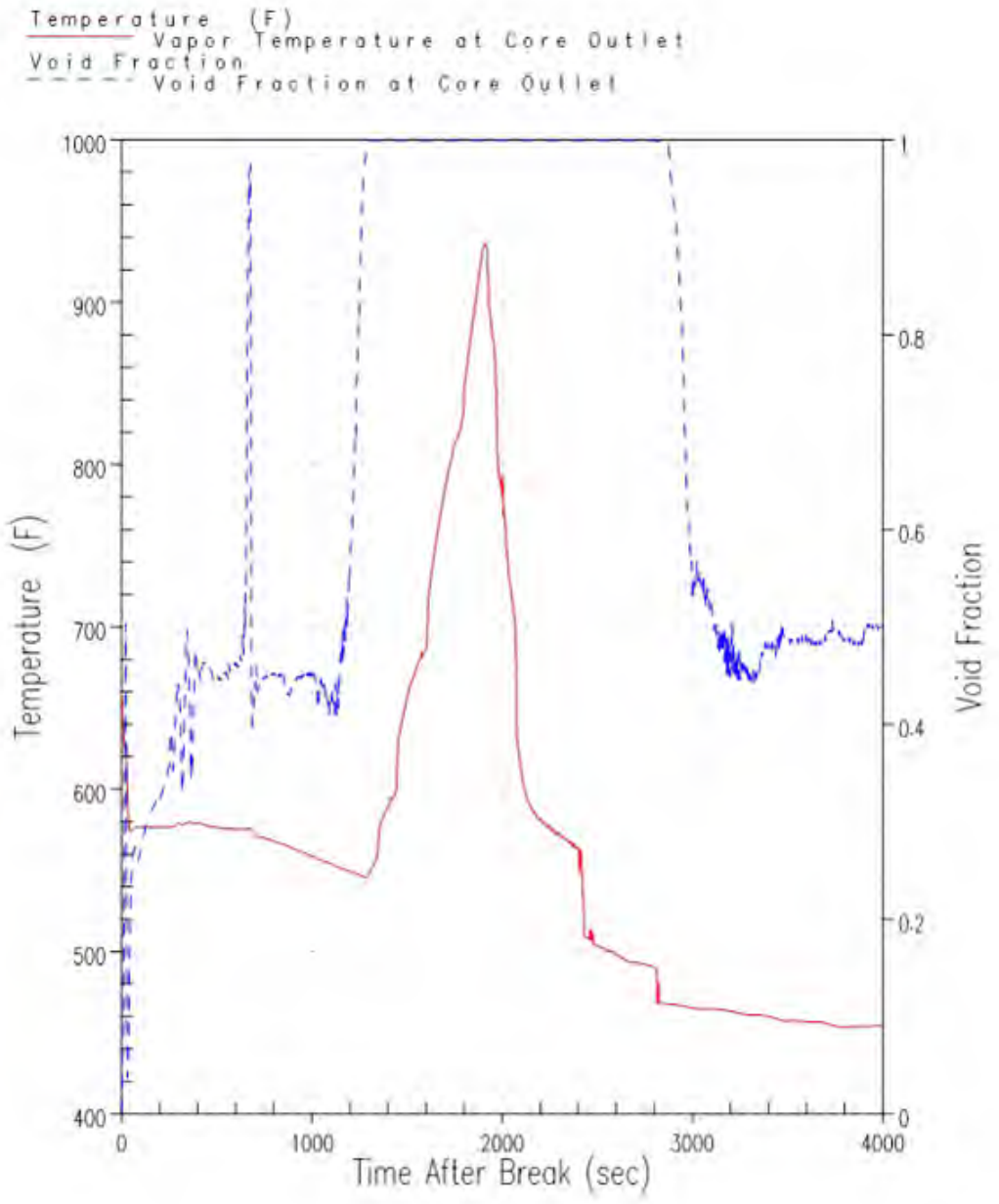


Figure 15.4-13: V.C. Summer Vapor Temperature and Void Fraction at Core Outlet for the Region I Analysis PCT Case

Figure 15.4-14
V.C. SUMMER PEAK CLADDING TEMPERATURE FOR ALL RODS FOR THE REGION II ANALYSIS PCT CASE

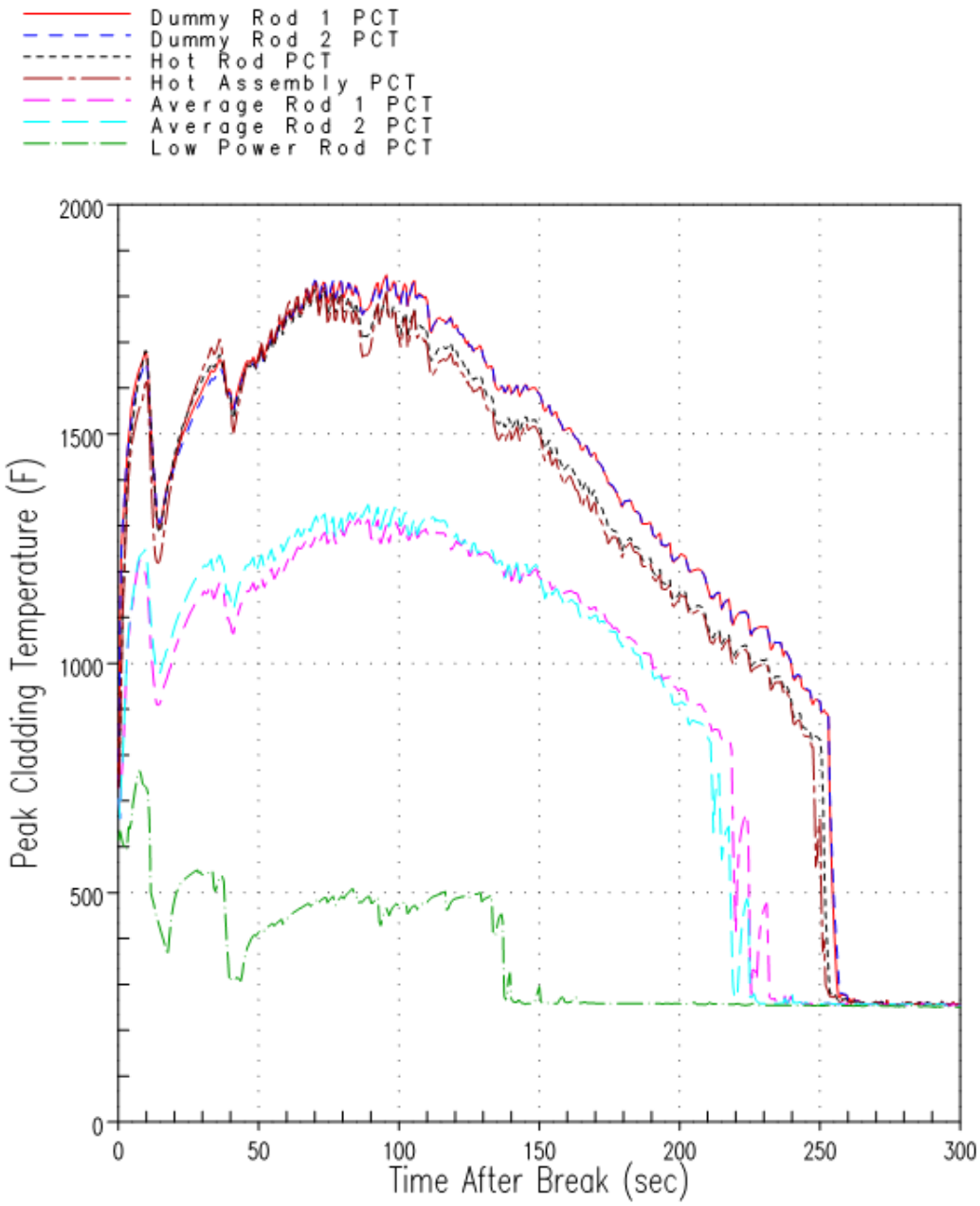


Figure 15.4-14: V.C. Summer Peak Cladding Temperature for all Rods for the Region II Analysis PCT Case

Figure 15.4-15
V.C. SUMMER PEAK CLADDING TEMPERATURE ELEVATION

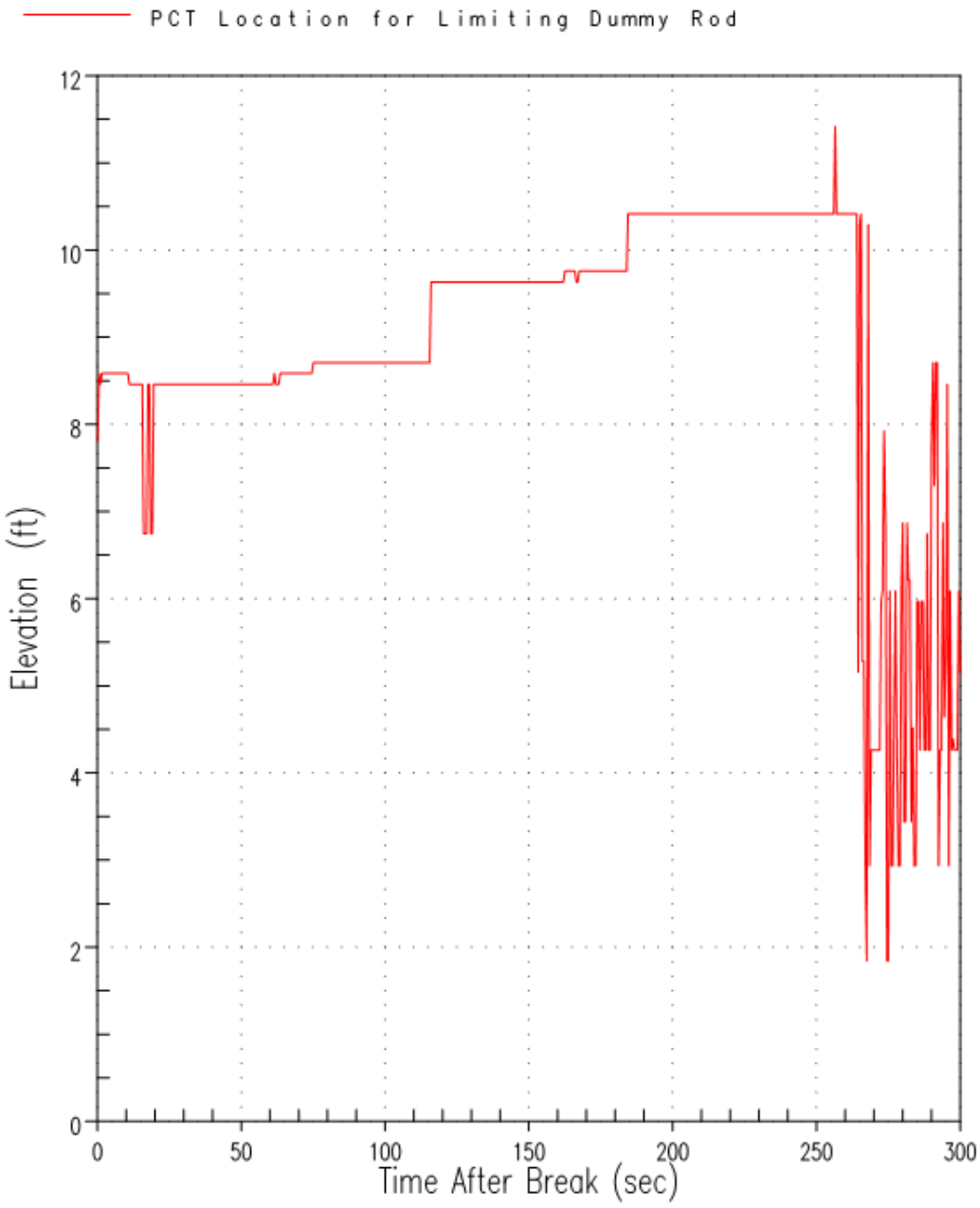


Figure 15.4-15: V.C. Summer Peak Cladding Temperature Elevation (Relative to Bottom of Active Fuel) for the Region II Analysis PCT Case

Figure 15.4-16a
V.C. SUMMER VESSEL-SIDE BREAK MASS FLOW RATE FOR THE REGION II ANALYSIS PCT CASE

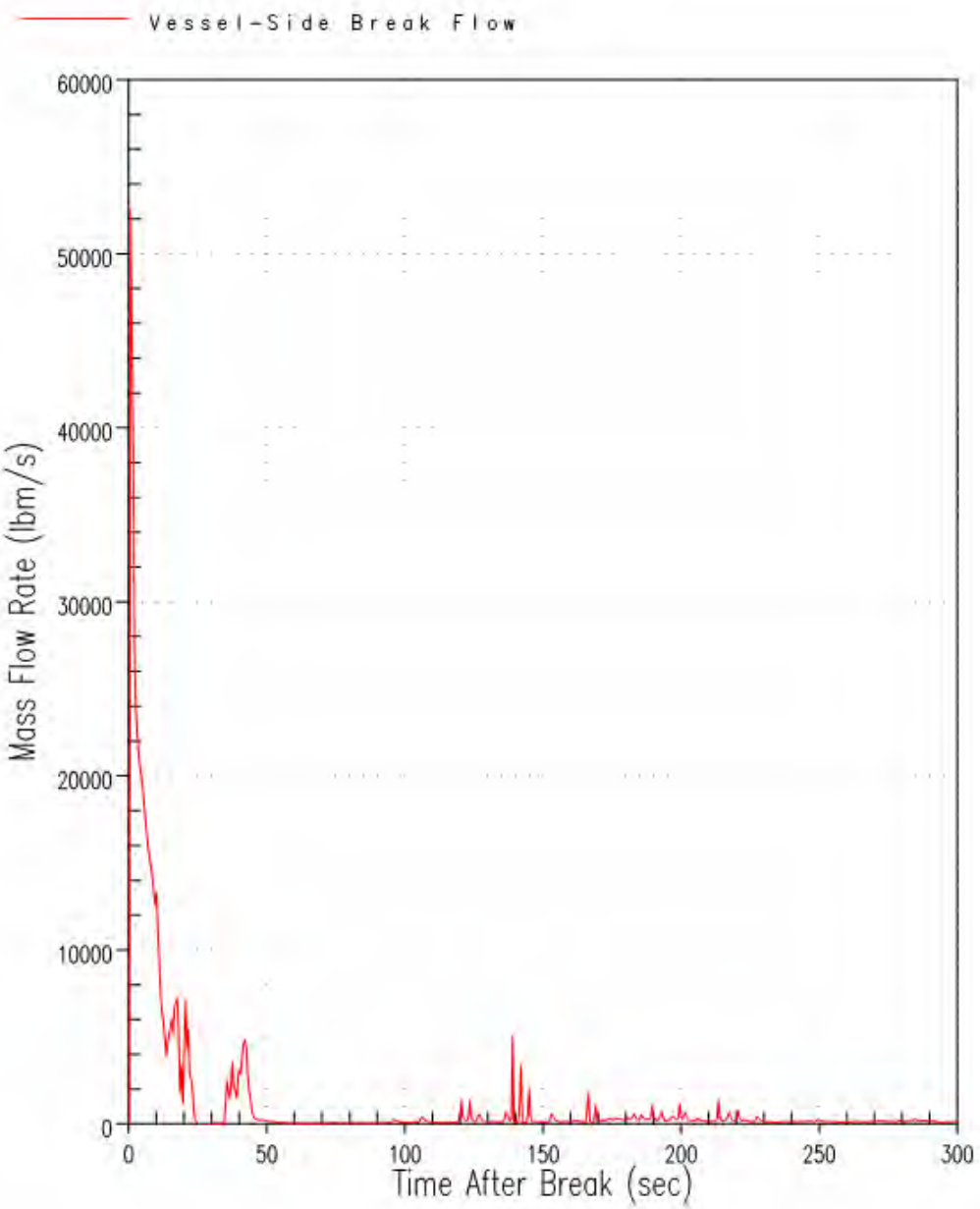


Figure 15.4-16a: V.C. Summer Vessel-Side Break Mass Flow Rate for the Region II Analysis PCT Case

Figure 15.4-16b
V.C. SUMMER PUMP-SIDE BREAK MASS FLOW RATE FOR THE REGION II ANALYSIS PCT CASE

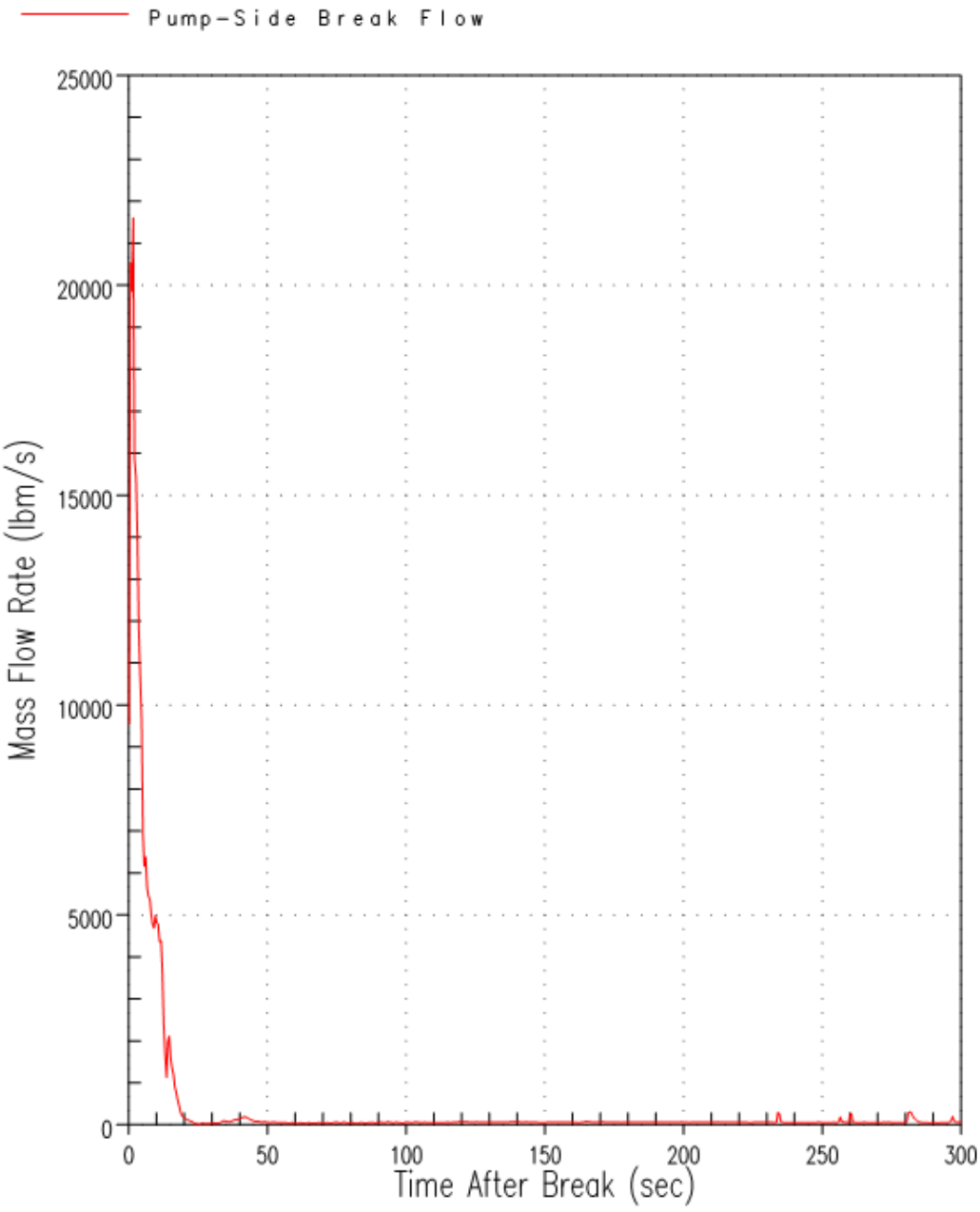


Figure 15.4-16b: V.C. Summer Pump-Side Break Mass Flow Rate for the Region II Analysis PCT Case

Figure 15.4-17
V.C. SUMMER LOWER PLENUM COLLAPSED LIQUID LEVEL

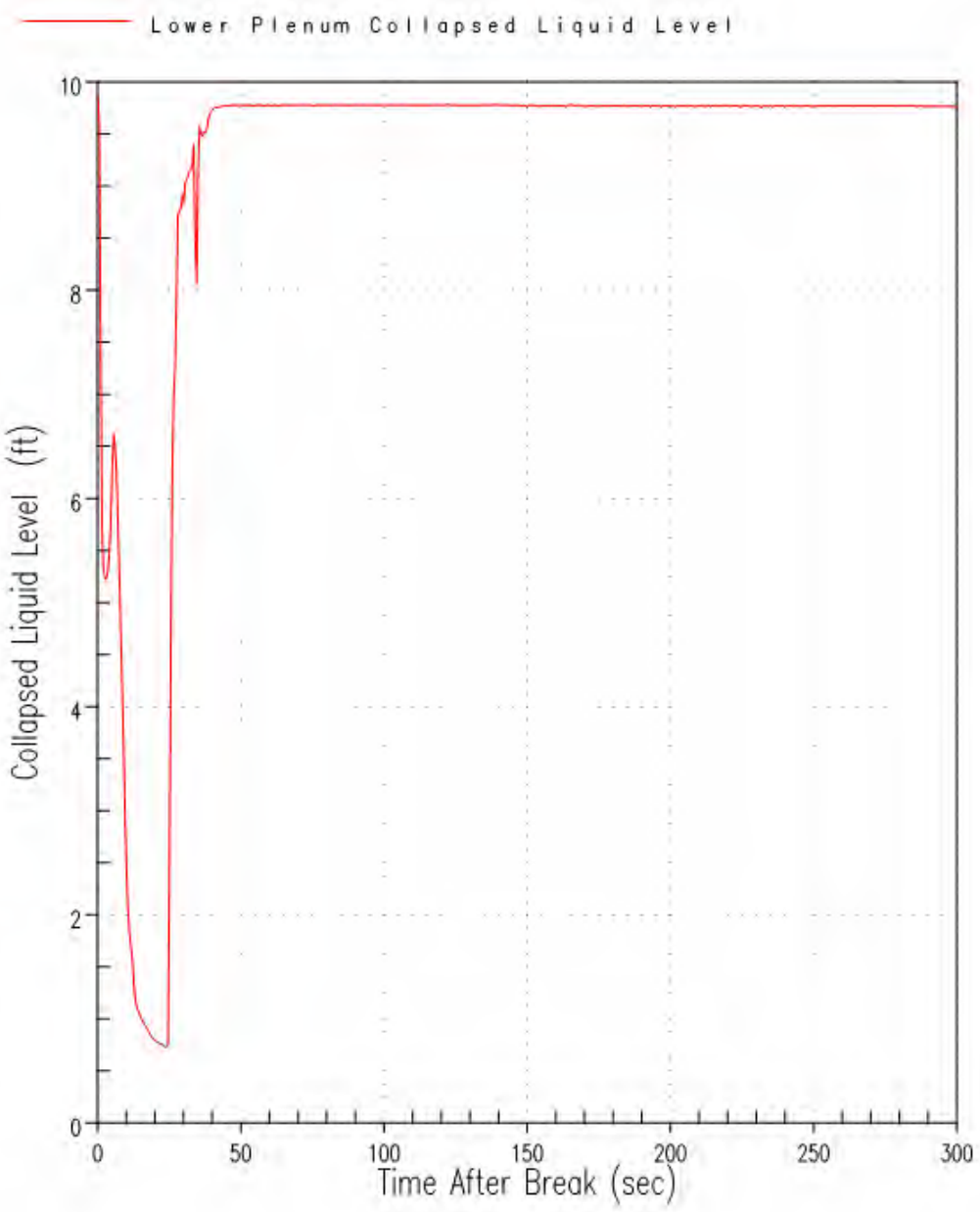


Figure 15.4-17: V.C. Summer Lower Plenum Collapsed Liquid Level (Relative to Inside Bottom of Vessel) for the Region II Analysis PCT Case

Figure 15.4-18
V.C. SUMMER VAPOR MASS FLOW RATE AT THE TOP CELL FACE OF THE CORE AVERAGE CHANNEL NOT UNDER GUIDE TUBES FOR THE REGION II ANALYSIS PCT CASE

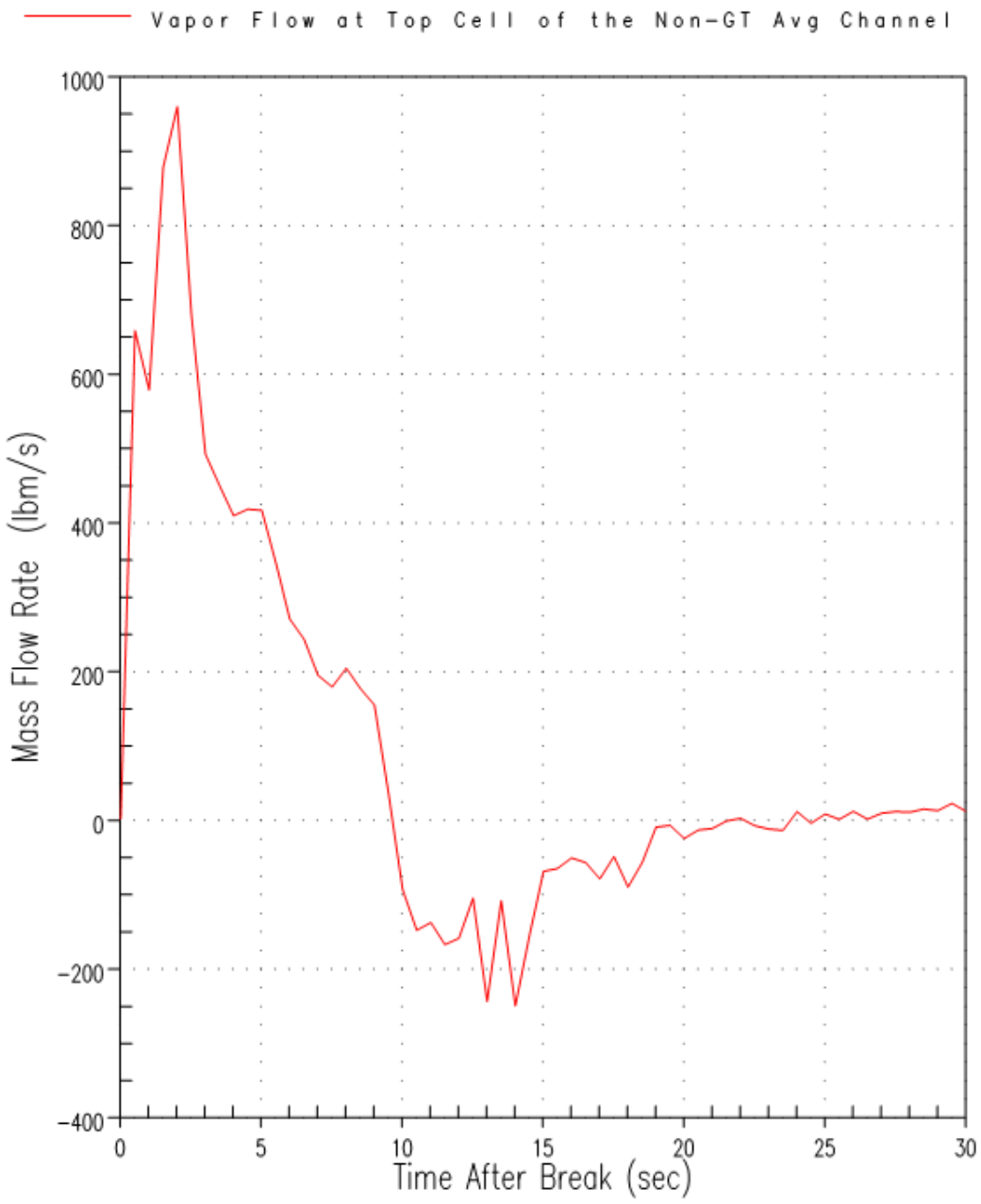


Figure 15.4-18: V.C. Summer Vapor Mass Flow Rate at the Top Cell Face of the Core Average Channel not Under Guide Tubes for the Region II Analysis PCT Case

Figure 15.4-19

V.C. SUMMER RCS PRESSURE FOR THE REGION II ANALYSIS PCT CASE

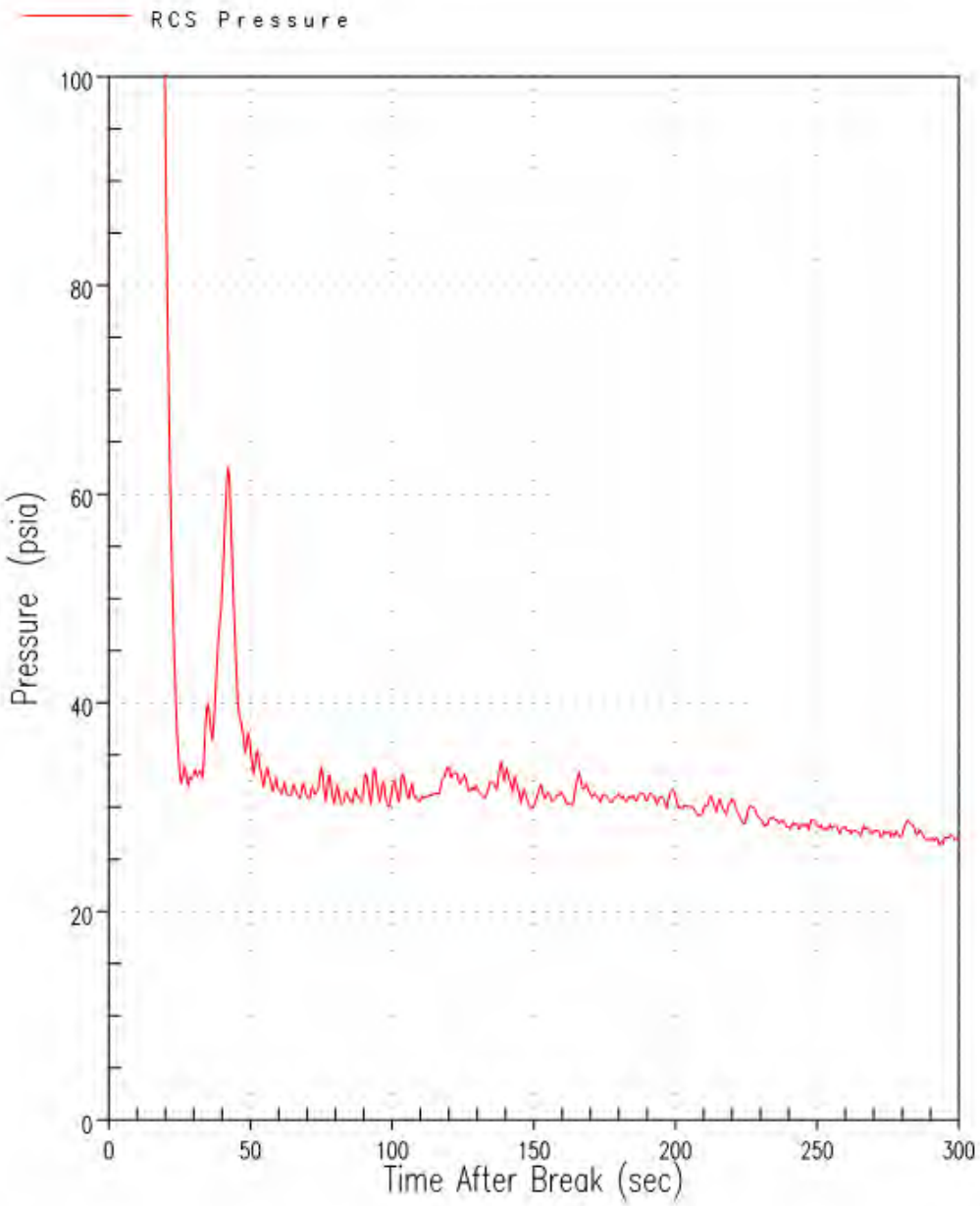


Figure 15.4-19: V.C. Summer RCS Pressure for the Region II Analysis PCT Case

Figure 15.4-20
V.C. SUMMER ACCUMULATOR INJECTION FLOW PER LOOP FOR THE REGION II ANALYSIS PCT CASE

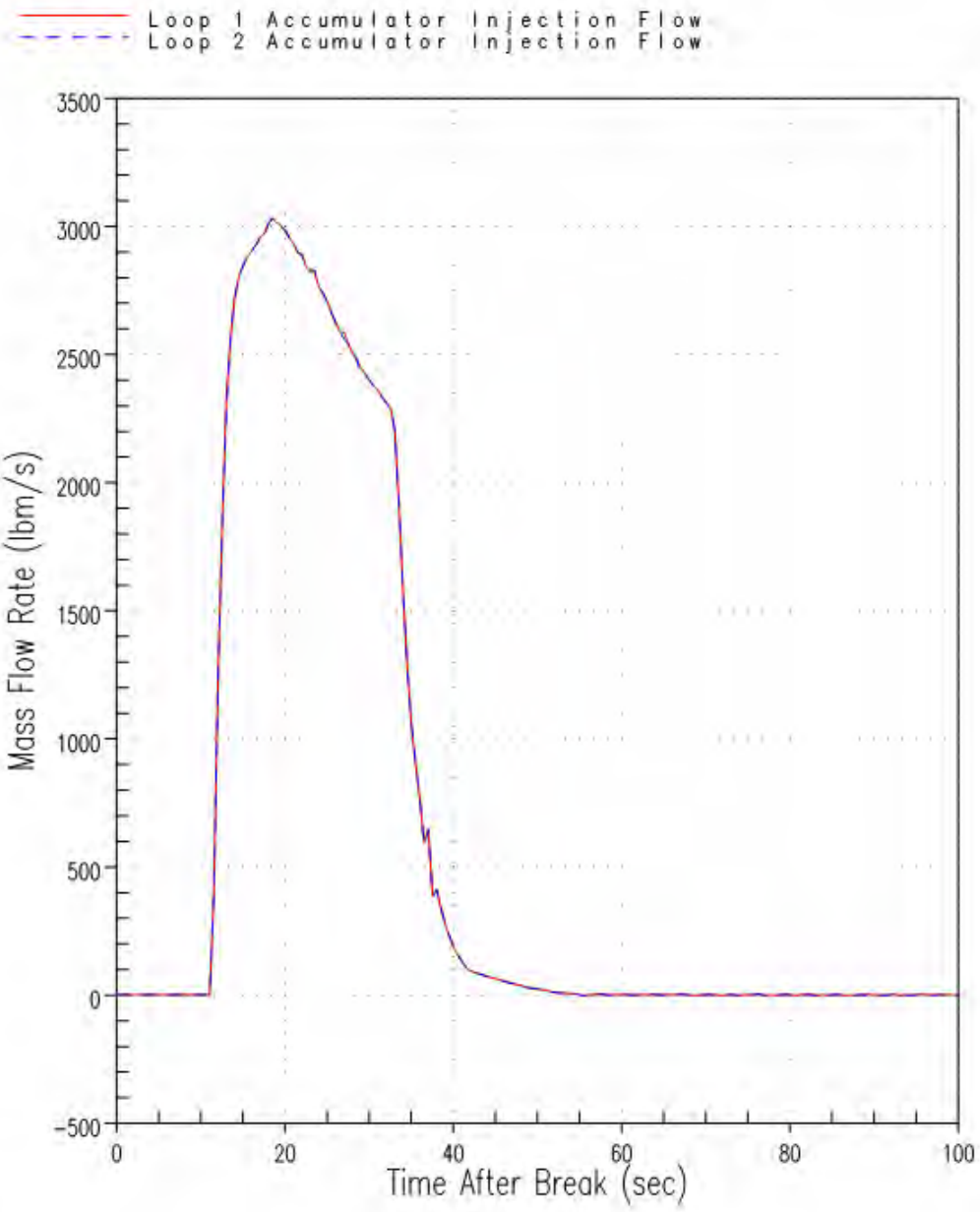


Figure 15.4-20: V.C. Summer Accumulator Injection Flow per Loop for the Region II Analysis PCT Case

Figure 15.4-21
V.C. SUMMER CONTAINMENT PRESSURE FOR THE REGION II ANALYSIS PCT CASE

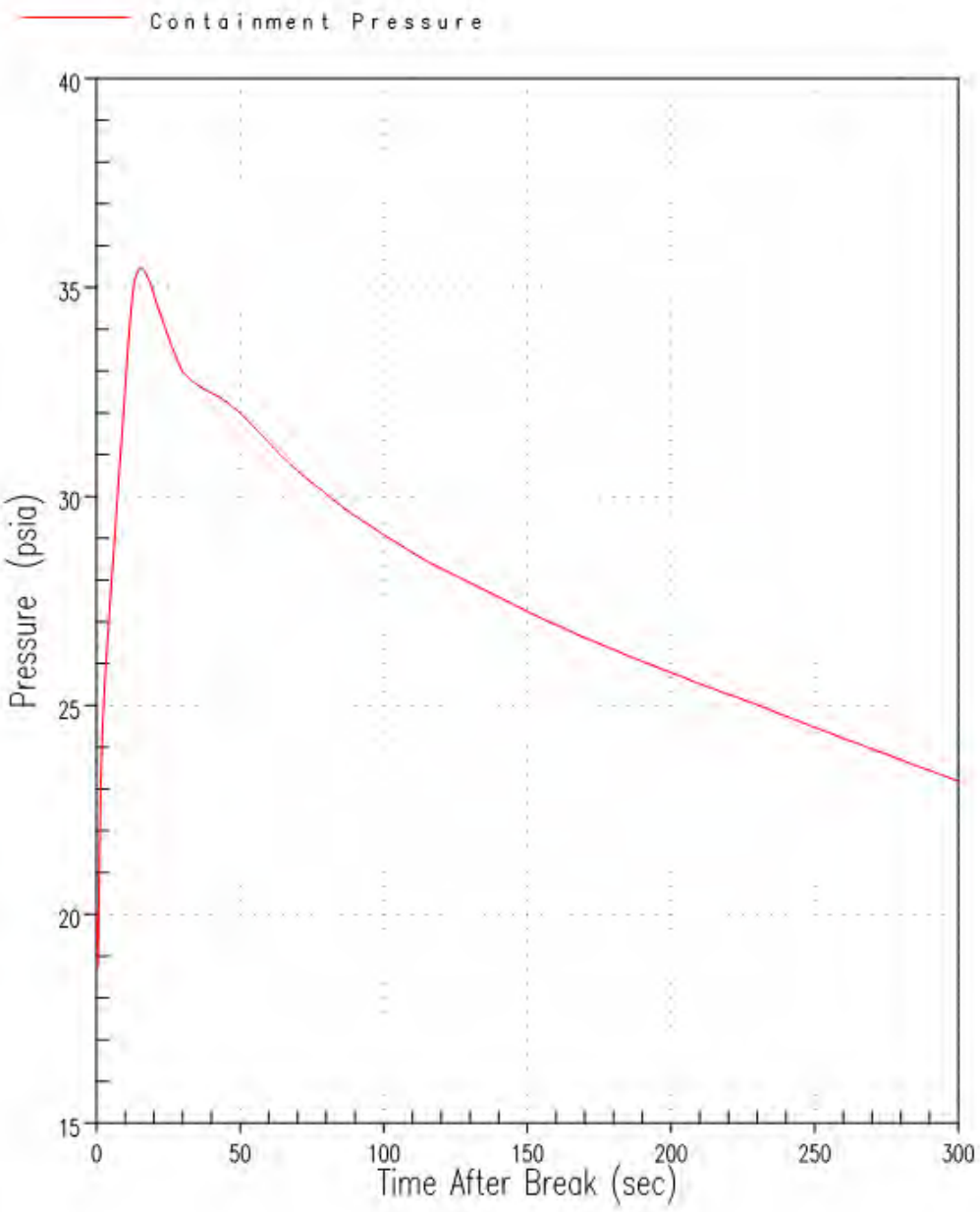


Figure 15.4-21: V.C. Summer Containment Pressure for the Region II Analysis PCT Case

Figure 15.4-22

V.C. SUMMER VESSEL FLUID MASS FOR THE REGION II ANALYSIS PCT CASE

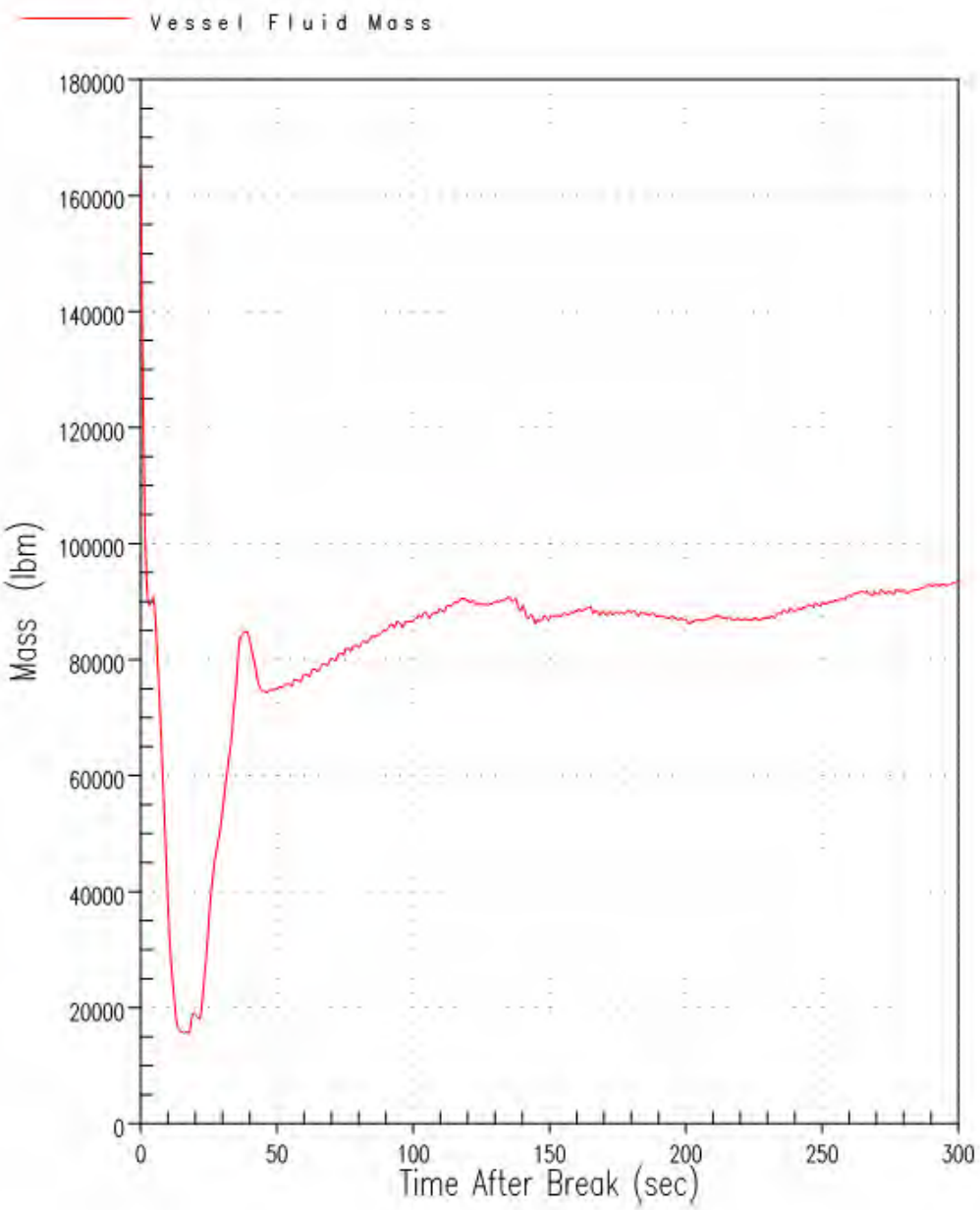


Figure 15.4-22: V.C. Summer Vessel Fluid Mass for the Region II Analysis PCT Case

Figure 15.4-23

V.C. SUMMER COLLAPSED LIQUID LEVEL FOR EACH CORE CHANNEL

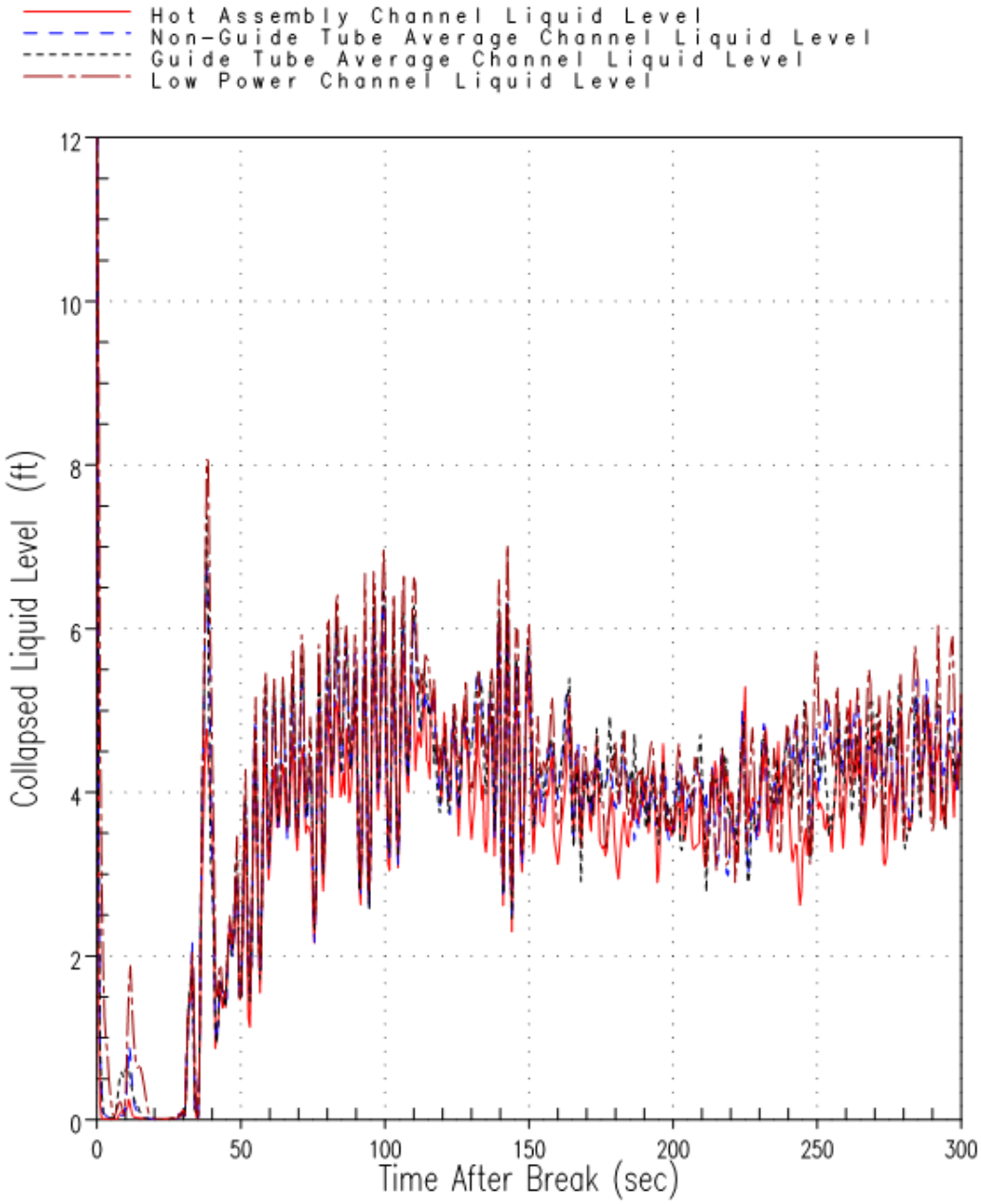


Figure 15.4-23: V.C. Summer Collapsed Liquid Level for Each Core Channel (Relative to Bottom of Active Fuel) for the Region II Analysis PCT Case

Figure 15.4-24
SUMMER AVERAGE DOWNCOMER COLLAPSED LIQUID LEVEL

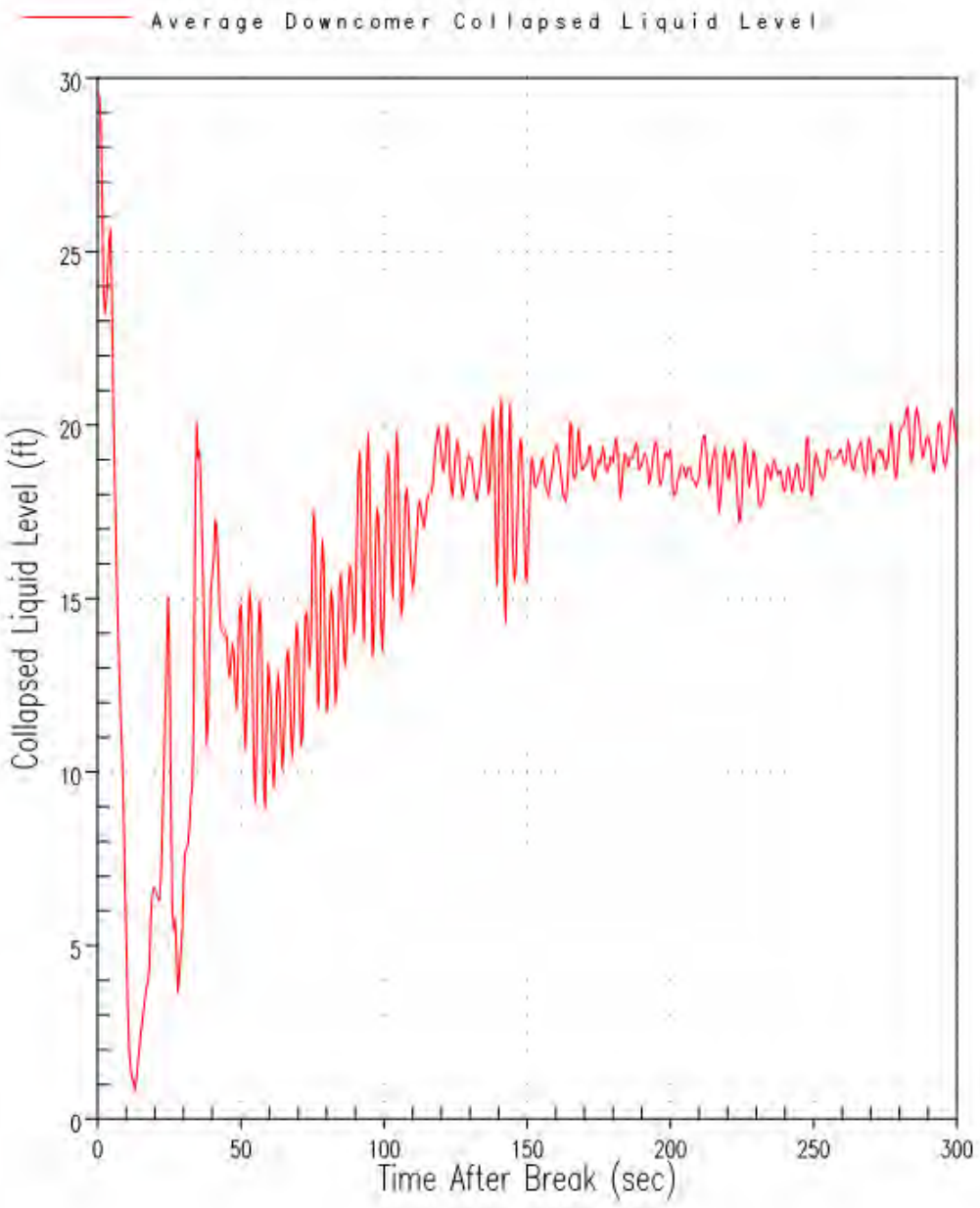


Figure 15.4-24: V.C. Summer Average Downcomer Collapsed Liquid Level (Relative to Bottom of Upper Tie Plate) for the Region II Analysis PCT Case

Figure 15.4-25
V.C. SUMMER TOTAL SAFETY INJECTION FLOW RATE PER LOOP

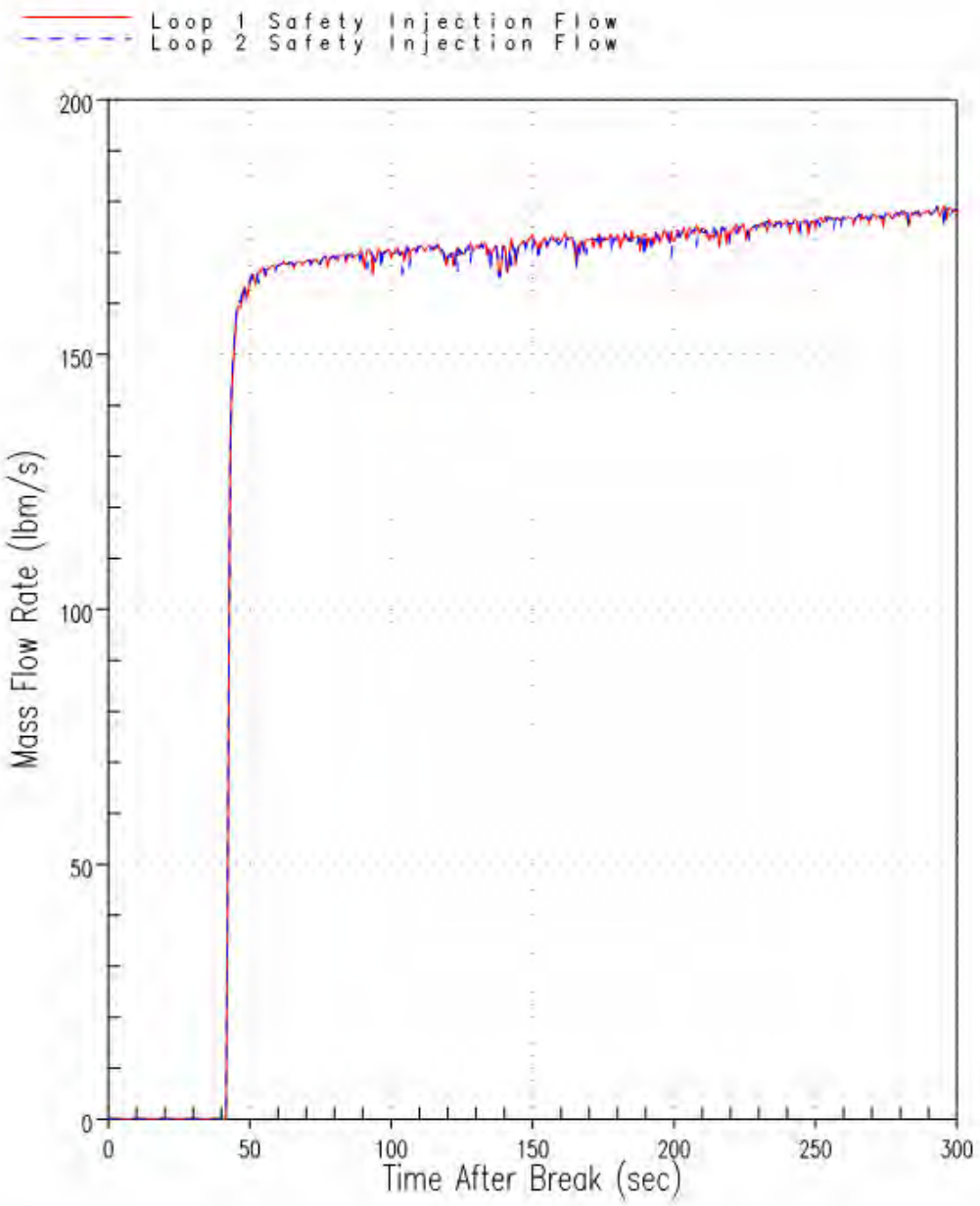


Figure 15.4-25: V.C. Summer Total Safety Injection Flow Rate per Loop (not Including Accumulator Flow) for the Region II Analysis PCT Case

Figure 15.4-26

V.C. SUMMER NORMALIZED CORE POWER SHAPES FOR THE REGION II ANALYSIS PCT CASE

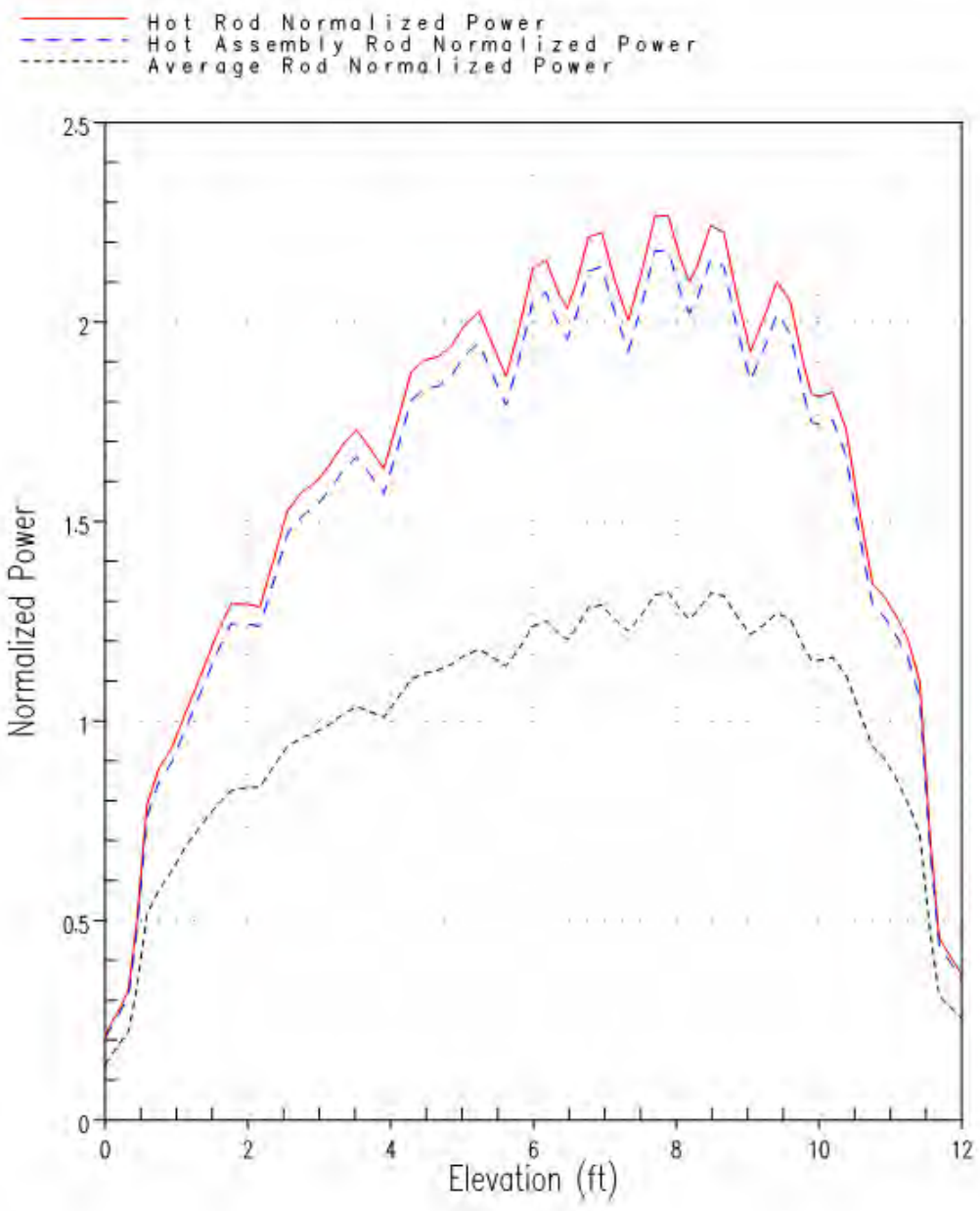


Figure 15.4-26: V.C. Summer Normalized Core Power Shapes for the Region II Analysis PCT Case

Note: The localized power decreases occur at grid elevations.

Figure 15.4-27
V.C. SUMMER RELATIVE CORE POWER FOR THE REGION II ANALYSIS PCT CASE

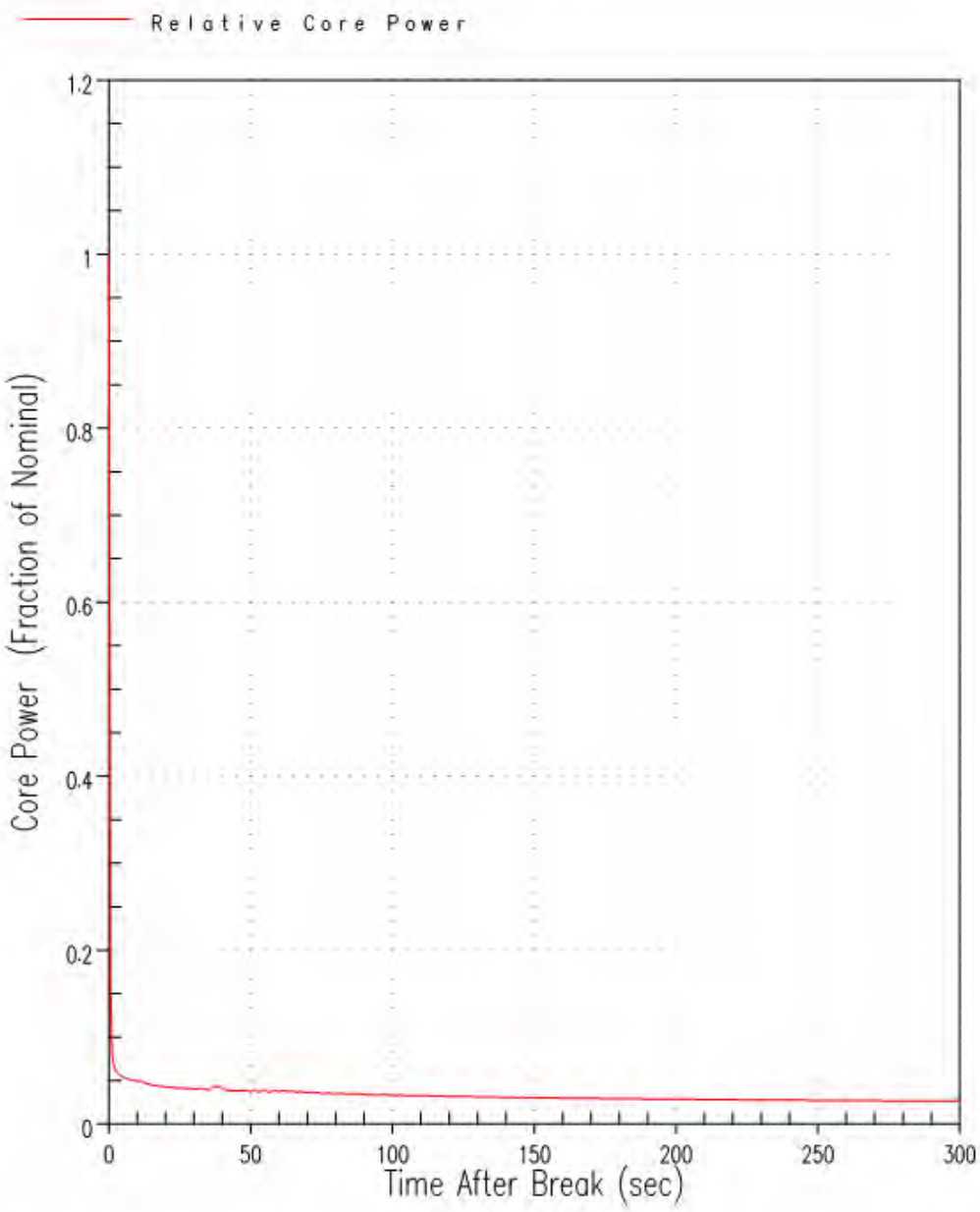
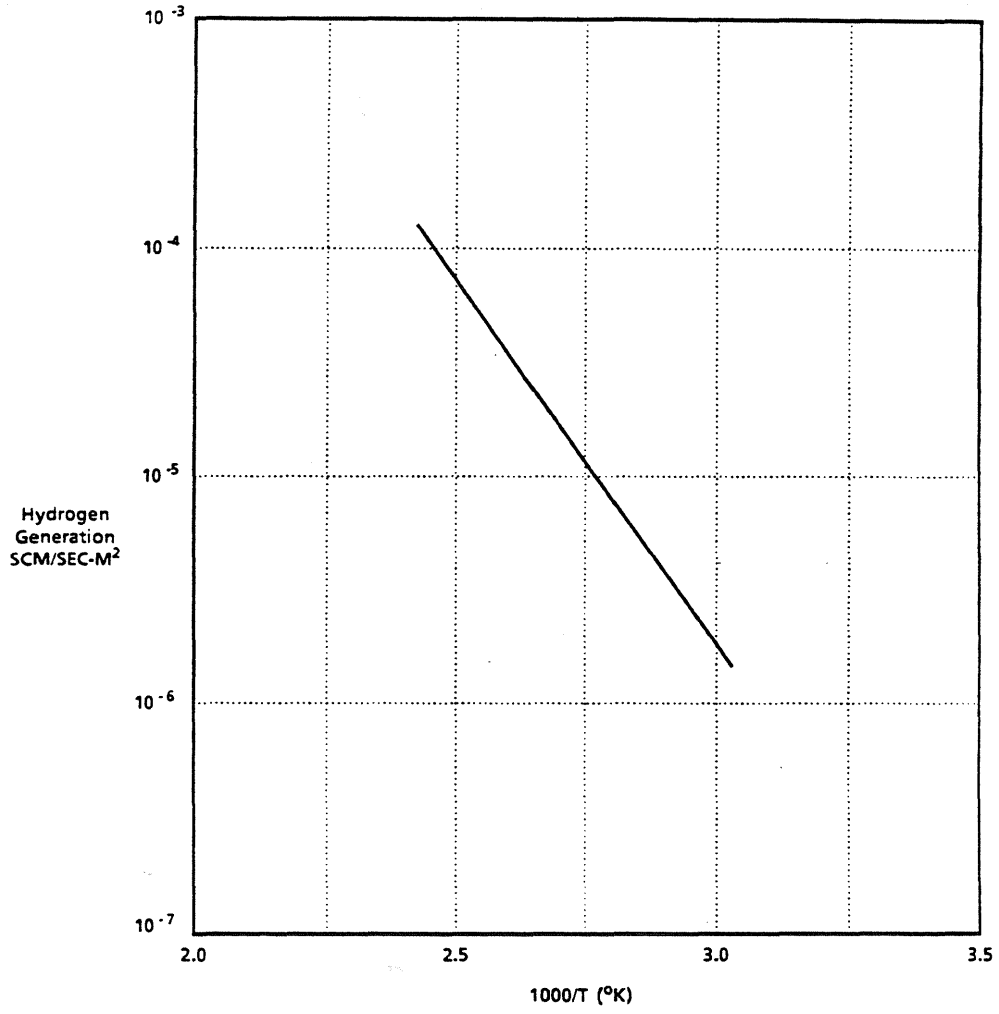


Figure 15.4-27: V.C. Summer Relative Core Power for the Region II Analysis PCT Case

Figures 15.4-28 through 15.4-67
DELETED PER RN 06-040

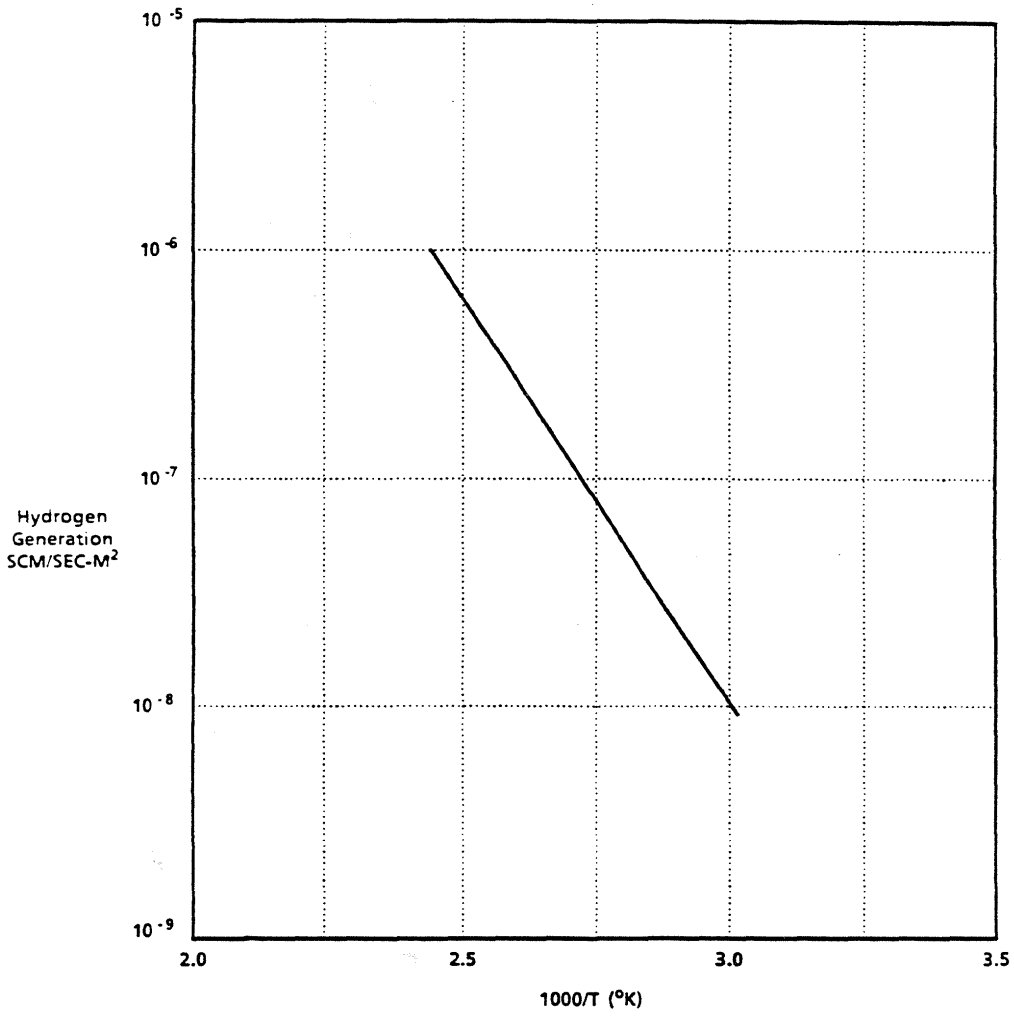
Figure 15.4-68
HYDROGEN GENERATION FROM ALUMINUM CORROSION - ANSI 56.1



AMENDMENT 96-03
SEPTEMBER 1996

SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Hydrogen Generation from Aluminum Corrosion - ANS 56.1 Figure 15.4-68

Figure 15.4-69
HYDROGEN GENERATION FROM ZINC CORROSION - ANS 56.1



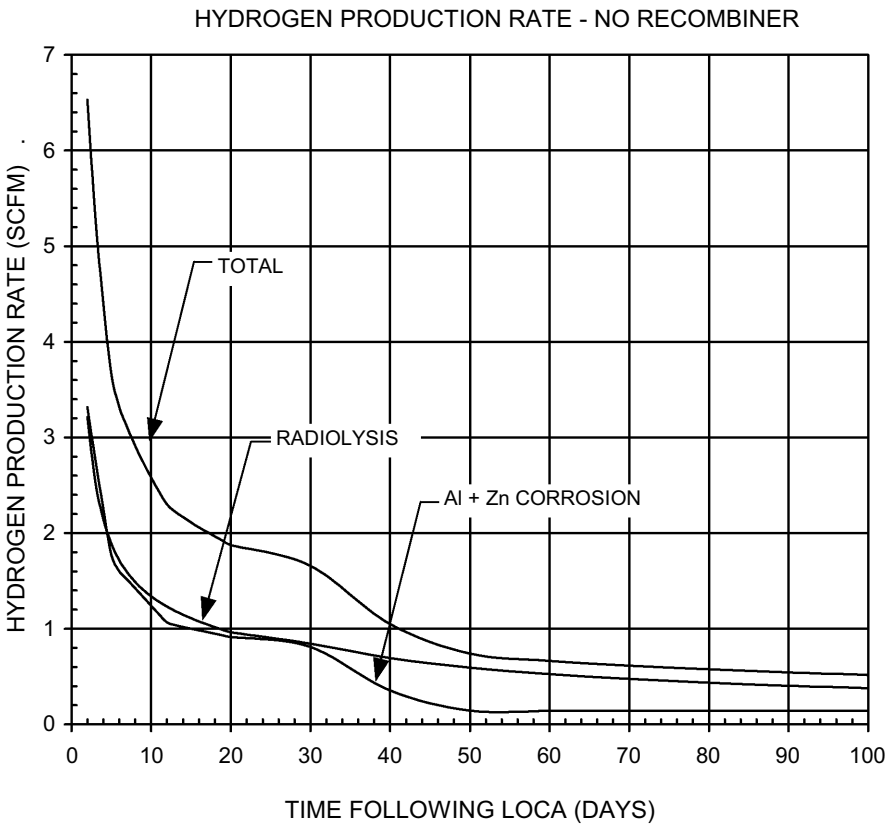
AMENDMENT 96-03
SEPTEMBER 1996

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Hydrogen Generation from Zinc Corrosion - ANS 56.1

Figure 15.4-69

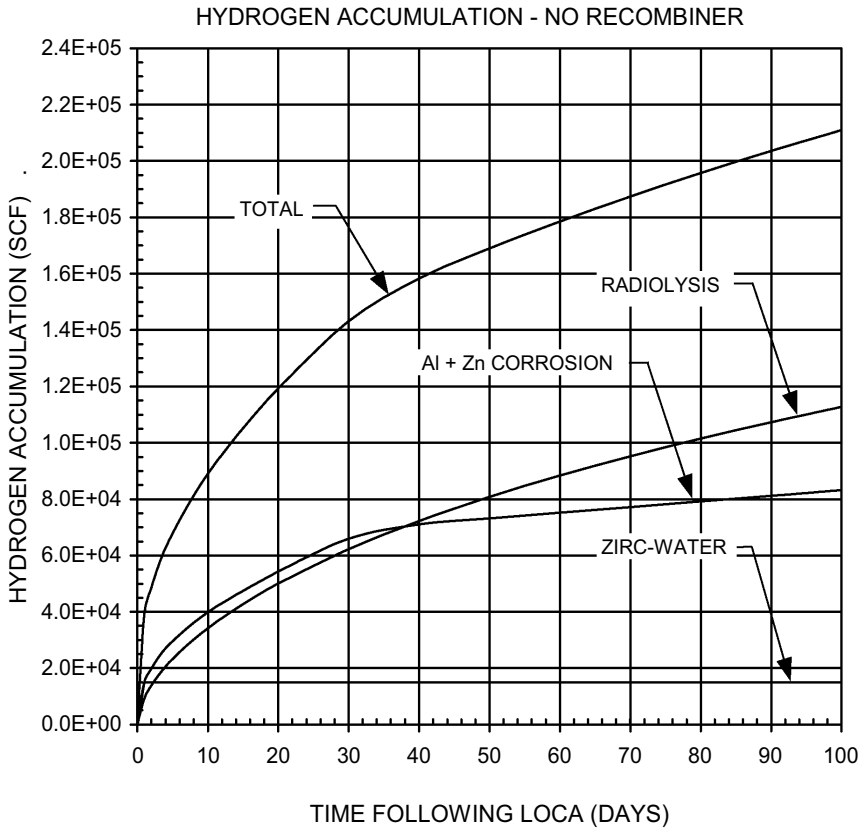
Figure 15.4-71
HYDROGEN PRODUCTION RATE NO RECOMBINER



RN 03-005
June 2003

SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Hydrogen Production Rate No Recombiner Figure 15.4-71

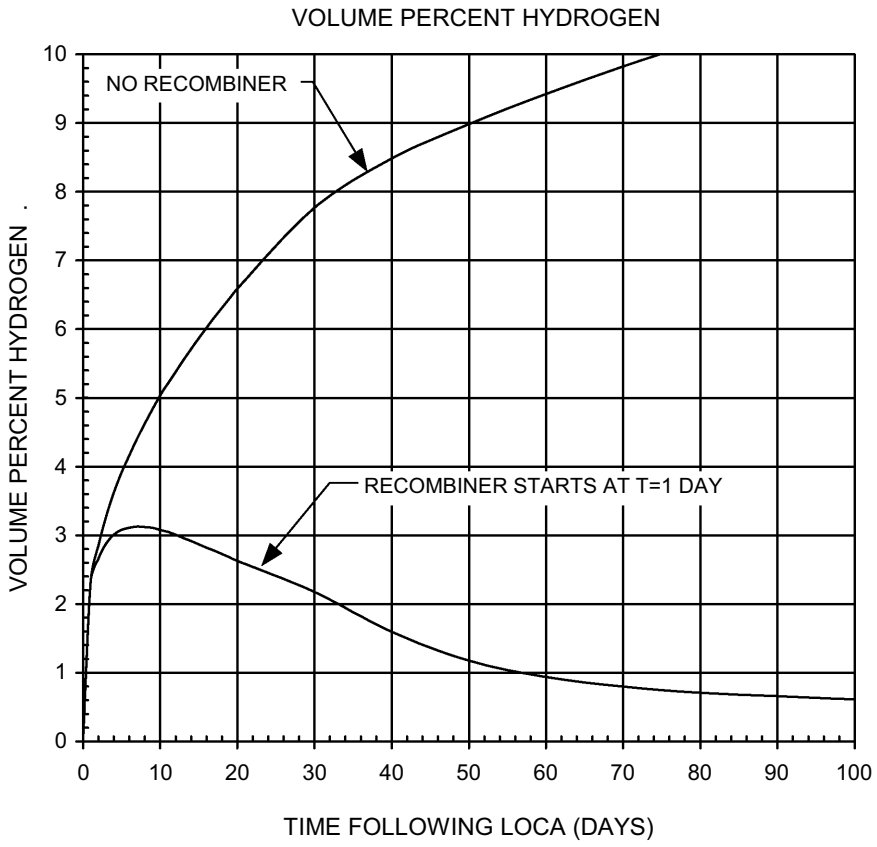
Figure 15.4-72
HYDROGEN ACCUMULATION NO RECOMBINER



RN 03-005
June 2003

SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Hydrogen Accumulation No Recombiner Figure 15.4-72

Figure 15.4-73
VOLUME PERCENT HYDROGEN IN CONTAINMENT

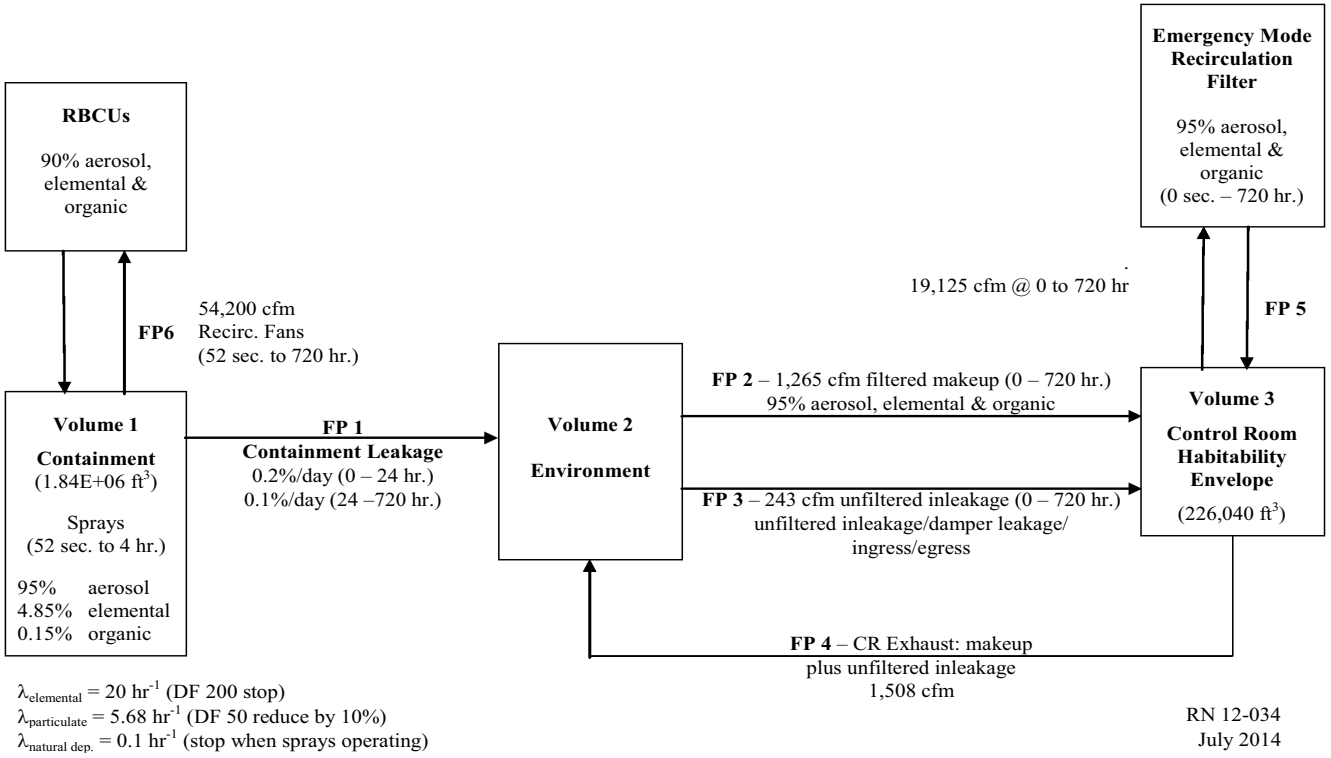


RN 03-005
June 2003

SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Volume Percent Hydrogen In Containment Figure 15.4-73

Figure 15.4-74

RADTRAD MODEL FOR CONTAINMENT SOURCE RELEASE - LOCA



RN 12-034
July 2014

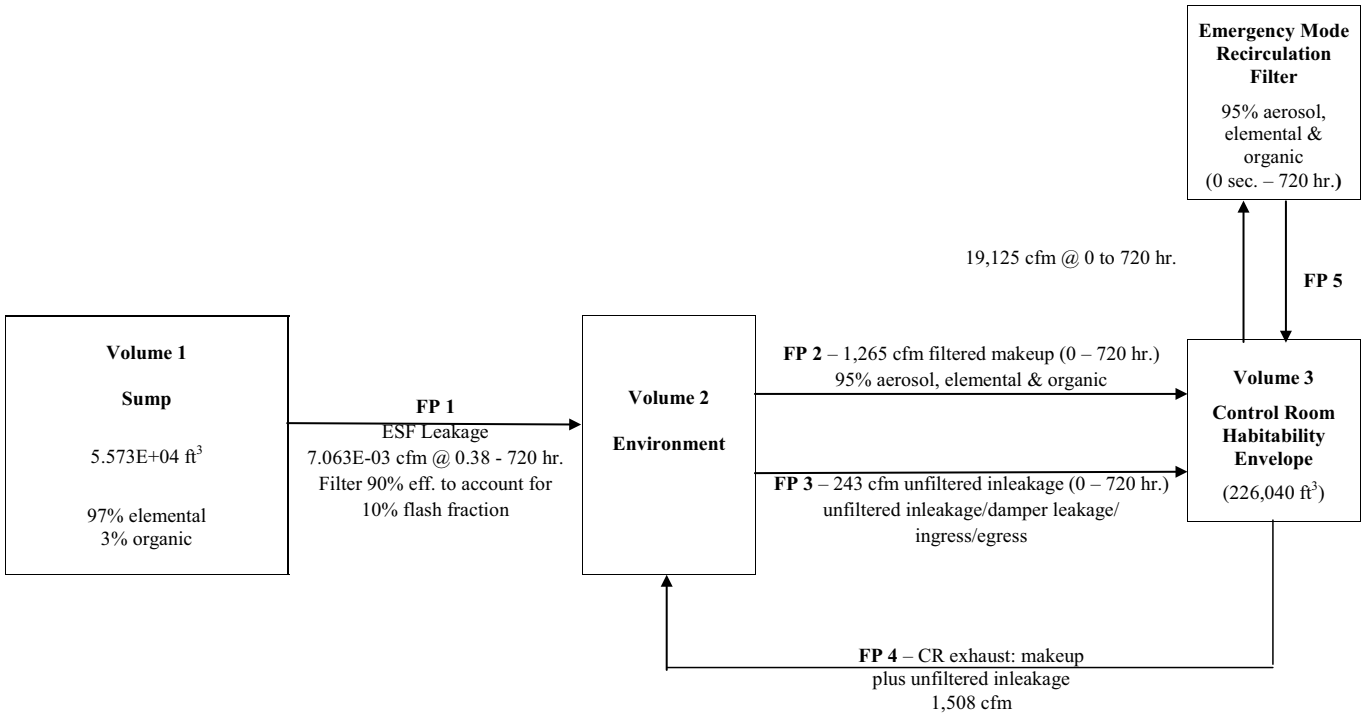
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

RADTRAD Model for
Containment Source Release - LOCA

Figure 15.4-74

Figure 15.4-74A

RADTRAD MODEL FOR ESF LEAKAGE SOURCE RELEASE - LOCA



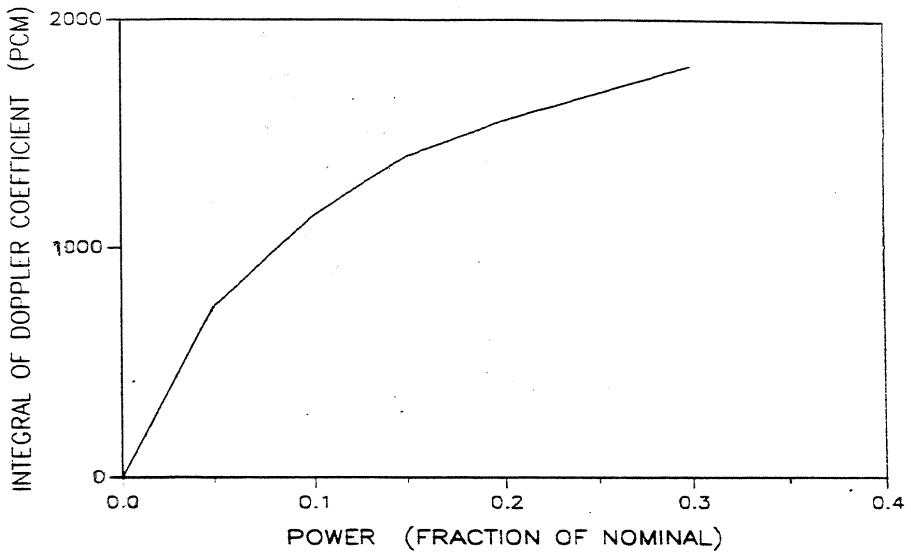
RN 12-034
July 2014

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

RADTRAD Model for
ESF Leakage Source Release - LOCA

Figure 15.4-74A

Figure 15.4-75
VARIATION OF REACTIVITY WITH POWER AT CONSTANT CORE AVERAGE TEMPERATURE

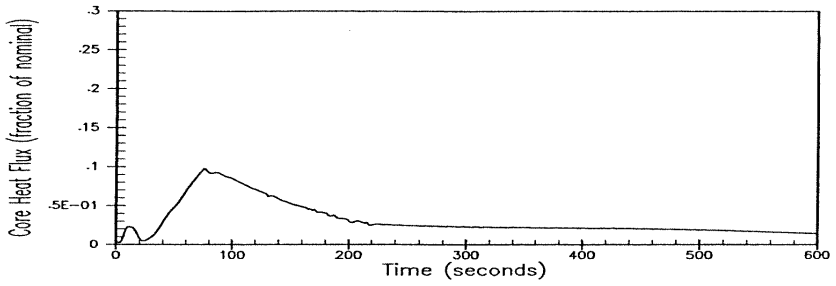


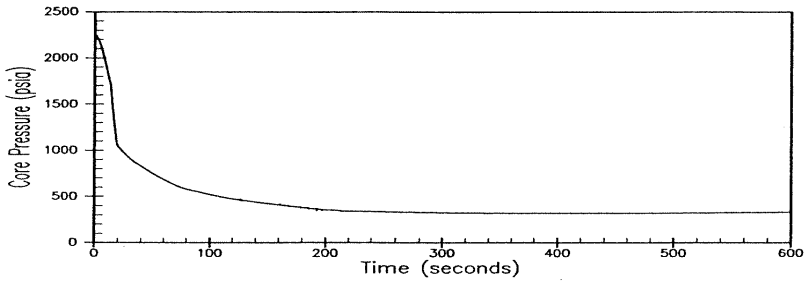
SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
Variation of Reactivity With Power At Constant Core Average Temperature Figure 15.4-75

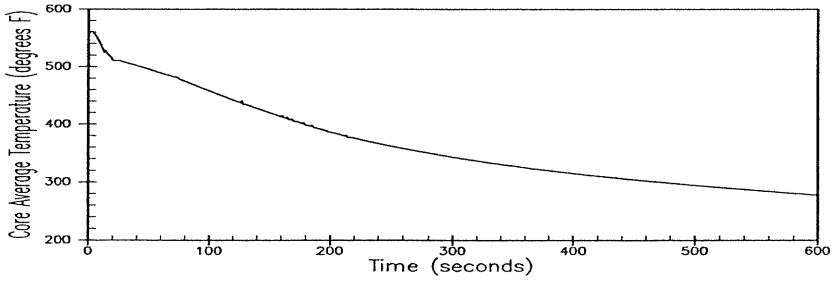
Amendment 96-02
July 1996

Figure 15.4-76

TRANSIENT RESPONSE TO A STEAM LINE BREAK DOUBLE ENDED RUPTURE WITH OFFSITE POWER AVAILABLE (CASE A)





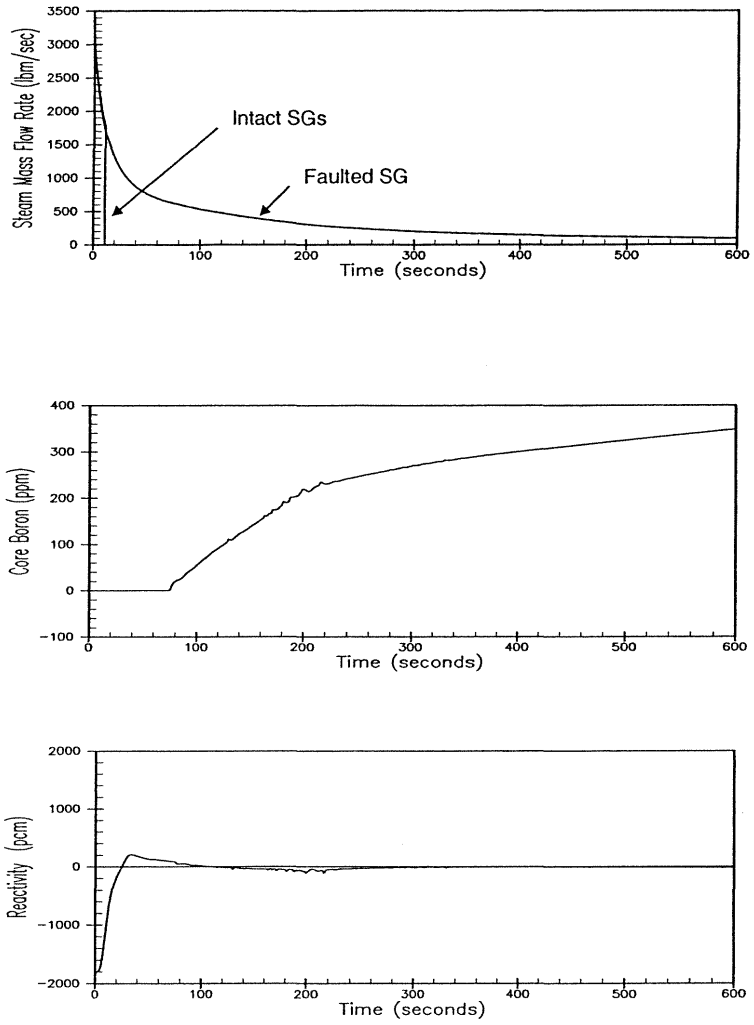


RN 01-125
May 2002

SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Transient Response to a Steam Line Break Double Ended Rupture With Offsite Power Available (Case A) Figure 15.4-76

Figure 15.4-77

TRANSIENT RESPONSE TO A STEAM LINE BREAK
DOUBLE ENDED RUPTURE WITH OFFSITE POWER AVAILABLE (CASE A)

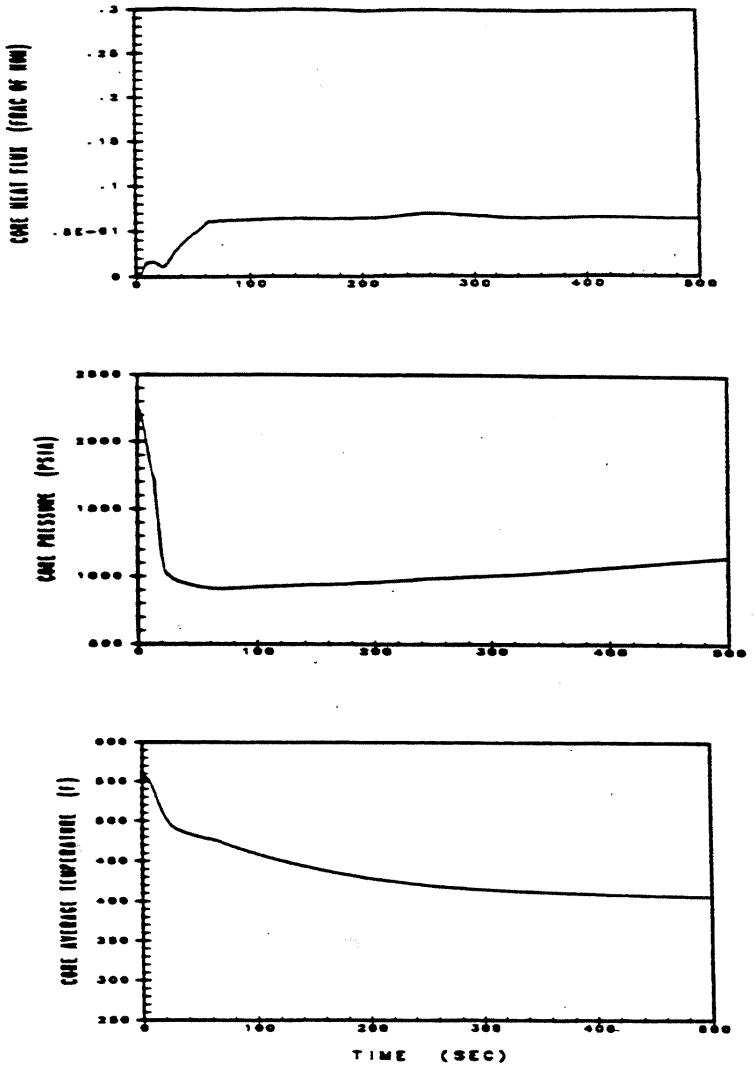


RN 01-125
May 2002

SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Transient Response to a Steam Line Break Double Ended Rupture With Offsite Power Available (Case A) Figure 15.4-77

Figure 15.4-78

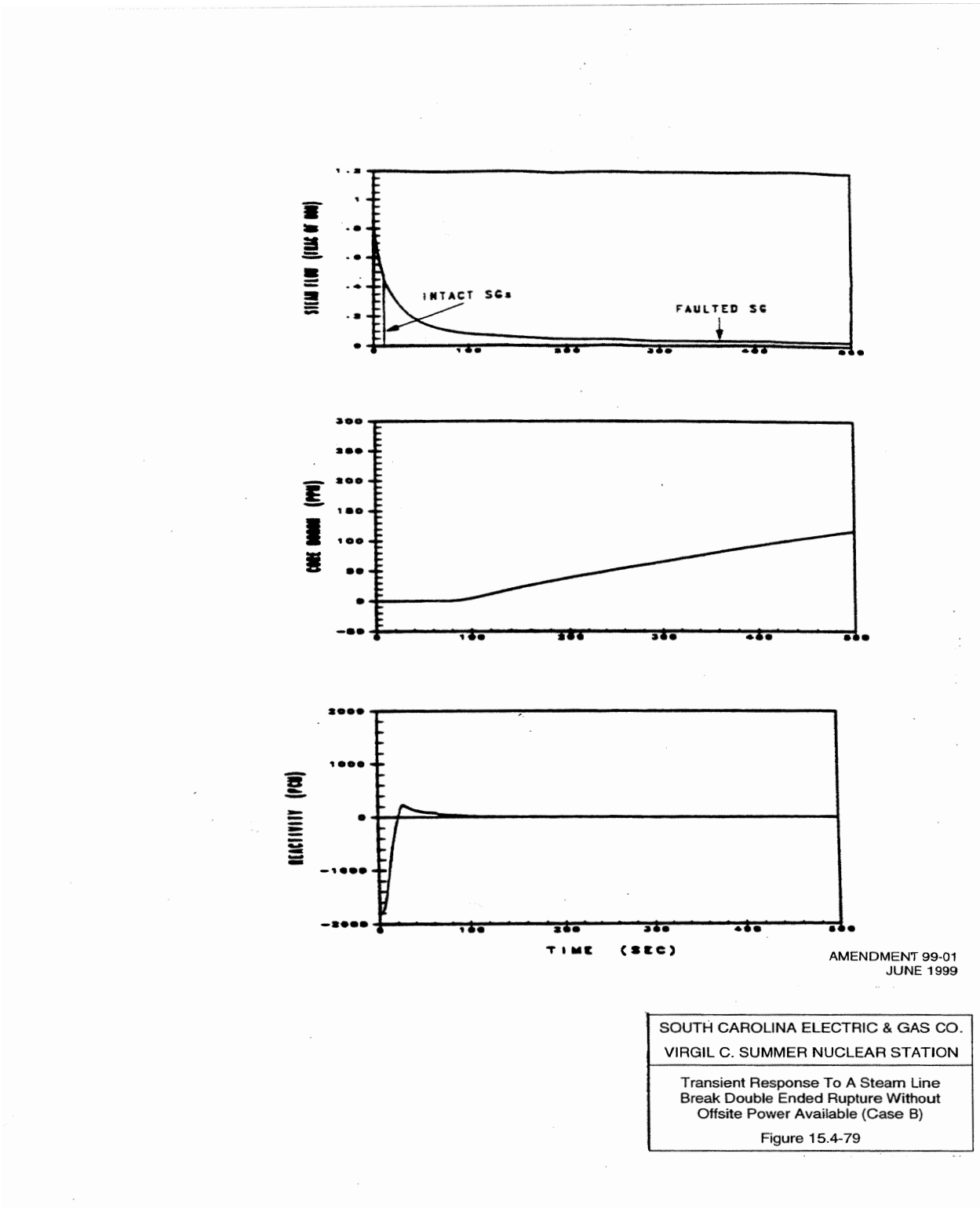
TRANSIENT RESPONSE TO A STEAM LINE BREAK DOUBLE ENDED RUPTURE WITHOUT OFFSITE POWER AVAILABLE (CASE B)



AMENDMENT 99-01
JUNE 1999

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
Transient Response To A Steam Line Break Double Ended Rupture Without Offsite Power Available (Case B)
Figure 15.4-78

Figure 15.4-79
TRANSIENT RESPONSE TO A STEAM LINE BREAK DOUBLE ENDED RUPTURE WITHOUT OFFSITE POWER AVAILABLE (CASE B)

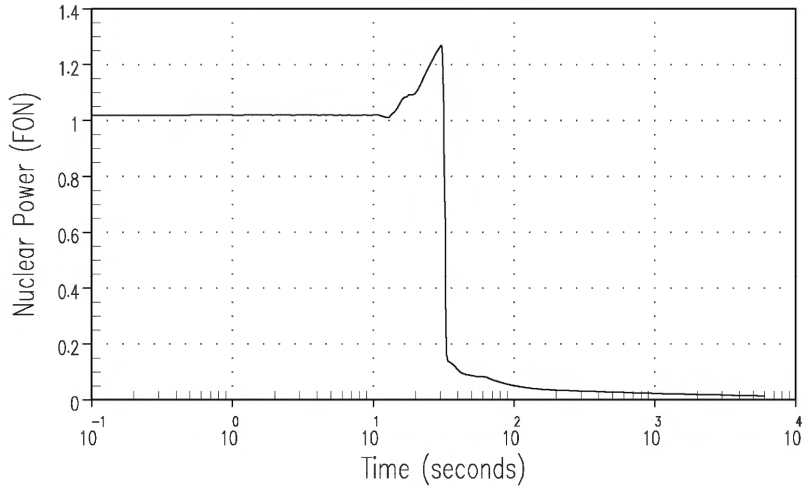


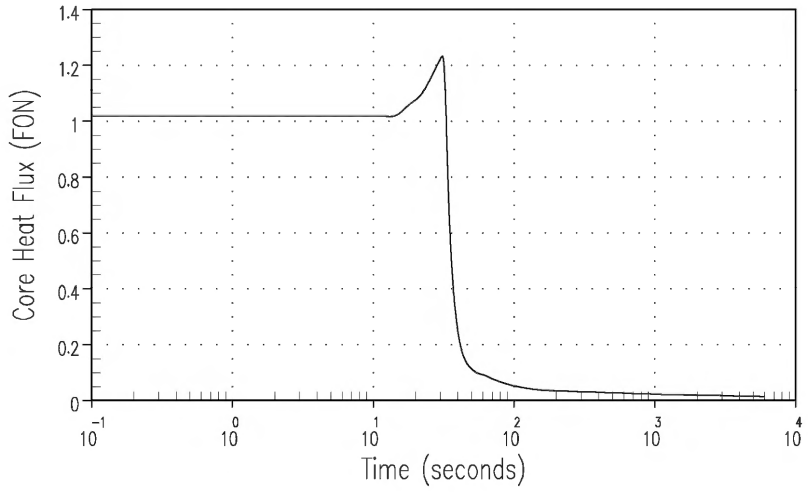
AMENDMENT 99-01
JUNE 1999

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION
Transient Response To A Steam Line Break Double Ended Rupture Without Offsite Power Available (Case B)
Figure 15.4-79

Figures 15.4-80 through 15.4-82
HAVE BEEN DELETED

Figure 15.4-83
MAIN FEEDWATER RUPTURE WITH OFFSITE POWER
NUCLEAR POWER AND CORE HEAT FLUX VS. TIME

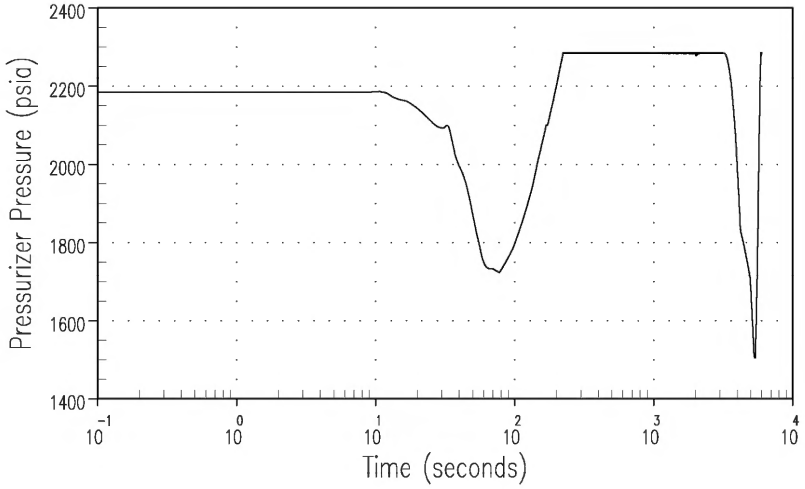


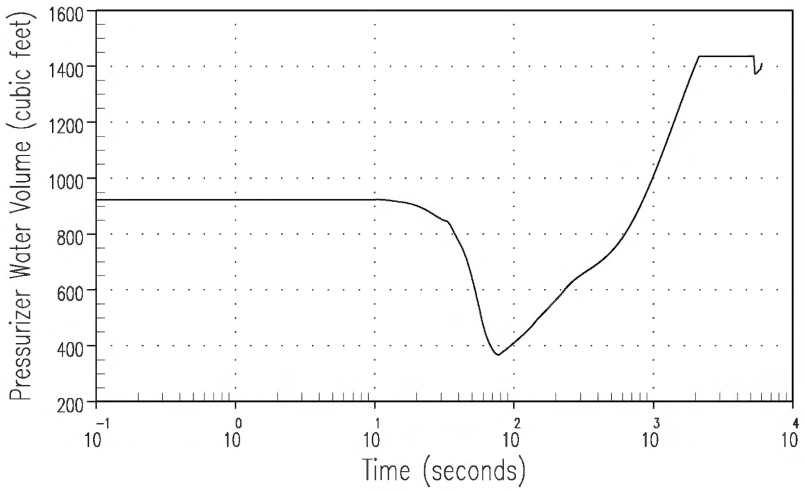


SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Main Feedwater Rupture With Offsite Power Nuclear Power and Core Heat Flux vs. Time Figure 15.4-83

Figure 15.4-84

MAIN FEEDWATER RUPTURE WITH OFFSITE POWER
PRESSURIZER PRESSURE AND WATER VOLUME VS. TIME

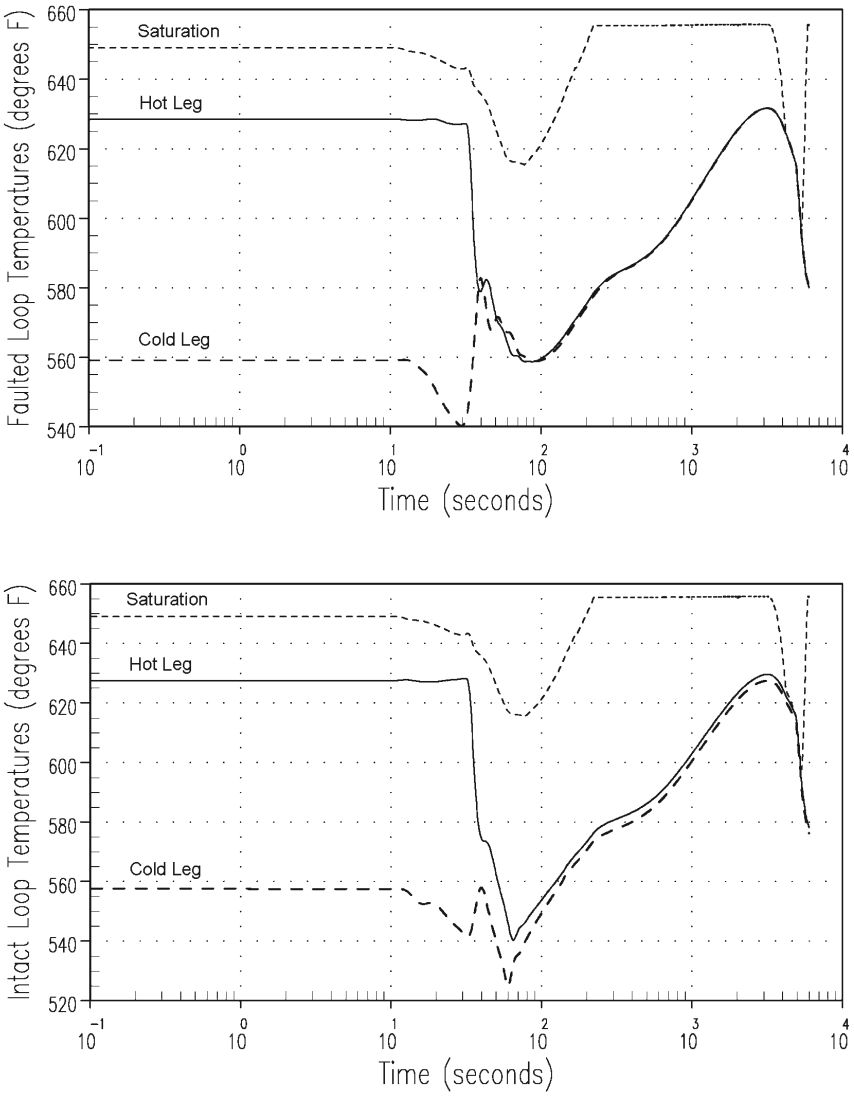




SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Main Feedwater Rupture With Offsite Power Pressurizer Pressure and Water Volume vs. Time Figure 15.4-84

Figure 15.4-85

MAIN FEEDWATER RUPTURE WITH OFFSITE POWER FAULTED AND INTACT LOOP COOLANT TEMPERATURE VS. TIME



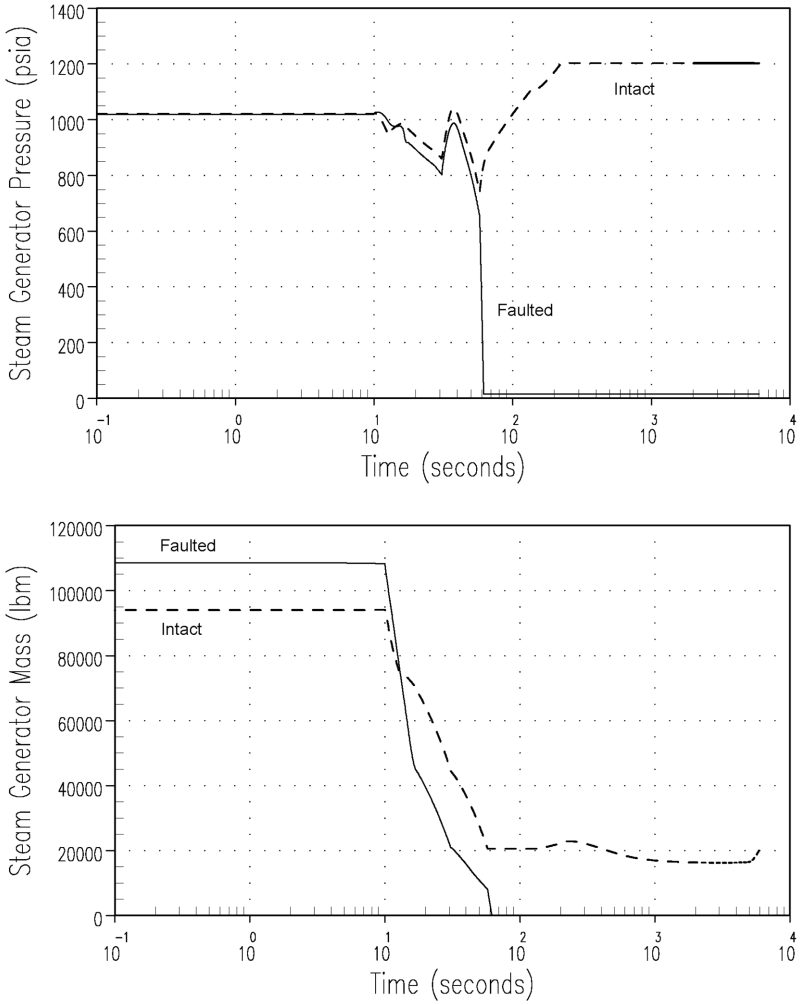
Note: A temperature penalty of +16.3°F has been assessed on the calculated hot leg temperature to account for the effects of using the PAD5 fuel rod performance code[68].

SOUTH CAROLINA ELECTRIC & GAS CO
VIRGIL C. SUMMER NUCLEAR STATION

Main Feedwater Rupture With Offsite Power Faulted and Intact Loop Coolant Temperature vs. Time

Figure 15.4-85

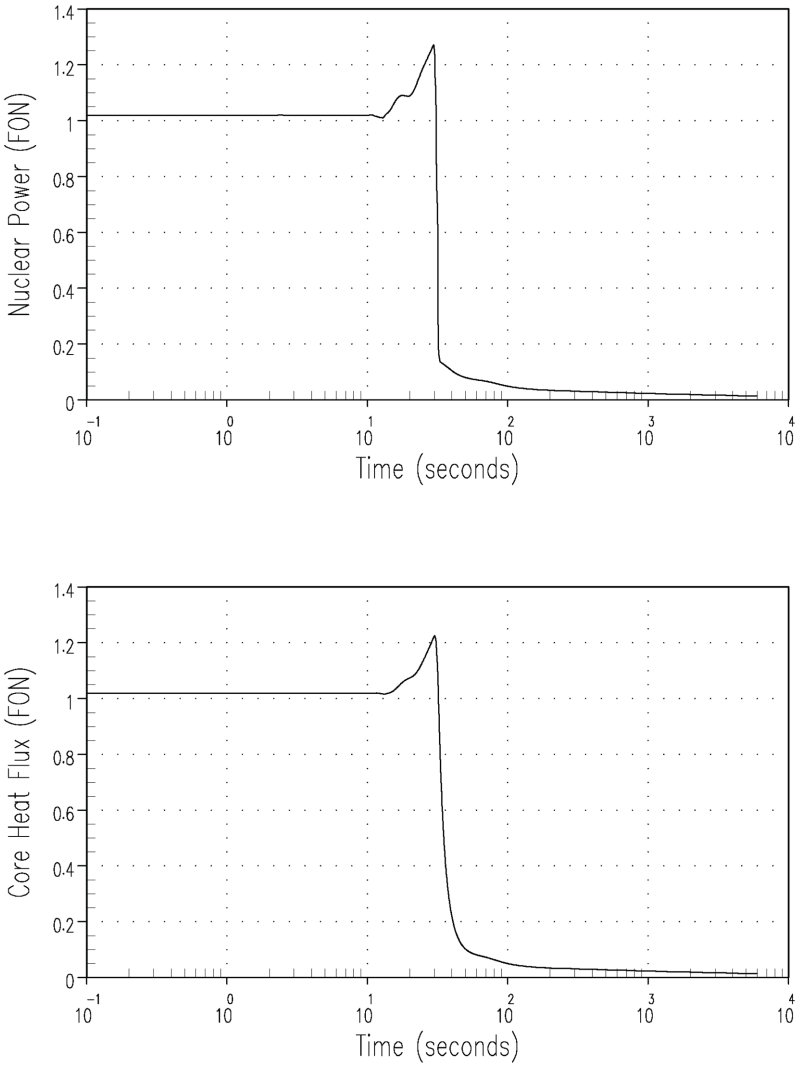
Figure 15.4-86
MAIN FEEDWATER RUPTURE WITH OFFSITE POWER STEAM GENERATOR PRESSURE AND WATER MASS VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Main Feedwater Rupture With Offsite Power Steam Generator Pressure and Water Mass vs. Time Figure 15.4-86

Figure 15.4-87

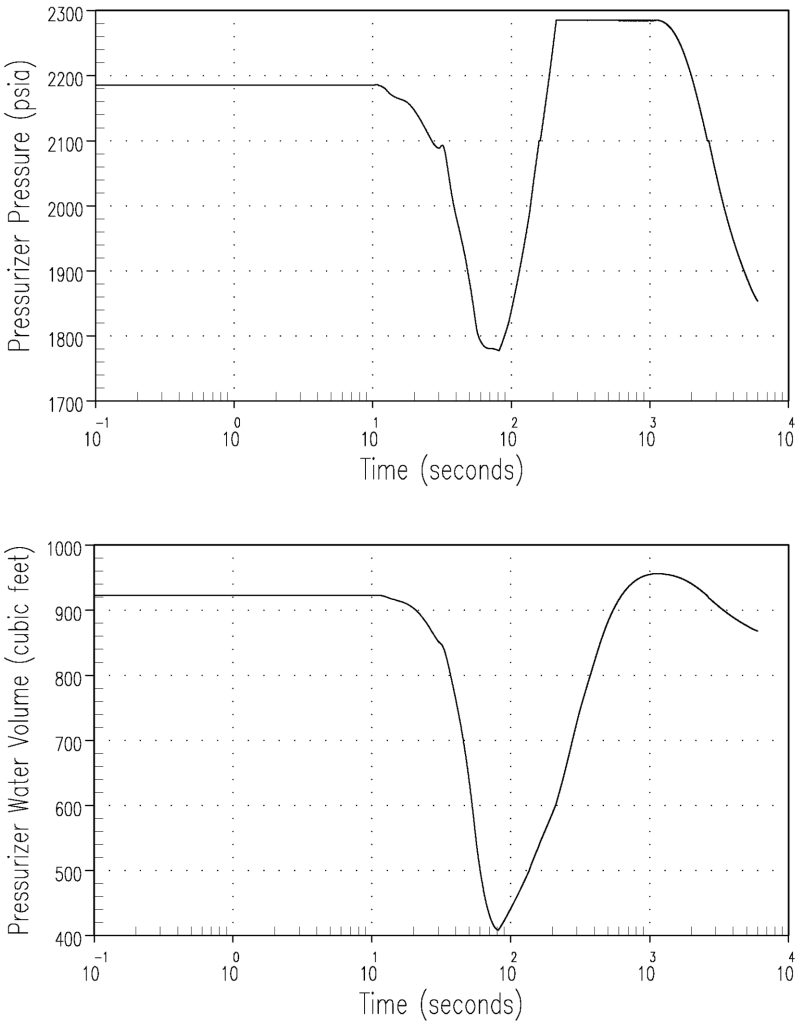
MAIN FEEDWATER RUPTURE WITHOUT OFFSITE POWER
NUCLEAR POWER AND CORE HEAT FLUX VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Main Feedwater Rupture Without Offsite Power Nuclear Power and Core Heat Flux vs. Time Figure 15.4-87

Figure 15.4-88

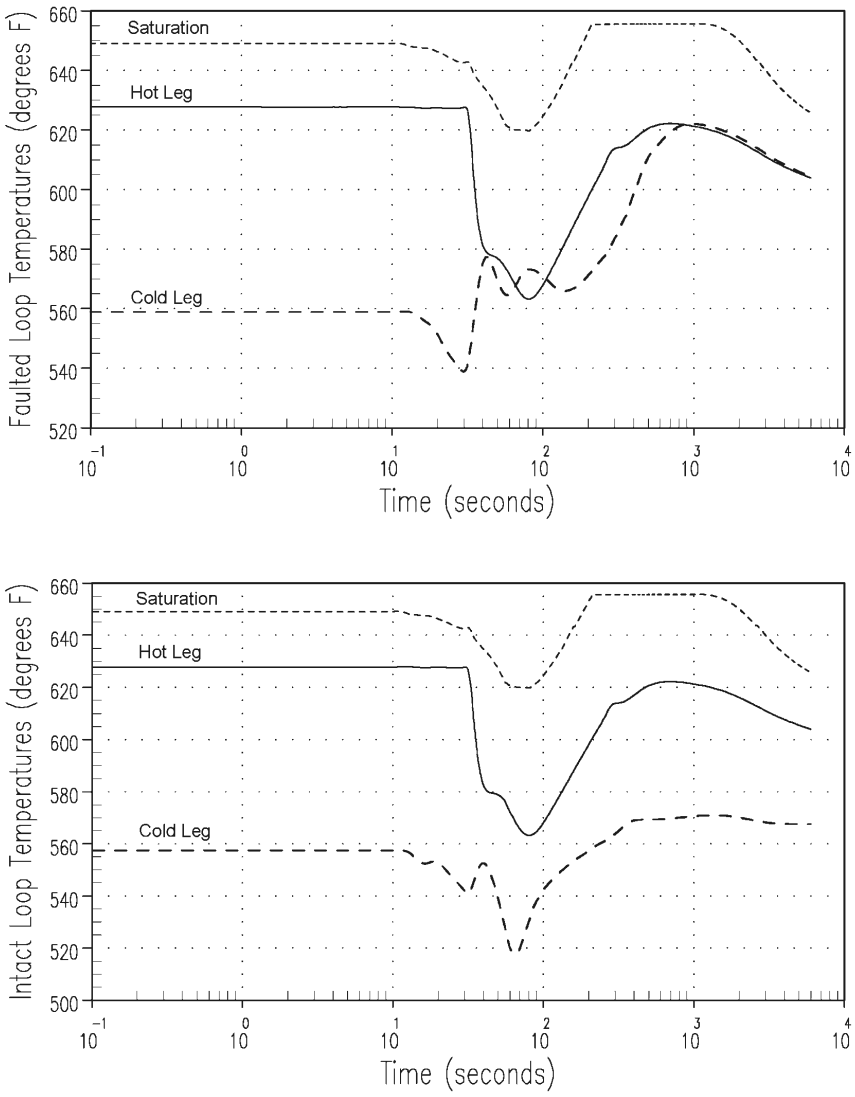
MAIN FEEDWATER RUPTURE WITHOUT OFFSITE POWER
PRESSURIZER PRESSURE AND WATER VOLUME VS. TIME



SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Main Feedwater Rupture Without Offsite Power Pressurizer Pressure and Water Volume vs. Time Figure 15.4-88

Figure 15.4-89

MAIN FEEDWATER RUPTURE WITHOUT OFFSITE POWER FAULTED AND INTACT LOOP COOLANT TEMPERATURE VS. TIME



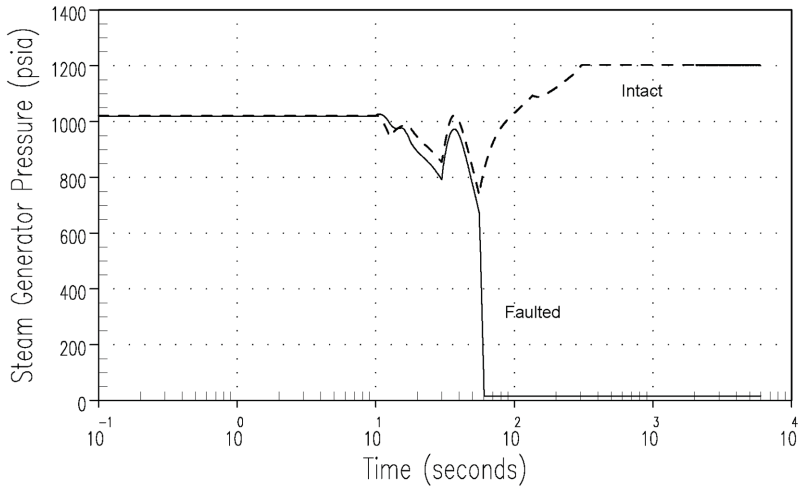
Note: A temperature penalty of +16.3°F has been assessed on the calculated hot leg temperature to account for the effects of using the PAD5 fuel rod performance code[68].

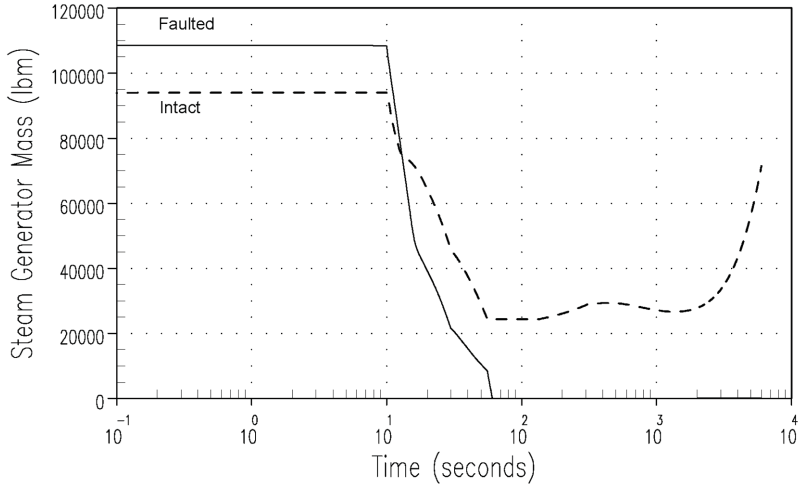
SOUTH CAROLINA ELECTRIC & GAS CO
VIRGIL C. SUMMER NUCLEAR STATION

Main Feedwater Rupture Without Offsite Power
Faulted and Intact Loop Coolant
Temperature vs. Time

Figure 15.4-89

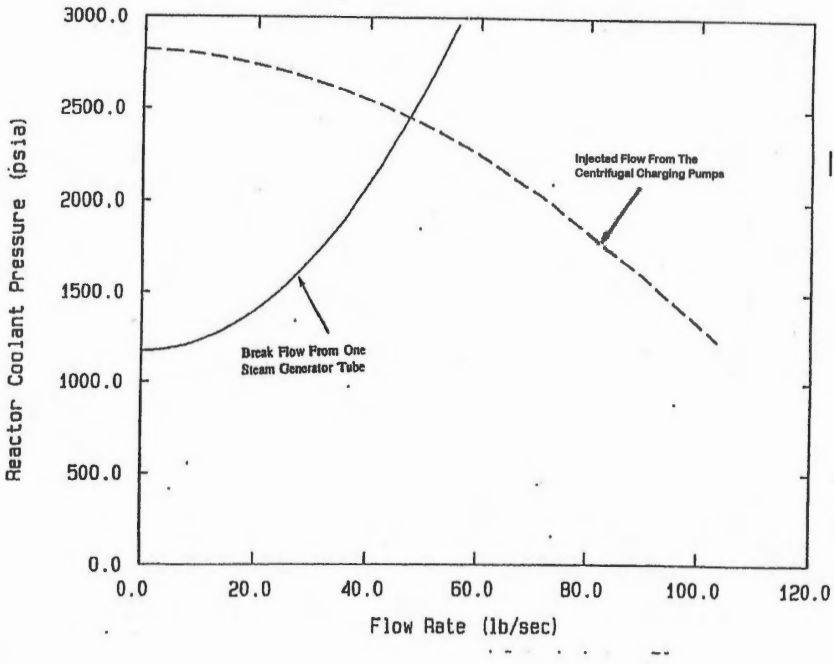
Figure 15.4-90
MAIN FEEDWATER RUPTURE WITHOUT OFFSITE POWER
STEAM GENERATOR PRESSURE AND
WATER MASS VS. TIME





SOUTH CAROLINA ELECTRIC & GAS CO VIRGIL C. SUMMER NUCLEAR STATION
Main Feedwater Rupture Without Offsite Power Steam Generator Pressure and Water Mass vs. Time Figure 15.4-90

Figure 15.4-91
BREAK FLOW AND INJECTED MASS FLOW
STEAM GENERATOR TUBE RUPTURE



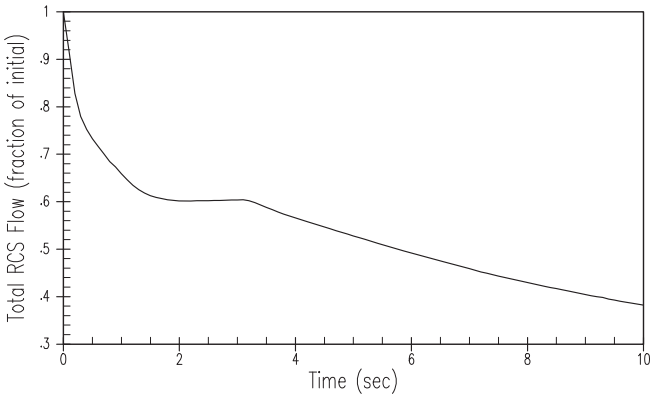
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

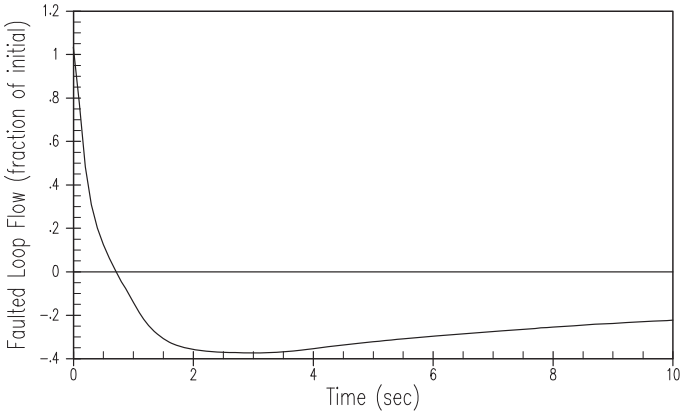
Break Flow and Injected Mass Flow
Steam Generator Tube Rupture

Figure 15.4-91 Rev. 1

Figures 15.4-92 through 15.4-94
HAVE BEEN DELETED

Figure 15.4-95
ALL LOOPS OPERATING, ONE LOCKED ROTOR: RCS FLOW AND FAULTED LOOP FLOW VS. TIME

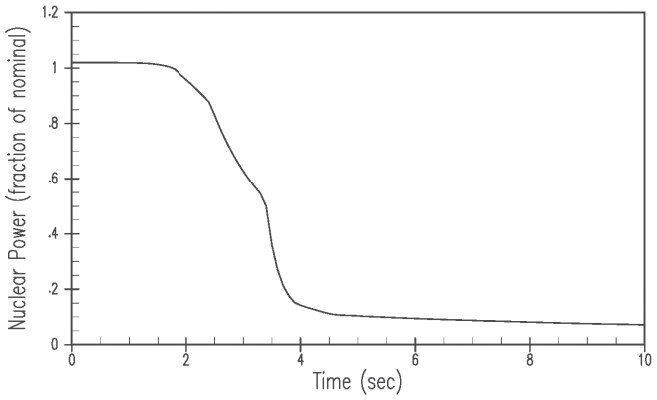


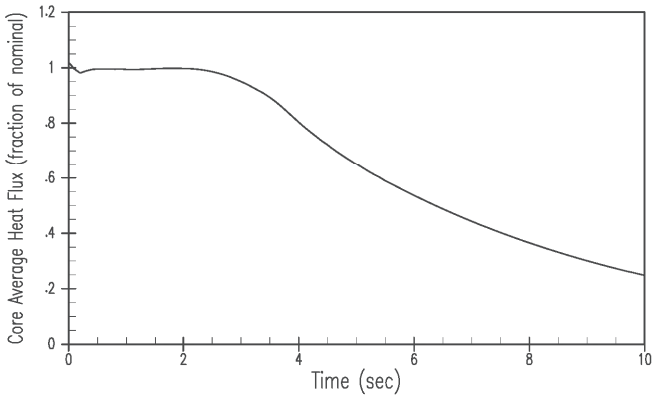


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
All Loops Operating, One Locked Rotor: RCS Flow and Faulted Loop Flow vs. Time Figure 15.4-95

Figure 15.4-96A

ALL LOOPS OPERATING, ONE LOCKED ROTOR: NUCLEAR POWER AND CORE HEAT FLUX VS. TIME

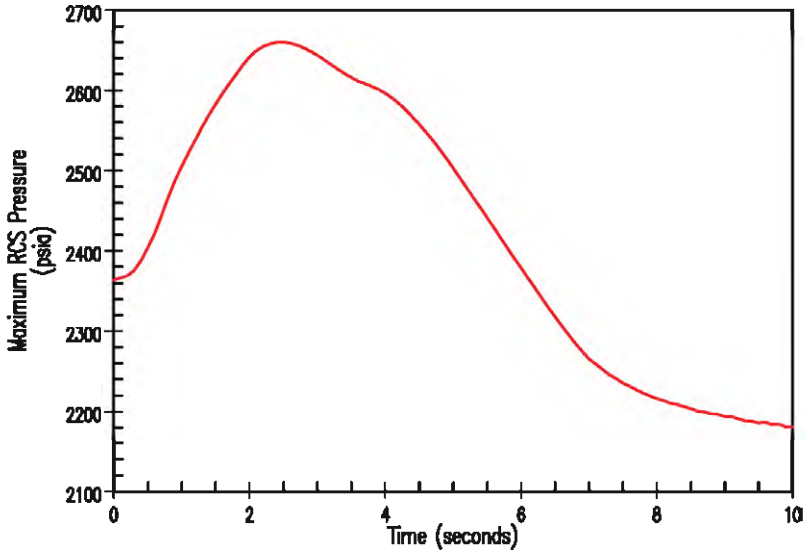


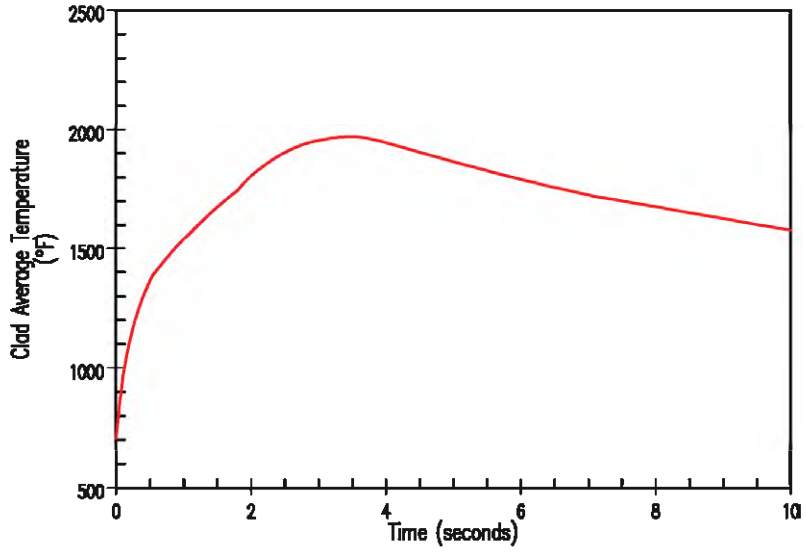


SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
All Loops Operating, One Locked Rotor: Nuclear Power and Core Heat Flux vs. Time Figure 15.4-96A

Figure 15.4-96B

ALL LOOPS OPERATING, ONE LOCKED ROTOR: MAXIMUM RCS PRESSURE AND HOT SPOT CLAD AVERAGE TEMPERATURE VS. TIME





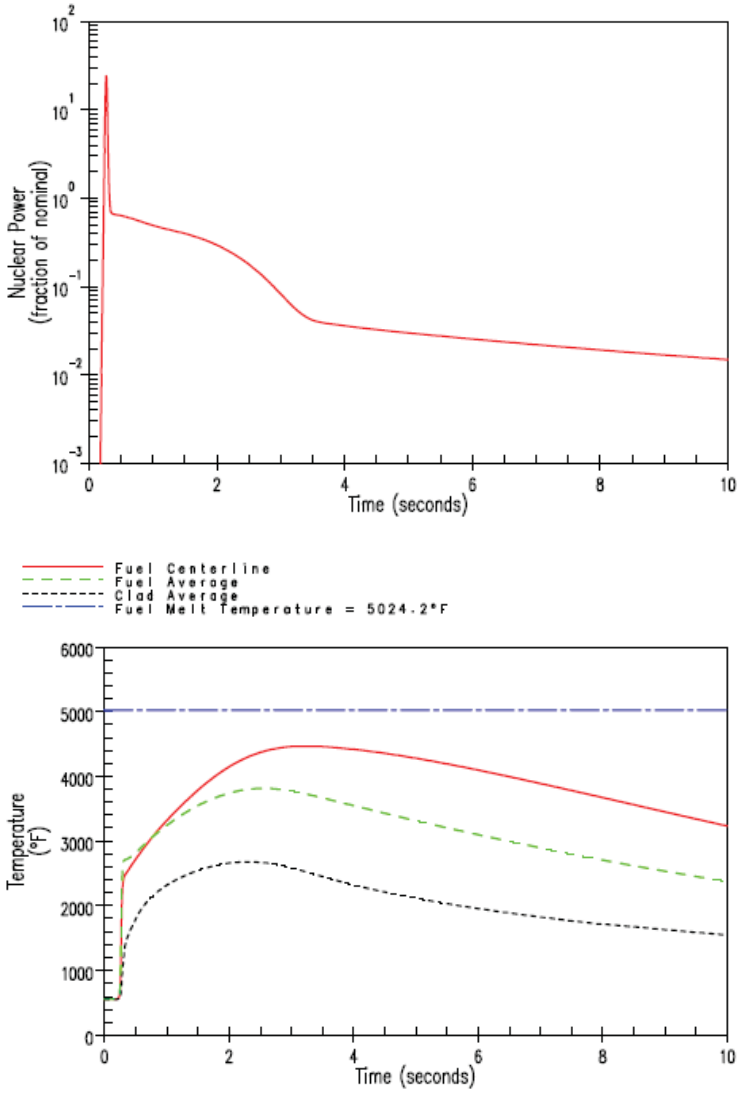
Note: A pressure penalty of +41 psi has been assessed on the calculated maximum RCS pressure, and a temperature penalty of +98°F has been assessed on the calculated maximum clad average temperature to account for the effects of using the PAD5 fuel rod performance code[68]. Also, an additional pressure penalty of +41 psi has been assessed on the calculated maximum RCS pressure to account for a maximum initial pressurizer level[63].

South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
All Loops Operating, One Locked Rotor: Maximum RCS Pressure and Hot Spot Clad Average Temperature vs. Time
Figure 15.4-96B

Figures 15.4-97 through 15.4-99
HAVE BEEN DELETED

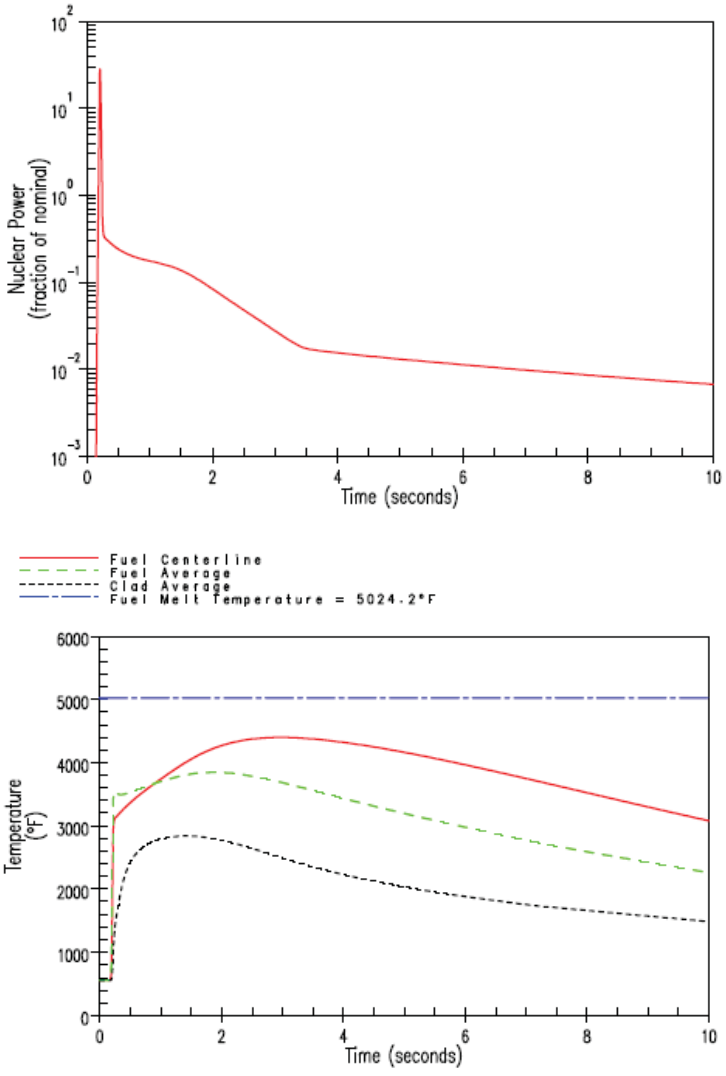
Figure 15.4-100

ROD EJECTION ACCIDENT BOL HZP
NUCLEAR POWER, HOT SPOT FUEL AND CLAD TEMPERATURE VS. TIME



South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
Rod Ejection Accident BOL HZP Nuclear Power, Hot Spot Fuel and Clad Temperature vs. Time
Figure 15.4-100

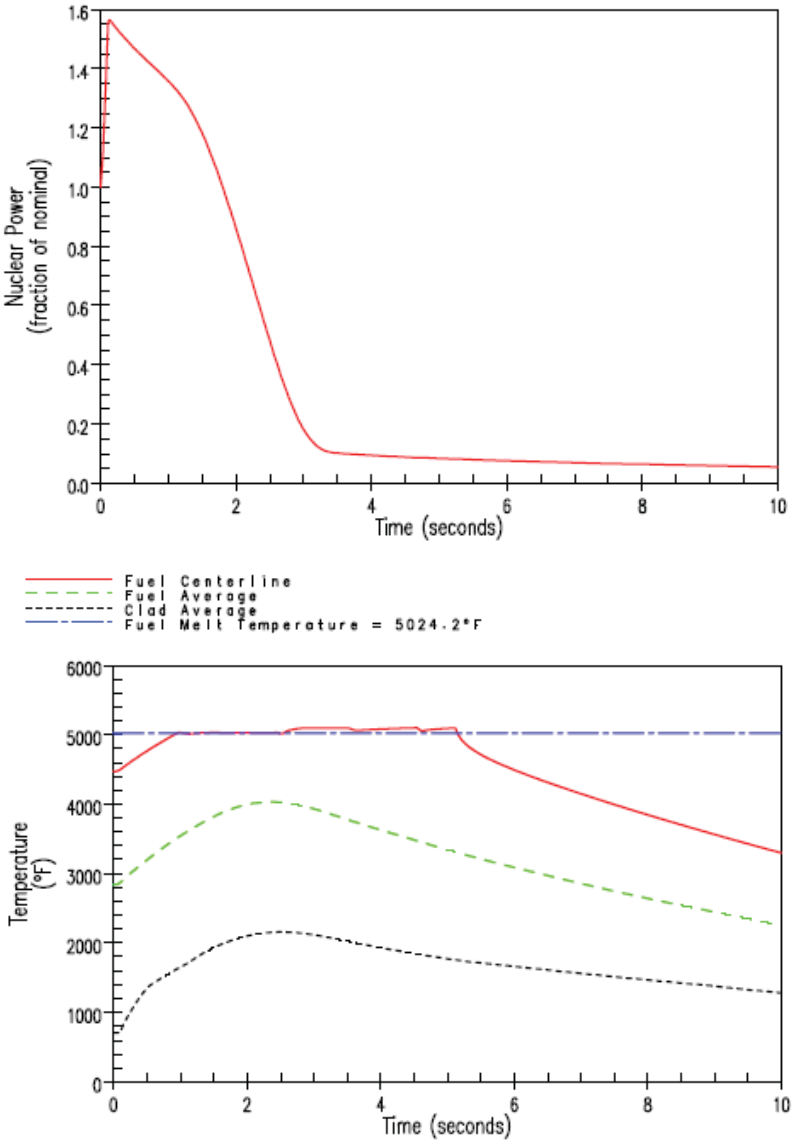
Figure 15.4-101
ROD EJECTION ACCIDENT EOL HZP
NUCLEAR POWER, HOT SPOT FUEL AND CLAD TEMPERATURE VS. TIME



South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
Rod Ejection Accident EOL HZP Nuclear Power, Hot Spot Fuel and Clad Temperature vs. Time
Figure 15.4-101

Figure 15.4-102

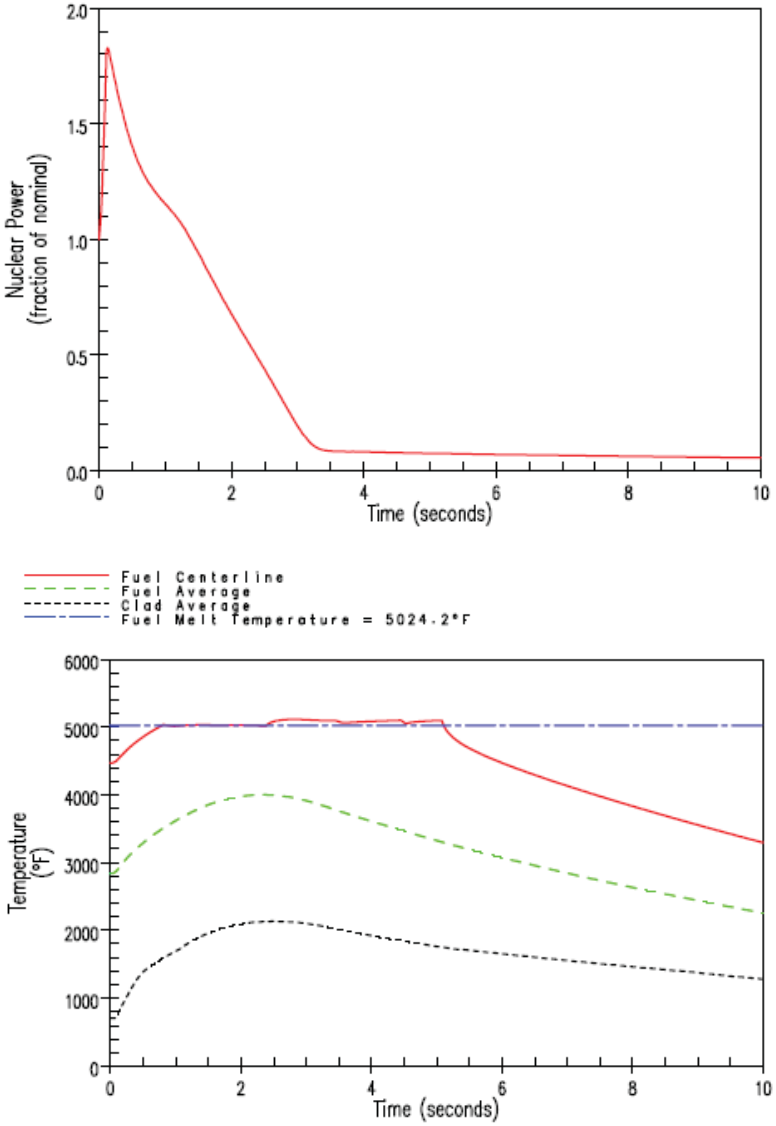
ROD EJECTION ACCIDENT BOL HFP
NUCLEAR POWER, HOT SPOT FUEL AND CLAD TEMPERATURE VS. TIME



South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
Rod Ejection Accident BOL HFP Nuclear Power, Hot Spot Fuel and Clad Temperature vs. Time
Figure 15.4-102

Figure 15.4-103

ROD EJECTION ACCIDENT EOL HFP
NUCLEAR POWER, HOT SPOT FUEL AND CLAD TEMPERATURE VS. TIME



South Carolina Electric & Gas Co. Virgil C. Summer Nuclear Station
Rod Ejection Accident EOL HFP Nuclear Power, Hot Spot Fuel and Clad Temperature vs. Time
Figure 15.4-103

Figure 15.4-104
HAS BEEN DELETED

Figures 15.4-105 through 15.4-122
DELETED PER RN 06-040 JUNE 2009

Figures 15.4-123 through 15.4-142
DELETED PER AMENDMENT 96-02

Figure 15.4-143

RADTRAD MODEL FOR MSLB

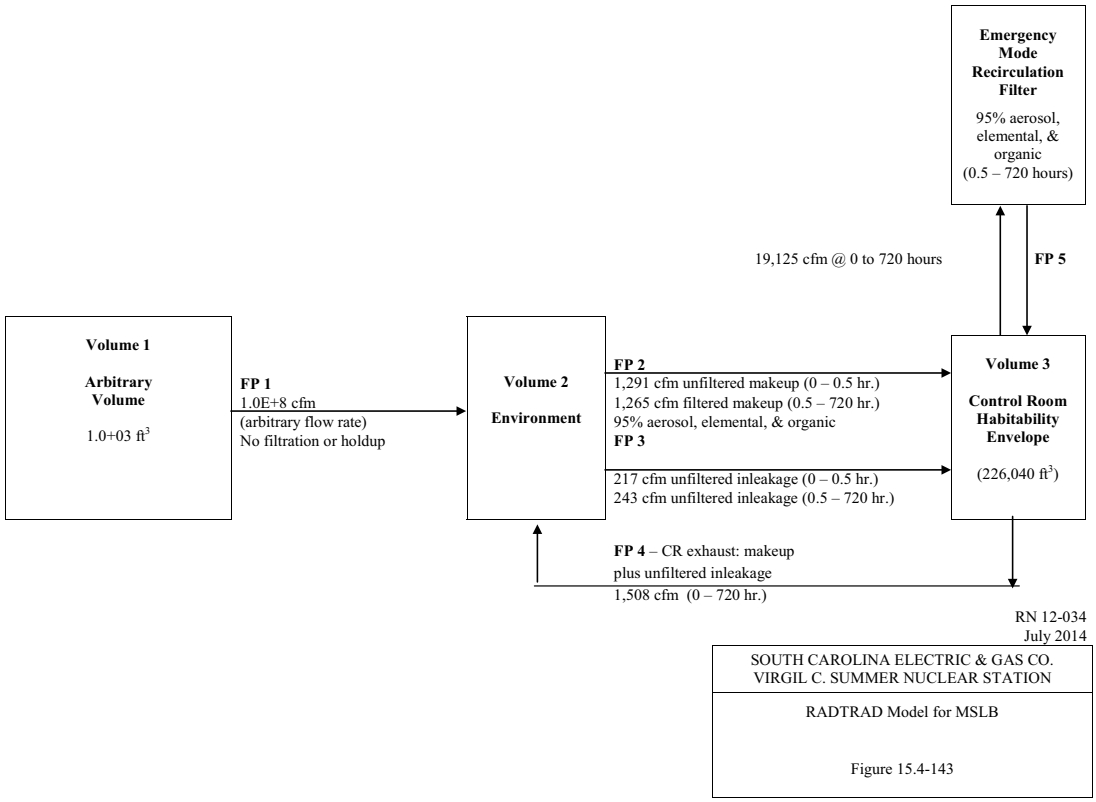


Figure 15.4-144
RADTRAD MODEL FOR SGTR

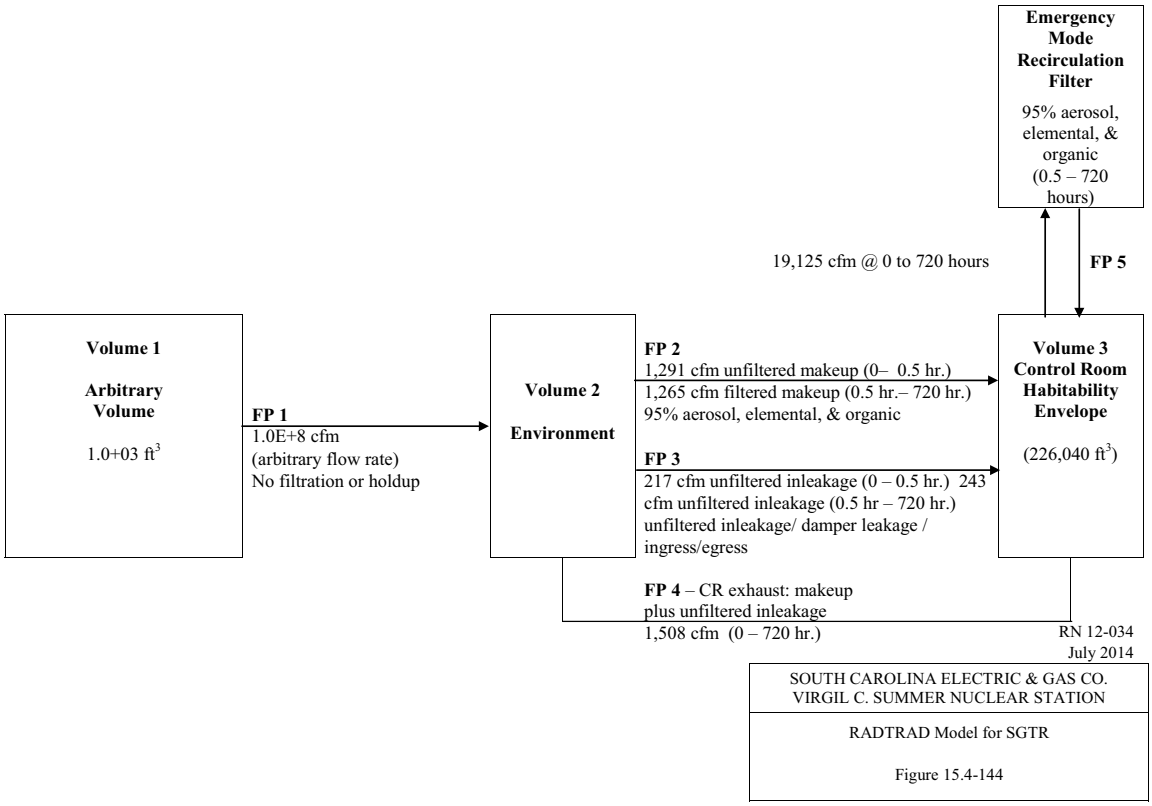


Figure 15.4-145
RADTRAD MODEL FOR RCPRA

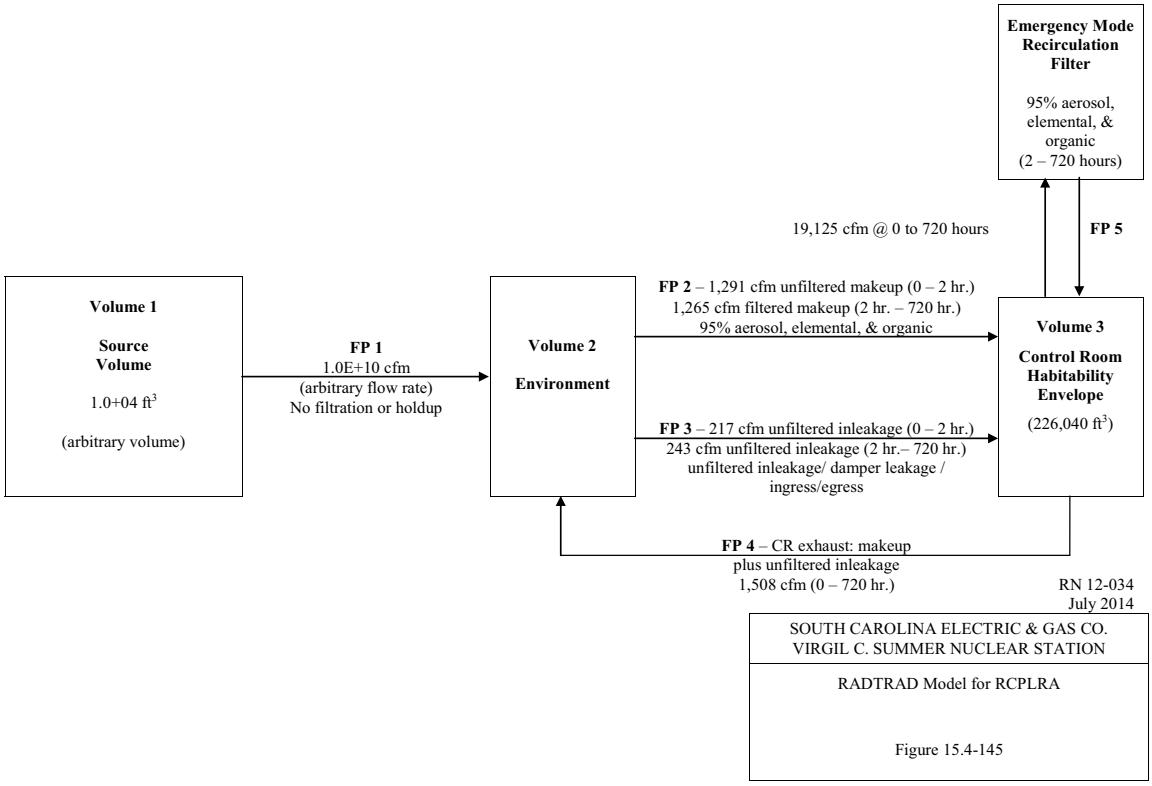
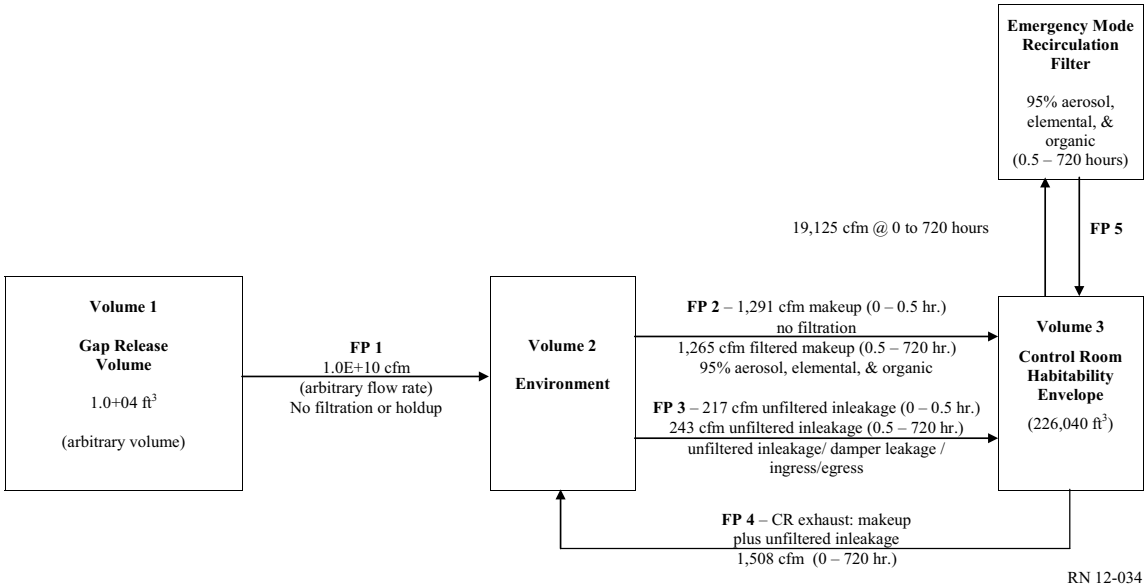


Figure 15.4-146

RADTRAD MODEL FOR INSIDE/OUTSIDE CONTAINMENT FHA



RN 12-034
July 2014

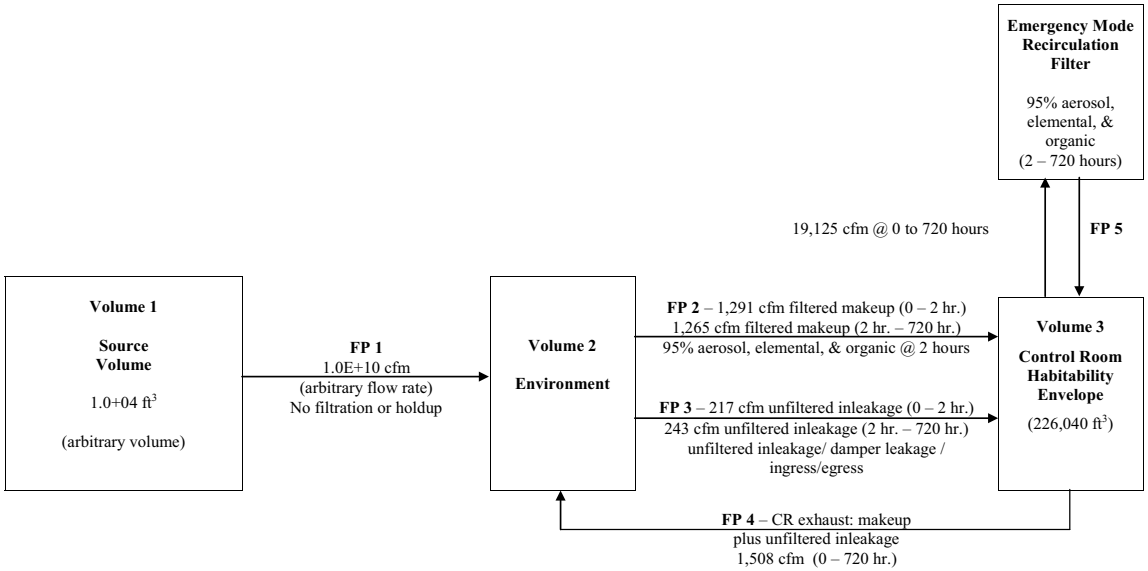
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

RADTRAD Model for Inside/Outside Containment FHA

Figure 15.4-146

Figure 15.4-147

RADTRAD MODEL FOR CREA (STEAM GENERATOR RELEASE)



RN 12-034
July 2014

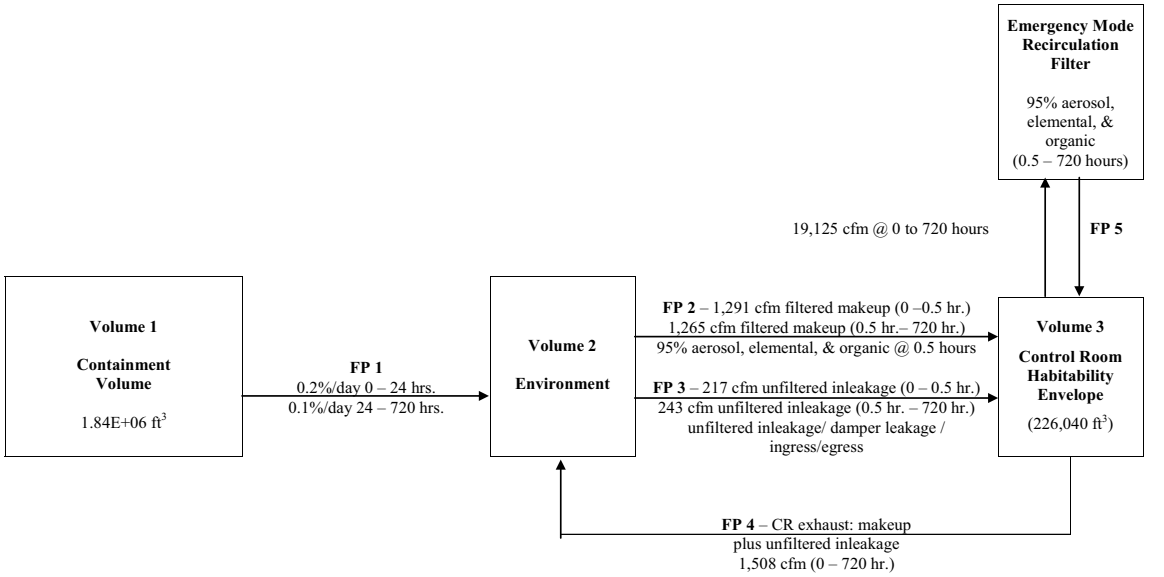
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

RADTRAD Model for CREA
(Steam Generator Release)

Figure 15.4-147

Figure 15.4-148

RADTRAD MODEL FOR CREA (CONTAINMENT RELEASE)



RN 12-034
July 2014

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

RADTRAD Model for CREA (Containment Release)

Figure 15.4-148

15.A DOSE MODELS USED TO EVALUATE THE ENVIRONMENTAL CONSEQUENCES OF ACCIDENTS

15.A.1 Introduction

This appendix identifies the models used to calculate offsite radiological doses that would result from releases of radioactivity due to various postulated accidents. The postulated accidents using this Appendix are as follows:

1. Loss of Offsite Power.
2. CVCS Line Rupture.

The following accidents are evaluated using the methods and models based on USNRC Regulatory Guide 1.183:

1. Loss of Coolant Accident.
2. Steam Line Break.
3. Steam Generator Tube Rupture.
4. Fuel Handling Accident.
5. Rod Ejection Accident.
6. Reactor Coolant Pump Locked Rotor Accident.

15.A.2 Assumptions

The following assumptions are basic to both the model for the gamma and beta doses due to immersion in a cloud of radioactivity and the model for the thyroid dose due to inhalation of radioactivity:

1. Direct radiation from the source point is negligible compared to gamma and beta radiation due to submersion in the radioactivity leakage cloud.
2. All radioactivity releases are treated as ground level releases regardless of the point of discharge.
3. The dose receptor is a standard man as defined by the International Commission on Radiological Protection (ICRP) (<hot spots>Reference 1).
4. Isotopic data, such as decay rates and decay energy emissions, are taken from Table of Isotopes (<hot spots>Reference 2) and Kocher (<hot spots>Reference 6).
5. No correction is made for depletion of the effluent plume due to deposition on the ground or for the radiological decay in transit.
6. The receptor is located at a point on or beyond the site boundary where the maximum ground level concentration is expected to occur.

15.A.3 Gamma Dose and Beta Skin Dose

External whole body doses are calculated using "infinite cloud" assumptions (i.e., the dimensions of the cloud are assumed to be large compared to the distance that the gamma rays and beta particles travel). Such a cloud is considered an infinite cloud for a receptor at the center because any additional gamma and beta emitting material beyond the cloud dimensions does not alter the flux of gamma rays and beta particles to the receptor. Under these conditions, the rate of energy absorption per unit volume is equal to the rate of energy release per unit volume. The dose at any distance from the reactor is calculated based on the maximum ground level concentration at that distance. The infinite cloud methods for calculating whole body beta and gamma doses are as follows:(<hot spots>Reference 3)

1. For the infinite uniform cloud containing χ Ci of beta radioactivity per cubic meter, the beta dose rate in air at the cloud center is:

   $$_{\beta}D'_{\infty} = 0.457E_{\beta}\chi$$

   Where:

   $_{\beta}D'_{\infty}$ = Beta dose rate from an infinite cloud (rem/sec).

   E_{β} = Average beta energy per disintegration (Mev/dis).

   χ= Concentration of beta emitting isotope in the cloud (Ci/m^3).

   Because of the limited range of beta particles in tissue, the surface body dose rate from beta emitters in the infinite cloud can be approximated as being one-half this amount or:

   $$_{\beta}D'_{\infty} = 0.23E_{\beta}\chi$$

   Thus, in terms of integrated dose, the total beta dose to an individual located at the center of the cloud path is approximated as:

   $$_{\beta}D_{\infty} = 0.23E_{\beta}A\chi/Q$$

   Where:

   $_{\beta}D_{\infty}$ = Total beta dose to an individual located at the center of the cloud path (rem).

   E_{β} = Average beta energy per disintegration (Mev/ dis).

   A= Isotopic activity released (Ci).

   χQ= Atmospheric diffusion factor at receptor location (sec/m^3).

2. For an infinite uniform cloud containing ÷ curies of gamma radioactivity per cubic meter, the gamma dose rate in tissue at the cloud center is:

$${}_{\beta}D'_{\infty} = 0.507E\gamma\chi$$

Where:

${}_{\beta}D'_{\infty}$ = Gamma dose rate from an infinite cloud (rem/sec).

$E\gamma$ = Average gamma energy per disintegration (Mev/dis).

χ= Concentration of gamma emitting isotope in the cloud (Ci/m^3).

However, because of the presence of the ground, the receptor is assumed to be exposed to only one-half of the cloud (semi-infinite) and the equation becomes:

$${}_{\gamma}D' = 0.25E\gamma\chi$$

Where:

${}_{\gamma}D'$ = Gamma dose rate from a semi-infinite cloud (rem/sec).

Thus, in terms of integrated dose, the total gamma dose to an individual located at the center of the cloud path is approximated at:

$$\gamma D = 0.25E\gamma A\chi/Q$$

Where:

γD = Total gamma dose to an individual located at the center of the cloud path (rem).

$E\gamma$ = Average gamma energy per disintegration (Mev/dis)

A = Isotopic activity released (Ci).

χ/Q = Atmospheric diffusion factor at receptor location (sec/m^3).

15.A.4 Thyroid Inhalation Dose

The integrated inhalation dose to the thyroid from a release of activity is approximated by use of the following equation (<hot spots>Reference 5):

${}_{I}D$ = Inhalation dose to the thyroid (rem).

A = Isotopic activity released (Ci).

K = Adult thyroid dose conversion factor for the isotope of interest (rem/Ci).

BR = Breathing rate (m^3/sec)

χ/Q = Atmospheric diffusion rate at receptor location (sec/m^3).

The isotopic data and "standard man" data are given in <hot spots>Table 15.A-2. The atmospheric dilution factors can be used in the analysis of the environmental consequences of accidents are given in <hot spots>Table 15.A-3.

15.A.5 References

1. "Permissible Dose for Internal Radiation," ICRP Publication 2, Report of Committee II, 1959.
2. Lederer, C. M., et al., "Table of Isotopes," Sixth Edition, 1968.
3. Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors," USNRC, Revision 2, June, 1974.
4. Deleted by RN 12-034.
5. Dinunno, J. J., et al., "Calculation of Distance Factors for Power and Test Reactor Sites," TID-14844, March, 1962.
6. Kocher, ORNL/NUREG/TM-102, August 1977.
7. Deleted by RN 12-034.

Table 15.A-2
Physical Data For Isotopes

Isotope	Decay (<hot spots 1 9pt>1<superscript><action>) Constant (sec^{-1})	Average (<hot spots 1 9pt>1<superscript><action>) Gamma Energy (Mev/dis)	Average (<hot spots 1 9pt>1<superscript><action>) Beta Energy (Mev/dis)	Thyroid Dose Conversion Factor (Rem/Curie)
I-131	9.96×10^{-7}	0.3708	0.202	1.48 x 106 (<hot spots 1 9pt>2<superscript><action>)
I-132	8.26×10^{-5}	2.337	0.706	5.35 x 104 (<hot spots 1 9pt>2<superscript><action>)
I-133	9.20×10^{-6}	0.477	0.423	4.00 x 105 (<hot spots 1 9pt>2<superscript><action>)
I-134	2.20×10^{-4}	1.85	0.81	2.50 x 104 (<hot spots 1 9pt>2<superscript><action>)
I-135	2.86×10^{-5}	1.77	0.47	1.24 x 105 (<hot spots 1 9pt>2<superscript><action>)
Kr-83m	1.04×10^{-4}	0.00081	-	-
Kr-85	2.04×10^{-9}	0.0021	0.223	-
Kr-85m	4.41×10^{-5}	0.1507	0.273	-
Kr-87	1.48×10^{-4}	1.374	1.27	-
Kr-88	6.95×10^{-5}	1.744	0.933	-
Kr-89	3.63×10^{-3}	1.9 (<hot spots 1 9pt>3<superscript><action>)	1.33	-

Table 15.A-2 (continued)
Physical Data For Isotopes

Xe-131m	6.80×10^{-7}	0.0033	-	-
Xe-133	1.52×10^{-6}	0.03	0.115	-
Xe-133m	3.49×10^{-6}	0.0326	-	-
Xe-135	2.11×10^{-5}	0.246	0.307	-
Xe-135m	7.40×10^{-4}	0.422	-	-
Isotope	Decay (<hot spots 1 9pt>1<superscript><action>) Constant (sec^{-1})	Average (<hot spots 1 9pt>1<superscript><action>) Gamma Energy (Mev/dis)	Average (<hot spots 1 9pt>1<superscript><action>) Beta Energy (Mev/dis)	Thyroid Dose Conversion Factor (Rem/Curie)
Xe-137	2.96×10^{-3}	0.1502	1.37	-
Xe-138	6.60×10^{-4}	1.127(<hot spots 1 9pt>3<superscript><action>)	0.80	-

Breathing Rates

Time Period (Hours)	Breathing Rates (M^3/sec)
0-8	3.47×10^{-4}
8-24	1.75×10^{-4}
24-720	2.32×10^{-4}

Table 15.A-2 (continued)
Physical Data For Isotopes

(1) See <hot spots 1 9pt not super>Reference 2
(2) See <hot spots 1 9pt not super>Reference 5
(3) See <hot spots 1 9pt not super>Reference 6

TABLE 15.A-3
Accident Atmospheric Dilution Factors

	(sec/m^3)	
Averaging Period (Hours)	1 Mile	3 Miles
1	4.08×10^{-4}	1.01×10^{-4}
8	8.43×10^{-5}	2.37×10^{-5}
16	1.34×10^{-5}	2.44×10^{-6}
72	6.12×10^{-6}	1.11×10^{-6}
624	3.52×10^{-6}	6.28×10^{-7}

V.C. Summer Nuclear Station
Safety Analysis Report

Technical Specifications

Chapter 16

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

16.1 TECHNICAL SPECIFICATIONS

Chapter 16, Technical Specifications, has been deleted. The Virgil C. Summer Nuclear Station Technical Specifications, as approved by the NRC, has been issued as Appendix A to the Facility Operating License.

V.C. Summer Nuclear Station
Safety Analysis Report

Quality Assurance

Chapter 17

Revision 26--06/25/26

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

Electric Power
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CHAPTER 17 - QUALITY ASSURANCE

NOTE 17.1

Section 17.1 is being retained for historical purposes only.

17.1 INTRODUCTION

South Carolina Electric & Gas Company (SCE&G) recognizes the need for a comprehensive, formalized, documented method of specifying and verifying that the Virgil C. Summer Nuclear Station design, procurement, construction, modification, maintenance, inservice inspection, and operation has been and will continue to be accomplished without undue risk to the health and safety of the public. Cognizant of its responsibilities as an applicant for an operating license, SCE&G has established and will execute an effective Quality Assurance (QA) Program for Virgil C. Summer Nuclear Station which meets the requirements of Title 10 CFR Part 50, Appendix B. The QA Program provides the necessary systematic activity and administrative control to provide checks to assure activities which affect quality and safety-related functions during design, procurement, construction, modification, maintenance, inservice inspection, and operation are performed in accordance with established requirements. The SCE&G QA Program is applied to those items identified as safety-related in Table 3.2-1.

SCE&G also recognizes that in addition to providing a high degree of confidence that structures, systems, and components; as designed, manufactured, constructed, maintained, and modified; reflect all safety-related requirements, the reliability and availability of the plant will be enhanced by the implementation of the Program. The philosophy used in the QA Program development ensures that systems, components, and structures have optimum quality consistent with safety, reliability, and plant availability considerations, as well as consideration for sound engineering.

17.1.1 Quality Assurance During Design, Construction, and Major Modification

The responsibility for the overall nuclear project rests with the SCE&G Executive Vice President Operations. On an independent organizational chain from Production Engineering and Construction, the responsibility for administration of the overall QA Program is delegated to the SCE&G Vice President and Group Executive, Nuclear Operations, who reports to the Executive Vice President Operations. He is assisted in executing this responsibility by the SCE&G Group Manager Nuclear Services, the Manager of QA, Gilbert Associates, Inc. (Gilbert), and other consultants, as needed, who have been or will be retained to implement the QA Program. Westinghouse provides a QA Program on the nuclear steam supply (NSSS) structures, systems, and components. Gilbert provides a balance of plant (BOP) QA Program on safety-related structures, systems, and components not included in NSSS scope. SCE&G, assisted by the Gilbert QA Division and others as agents, audits these programs to assure the effectiveness of the portion of the program performed by Gilbert and Westinghouse. The following sections describe the QA responsibilities and authorities of each major organization during construction and potentially during major outages.

17.1.1.1 South Carolina Electric and Gas Company

The Virgil C. Summer Nuclear Station QA organization chart (Figure 17.1-1) shows the lines of responsibility for design, procurement, construction, and QA for safety-related activities of the Virgil C. Summer Nuclear Station.

The overall responsibility for this nuclear project rests with SCE&G Executive Vice President of Operations. The executive management responsibility for assurance of provision of an adequate QA Program has been assigned to the SCE&G Vice President and Group Executive, Nuclear Operations, who is on an independent organization chain from production engineering and construction. Execution of this responsibility is by the SCE&G Group Manager Nuclear Services with implementation by the Manager of Quality Assurance.

The Gilbert QA Division and other consultants, as needed, have been and are expected to be retained to assist SCE&G QA in auditing the QA Program on the NSSS and safety-related structures, systems, and components. SCE&G QA and/or their agents audit these programs and perform surveillance to verify compliance with and effectiveness of the overall QA Program.

The SCE&G Vice President and Group Executive, Engineering and Construction directs the project construction with the assistance of the Group Manager, Construction and Quality Control, the QC Manager (Construction), and the Nuclear Site Manager. Construction is under the overall supervision of the SCE&G Nuclear Site Manager, with quality control (QC) the responsibility of the SCE&G QC Manager. Both report independently to the Group Manager of Construction and Quality Control.

The SCE&G Vice President and Group Executive, Rates/Purchasing assisted by the General Manager, Purchasing, and the Manager of Production and Construction Purchasing is responsible for procurement of equipment, material, and services.

17.1.1.1.1 Quality Assurance Program Organization

QA Figures 17.1-1 and 17.1-2 show the lines of responsibility for the QA Program. QA activities pertaining to the design, procurement, fabrication, handling, installation, and testing of safety-related structures, systems, and components are carried out in accordance with procedures that have been developed to conform to the 18 criteria as set forth in Appendix B of 10 CFR 50. These procedures are assembled in the SCE&G QA Procedures Manual, the Gilbert QA Manual, the SCE&G QC Manual, the SCE&G Nuclear Engineering Procedures Manual, the SCE&G Purchasing Procedures Manual, the Westinghouse WRD Quality Assurance Plan, the Daniel Construction Company (Daniel) Construction Procedures Manual, the Gilbert Project Management Manual, and vendor and contractor procedures manuals.

The SCE&G QA Program involves personnel from various organizational groups within the company. The general responsibilities of these groups are as follows:

1. Quality Assurance Group

The Group Manager, Nuclear Services provides administrative control and coordination of the role and mission of the QA section. He has the responsibility to evaluate the performance of the QA Program to assure adequacy and allocation of sufficient resources to perform the role and mission. The Group Manager is the link to effective executive corrective action whenever identified. The Group Manager, Nuclear Services through the Vice President Nuclear Operations has the responsibility to identify needed senior management action. The Manager of QA reports to the Group Manager. The Manager of QA is responsible for the direction and implementation of the total QA Program. These responsibilities include:

a. Preparation and revision of the overall QA Program, assisted as needed by the Gilbert QA Division, Westinghouse, each group or organization performing quality activities and/or other agents.

b. Review and approval of the QA Program and associated documents generated by SCE&G and its agents, Gilbert, Westinghouse, Daniel, vendors, and contractors.

c. Review and/or approve revisions to the QA program and associated documents.

d. Schedule, perform, and/or direct performance of audits of SCE&G, its agents, Gilbert, Westinghouse, Daniel, vendors, and contractors; and the surveillance of Daniel, vendors, and contractors.

e. Audit and approve solutions to safety-related interface problems which arise.

f. Monitor the status of the QA Program to assure effective implementation.

g. Identify that appropriate corrective action is taken to accomplish changes where activities do not comply with QA and QC plans or procedures.

h. Stop work on safety-related structures, systems, and/or components when designated codes, standards, design documents, or procedures are not being adhered to and cannot be immediately corrected.

i. Ensure that the collection, distribution, audit, and filing of all project QA records are accomplished in a controlled manner.

j. Notify the Nuclear Regulatory Commission of any significant breakdown in any portion of the QA Program.

k. Provide for the indoctrination, training and certification of SCE&G QA personnel in the performance of activities affecting quality.

Site QA personnel under the direction of the SCE&G QA Director of Surveillance Systems are responsible for surveillance of site quality-related activities including such areas as receiving, handling, site fabrication, installation, construction, and testing. When the scope of work activity during construction or major outage warrants it, a Quality Assurance coordinator may be assigned who reports to the Director of Surveillance Systems.

2. Nuclear Engineering and Licensing Department

   During the Construction phase of the project, the Nuclear Engineering and Licensing Department, under the direction of the Group Manager, Nuclear Engineering and Licensing; who is assisted by the Manager, Nuclear Engineering; the Manager, Nuclear Licensing; the Manager, Independent Safety Engineering Group; and the Manager, Corporate Health Physics and Environmental Programs, has the following responsibilities:

   a. Direct the activities of Gilbert through Gilbert's Project Manager and coordinate the activities of the Gilbert, Westinghouse, Dames and Moore (D&M), and other consultants and agents as needed.
   b. Review and approve basic designs as developed by the Gilbert, D&M, and other consultants.
   c. Review bidder's lists.
   d. Review and approve specifications.
   e. Evaluate vendor proposals and make recommendations for procurement sources.
   f. Participate in, review, and approve the preparation and distribution of the Safety Analysis Reports, Environmental Reports, and other documentation, as required by the Nuclear Regulatory Commission and other regulatory agencies.
   g. Review and approve amendments to the documents noted in item f, above.
   h. Review and approve Field Change Requests and Engineering Change Notices.
   i. Review and disposition Nonconformance Notices.
   j. Prepare bid documents for SCE&G purchases.
   k. Participate in plant testing and acceptance as required.
   l. Participate in the inspection program as required.
   m. Participate in the test control program as required.
   n. Perform functions as required in connection with the licensing of the Virgil C. Summer Nuclear Station.

3. Procurement

   Procurement is the responsibility of the Vice President and Group Executive, Rates/Purchasing who is assisted by the General Manager, Purchasing and the Manager of Purchasing, Production and Construction.

   a. Select qualified bidders with the assistance of engineering, operating, and QA groups.
   b. Solicit bids for equipment, materials, and services.
   c. Submit commercial, QA, and technical evaluations to the SCE&G Purchasing Committee which selects vendors.

d. Issue and control changes to purchase orders.

e. Prepare, in cooperation with the QA and nuclear engineering groups, procurement procedures.

4. Nuclear Site Manager

The SCE&G Nuclear Site Manager has the overall responsibilities for the construction activities performed on the site by Daniel, contractors, and subcontractors. Administratively, the SCE&G Nuclear Site Manager reports to the Group Manager Construction and Quality Control and is responsible for the cost and scheduling of the work done on the site. All work done on the site by the various crafts of Daniel, contractors, and subcontractors is under the jurisdiction of the Daniel Project Manager. The Daniel Project Manager also has the responsibility for compliance with the Daniel QA Manual for Nuclear construction in the fabrication and installation of ASME Code, Section III components. For major modifications, a project manager having the same responsibilities as the Nuclear Site Manager above may be appointed.

5. Quality Control Manager

The SCE&G QC Manager also reports to the Group Manager Construction and Quality Control. The SCE&G QC Manager supervises the QC efforts at the site in accordance with the SCE&G QC Plan. The QC organization performs the following major functions but are not limited to these:

a. Work and communicate with Daniel, Daniel QC and QA, and SCE&G QA groups at the site.

b. Supervise the activities of commercial testing organizations at the site, who are under contract with SCE&G.

c. Prepare QC procedures for inspection of construction activities.

d. Stop work on structures, systems, and/or components when work is not in compliance with specified standards, codes, design documents, or procedures.

e. Be responsible for the testing and inspection of work performed by Daniel, contractors, and subcontractors at the construction site except when QC is provided by Daniel (ASME Code Work), or ASME contractors or subcontractors. SCE&G/QC will be responsible for testing and inspection of piping hangers where the intent of ASME Code requirements is being met.

f. Inspect on receipt, material and equipment for conformity to purchase documents and perform acceptance tests as required except when QC is provided by Daniel (ASME Code work). File test reports, certificates of release, and other documents necessary to verify quality.

g. Perform warehousing functions.

h. Maintain the permanent file for QA records, inspection reports, tests, certificates of release, and other QA documents.

i. Report potentially significant deficiencies found in construction in accordance with approved procedures.

17.1.1.1.2 Lines of Authority and Communication

As noted in Figure 17.1-1, the complex multi-organizational QA Program requires definite lines of authority and communication with control by independent checks. These relationships warrant discussion to illustrate how overall administrative control of the Program by SCE&G is achieved.

1. Overall Project

   The line of authority within the organization clearly provides the flexibility for quality related problems to be identified and resolved. The SCE&G Manager of QA, having a direct line through the Group Manager Nuclear Services to the Vice President Nuclear Operations and the Senior Vice President Power Operations, can inform SCE&G top management of unresolved QA issues.

2. Quality Assurance

   The Vice President and Group Executive, Engineering and Construction is made aware of the QC activities by the SCE&G QC Manager through his line of authority to the Group Manager Construction and Quality Control.

   The QC staff and the independent test laboratories are under the direction and supervision of the SCE&G QC Manager.

   The General Manager, Purchasing, has a direct line of authority through the Vice President and Group Executive, Rates/Purchasing through which the Executive Vice President Finance is kept informed of the status of the purchasing operations. The line of authority extends downward such that the SCE&G Group Manager Nuclear Services monitors and controls the direction of QA activities through the Manager, Quality Assurance, his staff, QA organization onsite, the Gilbert Project Quality Coordinator, and other agents, as needed.

   As can be seen in Figure 17.1-1, there are five key Group Managers (General Managers) within the SCE&G organization who provide the necessary coordination and communication channels to allow information and project status to flow into the QA Program.

   a. The SCE&G manager QA is responsible for the overall functional control of the QA Program and provides guidance and coordination through communications with the Manager, Nuclear Engineering; the Manager, Nuclear Licensing; and the Manager, Purchasing, Production and Construction. The Manager of QA is responsible to review and comment on safety-related (including ASME Code) construction and QC procedures. Audits and site surveillance are performed to assure that safety-related work (including

ASME Code) is accomplished in accordance with the QA Program requirements described herein. This enables the QA functions and responsibilities within the overall administration of the project to be under the guidance and coordination of the SCE&G Manager of QA with the cooperation of SCE&G management. Thus, problem areas anywhere within the QA Program are resolved through the responsible SCE&G management.

b. The Gilbert Project Quality Coordinator provides the SCE&G Manager of QA with a focal point within the Gilbert organization, thus extending the authority and visibility of the QA Program. By communications with Gilbert project engineering and management, as well as Westinghouse and other vendors, the Gilbert Project Quality Coordinator provides the SCE&G Manager of QA with additional information for directing the QA Program.

c. The SCE&G Director of Site Surveillance and/or QA Coordinator, in close cooperation with the Nuclear Site Manager, SCE&G QC Manager, Daniel Project Manager, the Daniel Project Quality Manager (ASME Code work), and other constructor site managers, assures the understanding and implementation of quality associated requirements.

d. The SCE&G Construction QC Manager directs inspection and quality item control activities at the construction site except as defined in item e, below. Reporting offsite to the Manager of Construction and Group Manager Production Engineering, Quality Control and Construction; the SCE&G QC Manager effectively communicates and coordinates quality activities with the Daniel Project Manager and other contractors for effective implementation of the QC Program.

e. The Daniel Project Quality Inspector directs the inspection and QC activities required for the ASME Code work. The Daniel Project Quality Inspector reports to the Daniel Project Quality Manager onsite for effective coordination of ASME Code quality activities.

3. Functional Relationships

The functional relationships within the SCE&G QA Program provide control to assure effective program compliance.

a. Construction site work is verified by inspection performed by the SCE&G QC and Daniel QC Groups (ASME Code work only) or by contractor or subcontractor QC.

b. Site QC and construction activities are monitored by a formal surveillance program conducted by the SCE&G QA organization onsite.

c. Vendors are required to provide internal independent QA Programs to check design and fabrication work unless working under the SCE&G QA Program.

d. Gilbert QA, SCE&G QA, and/or its agents perform vendor audits and surveillance to verify vendor performance.

e. Westinghouse, for the NSSS components, is required to provide an internal QA Program (see Section 17.1.1.3).

f. Gilbert, for design and engineering, is required to provide a Design Control Program including internal audits.

g. SCE&G QA periodically audits Westinghouse, as NSSS supplier, Gilbert as architect-engineer, Gilbert QA Division as QA consultant, Daniel as the constructor, SCE&G QC, and internal SCE&G safety related activities. These or any other contractor or agent utilized during major modification will have equivalent controls imposed.

h. Daniel QA periodically audits the Daniel ASME Code program onsite, as required to maintain the Daniel ASME Certificate of Authorization.

17.1.1.1.3 Control of Contractors

1. General

The Virgil C. Summer Nuclear Station QA Program is effectively administered and controlled by SCE&G through close association with, supervision, and audit of the contractors who perform the duties and tasks outlined and delineated herein. The QA programs of the contractors were reviewed by SCE&G QA and/or its agents to assure that they contained adequate requirements and procedures to control the attainment of quality. All contractors performing safety-related work must have a QA Program reviewed and concurred with by SCE&G QA or its agents; unless the contractors are providing only labor for utilization under the direct control of the SCE&G QA Program. In some cases a contract specific QA plan, jointly approved by SCE&G and the contractor, may be used in lieu of a program manual. Contractors impose on their subcontractors a QA program commensurate with the complexity of the item and its importance to nuclear safety to assure that the high level of quality set forth in the contract documents is maintained.

2. Control Methods

Major responsibilities for implementation of the various QA activities included in the SCE&G QA Program during design, procurement, and manufacturing have been delegated to Gilbert and Westinghouse. These responsibilities are described in the Gilbert QA Plan and in the Westinghouse Electric Corporation Water Reactor Divisions QA Plan (Reference (1)). Primary responsibilities for the construction site QA and QC programs lie with SCE&G QA and the SCE&G QC organizations, respectively. The SCE&G Manager of QA controls, coordinates, and administers the overall QA Program by the use of the following planned and systematic checks of program status and progress:

a. Review and approval of the QA Program of contractors (including the Daniel ASME QA Program).

b. Regular QA Program development and implementation status checks.

c. Scheduled QA Program audits.

d. QA Program surveillance and corrective measures.

17.1.1.2 Gilbert Associates, Inc.

The corporate organizational chart of Gilbert is shown in Figure 17.1-4. In retaining Gilbert, SCE&G has two distinct groups providing professional services in the areas of engineering and QA. Gilbert Power Engineering, Reading, provides the design services of the various engineering departments including, but not limited to, Hydraulic and Civil, Structural, Architectural, Environmental, Mechanical, Electrical, Chemical, and Nuclear. QA services are provided by the Gilbert QA Division as shown in Figure 17.1-5. Gilbert has been retained to provide experienced personnel to assist SCE&G with the overall QA Program. The general responsibilities of the Gilbert Power Engineering, Reading, are described in the Gilbert Project Management Manual and general responsibilities of the Gilbert QA Division are described in the Gilbert QA Plan.

1. Engineering

   Engineering is responsible through the Gilbert Project Manager for the design of all areas of the plant with the exception of the equipment supplied by Westinghouse. The various engineering disciplines are responsible for their respective areas of design and preparation of specifications and drawings. Engineering specifies the level of quality inspection and test requirements, acceptance criteria, and documentation requirements. Any deviation or waiver request from approved drawings, specifications, or procedures must be acted upon by the same (or an SCE&G approved equivalent) engineering group which was responsible for the original design. They also review and approve vendor drawings and documents as appropriate. Design reviews are performed by engineering personnel not responsible for the original design. Design document control is under the control of the Gilbert Project Manager.

2. Quality Assurance

   The Gilbert QA Division and other QA agents or consultants assist the SCE&G Manager QA, as requested, in implementing the QA Program in the areas of specification review, A/E audit, vendor proposal review, NSSS supplier audits, vendor surveillance, and construction audits.

17.1.1.3 Westinghouse Electric Corporation

The Westinghouse QA Plans are given in References 1 and 2. The degree of QA for Westinghouse NSSS components is given in Table 3.2-1.

The original QA Program implemented by Westinghouse for the Virgil C. Summer Nuclear Station was described in Appendix 1C of the Virgil C. Summer PSAR. Over the course of performing the design and initial procurement activities for the Virgil C. Summer Nuclear Station, the Westinghouse QA Program was upgraded to reflect changes in regulatory requirements and industry standards as shown in References 1 and 2. These changes first culminated in WCAP-8370, Revision 7A. This revision of the Westinghouse QA Program was applicable to activities within Westinghouse scope performed for the Virgil C. Summer Nuclear Station which were initiated after January 1, 1975 to October 1, 1977. Subsequently, the present Westinghouse QA Program, which is described in WCAP-8370, Revision 8A, is applicable to activities within

Westinghouse scope which were initiated after October 1, 1977 to October 15, 1979. Presently, the Westinghouse QA Program is described in WCAP-8370, Revision 9, and is applicable to activities within the Westinghouse scope which were initiated after October 15, 1979.

17.1.1.4 Daniel Construction Company

Daniel has been retained by SCE&G as the constructor to perform the actual construction activities at the project site except for specialized phases of the work which will be performed by other qualified contractors and subcontractors. The Daniel organization for the Virgil C. Summer Nuclear Station project is shown in Figure 17.1-6. Daniel is under the direction of the Daniel Project Manager who is responsible to the SCE&G Nuclear Site Manager. Daniel is responsible for the development and implementation of effective controls over the construction and erection of the safety-related structures, systems, and components to assure their conformance to the design specifications and drawings, (including the fabrication and installation of ASME Code work). Daniel responsibilities include:

1. Selection and indoctrination of qualified personnel.
2. Direct supervision of work performed by the crafts.
3. Responsibility for the quality of work done.
4. Scheduling and planning of work.
5. Preparation of construction procedures as indicated in Gilbert construction specifications and as determined to be needed by Daniel construction management to complete a quality installation.
6. Reporting monthly on the status of the construction.
7. Ensuring that only the latest revisions or issues of field documents, i.e., drawings, specifications, procedures, etc., are used for construction.
8. Providing the Daniel QA Program for the Daniel scope of work which includes the Daniel QA Manual for ASME Code work.
9. Providing the QA, QC, and Construction procedures necessary to perform field fabrication and installation of ASME Code stamped work.
10. Regularly review the status and adequacy of the construction QA Program being executed by Daniel.

The Daniel QA Program is contained in the Daniel Construction Procedures Manual and the QA Manual for Nuclear Construction. Work procedures for performing the assigned construction activities are contained in the Daniel Construction Procedures Manual (procedures for ASME Code work are included).

Construction site QC is performed by SCE&G QC and/or its agents for Daniel activities in accordance with the SCE&G QA Plan and Field Quality Control Plan, except for specialized phases of work by other contractors and subcontractors who will perform the required QA and

QC; and the ASME Code work by Daniel who will perform the QA and QC required by the Daniel Certificates of Authorization. The construction site QA is provided by SCE&G QA in accordance with the SCE&G QA Plan and Manual, except as noted above.

17.1.2 Quality Assurance Program

The Virgil C. Summer Nuclear Station QA Program is comprised of planned and systematic activities and independent verification during design, procurement, equipment fabrication, site construction and erection, and system final inspection and testing. This QA Program is organized to provide an integrated plan under the direct control of SCE&G. A system of audit and surveillance provides assurance that elements of the Program are functioning as planned.

17.1.2.1 Applicability

The SCE&G QA Program is applicable to those structures, systems, and components classified as safety-related. These items are identified in Section 3.2. The items identified as within Westinghouse scope of supply are the responsibility of Westinghouse subject to SCE&G audit, assuring appropriate QA measures. The remaining safety-related items are controlled directly by SCE&G, using the assistance of Gilbert, Daniel, and other contractors for construction and installation. The QA Program is in force throughout the design and construction of the Virgil C. Summer Nuclear Station. During future major maintenance or modification, all or parts of the organizational structure shown on Figure 17.1-1 may be employed commensurate with the complexity of the activity. A QA Coordinator reporting to the Director of S. S. may be assigned if the scope of the activity requires dedicated QA follow-up. Agents and/or contractors including those herein discussed may be employed in accordance with QA program requirements herein specified.

17.1.2.2 Administrative Controls

The SCE&G corporate QA policies and procedures are aimed at the goal of obtaining a plant which is safe and reliable in accordance with the requirements of 10 CFR 50, Appendix B. The procedures used in implementing the QA Program incorporate provisions for proceeding to successive levels of management until resolution is obtained, with ultimate resolution by the Executive Vice President, Operations.

The Vice President Nuclear Operations performs a continuing review of the SCE&G QA Program with and through the SCE&G Group Manager Nuclear Services and Manager of Quality Assurance; and reports on the effectiveness of the programs to the Executive Vice President, Operations through the Senior Vice President Power Operations.

The Manager of QA through the SCE&G Group Manager Nuclear Services has been delegated the responsibility for the establishment, maintenance, control, distribution, and verification of implementation of the QA Program by the Vice President and Group Executive, Nuclear Operations. The Group Manager Nuclear Services shall annually, or as deemed necessary, have the SCE&G QA Program reviewed and revised where required. Affected organizations may submit recommended changes as they see fit. Proposed revisions, as a result of the QA review or

recommended changes by others, are submitted to SCE&G groups having responsibilities in the QA Program for comment prior to revision of the Program. Conflicting comments are resolved by the SCE&G Manager of QA with the concerned parties. Revisions affecting Code requirements shall be submitted to the Authorized Inspection Agency for acceptance prior to implementation.

The procedures and instructions which govern the activities of SCE&G in the design and construction of the Virgil C. Summer Nuclear Station are contained in the QA Manual, the Nuclear Engineering Procedures Manual, the QC Procedures Manual, and the Purchasing Procedures Manual. When required by the contract documents, each contractor of safety-related structures, systems, or components is required to develop and implement his own QA Program which is reviewed and audited by SCE&G. Audits of the contractors are conducted by SCE&G or its agents to ensure that the QA requirements are met.

The QA procedures in the area of procurement control require the Manager of QA to evaluate and accept contractor's QA Programs, by review of QA information submittals, review of QA activities on active purchase orders, and, where necessary, preaward surveys of the prospective contractor's QA Program, prior to award of a purchase order. During performance of the contract, SCE&G QA personnel or Gilbert QA personnel, at the request of the SCE&G Manager of QA, will conduct surveillance of the contractor to assure continued implementation of the accepted QA Program. These activities are recorded in surveillance reports, and findings of the reports resolved with the contractors.

QA personnel, in their reviews of programs and special process procedures implementing the QA Program, shall assure that procedures require that all prerequisites for a given action are satisfied, such as the presence and use of suitable equipment (certified or qualified when necessary), a suitable environment for accomplishing the activity, such as adequate cleanliness and lighting levels, and that necessary prerequisites for the activity have been met, e.g., prior specified examinations and processing operations or the establishment of test or inspection acceptance criteria. The QA Program requires that the procedures be prepared and made available for use prior to the need for each at the point of use. These special process procedures controlling safety-related work shall be reviewed and concurred with and a "release to fabricate" or "release to work" (for site activity) granted before work begins in the area, see Section 17.1.7.

17.1.2.3 Indoctrination and Training

The indoctrination and training is described in the indoctrination and training procedures for each organization within SCE&G with quality related responsibilities. The procedures require that personnel be familiar with the requirements of their position, and maintain expertise in their specialty. The SCE&G QA organization conducts a training course in the basics of plant familiarization and QA, with detailed emphasis on the conduct of surveillance and audits, for all personnel in the SCE&G QA organization. Expertise is also maintained by continuing experience in surveillance and auditing on the part of each member of the SCE&G QA organization.

The SCE&G Manager of QA shall have a B. S. Degree in engineering, or its equivalent in experience and/or correspondence courses. He shall be experienced in design, manufacturing, operations, construction, and/or administration in utility or related industries; have at least 1 year

experience in QA management and policies; and be knowledgeable of applicable codes and standards. QA Directors, QA Engineers, and the Site QA coordinator shall be graduates of accredited engineering curricula, or the equivalent, and, preferably, have had experience in the design, manufacturing, operation, construction, or QA areas relative to the nuclear and/or utility fields. QA specialists shall be graduates of a two year engineering technical school or have the equivalent in practical experience and/or correspondence courses.

17.1.3 Design Control

17.1.3.1 South Carolina Electric & Gas Company

During the construction phase, the SCE&G Nuclear Engineering and Licensing Department performs design control functions relative to design interface control, specification, drawing technical reviews, and SAR deviation control. The Nuclear Engineering and Licensing Department's Manager, Nuclear Licensing performs design control functions relative to SAR deviation control. The SCE&G activities are described in the SCE&G Nuclear Engineering Procedures Manual. SCE&G Nuclear Engineering Department monitors; through its reviews of design documents, and SCE&G QA or its agents audits; the design control activities of Gilbert, Westinghouse, and other vendors.

17.1.3.2 Gilbert Associates, Inc.

1. Design Review and Verification

   Safety-related design activity is reviewed and verified by a formalized and documented system described by the Gilbert Project Management Manual. The types of review used are:

   a. Checks to compare information presented on a drawing or other document with a definite, stipulated figure, criterion, or design base,

   b. Supervisory reviews which are critical inspections of design work, conducted by a superior in a given discipline, of work by a project team member in that discipline,

   c. Interface reviews by personnel of one discipline or company of work performed by another discipline or company to determine, with reasonable assurance, that the reviewers discipline requirements are provided for, and that specification requirements are satisfied for the reviewers discipline or company,

   d. Design verification which is independent confirmation of design adequacy and compliance with requirements, performed by an individual other than the originator, who did not perform work on the item being reviewed.

   Each discipline prepares a Design Verification Status Report identifying each item to be verified and indicating the status of each item. System design may be verified in whole or in parts. When in parts, separate verification attestations must be completed and the Design Verification Status Report must define and reflect the verification of each part. Each review and verification must be indicated on the specified form or by signature or reference to the

acceptance letter of the responsible engineering company on the document reviewed. Suitable equivalent controls will also be maintained during major modifications.

2. Specification Reviews

It is the responsibility of the Gilbert Project Engineer to ensure that the necessary QC and QA requirements are included in the specifications for structures, systems, and components for which he has design responsibility. In addition to reviews by SCE&G and other Gilbert design engineers, specifications are reviewed by the Gilbert QA Division and/or the SCE&G QA organization to assure that sufficient quality requirements have been incorporated for safety-related items. Procedures for the review of specifications are contained in the SCE&G QA and Gilbert QA Manuals.

3. Design Requirements Control

Interface and technical reviews are performed by Gilbert Project Engineering, the Gilbert QA Division, and/or the SCE&G QA organization. They also review vendor proposals, bills of material, and vendor and construction procedures to verify consistency with Gilbert procurement specifications. Procedures for these reviews are contained in Gilbert Project Management Manual for Virgil C. Summer Nuclear Station, and the Gilbert QA and SCE&G QA Manuals.

4. Design Document Control

Design documents are controlled as follows:

a. Specifications are issued and controlled from a controlled distribution section which maintains the record copy of specifications and a master distribution list.

b. Drawings are prepared and checked by designers and draftsmen. After review and approval by the Gilbert Project Engineer, they are issued through a central distribution group. Record copies and master distribution lists are used to provide assurance that the latest revisions are promptly forwarded to the proper organizations. Lists of latest available revisions of drawings are furnished to those on distribution lists to ensure that the latest revision is in use.

c. Changes to the SAR requirements are controlled by use of a form which is initiated by the cognizant project engineer. Significant changes and associated justifications are reviewed by the SCE&G Nuclear Engineering and Licensing Department.

d. Significant field or shop changes to drawings and specifications for safety-related equipment are allowed only after approval by Gilbert and/or SCE&G Manager Nuclear Engineering, or his designee. All authorized changes are documented and controlled as described below:

(1) Design initiated changes are accomplished by Engineering Change Notices (ECNs) and are included in the drawings, specifications, and bills of material by subsequent revision. ECNs for specifications and bills of materials are approved by the SCE&G

Nuclear Engineering Department before implementation, unless the ECN is written to implement a previously accepted Field Change Request (FCR), to respond to a letter from SCE&G requesting the change, or to change drawings which did not require original approval by SCE&G.

(2) Field initiated changes are handled by FCRs. A field engineer requests authorization to make a field change from the SCE&G Nuclear Engineering Department. ECNs are distributed as a followup to reflect the field change after acceptance of the FCR by the SCE&G Nuclear Engineering Department. Minor field changes which do not affect the design are documented by the SCE&G QC organization and approved by the resident engineer or SCE&G Nuclear Engineering Department on field prepared "as built documents" (ABDs). Field changes and applicable ABDs are incorporated into revised drawings as directed by the resident engineer or SCE&G Nuclear Engineering Department. FCRs may be authorized by telephone in accordance with approved procedures.

5. Record Accumulation and Control

The records associated with the design activity are maintained by the individual design group. Copies of these records are indexed and stored in a safe Record Retention Storage Area. These records are audited by the Gilbert QA Division, the SCE&G QA organization, and/or its agents.

17.1.3.3 Westinghouse Electric Corporation

The Westinghouse Design Control Program is described in Reference 1 and Section 17.1.1.3.

17.1.4 Procurement Document Control

The procurement of equipment for the Virgil C. Summer Nuclear Station involves activities performed by SCE&G, Westinghouse, and Gilbert. SCE&G makes the final selection of suppliers, except those under Westinghouse scope of supply. Procurement for the remainder of the plant is referred to as BOP. The purchase documents for safety-related equipment include requirements to the extent considered necessary based on safety classification, complexity, and other engineering considerations.

17.1.4.1 NSSS Purchases

NSSS purchases of safety-related structures, systems, and components are controlled under the QA Program described in Reference 1 and Section 17.1.1.3.

17.1.4.2 Balance of Plant Purchases

Safety-related BOP structures, systems, and components are procured by the use of procurement specifications which include QA requirements. Procurement documents require the bidder to have a QA Program which meets the requirements of 10 CFR 50, Appendix B unless working under the SCE&G QA Program, or when the quality of the item to be furnished can be verified by

receipt inspection, testing, or verification by an independent laboratory or performance testing prior to placing the affected system into service. This method is used when nonsafety related items are “upgraded” to safety related application or to confirm the quality of a safety-related commercial grade item. Any such actions will require QA concurrence prior to utilization. Procurement documents may also require the contractor to give the purchaser such rights as: access for inspection and audit, review and concurrence with certain special process procedures or instructions, design drawings and specifications, inspection and test records, and QA documents relative to the purchase.

Selected items; such as commercial items, repair parts, and services; may be procured by SCE&G and by the use of Gilbert or SCE&G prepared bills of material and/or SCE&G purchase requisitions. Applicable QA requirements are included in the contract documents.

For purchases made to Gilbert procurement specifications; proposals for materials, equipment, and services are subjected to a technical evaluation by Gilbert Engineering and/or SCE&G Nuclear Engineering with a QA review by the SCE&G QA organization and/or the Gilbert QA Division. Proposals for purchase from safety-related bills of material or SCE&G purchase requisitions are subject to a technical review by SCE&G Nuclear Engineering with a QA review by the SCE&G QA organization and/or the Gilbert QA Division except for the procurement of QA services. Proposals in this latter category are reviewed by the SCE&G QA organization only. The QA review is based on the requirements of the procurement specification or bill of material to ascertain that the proposed QA Program is adequate. The technical and QA reviews of the proposal request documents assure the inclusion of such requirements as correct and accurate regulatory, code, and design statements; technical and quality document preparation and submittal for review or approval, and the retention, control, and maintenance of the records; and acceptance criteria beyond which the vendor would have to request acceptance by SCE&G. These requirements are placed on the purchase order, including safety-related spares. SCE&G QA concurrence of acceptable bidders must be obtained before a request for proposal can be forwarded to a potential supplier. The bids are evaluated for technical, quality, and commercial acceptability. A preferred bidder is then selected. The preferred bidder must be accepted by SCE&G QA before a purchase order can be placed. The SCE&G QA organization and/or the Gilbert QA Division review available quality history information and QA Program submittals for the preferred bidder to determine whether the bidder is acceptable, and where sufficient QA Program information is not available from these sources, will perform a preaward survey of the preferred bidder’s QA Program, until an acceptable preferred bidder is determined.

For material, equipment, or services purchased from a Gilbert procurement specification; Gilbert prepares a bill of material based on the procurement specification, the successful bidder’s proposal, and any other pertinent documents. The actual provisions of the contract will appear within the bill of material by reference to the specification or incorporation of requirements in lieu of or in addition to the specification within the bill. For material, equipment, or services purchased from a bill of material without a procurement specification, Gilbert conforms the bill of material to the successful bidder’s proposal and other pertinent documents, as necessary. Again, the bill contains the actual requirements in lieu of references to correspondence (pricing excepted). These bills of material are used as contract documents and include technical and quality requirements. The bill of material is attached to the standard contractual provisions and

together they form the purchase order. The bill of material is reviewed and initialed by the SCE&G QA organization and/or the Gilbert QA Division, Gilbert Engineering, and/or SCE&G Nuclear Engineering. The preparation, review, approval, and issuance of bills of material are described in the SCE&G and Gilbert procedures which implement the QA Program.

17.1.5 Instructions, Procedures, and Drawings

Each of the organizations involved in safety-related work on the Virgil C. Summer Nuclear Station has been required to prepare program documents, instructions, procedures, and drawings to describe the work to be accomplished and the method by which the work is to be accomplished. This requirement has been imposed by contractual requirements, as with Westinghouse, or by specifications, as described in Section 17.1.4.

The SCE&G Manager of QA has been assigned the responsibility to review and concur with the QA Programs and associated documents of SCE&G and its agents; Gilbert, Westinghouse, Daniel, vendors, and contractors. The review of documents of vendors and contractors may be assigned to the Gilbert QA Division or any other qualified agent by the SCE&G Manager of QA. The reviews are performed to verify that:

1. Applicable requirements of 10 CFR 50, Appendix B have been included.
2. The plans and associated documents cover the required design, procurement, manufacturing, construction, and testing activities.
3. Adequate internal control methods have been provided for subcontractor activities.
4. Intended specific work functions are identified and established to afford a status check of planned activities, including the determination of that status (acceptance criteria).

17.1.6 Document Control

The procedures for the preparation, review, approval, and distribution of instructions, procedures, and drawings described in Section 17.1.5 require that all specified approvals be obtained prior to the issuance of the documents. These same requirements are imposed on such design and descriptive documents as specifications and SARs. The required reviews and approvals ensure that issued documents are adequate and correct for the use intended. The procedures controlling these documents require review and approval of changes to the documents by the same organizations which approved the original document, or SCE&G approved and designated equivalent.

Specifications are issued and controlled from a controlled distribution section which maintains the record copy of all specifications and a master distribution list.

Drawings are prepared and checked by designers and draftsmen. After review and approval by the project engineer, and/or by SCE&G, they are issued through a central distribution group. Record copies and master distribution lists are used to provide assurance that the latest revisions are promptly forwarded to the proper organizations.

Construction phase changes to the SAR's requirements are controlled by the use of a form which is initiated by the cognizant project engineer. Significant changes and associated justifications are reviewed by the SCE&G Nuclear Engineering and Licensing Department.

Significant field or shop construction phase changes to drawings and specifications for safety-related equipment are allowed only after written approval by the Gilbert Engineer and/or the SCE&G Group Manager, Nuclear Engineering and Licensing, or his designee as described in Section 17.1.3.2.

All construction drawings, procedures, and specifications are issued by the SCE&G Document Control Center, including distribution to Daniel. Construction personnel assigned controlled documents are responsible for maintenance and use of the latest documents as described by construction procedures. Records and reports are developed and maintained as required by construction procedures and are available for review and audit by QA and QC personnel on request.

The issue and control of field construction documents such as working drawings, specifications, procedures, and instructions are controlled in such a manner as to ensure that only the latest revisions or issues of the documents are used for construction and erection. Documents onsite are stamped to identify those being revised, and the area of revision indicated to limit use of the documents until the approved Engineering Change Notice, Field Change Request, or revised document is received. Procedures which control the field or engineering changes ensure that any changes made are properly authorized, documented, and distributed.

Document control within Westinghouse is described in Reference 1 and Section 17.1.1.3.

17.1.7 Control of Purchased Material, Equipment, and Services

The procurement of equipment for the Virgil C. Summer Nuclear Station involves activities performed by SCE&G, Westinghouse, and Gilbert. SCE&G makes the final selection of suppliers, except those under Westinghouse scope of supply. The purchase documents for safety-related equipment include QA requirements to the extent considered necessary based on safety classification, complexity, and other engineering considerations. The Westinghouse control program is described in Reference 1 and Section 17.1.1.3.

17.1.7.1 Construction Phase Source Selection

Upon receipt of bids; the SCE&G QA organization and/or the Gilbert QA Division, SCE&G Nuclear Engineering, and Gilbert Engineering will evaluate the bidder's capabilities, as described in Section 17.1.4. These evaluations are forwarded to the SCE&G General Manager, Purchasing, and used to select a preferred bidder. The SCE&G Purchasing Committee then selects a vendor, and requests concurrence of the SCE&G Manager of QA.

The SCE&G Manager of QA will accept or reject the preferred vendor, on the basis of current QA performance or preaward surveys conducted by the SCE&G organization, the Gilbert QA Division, or other agents, at the direction of the SCE&G Manager of QA when sufficient current

performance information is not available. In some cases, verification of the vendor's QA Program may not be necessary if quality can be verified by receipt inspection, testing, or verification by an independent laboratory or performance testing prior to returning the affected system to service. This method is used when nonsafety related items are "upgraded" to safety related application or to confirm the quality of a safety-related commercial grade item. Any such actions will require QA concurrence prior to utilization. Should the preferred vendor be unacceptable due to a deficient QA Program, the SCE&G Purchasing Committee selects another vendor, and requests concurrence of the SCE&G Manager of QA.

17.1.7.2 Work Release

Vendors or contractors may be required to submit a Contractor's QA Data Identification Report, including a listing of all special process procedures to be used on the contract. In such cases, the vendor must then submit the relevant manufacturing QC, inspection, and test procedures to the owner's QA representative. Fabrication cannot begin until all special process and QC procedures have been reviewed and concurred with, and a Release of Fabrication has been issued by the QA representative. The requirement for submittal of a Contractor's QA Data Identification Report will be determined at the qualification of the vendor.

Similar controls exist for contractors onsite, with the QA Group onsite performing the procedure reviews, and the Director, Surveillance Systems or Site QA Coordinator or their designees issuing a Release to work indicating procedure concurrence and permitting the contractor to begin work.

17.1.7.3 Audit, Surveillance, and Inspection

Regular review of each contractor's QA Program status is accomplished by various techniques depending on the contractor and stage of program implementation. Audits and surveillance of contractors are generally conducted during contract performance to assure that the contractor maintains an acceptable QA Program. These activities assure that control programs and methods are in place throughout performance. The reports of these activities provide a continuing status check to the SCE&G Manager of QA of the contractor's QA capabilities. The frequency of audit and surveillance is determined on the basis of safety classification of the item or service provided, complexity, other engineering considerations, and the current status of the contractor's QA Program, as evidenced by evaluation of the surveillance and audit reports, as well as evaluation of receipt inspections.

The QA specification which is imposed on applicable safety-related vendors requires the vendor to submit a schedule of major events and all inspections and tests for each procurement. A list of suggested inspection notification points is also submitted by the vendor on the Contractor's QA Data Identification Report. The SCE&G QA organization and/or the Gilbert QA Division selects inspection points as notification points, beyond which work may not proceed until acknowledgment of satisfactory notification and issues the list to the vendor. The QA representative performing surveillance for the procurement then either performs physical surveillance of inspection, or waives surveillance by letter or TWX. The list of notification points becomes part of the contractual requirements placed on the vendor.

17.1.7.4 Acceptance

Where required in the contract documents; a vendor of safety-related material, equipment, or services is required to obtain either a Certificate of Inspection (COI), which records physical surveillance of the vendor's final inspection and/or tests, or a Waiver of Inspection (WOI), which records acceptance of the vendor's final inspection and certificate of conformance without physical surveillance. COIs and WOIs are prepared by the SCE&G QA organization and/or the Gilbert QA Division to authorize product shipment. When the requirement exists for a WOI, COI, or Quality Release (in the case of Westinghouse equipment), safety-related hardware cannot be accepted onsite without appropriate documentation.

17.1.7.5 Documentation

When required in the contract documents, a vendor of safety-related material, equipment, or services prepares a Contractor's QA Data Identification Report identifying the documentation to be submitted by the vendor in satisfaction of the purchase order requirements, and submits the report to the SCE&G QA organization and/or the Gilbert QA Division. The SCE&G QA organization and/or the Gilbert QA Division then issues a list of required documentation to the vendor. The identified documentation becomes a part of the contractual requirements for the vendor. Westinghouse forwards the QA data package in support of their Quality Release to SCE&G within 120 days of the final shipment on orders for the Virgil C. Summer Nuclear Station project.

17.1.8 Identification and Control of Materials, Parts, and Components

When required in the contract documents; a vendor of safety-related BOP items is required to establish and maintain an identification system for materials, parts, and components; including partially fabricated assemblies which will assure that identity is maintained on the item or records traceable to the item throughout fabrication and, where required, installation. This identification system is to be capable of preventing the use of incorrect or defective items and verifying that only correct and acceptable items have been used. Each item shipped to the site is to be identified by its bill of material number or other tagging information as specified in the contract documents.

The existence and implementation of such a system is one of the areas covered during preaward evaluation and continuing audits and surveillance of each vendor conducted by the SCE&G QA organization, the Gilbert QA Division, or any other agent of the SCE&G QA organization. The surveillance of each vendor shall be conducted to assure that materials, parts, and components on SCE&G products are identified, and that this identification can be used to verify the correct application of materials, parts, and components for these products.

The Westinghouse program in this area is described in Reference 1 and Section 17.1.1.3.

At receipt onsite, the identification of equipment is verified and maintained by applying an identification tag giving the bill of material numbers, Westinghouse SPIN number, or other suitable identification. This identification tag maintains identification through installation. Control is maintained by the status tags, described in Section 17.1.4, applied by the SCE&G QC

organization. These tags are used to identify equipment in the warehouse area and after installation in the plant prior to startup.

Gilbert has generated an Equipment List, a Valve List, and an Instrumentation List, combining the NSSS and BOP purchase order information, to identify equipment within the Virgil C. Summer Nuclear Station. These lists will be used for control of plant equipment identification during construction.

17.1.9 Control of Special Processes

The control of special processes for NSSS vendors is described in Reference [1] and Section 17.1.1.3.

Vendors of safety-related items are required to identify and submit special process procedures for review and concurrence before use when required. Fabrication may not begin until these procedures have been reviewed and concurred with and the vendor notified of this by the Release of Fabrication Procedures from the SCE&G QA representative. Audits and surveillance of vendors conducted by the SCE&G QA organization, the Gilbert QA Division, or other agents of the SCE&G QA organization will assure that the qualifications of personnel, procedures, and equipment are obtained and maintained, and that documentation of these qualifications is maintained and available. A QA specification identifies the minimum special process procedures to be, as applicable: welding procedures, welding procedure qualifications, nondestructive examination (NDE) procedures, forming and bending procedures, cleaning procedures, heat treating procedures, performance test procedures, hydrostatic procedures, leak test procedures, electrical test procedures, painting procedures, seismic procedure or test results, packaging procedures, storage procedures, shipping procedures, and procedures for verifying wall thickness of pressure boundaries of castings and forgings for valve bodies, pump casings, pipe and pipe fittings, etc.

Special process procedures and qualifications of onsite contractors are subject to review and concurrence by the QA organization onsite. Site contractors may not begin work until the Release to Work has been issued by the Director, Surveillance Systems or the QA Coordinator. During the performance of site work, the Site QA organization performs surveillance to verify proper and complete implementation of the contractor’s special process procedures.

17.1.10 Inspection

17.1.10.1 Vendor Inspection

The control of inspection for NSSS suppliers is described in Reference 1 and Section 17.1.1.3.

Safety-related BOP vendors must satisfy the requirements of QA specifications. The submission of an Inspection Point Program, describing inspections to be performed by the vendor, concurrence with inspection procedures, and establishment of notification points is described in Sections 17.1.7 and 17.1.9. The review of the Inspection Point Plan and inspection procedures includes determination that the inspections are proper and adequate for the type of item and stage

of manufacture or fabrication, to determine that items do or will satisfy the requirement for a quality product, and that direct inspection or indirect process monitoring, or both, are used as necessary to determine quality.

Surveillance and audit of the vendor's QA Program and procedures by the SCE&G QA organization, the Gilbert QA Division, or any other SCE&G QA organization agent assures the existence of program elements requiring qualification or certification of inspectors, the existence and presence of inspection procedures, instructions, and/or drawings necessary to the inspection prior to performance of the inspection, and that items replaced, reworked, modified, or repaired are reinspected by the original inspection procedure or procedures equivalent to the original inspection procedure. Surveillance performed by the SCE&G QA organization, the Gilbert QA Division, or other SCE&G QA organization agents will verify implementation of such requirements. The independence of inspection personnel from those performing the activity being inspected is determined during review and evaluation of the vendor's QA Program at the preaward stage of procurement.

17.1.10.2 Onsite Inspection

Onsite inspection of the performance of contractors is performed by the SCE&G QC Organization, the Daniel QC Group (for ASME Code work), or by contractors or subcontractors. Test laboratories are utilized in the QC programs as needed. These laboratories are under the direction of the SCE&G QC Manager (except as noted below for ASME Code work). The general responsibilities of these laboratories are as follows:

1. Concrete material testing and sampling.
2. Concrete testing and sampling.
3. Soil testing and sampling.
4. Rebar Cadweld testing and sampling.
5. Concrete inspections.
6. Nondestructive examination.
7. Welding inspection.

Specific responsibilities are set forth in the SCE&G QC Manual.

The Onsite Laboratory NDE contractor will perform examinations and inspections required, including those required by Daniel in the fabrication and installation of ASME Code stamped work under the direction of the Daniel Project Quality Manager.

The final acceptance of a completed system, structure, or component is based on the completion of a final inspection. This inspection is performed by the appropriate QC organization in coordination with the QA group. Installation acceptance and release for testing will be made only after final inspection by QC with concurrence of QA.

The Programs of Daniel, site contractors, and the SCE&G QC organization are reviewed and audited by the SCE&G QA organization for the program requirements quoted in Section 17.1.10.1, above. The Site QA Staff reviews and comments on inspection procedures before they are implemented, and performs surveillance on the inspections of Daniel, site contractors, and the SCE&G QC organization to assure that the accepted procedures and instructions are implemented. Reports on the surveillance activities are prepared by QA personnel onsite to apprise the SCE&G Manager of QA of the status of site QC and construction activities.

17.1.11 Test Control

17.1.11.1 Vendor Testing

The control of NSSS supplier testing is described in Reference 1 and Section 17.1.1.3.

As required by contract documents, vendors of safety-related BOP equipment shall submit a schedule of major events and inspections and test within six weeks of the receipt of contract documents. The tests identified on the schedule are those performed to verify conformance to document requirements given in such documents as instructions, procedures, drawings, specifications, etc. The procedures for control of testing are submitted for review by SCE&G and/or Gilbert or other SCE&G agents and are required to describe what testing is to be performed, when tests will be performed, the instructions provided the person performing testing, including the acceptance criteria and tolerances, the personnel qualifications required to perform the test, what special environmental conditions must be provided, if any, and the type of report to be prepared to verify that the test results are acceptable. The procedures are reviewed and concurred with by SCE&G, Gilbert, or other SCE&G agents. Proper performance of tests and test evaluations to the accepted procedures is verified by surveillance of vendor performance and documentation by SCE&G QA, Gilbert QA, or other SCE&G QA agents.

17.1.11.2 Site Testing

Site testing by site contractors is performed to procedures submitted to SCE&G QA organization for review and concurrence as described in Sections 17.1.7 and 17.1.9. These procedures are reviewed to the requirements described in Section 17.1.11.1. Site testing performed by Daniel for ASME Code work is performed under the requirements of the ASME Certificate for Daniel at the site to procedures reviewed and accepted by SCE&G QA organization. The performance of tests is subjected to surveillance by SCE&G Site QA to assure that testing is performed in accordance with the accepted procedures.

The evaluation of onsite testing is conducted by the contractors, SCE&G Nuclear Engineering, and the SCE&G QA organization with technical assistance from Gilbert, Westinghouse, and other contractors and consultants, as necessary to determine that test results are acceptable.

17.1.12 Control of Measuring and Test Equipment

17.1.12.1 Vendor Controls

The control of measuring and test equipment for NSSS suppliers is described in Reference 1 and Section 17.1.1.3.

Vendors and contractors of safety-related materials, parts, components, and services for the Virgil C. Summer Nuclear Station are required to have a program to control measurement, inspection, and test equipment, as required, by the SCE&G QA Program, unless the quality of items furnished can be established by onsite receipt inspection, test, or other methods as indicated in Section 17.1.7.1. The program review and evaluation, surveillance, and audits of each vendor conducted by the SCE&G QA organization, the Gilbert QA Division, or other SCE&G Organization agents assures the existence of an acceptable program. When required by the control document, the following will be defined by the vendor:

1. A listing of measuring and test devices affecting quality that require calibration. Measuring equipment such as steel rules, levels, and similar equipment will not require calibration when their usage does not require a precise degree of accuracy.
2. The method of calibration for each item in the listing specified in item 1 above, including the National Bureau of Standards recognized standard used, for certification of calibrating equipment.
3. The established frequency of calibration.
4. The method of identification for each item under calibration control.
5. The method of determining the calibration status of each item, such as the attachment of a sticker showing the last calibration date, date when due for recalibration, and the person’s stamp, initials, or signature who performed the last calibration.
6. The type of records that will be maintained.
7. The method for determining and recalling equipment when calibration is due.
8. The measures to be exercised when equipment that is out of calibration has been found to have been used to accept parts, components, assemblies, etc.

17.1.12.2 Site Controls

The SCE&G QC Manager is responsible for maintaining the calibration of tools, gauges, instruments, and other inspection, measuring, and testing equipment and devices used by SCE&G onsite in activities affecting quality.

The calibration and control procedure approved by the SCE&G QC Manager assigns each discipline QC Supervisor the responsibility for establishing the criteria and documents required for the procurement of test and measuring equipment relating to his field of work and for assigning qualified personnel to perform calibrations. He is also responsible for developing

checklists or special calibration instructions for all instruments, gauges, tools, and equipment for which special calibration and control is required, and for assigning identifying numbers to equipment that requires calibration, as well as classifying the equipment as to standard or field measurement use, and assigning the frequency of calibration.

QC inspectors are responsible for: applying a calibration tag upon receipt and at recalibration; the accurate calibration of equipment; and inspection of equipment prior to use for damage, proper working order, a current calibration tag, and for proper use of equipment in accordance with procedures or manufacturer's instructions.

The Warehouse Supervisor is responsible for adequate storage facilities until equipment is issued, and for maintaining an issue log for all instruments, gauges, tools, and equipment showing the discipline QC Supervisor to whom the equipment was issued.

The Document Supervisor maintains records of calibration and control of test and measuring equipment by retaining the Calibration Record forwarded to him by the discipline QC Supervisor. The Calibration Record shows identification for each item of equipment, giving the required calibration accuracy, frequency of calibration, and the date of each calibration for an item of equipment.

Standards are purchased from suppliers which can provide certified traceability to the National Bureau of Standards, when possible. When this cannot be done, the discipline QC Supervisor documents the calibration method to be used, justifying its use. The discipline QC Supervisor establishes the frequency at which standards are to be recertified.

Each discipline QC Supervisor maintains a recall system for equipment recalibration.

Additional calibrations are required whenever calibration is suspect, and equipment found consistently out of calibration is repaired or replaced. Out of tolerance equipment may be used temporarily only if correction factors are available and applied. The discipline QC Supervisor approves all such temporary use and documents this use. Accuracy and tolerance of test and measuring equipment shall in no case be of lower order of accuracy than the equipment under test.

Test equipment which is found to be out of calibration during a periodic test is clearly identified as such, and an evaluation is made by the discipline QC Supervisor of the validity of all equipment tests performed with this equipment since its last acceptable calibration.

The QC Group regularly assures that calibration equipment and records are used properly and maintained in good order.

The SCE&G/QA organization performs audits and surveillance of the SCE&G QC organization to assure that the requirements of the QC calibration procedure are followed.

17.1.13 Handling, Storage, and Shipping

17.1.13.1 Vendor Controls

The handling, storage, shipping, cleaning, and preservation control measures used for NSSS suppliers are described in Reference 1 and Section 17.1.1.3.

The handling, storage, shipping, cleaning, and preservation measures of safety-related BOP vendors and site contractors are controlled by the requirements of current QC specifications.

The QA specifications require documented measures for protection of equipment during handling, storage, and shipping, including the use of specific procedures for control of special environmental controls or special handling equipment and verification of conformance to controls. Periodic inspections must be programmed for special handling equipment, as necessary, to ensure safe and adequate handling.

The QA specifications require that each item be identified, marked, and labeled to provide identity of the item and easy identification of special handling and storage requirements.

The documented measures required by the QA specifications must describe:

1. The methods and equipment that will be used for normal handling of items during fabrication, processes, storage, shipping, and installation.
2. The measures that will be utilized to protect items requiring special handling, storage, and shipping techniques.
3. Identification, marking, and labeling methods, i.e., stenciling (steel, paint), tag (metal, other).
4. Measures that will be used to protect identification, marking, and labeling from deterioration and loss of recognition when the method is not a permanent type.
5. Special protective environments that will be used for special products.

In addition, vendor procedures for cleaning, painting, packaging, storage, and shipping are regarded as special process procedures, and controlled as described in Section 17.1.9.

The SCE&G QA organization, the Gilbert QA Division, or other SCE&G QA agents review the QA Program of vendors, and perform audits and surveillance of vendors to ensure the existence and implementation of these requirements. The SCE&G QA organization performs audits and surveillance of site contractors to ensure the existence and application of these requirements.

17.1.13.2 Site Controls

Storage services onsite are provided by the SCE&G QC Group. The QC procedure for storage requires the classification of safety-related items to one of four protection levels provided. These are:

1. Level D includes those items not so sensitive to the environment as Level C (below), which may or may not require some protection against the elements, airborne contamination, and physical and mechanical damage. Level D items are stored outdoors in an area marked and designated for storage.
2. Level C items require protection from exposure to airborne contaminants, the environment, physical damage, and g-forces. Protection from water vapor and condensation may be required, but is not so important as for Level B (below). Level C items are stored indoors or in an environment equivalent to indoors. Temperature control is not required.
3. Level B items are sensitive to environmental conditions and require protection from the effects of temperature extremes in addition to the requirements for Level C, including protection from humidity and vapors. Level B items are stored within a fire resistant, weathertight and well ventilated building or equivalent tear resistant structure. Items are placed to allow air circulation, and temperatures are held within a range of 40°F minimum and 140° maximum.
4. Level A items are those which are exceptionally sensitive to environmental conditions or require special measures for protection from the effects of high or low temperature, sudden temperature changes, humidity and vapors, g-forces, physical damage, and airborne contamination such as rain, snow, dust, dirt, salt sprays, or fumes. Level A items are stored under conditions similar to those for Level B items, with additional requirements such as temperature control within a range of 60°F to 90°C, relative humidity to less than 60 percent, a filtered ventilation system, and other appropriate requirements.

The storage of items is periodically inspected by the SCE&G QC Group to ensure that the storage requirements are being satisfied.

The Constructor and Site Contractors prepare handling instructions for items which require special handling because of weight, size, or fragility. These instructions are reviewed by the SCE&G QA organization to ensure inclusion of quality criteria. The SCE&G QC Group observes these handling operations and the SCE&G QA organization performs surveillance on selected handling operations, to assure that accepted handling procedures and instructions are followed, and to preclude damage to the items handled.

Review of handling procedures and instructions, and inspection of hoisting and rigging equipment, is performed to assure that appropriate equipment and methods are used in handling.

17.1.14 Inspection, Test, and Operating Status

17.1.14.1 Vendor Controls

Requirements for the identification of inspection and test status for NSSS suppliers are described in Reference 1 and Section 17.1.1.3.

The QA specification requires vendors of safety-related items to have, within their material identification and control and nonconformance control programs, identification methods to assure

that only correct and acceptable materials, parts, and/or components are used in the fabrication, assembly, processing, installation, and repair of items. These measures must include provisions for control of nonconforming items to prevent further processing of the item by such methods as segregation, tagging, marking, or other positive means. The SCE&G QA organization, the Gilbert QA Division, or other SCE&G QA agents will review vendors programs and perform audits and surveillance of vendors to assure the existence and implementation of these requirements.

17.1.14.2 Site Controls

The SCE&G QC Group is responsible for applying inspection status tags to items onsite. These tags indicate that an item is accepted, on hold, conditionally accepted, or rejected.

Items with an ACCEPTED or CONDITIONAL tag applied may be installed in plant systems. Items with the CONDITIONAL tag applied are subject to further testing or inspection after issuance from the warehouse. Actions taken on items with a HOLD or REJECTED tag applied are described in Section 17.1.15.

Procedure requirements for identification of operating status for preoperational testing are described in Section 13.5.

The programs and procedures for identification of inspection, test, and operating status onsite are reviewed and commented on by the SCE&G QA organization. The SCE&G QA organization conducts audits and surveillance of onsite records and actions to verify the performance of site organizations to the accepted procedures.

17.1.15 Nonconforming Materials, Parts, or Components

17.1.15.1 Vendor Controls

The requirements placed on NSSS suppliers for control of nonconforming materials, parts, or components are described in Reference 1 and Section 17.1.1.3.

Normally the QA specification requires the vendor to establish documented measures to control items when there is evidence of nonconformance to established requirements, including the identification, documentation, segregation, disposition, and notification of all concerned parties of the nonconforming condition. The only exception is when the contractor is working under the SCE&G/QA Program and the nonconformances are processed in accordance with SCE&G/QA Program. The review of nonconformances and disposition authority must be defined. Dispositions may be; accepted “as is,” repair, rework, or scrap. The measures must include controls to prevent further processing where justified until the disposition has been approved. When the disposition is acceptance “as is”, repair, or rework; the documentation shall verify acceptability and describe the “as built” item. Approval must be obtained from the SCE&G Nuclear Engineering Department and QA organizations, or their agents, whenever the disposition would result in an item which would not satisfy the contract documents. The request for such approval must be in writing to the SCE&G Production Engineering Department, or their agent.

17.1.15.2 Site Controls

At receiving inspection, the QC Inspector will identify those items which do not conform to requirements by placing a HOLD or REJECT tag on the item. REJECT items are removed from the site.

HOLD items are placed in segregated storage when practical, and maintained there until disposition of the nonconformance. Large items, or those which may not practically or physically be segregated, shall have the HOLD tag placed on the item in a conspicuous location.

The QC Inspector or Engineer initiates a Deficiency Notice for the nonconformance or, after consulting the discipline QC Supervisor, a Nonconformance Notice for nonconformances which require SCE&G Production Engineering resolution. Deficiencies are those nonconformances which can be corrected by existing approved instructions or procedures or by replacement of a broken or nonconforming part. The discipline QC Supervisor reviews all Deficiency Notices to determine whether a Nonconformance Notice must be prepared. Deficiency Notices and Nonconformance Notices are distributed to SCE&G QA and other involved organizations.

The QC Inspector or Engineer follows disposition action determined by the discipline QC Supervisor and records the completion of action and acceptance of the item, and replaces the HOLD tag with an ACCEPTED tag or CONDITIONAL tag when further action must be taken after issuance from the warehouse. The completed Deficiency Notice is filed and copies sent to the SCE&G QA organization and other involved organizations.

Nonconformance Notices, except Daniel NCN Bs, are sent to SCE&G Nuclear Engineering for determination of disposition, with copies to the SCE&G QA organization and other concerned organizations. SCE&G Nuclear Engineering determines disposition for the nonconformance and forwards the disposition to the SCE&G QC Group for action. SCE&G Nuclear Engineering evaluates the nonconformance to determine whether it should be considered a potential significant deficiency, and be processed by the applicable Nuclear Engineering procedure.

Comments on the nonconformance are obtained from the SCE&G QA organization and a disposition prepared on the Nonconformance Notice. The disposition may involve acceptance “as is”, repair, rework, or direction to classify the item REJECT. Disposition action will be directed by SCE&G Nuclear Engineering. The SCE&G QC Group, and the SCE&G QA organization, under direction of the Director of Surveillance Systems or the QA Coordinator, follow-up on corrective action and assure that the QC Inspector or Engineer completes the disposition action portion of the Nonconformance Notice, documenting the final condition of the item, and forwards the form to the Document Supervisor for retention in the files.

Minor civil, mechanical, and electrical construction items which do not comply with the design documents but do not affect the design of the structures, systems, or components may be documented on “As-Built Documents” (ABDs). ABDs are filed with the associated quality records, and may be incorporated into drawing revisions as described in Section 17.1.3.2.

The discipline QC Supervisors analyze the logs of Deficiency Notices and Nonconformance Notices to determine whether any trend exists or any correction should be made to construction or QC procedures, and reports on this analysis quarterly to the SCE&G QC Manager.

Conformance to the SCE&G QC and SCE&G Nuclear Engineering procedures for the control of nonconformances is assured by audit and surveillance by the SCE&G QA organization and the Site QA organization.

17.1.16 Corrective Action

17.1.16.1 Vendor Controls

The corrective action controls for the NSSS supplier are described in Reference 1 and Section 17.1.1.3.

The QA specification requires vendors of safety-related items to have corrective action measures to assure that conditions adverse to quality are promptly identified, documented, and corrected. The only exception is when the contractor is working under the SCE&G/QA Program and the corrective measures are accomplished in accordance with the SCE&G/QA Program. These measures must identify the responsibilities for identification of the need for corrective action, and the preparation and approval of corrective action. The cause of the detrimental condition must be determined. When the corrective action is taken to preclude repetition of significant nonconforming conditions, the corrective actions must be monitored to assure that the corrective actions are effective. Guidelines for determining the need for corrective action must be given in the measures, and management distribution for notification identified.

The SCE&G QA organization, the Gilbert QA Division, or other SCE&G QA agents evaluate the vendor’s QA Program to ensure the existence of adequate corrective action measures, and perform surveillance of the vendors to ensure the implementation of these measures.

17.1.16.2 Site Controls

The SCE&G QA organization conducts audits and surveillance of organizations and contractors performing safety-related actions, and prepares reports on these audits and surveillances. Whenever a condition is discovered which indicates a significant omission of controls in an approved QA Program, or a deficient QA Program, a Corrective Action Request (CAR) is issued. The CAR must be acknowledged by the responsible individual and corrective action initiated to correct the condition.

The SCE&G Site QA staff also reviews Nonconformance Notices, Deviation Notices, and ABDs; and evaluates and examines the trend analysis data gathered by the SCE&G QC Group described in Section 17.1.15.2 to determine the existence of conditions significantly adverse to quality requiring the issuance of a CAR.

The SCE&G QC Group and the Site QA staff follow the implementation and effectiveness of corrective action.

SCE&G has established a Field Review Board and assigned it prime responsibility for identification and follow-up onsite corrective action.

The Field Review Board is composed of the SCE&G QC Manager as chairman, the SCE&G Nuclear Site Manager, the Daniel Project Manager, the Daniel Project Quality Manager (for ASME Code activities), SCE&G Group Manager, Nuclear Engineering and Licensing, the SCE&G Manager of QA, and the SCE&G Group Manager Production Engineering QC and Construction or their designee as permanent members. Other temporary members may be included to lend technical support as the need arises. Each permanent member designates a replacement to act in his stead in the case he is absent.

The Field Review Board reviews major Deficiency and Nonconformance Notices, change requests, stop work orders, and SCE&G QA Corrective Action Request, as deemed necessary by its members, and quality trend analyses. Through review of these documents, overall site quality performance is evaluated. Requests for corrective action are made for the purpose of improvements to construction and quality control operations.

The SCE&G QC Group ensures implementation of Field Review Board specified corrective action. The SCE&G QC Group also conducts trend analyses of deficiencies and nonconformances for presentation to the Field Review Board, as described in Section 17.1.15.2.

17.1.17 Quality Assurance Records

17.1.17.1 Vendor Records

The program for control of QA records for NSSS suppliers is described in Reference 1 and Section 17.1.1.3. In addition, the data packages in support of the Westinghouse Quality Release are forwarded to SCE&G for retention and storage at the Virgil C. Summer Nuclear Station.

The QA specification requires vendors of safety-related items to submit a list of required documentation as a part of the Contractor’s QA Identification Report. The SCE&G QA representative then prepares the list of minimum required documentation based on this submission and transmits it to the vendor for compliance. The required documentation package is forwarded to SCE&G for retention and storage at the Virgil C. Summer Nuclear Station.

The following are examples of the minimum records to be forwarded to the owner:

1. NDE reports.
2. Material test reports (shall be available for review prior to fabrication).
3. Final inspection reports/certificates.
4. Performance test reports.
5. Code data inspection reports.
6. Hydrostatic and leak test reports.

7. Electrical test reports.
8. Design changes/specification deviation requests.
9. Radiographs.
10. Weld maps and joint history records.
11. Verification of wall thicknesses.

The vendor's inspection and test procedures must require documentation of results and acceptability, identification of the inspector or data recorder, the type of observation performed, action taken to resolve nonconforming conditions, and the indexing of the documents for ready retrieval. Data related to the qualification of personnel, procedures, and equipment used to perform special processes is a part of the vendors records. Document packages bear identification of the owner (SCE&G), the owner's purchase order number, and the station name. The vendor must provide secure and fire-resistive or other acceptable storage for the nonreplacable records.

When required by contract documents, the data packages forwarded to SCE&G by the vendors will include, in addition to QA records specified in procurement packages, a certificate of conformance, a Certificate of Inspection or Waiver of Inspection provided by SCE&G QA or its agent and an index of the required documentation, and the documentation.

The existence of requirements for these actions is verified by audit, and their implementation by surveillance by the SCE&G organization, the Gilbert QA Division, or other SCE&G agents, and by audits of data packages onsite conducted by the Site QA organization.

17.1.17.2 Site Controls

The preparation and retention of documents onsite is controlled by the QA specification for site contractors and the SCE&G QA Plan and SCE&G QC Procedures. The requirements for inspection and test document preparation are as given in Section 17.1.17.1, above.

During the construction phase, the SCE&G QC Group maintains the Plant Numerical Records System, which is the permanent file for QA records at the Virgil C. Summer Nuclear Station. Complete records are maintained covering all aspects of QC activity. Inspection reports, fabrication and test procedures, radiographs and other nondestructive examination test reports, and any other documentation as required by applicable procedures, specifications, codes, and standards are retained and handled in accordance with written procedures. Receiving record reports, documentation packages, and other records are placed in the permanent QA file where they are available for record, information, and QA audit. The storage area affords protection against destruction or deterioration caused by fire, water, humidity, temperature, tornadoes, insects, and rodents as required by the QA and QC procedures and all records are required to be indexed for proper placement and ready retrieval. Access to the permanent files is controlled by the SCE&G QC Group through the site Documents Supervisor, who controls access to the records vault and files.

The SCE&G QC Group inspects equipment data packages against the package index before placement in the Plant Numerical Records System, and directs indexing and placement of the package. The SCE&G QA organization audits these records to assure that data packages are correct and complete.

SCE&G has prepared a Records Accumulation and Retention Chart giving the retention period for plant records by the type of record, and the SCE&G QC procedure for record filing and retention requires that the retention requirements be adhered to. The Chart is revised as necessary to assure adequate identification, accumulation, and retention of records.

The SCE&G QA audits the site records filing and retention function to assure conformance to the SCE&G QC procedures on QA record filing and retention.

17.1.18 Audits

The overall SCE&G Audit Program is composed of two sources of input, surveillances and audits. In the SCE&G program, an audit is normally a broad based multi Appendix B criteria programmatic evaluation which considers “could it work” system functionality. Surveillance is normally much narrower in scope (one or several criteria) and is deeper penetrating into examining sufficient evidence of actual work activity (in-process or documentation) to confirm satisfactory results. Extensive system surveillance (system attribute and type II) provides a much sharper, more detailed conclusion of the implementation status and adequacy of any QA program provided that a series of surveillance is evaluated to cover all applicable criteria. A lead auditor is able to judge QA program compliance and adequacy by a thorough evaluation of surveillance report, corrective action, followup, and quality history. In the most positive case, a combination of surveillances may confirm adequacy and implementation of a complete QA program therefore may, upon evaluation and documentation by a certified lead auditor, preclude the need for audit. In the most negative case, the evaluation will identify to the lead auditor where further audit activity should be concentrated.

17.1.18.1 Internal Audits

The internal audit program of Westinghouse is described in Reference 1 and Section 17.1.1.3.

The Gilbert Design Control Program includes procedures requiring audits of each Project Engineer, Project Management, and the Service Department, using the Gilbert QA Division as a consultant to the Gilbert Utilities Division. These audits are conducted across all Project lines to assure that the Design Control Program is operating successfully. Audits are conducted in accordance with the Gilbert QA Manual procedures with formal written reports transmitted to Department Heads for resolution, with copies to the Engineering Manager and Project Manager involved. The Departmental Head response is transmitted to the QA Audit Team Leader for evaluation. When necessary to assure that adequate action is taken in response to audits, reaudit is scheduled during subsequent design control audits.

The SCE&G QA organization conducts audits/surveillances of the SCE&G activities affecting quality to assure compliance with the SCE&G QA Plan, the QA Manual, the Nuclear Engineering

Procedures Manual, the Purchasing Procedures Manual, the SCE&G Site QC and Inspection Plan, and the Field QC Procedures Manual. These audits/surveillances are scheduled to cover each area of SCE&G performing safety-related work annually, or as frequently as deemed necessary to ensure that policies and procedures are effective.

The QA specification requires all vendors of safety-related materials, equipment, or services to conduct audits to determine the effectiveness of the vendor's QA Program. A description of the following is required of each vendor:

1. The criteria for determining when and at what frequency audits will be performed,
2. The system that will be used to conduct the audits,
3. How the audit findings, corrective actions, and results will be documented and to whom they will be distributed, and
4. The titles and duties of persons having responsibility for the audit.

17.1.18.2 External Audits

The audit program for suppliers of NSSS materials, equipment, or services is described in Reference 1 and Section 17.1.1.3.

Safety-related BOP purchases are made by SCE&G purchase order, and each vendor of safety-related materials, equipment, or services is required to have a QA Program consistent with the complexity and importance of the materials, equipment, or services to be provided. The SCE&G QA organization, or the Gilbert QA Division or other SCE&G QA agents, conducts audits of each of these vendors to assess their program, and evaluates the capability of their vendor evaluation programs, including the audits conducted by the vendors.

The SCE&G QA organization conducts audits and surveillance of vendors of safety related materials, parts, components, and services to verify continuing existence of an acceptable QA program. The audits and surveillances are conducted and reports are forwarded to the management of the vendor for response to the deficiencies identified during the audit, and to concerned management within SCE&G. The frequency of audits and surveillance is commensurate with the item or service to be provided. Each vendor which is required to have formal written QA program will be audited at least once during the performance of his work and vendors performing work over an extended period of time will be evaluated at least annually and audited on a triennial basis. Sufficient system surveillance or other inspection, testing, and verification defined in 17.1.7.3 will be performed to satisfy the intent of and preclude the need for audit, when properly evaluated and documented by a certified lead auditor.

The SCE&G QA organization, or the Gilbert QA Division as agent for the SCE&G organization, conducts audits of Westinghouse WRD to determine the effectiveness of the NSSS QA Program. The SCE&G QA organization audits Gilbert to determine the effectiveness of the Gilbert QA Program for BOP design.

Personnel from the Gilbert QA Division, acting through the Gilbert Project Quality Coordinator, may participate in or conduct these audits as agents of the SCE&G QA organization.

The SCE&G QA organization also audits the Gilbert QA Division and Gilbert Project Quality Coordinator to assure that the requirements of the Gilbert QA Program are being applied as described in the Gilbert QA Plan for the SCE&G project.

17.1.18.3 Audit Requirements

SCE&G conducts audits under the following requirements, and requires its agents, the NSSS supplier, contractors, and vendors to have an audit program applying similar requirements, consistent with the complexity and importance of the materials, equipment, or service being provided.

In all cases, audits are performed by a group which does not have direct responsibility for the area being audited. Audits are conducted in accordance with established procedures by appropriate individuals with the necessary education, training, and experience. The areas of design, procurement, shipping, storage, installation, manufacturing, and construction are audited for conformance to previously established QA requirements which have an effect on product quality. Audits include a review of completed and accepted operations, a review of documentation and records, and an evaluation of the adequacy and effectiveness of QA Program systems. Procedures for audits to be performed by the SCE&G QA organization are contained in the SCE&G QA Manual.

When required to fully assess a preferred bidder’s QA Program, a pre-award survey is conducted to determine whether the bidder has an effective QA Program. Audits of each vendor or contractor are conducted as frequently as necessary during the term of a contract to determine that an effective QA Program is being applied. The frequency of audits is scheduled commensurate with the item or service being provided and the vendor history of supplying quality related items or services.

An SCE&G QA Procedure provides guidelines and a format for the preparation of reports on audits conducted by SCE&G QA personnel. Program audit results are reported to the management of the organization being audited and to SCE&G QA management. The organization’s QA management in cooperation with SCE&G QA management takes appropriate action to ensure corrective action when it is required. The SCE&G QA organization reviews and analyzes pertinent quality assurance reports and data submitted for information by contractors and reports generated by agents of the SCE&G QA organization.

Similar controls on the preparation of audit reports and the forwarding of reports to management are required of vendors and contractors.

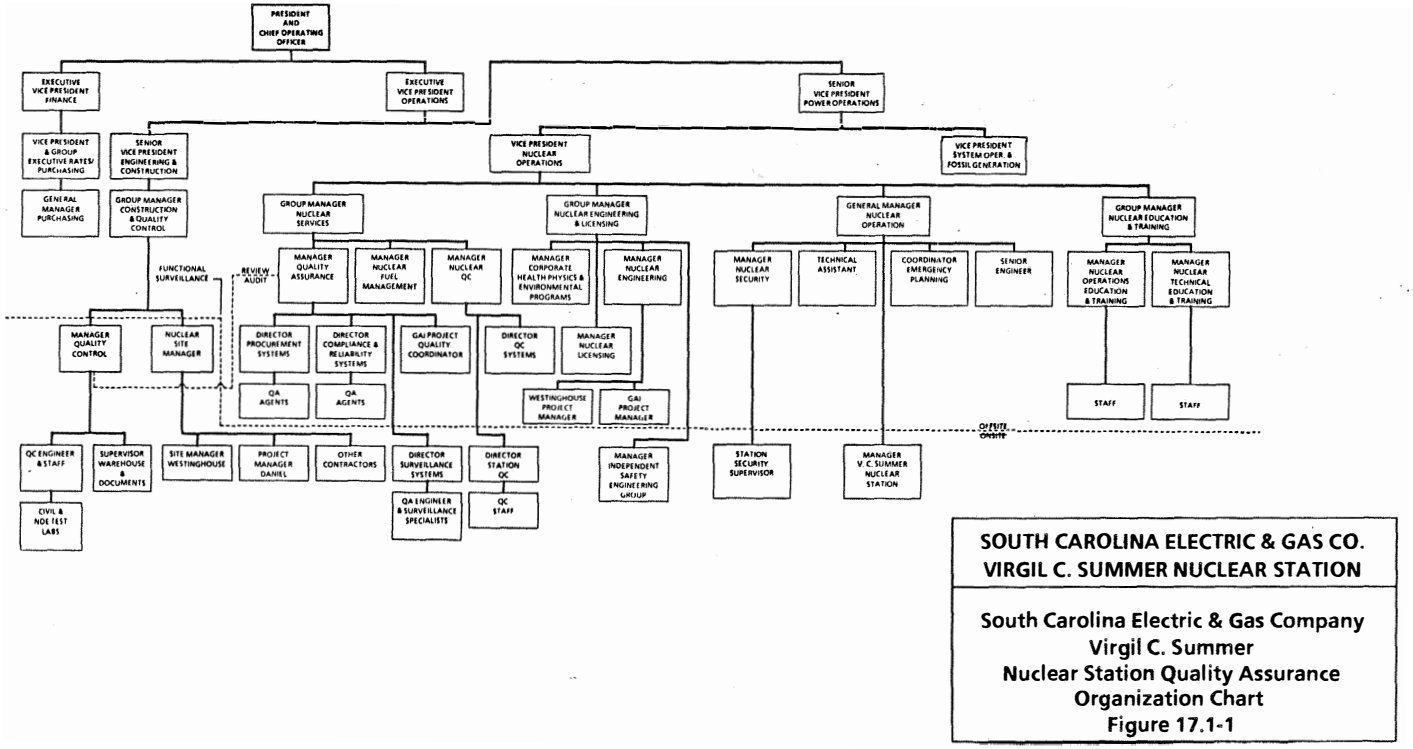
17.1.19 References

1. *Westinghouse Electric Corporation Water Reactor Division Quality Assurance Plan*, WCAP-8370.
2. *Nuclear Fuel Division Quality Assurance Program Plan, WCAP-7800.*

Figure 17.1-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION
QUALITY ASSURANCE ORGANIZATION CHART

Amendment 0
August 1984



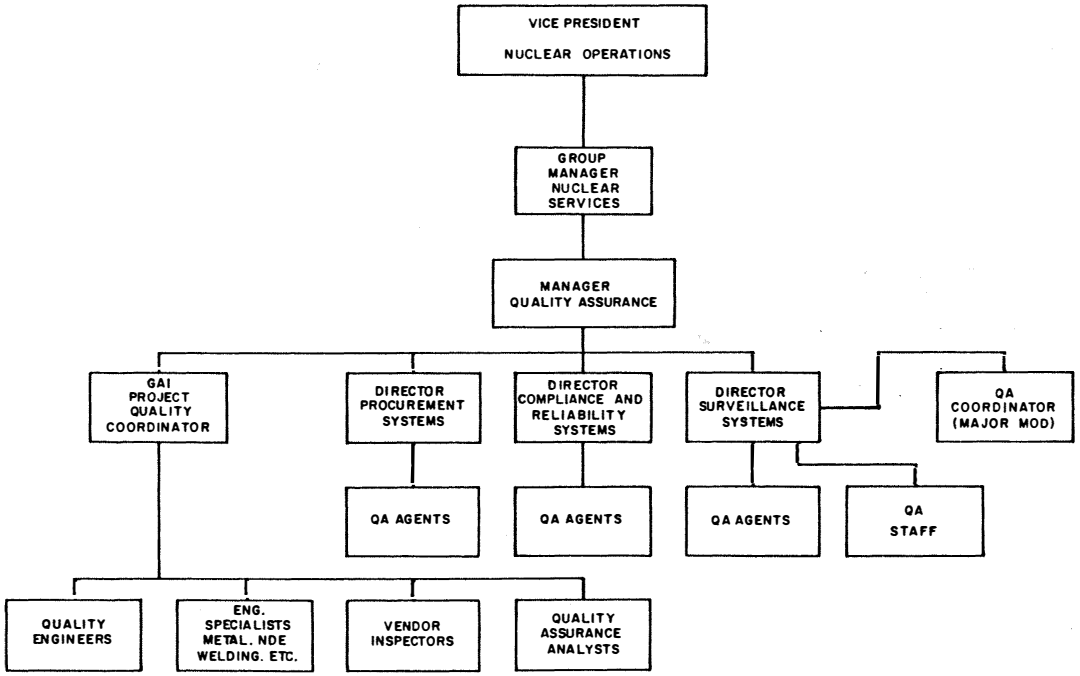
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

South Carolina Electric & Gas Company
Virgil C. Summer
Nuclear Station Quality Assurance
Organization Chart
Figure 17.1-1

Figure 17.1-2

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION
QUALITY ASSURANCE ORGANIZATION CHART

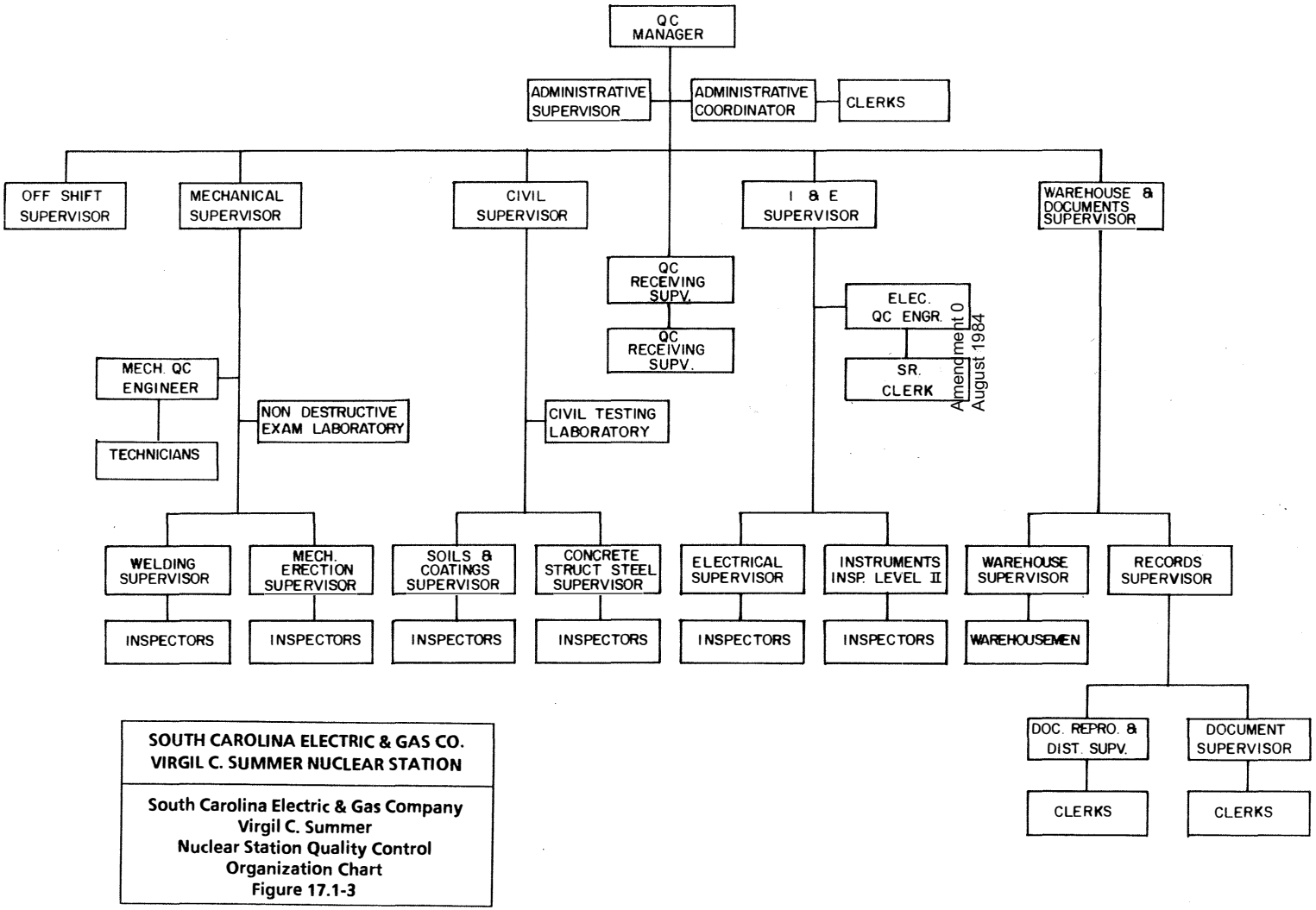
Amendment 0
August 1984



SOUTH CAROLINA ELECTRIC & GAS CO. VIRGIL C. SUMMER NUCLEAR STATION
South Carolina Electric & Gas Company Virgil C. Summer Nuclear Station Quality Assurance Organization Chart Figure 17.1-2

Figure 17.1-3

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION
QUALITY CONTROL ORGANIZATION CHART

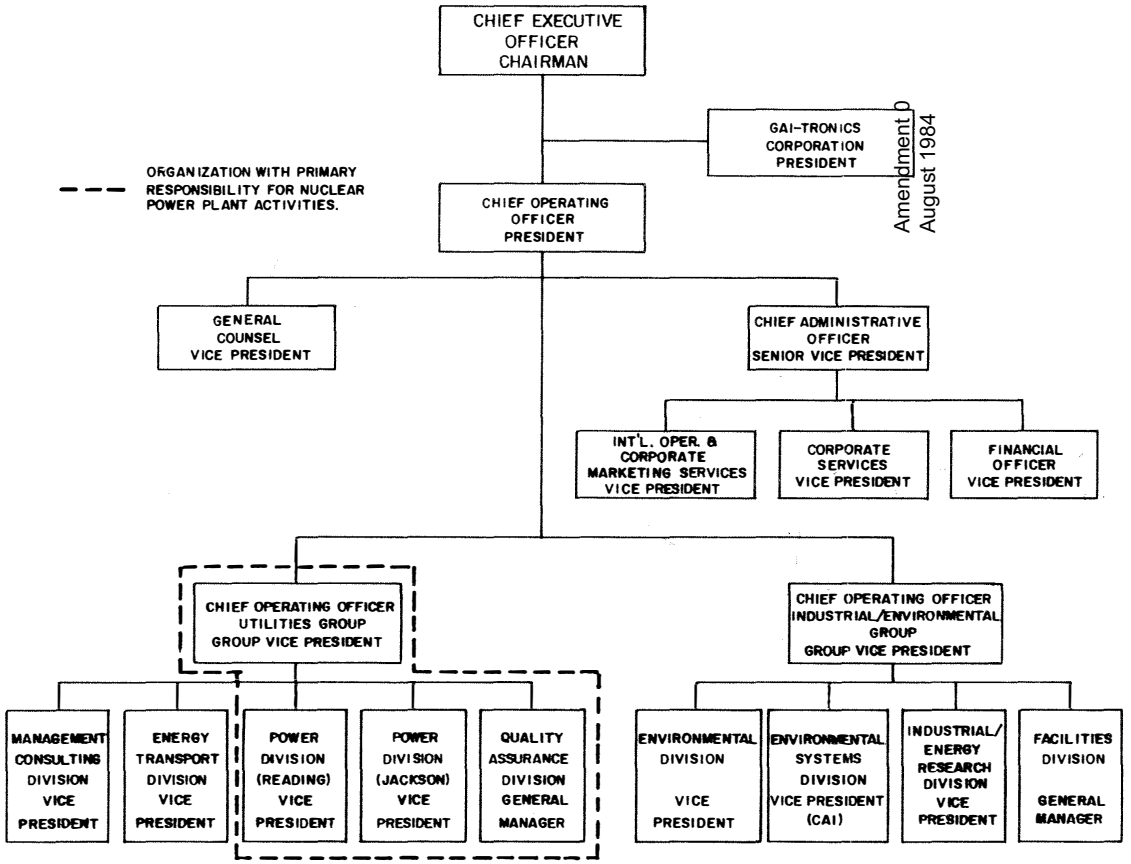


SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

South Carolina Electric & Gas Company
Virgil C. Summer
Nuclear Station Quality Control
Organization Chart
Figure 17.1-3

Figure 17.1-4

GILBERT ASSOCIATES, INC.
CORPORATE ORGANIZATION CHART



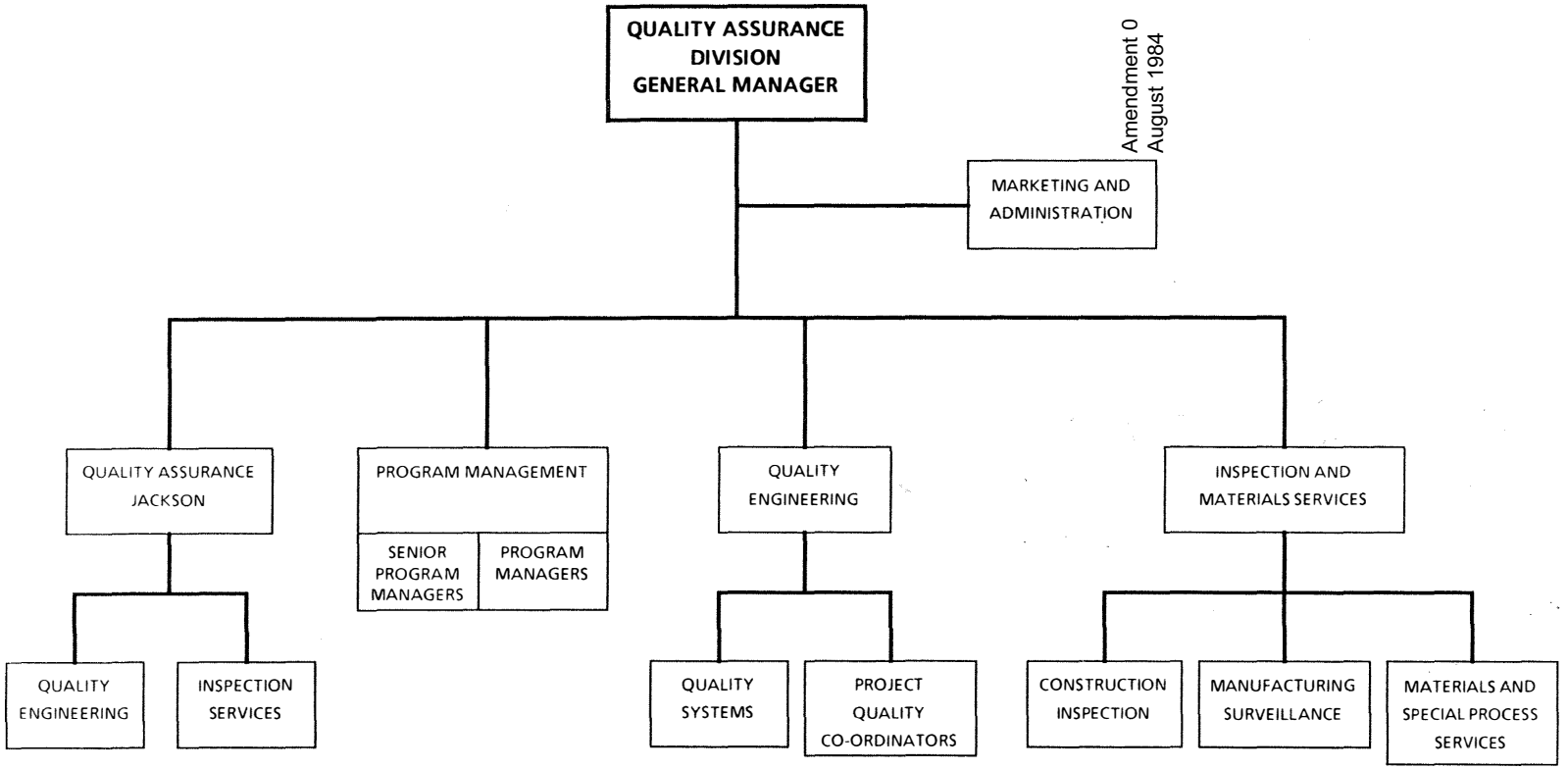
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Gilbert Associates, Inc.
Corporate Organization Chart

Figure 17.1-4

Figure 17.1-5

GILBERT ASSOCIATES, INC.
QUALITY ASSURANCE DIVISION
ORGANIZATION CHART



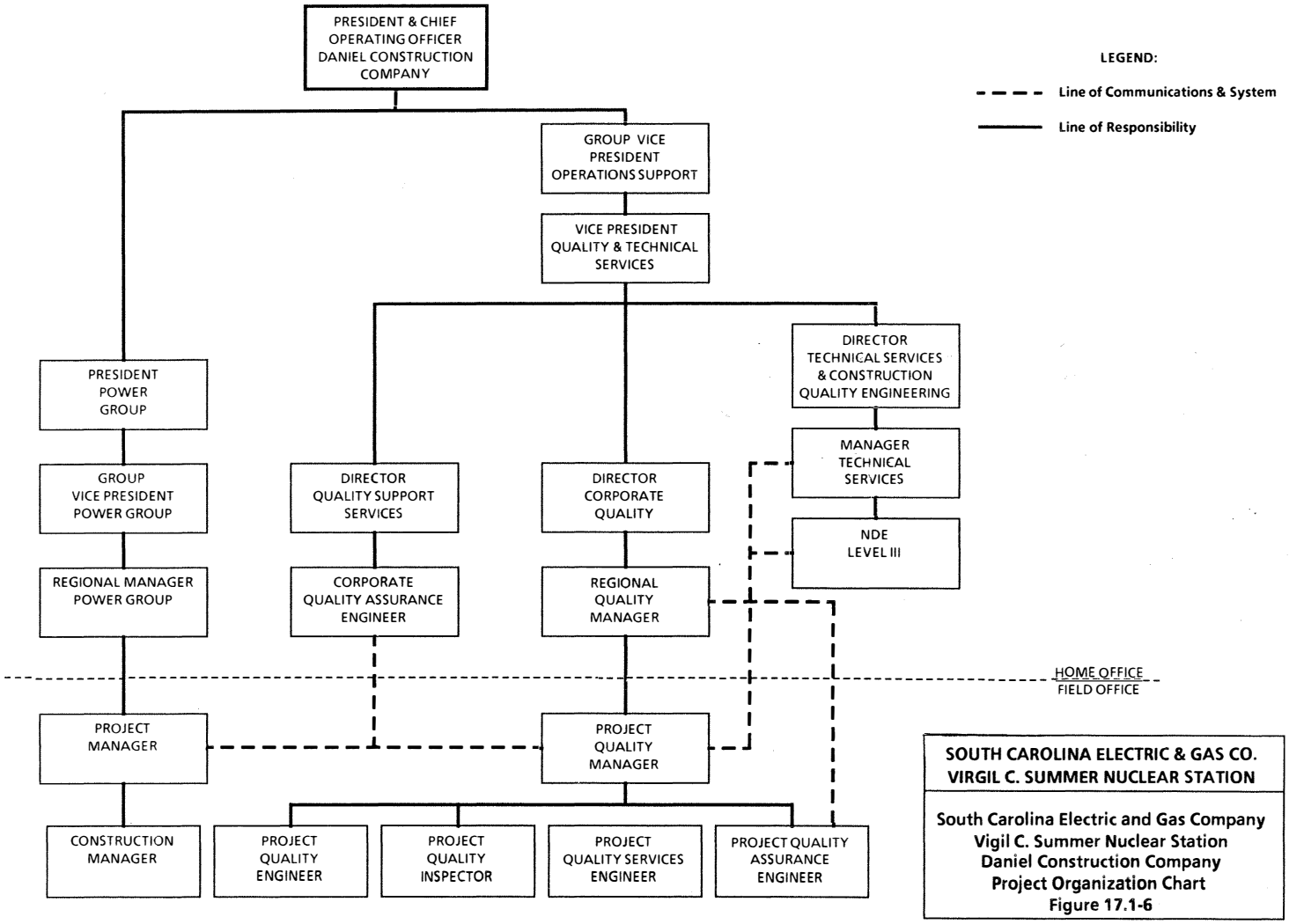
SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Gilbert Associates, Inc.
Quality Assurance Division
Organization Chart

Figure 17,1-5

Figure 17.1-6

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION
DANIEL CONSTRUCTION COMPANY
PROJECT ORGANIZATION CHART



17.2 QUALITY ASSURANCE DURING THE OPERATIONS PHASE

The description of the Quality Assurance Program at the Virgil C. Summer Nuclear Station Unit 1 is found in the Dominion Energy Nuclear Facility Quality Assurance Program Description (Topical Report DOM-QA-1) and is incorporated by reference. DOM-QA-1 is governed by 10 CFR 50.54(a).

V.C. Summer Nuclear Station
Safety Analysis Report

Aging Management Programs and Activities

Chapter 18

Revision 26--06/25/2026

The Revision summary replaces the List of Effective pages of the VC Summer FSAR, effective June 30, 2021. It will appear in Chapter 00 of the VC Summer FSAR and is the best history available of all the changes made to the original VC Summer FSAR.

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CHAPTER 18 - AGING MANAGEMENT PROGRAMS AND ACTIVITIES

18.0 AGING MANAGEMENT PROGRAMS AND ACTIVITIES

18.1 INTRODUCTION

South Carolina Electric & Gas Company prepared an Application for a Renewed Operating License of the Virgil C. Summer Nuclear Station (Application) (Reference 1). The application, including information provided in additional correspondence, provides sufficient information for the NRC to complete their technical and environmental reviews and provides the basis for the NRC to make the findings required by 10 CFR 54.29 (Final Safety Evaluation Report – Final SER) (Reference 2). Pursuant to the requirements of 10 CFR 54.21(d), the FSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation determined by 10 CFR 54.21 (a) and (c), respectively.

Table 18.1-1 provides a summary listing of the aging management programs and activities required for license renewal. Furthermore, Table 18.1-2 provides a summary listing of the evaluations of time-limited aging analyses (TLAA) required for license renewal. The first column of Table 18.1-1 and Table 18.1-2 provides a listing of aging management programs/activities and TLAA evaluations respectively. The second column of each table indicates where the issue is addressed in the Application. The third column of each table identifies where the description of the program/activity or TLAA is located in the Virgil C. Summer Nuclear Station FSAR.

The implementing documents are subject to administrative controls, including a formal review and approval process, and are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants”, and ANSI/ASME NQA-1-1994, “Quality Assurance Requirements for Nuclear Facility Applications”, as committed to in the FSAR. The confirmation process is part of the Aging Management Program implementing procedures and the Corrective Action Program, which are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants”, and ANSI/ASME NQA-1-1994, “Quality Assurance Requirements for Nuclear Facility Applications”, as committed to in the FSAR. The aging management activities required by this program would also reveal any unsatisfactory condition due to ineffective corrective action.

The implementing documents are subject to administrative controls, including a formal review and approval process, are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants”, and ANSI/ASME NQA-1-1994,“Quality Assurance Requirements for Nuclear Facility Applications”, as committed to in the FSAR.

For all programs a condition evaluation report (CER) is generated to provide a thorough description of identified aging problems along with a disposition specifying the corrective action(s). The VCSNS Corrective Action Program is utilized to provide specific corrective and confirmatory actions. Engineering reviews the inspection results for completeness and

acceptability. The corrective action processes ensure that degraded conditions are tracked and corrected in a timely manner. Engineering reviews the previous inspection reports to ensure implementation of recommended corrective actions and to determine their effectiveness. The license renewal programs and inspections are implemented in accordance with station procedures and work processes controlled by the quality assurance requirements of 10 CFR Part 50 Appendix B.

Table 18.1-1
Summary Listing of the Aging Management Programs and Activities

Program/Activity	Application Location	FSAR Location
10 CFR 50 Appendix J General Visual Inspection	B.1.11	18.2.1
10 CFR 50 Appendix J Leak Rate Testing	B.1.12	18.2.2
Above Ground Tank Inspection	B.2.1	18.2.3
Alloy 600 Aging Management Program	B.1.1	18.2.4
ASME Section XI ISI Program - IWF	B.1.13	18.2.5
Battery Rack Inspection	B.1.14	18.2.6
Boric Acid Corrosion Surveillances	B.1.2	18.2.7
Bottom-Mounted Instrumentation Inspection	B.1.3	18.2.8
Buried Piping and Tanks Inspection	B.2.10	18.2.9
Chemistry Program	B.1.4	18.2.10
Containment Coating Monitoring and Maintenance Program	B.1.15	18.2.11
Containment ISI Program – IWE/IWL	B.1.16	18.2.12
Diesel Generator Systems Inspection	B.2.2	18.2.13
Environmental Qualification (EQ) Program	B.3.1	18.2.14
Fire Protection Program (including Mechanical, Fire Barriers and Fire Barrier Penetration Seals, and Fire Doors activities)	B.1.5	18.2.15
Flood Barrier Inspection	B.1.17	18.2.16
Flow-Accelerated Corrosion Monitoring Program	B.1.6	18.2.17
Non-EQ Insulated Cables and Connections Inspection Program	B.2.9	18.2.18
In-Service Inspection (ISI) Plan	B.1.7	18.2.19
Inspections for Mechanical Components	B.2.11	18.2.20
Liquid Waste System Inspection	B.2.3	18.2.21
Maintenance Rule Structures Program	B.1.18	18.2.22
Material Handling System Inspection Program	B.1.19	18.2.23
Pressure Door Inspection Program	B.1.20	18.2.24

Table 18.1-1 (continued)
Summary Listing of the Aging Management Programs and Activities

Program/Activity	Application Location	FSAR Location
Preventive Maintenance Activities – Ventilation Systems Inspections	B.1.26	18.2.25
Reactor Building Cooling Unit Inspection	B.2.5	18.2.26
Reactor Vessel Closure Studs Program	B.1.8	18.2.27
Reactor Vessel Internals Inspection	B.2.4	18.2.28
Reactor Vessel Surveillance Program	B.1.24	18.2.29
Service Air System Inspection	B.2.6	18.2.30
Service Water Pond Dam Inspection Program	B.1.21	18.2.31
Service Water Structures Survey Monitoring Program	B.1.22	18.2.32
Service Water System Reliability and In-Service Testing Program	B.1.9	18.2.33
Small Bore Class 1 Piping Inspection	B.2.7	18.2.34
Steam Generator Management Program	B.1.10	18.2.35
Tendon Surveillance Program	B.3.3	18.2.36
Thermal Fatigue Management Program	B.3.2	18.2.37
Underwater Inspection Program (SWIS and SWPH)	B.1.23	18.2.38
Waste Gas System Inspection	B.2.8	18.2.39
Heat Exchanger Inspections	B.2.12	18.2.40
Preventive Maintenance Activities - Terry Turbine	B.1.25	18.2.41
Area Based Inspections for Refined 10 CFR 54.4(a)(2) Criteria	B.2.13	18.2.42
Aging Management Program for Electrical Cables Not Subject to 10CFR50.49 Environmental Qualification Requirements Used in Instrumentation Circuits		18.2.43
License Renewal Aging Management Program for Non-EQ Electrical Cables Used in Instrumentation Circuits		18.2.44
Aging Management Program for Inaccessible Medium-Voltage Cables Not Subject to 10CFR50.49 Environmental Qualification Requirements		18.2.45

Table 18.1-1 (continued)
Summary Listing of the Aging Management Programs and Activities

Program/Activity	Application Location	FSAR Location
Neutron Absorbing Material Monitoring Program	N/A (newly identified)	18.2.46

Table 18.1-2
Summary Listing of the TLAA Evaluations for License Renewal

Time Limited Aging Analysis	Application Location	FSAR Location
Crane Load Cycle Limit	4.7.2	18.3.6.1
Environmental Qualification	4.4	18.3.3
Metal Fatigue - ASME Section III, Class 1	4.3.1	18.3.2.1
Metal Fatigue - Leak-Before-Break Analysis	4.3.2	18.3.2.2
Metal Fatigue - ASME Section III, Class 2 and 3 Piping Fatigue	4.3.4	18.3.2.3
Reactor Building Liner	4.5.2	18.3.5
Reactor Building Tendon Prestress	4.5.1	18.3.4
Reactor Coolant Pump Flywheel	4.7.1	18.3.6.3
Reactor Vessel Neutron Embrittlement – Upper Shelf Energy	4.2.1	18.3.1.1
Reactor Vessel Neutron Embrittlement – Pressurizer Thermal Shock	4.2.2	18.3.1.2
Reactor Vessel Neutron Embrittlement – Pressure-Temperature (P-T) Limits	4.2.3	18.3.1.3
Service Water Intake Structure Settlement	4.7.3	18.3.6.2

18.2 AGING MANAGEMENT PROGRAMS AND ACTIVITIES

The programs and activities described in the subsequent sections are credited for the management of aging under all current licensing basis conditions. Evaluation of the programs and activities provides reasonable assurance that subject systems, structures, and components are capable of performing their intended function(s) under all current licensing basis conditions. Aging management is provided through activities such as continued monitoring and assessment of conditions, trending and/or through control of system/structure parameters to preclude degradation. Under certain circumstances, one-time inspections are performed to ascertain plant conditions and/or confirm that degradation is not occurring.

Herein, the names of the programs, or activities are used only in the context of aging management during the period of extended operation and do not necessarily align with existing formalized VCSNS programs and/or procedures. The program and activity names used in this Application are intended to describe the collection of activities that are necessary to effectively manage aging.

18.2.1 10 CFR 50 Appendix J General Visual Inspection

Prior to conducting a 10 CFR 50 Appendix J Type A Integrated Leak Rate Test (ILRT), a general visual structural examination of the containment system is conducted. The general visual examination satisfies Technical Specification surveillance requirement 4.6.1.6.3. The inspection manages loss of material, cracking of welds, deformed structural attachments, and surface discontinuities associated with the containment liner, deterioration of moisture barriers, and deterioration of the Reactor Building structure.

18.2.2 10 CFR 50 Appendix J Leak Rate Testing

10 CFR 50 Appendix J Leak Rate Tests are required by Technical Specifications Surveillance Requirement 4.6.1.2. Type A and Type B Leak Rate Tests are performed as described further in FSAR Section 6.2.6. The testing program consists of monitoring of leakage rates through containment liner/welds, penetrations, fittings and other access openings for detection of degradation of the containment pressure boundary.

18.2.3 Above Ground Tank Inspection

The Above Ground Tank Inspection is a new one-time inspection activity intended to determine if aging management is required for the internal surfaces of certain tanks and associated components (including pipe and valves) during the period of extended operation. The Above Ground Tank Inspection was created to detect and characterize loss of material due to galvanic and general corrosion in locations with exposure to ambient air conditions, loss of material due to general corrosion in locations with exposure to treated water in which dissolved oxygen levels are not controlled, and loss of material and/or cracking due to the corrosive effects of alternate wetting and drying of treated or borated water. The Above Ground Tank Inspection used suitable examination techniques at the most susceptible (sample) locations, including visual and volumetric techniques. It was concluded, based on the results of the one-time inspection program,

that additional aging management is not required during the period of extended operation for the Above Ground Tank Inspection.

18.2.4 Alloy 600 Aging Management Program

The purpose of the Alloy 600 Aging Management Program is to manage primary water stress corrosion cracking (PWSCC) of nickel-based alloy (Alloy 600 and 82/182) subcomponents of the reactor vessel, pressurizer, and steam generators that are exposed to borated water to ensure that the pressure boundary function is maintained during the period of extended operation. The Alloy 600 Aging Management Program includes elements of the Boric Acid Corrosion Surveillances and the ASME Section XI System Pressure Test Program, which detect the presence of system leakage, and the ASME Section XI In-service Examination Program, which specifies the NDE techniques and acceptance criteria applied to the evaluation of identified cracks.

18.2.5 ASME Section XI ISI Program - IWF

The ASME Section XI Subsection IWF In-service Inspection (ISI) Program manages loss of material for ASME Class 1, 2, and 3 piping supports (not including shock suppressors) and ASME Class 1, 2, and 3 major equipment supports for the period of extended operation. The ASME Section XI ISI Program - IWF was developed to implement the applicable requirements of 10 CFR 50.55a in accordance with ASME Section XI, Subsection IWF. The Subsection IWF scope of inspection for supports is based on sampling of the total support population. The inspection program includes periodic volumetric, surface and/or visual examination of component supports for signs of degradation and provides for corrective actions.

18.2.6 Battery Rack Inspection

The regulatory basis for inspecting battery racks is found in Technical Specifications Surveillance Requirement 3/4.8.2.1.c for the Electrical DC System. A visual inspection for loss of material due to corrosion is conducted for the Electrical DC System, in accordance with commitments in FSAR Section 8.3.2.2.2. A similar examination is conducted for the Fire Service System.

18.2.7 Boric Acid Corrosion Surveillances

The purpose of the Boric Acid Corrosion Surveillances is to manage loss of material due to boric acid corrosion of mechanical and structural components constructed of susceptible materials located in the Reactor Building and in specific areas of the Auxiliary, Intermediate, or Fuel Buildings where borated water leakage is possible. The Boric Acid Corrosion Surveillances also manage boric acid intrusion into electrical equipment located in proximity to borated water systems. Elements of the Boric Acid Corrosion Surveillances include the identification of leakage locations, procedures for locating small leaks, and corrective actions to ensure that boric acid corrosion does not lead to degradation of structures and components that could cause loss of intended function.

The Boric Acid Corrosion Surveillances program relies on implementation of Nuclear Regulatory (NRC) Generic Letter (GL) 88-05, as well as subsequent NRC bulletins and guidance, to monitor

the reactor coolant pressure boundary for borated water leakage. As a result of guidance in NUREG-1801, the program also includes monitoring for borated water leakage in all systems containing borated water.

18.2.8 Bottom-Mounted Instrumentation Inspection

The purpose of the Bottom-Mounted Instrumentation Inspection is to identify loss of material due to fretting (wear) in the bottom mounted instrumentation (BMI) thimble tubes prior to leakage in order to preclude a breach of the reactor coolant pressure boundary. Suitable inspection techniques are utilized and trended. The frequency of examination is based on wear rate relationships developed from Westinghouse research data.

18.2.9 Buried Piping and Tanks Inspection

The purpose of the Buried Piping and Tanks Inspection is to manage loss of material on the external surfaces of buried components. The conditions of coatings and wrappings are determined by visual inspection whenever buried components are excavated, such as for maintenance. Degraded coatings or wrappings are indicative of potential surface corrosion of the external piping or tank surfaces and require further evaluation.

18.2.10 Chemistry Program

The Chemistry Program controls the water chemistry in plant systems to minimize contaminant concentrations and adds chemicals, such as corrosion inhibitors and biocides, to manage loss of material, cracking, and fouling. The Chemistry Program is based on Electric Power Research Institute (EPRI) guidelines for water chemistry, specifically, Pressurized Water Reactor Primary Water Chemistry Guidelines, Pressurized Water Reactor Secondary Water Chemistry Guidelines, and Closed Cooling Water Chemistry Guideline. The Chemistry Program includes specifications for chemical species, limits, sampling and analysis frequencies, and corrective actions for primary, secondary, and auxiliary (borated or treated) water systems, as well as for oil and fuel oil.

Chemistry one-time inspections were also completed for low-alloy/carbon steel, stainless steel, and copper/copper alloy components to determine if aging management is required during the period of extended operation. The Chemistry one-time inspections were performed to detect and characterize loss of material due to crevice, pitting, general and galvanic corrosion and stress corrosion cracking. The inspections used a combination of volumetric and visual examination techniques at the most susceptible (sample) low-flow locations. It was concluded, based on the results of the one-time inspection program, that additional aging management is not required during the period of extended operation for the Chemistry Program.

18.2.11 Containment Coating Monitoring and Maintenance Program

The Containment Coating Monitoring and Maintenance Program provides for maintenance of protective coatings inside the containment. Maintenance of protective coatings manages loss of material due to corrosion. Visual inspections and condition assessments of certain coatings inside containment are periodically conducted as part of the containment structural integrity verification,

Maintenance Rule monitoring, general maintenance planning, and during recovery from refueling outages. Containment coatings are visually inspected via walkdowns from accessible floors, platforms or other permanent vantage points. The degree of examination depends on many factors such as accessibility, environmental and radiological conditions, and safety. In cases of inaccessibility, sampling approaches based on plant specific characteristics, industry wide experience and testing history are evaluated in lieu of actual visual inspections. Further discussions relevant to containment coatings is located in FSAR Appendix 3A (RG 1.54) and FSAR Section 6.2.1.6.

18.2.12 Containment ISI Program - IWE/IWL

10CFR 50.55a(g)(4) requires a detailed visual examination of the containment system for structural anomalies in accordance with ASME Section XI Subsection IWE, “Requirements for Class MC and Metallic Liners for Class CC Components for Light- Water Cooled Plants”, and Subsection IWL, “Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants” throughout the service life of nuclear power plants.

The VCSNS inspection program includes periodic visual examination of liner and concrete surfaces for signs of degradation and provides for corrective action. The CISI Program is conducted in accordance with the requirements of ASME Section XI, Subsections IWE and IWL, as modified by NRC rulemaking to 10CFR50.55a (initially published in the Federal Register on August 8, 1996). Consult the CISI Program Plan, ISE-4, for current CISI interval and ASME code information.

18.2.13 Diesel Generator Systems Inspection

The Diesel Generator Systems Inspection is a new one-time inspection activity intended to determine if aging management is required for certain carbon steel diesel generator support system components during the period of extended operation. The Diesel Generator Systems Inspection was created to detect and characterize loss of material due to general corrosion and/or corrosive impacts of alternate wetting and drying in pertinent starting air and exhaust air components. The Diesel Generator Systems Inspection used suitable examination techniques at the most susceptible (sample) locations, including visual and volumetric techniques. It was concluded, based on the results of the one-time inspection program, that additional aging management is not required during the period of extended operation for the Diesel Generator Systems Inspection.

18.2.14 Environmental Qualification (EQ) Program

The NRC has established environmental qualification (EQ) requirements in 10 CFR 50.49 and Appendix A (Criterion 4) to 10 CFR Part 50. EQ component aging limits are not based on condition or performance monitoring. However, such monitoring programs are an acceptable basis for modifying aging limits. Monitoring or inspection of environmental, condition, or component parameters may be used to ensure that the component is within its qualification, or to provide a basis to modify the qualification analyses. The EQ Program quantifies the plant service conditions (i.e., the operating environments) for defined environmental zones, such that the

severity of the aging effects (in comparison to other plant locations) can be determined. Further discussion of the EQ Program is contained in FSAR Section 3.11 and Appendix 3A (RG 1.89).

18.2.15 Fire Protection Program

The Fire Protection Program utilizes the concept of defense-in-depth to achieve a high degree of fire safety as discussed in Section 9.5.1. The Fire Protection Program provides administrative requirements for ensuring the operability of equipment required to ensure safe plant shutdown. The program includes visual inspections, system flushing, and performance tests of fire barriers, fire doors, and fire suppression system components. As described in Section 9.5.1, the Fire Protection Program includes the requirements 10 CFR 50.48 (c), which endorses, with exceptions, the National Fire Protection Association's (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants, 2001 Edition." Additional description of the portions of the program pertinent to the management of aging is provided below.

18.2.15.1 Mechanical

The Fire Protection Program includes the performance of flow tests and flushes to ensure that blockage of flow will not occur, performance testing of individual components to ensure they maintain their component intended function, and visual inspections to verify sprinkler and associated component condition. Fire suppression system components (e.g. piping, valves, nozzles, sprinkler heads, hydrants) are included within the scope of the mechanical inspections and tests. The normal Fire Service System pressure is monitored to provide further indication of the ability to maintain system function. Flow tests and flushes are conducted on the main distribution loops via hydrant testing. Performance testing is conducted on selected Fire Service System components based on NFPA recommendations. Visual inspections of Fire Service System components (e.g. sprinklers, hydrants, above ground piping) are periodically conducted to identify corrosion on the exterior surface, physical damage or obstructions that might impede performance of the intended functions.

In addition, disassembly/replacement of representative sprinkler heads in branch lines that do not receive flow during periodic testing is to be conducted in accordance with NFPA standards. Ultrasonic testing of a representative sample of these stagnant section of piping will to be conducted at 10-year intervals. The initial implementation of ultrasonic testing was completed in 2021, prior to the period of extended operation.

A one-time inspection of the Fire Service System will be performed to determine if aging management is required for brass and cast iron components during the period of extended operation. The inspection activity will detect and characterize loss of material due to selective leaching. This inspection will use suitable hardness measurement techniques at the most susceptible (sample) locations.

18.2.15.2 Fire Barriers and Fire Barrier Penetration Seals

The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire dampers, and fire barrier walls, ceilings, and floors to ensure that their operability is maintained.

18.2.15.3 Fire Doors

Fires rated door inspections are performed. Examination guidelines and results of periodic inspections of fire rated doors are provided. Inspections are credited with managing loss of material of doors and door hardware for the period of extended operation.

18.2.16 Flood Barrier Inspection

Periodic visual inspections are performed for flood barriers (walls, curbs, equipment pedestals), flood doors, and flood barrier penetration seals. The Flood Barrier Inspection activity is a subset of the Maintenance Rule Structures Program and the Fire Protection Program. The inspections serve to detect cracking and loss of material prior to loss of component intended function.

18.2.17 Flow-Accelerated Corrosion Monitoring Program

The purpose of the Flow-Accelerated Corrosion Monitoring Program is to manage loss of material for components located in systems within the scope of license renewal which are susceptible to flow-accelerated corrosion (FAC) (also called erosion-corrosion). The FAC program is also responsible for managing material loss due to Erosive wear due to Liquid Droplet Impingement (LDI), Cavitation, Flashing, and Solid Particle Erosion via the Erosion program. This program consists of (a) conducting appropriate analysis and baseline inspections, (b) determining the extent of thinning and replacement/repair of components, and (c) performing follow-up inspections to confirm or quantify and take long-term corrective actions. The program relies on implementation via EPRI Guidelines, NUREG guidelines, and applicable station and industry OE.

18.2.18 Non-EQ Insulated Cables and Connections Inspection Program

The Non-EQ Insulated Cables and Connections Inspection Program provides the inspection of accessible cables and connections including splices, terminal blocks and fuse holders that are found susceptible to potential degradation in adverse thermal and radiological areas of the plant. Accessible areas for cable and connection inspections were defined as those that can be approached and viewed easily. Those located in vaults or manholes were not considered accessible and therefore not within the scope of these inspections. While certain areas of the Intermediate and Auxiliary Buildings will be the focus, there will be flexibility to inspect cables and connections in a variety of Environmental Zones as determined by the responsible Electrical Engineering group at VCSNS. The program will be performed at 10-year intervals. The initial inspections were completed in 2017 (inside the Reactor Building) and 2018 (outside the Reactor Building), prior to the period of extended operation. In addition to the visual inspections of in-scope passive fuse holders, the metallic fuse clip portion that are found to be susceptible to age

related degradation will receive a continuity check or will undergo thermography or other appropriate tests on a representative sample basis to assure the metallic fuse clips are still making good connections. The visual inspections will assess the accessible cables to determine if the cable jackets show any signs of cracking, embrittlement, discoloration, crazing, melting, or any other visible evidence of age-related degradation which might indicate loss of insulation resistance.

18.2.19 In-Service Inspection (ISI) Plan

The In-Service Inspection (ISI) Plan implements the requirements of 10 CFR 50.55a for Class 1, 2 and 3 components is in accordance with ASME Section XI, Subsections IWB (Class 1), IWC (Class 2), and IWD (Class 3). The program consists of periodic volumetric, surface, and/or visual examination of components for signs of degradation and provides for corrective actions. The examinations are performed to the extent practicable within the limitations of design, geometry, and materials of construction of the component. The period of extended operation for VCSNS will contain the fourth, fifth, and sixth ten-year in-service inspection intervals. The program is addressed further in FSAR Section 5.7.

18.2.20 Inspections For Mechanical Components

The Inspections for Mechanical Components manage loss of material and cracking for mechanical components constructed of susceptible materials and exposed to ambient conditions. The inspections involve a visual examination of the exposed external surfaces of representative mechanical components. The inspections and associated evaluations also address conditions in locations susceptible to external pitting corrosion due to the presence of insulation materials and the potential for condensation to occur.

18.2.21 Liquid Waste System Inspection

The Liquid Waste System Inspection is a new one-time inspection activity intended to determine if aging management is required for certain stainless steel pipe, valves and heat exchanger components during the period of extended operation. The Liquid Waste System Inspection was created to detect and characterize loss of material due to crevice and pitting corrosion, and cracking due to stress corrosion cracking in systems and components containing unmonitored and uncontrolled water. The Liquid Waste System Inspection used a combination of volumetric and visual examination techniques at the most susceptible (sample) locations. It was concluded, based on the results of the one-time inspection program, that additional aging management is not required during the period of extended operation for the Liquid Waste System Inspection.

18.2.22 Maintenance Rule Structures Program

The Maintenance Rule Structures Program for the inspections of structures and structural components meets the regulatory requirements of 10 CFR 50.65, the Maintenance Rule. This program is implemented in accordance with NUMARC 93-01, Rev. 4F and Regulatory Guide 1.160, Rev. 4. Visual inspections and condition assessments of structures and structural components are conducted in accordance with the requirements of the Maintenance Rule. These

inspections include penetrations and associated piping at structural interfaces, which may be subject to degradation mechanisms (including microbiologically induced corrosion). The structures and structural components are visually inspected via walkdowns from accessible floors, platforms or other permanent vantage points. In cases of inaccessibility, sampling approaches are evaluated. The Maintenance Rule Structures Program includes chemical analysis of raw water (groundwater and Service Water Pond) per the Maintenance Rule intervals in support of condition assessment.

18.2.23 Material Handling System Inspection Program

The Material Handling System Inspection Program manages loss of material for applicable steel rails and girders. The Material Handling System Inspection Program has been in effect for many years at VCSNS and includes Nuclear Safety Related and Quality Related (seismically restrained) material handling system components. Material handling systems steel support structures (rails, runways, monorails, girders, jib cranes, seismic restraints, and associated connections) are inspected in accordance with guidance provided by ANSI standards. Inspections are implemented in the course of routine maintenance.

18.2.24 Pressure Door Inspection Program

The Pressure Door Inspection Program provides examination guidelines for periodic inspections of pressure doors. VCSNS pressure doors are Nuclear Safety Related or Quality Related. Most Nuclear Safety Related pressure doors are also fire doors. Pressure door inspection attributes include freedom of movement, function (closed during normal plant operation), structural deterioration, and loss of door/door hardware material. Pressure doors are required to be operable in Plant Operating Modes 1, 2, 3, and 4. The surveillance requirements include monitoring of door position and visual inspection that the door is closed and not impaired.

18.2.25 Preventative Maintenance Activities - Ventilation System Inspections

The Preventive Maintenance Activities – Ventilation Systems Inspections manage loss of material and fouling in susceptible components. Susceptible components include those components in the Air Handling, Local Ventilation and Component Cooling Systems that are exposed internally to ambient air. Routine maintenance inspections are conducted which include detection of age-related degradation.

18.2.26 Reactor Building Cooling Units Inspection

The Reactor Building Cooling Units Inspection is a new one-time inspection activity that will determine if aging management is required for reactor building cooling unit drain lines during the period of extended operation. The Reactor Building Cooling Unit Inspection will detect and characterize loss of material or cracking resulting from exposure to an unmonitored and uncontrolled (alternately wetted/dried) water environment. The Reactor Building Cooling Unit Inspection will use volumetric and/or visual examination techniques at the most susceptible (sample) locations in the reactor building cooling unit drain lines.

18.2.27 Reactor Vessel Closure Studs Program

The purpose of the Reactor Head Closure Studs Program is to manage loss of mechanical closure integrity due to stress relaxation, stress corrosion cracking, and wear for the alloy steel components of the reactor vessel closure stud assembly. The In-Service Inspection (ISI) Plan portion of the Reactor Head Closure Studs Program detects cracking and loss of material through the use of surface examination (magnetic particle or liquid penetrant) and/or ultrasonic examination. Reactor vessel studs may be examined in place (under tension), when the connection is disassembled, or when the studs are removed. Further discussions of the inspection and protection of reactor vessel closure stud assemblies is contained in FSAR Section 5.4.

18.2.28 Reactor Vessel Internals Inspection

The Reactor Vessel Internals Inspection (RVI) supplements the In-Service Inspection (ISI) Plan to assess the condition of reactor vessel internals in order to ensure that the intended functions are maintained during the period of extended operation. The RVI Program fulfills the NEI 03-08 requirements to implement MRP-227, Pressurized Water Reactor Internals Inspection and Evaluation Guidelines and MRP-228, Inspection Standards for PWR Intervals. The RVI Program also incorporates applicable NEI 03-08 Interim Guidance requirements. The inspection provides examination techniques and engineering evaluations to address the aging effects listed below:

- Changes in dimensions due to irradiation creep and void swelling
- Cracking due to irradiation-assisted stress corrosion cracking
- Cracking due to primary water stress corrosion cracking (PWSCC) for nickel-based materials
- Loss of material due to wear
- Loss of preload due to stress relaxation
- Reduction of fracture toughness due to irradiation embrittlement and void swelling

For those components that are accessible or can be rendered accessible by the removal of the core and other internals for examination, a visual inspection is performed to detect the presence and extent of cracking and loss of material. For bolts and for inaccessible components, a volumetric inspection is performed to detect the presence and extent of changes in dimensions, cracking, loss of preload, and reduction of fracture toughness. With respect to changes in dimensions due to void swelling, industry activities (including WOG and EPRI) are under way to better characterize the effect and, if necessary, to develop and qualify methods for detection and management. These activities will be monitored by VCSNS and implemented, as applicable.

18.2.29 Reactor Vessel Surveillance Program

The purpose of the Reactor Vessel Surveillance Program is to manage reduction of fracture toughness due to irradiation embrittlement of reactor vessel beltline materials to assure that the pressure boundary function is maintained for the period of extended operation. The program includes an evaluation of radiation damage based on testing of Charpy V-notch and tensile specimens. The Reactor Vessel Surveillance Program conforms to 10 CFR 50, Appendix H. Further discussions of this program are contained in FSAR Section 5.4.3.

Additionally, a one-time demonstration was performed to ensure that materials in the upper shell/nozzle course of the Reactor Vessel would not become limiting during the period of extended operation, with respect to radiation damage.

18.2.30 Service Air System Inspection

The Service Air System Inspection is a new one-time inspection activity intended to determine if aging management is required for certain carbon steel pipe and valves during the period of extended operation. The Service Air System Inspection was created to detect and characterize loss of material due to general corrosion on internal surfaces of subject components resulting from exposure to moist air. The Service Air System Inspection used a combination of volumetric and visual examination techniques at the most susceptible (sample) locations. It was concluded, based on the results of the one-time inspection program, that additional aging management is not required during the period of extended operation for the Service Air System Inspection.

18.2.31 Service Water Pond Dam Inspection Program

The purpose of the Service Water Dam Inspection Program is to assess the condition of the Service Water Pond Dams and the West Embankment with respect to loss of material (erosion), alignment (movement), surface cracking and seepage(1) that could result in loss of component intended function. This program is based on the recommendations of Regulatory Guide 1.127, Rev. 1. Additionally, the submerged slope stability of the West Embankment in the vicinity of the Intake Structure is monitored as specified by VCSNS Operating License Number NPF-12, Condition 2.C.5. Dominion Energy South Carolina (DESC) also conducts annual walkdowns of the Service Water Pond Dams scheduled in the course of routine maintenance. A visual inspection of the North Berm and piezometer monitoring of accessible piezometers on the North Dam and West Embankment are both performed on 5 year intervals.

18.2.32 Service Water Structures Survey Monitoring Program

Survey monitoring is required for structures that are supported by earthen fill material and which have exhibited the potential for settlement. Settlement is not considered to be adverse unless it imposes stresses on a structure that could exceed the design values. Initial settlement of the Service Water Pumphouse and Service Water Intake Structure was much more than the original pre-construction estimates. As a result, survey monitoring of the Service Water Pumphouse, Service Water Intake Structure, Electrical Duct Banks, and Service Water Intake Line “A” is conducted to satisfy the requirements specified by Operating License Condition 2.C.5 and FSAR Section 2.5.4.10.6.2. The purpose of the surveys is to monitor and evaluate any differential in vertical and horizontal displacement in order to identify settlement issues prior to their resulting in significant degradation or loss of function.

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(1) In accordance with Service Water Pond Dam Inspection Program implementing procedures, seepage monitoring is performed only in the event that the Monticello Reservoir is drawn down below elevation 415.0 feet. Seepage monitoring is not performed during normal plant conditions.

18.2.33 Service Water System Reliability and In-Service Testing Program

The purpose of the Service Water System Reliability and In-Service Testing Program is to manage cracking, fouling, and loss of material for susceptible materials located in systems that contain raw water from the Service Water Pond. The Service Water System Reliability and In-Service Testing Program is intended to detect the presence of and assess the extent of cracking, fouling and loss of material. The program also serves to mitigate aging effects through the use of chemical additives in order to minimize fouling. Visual inspections of Service Water System piping and components are conducted on a periodic basis to monitor the extent of cracking, fouling, and loss of material. The heat transfer capabilities of heat exchangers serviced by the Service Water System are evaluated to detect the presence of fouling.

18.2.34 Small Bore Class 1 Piping Inspection

The Small Bore Class 1 Piping Inspection is a new one-time inspection activity intended to determine if aging management is required for cracking due to flaw growth and stress corrosion cracking for Reactor Coolant System stainless steel piping and fittings less than four inches NPS. The Small Bore Class 1 Piping Inspection serves to increase confidence in the current condition of small bore Reactor Coolant System piping which does not receive a volumetric examination per the ASME Code. The Small Bore Class 1 Piping Inspection used suitable volumetric examination techniques at the most susceptible (sample) locations. It was concluded, based on the results of the one-time inspection program, that additional aging management is not required during the period of extended operation for the Small Bore class 1 Piping Inspection.

18.2.35 Steam Generator Management Program

The purpose of the Steam Generator Management Program is to perform examinations to ensure that cracking and loss of material of nickel-based alloy steam generator tubes and tube plugs are identified and corrected prior to exceeding allowable limits. The program implements the requirements of Technical Specification 4.4.5 for tube inspections. Other components, in addition to tubes, are inspected under this program. The program follows the recommendations provided by NEI 97-06 and associated EPRI guidelines for Steam Generator component inspections and chemistry controls.

18.2.36 Tendon Surveillance Program

The Tendon Surveillance Program meets the requirements of 10CFR50.55a(b)(2)(viii) and, as incorporated by reference therein, the requirements of ASME Section XI, Subsection IWL. The tendon lift-off forces are evaluated to ensure that the rate of tendon force loss is within predicted limits and that a minimum required tendon force level exists in the Reactor Building. Degradation of the Reactor Building post-tensioning system is detected by periodic inspections of randomly selected tendons. Further discussion pertinent to tendon stresses is contained in FSAR Section 3.8.1.5.1.2 and Regulatory Guide 1.35.1 (see Appendix 3A).

18.2.37 Thermal Fatigue Management Program

As defined for license renewal, the Thermal Fatigue Management Program seeks to preclude cracking due to low-cycle thermal fatigue by managing the thermal fatigue basis. Management of the fatigue basis is accomplished by continually showing that the severity and number of occurrences of the actual transients are enveloped (bounded) by the severity and number of occurrences of the analyzed transients. The program documents and evaluates plant operational transients/cycles using a specially designed computer program. The evaluation process includes comparison of the number of thermal cycles incurred against the design transient limit and/or calculation of cumulative usage factors (CUF) and verification that adequate margin exists. The Thermal Fatigue Management Program will incorporate applicable industry guidance once it is finalized to account for environmental effects of the reactor coolant fluid.

18.2.38 Underwater Inspection Program (SWIS and SWPH)

Underwater inspections of the Service Water Intake Structure are conducted and the conditions assessed in accordance with the requirements of VCSNS Operating License NPF-12, Condition 2.C.5.d. The purpose of the inspection is to monitor the condition of existing cracks in the Service Water Intake Structure that originated due to greater than expected settlement of the structure. Underwater inspections of the Service Water Intake Structure and the Service Water Pumphouse also serve to monitor corrosion and fouling within the Service Water System.

18.2.39 Waste Gas System Inspection

The Waste Gas System Inspection is a new one-time inspection activity intended to determine if aging management is required for certain stainless steel components of the Gaseous Waste Processing System during the period of extended operation. The Waste Gas System Inspection was created to detect and characterize loss of material due to crevice and pitting corrosion in portions of the system exposed to unmonitored and uncontrolled treated water, and cracking due to stress corrosion cracking in portions of the system containing gas. The Waste Gas System Inspection used a combination of volumetric and visual examination techniques at the most susceptible (sample) locations. It was concluded, based on the results of the one-time inspection program, that additional aging management is not required during the period of extended operation for the Waste Gas System Inspection.

18.2.40 Heat Exchanger Inspection

The Heat Exchanger Inspection is a new one-time inspection activity intended to determine if aging management is required for certain malleable heat exchanger components during the period of extended operation. The Heat Exchanger Inspection was created to detect and characterize loss of material due to selective leaching and erosion-corrosion, as well as particulate fouling. The Heat Exchanger Inspection used a combination of volumetric and visual examination and hardness measurement techniques at the most susceptible (sample) locations.

Selective leaching was identified as part of the program during original license renewal scoping; however, it was later determined to no longer be an applicable aging effect since there were no in

scope susceptible components (i.e., no copper/copper alloy/brass components with >15% zinc). It was concluded, based on the results of the one-time inspection program, that additional aging management is not required during the period of extended operation for the Heat Exchanger Inspection.

18.2.41 Preventative Maintenance Activities - Terry Turbine

The purpose of the Preventive Maintenance Activities - Terry Turbine is to manage loss of material in carbon steel due to general corrosion of the turbine casing and associated components in the steam inlet and exhaust paths that are normally exposed to ambient conditions with periodic exposure to steam allowing moisture to accumulate. The Preventive Maintenance Activities - Terry Turbine is a condition monitoring program composed of controlled plant procedures. Routine maintenance inspections are conducted which include detection of age-related degradation and initiation of corrective actions as necessary.

18.2.42 Area Based Inspections For Refined 10CFR 54.4(A)(2) Criteria

The Area Based Inspections for Refined 10 CFR 54.4(a)(2) Criteria is a new one-time inspection activity intended to determine if aging management is required for components that have an anti falldown requirement during the period of extended operation. The Area Based Inspections for Refined 10 CFR 54.4(a)(2) Criteria detects and characterizes loss of material or cracking resulting from exposure to an unmonitored and uncontrolled water environment. The Area Based Inspections for Refined 10 CFR 54.4(a)(2) Criteria uses a combination of volumetric and visual examination techniques at the most susceptible (sample) locations in the piping in carbon steel piping anti falldown systems with uncontrolled water, including reinspection of five (5) locations in Sewer and Miscellaneous Drain piping to trend wall thickness to further ensure intended function is not challenged during the period of extended operation.

18.2.43 Aging Management Program For Electrical Cables and Connections Not Subject To 10CFR50.49 Environmental Qualification Requirements Used In Instrumentation Circuits

The “Aging Management Program for Electrical Cables and Connections Not Subject to 10CFR50.49 Environmental Qualification Requirements Used in Instrumentation Circuits” provides for reasonable assurance that the intended functions of electrical cables and connections that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are used in instrumentation circuits with sensitive, low-level signals exposed to adverse localized environments caused by heat, radiation or moisture will be maintained consistent with the current licensing basis through the period of extended operation. In this aging management program, calibration results or findings of surveillance testing programs are used to identify the potential existence of aging degradation. This program applies to the in scope instrumentation cables and connections that are included in the circuit during loop calibrations.

This program will be implemented as appropriate at least once every 10 years. The initial implementation was completed in 2018 and 2019, prior to the period of extended operation.

18.2.44 License Renewal Aging Management Program For Non-EQ Electrical Cables and Connections Used In Instrumentation Circuits

High-range-radiation and neutron flux monitoring instrumentation cables and connections used in high voltage, low-level signal applications that are sensitive to reduction in insulation resistance for which calibrations are performed without the cable and connections in the “loop calibration” circuit will be subject to the “License Renewal Aging Management Program for Non-EQ Electrical Cables and Connections Used in Instrumentation Circuits”. In this program, an appropriate test, such as an insulation resistance test, will be used to identify the potential existence of a reduction in cable insulation resistance (IR). This program is an acceptable alternative to aging management program 18.2.43.

This program will be implemented at least once every 10 years. The initial implementation was completed in 2021, prior to the period of extended operation.

18.2.45 Aging Management Program For Inaccessible Medium-Voltage Cables Not Subject To 10CRFR50.49 Environmental Qualification Requirements

The purpose of this aging management program is to provide reasonable assurance that the intended functions of inaccessible medium-voltage cables that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by moisture while energized will be maintained consistent with the current licensing basis through the period of extended operation.

In this aging management program periodic actions are taken to prevent or minimize the possibility that cables may be exposed to moisture, such as inspecting for water collection in cable manholes and conduit, and draining water, as needed. In-scope, medium-voltage cables exposed to moisture and significant voltage are tested to provide an indication of the condition of the conductor insulation. The initial baseline cable testing was completed in 2012 and 2014 for in-scope circuits associated with Service Water Pump Motor power cables ESM191A and ESM221B, respectively. Initial testing frequency was established to occur at 10 year intervals, thereafter, in accordance with NUREG-1801 Rev.0 XI.E3. However, this frequency has since been changed to 6 years to align with the station’s response to NRC Generic Letter 2007-01, Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients, captured under RC-07-0074 and NUREG-1801 Rev. 2 XI.E3.

18.2.46 Neutron Absorbing Material Monitoring Program

The Neutron Absorbing Material Monitoring Program is an aging management program based on the guidance in NUREG-1801 Revision 2, XI.M40, Monitoring of Neutron-Absorbing Materials Other than Boraflex. The purpose of the program is to assure that degradation of the neutron-absorbing material used in spent fuel pool storage racks that could compromise the criticality analysis will be detected prior to loss of intended function. The program relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required sub-criticality margin is maintained during the license renewal period of extended operation. The

program complies with the requirements of Generic Letter 2016-01, Monitoring of Neutron-Absorbing Materials in Spent Fuel Pools.

18.3 TIME-LIMITED AGING ANALYSES (TLAA) EVALUATIONS

As part of the application for a renewed license, 10 CFR 54.21(c) requires that an evaluation of time-limited aging analyses (TLAAs) be provided for the period of extended operation. The following TLAAs have been identified and evaluated to meet this requirement.

18.3.1 Reactor Vessel Neutron Embrittlement

The reactor vessel is subjected to neutron irradiation from the core. This irradiation results in the embrittlement of the reactor vessel materials. Analyses have been performed that address the following:

- Upper-Shelf Energy
- Pressurized Thermal Shock
- Pressure-Temperature (P-T) Limits

18.3.1.1 Upper-Shelf Energy

The requirements on reactor vessel Charpy upper-shelf energy are included in 10 CFR 50, Appendix G. The Charpy upper-shelf energy must be maintained at no less than 50 ft-lb. throughout the life of the reactor vessel.

The upper shelf energy (USE) for VCSNS reactor vessel materials have been estimated for the end of the 60 year period of extended operation, 56 Effective Full Power Years (EFPY). The estimates were made using Figure 2 from Regulatory Guide 1.99, Revision 2, the estimated fluence and chemistry of the materials and the Charpy test data from surveillance capsules. The fluence projections were obtained from WCAP-16298-NP, Revision 0, “Analysis of Capsule Z from the SCE&G V. C. Summer Radiation Surveillance Program”, August 2004. The USE values are developed in WCAP-16306-NP, Revision 0, “Evaluation of Pressurized Thermal Shock for V. C. Summer”, August 2004, at ¼ the reactor vessel wall thickness. The calculated USE values for the limiting reactor vessel material is above 50 ft-lb for 56 EFPY.

18.3.1.2 Pressurized Thermal Shock

The requirements of 10 CFR 50.61 provide rules for protection against pressurized thermal shock events for pressurized water reactors. The screening criteria established by 10 CFR 50.61 are 270°F for plates, forgings, and axial weld materials and 300°F for circumferential weld materials. According to 10 CFR 50.61, if the calculated reference temperature (RT_{PTS}) for the limiting beltline materials is less than the specified screening criteria, then the vessel is acceptable with regard to the risk of vessel failure during postulated pressurized thermal shock transients. The regulations require updating the pressurized thermal shock assessment upon a request for a change in the expiration date of the facility operating license.

The RT_{PTS} values for VCSNS have been calculated for the end of the 60 year period of extended operation, 56 EFPY. The projected RT_{PTS} values are based upon surveillance capsule data. The

last capsule removed from the reactor vessel was exposed to a neutron fluence estimated to be equivalent to that exposed to the vessel wall at the end of 60 years. The RT_{PTS} fracture toughness of the reactor vessel beltline region has been evaluated according to the requirements of the Pressurized Thermal Shock (PTS) rules of 10 CFR 50.61. Using the PTS rules and surveillance capsule data, the evaluation is documented in WCAP-16306-NP, Revision 0, “Evaluation of Pressurized Thermal Shock for V. C. Summer “, August 2004. This evaluation shows maximum calculated RT_{PTS} values at 56 EFPY for the most limiting plate/axial weld and for the most limiting circumferential weld to be well below the screening criteria of 270° F and 300° F, respectively, as specified in the PTS rule.

18.3.1.3 Pressure-Temperature (P-T) Limits

Appendix G to 10 CFR 50 requires that heatup and cooldown of the reactor pressure vessel shall be accomplished within established pressure-temperature limits. The pressure-temperature limits are established by calculations that utilize the materials and fluence data obtained through the site reactor surveillance capsule program. Normally, the pressure-temperature limits are calculated for several years into the future and remain valid for an established period of time not to exceed the current operating license term.

Pressure-temperature limit curves have been developed for 56 EFPY in WCAP-16305-NP, Revision 0, “V. C. Summer Heatup and Cooldown Limit Curves for Normal Operation”, August 2004, that corresponds to the end of the 60 year extended operational period. These curves are based upon data from the last capsule removed from the reactor vessel which was exposed to a neutron fluence estimated to be equivalent to that exposed to the vessel wall at the end of 60 years. The Technical Specification has been updated to include these curves as required by 10 CFR 50. Therefore, the curves that are now in the Technical Specifications are valid for the period of extended operation.

18.3.2 Metal Fatigue

The thermal fatigue analyses of the station’s mechanical components have been identified as time-limited aging analyses.

18.3.2.1 ASME Boiler and Pressure Vessel Code, Section III, Class 1

The ASME Boiler and Pressure Vessel Code, Section III, Class 1 requires a design analysis to address fatigue and to establish limits such that the initiation of fatigue cracks is precluded.

Experience has shown that the transients used to analyze the ASME III requirements are often very conservative. The magnitude and frequency of the design transients are more severe than those occurring during plant operation. The magnitude and number of actual transients are monitored. This monitoring assures that the existing frequency and magnitude of transients are conservative and bounding for the period of extended operation, and that the existing ASME III equipment will perform their intended functions for the period of extended operation. A program for thermal transient cycle counting and analysis is in place and provides reasonable assurance

that the actual transients are smaller in magnitude and within the number of transients used in the design.

Prior to the end of year 40, the fatigue monitoring program will be revised to account for environmentally assisted fatigue using a Staff approved methodology. The present Staff approved methodology re-computes the CUF for the locations listed in NUREG/CR-6260 using the interim fatigue curves found in NUREG/CR-6583 (for carbon and low alloy steels), NUREG/CR-5704 (for austenitic stainless steel), and NUREG/CR-6909 (for carbon/low alloy steels, austenitic stainless steels, and nickel alloys).

Component CUF will be maintained below 1.0. If predictions show CUF could exceed 1.0, further action is required for management of environmental fatigue of the components for the period of extended operation. Fatigue will be managed using one or more of the following options:

1. CUF below 1.0.
2. Further refinement of the fatigue analyses to maintain the environmentally assisted fatigue CUF below 1.0.
3. Repair of the affected locations.
4. Replacement of the affected locations.
5. Manage the effects of fatigue through the use of an augmented in-service inspection program that has been reviewed and approved by the NRC. If this option is selected, the scope, qualification, method, and frequency will be provided to the NRC for review and approval prior to the CUF exceeding 1.0.

18.3.2.2 Leak-Before-Break Analyses

Leak-before-break analyses evaluate postulated flaw growth in the primary loop piping of the Reactor Coolant System. These analyses consider the thermal aging of the cast austenitic stainless steel material of the piping as well as the fatigue transients that drive the flaw growth over the operating life of the plant.

The leak-before-break analyses have been updated to demonstrate that the design is adequate for the extended period of operation, and the analyses are valid for 60 years.

18.3.2.3 ASME Boiler and Pressure Vessel Code, Section III, Class 2 and 3

Piping systems, designed in accordance with ASME Section III, Class 2 and 3 or ANSI B31.1, utilize allowable stress values based on a stress reduction factor to account for thermal cycles during normal operation. Adequate margin is available to account for 60 years of plant operation in the current analyses for the majority of the plant systems reviewed. Restrictions on sampling activities are required on the “B” Reactor Coolant System loop sampling line in order to account for 60 years of plant operation.

18.3.3 Environmental Qualification

The qualification analyses for some electrical equipment included in the Environmental Qualification (EQ) Program have been identified as time-limited aging analyses for license renewal. The qualification analyses for electrical equipment with a 40-year or greater qualified life have been determined as time-limited aging analyses.

Equipment included in the Virgil C. Summer EQ Program will be evaluated to determine if existing environmental qualification analyses can be projected to the end of the period of extended operation by reanalysis or additional analysis. Qualification into the license renewal period is treated the same as for equipment currently qualified at Virgil C. Summer for 40 years or less. When aging analyses cannot justify a qualified life to the end of the period of extended operation then the components or parts will be replaced prior to exceeding their qualified lives in accordance with the EQ Program.

The existing EQ process, in accordance with 10 CFR 50.49, will adequately manage aging of EQ equipment for the period of extended operation.

18.3.4 Reactor Building Tendon Prestress

The Reactor Building was prestressed in order to have low-strain linear response at design loads and thus assure integrity of the liner. The exterior wall is post-tensioned in both vertical and hoop directions. On the dome a three-way post-tensioning system is employed. The pre-stress of the containment tendons decreases over the life of the plant due to elastic deformation, creep, anchorage seating losses, tendon wire friction, stress relaxation and corrosion. Periodic inspections include examination of selected tendon parameters and provide data for prestress analyses. Tendon prestress analyses are used to determine if additional retensioning is required before the next scheduled inspection based on the state of the tendon stress. Therefore reactor building tendon prestress is a time-limited aging analysis.

The existing Tendon Surveillance Program will ensure that the Reactor Building tendons are analyzed for the period of extended operation.

18.3.5 Reactor Building Liner

The Reactor Building is lined on the inside face with a steel plate liner that provides an essentially leak-tight barrier. The liner is designed to remain within strain limits associated with serviceability in accordance with the ASME B&PV for normal operation.

The reactor building liner calculations evaluate liner fatigue for a 40 year period and conclude that the liner meets the criteria of ASME NB 3222.4 (d) for the suitability for cyclic condition and no fatigue analysis is required. The reactor building liner analyses have been revised for the period of extended operation.

18.3.6 Other Plant-Specific Time-Limited Aging Analyses

18.3.6.1 Crane Load Cycle Limit

The crane load cycle limit was identified as a time-limited aging analysis for the cranes within the scope of license renewal. The cranes within the scope of license renewal are listed below.

- Reactor Building Polar Crane
- Fuel Handling Machine (Spent Fuel Pit Bridge and Hoist)
- Refueling Machine (Reactor Cavity Manipulator Crane)
- Spent Fuel Cask Handling Crane

The cranes listed above are classified as Class “A” cranes by the Crane Manufacturers Association of America (CMAA) Specification No. 70 (CMAA 70) which specifies a design limit for the number of load cycles for the life of a crane. The load cycles for these cranes have been evaluated for the period of extended operation. For each crane, the actual usage over the projected life through the period of extended operation will be far less than the analyzed quantity of cycles. All the cranes in the scope of license renewal will continue to perform their intended function through the period of extended operation.

Therefore, the analyses associated with crane design, including fatigue, are valid for the period of extended operation.

18.3.6.2 Service Water Intake Structure Settlement

The Service Water Intake Structure is a reinforced concrete rectangular box culvert with two reinforced concrete wing walls at the intake end. The structure is mostly buried within the West Embankment. The portion not covered with soil is submerged within the Service Water Pond. The function of the Service Water Intake Structure is to draw water from the Service Water Pond into the Service Water Pump House. Excessive non-uniform settlement of the intake structure occurred during construction resulting in cracking of the structure. The settlement of the structure was analyzed based on a plant design life of 40 years. Therefore, Service Water Intake Structure settlement is a time-limited aging analysis for Virgil C. Summer.

The Service Water Intake Structure settlement calculation has been revised to evaluate the settlement of the structure for the period of extended operation.

18.3.6.3 Reactor Coolant Pump Flywheel

The reactor coolant pump motors are provided with flywheels to increase rotational inertia, thus prolonging pump coast-down and assuring a more gradual loss of main coolant flow to the core in the event that pump power is lost. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway from stresses due to starting the motor. An analysis has been performed to estimate the magnitude of fatigue crack growth during the plant life. The analysis assumes 6,000 cycles of pump starts and stops for a 60-year plant life.

The analysis associated with the reactor coolant pump flywheel has been evaluated and determined to remain valid for the period of extended operation.

18.4 REFERENCES

1. RC-02-0123, Letter from SCE&G (S. A. Byrne) to NRC (Document Control Desk) dated August 6, 2002, “APPLICATION FOR RENEWED OPERATING LICENSE”.
2. NUREG-1787 Safety Evaluation Report Related to the License Renewal of the Virgil C. Summer Nuclear Station Docket No. 50-395.
3. Fire Protection (FP) DBD
4. RC-02-0159, Letter from SCE&G (S. A. Byrne) to NRC (Document Control Desk) dated September 12, 2002, “Criteria 2 Supplement to the Application for Renewed Operating License”.